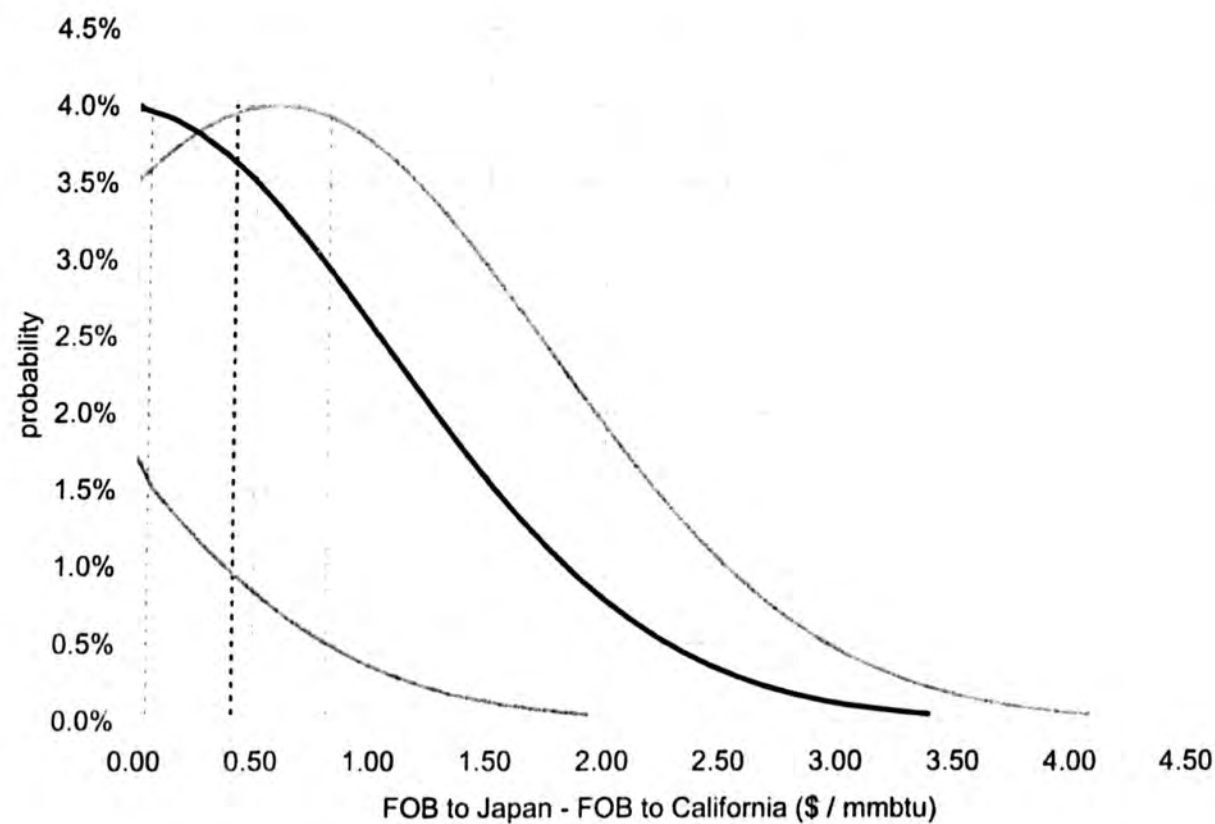


ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672

3107 SCOMM 143: SENATE SPEC.COMM.ON NATURAL GAS DEV. 2005-2006

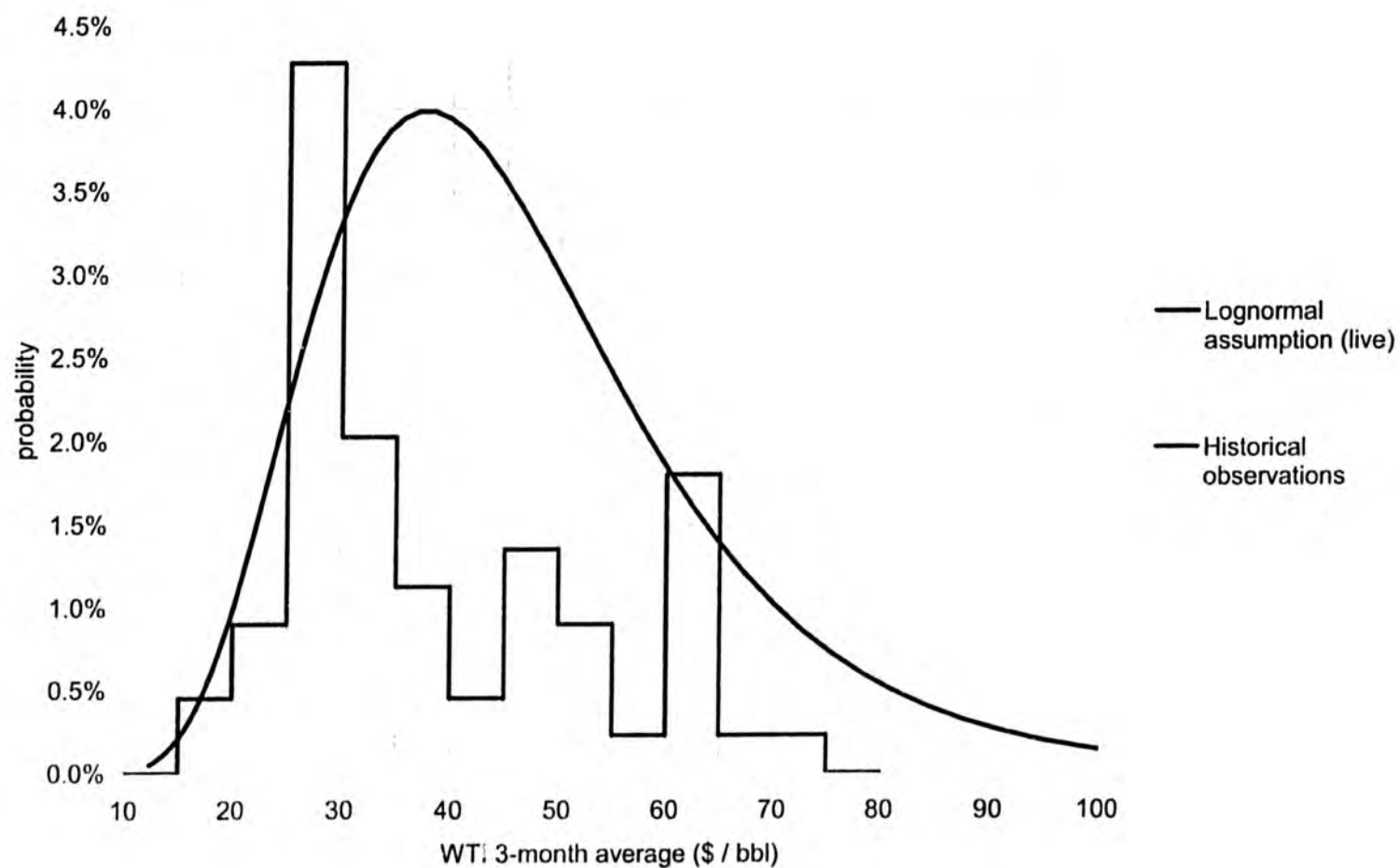
Value of Diversion Option (continued)



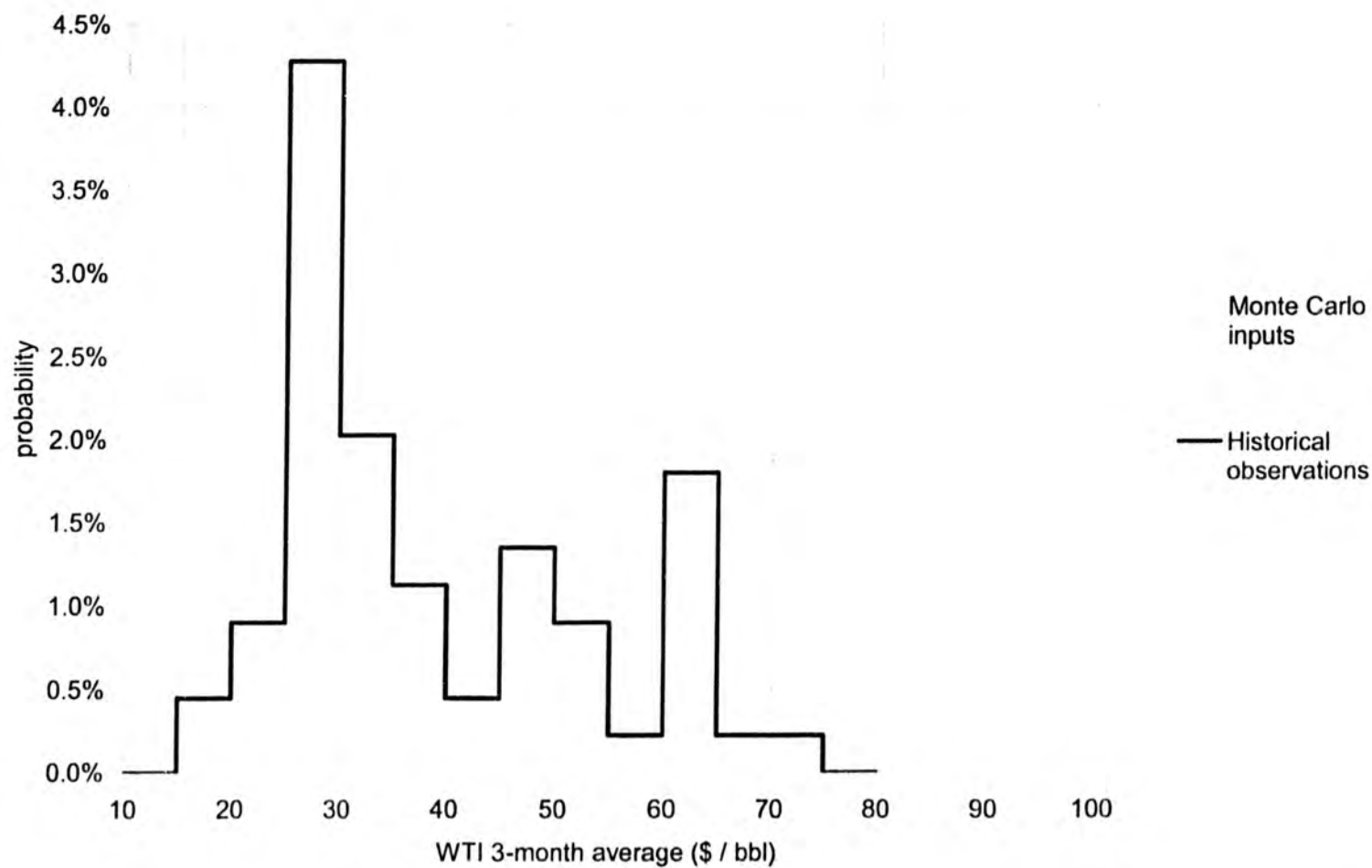
— WTI 3-month avg = \$25.00 / bbl .
 — WTI 3-month avg = \$39.36 / bbl .
 - - - WTI 3-month avg = \$70.00 / bbl .

- - - Expected premium = \$0.81 / mmbtu
 Expected premium = \$0.41 / mmbtu
 Expected premium = \$0.05 / mmbtu

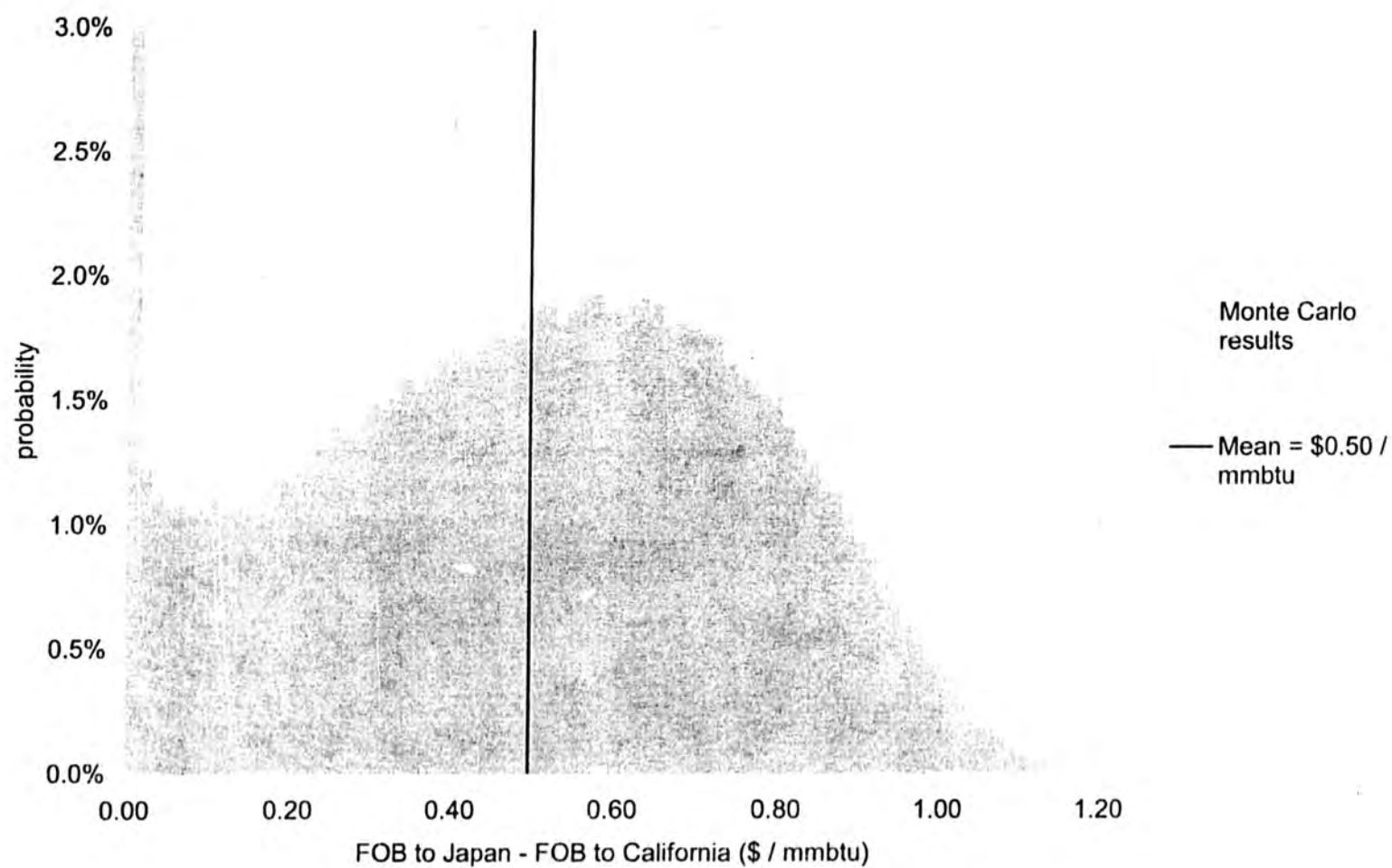
Value of Diversion Option (continued)



Value of Diversion Option (continued)

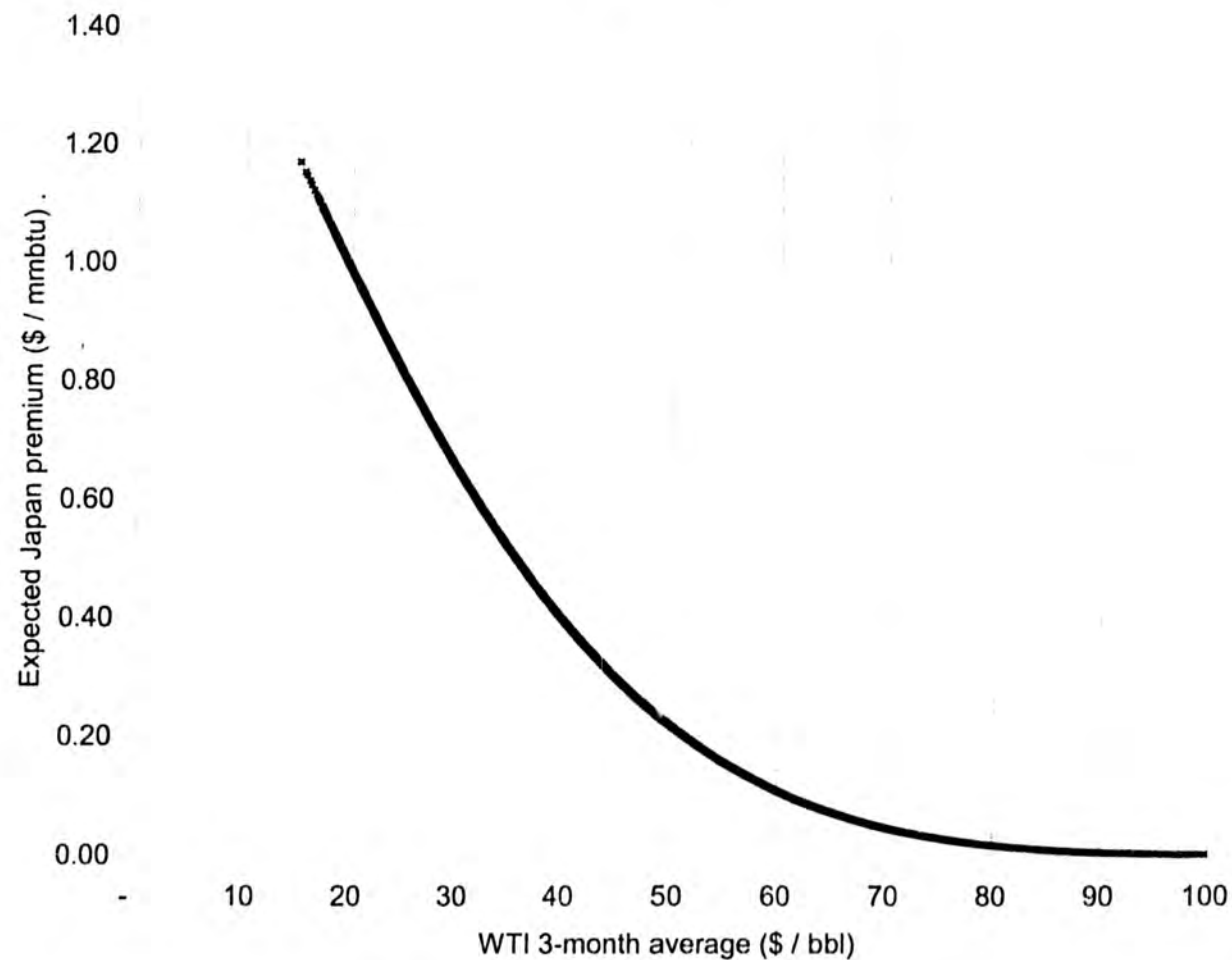


Value of Diversion Option (continued)



Value of Diversion Option (continued)

@RISK runs



Producer Returns With Diversion Optionality

- The diversion option value enhances the upstream returns significantly
- Upstream Producer returns with option value (Base Case prices)
 - NPV @ 12% discount rate: \$2.2 billion (increase of \$0.5 billion)
 - IRR: 31.9%
- The diversion option reduces the breakeven threshold price
 - breakeven HH price without diversion option: \$4.30 per mmBtu
 - breakeven HH price with diversion option: \$3.74 per mmBtu



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Economics of Y-Line Expansion

