

SCOMM

143:4

SENATE COMMITTEE REPORT First Committee of Referral

DATE: 7/12/06

Date of 5-Day Notice: Special Session
(in accordance with Uniform Rule 23)

FURTHER:

DATE TURNED
IN TO OFFICE: 4 Aug 2006

Senate Special Committee on Natural Gas Development considered SENATE BILL NO. 3002

SB 3002 STRANDED GAS AMENDMENTS

"An Act relating to the Alaska Stranded Gas Development Act; relating to municipal impact money received under the terms of a stranded gas fiscal contract; relating to determination of full and true value of property and required contributions for education in municipalities affected by stranded gas fiscal contracts; and providing for an effective date."

and recommends:

☒ be replaced with ☐ SCS or ☒ CS SB 3002 (NGD)

☐ adopt previous ☐ SCS or ☐ CS _____ (_____)

☐ attached amendment(s)

☐ adopt _____ Letter of Intent

☐ further referral to _____ Committee

SENATE BILL:

☐ Same Title
☒ New Title

HOUSE BILL:

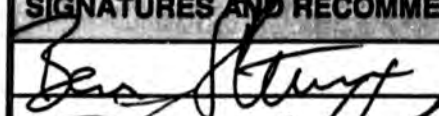
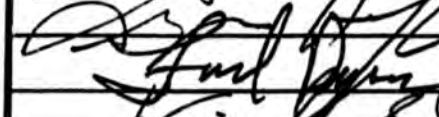
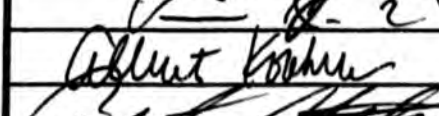
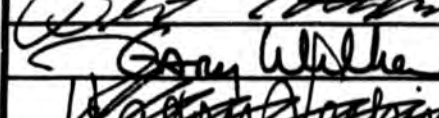
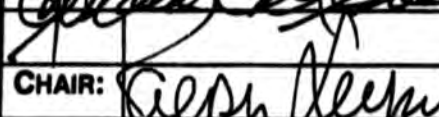
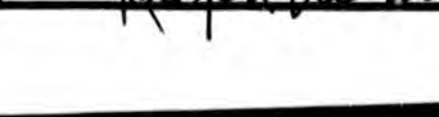
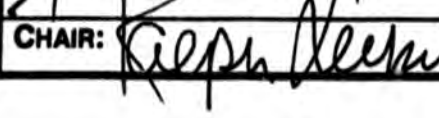
☐ Same Title
☐ Technical Title
Change
☐ New Title w/
SCR #

NEW FISCAL NOTE(S):

Department	Date	Fiscal	Indet.	Zero	FN#

PREVIOUS FISCAL NOTE(S):

Department	Date	Fiscal	Indet.	Zero	FN#
Revenue	7/12/06			✓	#1
Nat. Res.	7/12/06			✓	#2

SIGNATURES AND RECOMMENDATIONS:	PRINTED LAST NAME	Do PASS	Do NOT PASS	No REC	AMEND
		✓			
		✓			
		✓			
		✓			
				✓	
		✓			
		✓			
		✓			
CHAIR: 		✓			

LEGAL SERVICES

DIVISION OF LEGAL AND RESEARCH SERVICES
LEGISLATIVE AFFAIRS AGENCY
STATE OF ALASKA

(907) 465-3867 or 465-2450
FAX (907) 465-2029
Mail Stop 3101

State Capitol
Juneau, Alaska 99801-1182
Deliveries to: 129 6th St., Rm. 329

MEMORANDUM

August 4, 2006

SUBJECT: Technical correction to amended title (CSSB 3002(NGD)
(Work Order No. 24-GS2095V))

TO: Senator Seekins
Chairman of the Senate Special Committee on Natural Gas
Development
Attn: Brian Hove

FROM: Dennis C. Bailey *DCB*
Legislative Counsel

This memo is to bring to your attention a technical amendment to the title change approved by Amendment 13. We have added "and determinations" to the descriptive language of the commissioner's duties in order to conform more closely with the existing statutory language.

If you have any concerns about this technical amendment please let me know.

DCB:lmb
06-203.lmb

Enclosure

SB 3002

[illegible]

Special Committee on Natural Gas Development

8/4 /2006

COMMITTEE ACTION

Bill Number	SB 3002		
Amendment	CS "4"		
Motion	add to ss		
	Working document		
<u>Motion by</u>	Seekins		
<u>Objection by</u>	none		
<u>Removed</u>			
<u>Second Objection by</u>			
<u>Committee Member</u>	Y	<u>Vote</u>	N
Senator Kookesh			
Senator B. Stevens			
Senator Stedman			
Senator Bunde			
Senator Olson			
Senator Dyson			
Senator Wilken			
Senator Elton			
Senator Hoffman			
Vice-Chair Green			
Vice-Chair Wagoner			
Chair Seekins			
<u>Tally</u>			
Yea			
Nay			
Absent			
<u>MOTION</u>	Pass		

Special Committee on Natural Gas Development

8/3/2006

COMMITTEE ACTION

Bill Number	63 3002		
Amendment	CS "F" - as amended		
Motion	Report from Committee		
<u>Motion by</u>	Green		
<u>Objection by</u>	Wilken / Elton / Bunde		
<u>Removed</u>			
<u>Second Objection by</u>			
<u>Committee Member</u>	Y	<u>Vote</u>	N
Senator Kookesh			✓
Senator B. Stevens	✓		
Senator Stedman	✓		
Senator Bunde			✓
Senator Olson			✓
Senator Dyson			✓
Senator Wilken			✓
→ Senator Elton			✓
Senator Hoffman	✓		
Vice-Chair Green	✓		
Vice-Chair Wagoner			✓
Chair Seekins	✓		
<u>Tally</u>			
Yea	5		
Nay	7		
Absent			
<u>MOTION</u>	Fail		

Special Committee on Natural Gas Development

8/3/2006

COMMITTEE ACTION

Bill Number	SB 3002		
Amendment	CS "F"		
Motion	adopt		
<u>Motion by</u>	Green		
<u>Objection by</u>	none		
<u>Removed</u>			
<u>Second Objection by</u>			
<u>Committee Member</u>	Y	<u>Vote</u>	N
Senator Kookesh			
Senator B. Stevens			
Senator Stedman			
Senator Bunde			
→ Senator Olson			
Senator Dyson			
Senator Wilken			
Senator Elton			
Senator Hoffman			
Vice-Chair Green			
Vice-Chair Wagoner			
Chair Seekins			
<u>Tally</u>			
Yea			
Nay			
Absent			
<u>MOTION</u>	Pass		



Official Business

Alaska State Senate

Senate Finance Committee

Mail Stop 3100
State Capitol
Juneau, Alaska 99801-1182

FAX COVER SHEET

DATE: 3 Aug 2006 TIME: _____

TO: Legal Services

NUMBER OF PAGES, INCLUDING COVER SHEET: 8

FROM: MINDY ROWLAND
SENATE FINANCE COMMITTEE SECRETARY
PHONE: 465-4935
FAX: 465-2187

NOTES: Final Please
CS SB 3002 (NGD) 24-GS 2095\F
Bailey 8/3/06
plus amendments - attached
#9
#10
#11

Thanks
Mindy

Adopted 8/4/06

24-GS2095\Y

Bailey

8/4/06

CS FOR SENATE BILL NO. 3002(NGD)**IN THE LEGISLATURE OF THE STATE OF ALASKA****TWENTY-FOURTH LEGISLATURE - THIRD SPECIAL SESSION****BY THE SENATE SPECIAL COMMITTEE ON NATURAL GAS DEVELOPMENT****Offered:****Referred:****Sponsor(s): SENATE RULES COMMITTEE BY REQUEST OF THE GOVERNOR****A BILL****FOR AN ACT ENTITLED**

1 "An Act relating to the Alaska Stranded Gas Development Act; amending the time
2 allowed for the commissioner of revenue to summarize public comments, propose
3 amendments, if any, and make findings; and providing for an effective date."

4 **BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:**

5 * **Section 1.** AS 43.82.430(a) is amended to read:

6 (a) Within 120 [30] days after the close of the public comment period under
7 AS 43.82.410(4), the commissioner of revenue shall

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

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

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

4 * **Sec. 2.** This Act takes effect immediately under AS 01.10.070(c).

24-GS2095\F

Bailey

8/3/06

CS FOR S FOR SENATE BILL NO. 3002(NGD)
IN THE LEGISLATURE OF THE STATE OF ALASKA
TWENTY-FOURTH LEGISLATURE - THIRD SPECIAL SESSION

BY THE SENATE SPECIAL COMMITTEE ON NATURAL GAS DEVELOPMENT

Offered:

Referred:

Sponsor(s): SENATE RULES COMMITTEE BY REQUEST OF THE GOVERNOR

A BILL
FOR AN ACT ENTITLED

1 "An Act relating to the Alaska Stranded Gas Development Act, including clarifications
2 or provision of additional authority for the development of stranded gas fiscal contract
3 terms; making a conforming amendment to the Revised Uniform Arbitration Act;
4 relating to municipal impact money received under the terms of a stranded gas fiscal
5 contract; relating to determination of full and true value of property and required
6 contributions for education in municipalities affected by stranded gas fiscal contracts;
7 and providing for an effective date."

8 **BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:**

9 * **Section 1.** AS 09.43.300(a) is amended to read:

10 (a) AS 09.43.300 - 09.43.595 govern an agreement to arbitrate made on or
11 after January 1, 2005, except as otherwise provided in a contract term developed
12 under AS 43.82.200(a)(5) and (b).

13 * **Sec. 2.** AS 43.82.010 is amended to read:

1 **Sec. 43.82.010. Purpose.** The purpose of this chapter is to

2 (1) encourage new investment to develop the state's stranded gas
3 resources by authorizing establishment of fiscal terms related to oil and gas
4 agreements and taxes for a qualified sponsor, the members of a qualified sponsor
5 group, or a related party and related to their oil and gas business activity in the
6 state, including gas pipeline expansion pricing that encourages further gas
7 exploration [THAT NEW INVESTMENT WITHOUT SIGNIFICANTLY
8 ALTERING TAX AND ROYALTY METHODOLOGIES AND RATES ON
9 EXISTING OIL AND GAS INFRASTRUCTURE AND PRODUCTION];

10 (2) allow the fiscal terms applicable to a qualified sponsor or the
11 members of a qualified sponsor group, or a related party, with respect to a qualified
12 project, to be tailored to the particular economic conditions of the project and to
13 establish those fiscal terms in advance with as much certainty as the Constitution of
14 the State of Alaska allows; and

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

17 * **Sec. 3.** AS 43.82.100 is amended by adding a new subsection to read:

18 (b) A project may not be considered a qualified project under this chapter if
19 the pipeline to transport natural gas from land within the Prudhoe Bay oil and gas
20 lease area follows a route that

21 (1) traverses land beneath navigable waters (as defined in section 2 of
22 the Submerged Lands Act (43 U.S.C. 1301)) of the Beaufort Sea or traverses the
23 shoreline adjacent to the Beaufort Sea; or

24 (2) enters Canada at any point north of 64 degrees North latitude.

25 * **Sec. 4.** AS 43.82.200 is amended by adding a new subsection to read:

26 (b) Terms relating to arbitration and alternate dispute resolution may provide
27 for a waiver, with the concurrence of the attorney general, of the state's immunity from
28 suit. The waiver may include waiver of the state's sovereign or other immunity.

29 * **Sec. 5.** AS 43.82.210(a) is amended to read:

30 (a) If the commissioner approves an application and proposed project plan
31 under AS 43.82.140, the commissioner may develop proposed terms for inclusion in a

1 contract under AS 43.82.020 for periodic payment in lieu of one or more of the
2 following taxes that otherwise would be imposed by the state or a municipality on the
3 qualified sponsor, a [OR] member of a qualified sponsor group, or a related party
4 [AS A CONSEQUENCE OF PARTICIPATING IN AN APPROVED QUALIFIED
5 PROJECT]:

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

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

9 (3) [REPEALED]

10 (4)] Alaska net income tax under AS 43.20;

11 (4) [(5)] municipal sales and use tax under AS 29.45.650 - 29.45.710;

12 (5) [(6)] municipal property tax under AS 29.45.010 - 29.45.250 or
13 29.45.550 - 29.45.600;

14 (6) [(7)] municipal special assessments under AS 29.46;

15 (7) [(8)] a comparable tax or levy imposed by the state or a
16 municipality after June 18, 1998;

17 (8) [(9)] other state or municipal taxes or categories of taxes identified
18 by the commissioner.

19 * Sec. 6. AS 43.82.220(c) is amended to read:

20 (c) The commissioner of revenue shall include any proposed terms
21 [RELATING TO ROYALTY] developed in accordance with this section in the
22 proposed contract under AS 43.82.400.

23 * Sec. 7. AS 43.82.220 is amended by adding a new subsection to read:

24 (e) An agreement by the state to take royalty gas in kind as part of a contract
25 developed under this chapter that satisfies (a) of this section is not subject to the
26 provisions of AS 38, or regulations adopted under that title, relating to decisions to
27 take royalty in kind.