Producer Returns and State NPV with Y-Line

- It is assumed that the Highway Project commences operations in 2016
- Producer NPV
 - standalone LNG Project (2012): \$2.2 billion
 - standalone Highway Project (2016): \$10.8 billion
 - Y-Line (1.2 Bcf/d in 2012 + 4.3 Bcf/d in 2016): \$13.1 billion
- Netback price for the Highway Project improves from \$4.23/mmBtu to \$4.34 in 2012 (nominal terms) due to cost savings associated with shared line
- State NPV @ 7% discount rate, assuming status quo fiscal regime
 - standalone LNG Project (2012): \$5.1 billion
 - standalone Highway Project (2016): \$16.5 billion
 - Y-Line (1.2 Bcf/d in 2012 + 4.3 Bcf/d in 2016): \$21.8 billion



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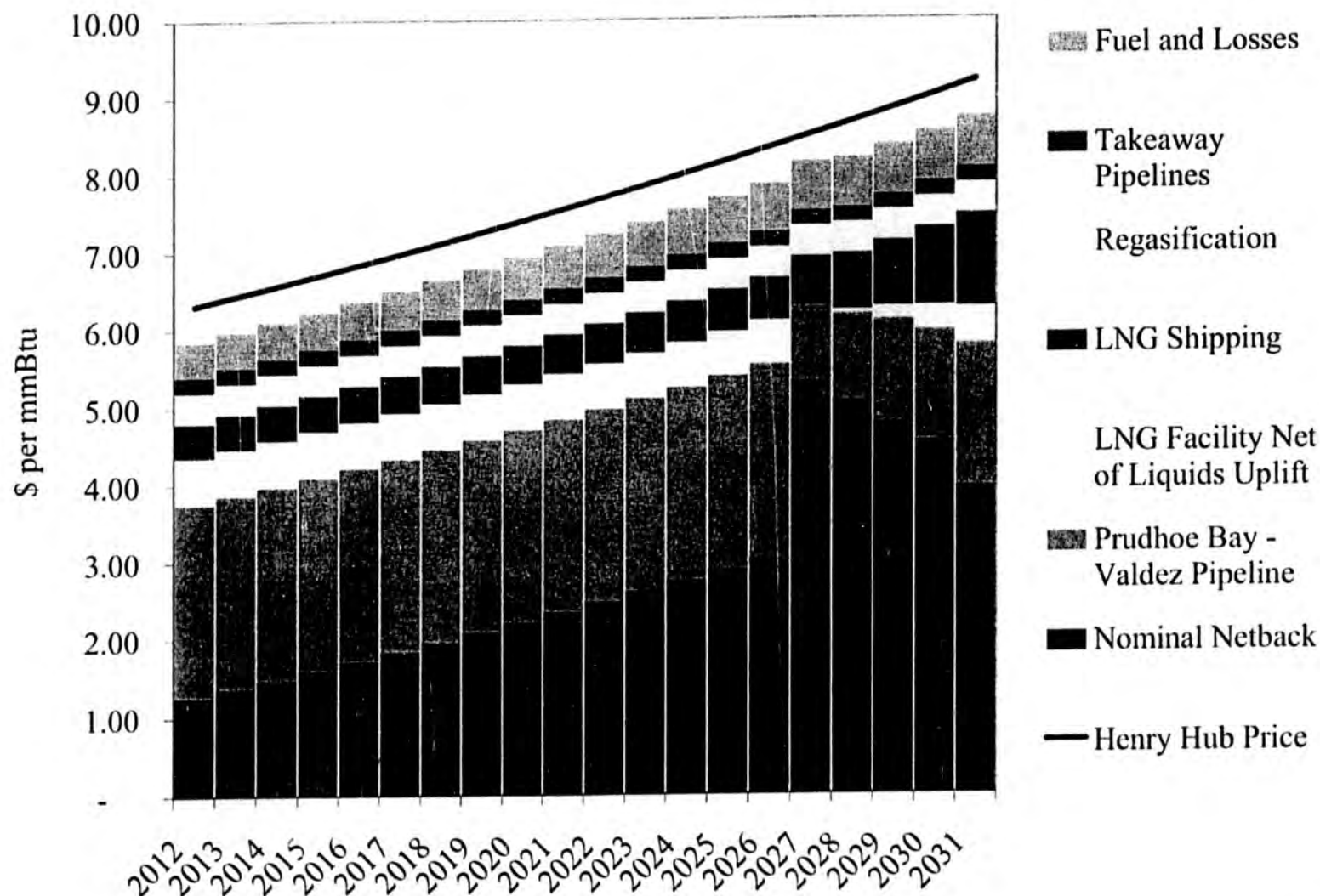
Sensitivity Case: Point Thomson Only

Scenario Description

- Only PTU is made available to supply project
- Case is analogous to LNG stand-alone project, but with slightly lower volume and shorter project life
- Does not take into account economics of liquids/condensates from PTU
- Assumed that production is curtailed when wellhead netback becomes negative due to production decline
- Without counting the value of the diversion option, negative wellhead netback occurs after 22 years of production
- Midstream capital is assumed to be repaid in 15 years, when production decline sets in, with about 20% of PTU remaining



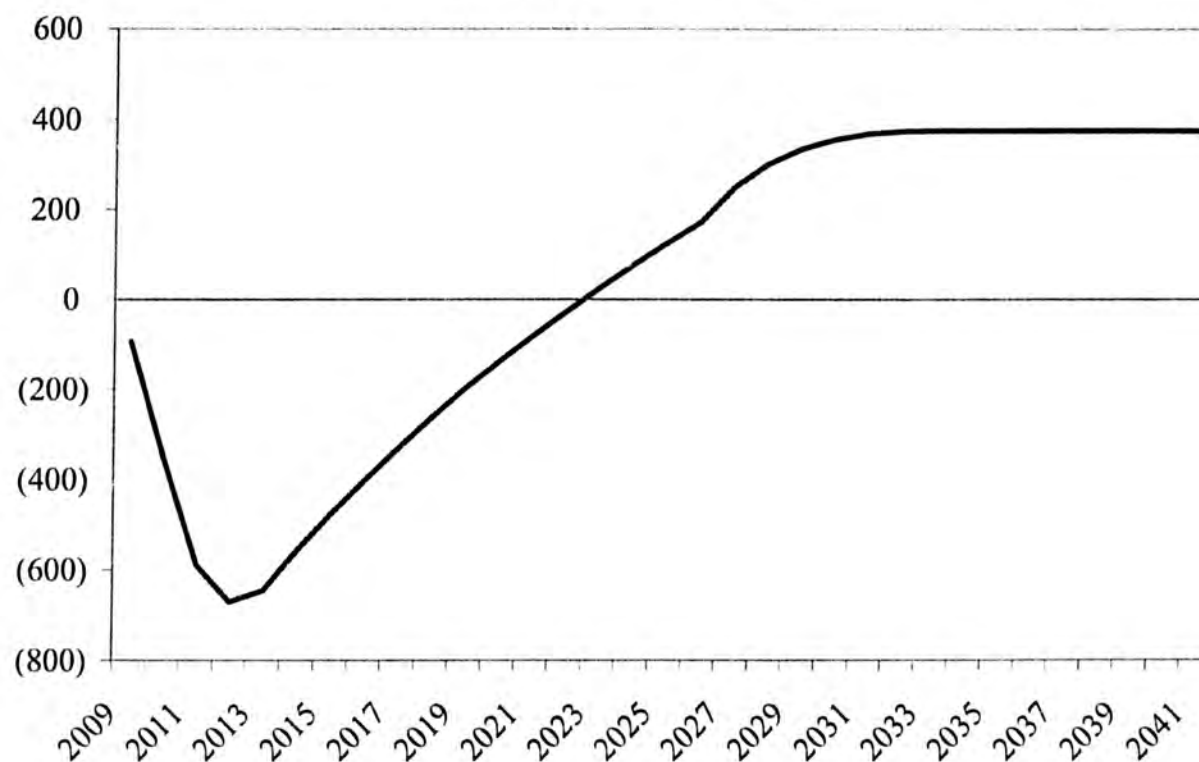
PTU Only: Nominal Netback Price at Pipeline Inlet (No Option)



PTU Case: Base Case Producer Returns (No Diversion Option Value)

- Upstream Producer returns at the Base Case Henry Hub price of \$5.50/mmBtu
 - NPV @ 12% discount rate: \$375 million
 - IRR: 17.1%

Producer Upstream NPV@12



- Discounted payback is achieved – after 12 years of operations



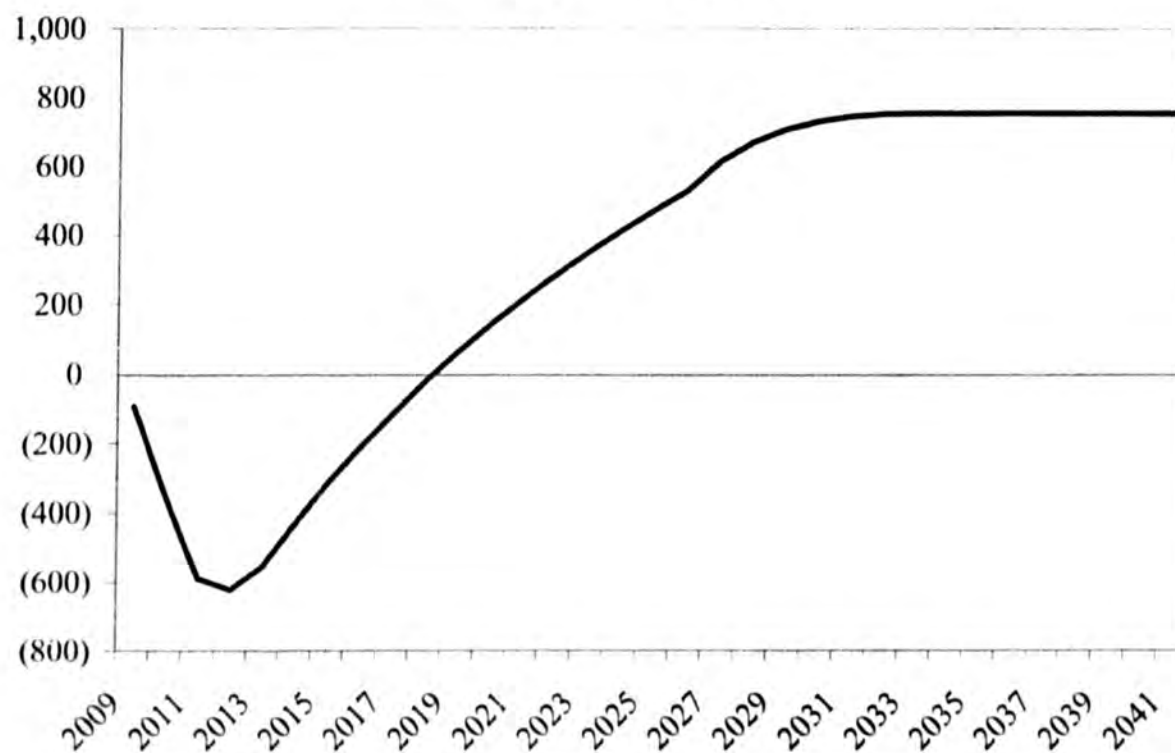
PTU Case: Sensitivity of Producer Returns (No Diversion Option Value)

- Producer upstream returns at the high price scenario (\$7.70/mmBtu Henry Hub and \$70/bbl WTI):
 - NPV @ 12% discount rate: \$2.7 billion
 - IRR: 46.8%
- The breakeven Henry Hub price (at which the Producer IRR equals 12%) is \$5.26/mmBtu

PTU Case: Base Case Producer Returns (With Option Value)

- Upstream Producer returns at the Base Case Henry Hub price of \$5.50/mmBtu
 - NPV @ 12% discount rate: \$753 million
 - IRR: 22.4%

Producer Upstream NPV@12



- Discounted payback is achieved – after 8 years of operations

PTU Case: Sensitivity of Producer Returns (With Option Value)

- Producer upstream returns at the high price scenario (\$7.70/mmBtu Henry Hub and \$70/bbl WTI):
 - NPV @ 12% discount rate: \$2.8 billion
 - IRR: 47.5%
- The breakeven Henry Hub price (at which the Producer IRR equals 12%) is \$4.67/mmBtu
- The sensitivity results above understates the true economics of the PTU-only case because:
 - condensates and NGL are excluded
 - midstream capital cost is not optimized for reduced volume
 - LNG vessel fleet is not optimized for reduced volume

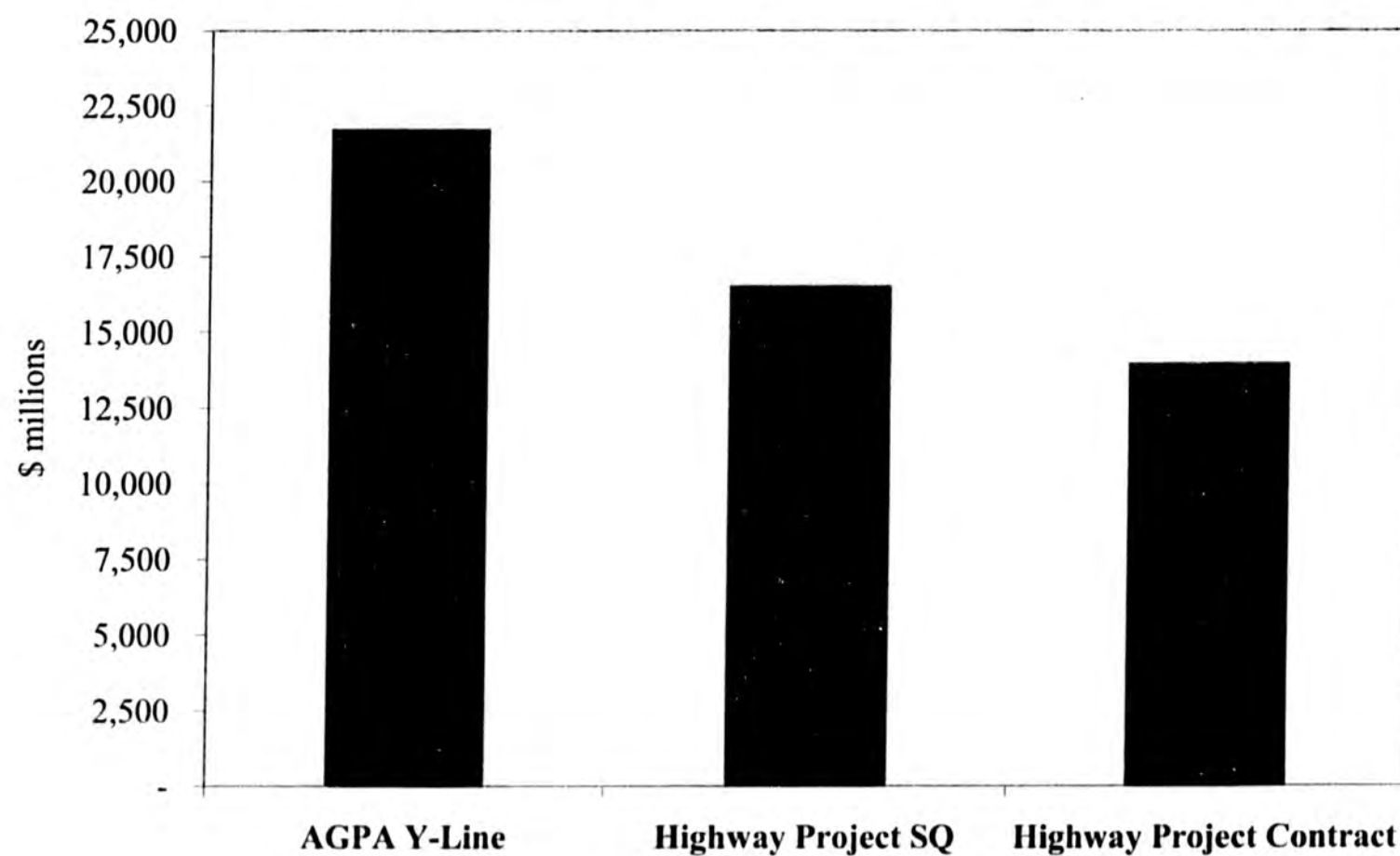


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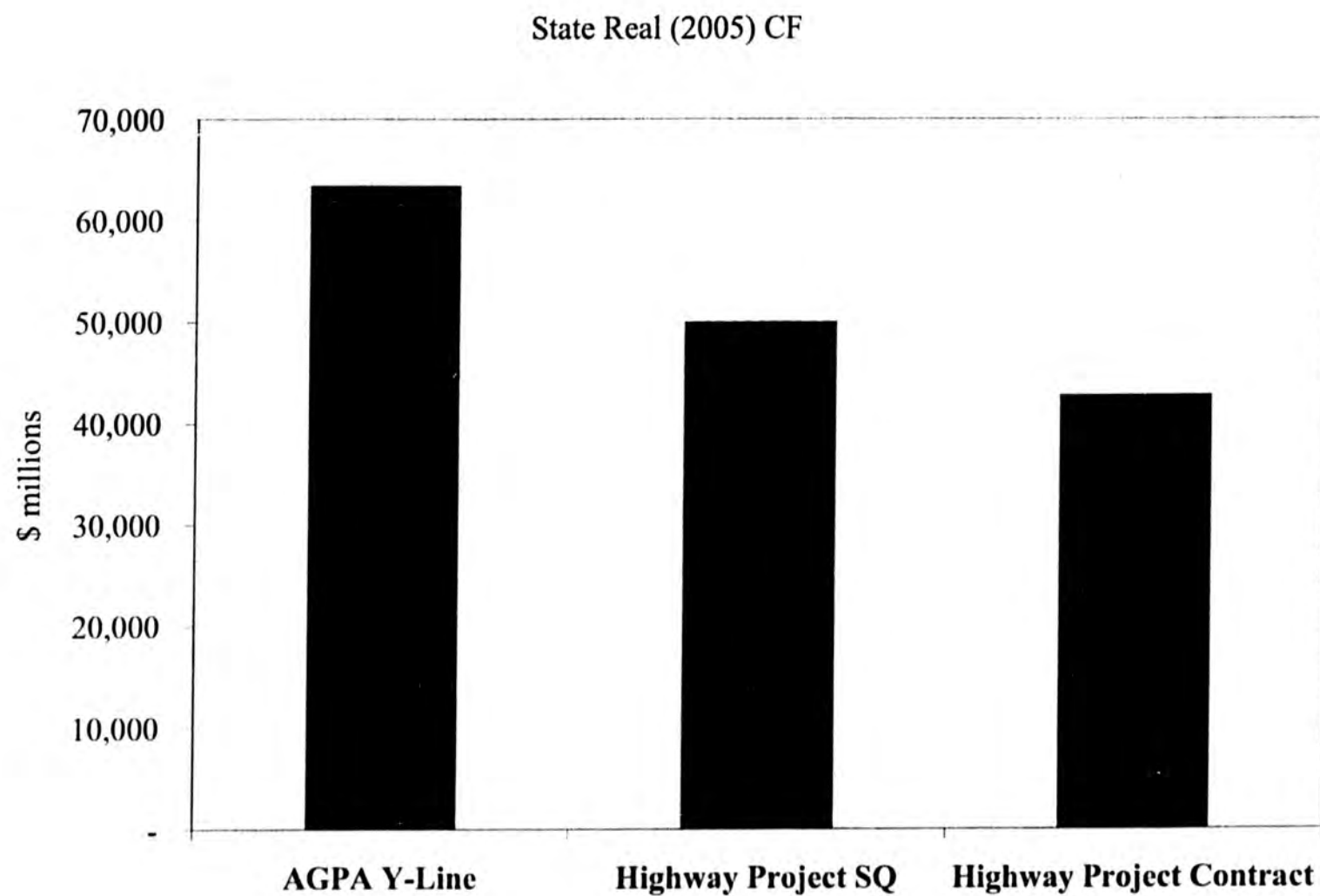
Comparison of State Revenues

Comparison of State NPV

State NPV@7%



Comparison of State Real Cash Flows (2005 dollars)





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Conclusions / Questions

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STATE OF ALASKA

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MEMORANDUM

August 1, 2006

SUBJECT: Amendment #2 to CSSB 3002(NGD)
(Work Order No. 24-GS2095\G)

TO: Senator Donny Olson
Senator Hollis French

FROM: Dennis C. Bailey *DCB*
Legislative Counsel

The following are answers to your questions pertaining to Amendment #2 to CSSB 3002, submitted by Senator Ben Stevens to the Special Committee on Natural Gas Development.