28 * Sec. 8. AS 43.82.230(a) is amended to read:

29 (a) The commissioner shall include in a contract under AS 43.82.020 a term
30 requiring the qualified sponsor, [OR] qualified sponsor group, or a related party, and
31 contractors of the qualified sponsor, [OR] qualified sponsor group, or a related party,

1 to comply with all valid federal, state, and municipal laws relating to hiring Alaska
2 residents and contracting with Alaska businesses to work in the state on the approved
3 qualified project and not to discriminate against Alaska residents or Alaska businesses.
4 Within the constraints of law, (1) the commissioner shall also include in a contract
5 under AS 43.82.020 a term that requires the qualified sponsor, [OR] qualified sponsor
6 group, or a related party, and contractors of the qualified sponsor, [OR] qualified
7 sponsor group, or a related party, to employ Alaska residents and to contract with
8 Alaska businesses to work in the state on the approved qualified project to the extent
9 the residents and businesses are available, competitively priced, and qualified and (2)
10 should the state acquire an ownership interest in the qualified projects as part of
11 a contract developed under this chapter, the parties shall agree to enter into
12 negotiations for project labor agreements to facilitate the construction of the
13 qualified project. To the extent lawful, the parties shall include provisions in any
14 project labor agreement that would promote hiring of Alaska residents and the
15 establishment of hiring halls in both rural and urban communities of the state.

16 * Sec. 9. AS 43.82.250 is amended to read:

17 Sec. 43.82.250. Term of contract; effective date. The term of a contract
18 developed under AS 43.82.020 [MAY BE FOR NO LONGER THAN IS
19 NECESSARY TO DEVELOP THE STRANDED GAS THAT IS SUBJECT TO THE
20 CONTRACT; HOWEVER, THE TERM OF THE CONTRACT] may not exceed 25
21 [35] years from the commencement of commercial operations of the approved
22 qualified project, excluding suspensions of contract obligations that are covered by
23 the force majeure terms of any contract developed under this chapter. However,
24 the term of contract may not exceed 35 years from the effective date of a contract
25 approved under AS 43.82.435.

26 * Sec. 10. AS 43.82.270 is amended to read:

27 Sec. 43.82.270. Project plans and work commitments. A contract under
28 AS 43.82.020 must include provisions for implementation of the qualified project
29 plan approved under AS 43.82.140, as may be modified as a result of the
30 development of a contract under this chapter, and provisions for updating the plan
31 at reasonable intervals until the commencement of commercial operations of the

1 approved qualified project. The commissioner of revenue, in consultation with the
2 commissioner of natural resources, may, as a term in a contract under AS 43.82.020,
3 include work commitments or other obligations in the contract to be accomplished
4 before the commencement of commercial operations of the approved qualified project.

5 **A minimum project expenditure commitment shall be included in a contract**
6 **under AS 43.82.020 that meets the requirements set out in (b) - (d) of this section.**

7 * **Sec. 11.** AS 43.82.270 is amended by adding new subsections to read:

8 (b) The sponsors of the Alaska Highway Natural Gas Pipeline Project shall
9 incur a minimum of \$1,500,000,000 in project expenditures beginning with the date
10 the contract is fully executed by the parties and continuing until December 31, 2010.
11 The project expenditures required by this subsection must be necessary to finance the
12 planning and permitting phase of the project leading up to the decision on full project
13 funding. The sponsors shall allocate and incur expenditures regularly throughout the
14 period covered by the minimum expenditure commitment. If the commissioner of
15 natural resources with the concurrence of the commissioner of revenue determines that
16 a sponsor breached the minimum expenditure commitment imposed by the contract,
17 the unexpended balance of the expenditure obligation attributed to that sponsor shall
18 be paid to the state treasury.

19 (c) The sponsors shall establish an escrow account, letter of credit, or other
20 form of financial security satisfactory to the commissioner of revenue to cover the
21 minimum project expenditure commitments imposed in (b) of this section.

22 (d) The sponsors shall provide the commissioner of natural resources with an
23 expenditure report at the end of each month containing enough information to permit
24 an audit of compliance with the expenditure commitments imposed in (b) of this
25 section.

26 * **Sec. 12.** AS 43.82.410 is amended to read:

27 **Sec. 43.82.410. Notice and comment regarding the contract.** The
28 commissioner shall

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

31 (2) make copies of the proposed contract, the commissioner's

1 preliminary findings and determination, and, to the extent the information is not
2 required to be kept confidential under AS 43.82.310, the supporting financial,
3 technical, and market data, including the work papers, analyses, and recommendations
4 of any independent contractors used under AS 43.82.240 available to the public and to

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

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

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

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

19 (4) establish a period of at least 60 [30] days for the public and
20 members of the legislature to comment on the proposed contract and the preliminary
21 findings and determination made under AS 43.82.400.

22 * Sec. 13. AS 43.82.430(a) is amended to read:

23 (a) Within 60 [30] days after the close of the public comment period under
24 AS 43.82.410(4), the commissioner of revenue shall

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

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

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

* **Sec. 14.** AS 43.82.500 is amended to read:

Sec. 43.82.500. Obligation to share payments with municipalities. If the commissioner develops a contract under AS 43.82.020 that includes terms that exempt a qualified sponsor, the members of a qualified sponsor group, or a related party to the contract, and the property, gas, products, and activities associated with the approved qualified project that is subject to the contract, from a municipal tax or assessment in accordance with AS 29.45.810 or AS 29.46.010(b), or AS 43.82.200 and 43.82.210, the commissioner shall include a term in the contract that provides for [THE PARTY PAY] a portion of the periodic payments to be made payable [DUE UNDER THE CONTRACT] to the revenue-affected municipality.

* **Sec. 15.** AS 43.82.505 is amended to read:

Sec. 43.82.505. Payments to economically affected municipalities. If the commissioner executes a contract under AS 43.82.020 that will produce one or more economically affected municipalities, the commissioner shall include a term in the contract that provides for [A PORTION OF THE] periodic impact payments to the economically affected municipalities under the principles in AS 43.82.520.

* **Sec. 16.** AS 43.82.510(c) is amended to read:

(c) Each municipal advisory group serves until the later of 90 days after final distribution of impact payment money under AS 43.82.505, or commencement of operations of the qualified project. Expenses of a municipal advisory group are eligible for reimbursement under AS 43.82.505 [A FINAL ACTION IS TAKEN ON THE APPLICATION FOR WHICH THE GROUP WAS APPOINTED].

* **Sec. 17.** AS 43.82 is amended by adding a new section to article 7 to read:

Sec. 43.82.650. Calculations of education funding. To determine the amount of required local contribution under AS 14.17.410(b)(2) and (c) for a school district in a revenue-affected municipality, and to perform its duties under AS 14.17.510, the Department of Commerce, Community, and Economic Development shall adopt

1 regulations. The regulations must establish assessment standards for any property that
2 would have been assessed under AS 43.56 but is instead generating a payment to a
3 revenue-affected municipality in lieu of a municipal property tax as provided in a
4 contract developed under this chapter. The regulations must ensure that the property is
5 included in the full and true value of the city or borough school district for the purpose
6 of determining required local contributions for education funding under
7 AS 14.17.410(b)(2) and (c).

8 * **Sec. 18.** AS 43.82.900 is amended by adding a new paragraph to read:

9 (14) "related party" means an entity, including a limited liability
10 company or similar incorporated or unincorporated entity, that

11 (A) is affiliated with a qualified sponsor or qualified sponsor
12 group;

13 (B) owns or operates a qualified project or any segment of a
14 qualified project; and

15 (C) is an intended beneficiary of the fiscal terms included in a
16 contract developed under this chapter.

17 * **Sec. 19.** The uncoded law of the State of Alaska is amended by adding a new section to
18 read:

19 REVISOR'S INSTRUCTION. The revisor of statutes is instructed to change the
20 section heading of AS 43.82.220 from "Contract terms relating to royalty" to "Contract terms
21 relating to oil and gas lease, royalty provisions, and other agreements."

22 * **Sec. 20.** The uncoded law of the State of Alaska is amended by adding a new section to
23 read:

24 RETROACTIVITY. (a) Sections 2 - 14 and 16 - 18 of this Act are retroactive to
25 January 1, 2004.

26 (b) Section 1 of this Act is retroactive to January 1, 2005.

27 * **Sec. 21.** This Act takes effect immediately under AS 01.10.070(c).



Official Business

Alaska State Senate

Senate Finance Committee

Mail Stop 3100
State Capitol
Juneau, Alaska 99801-1182

FAX COVER SHEET

DATE: 4 Aug 2006 TIME: 4:55pm

TO: Legal Services

NUMBER OF PAGES, INCLUDING COVER SHEET: 2

FROM: MINDY ROWLAND
SENATE FINANCE COMMITTEE SECRETARY
PHONE: 465-4935
FAX: 465-2187

NOTES: Final Please
CS SB 3002 (NGD) 24-GS20951 Y
Bailey 8/4/06
plus 1 amendment - attached
Thanks
Mindy

SB 3002

7/28	#1	B. Stevens	35 yrs to chug 45 yrs to 55 yrs			✓
↓	#2	↓	Just Review Advisory vote of contract		Withdrawn	
8/1	#3	Stedman	arbitration			✓
↓	#4	Seekins	hiring AK residents			✓
↓	#5	↓	Qualified Project		* rescinded	✓
8/3	#5A	↓	amends #5			✓
	#6	B. Stevens	replaces #2		Withdrawn	
	#7	↓	work commitments min \$1.5B expend by 2010		*	✓
	#8	↓	final findings w/in 60 days of public comment			✓
	#9	↓	oil, contract related to			✓
	#10	↓	75 days			✓
	#11	Wilken	Sec 15 & 16			✓
	#12	↓	distribution of pymnt lieu of taxes	failed	6-6	
8/4	#13		title change limit bill to public comments...			

Natural Gas Development
COMMITTEE
Amendment # #1
To Bill Number: SB3B02

24-GS2095\GSponsor: B. Stevens
7/28/06 Date: 7/28/06 logged by: Mindy

Adopted

AMENDMENT

OFFERED IN THE SENATE

BY SENATOR BEN STEVENS

TO: CSSB 3002(NGD) -Version G

- 1 Page 6, line 6:
- 2 Delete "35"
- 3 Insert "25"
- 4
- 7 Page 6, line 10:
- 8 Delete "45"
- 9 Insert "35"
- 10
- 11
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Special Committee on Natural Gas Development

7/28/2006

COMMITTEE ACTION

Bill Number	SB 3002		
Amendment	#1		
Motion	adopt		
<u>Motion by</u>	B. Stevens		
<u>Objection by</u>	Elton		
<u>Removed</u>	✓		
<u>Second Objection by</u>			
<u>Committee Member</u>	Y	<u>Vote</u>	N
Senator Kookesh			
Senator B. Stevens			
Senator Stedman			
Senator Bunde			
Senator Olson			
Senator Dyson			
Senator Wilken			
Senator Elton			
Senator Hoffman			
Vice-Chair Green			
Vice-Chair Wagoner			
Chair Seekins			
<u>Tally</u>			
Yea			
Nay			
Absent			
<u>MOTION</u>	Passed		

Natural Gas Development
COMMITTEE
Amendment # #2
To Bill Number: SB 3002
Sponsor: B Stevens
Date: 7/29/06 Logged by: Mindy

AMENDMENT

OFFERED IN THE SENATE SPECIAL
COMMITTEE ON NATURAL GAS DEVELOPMENT
TO: CSSB 3002(NGD)(24-GS2095\G)

BY B. STEVENS

Page 8, following line 8:

Insert new bill sections to read:

**** Sec. 14.** AS 43.82.430(b) is amended to read:

(b) After considering the material described in (a) of this section and securing the agreement of the other parties to the proposed contract regarding any proposed amendments prepared under (a) of this section, if the commissioner determines that the contract is in the long-term fiscal interests of the state, the commissioner may execute [SHALL SUBMIT] the contract [TO THE GOVERNOR].

*** Sec. 15.** AS 43.82.430(c) is amended to read:

(c) The commissioner's final findings and determination under (a) of this section and decision regarding whether to execute the contract under (b) of this section are final agency decisions under this chapter.

*** Sec. 16.** AS 43.82.440 is amended to read:

Sec. 43.82.440. Judicial review. An [A PERSON MAY NOT BRING AN] action challenging the constitutionality of a law authorizing a contract developed under this chapter [ENACTED UNDER AS 43.82.435] or the enforceability of a contract executed under a process authorized by [A] law may not be brought [AUTHORIZING A CONTRACT ENACTED UNDER AS 43.82.435] unless the action is commenced within 120 days after the date that the contract was executed by the state and the other parties to the contract."

1 Renumber the following bill sections accordingly.

2
3 Page 11, following line 30:

4 Insert new bill sections to read:

5 **"* Sec. 24.** The uncoded law of the State of Alaska is amended by adding a new section to
6 read:

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

11 *** Sec. 25.** The uncoded law of the State of Alaska is amended by adding a new section to
12 read:

13 **SUSPENSION OF OTHER LAW.** The provisions of the Alaska Stranded Gas Fiscal
14 Contract between the State of Alaska and BP Exploration (Alaska) Incorporated, ConocoPhillips
15 Alaska, Incorporated, and ExxonMobil Alaska Production, Incorporated, as amended to conform
16 to the provisions of this Act, are effective notwithstanding the provisions of any other law,
17 including AS 43.82.200 - 43.82.270. Any inconsistency between the Alaska Stranded Gas
18 Development Act (AS 43.82) and the fiscal contract executed under AS 43.82 are cured and
19 authorized by this section.