1. *Does the amendment approve the contract without a public vote?*

The text of sec. 24, prepared to be added by amendment #2, reads as follows:

Sec. 24. The uncodified law of the State of Alaska is amended by adding a new section to read:

APPROVAL AND RATIFICATION. The provisions of the Alaska Stranded Gas Fiscal Contract between the State of Alaska and BP Exploration (Alaska) Incorporated, ConocoPhillips Alaska, Incorporated, and Exxon Mobil Alaska Production, Incorporated as amended to conform to the provisions of this Act, are approved and ratified.

Section. 24 confers legislative "approval and ratification" of the fiscal contract. It is not clear whether this is synonymous with the concept of "authorization to execute" under the Stranded Gas Development Act (SGDA) but that seems to be a reasonable conclusion since one would not normally authorize or ratify without approving the contract. One might ask why, if the approvals were intended to be identical, was identical language not used. In my judgment, the legislative act of approving and passing sec. 24 would confer "legislative approval" of the contract.

Sec. 24 becomes effective immediately. It conflicts with the language in sec. 26 which requests an advisory vote to determine whether the commissioner shall sign and make binding the fiscal contract. Based on the immediate effective date of sec. 24 and assuming both enactment and amendments conform to sec. 24, the contract would already have been authorized. Nothing in the amendment attempts to make these provisions

consistent. The effective date of sec. 24 is not contingent on the election proposed in sec. 26. Further, nothing in the amendment says that the commissioner should withhold signature pending certification of election results, or that tells him to stay or withhold his signature if the public vote on the issue is negative.¹

Sec. 14 of the amendment also appears to allow the commissioner to sign the contract within 30 days following the close of the public comment period set out in AS 43.82.430. Sec. 14 is also effective immediately.

In short, both sec. 14 and sec. 24 arguably approve or permit approval without a popular vote.

2. Are the results of the public vote binding?

Sec. 26 requires a vote by the electorate regarding whether the commissioner should sign the fiscal contract and make it binding on the state. The outcome may turn on whether the vote is advisory or binding. Although the vote is characterized in its title as "advisory," the text of the question may be considered "binding."² This distinction may make a difference in a court's analysis concerning whether a public vote on an issue is allowed. The question has not been considered by a court in this state.³

This question is closely related to whether the legislature may submit legislation to the public for a vote.

State general law does not address the issue of advisory votes. In the past, the legislature has placed several advisory votes on the ballot. In 1976 an advisory question on unicameralism was placed on the ballot, in 1978 an advisory vote on limiting the legislation session to 120 days was placed on the ballot, and in 1986 an advisory vote on the longevity bonus annuity program was placed on the ballot. In each of these instances a statute was enacted that required that the questions appear and they were voted on during general elections. In 1999, there was an advisory vote on the use of permanent

¹ A similar difficulty exists between the immediate effective date for sec. 25 contained in sec. 30, and the delayed effective date for sec. 25 (effective following certification of the advisory vote) contained in sec. 27.

² Similarly, sec. 27 of the bill apparently provides for sec. 25 to take effect following certification of the November general election. Sec. 25 arguably has the effect of making AS 43.82.200 - 43.82.270 inoperative, and may further be considered to render ineffective all of AS 43.82. The language of sec. 27 appears to be mandatory.

³ In one circumstance, a law has been submitted to the voters for a binding vote, and, so far as I can tell, that action was never challenged. That law was ch. 211, SLA 1968, establishing a system of voter registration.

fund investment earnings to balance the state budget that was presented through approval of a special act and voted on at a special election held in September of that year.

In other contexts, the attorney general has reached the conclusion and is of the opinion that the Alaska Supreme Court would uphold a delegation of legislative power to the people, at least when the topic is not appropriation, Attorney General Opinion J66-479-82 (Feb. 9, 1982) and Attorney General Opinion J66-545-82 (April 23, 1982), and the courts would seem to give due respect to that office's conclusion:

While opinions of the attorney general are not controlling as to the meaning of the statute the fact that his opinions have not been challenged and that he is the officer charged by law with advising the officers charged with the enforcement of the law as to the meaning of it, entitle his opinions to great weight. (internal cites omitted)

Allison v. State, 583 P.2d 813, 816, n.15 (Alaska 1978)

However, it is possible that a provision of a bill making the Act effective only if approved by the voters would be held unconstitutional because such a referendum is not specifically authorized by the state constitution. Section 1 of Article II of the Constitution of the State of Alaska provides that the legislative power of the state is vested in the legislature. Laws may be enacted in Alaska in two ways: by the legislature acting under the power vested in it by Article II and by the people acting under the power of initiative and referendum as established in Article XI.

The constitution provides the method for proposing an initiative or referendum in sections 1, 2, and 3 of Article XI:

SECTION 1. The people may propose and enact laws by the initiative, and approve or reject acts of the legislature by the referendum. (Emphasis added)

SECTION 2. An initiative or referendum is proposed by an application containing the bill to be initiated or the act to be referred. The application shall be signed by not less than one hundred qualified voters as sponsors, and shall be filed with the lieutenant governor. If he finds it in proper form he shall so certify. Denial of certification shall be subject to judicial review.

SECTION 3. After certification of the application, a petition containing a summary of the subject matter shall be prepared by the lieutenant governor for circulation by the sponsors. If signed by qualified voters, equal in number to ten per cent of those who voted in the preceding

general election and resident in at least two-thirds of the election districts of the State, it may be filed with the lieutenant governor.

Since the constitution reserves the power of initiative and referendum to the people, the legislature may not usurp that power. A court might well hold that the method for exercising the power of initiative and referendum set out in those sections is exclusive.

In U.S. v. Northern Commercial Co., 6 Alaska 94 (1918), the territorial legislature provided that an act be submitted to a referendum vote of the people. The court struck the act down, holding that neither the organic law creating the legislature, nor any other Act of Congress authorized the submission of such an act to the popular vote. In People v. Barnett, 176 N.E. 108 (Ill. 1931), the court struck down a statute on similar grounds. The court concluded that the legislature alone has the power, duty, and responsibility to legislate.

Under the constitution of the State of Alaska, I think it likely that the courts would hold that neither the governor nor the legislature is authorized to submit an act to the popular vote for binding effect. This conclusion is bolstered by the fact that the delegates to the Alaska Constitutional Convention considered and rejected a proposal that would have authorized bills to be referred to the voters.

Section 21 of Committee Proposal 5, dated December 14, 1955, stated:

SECTION 21. Any bill failing of passage by the legislature may be submitted to referendum by order of the governor either in its original form or with such amendments which were considered by the legislature, as he may designate. Any bill which, having passed the legislature, is returned thereto by the governor with objections, and, upon reconsideration is not approved by the majorities required by this constitution, may be submitted to referendum by a majority of all the members sitting as one body. Bills thus submitted to referendum shall be voted on at the next succeeding regular election occurring at least sixty days after action is taken to submit them, unless the legislature shall provide for their submission at an earlier date. This section shall not apply to bills containing appropriations, raising or earmarking revenues, nor to local or special bills.

This section on legislative referendum was considered by the delegates as a body on January 11, 1956, recorded at pages 1737, 1777-1778, Minutes of the Daily Proceedings, Alaska Constitutional Convention. In explaining the intent of Section 21, Committee Proposal 5, Delegate McCutcheon stated at page 1777 of the Proceedings:

MCCUTCHEON: The terminology is taken directly out of the model constitution. The point is that at the time our Committee was drafting this

particular section, or considering it I should say, there was some doubt in my mind, and I think in the minds of others on our Committee, that there may not be an initiative device in the constitution. With the initiative device, this certainly may be stricken in toto. You do have initiative protection. This device was placed in the legislative article in the event that there was no initiative. It was a device that was designed to get good legislation out before public opinion to react on, but since there is an initiative device, the public can take any bill that is offered in the legislature and put it as an initiative measure.

Based on Delegate McCutcheon's statement, Delegate Gray moved to delete Section 21, stating at page 1778:

Taking Mr. McCutcheon's suggestion and word, that if this article is unnecessary, if it is already cured by initiative, why I'll make a motion to strike Section 21 because it is superfluous.

Delegate Gray's motion carried, indicating that the Alaska Constitution does not allow the governor or the legislature to refer legislation to a popular vote for binding effect.

Except for the areas in which the Constitution expressly authorizes submission of questions to the voters, the legislature arguably may not constitutionally avoid its responsibility and the requirements of section 2 of Article XI of the Constitution by placing questions on the ballot for a decision of the voters, particularly when the vote is binding.

The proposed question for approval of the fiscal contract to the voters may be considered a binding vote or merely an advisory vote. If it is the former, in my view, it is disfavored; if the latter, it is more likely to survive judicial scrutiny. While there may be a difference of opinion as to the outcome of litigation on this question, there appears to be little doubt that the question is an open one in this state and any legislation providing for a binding vote of the people would be subject to legal challenge.

3. Are there any grounds remaining for a statutory challenge to the contract under the amendment?

Sec. 25 states that after a contract is amended to conform with CSSB 3002, its terms are effective notwithstanding any other law or AS 43.82.200 - 43.82.270, (the Stranded Gas Development Act sections related to contract development). Sec. 25 also states that any inconsistency between the Stranded Gas Development Act and the fiscal contract are "cured and authorized" by sec. 25. This language could preclude legal challenges and application of the Stranded Gas Development Act to the fiscal contract.

Senator Donny Olson
Senator Hollis French
August 1, 2006
Page 6

4. *Is the "approval and ratification" provision of sec. 24 equivalent to giving the governor authority to execute the contract under AS 43.82.435.*

Approval and ratification under sec. 24 differs from SGDA approval. The SGDA now requires the commissioner to summarize comments, list proposed amendments, if any, and make final findings before submitting the contract to the governor. AS 43.82.430. If the commissioner's actions are not completed before sec. 24 is enacted, the approval and ratification action probably does not comply with the SGDA. Assuming the approval does not comply with the SGDA, sec. 25 of the bill is apparently included in order to "cure and authorize" any inconsistency between the SGDA and the fiscal contract.

5. *Under sec. 25 of the amendment is there any requirement for the state to abide by the provisions of the Stranded Gas Development Act?*

As discussed in under item 3 above, any requirement to comply with the Stranded Gas Development Act would be overcome by the provision in sec. 25 stating that the approval of the contract is effective notwithstanding any other law combined with the provision that any inconsistency between the Stranded Gas Development Act and the fiscal contract is cured and authorized.

6. *Is there anything in the amendment that is statutorily or constitutionally problematic.*

It is not clear from the language of sec. 24 whether the existing contract or an amended contract would receive approval. Although sec. 24 appears to approve the fiscal contract in its existing state, this section requires the contract receiving approval and ratification to conform to CSSB 3002, i.e., "this Act." Apparently, after CSSB 3002 is enacted, the parties could, or must, revise the contract to conform to CSSB 3002. Only then would the contract be approved and ratified. By approving the fiscal contract under sec. 24 with the amendment provision, the legislature may be approving and ratifying a contract with terms to which the parties have not agreed. The legislature would effectively be agreeing to a contract that is not in final form.

Sec. 24 does not address what would happen to the contract if it does not conform to the provisions of CSSB 3002 or if certain provisions did not conform to CSSB 3002.

If I may be of further assistance, please advise.

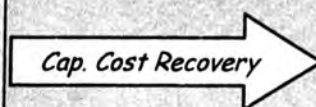
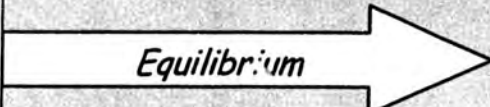
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Oil Tax Fiscal Certainty

SB 2004

Amendment #4

25 Years

	Contract Effective Date	"4" years +/-	Project Sanctioning	"5" Years +/-	Build to First Gas	9 years fixed	Capital Cost Recovery Complete	Remaining years <u>equals</u> 25 years <u>minus</u> ("Pre-build" years) <u>minus</u> ("Capital Cost Recovery" years)
								
Period Description		Design Permit Pre-build		Procure and Build		Capital Cost Recovery		Stabilization
Oil Tax Certainty		<u>None</u> Dependent on gasline progress		<u>Fixed</u> oil tax certainty "PPT"		<u>Fiscal Stabilization</u> ("Material change" criteria)		
Comment						<u>Firm Transportation Commitments (FT)</u> are typically 20 year contracts		If oil taxes change, gas taxes may be adjusted to maintain "fiscal stability".

Unions say labor agreement needed for gas line

By Melissa Campbell
Alaska Journal of Commerce
Publication Date: 07/30/06

Union leaders met with the governor recently asking him to add to the proposed gas pipeline contract language that would commit producers to hire organized labor for pipeline construction.

Union leaders told the governor during the meeting, held July 12, that they want assurances through a project labor agreement, or PLA, to be written in the fiscal contract for the \$25 billion project.

"We believe they are going to have to have a PLA to build the pipeline," Jim Sampson, president of the Alaska AFL-CIO, said during an interview. "We'd like to see some recognition, on a project that will require 54 million man hours of work, that they are going to have to seek or secure a labor agreement."

Representatives from the major oil and gas producers and the state say they don't argue the fact that they will need a PLA and know they will need union workers to build the pipeline. But, they say, now is not the time.

"Those discussions can happen when a fiscal contract is approved," said Dave MacDowell, spokesman for BP's gas pipeline team.

"It is premature to enter into any detailed PLA negotiations and, in fact, there would not be a reason for a PLA unless the project can proceed as a result of agreement on the fiscal contract with the state," ConocoPhillips spokeswoman Natalie Knox said in an e-mail to the Journal. "ConocoPhillips is discussing the project with local union representatives and will continue to do so."

State Department of Labor Commissioner Greg O'Claray said some reference to a PLA likely will be added to the fiscal contract, but noted that the fiscal document is not a construction contract. That's where the finer details of building the line should be laid out.

"We're waiting on language from union leaders now," O'Claray said July 20. "We may not mandate a PLA, but we can reference it."

State legislators are considering the fiscal contract in the year's second special session, which began July 13. Lawmakers failed to come to agreement on a contract and on special tax considerations in the first special session, held in June.

If approved, it will take 8,000 to 10,000 workers to build a gas pipeline - the largest private construction project ever conceived - and there's no doubt

unions will be involved.

More than a half-dozen organized labor halls would be called, including Laborers, Pipefitters, Welders, Teamsters and Operating Engineers, among others. Workers will also be needed for support services, such as caterers, carpenters, maintenance and camp services, to name a few.

Project labor agreements typically are formed between unions and project owners. Assuming a gas line is approved in the political process, the owners - the state of Alaska in partnership with producers BP, ConocoPhillips and Exxon Mobil - will form an organization to oversee the construction and maintenance of the pipe.

That organization would be much like Alyeska Pipeline Service Co., formed in the 1970s to build and maintain the trans-Alaska oil pipeline system.

Representatives from that organization should be the ones to develop a project labor agreement with union labor, the producers and state said.

Labor agreements have their advantages for everyone involved. Owners can lay out strict rules deterring work stoppages and set timelines, which could keep cost overruns down. Labor can lay out wages and conditions, setting standards to keep workers happy on the job.

Perhaps most importantly, both sides say, a PLA can set a standard for Alaska hire preferences. Gov. Frank Murkowski has set a goal for 90 percent Alaska hire for the project, and a PLA is the only method of setting such a standard that has been backed by the U.S. Supreme Court, O'Claray said.

"We want to make sure every Alaskan who desires to work on the project has the opportunity," he said. "I'd like to see Alaskans work in however a way it takes to get there."

Depending on how it's written, a PLA could preclude nonunion workers from the project. That could mean that Alaskans would have to join a union.

Some labor leaders want a PLA that requires union-only labor, both for the construction and the support jobs.

"It would offer a health package, a pension and training," said Bob Morigeau, the Anchorage-area representative for the Operating Engineers Local 302.

"How can anyone argue that that's a bad thing? If you're covered, it covers your whole family. We're not out for highway robbery, we're trying to generate a prevailing wage."

Barring nonunion workers would be unfair, said Rebecca Logan, president of the Associated Builders and Contractors, a trade group that represents nonunion employers.

"It's discriminatory to give unions the exclusive right to represent all

employees," she said. "It didn't work on (the trans-Alaska oil pipeline), and it won't work with this."

Requiring union labor may also keep strong Alaska nonunion companies, such as portions of VECO Corp. and Udelhoven Oilfield System Services Inc., off the job, Logan said.

Not only that, she added, those who join a union to work on the gas line may not be employed long enough to be vested, meaning payments into health and pension plans may be lost.

AFL-CIO's Sampson said a labor agreement wouldn't necessarily limit the project to unionized labor.

"All contractors, union or nonunion, should be able to bid on a project," he said. "It should be a union project, but not preclude nonunion. All people should have a chance to work."

Regardless, those in the industry say that some non-Alaskans will have to be called no matter what. There just won't be enough trained, qualified Alaskans to fill the jobs.

"The hiring will be done in Alaska halls, but we all know we're not going to be able to supply all the workers in Alaska," said Morigeau of the Operating Engineers.

The contract should also have a provision stating the owners will hire Alaska contractors, industry leaders say.

"There's nothing in the contract that's even talking about using Alaska employers. If you want to use Alaska hire, use Alaska employers," said Dick Cattanach, executive director of the trade organization Associated General Contractors of Alaska, whose members are both union and nonunion. "They are up here, they train workers, they know the environment."

Without some requirement to hire Alaska contractors, large international companies, like Halliburton or Bechtel, may end up with the work.

"They are opportunists," Cattanach said. "They don't care about Alaska."

Melissa Campbell can be reached at

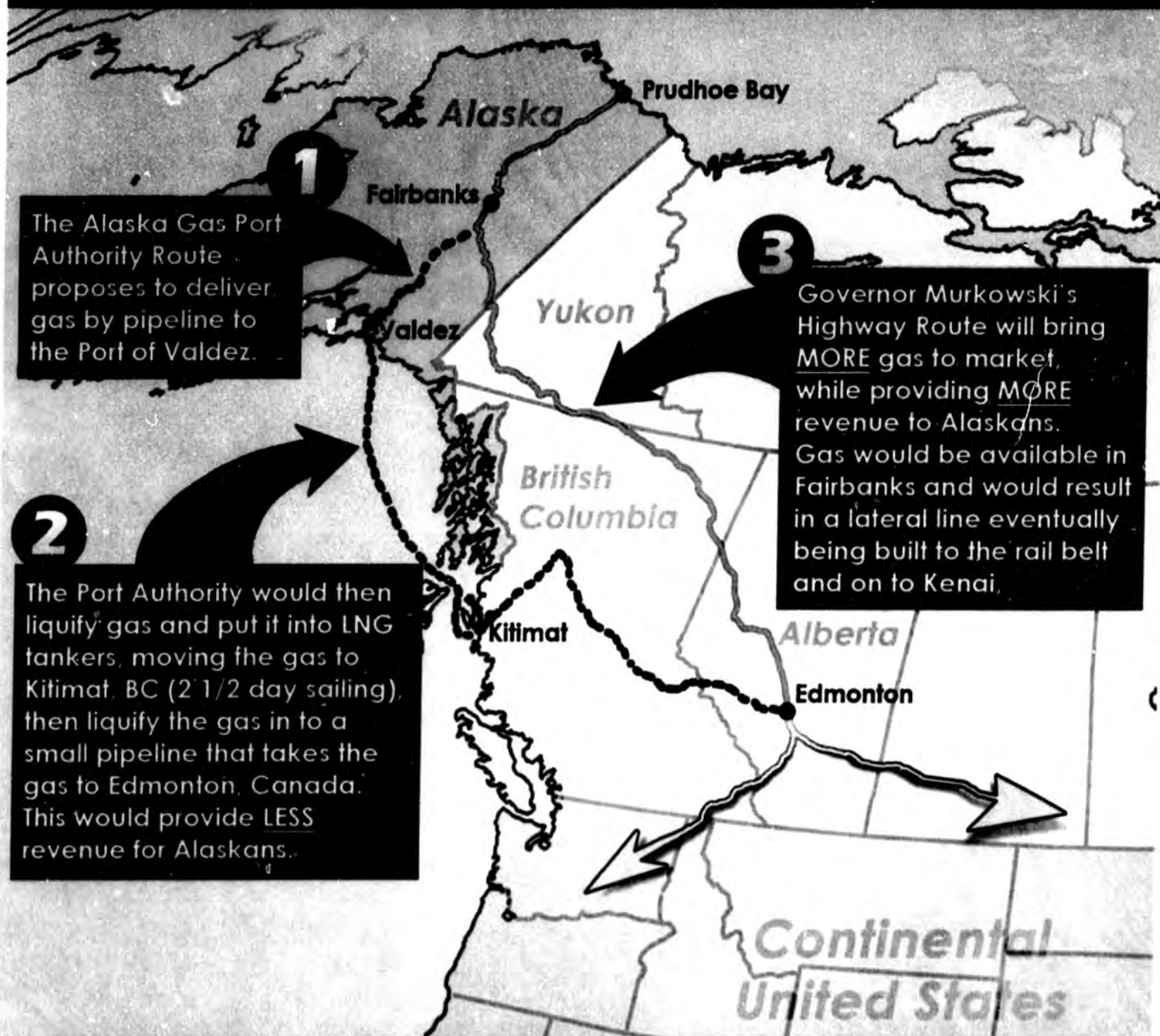
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A GAS PIPELINE FOR ALL ALASKANS



So which project is really the ALL ALASKA LINE?

Every project was examined at great length, and only one showed the merits Alaskans deserve. The Alaska Highway Route....a project that will provide the MOST revenue for ALL Alaskans, a pipeline that will provide jobs for ALL of us and our children, the dawning of a new age in Alaska.

The Alaska Highway Route is truly the pipeline to Alaska's Future.

PUBLIC LAW 109-58—AUG. 8, 2005

ENERGY POLICY ACT OF 2005

(Amendments to Natural Gas Act and Natural Gas Policy Act of 1978)

license, concurrence, or approval (hereinafter collectively referred to as 'permit') required under Federal law, other than the Coastal Zone Management Act of 1972 (16 U.S.C. 1451 et seq.).

"(2) AGENCY DELAY.—The United States Court of Appeals for the District of Columbia shall have original and exclusive jurisdiction over any civil action for the review of an alleged failure to act by a Federal agency (other than the Commission) or State administrative agency acting pursuant to Federal law to issue, condition, or deny any permit required under Federal law, other than the Coastal Zone Management Act of 1972 (16 U.S.C. 1451 et seq.), for a facility subject to section 3 or section 7. The failure of an agency to take action on a permit required under Federal law, other than the Coastal Zone Management Act of 1972, in accordance with the Commission schedule established pursuant to section 15(c) shall be considered inconsistent with Federal law for the purposes of paragraph (3).

"(3) COURT ACTION.—If the Court finds that such order or action is inconsistent with the Federal law governing such permit and would prevent the construction, expansion, or operation of the facility subject to section 3 or section 7, the Court shall remand the proceeding to the agency to take appropriate action consistent with the order of the Court. If the Court remands the order or action to the Federal or State agency, the Court shall set a reasonable schedule and deadline for the agency to act on remand.

"(4) COMMISSION ACTION.—For any action described in this subsection, the Commission shall file with the Court the consolidated record of such order or action to which the appeal hereunder relates.

"(5) EXPEDITED REVIEW.—The Court shall set any action brought under this subsection for expedited consideration."

SEC. 314. PENALTIES.

(a) CRIMINAL PENALTIES.—

(1) NATURAL GAS ACT.—Section 21 of the Natural Gas Act (15 U.S.C. 717t) is amended—

(A) in subsection (a)—

(i) by striking "\$5,000" and inserting "\$1,000,000";

and

(ii) by striking "two years" and inserting "5 years";

and

(B) in subsection (b), by striking "\$500" and inserting "\$50,000".

(2) NATURAL GAS POLICY ACT OF 1978.—Section 504(c) of the Natural Gas Policy Act of 1978 (15 U.S.C. 3414(c)) is amended—

(A) in paragraph (1)—

(i) in subparagraph (A), by striking "\$5,000" and inserting "\$1,000,000"; and

(ii) in subparagraph (B), by striking "two years" and inserting "5 years"; and

(B) in paragraph (2), by striking "\$500 for each violation" and inserting "\$50,000 for each day on which the offense occurs".

(b) CIVIL PENALTIES.—

(1) NATURAL GAS ACT.—The Natural Gas Act (15 U.S.C. 717 et seq.) is amended—

- (A) by redesignating sections 22 through 24 as sections 24 through 26, respectively; and
- (B) by inserting after section 21 (15 U.S.C. 717t) the following:

15 USC
717u-717w.

“CIVIL PENALTY AUTHORITY

“SEC. 22. (a) Any person that violates this Act, or any rule, regulation, restriction, condition, or order made or imposed by the Commission under authority of this Act, shall be subject to a civil penalty of not more than \$1,000,000 per day per violation for as long as the violation continues.

15 USC 717t-1.

“(b) The penalty shall be assessed by the Commission after notice and opportunity for public hearing.

“(c) In determining the amount of a proposed penalty, the Commission shall take into consideration the nature and seriousness of the violation and the efforts to remedy the violation.”

(2) NATURAL GAS POLICY ACT OF 1978.—Section 504(b)(6)(A) of the Natural Gas Policy Act of 1978 (15 U.S.C. 3414(b)(6)(A)) is amended—

(A) in clause (i), by striking “\$5,000” and inserting “\$1,000,000”; and

(B) in clause (ii), by striking “\$25,000” and inserting “\$1,000,000”.

SEC. 315. MARKET MANIPULATION.

The Natural Gas Act is amended by inserting after section 4 (15 U.S.C. 717c) the following:

“PROHIBITION ON MARKET MANIPULATION

“SEC. 4A. It shall be unlawful for any entity, directly or indirectly, to use or employ, in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to the jurisdiction of the Commission, any manipulative or deceptive device or contrivance (as those terms are used in section 10(b) of the Securities Exchange Act of 1934 (15 U.S.C. 78j(b))) in contravention of such rules and regulations as the Commission may prescribe as necessary in the public interest or for the protection of natural gas ratepayers. Nothing in this section shall be construed to create a private right of action.”

15 USC 717c-1

SEC. 316. NATURAL GAS MARKET TRANSPARENCY RULES.

The Natural Gas Act (15 U.S.C. 717 et seq.) is amended by inserting after section 22 the following:

“NATURAL GAS MARKET TRANSPARENCY RULES

“SEC. 23. (a)(1) The Commission is directed to facilitate price transparency in markets for the sale or transportation of physical natural gas in interstate commerce, having due regard for the public interest, the integrity of those markets, fair competition, and the protection of consumers.

15 USC 717t-2.

“(2) The Commission may prescribe such rules as the Commission determines necessary and appropriate to carry out the purposes of this section. The rules shall provide for the dissemination, on a timely basis, of information about the availability and prices

of natural gas sold at wholesale and in interstate commerce to the Commission, State commissions, buyers and sellers of wholesale natural gas, and the public.

"(3) The Commission may—

"(A) obtain the information described in paragraph (2) from any market participant; and

"(B) rely on entities other than the Commission to receive and make public the information, subject to the disclosure rules in subsection (b).

"(4) In carrying out this section, the Commission shall consider the degree of price transparency provided by existing price publishers and providers of trade processing services, and shall rely on such publishers and services to the maximum extent possible. The Commission may establish an electronic information system if it determines that existing price publications are not adequately providing price discovery or market transparency.

"(b)(1) Rules described in subsection (a)(2), if adopted, shall exempt from disclosure information the Commission determines would, if disclosed, be detrimental to the operation of an effective market or jeopardize system security.

"(2) In determining the information to be made available under this section and the time to make the information available, the Commission shall seek to ensure that consumers and competitive markets are protected from the adverse effects of potential collusion or other anticompetitive behaviors that can be facilitated by untimely public disclosure of transaction-specific information.

Deadline.
Memorandum.

"(c)(1) Within 180 days of enactment of this section, the Commission shall conclude a memorandum of understanding with the Commodity Futures Trading Commission relating to information sharing, which shall include, among other things, provisions ensuring that information requests to markets within the respective jurisdiction of each agency are properly coordinated to minimize duplicative information requests, and provisions regarding the treatment of proprietary trading information.

"(2) Nothing in this section may be construed to limit or affect the exclusive jurisdiction of the Commodity Futures Trading Commission under the Commodity Exchange Act (7 U.S.C. 1 et seq.).

"(d)(1) The Commission shall not condition access to interstate pipeline transportation on the reporting requirements of this section.

"(2) The Commission shall not require natural gas producers, processors, or users who have a de minimis market presence to comply with the reporting requirements of this section.

"(e)(1) Except as provided in paragraph (2), no person shall be subject to any civil penalty under this section with respect to any violation occurring more than 3 years before the date on which the person is provided notice of the proposed penalty under section 22(b).

"(2) Paragraph (1) shall not apply in any case in which the Commission finds that a seller that has entered into a contract for the transportation or sale of natural gas subject to the jurisdiction of the Commission has engaged in fraudulent market manipulation activities materially affecting the contract in violation of section 4A."

SEC. 317. FEDERAL-STATE LIQUEFIED NATURAL GAS FORUMS.

(a) **IN GENERAL.**—Not later than 1 year after the date of enactment of this Act, the Secretary, in cooperation and consultation with the Secretary of Transportation, the Secretary of Homeland Security, the Federal Energy Regulatory Commission, and the Governors of the Coastal States, shall convene not less than 3 forums on liquefied natural gas. ^{Deadline.}

(b) **REQUIREMENTS.**—The forums shall—

(1) be located in areas where liquefied natural gas facilities are under consideration;

(2) be designed to foster dialogue among Federal officials, State and local officials, the general public, independent experts, and industry representatives; and

(3) at a minimum, provide an opportunity for public education and dialogue on—

(A) the role of liquefied natural gas in meeting current and future United States energy supply requirements and demand, in the context of the full range of energy supply options;

(B) the Federal and State siting and permitting processes;

(C) the potential risks and rewards associated with importing liquefied natural gas;

(D) the Federal safety and environmental requirements (including regulations) applicable to liquefied natural gas;

(E) prevention, mitigation, and response strategies for liquefied natural gas hazards; and

(F) additional issues as appropriate.

(c) **PURPOSE.**—The purpose of the forums shall be to identify and develop best practices for addressing the issues and challenges associated with liquefied natural gas imports, building on existing cooperative efforts.

(d) **AUTHORIZATION OF APPROPRIATIONS.**—There are authorized to be appropriated such sums as are necessary to carry out this section.

SEC. 318. PROHIBITION OF TRADING AND SERVING BY CERTAIN INDIVIDUALS.

Section 20 of the Natural Gas Act (15 U.S.C. 717s) is amended by adding at the end the following:

“(d) In any proceedings under subsection (a), the court may prohibit, conditionally or unconditionally, and permanently or for such period of time as the court determines, any individual who is engaged or has engaged in practices constituting a violation of section 4A (including related rules and regulations) from—

“(1) acting as an officer or director of a natural gas company; or

“(2) engaging in the business of—

“(A) the purchasing or selling of natural gas; or

“(B) the purchasing or selling of transmission services subject to the jurisdiction of the Commission.”.

Report
Submitted to the
United States Congress
by the Federal Energy Regulatory Commission

Second Report to Congress on Progress Made in Licensing
and Constructing the Alaska Natural Gas Pipeline

July 10, 2006

Second Report to Congress on Progress Made in Licensing and Constructing the Alaska Natural Gas Pipeline

I. Executive Summary

This report by the Federal Energy Regulatory Commission (Commission) is submitted pursuant to section 1810 of the Energy Policy Act of 2005 (EPAcT 2005).¹ Section 1810 of EPAcT 2005 provides that within 180 days of the date of enactment, and every 180 days thereafter until the Alaska natural gas pipeline commences operation, the Commission shall submit to Congress a report describing the progress made in licensing and constructing the Alaska natural gas pipeline and any impediments thereto.

During the period covered by this report, the following events have occurred: an agreement on components of a draft contract between the State of Alaska and the Producer Group; the execution of the Federal Agency Memorandum of Understanding among 15 federal departments and agencies, which establishes a cooperative project management framework for the approval of an Alaska natural gas pipeline; and the nomination of a Federal Coordinator for Alaska Natural Gas Transportation Projects.

The United States energy market is moving forward to make arrangements to obtain adequate natural gas supplies to satisfy future demand. Significant progress has been made in developing infrastructure to support liquefied natural gas (LNG) projects that would satisfy this need. Many nations, in partnership with commercial entities, are quickly bringing LNG supply projects on-line. In the next two to three years, this worldwide capacity to supply LNG to the market will greatly increase.

This report describes the events and the progress that have transpired since the Commission's First Report on February 1, 2006. The report also explains the urgency of completing the next steps toward approval of an Alaskan gas pipeline so that Alaskan gas supplies also can be part of the solution to the nation's growing need for gas.

II. Status Report

A. Status of Three Potential Projects

The three potential projects described in the Commission's First Report are still being pursued by the project sponsors. One of these potential projects is the Alaska Natural Gas Transportation System (ANGTS) which is supported by the TransCanada Corporation. This project is proposed pursuant to the Alaska Natural Gas Transportation Act of 1976 (ANGTA), Canada's Northern Pipeline Act (1978), and a 1977 Agreement

¹ P.L. 109-58, 119 Stat. 594 (2005), 42 U.S.C §16,523.

on Principles between the United States and Canada. A second potential project is the Trans-Alaska Gas System (TAGS), an LNG export project which is being promoted by the Alaska Gas Port Authority. The third potential project involves an entirely new pipeline to transport gas from the North Slope of Alaska to the Canadian border, which would seek authorization pursuant to the provisions of section 103 of the Alaska Natural Gas Pipeline Act (ANGPA) ² and section 7 of the Natural Gas Act (NGA).³ The sponsor of this project is the Producer Group, which is composed of BP, ConocoPhillips, and ExxonMobil.

B. Progress on Alaska Stranded Gas Development Act Agreement Negotiations and Related Legislation

1. Draft fiscal contract issued

As stated in the Commission's First Report, the Producer Group has indicated that it will only begin to develop an application once it has successfully negotiated a contract establishing fiscal certainty in Alaska. On February 21, 2006, Governor Frank H. Murkowski announced that the State of Alaska and the Producer Group had reached agreement on the major components of an Alaska Stranded Gas Development Act fiscal contract. This agreement represents significant progress towards development of an Alaskan natural gas pipeline.

Under the terms of the draft agreement between the state and the Producer Group, the State of Alaska would own 20 percent of the primary project elements – the gas treatment plant, the mainline in Alaska, and the Alaska-to-Alberta pipeline. The state would own other elements of the project in proportion to its share of the expected throughput in those elements. The state also would receive its royalty gas in kind and receive gas, not cash, in payment of the producers' production tax obligations. In return for the state's participation in and financial support of the project, the producers would receive fiscal stability on their oil and gas obligations in Alaska for decades, as spelled out in the contract.

On May 10, 2006, Governor Murkowski provided the draft fiscal contract to the Alaska legislature for its review and to the public for comment and called the legislature into a special session. The special session was called to consider six subjects, all related to the natural gas pipeline. After the public comment period is completed, the governor's

² P.L. 108-324, 118 Stat. 1220 (2004), 15 U.S.C § 719.

³ 15 U.S.C. § 717f.

staff will finalize the contract and formally submit it to the state legislature for its approval.⁴

The release of the proposed contract was followed by a series of statewide public hearings and a special session of the state legislature. The first special session that considered the new petroleum production tax changes (see details below) adjourned on June 8, 2006 without the legislature acting on the tax and credit rates. A series of amendments to the Stranded Gas Development Act that are necessary to make that Act conform to provisions of the draft fiscal contract with the producers were not voted on during the first special session and, therefore, will have to be reintroduced in the next special session for the legislature's consideration and vote. On June 23, 2006, the governor announced a second special session of the state legislature to begin on July 12, 2006 to consider the Petroleum Production Tax (PPT) and amendments to the Stranded Gas Development Act.

2. Oil tax revision

On May 24, 2006, Governor Murkowski announced that state and industry negotiators had reached agreement on the oil fiscal certainty portion of the gas pipeline contract.⁵ The governor introduced oil tax-reform/modernization legislation designed to link taxes to the oil companies' Alaska profits. The governor announced that state and industry negotiators had reached initial agreement on the PPT including a 20 percent tax rate with a 20 percent tradable tax credit to strike a balance between exploration and development incentives and a tax rate. He said that this tax revision was designed to encourage investment – which leads to more exploration, which leads to more barrels of oil, which leads to more state tax revenue than a higher tax might bring.

The new PPT would change the existing oil taxation system in Alaska. The current production tax on oil is based on a percentage of the gross value of production. The proposed new tax structure would be based on a percentage of the net profit. The current production tax rate is driven by the Economic Limit Factor, or ELF. The governor has said that the ELF-based system is no longer working for Alaska. The Alaska legislature adjourned both its regular session and the special session without completing action on the PPT. As noted above, the governor called another special session to begin on July 12, 2006.

⁴ The governor extended the public comment period an additional 45 days, until July 23, 2006.

⁵ An amendment (to be addressed in the next special session of the Alaska Legislature) to the Stranded Gas Production Act would allow the governor to negotiate existing oil and gas tax agreements as part of the gas contract. Current law prohibits significantly altering tax and royalty rates on existing oil and gas production.

C. Federal Interagency Memorandum of Understanding

In June 2006, the Federal Interagency Memorandum of Understanding for the Alaska Natural Gas Transportation Project (MOU) was fully signed and executed by senior executives and heads from 15 federal departments and agencies.⁶ The signing of an MOU by this large number of agencies demonstrates that the federal agencies are prepared to work together to expedite the permitting and construction of an Alaska natural gas pipeline project.