20 *** Sec. 26.** The uncoded law of the State of Alaska is amended by adding a new section to
21 read:

22 **ADVISORY VOTE.** At the 2006 general election to be held on November 7, 2006, in
23 substantial compliance with the election laws of the state, the lieutenant governor shall place
24 before the qualified voters of the state a question advisory to the governor and the commissioner
25 of revenue. Notwithstanding other laws relating to preparation of the ballot proposition, the
26 question shall appear on the ballot in the following form:

27 **Q U E S T I O N**

28 Shall the commissioner of revenue sign and make binding upon the State of Alaska the Alaska
29 Stranded Gas Fiscal Contract between the State of Alaska and BP Exploration (Alaska)
30 Incorporated, ConocoPhillips Alaska, Incorporated, and ExxonMobil Alaska Production,
31 Incorporated ?

1 Yes [] No []

2 * **Sec. 27.** If secs. 14 - 16 and 25 of this Act take effect, they take effect on the date that the
3 director of elections certifies the results of the 2006 general election at which a majority of the
4 votes cast on the proposition favor execution by the commissioner of revenue and binding effect
5 on the State of Alaska of the Alaska Stranded Gas Fiscal Contract between the State of Alaska
6 and BP Exploration (Alaska) Incorporated, ConocoPhillips Alaska, Incorporated, and
7 ExxonMobil Alaska Production, Incorporated."

8

9 Renumber the following bill sections accordingly.

10

11 Page 12, line 7:

12 Delete "Sections 2 - 14 and 17 - 20"

13 Insert "Sections 2 - 13, 17, and 20 - 23"

14

15 Page 12, following line 9:

16 Insert a new bill section to read:

17 "** **Sec. 30.** Sections 24, 25, and 26 of this Act take effect immediately under
18 AS 01.10.070(c)."

19

20 Page 12, line 10:

21 Delete "This"

22 Insert "Except as provided in sec. 30 of this Act, this"

Special Committee on Natural Gas Development

7/28/2006

COMMITTEE ACTION

Bill Number	SB 3002		
Amendment	#2		
Motion	adopt		
<u>Motion by</u>	B. Stevens		
<u>Objection by</u>	B. Stevens		
<u>Removed</u>			
<u>Second Objection by</u>			
<u>Committee Member</u>	Y	<u>Vote</u>	N
Senator Kookesh			
Senator B. Stevens			
Senator Stedman			
Senator Bunde			
Senator Olson			
Senator Dyson			
Senator Wilken			
Senator Elton			
Senator Hoffman			
Vice-Chair Green			
Vice-Chair Wagoner			
Chair Seekins			
<u>Tally</u>			
Yea			
Nay			
Absent			
<u>MOTION</u>	WITHDRAWN		

7/28 - motion made to adopt
amendment HELD w/ no action
taken

8/1 11:45am Sen. Stevens
motion to table until after other
amendments considered

8/3 - Sen. Stevens withdrew motion to adopt
defer to amendment #6

Natural Gas Development
COMMITTEE
Amendment # 3
To Bill Number: 3002
Sponsor: Stedman
Date: 8/1/06 Logged by: Rose

AMENDMENT

Adopted

OFFERED IN THE SENATE

BY SENATOR STEDMAN

TO: CSSB 3002(NGD), Draft Version "G"

- 1 Page 4, lines 2 - 6:
- 2 Delete "and consent to entrance and enforcement of an arbitration award in any state
- 3 court in the United States that has jurisdiction over the State of Alaska. The authority granted
- 4 in this subsection is effective only after the arbitration award is entered and enforcement is
- 5 sought in the superior court of the state"

Special Committee on Natural Gas Development

8/1/2006

COMMITTEE ACTION

Bill Number	SB 3002		
Amendment	# 3		
Motion	adopt		
<i>Motion by</i>	Stedman		
<i>Objection by</i>	none		
<i>Removed</i>			
<i>Second Objection by</i>			
<u>Committee Member</u>	Y	<u>Vote</u>	N
Senator Kookesh			
Senator B. Stevens			
Senator Stedman			
Senator Bunde			
Senator Olson			
Senator Dyson			
Senator Wilken			
Senator Elton			
Senator Hoffman			
Vice-Chair Green			
Vice-Chair Wagoner			
Chair Seekins			
<u>Tally</u>			
Yea			
Nay			
Absent			
<u>MOTION</u>	Pass		

Natural Gas Development
COMMITTEE
Amendment # #4
To Bill Number: SB 3002
Sponsor: Seekins
Date: 8/1/00 Logged by: Mindy

AMENDMENT

OFFERED IN THE SENATE
TO: SB 3002 24-GS2095\G

BY SENATOR RALPH SEEKINS

AS 43.82.230(a) is amended to read:

Sec. 43.82.230. Contract terms relating to hiring of Alaska residents and contracting with Alaska businesses. (a) The commissioner shall include in a contract under AS 43.82.020 a term requiring the qualified sponsor, [OR] qualified sponsor group, or a related party, and contractors of the qualified sponsor, [OR] qualified sponsor group, or a related party, to comply with all valid federal, state, and municipal laws relating to hiring Alaska residents and contracting with Alaska businesses to work in the state on the approved qualified project and not to discriminate against Alaska residents or Alaska businesses. Within the constraints of law:

(1) [,] the commissioner shall also include in a contract under AS 43.82.020 a term that requires the qualified sponsor, [OR] qualified sponsor group, or a related party, and contractors of the qualified sponsor, [OR] qualified sponsor group, or a related party, to employ Alaska residents and to contract with Alaska businesses to work in the state on the approved qualified project to the extent the residents and businesses are available, competitively priced, and qualified; [.] and (2) should the state acquire an ownership interest in the qualified projects as part of a contract developed under this chapter, the parties shall agree to enter into negotiations for project labor agreements to facilitate the construction of the qualified project. To the extent lawful, the parties shall include provisions in any project labor agreement that would promote hiring of Alaska residents and the establishment of hiring halls in both rural and urban communities of the state.

Natural Gas Development
COMMITTEE
Amendment # # 4
To Bill Number: SB 3002
Sponsor: Seekins
Date: 8/1/00 Logged by: Mindy

AMENDMENT

OFFERED IN THE SENATE
TO: SB 3002 24-GS2095\G

BY SENATOR RALPH SEEKINS

Amend
failed

AS 43.82.230(a) is amended to read:

Sec. 43.82.230. Contract terms relating to hiring of Alaska residents and contracting with Alaska businesses. (a) The commissioner shall include in a contract under AS 43.82.020 a term requiring the qualified sponsor, [OR] qualified sponsor group, or a related party, and contractors of the qualified sponsor, [OR] qualified sponsor group, or a related party, to comply with all valid federal, state, and municipal laws relating to hiring Alaska residents and contracting with Alaska businesses to work in the state on the approved qualified project and not to discriminate against Alaska residents or Alaska businesses. Within the constraints of law:

(1) [,] the commissioner shall also include in a contract under AS 43.82.020 a term that requires the qualified sponsor, [OR] qualified sponsor group, or a related party, and contractors of the qualified sponsor, [OR] qualified sponsor group, or a related party, to employ Alaska residents and to contract with Alaska businesses to work in the state on the approved qualified project to the extent the residents and businesses are available, competitively priced, and qualified; [.] and (2) should the state acquire an ownership interest in the qualified projects as part of a contract developed under this chapter,
the parties shall ^{negotiate and} agree to enter into negotiations for project labor agreements to facilitate the construction of the qualified project. To the extent lawful, the parties shall include provisions in any project labor agreement that would promote hiring of Alaska residents and the establishment of hiring halls in both rural and urban communities of the state.

Special Committee on Natural Gas Development

8 / 1 / 2006

COMMITTEE ACTION

Bill Number	SB 3002		
Amendment	#4		
Motion	adopt		
<i>Motion by</i>	Seekins		
<i>Objection by</i>	Wagner		
<i>Removed</i>	Wagner / Bunde		
<i>Second Objection by</i>			
<u>Committee Member</u>	Y	<u>Vote</u>	N
Senator Kookesh		—	
Senator B. Stevens			✓
Senator Stedman	✓		
Senator Bunde	✓		
Senator Olson	✓		
Senator Dyson	✓		
Senator Wilken	✓		
Senator Elton	✓		
Senator Hoffman	✓		
Vice-Chair Green		—	
Vice-Chair Wagoner		—	
Chair Seekins	✓		
<u>Tally</u>			
Yea	8		
Nay	1		
Absent	3		
<u>MOTION</u>	Pass		

Special Committee on Natural Gas Development

8/1/2006

COMMITTEE ACTION

Bill Number	SB 3002		
Amendment	#4		
Motion	amend		
Motion by	Elton		
Objection by	Dyson		
Removed			
Second Objection by			
Committee Member	Y	Vote	N
Senator Kookesh			
Senator B. Stevens			✓
Senator Stedman			✓
Senator Bunde			✓
Senator Olson	✓		
Senator Dyson			✓
Senator Wilken			✓
Senator Elton	✓		
Senator Hoffman	✓		
Vice-Chair Green			
Vice-Chair Wagoner			
Chair Seekins			✓
Tally			
Yea	3		
Nay	6		
Absent	3		
MOTION	Fail		

Natural Gas Development
COMMITTEE #5 Amended
Amendment #
To Bill Number: SB 3002
Sponsor: Seekins
Date: 8/1/06 Logged by: Mindy

AMENDMENT

OFFERED IN THE SENATE
TO: SB 3002 24-GS2095\G

BY: SENATOR RALPH SEEKINS

(2ND amendment)

Sec. 43.82.100. Qualified project.

~~adopted~~
RESCINDED

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

(1) principally involves

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

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

(C) any other technology that commercializes the shipment of natural gas within the state or from the state to one or more other states or countries;

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

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

(4) no project may be considered a qualified project under this chapter if the project enters Canada at any point north of 68 degrees latitude.

pipe line to transport natural gas from land within the Prudhoe Bay oil and gas lease area follows a route that:

- enters Canada at any point north of 64 degrees north latitude; and

- traverses land beneath navigable waters, as defined in section 2 of the Submerged Lands Act 43 U.S.C 1301, beneath, or the adjacent shoreline of, the Beaufort Sea.

[Note: language taken from H.R. 4837-36, Division C, Section 103(d)]

AMENDMENT

OFFERED IN THE SENATE
TO: SB 3002 24-GS2095\G

BY: SENATOR RALPH SEEKINS

Sec. 43.82.100. Qualified project.

1st amendment
to the amendment
- replaced w/ 2nd amendment
to amendment

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

(1) principally involves

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

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

(C) any other technology that commercializes the shipment of natural gas within the state or from the state to one or more other states or countries;

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

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

(4) no project may be considered a qualified project under this chapter if the project enters Canada at any point north of 68 degrees latitude.

pipe line to
transport natural gas from land within
the Prudhoe Bay oil and gas lease
area follows a route that:

- enters Canada at any point north of
64 degrees latitude; and

- traverses land beneath navigable
waters, as defined in section 2 of the
Submerged Lands Act 43 U.S.C 1301, beneath,
or the adjacent shoreline of, the
Beaufort Sea.

Natural Development
COMMITTEE
Amendment # #5
To Bill Number: SB 3002
Sponsor: Seekins
Date: 8/1/06 Logged by: Mindy

AMENDMENT

OFFERED IN THE SENATE
TO: SB 3002 24-GS2095\G

BY: SENATOR RALPH SEEKINS corrected

Sec. 43.82.100. Qualified project.

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

(1) principally involves

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

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

(C) any other technology that commercializes the shipment of natural gas within the state or from the state to one or more other states or countries;

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

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

(4) no project may be considered a qualified project under this chapter if the project enters Canada at any point north of 68 degrees latitude.

Special Committee on Natural Gas Development

8/1/2006**COMMITTEE ACTION**

①

Bill Number	SB 3002		
Amendment	#5		
Motion	Amend		
<u>Motion by</u>	Olson		
<u>Objection by</u>			
<u>Removed</u>			
<u>Second Objection by</u>			
<u>Committee Member</u>	Y	<u>Vote</u>	N
Senator Kookesh		—	
Senator B. Stevens	✓		
Senator Stedman			✓
Senator Bunde			✓
Senator Olson	✓		
Senator Dyson			✓
Senator Wilken			✓
Senator Elton	✓		
Senator Hoffman	✓		
Vice-Chair Green		—	
Vice-Chair Wagoner		—	
Chair Seekins	✓		
<u>Tally</u>			
Yea		5	
Nay		4	
Absent		3	
<u>MOTION</u>	Pass		

Special Committee on Natural Gas Development

8/1 /2006

COMMITTEE ACTION

(2)

Bill Number	SB 3002		
Amendment	Amendment to #5		
Motion	rescind action in amending #5		
<u>Motion by</u>	Bunde		
<u>Objection by</u>	Olson		
<u>Removed</u>			
<u>Second Objection by</u>			
<u>Committee Member</u>	Y	<u>Vote</u>	N
Senator Kookesh		—	
Senator B. Stevens			✓
Senator Stedman			✓
Senator Bunde	✓		
Senator Olson			✓
Senator Dyson		—	
Senator Wilken	✓		
Senator Elton			✓
Senator Hoffman			✓
Vice-Chair Green		—	
Vice-Chair Wagoner			✓
Chair Seekins			✓
<u>Tally</u>			
<u>Yea</u>	2		
<u>Nay</u>	7		
<u>Absent</u>	3		
<u>MOTION</u>	failed		

Special Committee on Natural Gas Development

8/1/2006**COMMITTEE ACTION**

(3)

Bill Number	SB 3002		
Amendment	#5		
Motion	2ND amend		
<u>Motion by</u>	Seekins		
<u>Objection by</u>	none		
<u>Removed</u>			
<u>Second Objection by</u>			
<u>Committee Member</u>	Y	<u>Vote</u>	N
Senator Kookesh			
Senator B. Stevens			
Senator Stedman			
Senator Bunde			
Senator Olson			
Senator Dyson			
Senator Wilken			
Senator Elton			
Senator Hoffman			
Vice-Chair Green			
Vice-Chair Wagoner			
Chair Seekins			
<u>Tally</u>			
<u>Yea</u>			
<u>Nay</u>			
<u>Absent</u>			
<u>MOTION</u>	Pass		

Special Committee on Natural Gas Development

8 / 1 / 2006

(4)

COMMITTEE ACTION

Bill Number	SB 3002		
Amendment	#5		
Motion	adopt		
<u>Motion by</u>	Seekins		
<u>Objection by</u>			
<u>Removed</u>			
<u>Second Objection by</u>			
<u>Committee Member</u>	Y	<u>Vote</u>	N
Senator Kookesh		→	
Senator B. Stevens	✓		
← Senator Stedman	✓		
- Senator Bunde			✓
Senator Olson	✓		
Senator Dyson	✓		
Senator Wilken	✓		
Senator Elton	✓		
Senator Hoffman	✓		
Vice-Chair Green		→	
Vice-Chair Wagoner			✓
Chair Seekins	✓		
<u>Tally</u>			
Yea	8		
Nay	2		
Absent	2		
<u>MOTION</u>	Pass		

Special Committee on Natural Gas Development

8/3/2006

COMMITTEE ACTION

54

Bill Number	SB 3002		
Amendment	#5 amended		
Motion	Rescind		
<u>Motion by</u>	Seekins		
<u>Objection by</u>	None		
<u>Removed</u>			
<u>Second Objection by</u>			
<u>Committee Member</u>	Y	<u>Vote</u>	N
Senator Kookesh			
Senator B. Stevens			
Senator Stedman			
Senator Bunde			
Senator Olson			
Senator Dyson			
Senator Wilken			
Senator Elton			
Senator Hoffman			
Vice-Chair Green			
Vice-Chair Wagoner			
Chair Seekins			
<u>Tally</u>			
Yea			
Nay			
Absent			
<u>MOTION</u>	Pass		

Natural Gas Development
COMMITTEE
Amendment # # 5 ft
To Bill Number: SB 3002
Sponsor: Sen. Seekins
Date: 8/3/06 Logged by: Mindy

AMENDMENT

OFFERED IN THE SENATE
TO: SB 3002 24-GS2095\G

BY: SENATOR RALPH SEEKINS

Adopted

Sec. 43.82.100. Qualified project.

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

(1) principally involves

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

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

(C) any other technology that commercializes the shipment of natural gas within the state or from the state to one or more other states or countries;

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

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

(4) no project may be considered a qualified project under this chapter if the pipeline to transport natural gas from land within the Prudhoe Bay oil and gas lease area follows a route that:

(1) traverses land beneath navigable waters (as defined in section 2 of the Submerged Lands Act (43 U.S.C. 1301)) beneath, or adjacent shoreline of, the Beaufort Sea; or

(2) enters Canada at any point north of 64 degrees north latitude.

Special Committee on Natural Gas Development

8/ 3 /2006

COMMITTEE ACTION

Bill Number	SB 3002		
Amendment	#5 ft		
Motion	adopt		
<u>Motion by</u>	Seekins		
<u>Objection by</u>	none		
<u>Removed</u>	.		
<u>Second Objection by</u>			
<u>Committee Member</u>	Y	<u>Vote</u>	N
Senator Kookesh			
Senator B. Stevens			
Senator Stedman			
Senator Bunde			
→ Senator Olson			
Senator Dyson			
Senator Wilken			
Senator Elton			
Senator Hoffman			
Vice-Chair Green			
Vice-Chair Wagoner			
Chair Seekins			
<u>Tally</u>			
Yea			
Nay			
Absent			
<u>MOTION</u>	Pass		

Natural Gas Development
COMMITTEE
Amendment # #16
To Bill Number: SB 3002
Sponsor: B. Stevens
Date: 8/3/06 Logged by: Mindy

August 3, 2006
(8:10 AM)

AMENDMENT

Failed

BY B. STEVENS

OFFERED IN THE SENATE SPECIAL

COMMITTEE ON NATURAL GAS DEVELOPMENT

TO: CSSB 3002(NGD) (24-GS2095\G)

1 Page 1, line 3, following "terms;":

2 Insert "providing for an advisory vote, treatment of certain laws, and approval and
3 ratification regarding a stranded gas fiscal contract;"
4

5 Page 8, following line 8:

6 Insert new bill sections to read:

7 "** Sec. 14. AS 43.82.430(b) is amended to read:

8 (b) After considering the material described in (a) of this section and securing the
9 agreement of the other parties to the proposed contract regarding any proposed
10 amendments prepared under (a) of this section, if the commissioner determines that the
11 contract is in the long-term fiscal interests of the state, the commissioner may execute
12 [SHALL SUBMIT] the contract [TO THE GOVERNOR].

13 * Sec. 15. AS 43.82.430(c) is amended to read:

14 (c) The commissioner's final findings and determination under (a) of this section
15 and decision regarding whether to execute the contract under (b) of this section are
16 final agency decisions under this chapter.

17 * Sec. 16. AS 43.82.440 is amended to read:

18 Sec. 43.82.440. Judicial review. An [A PERSON MAY NOT BRING AN]
19 action challenging the constitutionality of a law authorizing a contract developed under
20 this chapter [ENACTED UNDER AS 43.82.435] or the enforceability of a contract
21 executed under a process authorized by [A] law may not be brought [AUTHORIZING

1 A CONTRACT ENACTED UNDER AS 43.82.435] unless the action is commenced
2 within 120 days after the date that the contract was executed by the state and the other
3 parties to the contract."
4

5 Renumber the following bill sections accordingly.
6

7 Page 11, line 30:

8 Delete all material and insert the following:

9 **Sec. 23. (a) AS 43.82.435 is repealed.

10 (b) AS 43.82.445 is repealed."
11

12 Page 11, following line 30:

13 Insert new bill sections to read:

14 ** Sec. 24. The uncoded law of the State of Alaska is amended by adding a new section to
15 read:

16 APPROVAL AND RATIFICATION. Notwithstanding AS 43.82.435, repealed by sec.
17 23(a) of this Act, the provisions of the Alaska Stranded Gas Fiscal Contract between the State of
18 Alaska and BP Exploration (Alaska) Incorporated, ConocoPhillips Alaska, Incorporated, and
19 ExxonMobil Alaska Production, Incorporated, as amended to conform to the provisions of this
20 Act, are approved, and the process and procedures followed in formulating that contract are
21 ratified.

22 * Sec. 25. The uncoded law of the State of Alaska is amended by adding a new section to
23 read:

24 SUSPENSION OF OTHER LAW. The provisions of the Alaska Stranded Gas Fiscal
25 Contract between the State of Alaska and BP Exploration (Alaska) Incorporated, ConocoPhillips
26 Alaska, Incorporated, and ExxonMobil Alaska Production, Incorporated, as amended to conform
27 to the provisions of this Act, are effective notwithstanding the provisions of any other law,
28 including AS 43.82.200 - 43.82.270. Any inconsistency between the Alaska Stranded Gas
29 Development Act (AS 43.82) and the fiscal contract executed under AS 43.82 are cured and
30 authorized by this section.

31 * Sec. 26. The uncoded law of the State of Alaska is amended by adding a new section to

1 read:

2 ADVISORY VOTE. At the 2006 general election to be held on November 7, 2006, in
3 substantial compliance with the election laws of the state, the lieutenant governor shall place
4 before the qualified voters of the state a question advisory to the governor and the commissioner
5 of revenue. Notwithstanding other laws relating to preparation of the ballot proposition, the
6 question shall appear on the ballot in the following form:

7 QUESTION

8 Shall the commissioner of revenue sign and make binding upon the State of Alaska the Alaska
9 Stranded Gas Fiscal Contract between the State of Alaska and BP Exploration (Alaska)
10 Incorporated, ConocoPhillips Alaska, Incorporated, and ExxonMobil Alaska Production,
11 Incorporated ?

12 Yes [] No []"

13

14 Renumber the following bill sections accordingly.

15

16 Page 12, line 7:

17 Delete "Sections 2 - 14 and 17 - 20"

18 Insert "Sections 2 - 13, 17, 20 - 22, and 23(b)"

19

20 Page 12, following line 9:

21 Insert new bill sections to read:

22 **"* Sec. 29. CONDITIONAL EFFECT.** Sections 14 - 16, 23(a), and 24 of this Act take effect
23 only if a majority of the votes cast in the 2006 general election on the ballot proposition in sec.
24 26 of this Act favor execution by the commissioner of revenue and binding effect on the State of
25 Alaska of the Alaska Stranded Gas Fiscal Contract between the State of Alaska and BP
26 Exploration (Alaska) Incorporated, ConocoPhillips Alaska, Incorporated, and ExxonMobil
27 Alaska Production, Incorporated.

28 *** Sec. 30.** If secs. 14 - 16, 23(a), and 24 of this Act take effect under sec. 29 of this Act, they
29 take effect on the date that the director of elections certifies the results of the 2006 general
30 election."

31

1 Page 12, line 10:

2 Delete "This"

3 Insert "Except as provided in sec. 30 of this Act, this"

Special Committee on Natural Gas Development

8/3/2006

COMMITTEE ACTION

Bill Number	SB 3002		
Amendment	#6		
Motion	adopt		
<u>Motion by</u>	B. Stevens		
<u>Objection by</u>	B. Stevens		
<u>Removed</u>			
<u>Second Objection by</u>	Elton / Wagner		
<u>Committee Member</u>	Y	Vote	N
Senator Kookesh			✓
Senator B. Stevens	✓		
Senator Stedman	✓		
Senator Bunde		—	
Senator Olson			✓
Senator Dyson			✓
Senator Wilken			✓
Senator Elton			✓
→ Senator Hoffman	✓		
Vice-Chair Green		—	
Vice-Chair Wagoner			✓
Chair Seekins	.		✓
<u>Tally</u>			
Yea	3		.
Nay	7		
Absent	2		
<u>MOTION</u>	Failed		

8/3 10:15 am - HELD

9:45 pm - WITHDRAWN

8/4 4:10 pm - reoffered by B. Stevens
objection by B. Stevens

Special Committee on Natural Gas Development

8/3/2006

COMMITTEE ACTION

Bill Number	SB 3002		
Amendment	#6		
Motion	Adopt		
<u>Motion by</u>	B. Stevens		
<u>Objection by</u>	B. Stevens		
<u>Removed</u>			
<u>Second Objection by</u>			
<u>Committee Member</u>	Y	<u>Vote</u>	N
Senator Kookesh			
Senator B. Stevens			
Senator Stedman			
Senator Bunde			
→ Senator Olson			
Senator Dyson			
Senator Wilken			
Senator Elton			
Senator Hoffman			
Vice-Chair Green			
Vice-Chair Wagoner			
Chair Seekins			
<u>Tally</u>			
Yea			
Nay			
Absent			
<u>MOTION</u>	Withdrawn		

8/3 10:15 am HELD

8/3 9:45 pm W/drawn

8/4 4:10 pm re-offered-B. Stevens

AMENDMENT

OFFERED IN THE SENATE SPECIAL
COMMITTEE ON NATURAL
GAS DEVELOPMENT

BY SENATOR BEN STEVENS

TO: CSSB3002(NGD) – Version G

Natural Gas Development
COMMITTEE # 7 Amended
Amendment # 33 3002
To Bill Number: 33 3002
Sponsor: B. Stevens
Date: 8/3/06 Logged by: Mindy

Adopted

Page 7, lines 3 – 12”

Delete all material and insert the following new material in its place:

“ * Sec. 12. AS 43.82.270 is amended to read:

Sec. 43.82.270. Project plans and work commitments. A contract under AS 43.82.020 must include provisions for implementation of the qualified project plan approved under AS 43.82.140, as may be modified as a result of the development of a contract under this chapter, and provisions for updating the plan at reasonable intervals until the commencement of commercial operations of the approved qualified project. The commissioner of revenue, in consultation with the commissioner of natural resources, may, as a term in a contract under AS 43.82.020, include work commitments or other obligations in the contract to be accomplished before the commencement of commercial operations of the approved qualified project. A minimum project expenditure commitment shall be included in a contract under AS 43.82.020 that meets the requirements set out in (b) – (d) of this section.