The MOU establishes a project management framework for cooperation among participating federal agencies with responsibilities related to the approval of an Alaska natural gas transportation project. In particular, the MOU provides for early agency coordination in order to streamline regulatory reviews of applications for permits needed to construct and operate the project. Coordination among these agencies on issues such as project review and implementation schedules, data requirements, and mitigation measures is critical to enable agencies to discharge their responsibilities expeditiously. A coordinated project management approach will facilitate and expedite completion of an Alaska natural gas transportation project. Because federal loan guarantees are authorized, the federal government may bear a significant portion of the financial risk associated with this project. Therefore, it is of critical importance that the project be completed on time and within budget, and the MOU will help the federal government achieve that goal.

The MOU includes agreement by the Participating Agencies to participate and work within the pre-filing time frame set by the Commission to identify and seek to resolve issues at the earliest stages of project development. The Commission's pre-filing process, which is initiated by a request of the project sponsor, serves as a mechanism to meet requirements of the National Environmental Policy Act of 1969 (NEPA) while optimizing scheduling. The Commission agreed to consult with the Federal Coordinator and relevant Participating Agencies as it establishes a schedule for the project review process. The schedule established by the Commission will be as expeditious as possible while consistent with any statutory permit review periods. To the extent practicable and

⁶ Department of Agriculture, Department of Commerce, Department of Defense, Department of Energy, Department of Homeland Security, Department of the Interior (Bureau of Indian Affairs, Bureau of Land Management, Fish and Wildlife Service, and National Park Service), Department of Labor, Department of State, Department of Transportation (Pipeline and Hazardous Materials Safety Administration and Federal Highway Administration), Department of the Treasury, Advisory Council on Historic Preservation, Council on Environmental Quality, Environmental Protection Agency, Federal Coordinator for Alaska Natural Gas Transportation Projects (acting), and the Federal Energy Regulatory Commission.

permitted by law, the relevant Participating Agencies agree to implement, with the assistance of the Federal Coordinator, their related agency review and permitting processes on a concurrent rather than sequential basis to enable completion of the environmental impact statement (EIS) within the time limits required by ANGPA .

D. Nomination of Federal Coordinator

On June 12, 2006, President George W. Bush nominated Drue Pearce, of Alaska, to be Federal Coordinator for Alaska Natural Gas Transportation Projects, for a term ending one year following the completion of the Alaska Natural Gas Transportation Project. Under section 106 of ANGPA, the Federal Coordinator will head the Office of the Federal Coordinator for Alaska Natural Gas Transportation Projects. The advice and consent of the United States Senate is required before Ms. Pearce can begin her service as the Federal Coordinator. Until the nominee's confirmation, ANGPA temporarily vests the Federal Coordinator authority in the Secretary of Energy.

The Federal Coordinator shall be responsible for: (1) coordinating the expeditious actions of all Federal agencies with respect to an Alaska natural gas transportation project; and (2) ensuring the compliance of Federal agencies with the provisions and deadlines of ANGPA.

E. U.S. Department of Energy Activities

1. In-state Demand/Needs Study

a. Purpose of Study

In June 2006 the U.S. Department of Energy (DOE) released a report, "Alaska Natural Gas Needs and Market Assessment" (Needs Study), which estimates the potential demand for natural gas in South Central and other areas of Alaska directly associated with a potential spur pipeline connecting the proposed Alaska North Slope gas pipeline to the Cook Inlet pipeline infrastructure. The Needs Study is a conceptual engineering and socio-economic analysis intended to provide an independent estimate of in-state natural gas demand and supply options for the years 2015 through 2035. The study could be used to satisfy the Commission's Order No. 2005 requirement that applicants desiring to build an Alaskan natural gas pipeline conduct a study to determine in-state natural gas needs prior to holding an open season.⁷ The applicants could adopt this study to design their proposed in-state service which would be bid upon in the open season.

⁷ Order No. 2005 110 FERC ¶ 61,095 (Feb. 9, 2005),; 70 Fed. Reg. 8,269 (Feb. 18, 2005); *rehearing*, Order No. 2005-A 111 FERC ¶ 61,332 (June 1, 2005), 70 Fed. Reg. 35,011 (June 16, 2005).

b. Study Results

The Needs Study looked at future South Central Alaska yearly-average natural gas demand use for residential/commercial consumption and electric power generation estimated for 2015, 2025, and 2035, the relevant 20-year period that could be the initial years of Alaska pipeline operation. The study found a modest predicted natural gas demand ranging from 280 million cubic feet (MMcf) per day in 2015 increasing to over 500 MMcf per day by 2035.

While this study examined opportunities presented by a spur line that would start at a take-off point from the North Slope pipeline near Fairbanks or other Central Alaska locations near the pipeline route, it does not dismiss the assumption that South Central Alaska demand can potentially be met by increasing natural gas reserves from the Cook Inlet basin through exploration and development. There are both positive and negative assessments of the success expected for the exploration and development of Cook Inlet natural gas resources. The remaining option for South Central Alaska is importing LNG to meet basic demand.

The Needs Study also examined alternative cases of including additional natural gas markets for LNG, gas-to-liquids, petrochemicals and propane, and lower prices. If these alternative cases prove valid, a much larger spur pipeline would be needed; one with a capacity of 700 MMcf per day to 1,300 MMcf per day. The Needs Study notes that such a large local market withdrawal of petrochemical and propane from a natural gas pipeline from the North Slope could require design changes in the pipeline and cause significant economic and political hurdles for that project.

c. Commission Staff's Role

One element of the Needs Study involves an estimate of the transportation tariff rate for the Alaskan pipeline and any potential spur pipeline for use in the natural gas market modeling programs. The Commission staff was asked to review the appendix to the Needs Study which supports the transportation tariff rate calculations. The Commission staff advised DOE that there is insufficient detail in the Appendix to do anything other than say that the underlying bases of the analysis are generally consistent with the approach the Commission uses to develop gas transportation rates for interstate pipelines, e.g., the calculations reflect the net book value of the pipeline and related facilities, a 30-year, straight-line depreciation, federal and state taxes, and fuel and non-fuel costs. The approach used could yield ballpark estimates of per unit transportation charges.⁸

⁸ There are many issues raised by the calculations that cannot be adequately analyzed or addressed absent a specific proposal, including: the appropriate capital

The Commission staff noted that the study correctly takes into account the very high pressure design of an Alaskan gas pipeline that will make treatment and economics of natural gas liquids an important factor of the overall assessment. Another adequate assumption of the Appendix is the use of the *Panhandle Eastern* equation for the evaluation required for the examination of a range of potential off-take volumes that the spur line would receive.⁹

2. Alternative Means of Construction Study

DOE has undertaken a pre-scoping study to evaluate options, risks, and resources needed for further study. Section 109 of ANGPA states that if no application for the issuance of a certificate or amended certificate of public convenience and necessity authorizing the construction and operation of an Alaska natural gas transportation project has been filed with the Commission by the date that is 18 months after the October 13, 2004 date of enactment, the DOE shall conduct a study of alternative approaches to the construction and operation of such an Alaska natural gas transportation project. On April 13, 2006, the DOE commenced an Alternative Means of Construction Study as required by section 109 of ANGPA.

In conducting the actual alternatives study, the Act requires DOE to consult with the Secretary of the Treasury and the Secretary of the Army (acting through the Chief of Engineers) and include in the scope of the study consideration of the feasibility of establishing a Federal Government corporation to construct an Alaska natural gas transportation project. The study must also take into consideration the feasibility of securing alternative means of providing federal financing and ownership (including alternative combinations of Government and private corporate ownership) of the Alaska natural gas transportation project. Upon completion of the study, DOE must submit a report to Congress that describes the results of the study and any recommendations (including proposals for legislation to implement such recommendations).

3. Federal Loan Guarantee

The DOE program for the federal loan guarantee for the Alaskan natural gas transportation project is monitoring the progress of the commercial negotiations with the State of Alaska and the bills before the Alaska state legislature. When the commercial project emerges, DOE will proceed with structuring the loan guarantee.

structure, the return on equity level, the presumed debt cost, the lack of amounts for general and intangible plant, the lack of inclusion of certain taxes, and rate design.

⁹ Handbook of Natural Gas Engineering, Katz, et al., p. 626 (1959).

F. Commission's Environmental Review - Update

As described in the First Report, the Commission has been active for the past several years in preparing to fulfill its NEPA and certificate application responsibilities. The First Report includes a list of the siting activities associated with an Alaska natural gas pipeline in which the Commission staff has participated. Since that time, the staffs of the Commission and the Department of the Interior have met to continue discussions of resources and training needs for the EIS and project permitting. In April 2006, representatives of the steel industry met with Commission staff to present their perspective about the design, testing, and manufacturing of the great amount of steel pipe that will be needed for the Alaskan pipeline project. As discussed above, the Commission staff participated in the completion of the Federal agency MOU. Finally, the Commission staff plans to tour the route of the northern segment of the pipeline in July 2006.

With the release of the draft fiscal contract by Governor Murkowski in May 2006, the governor's administration and the Producer Group have provided more details on a schedule for planning, permitting, and constructing the project. In summary, the Producer Group estimates a period of 10 years from the beginning of formal project planning activities to date of first gas deliveries. The project planning activities would commence within 90 days after the signing of the fiscal contract. Following the planning phase would be the Front-End Engineering Design, the open-season process, field data collection (the open season and field work could occur simultaneously), and preparation of an application for a FERC certificate of public convenience and necessity.

In its conceptual schedule, the Producer Group estimates it could file permit applications at the end of 2008 if the commercial negotiations are completed with the State of Alaska in 2006. This timeline reflects the complexity of the project, which requires more than two years from initial planning to the filing of permit applications. The Commission staff and the participating federal agencies have committed to assisting in the development of the application through the Commission's pre-filing process. The purpose of the pre-filing process is to encourage the early involvement of interested stakeholders, facilitate interagency cooperation, and identify and resolve issues before an application is filed with the Commission. Based on its consultations with the industry, the Commission staff had previously estimated that the development of the application, and the concurrent pre-filing process, could take as long as 18 months in order to complete the substantial field data collection and engineering design. This timeframe fits easily within the Producer Group's estimated two years.

The Commission's First Report described some of the difficulties associated with the development of an application for an Alaska pipeline project. Specifically, it noted that two field seasons may be necessary to complete the required field studies and surveys due to the shortened field season in Alaska and that mobilization needs to begin

early in the calendar year to get the personnel and equipment into the field the following summer. The First Report concluded that any realistic expectation for the development of an application in 2006 was dependent on the legislative approval of a fiscal contract with the State of Alaska under the Stranded Gas Development Act soon after issuance of the First Report in February. Because no agreement has been finalized at the time of this report, the opportunity for beginning meaningful development of an application in 2006 has been missed.

If a project sponsor is ready to begin developing its application and conducting field surveys in the spring of 2007, it is possible that an application would be filed at the Commission before the end of 2008. The ANGPA streamlines the time from the filing of a complete application to final certificate from the Commission, mandating that the EIS be completed within 18 months, and that the Commission must issue a final certificate order no more than 60 days after the EIS is final. The Commission staff stands ready to begin processing any complete application that is filed for an Alaska natural gas transportation project and to meet the processing timelines established by the ANGPA. Whether the project sponsor begins developing an application and conducting field surveys in the spring of 2007 depends largely on the Alaska state legislature acting this summer. If not, the Alaska gas pipeline will be further delayed.

G. Developments in Canada

The Mackenzie Gas Project continues under consideration by the Government of Canada. The Mackenzie Gas Project includes development of natural gas fields, gathering lines, and processing facilities in the Mackenzie River Delta of Canada's Northwest Territories, and a transportation pipeline along the Mackenzie River Valley to deliver the natural gas to market. This major pipeline project consists of over 750 miles of 30-inch natural gas transmission pipeline that would transport 1.2 billion cubic feet (Bcf) per day of new Arctic gas to market. The capital cost of this project is estimated at over \$7 billion, and it is planned to be in operation by 2011. However, it has been reported in the press that Imperial Oil Ltd., the lead partner proposing the project, will revise the project's cost estimate and construction schedule within the next six months.

Although this project is neither a complement to nor competitor of an Alaska natural gas pipeline, its development presents certain problems and risks to an Alaskan project. First, industry reports indicate that there will not be enough pipeline grade steel available to construct both projects at the same time. Similarly, there could be a shortage of the skilled labor force required to build two technically-challenging Arctic projects of such magnitude at the same time.

Sponsors of the Mackenzie Gas Project have been discussing royalty and fiscal issues concerning the project with the Government of Canada, but it is reported that these talks have paused pending the review of the project's cost estimate and construction

schedule. However, the regulatory review process in Canada for the Mackenzie Gas Project is continuing as scheduled. The Joint Review Panel is examining issues and impacts in the areas of the natural and human environments associated with the proposed Mackenzie Gas Project to determine how the project could affect the land, environment and lives of people and communities in the project area.¹⁰ The National Energy Board (NEB) is reviewing the technical aspects, such as engineering, economic feasibility, tolls and tariffs, and lands issues associated with the proposed project. The NEB will consider the Joint Review Panel's report in deciding whether the project is in the public interest. If at the end of the process the NEB Panel decides the project is in the public interest, the federal Cabinet must then decide whether to authorize the NEB to issue a certificate so that the project can proceed. If the NEB Panel decides that a project is not in the public interest, then no further approval of its decision is required.

III. Need for Greater Progress

A. Overview

Government and industry in the United States are acting in various ways to obtain adequate natural gas supplies to satisfy future demand. There are projects being developed to access: imported LNG, deepwater Gulf of Mexico reserves, non-conventional sources – coal bed methane, tight sands and, shale – in the U.S. and Canada, Canadian Arctic reserves, as well as Alaskan natural gas. At best, it appears that the non-conventional sources of natural gas, along with production from the deepwater Gulf of Mexico, only will serve to replace declining conventional sources, albeit at higher cost. In addition, our major source of imports, pipeline gas from Canada, is expected to decline as Canadian domestic demand increases and gas production from its major production area, the Western Canadian Sedimentary Basin, declines over time.

The U.S. natural gas market increasingly is turning to imported LNG to meet incremental growth. Many nations, in partnership with commercial entities, are quickly developing LNG supply projects. In the next two to three years, the worldwide capacity to supply LNG to the market will greatly increase. Alaskan North Slope gas can also be part of the solution to the nation's natural gas needs in this generation. Alaskan gas is not the only option available to the Lower 48. Twenty years ago, Alaskan gas would have been in competition only with other North American gas production. Now, Alaskan natural gas production will also face competition from low-cost production in LNG exporting countries across the globe. Natural gas markets have changed significantly over the past 20 years, and are becoming increasingly international markets.

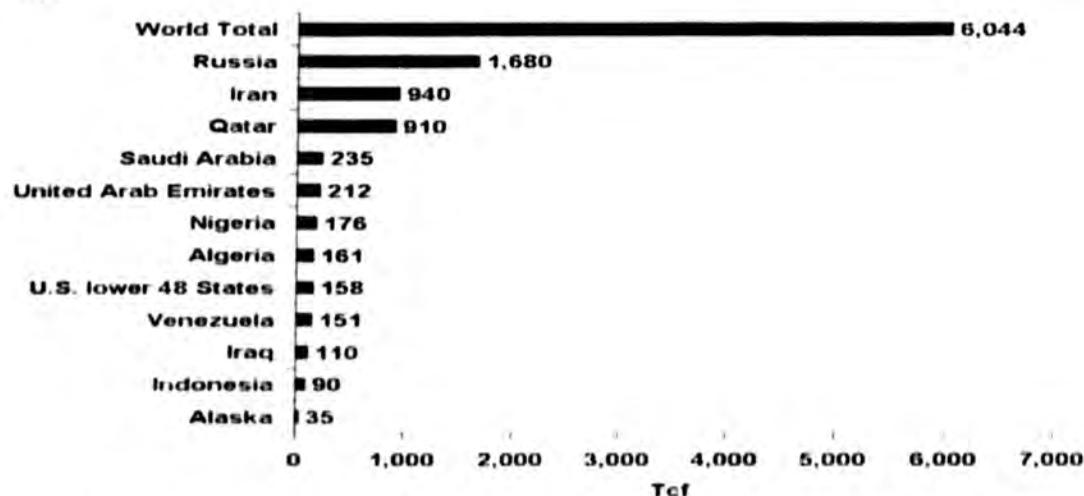
¹⁰ The Joint Review Panel for the Mackenzie Gas Project is a seven-member, independent body that will evaluate the potential impacts of the project on the environment and lives of the people in the project area.

Prompt action by the project sponsors, Governor Murkowski and the Alaska Legislature is necessary to enable Alaska to provide a reliable continental source of natural gas for the Lower 48 that will not only assist in the growth of the U.S. economy, but also contribute to the economic well being of the State of Alaska. Timely action on an Alaska natural gas project will allow North Slope gas to reach the Lower 48 states.

B. Reserves: Alaska vis-a-vis the World

It is estimated that as of January 1, 2005 there are 6,044 trillion cubic feet (Tcf) of proved gas reserves in the world, 5,780 Tcf of which is located outside of North America.¹¹ Of the North American total (264 Tcf), the North Slope of Alaska contains about 35 Tcf of proved reserves. To put this in perspective, while North Slope natural gas reserves represent approximately 13 percent of North American gas reserves, they are less than 1 percent of the world's gas reserves. Consequently, potential importers and energy infrastructure developers are realizing that there is an opportunity to secure substantial new gas supplies for the U.S. by looking abroad.

Of the top five countries with the most proved natural gas reserves, Russia has 28 percent of the world total. The following chart displays the total world proved reserves and compares the top ten countries' proved reserves along with those of the Lower 48 and Alaska.



Source: Based on data from EIA, *International Energy Review*, 2004, Table 8.1 World Crude Oil and Natural Gas Reserves (January 1, 2005).

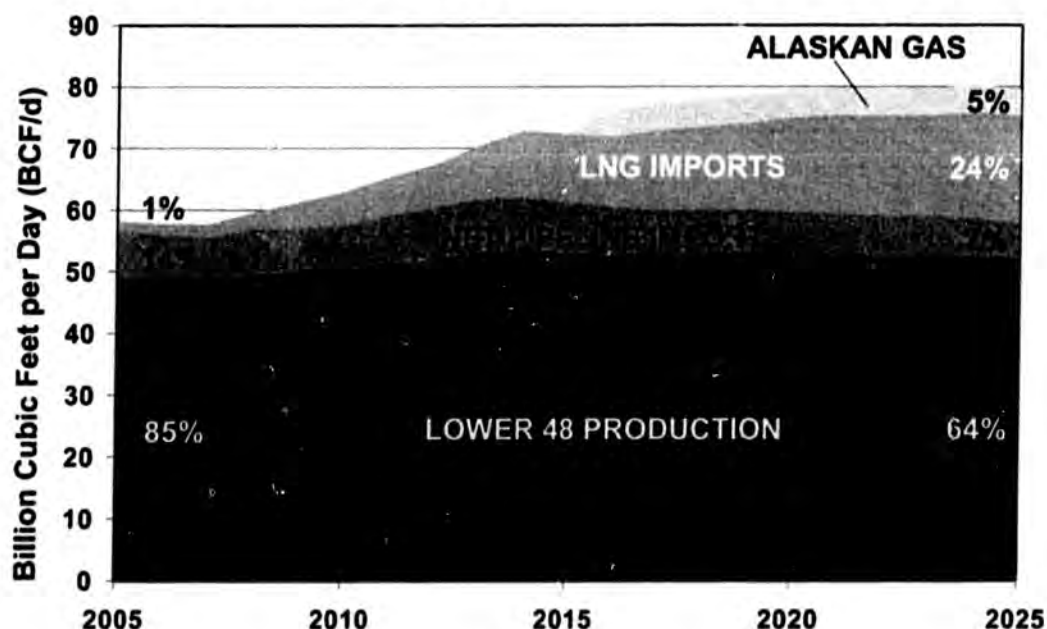
C. Alaska Gas's Potential Market Share

Gas supply from Alaska, estimated to flow at about 4.5 Bcf per day, will only partially fulfill the nation's future natural gas needs. LNG also will be a major source of future U.S. gas supply and the necessary infrastructure is being developed. For Alaska to

¹¹ PennWell Corporation, *Oil & Gas Journal*, Vol. 102, No. 47 (December 20, 2004).

be a meaningful part of the natural gas supply mix of the U.S. in the coming years, action needs to be taken now. At best, if the draft contract were approved under the Alaskan Stranded Gas Development Act, gas would not flow in significant quantities to the Lower 48 prior to 2016. As U.S. energy markets make decisions regarding where future supplies will be obtained, they will carefully examine the likelihood that particular supplies will be available when needed. To the extent that Alaska gas is to play a role in meeting future needs, progress towards the construction of an Alaska gas pipeline is crucial.