*Sec.13 . AS 43.82.270 is amended by adding new subsections to read:

(b) The sponsors of the Alaska Highway Natural Gas Pipeline Project shall incur a minimum of \$1,500,000,000 in project expenditures beginning with the date the contract is fully executed by the parties and continuing until December 31, 2010. The project expenditures required by this subsection must be necessary to finance the planning and permitting phase of the project leading up to the decision on full project funding. The sponsors shall allocate and incur expenditures regularly throughout the period covered by the minimum expenditure commitment. If the commissioner of natural resources* determines that a sponsor breached the minimum expenditure commitment imposed by the contract, the unexpended balance of the expenditure obligation attributed to that sponsor shall be paid to the state treasury.

(c) The sponsors shall establish an escrow account, letter of credit, or other form of financial security satisfactory to the commissioner of revenue to cover the minimum project expenditure commitments imposed in (b) of this section.

(d) The sponsors shall provide the commissioner of natural resources with an expenditure report at the end of each month containing enough information to permit an audit of compliance with the expenditure commitments imposed in (b) of this section.”

Renumber remaining sections.

* insert: “With the concurrence of the
commissioner of the department of revenue”

Natural Gas Development
COMMITTEE #7
Amendment # #7
To Bill Number: SB 3002
Sponsor: B. Stevens
Date: 8/3/06 Logged by: Mindy

AMENDMENT

OFFERED IN THE SENATE SPECIAL
COMMITTEE ON NATURAL
GAS DEVELOPMENT

BY SENATOR BEN STEVENS

TO: CSSB3002(NGD) – Version G

Page 7, lines 3 – 12”

Delete all material and insert the following new material in its place:

“ * Sec. 12. AS 43.82.270 is amended to read:

Sec. 43.82.270. Project plans and work commitments. A contract under AS 43.82.020 must include provisions for implementation of the qualified project plan approved under AS 43.82.140, as may be modified as a result of the development of a contract under this chapter, and provisions for updating the plan at reasonable intervals until the commencement of commercial operations of the approved qualified project. The commissioner of revenue, in consultation with the commissioner of natural resources, may, as a term in a contract under AS 43.82.020, include work commitments or other obligations in the contract to be accomplished before the commencement of commercial operations of the approved qualified project. A minimum project expenditure commitment shall be included in a contract under AS 43.82.020 that meets the requirements set out in (b) – (d) of this section.

*Sec.13 . AS 43.82.270 is amended by adding new subsections to read:

(b) The sponsors of the Alaska Highway Natural Gas Pipeline Project shall incur a minimum of \$1,500,000,000 in project expenditures beginning with the date the contract is fully executed by the parties and continuing until December 31, 2010. The project expenditures required by this subsection must be necessary to finance the planning and permitting phase of the project leading up to the decision on full project funding. The sponsors shall allocate and incur expenditures regularly throughout the period covered by the minimum expenditure commitment. If the commissioner of natural resources determines that a sponsor breached the minimum expenditure commitment imposed by the contract, the unexpended balance of the expenditure obligation attributed to that sponsor shall be paid to the state treasury.

(c) The sponsors shall establish an escrow account, letter of credit, or other form of financial security satisfactory to the commissioner of revenue to cover the minimum project expenditure commitments imposed in (b) of this section.

(d) The sponsors shall provide the commissioner of natural resources with an expenditure report at the end of each month containing enough information to permit an audit of compliance with the expenditure commitments imposed in (b) of this section.”

Renumber remaining sections.

Special Committee on Natural Gas Development

8/3/2006

COMMITTEE ACTION

Bill Number	SB 3002		
Amendment	#7		
Motion	adopt as amended		
<u>Motion by</u>	B. Stevens		
<u>Objection by</u>	B. Stevens		
<u>Removed</u>	✓		
<u>Second Objection by</u>			
<u>Committee Member</u>	Y	<u>Vote</u>	N
Senator Kookesh	✓		
Senator B. Stevens	✓		
Senator Stedman	✓		
Senator Bunde	✓		
→ Senator Olson	✓		
Senator Dyson			✓
Senator Wilken	✓		
Senator Elton	✓		
Senator Hoffman	✓		
Vice-Chair Green	✓		
Vice-Chair Wagoner	✓		
Chair Seekins	✓		
<u>Tally</u>			
Yea	11		
Nay	1		
Absent			
<u>MOTION</u>	Pass		

8/3 10:10 am held (also held: motion to amend)

Special Committee on Natural Gas Development

8/3/2006

COMMITTEE ACTION

Bill Number	SB 3002		
Amendment	#7		
Motion	amend		
<u>Motion by</u>	Wilken		
<u>Objection by</u>	none		
<u>Removed</u>			
<u>Second Objection by</u>			
<u>Committee Member</u>	Y	<u>Vote</u>	N
Senator Kookesh			
Senator B. Stevens			
Senator Stedman			
Senator Bunde			
Senator Olson			
Senator Dyson			
Senator Wilken			
Senator Elton			
Senator Hoffman			
Vice-Chair Green			
Vice-Chair Wagoner			
Chair Seekins			
<u>Tally</u>			
Yea			
Nay			
Absent			
<u>MOTION</u>	Pass		

8/3 10:10 am held
7:15pm brought up again

AMENDMENT

Offered by Senator Ben Stevens

SB 3002 version 24-GS2095\G

Natural Gas Development
COMMITTEE
Amendment # #8
To Bill Number: SB 3002
Sponsor: B. Stevens
Date: 2/3/06 Logged by: Mindy

Adopted

Delete "30"

Insert "60"

In the following section:

Sec. 43.82.430. Final findings, determination, and proposed amendments;
execution of the contract. (a) within [30] 60 days after the close of the public comment
period under AS 43.82.410(4), the commissioner of Revenue shall

Special Committee on Natural Gas Development

8/ /2006

COMMITTEE ACTION

Bill Number	SB 3002		
Amendment	#8		
Motion	adopt		
<u>Motion by</u>	B. Stevens		
<u>Objection by</u>	B. Stevens		
Removed	✓		
<u>Second Objection by</u>			
<u>Committee Member</u>	Y	<u>Vote</u>	N
Senator Kookesh			
Senator B. Stevens			
Senator Stedman			
Senator Bunde			
→ Senator Olson			
Senator Dyson			
Senator Wilken			
Senator Elton			
Senator Hoffman			
Vice-Chair Green			
Vice-Chair Wagoner			
Chair Seekins			
<u>Tally</u>			
Yea			
Nay			
Absent			
<u>MOTION</u>	Pass		

Natural Gas Development
COMMITTEE #19
Amendment #
To Bill Number: SB 3002
Sponsor: B. Stevens
Date: 8/3/06 Logged by: Mindy
Adopted

AMENDMENT

OFFERED IN THE SENATE
TO: SB 3002 24-GS2095\C

BY SENATOR BEN STEVENS

1 AS 43.82 is amended by adding a new section to read:

2 **Sec. 43.82.255. Term of contract provisions related to oil.** (a) The
3 provisions of this section apply to a contract developed under AS 43.82.020 that
4 provides for periodic payment in lieu of taxes on oil under AS 43.55.

5
6 (b) For the part of the contract term beginning immediately after the date
7 of full project funding or the date of issuance of a certificate of public convenience
8 and necessity for construction and initial operation of the Alaska Natural Gas pipeline,
9 whichever date is later, and ending 14 years after that date, the commissioner may
10 develop a term for the contract that provides for payments in lieu of the taxes on oil
11 set out in AS 43.55. For the part of the contract term established with as much
12 certainty as the Constitution of the State of Alaska allows.

13
14 (c) For the part of the contract term beginning immediately after the period
15 described in (b) of this section, and ending on a date not later than 25 years after the
16 effective date of the contract, the amount of the payment in lieu of tax on oil under
17 AS 43.55 must be equal to the amount of the tax levied by the law. However, the
18 commissioner may develop a contract term that, in the event of a material change in
19 the taxes enacted after the effective date of the contract, establishes a procedure for
20 restoring the parties to substantially the same economic position they had as of the
21 end of the period described in (b) of this section immediately before the change.

22
23 (d) Implementation of a contract provision authorized in this section may
24 be made subject to the dispute resolution procedures of the contract.

Special Committee on Natural Gas Development

8/3/2006

COMMITTEE ACTION

Bill Number	SB 3002		
Amendment	#9		
Motion	adopt		
<u>Motion by</u>	B. Stevens		
<u>Objection by</u>	B. Stevens		
<u>Removed</u>	✓		
<u>Second Objection by</u>	Dyson / removed		
<u>Committee Member</u>	<u>Y</u>	<u>Vote</u>	<u>N</u>
Senator Kookesh			
Senator B. Stevens			
Senator Stedman			
Senator Bunde			
Senator Olson			
→ Senator Dyson			
Senator Wilken			
Senator Elton			
Senator Hoffman			
Vice-Chair Green			
Vice-Chair Wagoner			
Chair Seekins			
<u>Tally</u>			
Yea			
Nay			
Absent			
<u>MOTION</u>	Pass		

adopted

1 preliminary findings and determination, and, to the extent the information is not
2 required to be kept confidential under AS 43.82.310, the supporting financial,
3 technical, and market data, including the work papers, analyses, and recommendations
4 of any independent contractors used under AS 43.82.240 available to the public and to

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

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

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

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

19 (4) establish a period of at least ~~60~~⁷⁵ [30] days for the public and
20 members of the legislature to comment on the proposed contract and the preliminary
21 findings and determination made under AS 43.82.400.

22 * Sec. 13. AS 43.82.430(a) is amended to read:

23 (a) Within 60 [30] days after the close of the public comment period under
24 AS 43.82.410(4), the commissioner of revenue shall

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

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

Special Committee on Natural Gas Development

8/3/2006

COMMITTEE ACTION

Bill Number	SB 3002		
Amendment	#10		
Motion	adopt		
<u>Motion by</u>	B. Stevens		
<u>Objection by</u>	none		
<u>Removed</u>			
<u>Second Objection by</u>			
<u>Committee Member</u>	Y	<u>Vote</u>	N
Senator Kookesh			
Senator B. Stevens			
Senator Stedman			
Senator Bunde			
Senator Olson			
Senator Dyson			
Senator Wilken			
Senator Elton			
Senator Hoffman			
Vice-Chair Green			
Vice-Chair Wagoner			
Chair Seekins			
<u>Tally</u>			
Yea			
Nay			
Absent			
<u>MOTION</u>	Pass		

Amendment #11

adopted

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

* Sec. 14. AS 43.82.500 is amended to read:

Sec. 43.82.500. Obligation to share payments with municipalities. If the commissioner develops a contract under AS 43.82.020 that includes terms that exempt a qualified sponsor, the members of a qualified sponsor group, or a related party to the contract, and the property, gas, products, and activities associated with the approved qualified project that is subject to the contract, from a municipal tax or assessment in accordance with AS 29.45.810 or AS 29.46.010(b), or AS 43.82.200 and 43.82.210, the commissioner shall include a term in the contract that provides for [THE PARTY PAY] a portion of the periodic payments to be made payable [DUE UNDER THE CONTRACT] to the revenue-affected municipality.

* ~~Sec. 15. AS 43.82.505 is amended to read:~~

delete

~~**Sec. 43.82.505. Payments to economically affected municipalities.** If the commissioner executes a contract under AS 43.82.020 that will produce one or more economically affected municipalities, the commissioner shall include a term in the contract that provides for [A PORTION OF THE] periodic impact payments to the economically affected municipalities under the principles in AS 43.82.520.~~

* Sec. 16. AS 43.82.510(c) is amended to read:

Insert Sec. 15 + Sec. 16 of CS Version "G"

(c) Each municipal advisory group serves until the later of 90 days after final distribution of impact payment money under AS 43.82.505, or commencement of operations of the qualified project. Expenses of a municipal advisory group are eligible for reimbursement under AS 43.82.505 [A FINAL ACTION IS TAKEN ON THE APPLICATION FOR WHICH THE GROUP WAS APPOINTED].

* Sec. 17. AS 43.82 is amended by adding a new section to article 7 to read:

Sec. 43.82.650. Calculations of education funding. To determine the amount of required local contribution under AS 14.17.410(b)(2) and (c) for a school district in a revenue-affected municipality, and to perform its duties under AS 14.17.510, the Department of Commerce, Community, and Economic Development shall adopt

Special Committee on Natural Gas Development

8/3/2006

COMMITTEE ACTION

Bill Number	SB 3002		
Amendment	# 11		
Motion	adopt		
<u>Motion by</u>	Wilken		
<u>Objection by</u>	none		
<u>Removed</u>			
<u>Second Objection by</u>			
<u>Committee Member</u>	Y	<u>Vote</u>	N
Senator Kookesh			
Senator B. Stevens			
Senator Stedman			
Senator Bunde			
Senator Olson			
Senator Dyson			
Senator Wilken			
Senator Elton			
Senator Hoffman			
Vice-Chair Green			
Vice-Chair Wagoner			
Chair Seekins			
<u>Tally</u>			
Yea			
Nay			
Absent			
<u>MOTION</u>	Pass		

delete: Version "F" Sec 15
Page 7, lines 14 - 19

insert: Version "G" Sec. 15 & Sec. 16
Page 8, line 19 through
Page 11, line 1

1 commissioner's offer, the committee shall give notice of the committee's meeting to
2 the public and all members of the legislature; if the financial, technical, and market
3 data that is to be provided must be kept confidential under AS 43.82.310, the
4 commissioner may not release the confidential information during a public portion of
5 a committee meeting; and

6 (4) establish a period of at least 60 [30] days for the public and
7 members of the legislature to comment on the proposed contract and the preliminary
8 findings and determination made under AS 43.82.400.

9 * Sec. 14. AS 43.82.500 is amended to read:

10 **Sec. 43.82.500. Obligation to share payments with municipalities.** If the
11 commissioner develops a contract under AS 43.82.020 that includes terms that exempt
12 a qualified sponsor, the members of a qualified sponsor group, or a related party
13 to the contract, and the property, gas, products, and activities associated with the
14 approved qualified project that is subject to the contract, from a municipal tax or
15 assessment in accordance with AS 29.45.810 or AS 29.46.010(b), or AS 43.82.200
16 and 43.82.210, the commissioner shall include a term in the contract that provides for
17 [THE PARTY PAY] a portion of the periodic payments to be made payable [DUE
18 UNDER THE CONTRACT] to the revenue-affected municipality.

19 * Sec. 15. AS 43.82.505 is amended to read: **Insert to CS "F"**

20 **Sec. 43.82.505. Payments to economically affected municipalities.** If the
21 commissioner executes a contract under AS 43.82.020 that will produce one or more
22 economically affected municipalities, the commissioner shall include a term in the
23 contract that provides for [A PORTION OF THE] periodic impact payments to the
24 state that may be appropriated to the Alaska natural gas pipeline construction
25 impact fund established in (c) of this section to benefit the economically affected
26 municipalities under the principles in AS 43.82.520.

27 * Sec. 16. AS 43.82.505 is amended by adding new subsections to read:

28 (b) A special account is established in the general fund into which the
29 Department of Revenue shall deposit impact payments received by the state under (a)
30 of this section.

31 (c) The Alaska natural gas pipeline construction impact fund is established in

1 the Department of Commerce, Community, and Economic Development. The
2 legislature may appropriate money deposited in the special account established in (b)
3 of this section, as well as any additional money considered necessary, to the Alaska
4 natural gas pipeline construction impact fund to address the economic and social
5 impacts incurred by an economically affected municipality, or incurred by a nonprofit
6 organization serving the unorganized borough, during the construction of a project that
7 is the subject of a proposed contract developed under this chapter.

Insert
to
CS" F"

8 (d) The Department of Commerce, Community, and Economic Development
9 shall adopt regulations under which economically affected municipalities and
10 nonprofit organizations may apply for and be eligible to receive grants to alleviate
11 impact caused by construction of a gas pipeline. The department shall give priority in
12 the allocation of grants to municipalities and organizations that are experiencing or
13 will experience the most direct or severe impact from gas pipeline construction. The
14 department shall finance, under (e) of this section, all meritorious grant applications
15 each year, to the extent money is available in the Alaska natural gas pipeline
16 construction impact fund. Within 10 days after the convening of each regular session
17 of the legislature, the department shall submit to the legislature a list of all
18 municipalities and organizations that have received grants, a list of all municipalities
19 and organizations determined by the department to be eligible for further grants, a
20 recommendation of the amount of money to be granted for those additional
21 applications, and written justification of each past and potential grant.

22 (e) The commissioner of commerce, community, and economic development,
23 in consultation with the relevant municipal advisory group established under
24 AS 43.82.510, shall use money appropriated to the Alaska natural gas pipeline
25 construction impact fund to make grants to municipalities, and to nonprofit
26 organizations serving the unorganized borough, for impacts on transportation,
27 infrastructure, law enforcement, emergency services, health and human services,
28 education, the labor force, population, wages, and subsistence and for socio-cultural
29 impacts, brought about by the construction of the gas pipeline. In determining whether
30 an expenditure or proposed expenditure by a municipality or nonprofit organization is
31 eligible for a grant under this subsection and in allocating available money among

1 grant proposals, the commissioner shall consider the recommendations of the relevant
2 municipal advisory group established under AS 43.82.510 and whether the proposed
3 expenditure meets the purposes of this section.

4 (f) Before making awards of grants under this section for a fiscal year, the
5 commissioner of commerce, community, and economic development shall provide
6 reasonable public notice of all grant applications received, the recommendations of the
7 relevant municipal advisory group, preliminary determinations made concerning the
8 eligibility of each municipality or organization for a grant, the eligibility of each
9 expenditure or proposed expenditure for a grant, and the proposed allocation of
10 available money among grant proposals. The public notice must specify a time and
11 place for a public hearing during which the commissioner will receive comments
12 concerning the preliminary determinations and allocations of the department. The
13 commissioner shall give reasonable public notice of the final awards of grants made
14 under this section. Thirty days after such public notice is given, final awards take
15 effect and may be paid to the grantees according to procedures established by
16 regulation.

17 (g) Grant money received under this section may not be used for the
18 retirement of municipal debt.

19 (h) Amounts appropriated to the Alaska natural gas pipeline construction
20 impact fund under (c) of this section for a fiscal year that are not used for grants to
21 municipalities and organizations under (d) and (e) of this section shall be retained in
22 the Alaska natural gas pipeline construction impact fund and remain available for
23 distribution as grants under this section in succeeding fiscal years.

24 (i) Nothing in this chapter exempts money deposited into the special account
25 in the general fund established in (b) of this section from the requirements of AS 37.07
26 (Executive Budget Act) or dedicates that money, or money appropriated to the Alaska
27 natural gas pipeline construction impact fund, for a specific purpose.

28 (j) In this section, "direct or severe impact" means a clearly demonstrable
29 effect on a community that proximately contributes to a material change to
30 transportation, infrastructure, law enforcement, emergency services, health and human
31 services, education, the labor force, population, wages, subsistence, or for socio-

Insert
to
CS"F"

Insert
to
CS"F"

cultural impacts brought about by the construction of a gas pipeline.

* ~~Sec. 17.~~ AS 43.82.510(c) is amended to read:

(c) Each municipal advisory group serves until the later of 90 days after final distribution of impact payment money under AS 43.82.505, or commencement of operations of the qualified project. Expenses of a municipal advisory group are eligible for reimbursement under a grant made under AS 43.82.505 [A FINAL ACTION IS TAKEN ON THE APPLICATION FOR WHICH THE GROUP WAS APPOINTED].

* Sec. 18. AS 43.82 is amended by adding a new section to article 7 to read:

Sec. 43.82.650. Calculations of education funding. To determine the amount of required local contribution under AS 14.17.410(b)(2) and (c) for a school district in a revenue-affected municipality, and to perform its duties under AS 14.17.510, the Department of Commerce, Community, and Economic Development shall adopt regulations. The regulations must establish assessment standards for any property that would have been assessed under AS 43.56 but is instead generating a payment to a revenue-affected municipality in lieu of a municipal property tax as provided in a contract developed under this chapter. The regulations must ensure that the property is included in the full and true value of the city or borough school district for the purpose of determining required local contributions for education funding under AS 14.17.410(b)(2) and (c).

* Sec. 19. AS 43.82.900 is amended by adding a new paragraph to read:

(14) "related party" means an entity, including a limited liability company or similar incorporated or unincorporated entity, that

(A) is affiliated with a qualified sponsor or qualified sponsor group;

(B) owns or operates a qualified project or any segment of a qualified project; and

(C) is an intended beneficiary of the fiscal terms included in a contract developed under this chapter.

* Sec. 20. AS 43.82.445 is repealed.

* Sec. 21. The uncodified law of the State of Alaska is amended by adding a new section to

Natural Gas Development
COMMITTEE
Amendment # 12
To Bill Number: SB 3002
Sponsor: Sen. Wilken
Date: 8/3/06 Logged by: Rose

AMENDMENT

OFFERED IN THE SENATE

BY SENATOR WILKEN

TO: Any version of CSSB 3002(NGD)

- 1 * ⁶Sec. ~~A~~ AS 43.82.210 is amended by adding a new subsection to read:
- 2 (d) A contract developed under this chapter may not contain a provision for
- 3 distribution of payments received in lieu of taxes. The method of distribution of
- 4 payments received in lieu of taxes are not effective unless the methods are
- 5 enacted by law.

page 3 , following line 18
insert: ↑

Special Committee on Natural Gas Development

8/3/2006

COMMITTEE ACTION

Bill Number	SB 3002		
Amendment	# 12		
Motion	adopt		
<u>Motion by</u>	Wilken		
<u>Objection by</u>			
<u>Removed</u>			
<u>Second Objection by</u>			
<u>Committee Member</u>	Y	<u>Vote</u>	N
Senator Kookesh			✓
Senator B. Stevens			✓
Senator Stedman			✓
Senator Bunde	✓		
Senator Olson			✓
Senator Dyson	✓		
Senator Wilken	✓		
Senator Elton			✓
Senator Hoffman			✓
Vice-Chair Green	✓		
Vice-Chair Wagoner	✓		
Chair Seekins	✓		
<u>Tally</u>			
Yea	6		
Nay	0		
Absent	0		
<u>MOTION</u>	Failed		

Natural Gas Development
COMMITTEE
Amendment # # 13
To Bill Number: SB 3002
Sponsor: Wilken
Date: 8/4/00 Logged by: Mindy

AMENDMENT

TO SENATE BILL 3002

By Senator Gary Wilken

"An Act amending the time allowed, under the Alaska Stranded Gas Development Act, for the commissioner of revenue to summarize public comments, propose amendments, if any, and make findings; and providing for an effective date."

Special Committee on Natural Gas Development

8/4/2006

COMMITTEE ACTION

Bill Number		SB 3002		
Amendment		# 13		
Motion		adopt		
<u>Motion by</u>		Wilken		
<u>Objection by</u>		Seekins		
<u>Removed</u>		✓		
<u>Second Objection by</u>		Stedman		
<u>Committee Member</u>		Y	Vote	N
→ Senator Kookesh		✓		
Senator B. Stevens				✓
Senator Stedman				✓
Senator Bunde			—	
Senator Olson			—	
Senator Dyson		✓		
Senator Wilken		✓		
Senator Elton		✓		
Senator Hoffman				✓
Vice-Chair Green			—	
Vice-Chair Wagoner		✓		
Chair Seekins				✓
<u>Tally</u>				
Yea		4 5		
Nay		4		
Absent		3		
<u>MOTION</u>		Pass		

SENATE COMMITTEE REPORT First Committee of Referral

DATE: 7/12/06

Date of 5-Day Notice: Special Session
(in accordance with Uniform Rule 23)

FURTHER:

DATE TURNED
IN TO OFFICE: 4 Aug 2006

Senate Special Committee on Natural Gas Development considered SENATE BILL NO. 3002

SB 3002 STRANDED GAS AMENDMENTS

"An Act relating to the Alaska Stranded Gas Development Act; relating to municipal impact money received under the terms of a stranded gas fiscal contract; relating to determination of full and true value of property and required contributions for education in municipalities affected by stranded gas fiscal contracts; and providing for an effective date."

and recommends:

☒ be replaced with ☐ SCS or ☒ CS SB 3002 (NGD)

☐ adopt previous ☐ SCS or ☐ CS _____ (_____)

☐ attached amendment(s)

☐ adopt _____ Letter of Intent

☐ further referral to _____ Committee

SENATE BILL:

☐ Same Title
☒ New Title

HOUSE BILL:

☐ Same Title
☐ Technical Title Change
☐ New Title w/ SCR #

NEW FISCAL NOTE(S):

Department	Date	Fiscal	Indet.	Zero	FN#

PREVIOUS FISCAL NOTE(S):

Department	Date	Fiscal	Indet.	Zero	FN#
Revenue	7/12/06			✓	#1
Net. Res.	7/12/06			✓	#2

SIGNATURES AND RECOMMENDATIONS:	PRINTED LAST NAME	Do PASS	Do NOT PASS	No REC	AMEND
		✓			
		✓			
		✓			
		✓			
		✓			
		✓			
		✓			
		✓			
		✓			
		✓			
CHAIR:		✓			

LEGAL SERVICES

DIVISION OF LEGAL AND RESEARCH SERVICES
LEGISLATIVE AFFAIRS AGENCY
STATE OF ALASKA

(907) 465-3867 or 465-2450
FAX (907) 465-2029
Mail Stop 3101

State Capitol
Juneau, Alaska 99801-1182
Deliveries to: 129 6th St., Rm. 329

MEMORANDUM

August 4, 2006

SUBJECT: Technical correction to amended title (CSSB 3002(NGD)
(Work Order No. 24-GS2095U))

TO: Senator Seekins
Chairman of the Senate Special Committee on Natural Gas
Development
Attn: Brian Hove

FROM: Dennis C. Bailey *DB*
Legislative Counsel

This memo is to bring to your attention a technical amendment to the title change approved by Amendment 13. We have added "and determinations" to the descriptive language of the commissioner's duties in order to conform more closely with the existing statutory language.

If you have any concerns about this technical amendment please let me know.