The following chart shows the role that Alaskan gas is expected to play in the future composition of U.S. natural gas supply.



Source: Lower 48 Production, Net Pipeline Imports, and LNG Imports: Energy Information Administration, Annual Energy Outlook 2006; Alaskan Gas: Assumed Flow Rate of 4.5 Bcf per day.

D. The Closing Window for Alaska Gas Delivery

The Energy Information Administration (EIA) of DOE projects that demand for natural gas in the U.S. will grow by more than 23 percent between 2005 and 2025, while domestic production in the Lower 48 is expected to increase by close to 7 percent, further widening the existing gap between supply and demand.¹² During this same time period, the EIA projects that net pipeline imports to the U.S. will decline by 55 percent. Even if the Mackenzie Gas Project in Canada goes into operation, it is doubtful that the U.S. will

¹² "Annual Energy Outlook 2006," Energy Information Administration, Reference Case Tables 13, 14 (February 2006).

see any of this gas due to the development of the Canadian oil sands in Alberta (necessitating natural gas for the mining operations), increased demand in Canada, and the decline in production from the Western Canadian Sedimentary Basin. In fact, the National Energy Board of Canada projects that by 2015, the oil sands will have a gas requirement of 2.1 Bcf per day; the oil sands gas requirement was about 0.5 Bcf per day in 2002.¹³

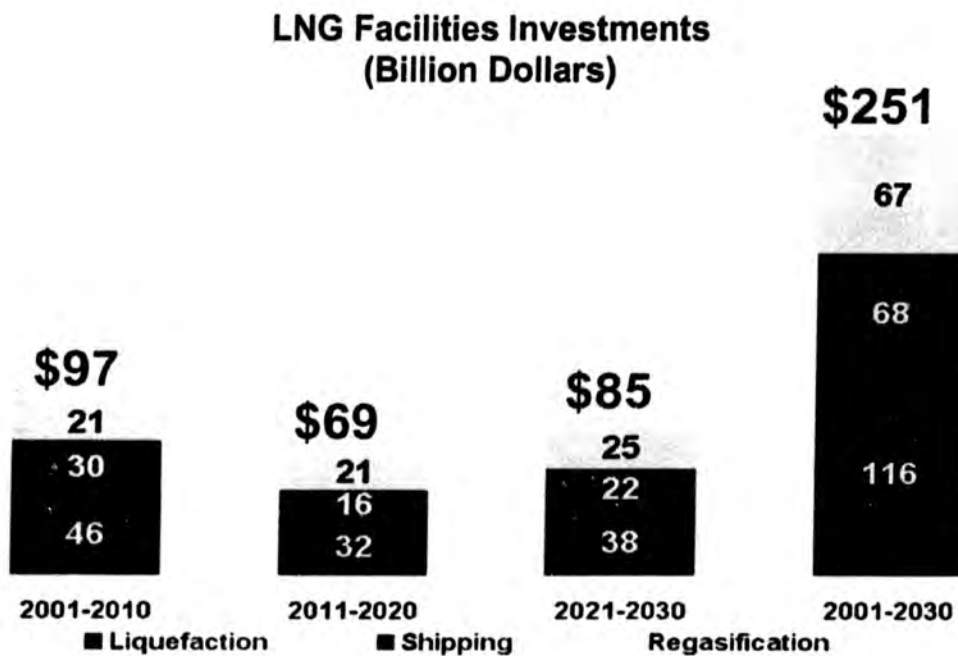
Therefore, the largest sources for growth in U.S. gas supply are Alaskan gas and LNG. As previously stated, gas flow from the Alaskan North Slope is expected to be 4.5 Bcf per day, a not inconsiderable amount. However, this amount pales in comparison to recent LNG infrastructure activity at the Commission. Beginning with the approval of the Cameron (formerly, Hackberry) LNG terminal in September 2003, the Commission has approved eleven new LNG terminals in the Lower 48 that have a total redelivery capacity of 20.6 Bcf per day. In addition, the Commission has also approved an expansion of an existing LNG terminal and an expansion of an approved (but not yet in operation) LNG terminal, totaling an additional 2.2 Bcf per day of deliverability. When combined with the nation's existing deliverability of 5.8 Bcf per day, there is the potential for 28.6 Bcf per day of deliverability from LNG. Further, there are ten new LNG sites that have been proposed to the Commission with a total delivery capacity of 11.5 Bcf per day and pending expansions for about 4.6 Bcf per day at three LNG terminals (existing and approved).

Given the large capital investment in LNG liquefaction facilities, LNG exporters will prefer to negotiate long-term arrangements to sell their LNG to provide the necessary cash flow to finance their facilities. While some LNG volumes are sold in the "spot" market, the execution of long-term arrangements will serve to make this supply a reliable source. Gas buyers in the Lower 48 are more likely to enter into long-term LNG contracts if there is no substantial progress on building an Alaska pipeline. And, the longer an Alaskan pipeline is delayed, the more strength is gained by the proponents of LNG.

Currently, much work is being done to develop the supply "chain" (production, liquefaction, shipping and regasification) that will deliver LNG to the U.S. and other countries that do not have adequate domestic production to satisfy their gas needs. The International Energy Agency states that, through the year 2030, over \$250 billion will be invested worldwide to develop LNG infrastructure. This large investment in LNG infrastructure necessarily requires commitments and establishes long-term relationships.

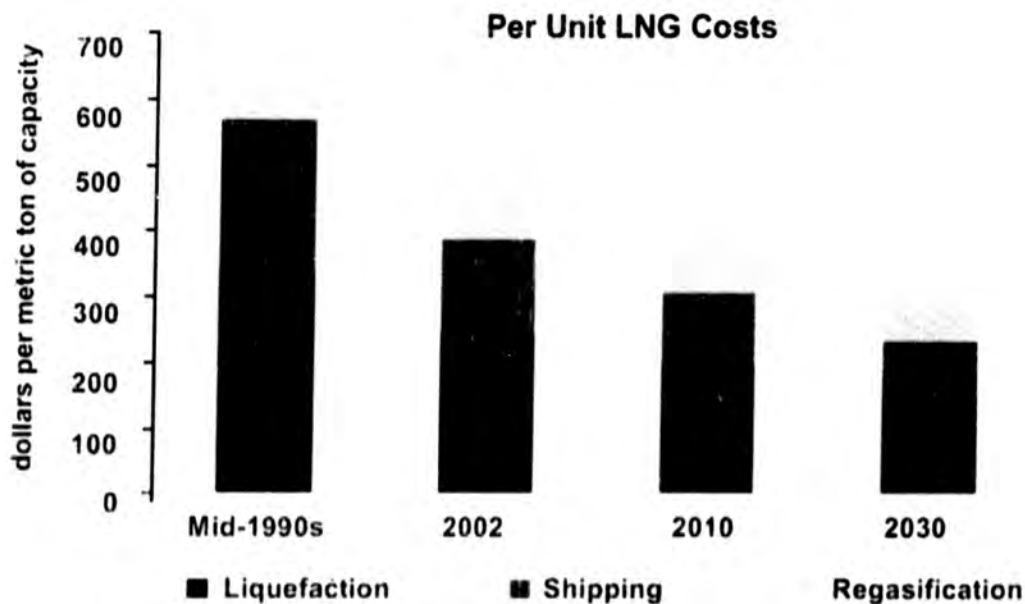
¹³ "Canada's Oil Sands, Opportunities and Challenges to 2015: An Update," National Energy Board, p. 16 (June 2006).

The chart below shows worldwide LNG investments for the three sectors of the LNG supply chain already made or underway for the period 2001-2010, expected expenditures for the next two decades, and then a column summing the entire period.



Source: Based on data from "World Energy Investment Outlook 2003".

Also, the chart below shows that there has been a decline in investment required per unit of LNG produced, which is expected to continue as technology progresses.



Source: Based on International Energy Agency, The Global Outlook for LNG, 2004

At the time of ANGPA, an Alaskan pipeline generally following the ANGTS route had been estimated to cost \$18-20 billion. Now, estimates are running as high as \$25 billion. Any further delays may serve to make the Alaska gas pipeline uneconomic in comparison to LNG imports. As demonstrated by the magnitude of monies being invested in LNG facilities and the falling costs per unit of LNG infrastructure, Alaska is at risk of being marginalized in the search for new natural gas supplies for U.S. consumption.

IV. Conclusion

The Federal Government has made great strides to prepare for the review of a final proposal to build a natural gas transportation project for Alaskan natural gas. Significant progress on an Alaska natural gas pipeline is needed for North Slope gas to become part of the supply mix which will satisfy the U.S. need for natural gas in this generation. Alaska offers a reliable continental source of natural gas for the Lower 48 States that will help the U.S. economy to grow and thrive, and also contribute to the economic well being of the State of Alaska. Whether the long-term arrangements needed to make delivery of Alaska gas a reality are put into place in the near future will determine Alaska's role as a supplier as the dynamic global gas market moves forward to match supply with demand.

The NewsRoom
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Royalty in Kind Report Highlights '05 Performance

Revenues up, Administrative Costs and Conflicts Down

DENVER -- Decreased administrative costs and increased revenue of more than \$32 million are among the highlights of a recently completed government analysis that examined the Fiscal Year 2005 performance of the Minerals Management Service's Royalty in Kind (RIK) program.

"The Royalty in Kind program continues to deliver solid and measurable benefits to the American taxpayer," director of the Department of the Interior's Minerals Management Service (MMS), Johnnie Burton said. "Through this program, we've been able to improve government efficiency, reduce conflicts with industry, and increase taxpayer returns."

The report, available on the Minerals Revenue Management web site at:

<http://www.mrm.mms.gov/rikweb/PDFDocs/RIKPRPFY2005.pdf>, highlights the RIK program's performance during Fiscal Year 2005, the second full year the program was in an operational status after six years of pilot testing.

Historically, the MMS collected the majority of its royalties in the form of cash, or royalty in value (RIV), payments. In the mid-1990s, MMS began exploring whether it was in the nation's best interest to take royalties in kind--in the form of product--and then competitively sell that product in the marketplace.

MMS conducted a series of feasibility studies and pilot projects to test that approach, and in 2004 released the *Five Year Royalty in Kind Business Plan* and moved the program to an operational phase. The business plan incorporated suggestions of the Government Accountability Office and a commercial consultant, and included clear program objectives. The plan also emphasized MMS's commitment to measure program performance and report to Congress on progress in achieving the plan's goals.

During Fiscal Year 2005, a total of 82,364,035 barrels of oil equivalent were taken in kind and sold or exchanged under the RIK program. The RIK oil and gas were valued at approximately \$3.7 billion, a 39 percent increase over the FY 2004 value, attributable to markedly higher energy prices in 2005.

The bulk of the RIK activity occurred in the Gulf of Mexico, where the MMS took in kind approximately 75 percent of the crude oil and approximately 30 percent of natural gas royalty volumes produced daily.

According to Burton, measurement of the RIK revenue performance for Fiscal Year 2005 indicated a revenue gain

of \$30.8 million related to both the natural gas and crude oil business units. Combined with an additional revenue gain of \$1.5 million in additional interest earned by receiving RIK revenues five to 10 days earlier than under the royalty in value program, a total revenue gain of \$32.3 million was achieved, she said.

Burton also noted that the MMS, in conducting its RIK program, reduced its administrative costs by more than \$3.74 million. That is, without the RIK program, MMS would have needed to spend an additional \$3.74 million for royalty compliance. Taking royalties in kind in the form of product simplifies the auditing process for these transactions, which is one reason the oil and gas industry generally supports the government's RIK efforts.

In addition to increased revenue and improved government efficiencies, Burton noted that the RIK program was instrumental in helping fill the nation's Strategic Petroleum Reserve to support energy security and provided a reliable supply of crude oil to support small refiner operations in the United States.

The RIK program grew from MMS's responsibility to ensure that all revenues from Federal and Indian mineral leases are efficiently and accurately collected, accounted for, and disbursed to recipients. These revenues totaled approximately \$10 billion in 2005 and more than \$156 billion since MMS's inception in 1982. The funds are disbursed to the U.S. Treasury, five Federal agencies, 35 states, 41 American Indian tribes, and some 30,000 individual American Indian mineral owners.

Relevant Web Sites:

MMS Main Website

Gulf of Mexico Website

Media Contacts:

Patrick Etchart, 303/231-3162

MMS: Securing Ocean Energy & Economic Value for America

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**Minerals Management Service
Minerals Revenue Management**

**Royalty in Kind Program
Fiscal Year 2005 Report**

April 2006

Table of Contents

Executive Summary

1	Background.....	1
2	RIK Program Status.....	2
	Business Model/Approach	
	Status and Scope of the Program	
	Natural Gas RIK Business Unit	
	Crude Oil RIK Business Unit	
	Partnerships with States and Other Federal Agencies	
3	Business Plan Implementation.....	6
	Accomplishments	
4	RIK Program Performance.....	9
	Administrative Cost Performance	
	Revenue Performance	
5	Conclusions and Preview of FY 2006.....	14
	FIGURE 1: Overall RIK Revenue Performance for FY 2005.....	10
	FIGURE 2: FY 2005 Natural Gas RIK Revenue Performance.....	15
	FIGURE 3: FY 2005 Crude Oil RIK RevenuePerformance.....	15

Executive Summary

This annual report documents the status of the Minerals Management Service's Royalty in Kind (RIK) program as of the end of fiscal year (FY) 2005.

The MMS RIK Program is now in its second full year of operational status after the May 2004 *Five Year Royalty in Kind Business Plan* marked the transition of the program from pilot projects to operational program.

FY 2005 saw the continuing positive evolution of the MMS RIK program as a fully operational component of MMS's asset management approach to managing the Nation's mineral royalty asset stream. Program performance far outpaced program goals. Administrative costs continued to decrease compared to the cash royalty alternative. Revenues to the Treasury were increased. Accounting periods were closed within 6 months. Conflict with producers was virtually non-existent. Agency knowledge of the Nation's energy infrastructure/markets was increased.

Program Status and Scope. In FY 2005, the MMS RIK Program was relatively static in scope compared to the previous year. A total of 82,364,035 barrels of oil equivalent (BOE) was taken in kind and sold or exchanged by MMS in FY 2005. This volume is 97% of the volumes taken in kind for FY 2004 - the reduction mostly reflecting the effects of the 2005 hurricane season on RIK activity. The value of RIK oil and gas in FY 2005 was \$3,727,467,532, a 39% year-on-year increase in value - the increase reflecting the effect of markedly higher energy commodity prices in 2005.

The Gulf of Mexico remains the core source area for RIK volumes sold or exchanged. As of the end of FY 2005, MMS took in kind approximately 75% and 30% of the crude oil and natural gas royalty volumes, respectively, produced daily in the Gulf of Mexico. Notably, MMS and the State of Wyoming decided to begin a natural gas RIK project for Federal gas production in Wyoming, a project that will commence in FY 2006.

In August, 2005, the RIK Program achieved a notable milestone by completing the Presidential directed initiative to fill the Strategic Petroleum Reserve (SPR) with some 115 million barrels of RIK crude oil. This joint project with the Department of Energy was completed well ahead of schedule, effectively and efficiently increasing our Nation's energy security. Gulf of Mexico producing properties that supported the SPR initiative are now supporting a fully commercial crude oil RIK sales program.

Program Performance. The MMS has fully implemented a comprehensive system of RIK program performance measurement - for both revenue receipts and administrative costs. Accordingly, GAO concluded in FY 2005 that MMS has fully implemented their recommendations that MMS should routinely monitor RIK program performance. These recommendations are now closed.

Administrative Cost Performance. FY 2005 was the second year in which MMS performed a comprehensive comparative analysis of the costs of administering the RIK and Royalty in Value (RIV) programs at MMS. The FY 2005 cost per "barrel of oil equivalent" or BOE for RIK is 5.9 cents (nearly identical to FY 2004's cost of 5.6 cents/BOE). This compares to a FY 2005 cost of 10.2 cents/BOE for RIV, and represents a 42 percent reduction attributable to RIK. Using producing properties as the unit of measurement, the FY 2005 RIK cost per unit is \$7,128 compared to \$15,015 for RIV, a 52 percent reduction in costs.

Using a more conservative BOE unit comparison, increases in efficiency from RIK activity translate to cost avoidance of \$3.74 million. That is, if RIV were applied to all BOE at the 10.2 cent rate versus a combination of RIK/RIV at the 5.9 and 10.2 cent rates, respectively, additional costs of \$3.74 million would have accrued.

Revenue Performance. Measurement of MMS's RIK revenue performance for FY 2005 indicates a revenue gain of \$30.8 million related to both the natural gas and crude oil business units. Combined with an additional revenue gain of \$1.5 million in additional interest earned on RIK revenues received 5 to 10 days earlier than under the RIV program, a total revenue gain of \$32.3 million was measured for the MMS RIK program in FY 2005. These results indicate that the five-year, \$50 million incremental revenue goal for the MMS RIK program is quite achievable. However, it should be noted that revenue gains will be variable and future gains – or losses – are not possible to predict. This fact underscores the importance of the associated administrative benefits of RIK described above.

Overall RIK Revenue Performance for FY 2005

Category	Revenue Gain (Natural Gas)	Revenue Gain (Crude Oil)	Total
Sales	\$18,640,086	\$12,150,397	\$30,790,483
Interest	\$505,002	\$1,023,548	\$1,528,550
Total	\$19,145,088	\$13,173,945	\$32,319,033

The RIK revenue performance far exceeded goals, reflecting the commercial leverage that the scale of the Federal royalty portfolio provides. The overarching factor in this success, however, is the development and maturation of the skill sets and business experience of the RIK staff.

In FY 2006, MMS will continue to explore opportunities for program application. We expect that the natural gas RIK business unit will expand substantially in the GOM and Wyoming now that the RIK internal control, risk policy, and human resource foundations have been built. The crude oil business unit will remain relatively static in size. Modest expansions of the RIK business model for both oil and gas will include diversification of sales methods and increased movement of energy commodities to market centers.

**Minerals Management Service/Minerals Revenue Management
Royalty in Kind Program FY 2005 Report
April 2006**

This report documents the status of the Minerals Management Service's Royalty in Kind (RIK) program as of the end of fiscal year (FY) 2005. The size, scope, and nature of the program are described as are measurements of the performance of the RIK program for FY 2005. We also report on progress made in implementing the MMS *Five Year Royalty in Kind Business Plan*.