DCB:lmb
06-203.lmb

Enclosure

LEGAL SERVICES

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Juneau, Alaska 99801-1182
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MEMORANDUM

August 3, 2006

SUBJECT: Questions concerning amendment #6 (CSSB 3002(NGD), Draft version "G"; Work Order No. 24-GS2095\G)

TO: Senator Ben Stevens

FROM: Dennis C. Bailey 
Legislative Counsel

I prepared a memo for Senator Olson and one for Senator French responding to their questions related to Amendment #2 to CSSB 3002, version G, which you have copies of. You have asked me to review the same questions posed by Senator Olson and Senator French as they pertain to Amendment #6 to CSSB 3002(NGD), version G, which has now been substituted for Amendment #2.

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

Because sec. 25 states that the provisions of the contract "are effective," it is possible that this section -- which is effective immediately -- would be construed as an approval without a public vote. If sec. 25 were added to sec. 29 or reworded to make it clear that it is not an approval, then a public vote would be required to trigger the approval of the contract. Sec. 29 gives effect to sections 14 - 16, 23(a) and 24 only on receipt of a favorable vote in the 2006 general election. Assuming the public vote is favorable, secs. 14 - 16, 23(a) and 24 become effective on the date the election results are certified by the director of elections. The sections that are subject to the condition are as follows:

Sec. 14 allows the commissioner to execute the contract within 30 days after the public comment period is closed. Since the public comment period has already closed, the commissioner would be permitted to sign the contract immediately after addressing the requirements of AS 43.82.430(a) and (b).

Sec. 15 states that the commissioner's decision is the final agency action.

Sec. 16 limits the time period for judicial challenges to 120 days.

Sec. 23(a) repeals the requirement that legislative authorization is required to execute the contract.

Sec. 24, slightly modified by Amendment #6, reads as follows:

APPROVAL AND RATIFICATION. Notwithstanding AS 43.82.435, repealed by sec. 23(a) of this Act, 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 procedures followed in formulating that contract are ratified.

2. Are the results of the public vote binding?

The vote is binding in the sense that it triggers the amendments to statutory law in secs. 14 - 16 and 23(a), as well as the approval in sec. 24. If these amendments occur, the commissioner will be authorized, but not required, to sign the contract.

State general law does not address the issue of advisory votes.

The attorney general is of the opinion that the Alaska Supreme Court would uphold a delegation of legislative power to the people by submitting a question for a binding vote, at least when the topic is not an appropriation, Attorney General Opinion J66-479-82 (Feb. 9, 1982) and Attorney General Opinion J66-545-82 (April 23, 1982). The courts give due respect to that office's conclusions:

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.

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 made dependent on a 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. In addition, sec. 24 states that the process and procedures in formulating the contract are ratified. These sections should preclude legal challenges and application of the Stranded Gas Development Act to the fiscal contract.

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 effective, 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. Basically sec. 25 says that the contract is effective.

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

The issue of making law dependent on voter approval is discussed above.

In addition, sec. 25 is ambiguous as to whether it constitutes immediate approval of the contract.

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 be amended 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. It is not clear what terms of the contract would need to be amended to comply with CSSB 3002. 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.

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.

In a similar vein, the question has arisen, whether the descriptive language in both sec. 24 and sec. 25, "the provisions of the contract," creates a distinction between the provisions of a contract and the contract itself? In other words, is something less than the entire contract approved in sec. 24 by the reference to "the provisions of the contract." Although debatable, in my view, this is a distinction without a difference. There is no real difference between "approving the contract" and "approving the terms of the contract." Since a contract is only made up of its terms or provisions, using the language "the provisions of" is nothing more than referring to the contract. One could refer to either "the contract" or "the provisions of the contract" interchangeably; using both is redundant. Only an excessively technical analysis could change the meaning of a contract or its provisions based on this distinction. The potential problem can be removed by referring to "the contract" when referring to the whole contract and refer to "a provision" or "the provision" when referring to a particular provision.

You might want to include sec. 25 within the conditional provisions of sec. 29. This may eliminate a potential problem because, without a change, sec. 25 would become effective immediately. As currently drafted, if the popular vote were not in favor of approving the contract sec. 25 would still be effective.

If I may be of further assistance, please advise.

DCB:ljw

06-288.ljw

1. Chapter 9, SLA 1987 -- curative statute authorizing and ratifying a prior act of the governor.
2. Fairbanks North Star Borough v. State -- curative legislation is valid.
3. Minutes of Constitutional Convention -- referral of an act to the people by the legislature would be allowed under Alaska Constitution.
4. 1982 Informal AG Opinion -- effect of legislature conditional on voter approval likely valid.



LAWS OF ALASKA

1987

Source

Chapter No.

CSHB 132 (Fin) am S

9

AN ACT

Approving and ratifying executive restrictions on the fiscal year 1987 operating budget; and providing for an effective date.

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

THE ACT FOLLOWS ON PAGE 1, LINE 10

Approved by the Governor: May 15, 1987
Actual Effective Date: May 16, 1987, retroactive
to July 1, 1986

AN ACT

Approving and ratifying executive restrictions on the
fiscal year 1987 operating budget; and providing for an
effective date.

* Section 1. LEGISLATIVE FINDINGS, PURPOSE, AND INTENT. (a) The
legislature finds that

(1) estimated receipts and surpluses will not be sufficient to
cover appropriations for fiscal year 1987;

(2) in response to the anticipated deficit, Governor Sheffield
issued Administrative Order Number 90 on August 22, 1986, which restricted
the rate of obligation or expenditure of a number of appropriations under
the authority conferred by AS 37.07.080; Governor Cowper made a similar but
more limited reduction in Administrative Order Number 91 on December 8,
1986;

(3) the orders were in response to a fiscal crisis that was
facing the state;

(4) the orders have been challenged in court by the Fairbanks
North Star Borough and others, and the supreme court has invalidated those
orders;

(5) if the restrictions on the one-year appropriations for
fiscal year 1987 in Administrative Orders Numbers 90 and 91 are overturned
in full or in part, the consequences would impede rational state fiscal
management.

(b) It is the purpose of this Act to approve and ratify the order

Chapter 9

1 and the actions taken by the governor and the executive branch under t
2 orders and to remove any uncertainty about the status of the money w
3 held, insofar as the orders concern the restrictions on one-year approp
4 tions for fiscal year 1987.

5 (c) In approving the restrictions on the one-year appropriations
6 fiscal year 1987, the legislature intends that the unobligated portion
7 those appropriations restricted by Administrative Orders Numbers 90 and
8 lapse in accordance with AS 37.25.010.

9 * Sec. 2. APPROVAL AND RATIFICATION. The actions of the governor
10 the executive branch in restricting one-year appropriations for fiscal
11 1987 by issuing and implementing Administrative Orders Numbers 90 and 9
12 reflected in the budget workbooks submitted to the legislature under AS
13 07.040 and entitled "Operating Budget FY 87 Revised" are approved
14 ratified.

15 * Sec. 3. SUSPENSION OF OTHER LAW. The provisions of sec. 2 of
16 Act are effective notwithstanding the provisions of any other law, inc
17 ing but not limited to AS 37.05.315, 37.05.316, and 37.05.317.

18 * Sec. 4. This Act is retroactive to July 1, 1986.

19 * Sec. 5. This Act takes effect immediately under AS 01.10.070(c).
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security claims. Frick, acting on behalf of ARCO, sent a form to the Employment Security Division indicating the reason for Akers' discharge as insubordination in willful disregard of the employer's interest.

At trial, Akers claimed that ARCO had, in bad faith, attempted to prevent Akers from obtaining unemployment compensation. At the close of Akers' case, however, this claim was dismissed because insufficient evidence had been presented. ARCO later moved that the Frick report be removed from the jury's consideration because the unemployment compensation claim had been dismissed and because there had been no evidence connecting the content of the report to any of the individuals responsible for the discharge. The trial court rejected this argument and allowed the jury to consider the report.

ARCO argues that since none of the individual defendants had anything to do with the filing of the Frick report, this evidence could not be probative of bad faith by either those individuals or ARCO.

Akers argues that the report is attributable to ARCO. The report was ARCO's response to Akers' claim for unemployment compensation. Akers claims that since the report is attributable to ARCO, the fact that the reason for termination stated in the report was different from the reason Akers was given is relevant to the claim that ARCO acted in bad faith. "Obviously, if an employer gives inconsistent reasons for the discharge of the employee, this inconsistency casts doubt on whether reasons exist for the discharge and which, if either, is the true reason."

Although the Frick report may not be attributable to any of the individuals involved in the termination of Akers, the report was nonetheless attributable to ARCO. The fact that this report listed a reason for termination that was different from the reason Akers was previously given by ARCO is relevant to the issue of whether ARCO was acting in good faith.

3. We have reviewed the issues raised by Akers on cross-appeal and find they do not warrant

Thus, the trial court did not err in allowing the jury to consider the Frick report.

CONCLUSION

The award of punitive damages is REVERSED. In all other respects the judgment of the trial court is AFFIRMED.³



**FAIRBANKS NORTH STAR BOROUGH
and Fairbanks North Star Borough
School District, Appellants,**

v.

STATE of Alaska, William Sheffield Governor of the State of Alaska, Marshall Lind, Commissioner of Education, Eleanor Andrews, Commissioner of Administration, Emil Notti, Commissioner of Community and Regional Affairs, Loren Lounsbury, Commissioner of Commerce and Economic Development, Milton Barker, Acting Commissioner of Revenue, all in their official capacities, Appellees.

No. S-2254.

Supreme Court of Alaska.

May 6, 1988.

Borough and borough school district brought suit challenging the constitutionality of Executive Budget Act section pursuant to which governors withheld or reduced appropriations to state agencies in view of anticipated revenue shortfalls. The Superior Court, Fourth Judicial District, Fairbanks, James R. Blair, J., found the statute an unconstitutional delegation of legislative power. State appealed. The Supreme Court, 736 P.2d 1140, affirmed and remanded. On remand, the Superior Court concluded that later legislation was a valid

the granting of a new trial in this case.

concluded that H.B. 132 was a valid curative act, and modified its earlier judgment to affirm the withholdings. Now, with the governor and the legislature in complete agreement on the cuts, appellant local governments approach this court seeking compelled payment of the originally appropriated funds. We affirm the modified decision of the trial court.

A curative statute is

a statute passed to cure defects in prior law, or to validate legal proceedings, instruments, or acts of public and private administrative authorities which, in the absence of such an act would be void for want of conformity with existing legal requirements, but which would have been valid if the statute had so provided at the time of enacting.

2 C. Sands, Sutherland Statutory Construction § 41.11 (4th ed. 1973); see generally *School District No. 26 Bouse Elementary of Yuma County v. Strohm*, 106 Ariz. 7, 469 P.2d 826, 828 (1970); *McCormack v. Houston*, 84 Cal.App.2d 665, 191 P.2d 569, 576-77, cert. denied, 335 U.S. 868, 69 S.Ct. 138, 93 L.Ed. 412 (1948). In this case, the state legislature passed H.B. 132 with the express intention of validating the governor's impoundment orders, which had been rendered void by the *Fairbanks I* decision. See ch. 9, § 1(b), SLA 1987. Thus, if the statute qualifies as a valid curative act, it should be given its intended retroactive effect, thereby legitimizing the governor's heretofore improper exercise of executive power.

Courts have uniformly upheld the validity of curative legislation where (1) the legislature originally had the power to authorize the acts done, and (2) there is no unconstitutional impairment of vested rights as a result of the act's passage. See *State ex rel. Tomasic v. Kansas City*, 230 Kan. 404, 636 P.2d 760, 775 (1981); accord *Strohm*, 469 P.2d at 828; *Hoffman v. City of Red Bluff*, 63 Cal.2d 584, 47 Cal.Rptr. 553, 558, 407 P.2d 857, 862 (1965); *Labor Inv. Corp. v. Russell*, 405 P.2d 1008, 1012

We denied the motion, but we expressly noted that our denial was "without prejudice to appellants' right to move for a modified judgment in the superior court" on remand.

(Okla.1965); 2 C. Sands, Sutherland Statutory Construction § 41.11-12 (4th ed. 1973), see also *Zurfluh v. State*, 620 P.2d 690, 692-93 (Alaska 1980) (applying retroactively a curative statute relating to criminal sentencing). H.B. 132 easily satisfies both requirements.

[1] First, it can hardly be argued that the legislature is without power to enact a statute authorizing the governor to withhold payment on specific appropriations. See, e.g., *State ex rel. Holmes v. State Board of Finance*, 69 N.M. 430, 367 P.2d 925, 929 (1961); *State ex rel. Boyle v. Ernst*, 195 Wash. 214, 78 P.2d 526, 528 (1938); see also *Fairbanks I*, 736 P.2d at 1144 ("[t]his court does not hold that the legislature could not draft a statute which would permit the executive to exercise limited authority to control expenditures as [the governor has] done"). H.B. 132 does not grant the governor "sweeping power over the entire budget with no guidance or limitation," as did AS 37.07.080(g)(2). *Fairbanks I*, 736 P.2d at 1142-43. Rather, it is narrowly tailored to authorize only those impoundments specified in Administrative Orders 90 and 91. See ch. 9, § 2, SLA 1987. The Borough's argument that H.B. 132 "is unconstitutional for the same reasons AS 37.07.080(g)(2) was unconstitutional" is therefore unconvincing.