1 Background

The MMS is responsible for ensuring that all revenues from Federal and Indian mineral leases are effectively, efficiently, and accurately collected, accounted for, and disbursed to recipients. These substantial revenues, nearly \$10 billion annually, are disbursed to the U.S. Treasury, 5 Federal agencies, 36 states, 41 Indian tribes, and some 30,000 individual Indian mineral owners.

Historically, most of these revenues have been received in the form of cash payments, also known as royalty in value (RIV) payments, paid by mineral development interests. In the mid-1990s, MMS began exploring the potential for a broadly applied RIK program, in which royalties are paid in commodity, rather than cash, to increase efficiencies, decrease conflict, and enhance net revenues generated from oil and gas production royalties. Several pilot projects tested this approach under a variety of conditions for crude oil and natural gas, and for onshore and offshore production volumes. Based on the pilot projects, MMS concluded that the RIK method is a viable tool to use in managing the Nation's oil and gas royalty assets. The MMS also concluded that RIK is not optimal for all oil and gas production scenarios. Accordingly, selective and strategic use of both RIK and RIV, based on systematic economic analysis of the Federal oil and gas portfolio, is the royalty asset management strategy adopted and used by MMS.

In May 2004, MMS released its *Five Year Royalty in Kind Business Plan* outlining the business principles, objectives, and specific action items that will guide and evolve the Federal RIK program from FY 2005 through FY 2009. The Plan, which marks the transition of the MMS RIK initiative from pilot projects to operational program, is aimed at attaining an effective, steady-state RIK program of the highest quality and integrity. The first two years of operations under the Plan are dedicated to enhancement of the internal control environment, organizational structure, in-house human resource skill sets, and performance measurement capability. The Plan's out-years focus on refining the RIK commercial business model to optimize benefits to the Government.

2 RIK Program Status

2.1 Business Model/Approach

The Minerals Management Service Royalty in Kind program has adopted the business strategy of a conservative producer/seller of energy commodities at entry points into the wholesale market at or near the lease in producing areas. All sales are competitively made and revenues are received based on the spot market for physical sales transactions as reported by the major price reporting publications at the most liquid and transparent market points. The MMS does not employ strategies involving speculative storage positions, fixed prices, hedging, or financial derivatives. Typically, sales are for multi-month terms, at this point in time for periods no more than 1 year in length. Transportation and processing contracts are negotiated and executed where favorable to optimize revenue returns over RIV. Standard industry contracts and business processes are used.

The above business model is consistent with statutory authorities, and reflects a conservative approach designed to minimize the government's risk profile and selectively leverage the value of oil and gas lease terms that allow both the RIV and RIK options.

2.2 Status and Scope of the Program

The Federal RIK Program has matured and is now in its second full year of operational status after six years of pilot testing. Budgets, organization, staff, and management are in place. A focused business model, internal controls, information systems, risk policies/procedures, and standard commercial business processes are operating. Business relationships with state partners and industry counterparties and partners are established.

In FY 2005, a total of 82,364,035 barrels of oil equivalent (BOE) was taken in kind and sold or exchanged by MMS, reflecting a value of \$3,727,467,532. This volume is 97% of the volumes taken in kind for FY 2004, and the value represents a 39% increase over FY 2004 RIK values.

Federal oil and gas royalties are taken in kind in 22 portfolios within the two major business units of crude oil and natural gas RIK. The Federal royalty position in the Gulf of Mexico is the core business focus area for both the crude oil and natural gas programs. As of the end of FY 2005, MMS took in kind approximately 75% and 30% of the crude oil and natural gas royalty volumes, respectively, produced daily in the Gulf of Mexico.

As of September 30, 2005, MMS RIK held 90 active contracts, including 27 active sales or exchange contracts and 63 contracts for transportation, processing, and miscellaneous services executed pursuant to DOI annual appropriations authorities. Payments for services under these contracts totaled \$16,011,906 for crude oil and \$1,521,884 for natural gas in FY 2005.

2.3 Natural Gas RIK Business Unit

During FY 2005, the MMS RIK program for natural gas was exclusively applied to Gulf of Mexico royalty volumes. No onshore Federal natural gas was taken in kind, although, on behalf of the Bureau of Land Management, MMS sold natural gas volumes associated with decommissioning of the National Helium Reserve. In FY 2005, gas RIK volumes totaled nearly 183 million MMBtu (million British Thermal Units) – over 500,000 MMBtu/day - sold in 17 sales portfolios. Revenues received from competitive sales of these royalty volumes equaled nearly \$1.25 billion, a 37% increase from FY 2004.

In FY 2005, the MMS natural gas RIK program increased a modest 8% in volumes taken relative to FY 2004. Two major sales events occurred, in October 2004 and March 2005 for the ensuing U.S. domestic heating and cooling seasons, respectively. Participation and competition continued at a high level in these sales with respect to both numbers and diversity of bidders. Bidders included mid-stream marketers, major producers, utilities, industrial end users, and financial institutions. The October 2004 sale attracted 19 companies offering a total of 97 bids, and the March 2005 sale attracted 19 companies offering 126 bids. Individual sales packages typically generated more than seven bids each.

At the end of FY 2005, natural gas royalty production from 361 leases in the Gulf of Mexico delivered into 16 pipelines was being sold in kind by MMS to 14 counterparties. A total of 19 purchasers bought RIK gas in FY 2005. These sales were supported by 43 transportation, processing, and miscellaneous service contracts. Significant additions to the RIK gas program in FY 2005 included Gulf of Mexico leases producing gas into the Transco Southeast Lateral and Trunkline Pipeline, together adding nearly 51,000 MMBtu/day to the RIK gas volumes sold. In March 2005, leases producing into the Matagorda Offshore Pipeline System were reverted back to RIV status, after economic analysis indicated revenues would likely be increased by that action.

In August 2005, the MMS Executive Committee approved the first MMS RIK natural gas project for onshore leases – focused on Federal leases in Wyoming. This decision, based on a nearly one year study of Wyoming natural gas markets involving both MMS staff and outside commercial consultants, was also endorsed by the Wyoming State Land Board. The project commences in April 2006 with approximately 30,000 MMBtu/day of gas production from the Madden Field and is anticipated to grow commensurate with opportunities and success.

2.4 Crude Oil RIK Business Unit

The FY 2005 MMS RIK program for crude oil was applied to royalty volumes produced in the Gulf of Mexico, Pacific Outer Continental Shelf (OCS), and Federal lands in Wyoming. Crude oil RIK volumes totaled nearly 52 million barrels (or over 142,000 barrels/day) in five sales/exchange portfolios. This represents a 9% decline in volumes taken in kind, resulting primarily from

hurricane effects. The value of these royalty volumes was nearly \$2.5 billion. Revenues received from competitive sales of these royalty volumes equaled over \$1.263 billion, while the value of crude oil involved in the non-monetary exchange to the Department of Energy for the Strategic Petroleum Reserve (SPR) was \$1.195 billion. The five crude oil RIK portfolios in FY 2005 were:

- Small Refiner Program (Gulf of Mexico): 12,556,031 barrels sold for net value of \$597,608,325
- Small Refiner Program (Pacific OCS): 2,768,916 barrels sold for net value of \$105,848,071
- "Unrestricted" Crude Oil Sales (Gulf of Mexico): 10,079,297 barrels sold for net value of \$527,705,356
- Wyoming Crude Oil Sales: 684,719 barrels sold for net value of \$31,914,004
- SPR Crude Oil Exchange: 25,608,852 barrels exchanged to DOE representing net value of \$1,194,617,678

In FY 2005, the MMS crude oil RIK business unit saw significant change. The SPR Fill Initiative began winding down in April 2005 and was completed at the end of August 2005. Volumes committed to the SPR decreased from 38.8 million barrels in FY 2004 to 25.6 million in FY 2005, a decrease of 13.2 million barrels. Volumes supporting the Pacific Small Refiner Program decreased by 10% from FY 2004. On the other hand, volumes supporting the unrestricted commercial sales portfolio increased from 731,000 barrels in FY 2004 to 10.1 million in FY 2005.

The marked increase in the unrestricted sales portfolio reflects conversion of crude oil producing properties from the SPR Fill Initiative to this revenue-generating RIK sales portfolio. The unrestricted crude oil sales portfolio is distinct from the small refiner portfolio, which is open only to bids from companies that qualify by regulation as "small refiners". The unrestricted portfolio originally began operations in October 2001, but was terminated in April 2002 due to the need to promptly respond to the President's directive to fill the SPR. Several factors drove the re-emergence of this sales portfolio:

- Marked increases in crude oil transportation routes to markets in the Gulf of Mexico. Crude oil marketers of larger size and capabilities than the small refiner community are better able to exploit this increase in diversity of transportation and markets, providing greater revenues to the government
- Joint desire of MMS and the State of Louisiana to increase the number of market participants in a new RIK partnership (see below)

Royalty production from two major crude oil types – HOOPS and Southern Green Canyon – was converted to RIK during FY 2005. New RIK production from these properties was approximately 20,000 barrels/day. However, these additions were

not sufficient to offset significant production losses due to the devastating effects of Hurricane Katrina in September 2005, in which the entire stream of Heavy Louisiana Sweet and the majority of Mars crude oil production were shut in.

At the end of FY 2005, crude oil royalty production from 1,378 onshore and offshore leases (596 in Wyoming; 782 on the OCS) delivered into 55 pipelines was being competitively sold or exchanged to 13 counterparties. The sales and exchanges were supported by 20 transportation and miscellaneous service contracts.

2.5 Partnerships with States and Other Federal Agencies

The MMS continued to jointly engage in RIK activities under a series of memorandums of understanding with states and federal agencies:

- Joint sales of crude oil produced from Federal and State leases in the State of Wyoming, a business partnership in place since 1998. This agreement now includes natural gas RIK sales as well.
- RIK sales of natural gas produced from the 8(g) zone offshore Texas, a collaborative project with the State of Texas since 1999.
- RIK sales of natural gas/crude oil produced from the 8(g) zone offshore Louisiana, a partnership with the State of Louisiana begun in FY 2004.
- Sales of natural gas produced from the National Helium Reserve as the Reserve is decommissioned by the Bureau of Land Management
- Crude oil exchanges from producing leases in the Gulf of Mexico for delivery to the Department of Energy in the joint SPR Fill Initiative

3 Business Plan Implementation

The Minerals Management Service continued implementing management action items of the *Five Year Royalty in Kind Business Plan* in FY 2005. The Plan includes guiding business principles, commercial objectives, and administrative goals, including:

- Meet or exceed revenue benchmarks consistent with statutory authorities
- Enhance net revenue by \$50 million over 5 years
- Effectively manage/reduce administrative costs by 10%, per unit volume
- Effectively contribute to the Nation's strategic energy initiatives
- Implement systematic measurement of RIK program performance
- Maintain the highest ethical and professional standards

The Plan calls for completion of organizational changes, process improvements and personnel enhancements during the first and second years. When this RIK framework is fully operational, MMS will be in a better position to take advantage of market opportunities through implementing the enhanced marketing strategies and expand RIK volumes. All the specific goals and objectives are designed for completion by the end of the five year business plan.

Business Plan Segment	Implementation Steps	Quarter	Year 1				Year 2				Year 3				Year 4				Year 5			
			1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4
Policy Oversight Function	Develop & Implement RIK Risk Policy & Procedures																					
	Develop Internal Management Control Review ("IMCR") Guidelines																					
Performance Measurement	Develop & Implement Rev. Perf. Measurement Metrics & Procedures																					
	Develop & Implement Admin. Perf. Measurement Metrics & Procedures																					
	Complete Administrative Cost Comparison for RIV/RIK																					
Organization & Human Resources	Complete RIK Organizational Structure																					
	Acquire or Contract for Required Personnel and Skill Sets																					
	Ongoing Training Program for Mktg. & Scheduling Functions																					
Expanding Marketing Strategies	Develop, Implement & Utilize Expanded Marketing Strategies																					
	Complete Initial WY Assessments																					
	Assess & Develop Specific Opportunities with Producing States																					
Information Systems Improvements & Process Controls	Finalize/Develop Implementation of Perf. Measurement Modules																					
	Implement Pipeline Pool Scheduling Capabilities																					
	Assess/Improve Systems Capabilities to Reflect Expanded Marketing																					
Business Plan Performance Monitoring	Measure Progress on 5-year Objectives Periodically																					
	Reevaluate Assumptions and Drivers of the Business Plan																					
	Develop New Five-Year Business Plan																					
Communication & Outreach	Brief Congressional Members and Staff on RIK 5-year Plan																					
	Provide Presentations/ Feedback Sessions with States, Industry, and other Stakeholders																					
	Facilitate Review Session within MRM Organization Regarding Interrelationships and Synergies																					

3.1 Accomplishments

Actions envisioned for the second year of the Plan (FY 2006) are on schedule. These include actions in risk procedures, performance measurement, and human resource areas. Performance measurement is described in the next section of this status report.

3.1.1 Risk Policy Tasks

The Plan calls for the development of a comprehensive RIK risk policy framework consisting of both a risk policy and associated procedures. The RIK Risk Management Policy was completed in August 2005, and can be found on the MMS web site. Procedures to implement the risk policy have also been developed and are now being implemented.

3.1.2 Organizational Tasks

The organizational objectives of the Plan include further increasing efficiencies and internal controls through complete implementation of the industry-standard front, mid, and back office environment, augmented by an independent risk office with economic analysis capability.

The primary organizational changes outlined in the Plan have been accomplished. Further organizational changes may be necessary in the Plan's out-years. The following changes have occurred to date:

- Creation of a SES-level RIK organizational entity
- Establishment and filling of a Chief Risk Officer position/role outside of RIK line management, with responsibility for oversight of the RIK risk policy environment.
- Creation of an RIK Back Office and movement of the back office functions of accounting, reconciliation, and receivables/payables into this office from the front office entities where they previously resided – resulting in even tighter internal controls.
- Establishment of an Economic Analysis Office in which support services related to portfolio analysis and performance measurement now reside. Performance measurement services are conducted under the guidance and review of the Chief Risk Officer.

3.1.3 Human Resources Tasks

A primary human resource-related objective of the Plan is to institute an internal commercial capability to expand the RIK business model to that of an active energy commodity producer/seller in upstream locations. Additionally, other activities will be best served through commercial contract support. The identified internal skill sets needing enhancement include marketing, scheduling, and economic analysis. The Plan stresses the importance of building a significant RIK front office (marketing and scheduling) capability in Houston, the production/marketing hub of the domestic petroleum industry.

The following tasks have been accomplished:

- Filled management positions in the new RIK organization: deputy manager, gas front office and economic analysis office
- Staffed the RIK Economic Analysis Office nearly to full build-out

Several additional human resource elements in the Plan, including enhancement of commercial/legal contracting capabilities and retention of scheduling and marketing expertise, are currently being implemented.

4 RIK Program Performance

In the first year of the *Five Year Royalty in Kind Business Plan* (FY 2004), Minerals Management Service fully established a comprehensive system of RIK program performance measurement - for both revenue receipts and administrative costs. Based on this action, the GAO concluded that MMS had fully implemented their recommendations that MMS should routinely monitor RIK program performance. Accordingly, these recommendations are now closed.

4.1 Administrative Cost Performance

FY 2005 was the second year in which MMS performed a comprehensive comparative analysis of the costs of administering the RIK and RIV programs at MMS. The FY 2005 cost per "barrel of oil equivalent" or BOE for RIK is 5.9 cents (nearly identical to FY 2004's cost of 5.6 cents/BOE). This compares to a FY 2005 cost of 10.2 cents/BOE for RIV, and represents a 42 percent reduction attributable to RIK. Using producing properties as the unit of measurement, the FY 2005 RIK cost per unit is \$7,128 compared to \$15,015 for RIV, a 52 percent reduction in costs.

Using the more conservative BOE unit comparison, the increase in efficiency from RIK activity translates to a cost avoidance of \$3.74 million. That is, if RIV were applied to all BOE at the 10.2 cent rate versus a combination of RIK and RIV at the 5.9 and 10.2 cent rates, respectively, additional costs of \$3.74 million would have accrued.

The RIV activities cost more than RIK primarily due to the necessity to audit the value and transportation costs associated with sales and movement of Federal mineral production. These audit requirements are inherently labor intensive due to the complexity of the interrelationships between the business practices of hundreds of mineral lessees and a set of valuation regulations that prescribe royalty payment standards applied to complex, dynamic market conditions. In RIK situations, valuation and transportation are determined by unambiguous contract terms, thus providing for efficiencies and lack of conflict.

Additionally, we note several lines of qualitative data that indicate efficiencies due to RIK implementation. As of the end of FY 2005, out of 120 pending administrative appeals of mineral royalty management decisions, none were RIK-related. The number of appeals is a direct measurement of the potential for litigation and thus cost. Additionally, the time taken to close accounting periods under the RIK method is notably condensed compared to the RIV business cycle of at least 3 years. Specifically, for FY 2005, 85% of RIK business activity was closed within 180 days of the month of RIK production.

4.2 Revenue Performance

Similar to administrative cost measurement, FY 2005 was the second full year in which the revenue performance of all RIK sales portfolios was measured. Revenue performance of the SPR Fill Initiative was not measured since it is not

revenue producing. Measurements took place quarterly, approximately 4 months after the end of the quarter being measured. The measurement process is performed under the direction, guidance, and review of the MRM Chief Risk Officer, reporting outside of RIK line management to the Associate Director for Minerals Revenue Management, with "dotted line" reporting to the MMS Executive Committee. This is directly analogous to the organizational structure and reporting relationships existing in commercial enterprises relative to revenue performance measurement.

4.2.1 Principles Underlying the Measurement

In MMS's revenue performance metrics, the objective is to measure RIK revenues against benchmarks created to represent fair market value. The primary principle underlying this system is that the benchmarks should represent a defensible interpretation of MMS's RIK statutory requirements to achieve both fair market value (authorizing legislation) and the value MMS would have received under a comparable royalty in value program (appropriations legislation). Additional principles in this area are that the methodology used to create the "fair market value" benchmarks should:

- Recognize that fair market value is a range of values rather than an absolute number
- Be well-defined, repeatable, and statistically accurate
- Apply across different time periods and groupings of properties/portfolios
- Reflect reasonable labor requirements
- Use as much royalty in value data as possible
- Use transparent market data as much as possible when accurate in value data are not available

4.2.2 Results

Measurement of MMS's RIK revenue performance for FY 2005 indicates a revenue gain of \$30.8 million related to both the natural gas and crude oil business units. Combined with an additional revenue gain of \$1.5 million in additional interest earned on RIK revenues received 5 to 10 days earlier than under the RIV program, a total revenue gain of \$32.3 million was measured for the MMS RIK program in FY 2005 (Figure 1). These results indicate that the five-year, \$50 million incremental revenue goal for the MMS RIK program is quite achievable. However, it should be noted that revenue gains will be variable and future gains – or losses – are not possible to predict. This fact underscores the importance of the associated administrative benefits of RIK described above.

Figure 1: Overall RIK Revenue Performance for FY 2005

Category	Revenue Gain (Natural Gas)	Revenue Gain (Crude Oil)	Total
Sales	\$18,640,086	\$12,150,397	\$30,790,483
Interest	\$505,002	\$1,023,548	\$1,528,550
Total	\$19,145,088	\$13,173,945	\$32,319,033

The revenue results discussed in this section are used by MMS in several ways. This report conveys the results to MMS stakeholders in the minerals revenue management program. Internally, MMS uses the results to measure RIK program performance relative to the program objectives. Lastly, the results are provided to the RIK front office marketers to enhance their ongoing commercial decision making. Suboptimal results for individual sales portfolios may result in changes to marketing/contracting practices or conversion of properties or portfolios to RIV status.

RIK Natural Gas Portfolios. Domestic natural gas markets in FY 2005 were robust, with GOM prices ranging from \$5 to \$7 per MMBtu. August and, especially, September 2005 brought a notable spike in GOM prices up to \$12 per MMBtu, as the effects of devastating hurricanes on natural gas markets were seen. Price volatility was high. Although domestic crude oil prices also increased with corresponding increases in NGL prices, gas processing economics were generally negative in FY 2005 (i.e., unprocessed gas was generally of greater value than residue gas plus NGLs).

For FY 2005, the average RIK sales price for GOM gas was \$6.88/MMBtu, whereas the average Henry Hub price was \$7.15/MMBtu. The 29 cent difference in these prices is a reasonable and demonstrable effect of transportation differentials and processing costs on a net MMS price at the offshore platform versus a gross Henry Hub price at the primary GOM onshore market center.

Figure 2 shows FY 2005 revenue performance for the RIK natural gas portfolios - a revenue gain of \$18.6 million or 10.1 cents/MMBtu. (FY 2004 gain was \$8.4 million). This represents a gain of slightly less than 1.5% over fair market value benchmarks, compared to a FY 2004 gain of 1%. The significantly higher FY 2005 revenue gains reflect the impact of a slight increase in percentage gain applied to the substantially higher FY 2005 absolute natural gas prices.

Performance for the 17 sales portfolios ranges from a low of a 3.65% loss for the Matagorda Offshore Pipeline System (MOPS) to a gain of nearly 4% for the Texas Eastern Transmission Company Pipeline (TETCO). Thirteen of the 17 portfolios show revenue gains. The sales packages with the largest revenue gains were TETCO, Garden Banks, Mississippi Canyon, ANR, and Viosca Knoll. Factors contributing to these gains include:

- Processing: The size of the Federal royalty position was used to leverage greater processing returns where options to process at several plants exist. Many producers have locked in multi-year processing arrangements negotiated at prior times more favorable to processors than producers. Although processing economics were generally negative in FY 2005, MMS processing contracts provided more economic options than most producers and acted to limit negative returns on production taken in kind. For one

particularly favorable contract, MMS was able to share in liquids revenues at no cost in either cash or relinquished gas volumes – a unique success accruing from the large Federal portfolio on this pipeline.

- **Transportation:** Again, MMS leveraged the size of the Federal portfolio for significantly discounted transportation rates where multiple transportation options exist, as pipelines competed against each other to service MMS gas that was previously contracted by producers for long periods to just one pipeline. Lower rates translate to higher net receipts to the Treasury.
- **Basis Transactions:** Based on market intelligence, MMS priced several sales packages not on the most local price index but on a more regional index with a location differential (basis) typically deducted from the price. As absolute gas prices increased during FY 2005, the basis between pricing points generally increased (reflecting increased cost of fuel) beyond the basis included in MMS contracts. Accordingly, MMS's net value received for these transactions reflected lesser basis deductions than the market indicated and thus exceeded the market.

The RIK front office has determined that revenue losses for the "MOPS" sales portfolio during FY 2005 were likely to continue under RIK. Accordingly, this sales package was converted back to RIV status effective April 2005.

RIK Crude Oil Portfolios. Domestic crude oil markets were also robust in FY 2005 with prices increasing to new benchmark levels. Crude oil (WTI Cushing – the NYMEX crude oil benchmark price) steadily rose from the mid \$40 level early in the fiscal year to the mid \$60s in September 2005 in the aftermath of Hurricane Katrina. Sweet grades of Gulf Coast crude oil ("LLS" and "HLS") were particularly strong, while Gulf Coast sour grades trailed behind as published differentials to WTI approached \$10 at times. The MMS RIK barrels are predominantly Gulf Coast sour crude types, and thus the 2005 value of the RIK crude oil portfolio reflected these steep differentials to WTI (see below). Sour crude oil grades produced in Wyoming were valued at even higher discounts to WTI - over \$20/barrel at times.

Importantly, the domestic crude oil market in FY 2005 exhibited a persistent "contango" trend (lower near term value and higher future values). The FY 2005 average contango value exceeded 70 cents. This observation is important to crude oil royalties because buyers and sellers adopt pricing provisions that can favor a contango market or its opposite, a backwardated market.

For FY 2005, the average RIK sales price for GOM crude oil was \$48.41/barrel, whereas the average NYMEX WTI price was \$53.80/barrel. The \$5.39 difference in these prices is a reasonable and demonstrable effect of transportation, quality, and crude oil grade type differentials from the WTI Cushing price to the offshore platform. Deductions for transportation can often range between \$1 to \$2/barrel.

However, the most significant factor in this comparative difference is far and away the effect of sour crude oil grade types on RIK price in the Gulf of Mexico. In particular, significant discounts to WTI were seen for the following GOM crude types (stated as averages/barrel for the fiscal year): Mars (\$7.03), Bonito Sour (\$3.49), Poseidon (\$5.85), and Eugene Island (\$3.73).

Figure 3 shows FY 2005 revenue performance for the RIK crude oil portfolios – a revenue gain of \$12.2 million or 47 cents per barrel (FY 2004 gain was \$8.4 million). This represents a gain of nearly 1% over fair market value benchmarks, compared to a FY 2004 gain of 1.5%. The significantly higher FY 2005 revenue gains reflect the impact of continued solid percentage gains applied to 66% more crude oil volumes sold (rather than exchanged to SPR) at much higher prices.

Performance of the four measured portfolios was revenue positive in all cases and ranges from a low of .3% gain for the small refiner portfolio in the Gulf of Mexico to a high of a 5.8% gain for the Wyoming portfolio. Factors contributing to these gains include:

- The MMS priced a portion of crude oil sales on a fixed 6-month "NYMEX roll" methodology that, in a contango market, can significantly improve revenues relative to the routine 3-month market pricing method.
- Increasing optionality in crude oil transportation and sales markets was leveraged for substantial RIK volumes, leading to increased revenues.
- The MMS priced a major Wyoming sales transaction off NYMEX quotes rather than the more routine Canadian indices, just prior to significant increases in NYMEX prices and decreases in Canadian indices.

5 Conclusions and Preview of FY 2006

Fiscal Year 2005 saw the continuing positive evolution of the Minerals Management Service Royalty in Kind program as a fully operational component of MMS's asset management approach to managing the Nation's mineral royalty asset stream. The President's directive to fill the SPR was completed, well ahead of schedule and at the least cost and highest effectiveness and efficiency. Producing properties supporting the SPR fill were seamlessly converted to commercial sales programs. Capabilities to manage the RIK portfolio were enhanced through development and publication of the RIK Risk Management Policy. RIK program performance far outpaced program goals, reflecting the influences of the various technical factors described above. However, more important than technical considerations, the overarching factor in this success is the development and maturation of the skill sets and experience of the RIK staff applied to the substantial Federal oil and gas royalty portfolio.

In FY 2006, continued progress is being made in implementing the RIK business plan. Work will continue on enhancing human resource skill sets, focused on strengthening a Houston RIK presence. We anticipate completion of the RIK risk management framework through full implementation of risk procedures and metrics that will fully implement the RIK risk policy.

Operationally, MMS will continue to explore opportunities for program application. We expect that the natural gas RIK business unit will expand substantially in the GOM and Wyoming now that the RIK internal control, risk policy, and human resource foundations have been built. The crude oil business unit will remain relatively static in size. Modest expansions of the RIK business model for both oil and gas will include diversification of transactional structures and increased transportation of commodity to market centers.

Energy commodity markets are showing continued strength in FY 2006. Market strength at these levels is associated with a seller's market, a situation favoring producer/sellers of crude oil and natural gas, like the MMS RIK presence. However, several challenges exist. High energy commodity prices bring high volatility and dynamic basis relationships between pricing points. MMS RIK entry into the Rocky Mountain natural gas markets presents more direct exposure to a delicate balance between rapidly expanding regional production and the capacity to transport gas to consuming regions. As a result, price risk is increased. Lastly, large builds in both crude oil and natural gas inventories in early FY 2006 are causing domestic market softness for wholesale energy sales, especially with respect to natural gas. Each of these challenges is manageable by capture and application of market intelligence and diligence in sales execution.

Figure 2: FY 2005 Natural Gas RIK Revenue Performance

Gas System	Total Volumes	per day	RIK Revenues	Gain (Loss)	Per MMBtu	Percent
ANR Nearshore	15,305,028	41,932	\$106,243,970	\$2,689,981	\$0.176	2.53%
Columbia	6,185,601	16,947	\$43,662,256	\$577,531	\$0.093	1.32%
CTGS	14,416,248	39,497	\$94,603,370	\$(47,982)	\$(0.003)	-.05%
Garden Banks	15,654,027	42,888	\$108,788,054	\$2,251,167	\$0.144	2.07%
HIOS	19,690,035	53,945	\$133,699,258	\$2,143,515	\$0.109	1.60%
Manta Ray	7,032,080	19,266	\$49,541,378	\$819,882	\$0.117	1.65%
MOPS	2,512,876	13,883	\$15,782,037	\$(576,555)	\$(0.229)	-3.65%
NHIS	21,508,086	58,926	\$152,934,981	\$947,952	\$0.044	0.62%
Seagull/Blessing	5,538,606	15,174	\$37,617,686	\$143,218	\$0.026	0.38%
Stingray	15,023,297	41,160	\$100,869,162	\$(121,585)	\$(0.008)	-0.12%
TGP 500/Viosca Knoll	6,887,220	18,869	\$46,788,577	\$529,164	\$0.077	1.13%
TGP 800	5,750,582	15,755	\$40,207,854	\$239,513	\$0.042	0.60%
Transco SE	6,944,258	20,791	\$49,799,999	\$949,442	\$0.137	1.91%
Trunkline	5,459,839	29,999	\$39,550,059	\$(211,835)	\$(0.039)	-0.54%
TETCO (E. La)	12,095,584	33,139	\$83,512,513	\$3,293,777	\$0.272	3.94%
Mississippi Canyon	13,911,568	38,114	\$93,045,979	\$3,283,204	\$0.236	3.53%
Viosca Knoll	10,082,386	27,623	\$68,977,988	\$1,729,697	\$0.172	2.51%
Grand Totals	183,997,321	527,907	\$1,265,625,121	\$18,640,086	\$0.101	1.47%

Figure 3: FY 2005 Crude Oil RIK Revenue Performance

Oil Sale	Total Volumes	per day	RIK Revenues	Gain (Loss)	Per bbl	Percent
Small-Refiner (GOM)	12,556,031	34,400	\$597,608,325	\$1,803,837	\$0.14	0.30%
Small-Refiner (Pacific)	2,768,916	7,586	\$105,848,071	\$2,770,092	\$1.00	2.62%
Unrestricted Sale (GOM)	10,079,297	27,615	\$527,705,356	\$5,741,065	\$0.57	1.09%
Wyoming	684,719	1,876	\$31,914,004	\$1,835,404	\$2.68	5.8%
Grand Totals	26,088,963	71,477	\$1,263,075,756	\$12,150,397	\$0.47	0.96%

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 157

(Docket No. RM05-1-000)

Order No. 2005

Regulations Governing the Conduct of Open Seasons for Alaska Natural Gas
Transportation Projects

(Issued February 9, 2005)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule.

SUMMARY: The Federal Energy Regulatory Commission is amending its regulations to establish requirements governing the conduct of open seasons for proposals to construct Alaska natural gas transportation projects. This Final Rule fulfills the Commission's responsibilities to issue open season regulations under section 103 of the Alaska Natural Gas Pipeline Act (the Act), enacted on October 13, 2004. Section 103(e)(1) of the Act directs the Commission, within 120 days from enactment of the Act, to promulgate regulations governing the conduct of open seasons for Alaska natural gas transportation projects, including procedures for allocation of capacity. As required by section 103(e)(2) of the Act, these regulations (1) include the criteria for and timing of any open season, (2) promote competition in the exploration, development, and production of Alaska natural gas, and (3) for any open seasons for capacity exceeding the initial capacity, provide for the opportunity for the transportation of natural gas other than from the Prudhoe Bay and Point Thomson units.

EFFECTIVE DATE: The rule will become effective 90 days after publication in the FEDERAL REGISTER.

FOR FURTHER INFORMATION CONTACT:

Whit Holden, Office of the General Counsel, (202) 502-8089, edwin.holden@ferc.gov
Richard Foley, Office of Energy Projects, (202) 502-8955, richard.foley@ferc.gov
Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426

SUPPLEMENTARY INFORMATION:

110 FERC ¶ 61,095
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
Nora Mead Brownell, Joseph T. Kelliher,
and Suede G. Kelly.

Regulations Governing the Conduct of Open
Season for Alaska Natural Gas Transportation
Projects

Docket No. RM05-1-000

ORDER NO. 2005

FINAL RULE

(Issued February 9, 2005)

1. The Federal Energy Regulatory Commission is amending its regulations to establish requirements governing the conduct of open seasons for capacity on proposals to construct Alaska natural gas transportation projects. This Final Rule fulfills the Commission's responsibilities to issue open season regulations under section 103 of the Alaska Natural Gas Pipeline Act (the Act), enacted on October 13, 2004.¹ Section 103(e)(1) of the Act directs the Commission, within 120 days from enactment of the Act, to promulgate regulations governing the conduct of open seasons for Alaska natural gas transportation projects, including procedures for allocation of capacity. As required by section 103(e)(2) of the Act, these regulations (1) include the criteria for and timing of any open season, (2) promote competition in the exploration, development, and production of Alaska natural gas, and (3) for any open seasons for capacity exceeding the initial capacity, provide for the opportunity for the transportation of natural gas other than from the Prudhoe Bay and Point Thomson units.

¹ Public Law 108-324, October 13, 2004, 118 Stat. 1220.

2. As Congress has recognized, construction of a natural gas pipeline from the North Slope of Alaska to markets in the lower 48 states is in the national interest and will enhance national energy security by providing access to the significant gas reserves in Alaska to meet anticipated demand for natural gas. A successful Alaska natural gas transportation project will have to overcome a variety of significant logistical and procedural obstacles. The Commission strongly believes that it is in the mutual interest of the parties interested in such a project to reach a common understanding, in order to support a proposal that meets their needs and those of the Nation. To that end, the Commission urges the parties to expend their efforts in negotiation, compromise, and project development, such that this vital project can become a reality.

Background

3. Under the Act, Congress mandated the expedited processing by the Commission of any application for an Alaska natural gas transportation project, namely any natural gas pipeline that carries natural gas derived from that portion of Alaska lying north of 64 degrees north latitude to the border between Alaska and Canada. The Act specifically directs the Commission to prescribe the rules which will apply to any open season held for the purpose of acquiring capacity on any Alaska natural gas transportation project, including the criteria for allocating capacity among competing bidders.

4. In response to the Act's directive, on November 15, 2004, the Commission issued in Docket No. RM05-1-000 a Notice of Proposed Rulemaking (NOPR) containing the Commission's proposed Alaska natural gas transportation project open season regulations as a new Subpart B to Part 157 of the Commission's regulations. The NOPR stated that comments were to be filed by December 17, 2004, and that the Commission intended to issue the final regulations by February 10, 2005, in order to comply with the Act's 120-day deadline.

5. The Commission held a public technical conference in Anchorage, Alaska on December 3, 2004 to develop a record in this proceeding. At the conference, speakers including Alaska elected officials, Alaskan Natives, representatives of potential project sponsors, representatives of potential shippers, and representatives from other agencies or

affected enterprises or the general public presented their views on the NOPR and related issues. A transcript of the technical conference was filed in the record in this proceeding.²

6. Before the NOPR was issued, the Commission received comments and suggested open season requirements from several interested parties, including BP, ConocoPhillips, and ExxonMobil (North Slope Producers),³ other natural gas producers, potential project sponsors, and members of the Alaska legislature. In addition to the pre-NOPR comments and technical conference presentations, comments were filed by 25 interested parties.⁴ One group of commenters, including the North Slope Producers, who together own the majority of proven gas reserves on Alaska's North Slope at Prudhoe Bay and Point Thomson, and several pipeline companies (TransCanada, MidAmerican/AGTA, and Enbridge) are potential sponsors of an Alaska natural gas transportation project. Another group of commenters is made up of entities with Alaska-based interests⁵, including elected officials. Yet another definable group consists of potential shippers, including explorers and producers other than the North Slope Producers, marketers, local distribution companies, power generators, and industrial end users.

Overview of Regulatory Approach

7. The comments filed in response to the NOPR are discussed at length below, broken down by specific issues. However, broadly speaking, several commenters, led by the North Slope Producers, MidAmerican/AGTA, and TransCanada, expressed general

² The Commission received, on December 23, 2004, January 10, 2005, and February 2, 2005, three motions to correct the transcript. The Commission approves the proposed corrections and incorporates them into the record of this proceeding. Commenters at the technical conference are listed in the Appendix.

³ The short-form names used for commenters and other abbreviations used in this order are listed in the Appendix.

⁴ These commenters are also listed in the Appendix.

⁵ This group includes AOGCC, ANGDA, Alaska, Alaska Legislators, Arctic Slope and Doyon.

support for the Commission's approach in developing the proposed regulations in the NOPR.⁶ These commenters perceive the proposed regulations as being not overly prescriptive, yet providing a fair and open process to obtain capacity on an Alaska pipeline on a non-discriminatory, non-preferential basis. As potential shippers, these commenters are encouraged that the proposed rules permit the sponsors the flexibility to design and conduct the initial and expansion open seasons. They claim that such flexibility is important in helping a project sponsor properly size the pipeline and satisfy the demands of financiers.

8. A number of the commenters, however, fault the Commission for not proposing detailed rules regarding certain elements of the open season, including timing of the open season, and the criteria for evaluating bids and allocating capacity in the event capacity on the proposed project is oversubscribed. These commenters claim that the Commission has deferred to the project sponsors too much of the responsibility of establishing the criteria for and timing of open seasons for Alaska projects. In addition, commenters whose interests are tied to the State of Alaska claim that the proposed rules ignore the requirements of section 103(g) regarding in-state needs for natural gas.⁷ Potential project sponsors favor the flexibility they believe is provided in the proposed rules in order to appropriately develop an Alaska natural gas transportation project. Other interested parties express concern that the North Slope Producers, either as project sponsors or as producers whose reserves will support the initial development of the project, will use that flexibility to develop open season rules to accommodate their own interests, to the exclusion and detriment of other explorers, developers and producers of Alaska natural gas, as well as of those seeking access to the pipeline for in-state natural gas demands.

9. As explained in the NOPR, there are no current Commission regulations respecting open seasons. To date, the Commission's policy, developed through its orders and opinions, is that all new interstate pipeline construction be preceded by a non-discriminatory "open season" process through which potential shippers may seek and obtain firm capacity rights. Congress has determined that it is necessary to formalize this Commission policy with specific regulations governing the conduct of open seasons for

⁶ AGA and Northwest Industrial Gas Users also stated general support for the NOPR's proposed rules.

⁷ This section of the Act requires a certificate holder for an Alaska project to demonstrate that it has conducted a study of Alaska in-state needs.