[2] Second, H.B. 132 does not unconstitutionally impair any vested rights. The Borough's claimed violations of due process and equal protection fail for a number of reasons, not the least of which is our recent holding in *Kenai Peninsula Borough v. State, Department of Community and Regional Affairs*, 751 P.2d 14, 18-19 (Alaska 1988), wherein we concluded that political subdivisions of the state are prohibited from asserting due process and equal protection claims against their creator. In sum, we see no bar to enforcement of H.B. 132 as a valid curative act.⁴

4. We reject as meritless the Borough's numerous other claims of error.

Our decision in *Fairbanks I* comports with our analysis here. In *Fairbanks I*, we affirmed the trial court's finding that the governor acted unconstitutionally in withholding the Borough's funds because he purported to act under the authority of a statute so broadly worded as to amount to an abrogation of the legislature's responsibility over appropriations. 736 P.2d at 1142-43. The legislature has since recognized its responsibility, and has taken it upon itself to consider and approve each of the heretofore unconstitutional impoundments. To now hold, as the Borough suggests, that our earlier decision gave the Borough some inviolate right to receipt of the funds, would be to effectively place the purse strings in the hands of the judiciary,

a branch no more qualified to possess them than was the executive.

We conclude that H.B. 132 is a valid and constitutional exercise of the legislative power, which effectively cured any constitutional infirmities in the governor's earlier actions. Accordingly, the judgment of the superior court is AFFIRMED.

RABINOWITZ, J., not participating.



appropriations would have to be included --

PRESIDENT EGAN: Mrs. Sweeney.

SWEENEY: Point of order, Mr. President.

PRESIDENT EGAN: Your point of order.

SWEENEY: The enrolled copy is in error in that last portion of that sentence, the material after "health and safety", beginning with the word "and" to the word "institution" should not have been on the enrolled copy. Through the mechanics of engrossing and enrolling in the early stages this was an error that we did not pick up. I have just checked the enrolled copy and also the journal and for those who wish to check they will find that on December 17 all the words after "safety" were stricken and they should not have been shown on the enrolled copy. So it is probably not in order even to discuss that motion, Mr. Sundborg.

SUNDBORG: Mr. President, we proceeded in our Committee without knowing that. After analyzing it, those words were redundant and unnecessary, and they are not included in our draft because we figured they are covered fully by the word "appropriations" on line 2 of the page 3.

PRESIDENT EGAN: Mr. Coghill.

COGHILL: A point of information through the Chair as to the question by Mr. Sundborg. Mr. Sundborg, on that "local or special legislation", would that refer that the legislature could not refer to the people any legislation under the referendum, on say, a bonding issue, a Territorial or statewide bonding issue for a specific purpose, or referring to them a road project as to taking part in, perhaps, a national road program that would revert to the state.

SUNDBORG: Mr. President and Mr. Coghill, I believe that the restriction here is upon the referendum; the referendum as defined in this article which requires the filing of an application, the preparation of a petition, and the obtaining of a lot of signatures to get a proposition on the ballot. Now, I think there is nothing in this, and nothing elsewhere, that would prevent the legislature from simply saying in the law that, "This law shall become effective after it has been approved at the general election of such-and-such a date." That is not really the referendum as it is described in this article which is one on direct legislation initiated by the people. I am sure the legislature has that power without any reference to what is in this article.

PRESIDENT EGAN: Are there other questions with relation to Section 7? Mr. Poulsen.

STATE OF ALASKA

DEPARTMENT OF LAW

OFFICE OF THE ATTORNEY GENERAL

JAY S. HAMMOND, GOVERNOR

POUCH K-STATE CAPITOL
JUNEAU, ALASKA 99811

April 23, 1982

Hon. Samuel R. Cotten
Alaska State Legislature
Pouch V
Juneau, AK 99811

Re: Voter approval of capital
appropriations
Our file: J66-545-82

Dear Representative Cotten:

You have requested our opinion concerning the validity of appropriation bills, the enactment of which is conditioned upon approval of the voters at a general election. As you are no doubt aware, Legislative Resolve No. 1, Twelfth Alaska State Legislature, First Session (FSS-FCCSSJR 4) has been passed by the Twelfth Alaska State Legislature. This joint resolution proposes an amendment to the Alaska Constitution relating to limitations on appropriations of state money. Under the proposed amendment, appropriations for capital projects which exceed the spending limit must be approved by the voters. The existing provisions of the Alaska Constitution place in doubt the validity of appropriations which must be approved by the voters before they are enacted. See art. XI, § 7, of the Alaska Constitution.

We have earlier given an informal opinion that the legislature may refer to the voters a general law on any subject which is capable of direct legislation under article XI of the Alaska Constitution. Inf. Opin. Atty. Gen., Feb. 9, 1982 (our file J66-479-82). Clearly, the voters may not refer a capital appropriation enacted by the legislature. A question which remains unanswered in the courts of this state is whether the prohibition set out in article XI, section 7 prevents the legislature from passing a capital appropriation with enactment conditioned on the approval of the voters.

The Alaska Supreme Court has cited with favor the rule set out in 16 C.J.S. Constitutional Law § 133 (1956), which provides:

. . . a legislature . . . may not delegate purely legislative powers in the absence of constitutional authorization.

DeArmond v. Alaska State Dev. Corp., 376 P.2d 717, 723, n. 16 (Alaska 1962). However, during the debate on the adoption of article XI, section 7, the opinion was expressed, and not challenged, that the prohibitions contained in section 7 applied only to action taken directly by the voters and not to matters referred to them by the legislature. */

We believe that it is consistent with the Alaska Constitution for the legislature to enact an appropriation on the condition that it take effect only upon approval of the voters. However, you should be aware that a significant number of jurisdictions in the United States have held that conditioning the enactment of general legislation on voter approval is an inval-

*/ During the floor debate on consideration of article XI, section 7, the following exchange occurred:

COGHILL: A point of information through the Chair as to the question by Mr. Sundborg. Mr. Sundborg, on that "local or special legislation", would that refer that the legislature could not refer to the people any legislation under the referendum, on say, a bonding issue, a Territorial or statewide bonding issue for a specific purpose, or referring to them a road project as to taking part in, perhaps, a national road program that would revert to the state.

SUNDBORG: Mr. President and Mr. Coghill, I believe that the restriction here is upon the referendum; the referendum as defined in this article which requires the filing of an application, the preparation of a petition, and the obtaining of a lot of signatures to get a proposition on the ballot. Now, I think there is nothing in this, and nothing elsewhere, that would prevent the legislature from simply saying in the law that, "This law shall become effective after it has been approved at the general election of such-and-such a date." That is not really the referendum as it is described in this article which is one on direct legislation initiated by the people. I am sure the legislature has that power without any reference to what is in this article.

Alaska Constitutional Convention, MINUTES at 2970.

id delegation of legislative power to the people. See the cases collected at 76 ALR 1053 -- 1058. These courts have reasoned that the legislature is attempting to evade its responsibility to exercise the law making power assigned to it under the state constitution. See Alaska Const., art. II, § 1.

There are a minority of jurisdictions that have found such a referral to be valid. See the cases collected at 76 ALR 1058 -- 1062. We believe the so-called minority rule has a high likelihood of being adopted by the Alaska Supreme Court if presented with the question. In many of the jurisdictions which have found an unconstitutional delegation of the law making power, the people in adopting the state constitution, did not reserve broad powers to initiate or refer laws enacted by the legislature.

Some jurisdictions have found that an improper delegation has not occurred if the legislature enacts a law but makes it effective only if it is approved by the voters. State v. Parker, 26 Vt. 357 (1854); 76 ALR 1059. This distinction has been criticized. People ex rel. Thompson v. Barnett, 176 N.E. 108 (Ill. 1931).

We suggest that if you wish to enact a capital appropriation subject to voter approval, all sections of the bill should take effect on a specified date. Then insert sections in the bill which

- (1) repeal the appropriations; and
- (2) make the repeal effective on a favorable vote of the people.

We believe this method of obtaining a popular vote will not invalidate the appropriation if the referral is successfully attacked as an improper delegation.

A second precaution could be taken by having the capital appropriation take effect 90 days after the spending limit amendment is approved by the voters. This condition would be in addition to the voter approval requirement. This means that the capital appropriation would be referred to and approved by the voters before the spending limit amendment takes effect (90 days after certification of election results). If there is a compelling public purpose, the legislature may implement by law a constitutional amendment before it is adopted by the voters.

Hon. Samuel R. Cotten

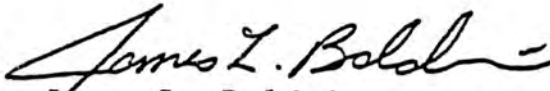
-4-

April 23, 1982

Assembly of Calif. v. Deukmejian, 639 P.2d 404 (Cal. 1982).

Sincerely yours,

WILSON L. CONDON
ATTORNEY GENERAL

By: 
James L. Baldwin
Assistant Attorney General

JLB/pjg

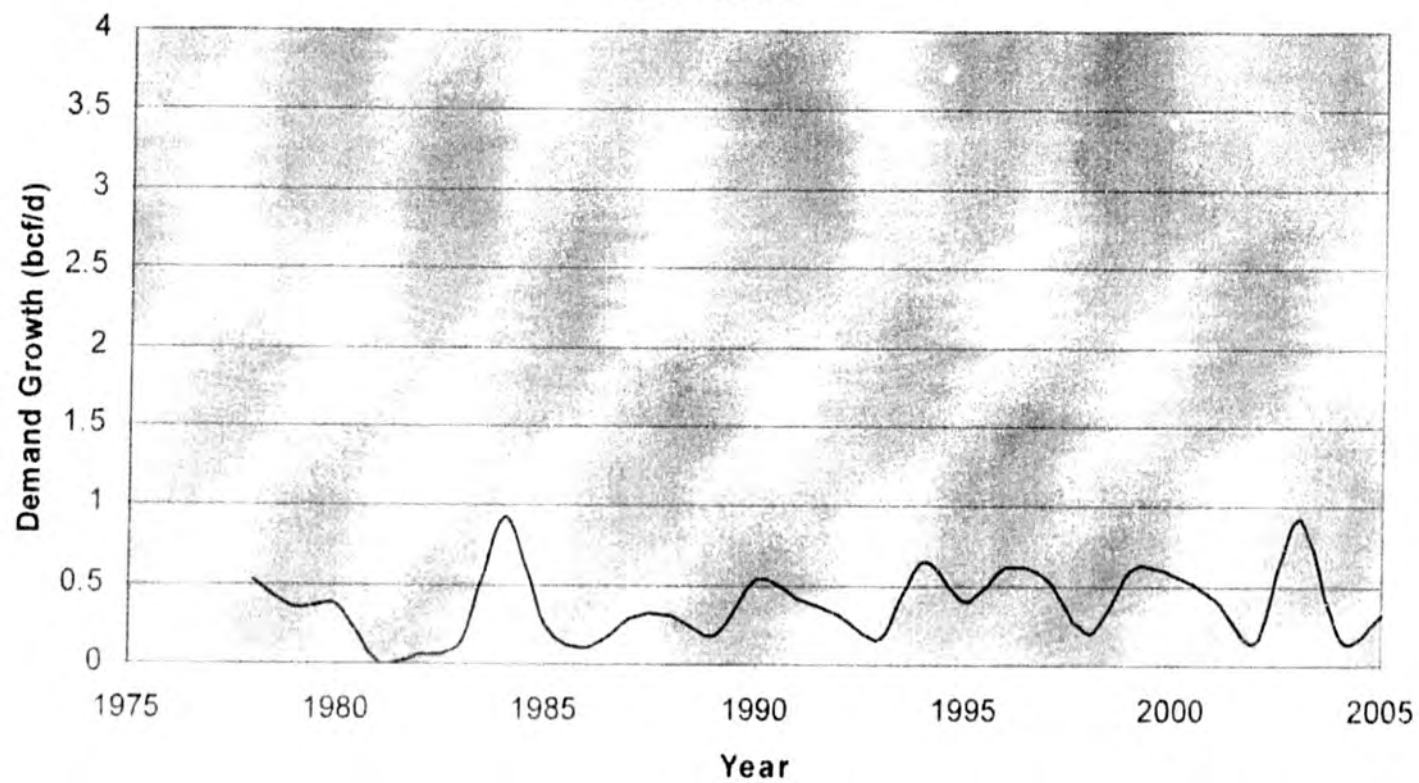
Options: Pipeline and LNG Economics

State of Alaska
August 4, 2006

Asia as an LNG Market

- Cannot compete with large reserves of LNG supply that has access to gas at tidewater and foreign tankers:
 - Qatar
 - Indonesia
 - Australia
 - Sakhalin

Yearly Increase in Asia LNG Demand 1977-2005



Source: Cedigaz

Asia as an LNG Market

- Cannot compete with large reserves of LNG supply that has access to gas at tidewater and foreign tankers:
 - Qatar
 - Indonesia
 - Australia
 - Sakhalin

Outline

- Markets
 - Demand
 - Supply
 - Siting Issues
- Costs
 - LNG Issues
 - Y-line Economics
 - Jones Act Tankers
 - Value of Tax Exemption

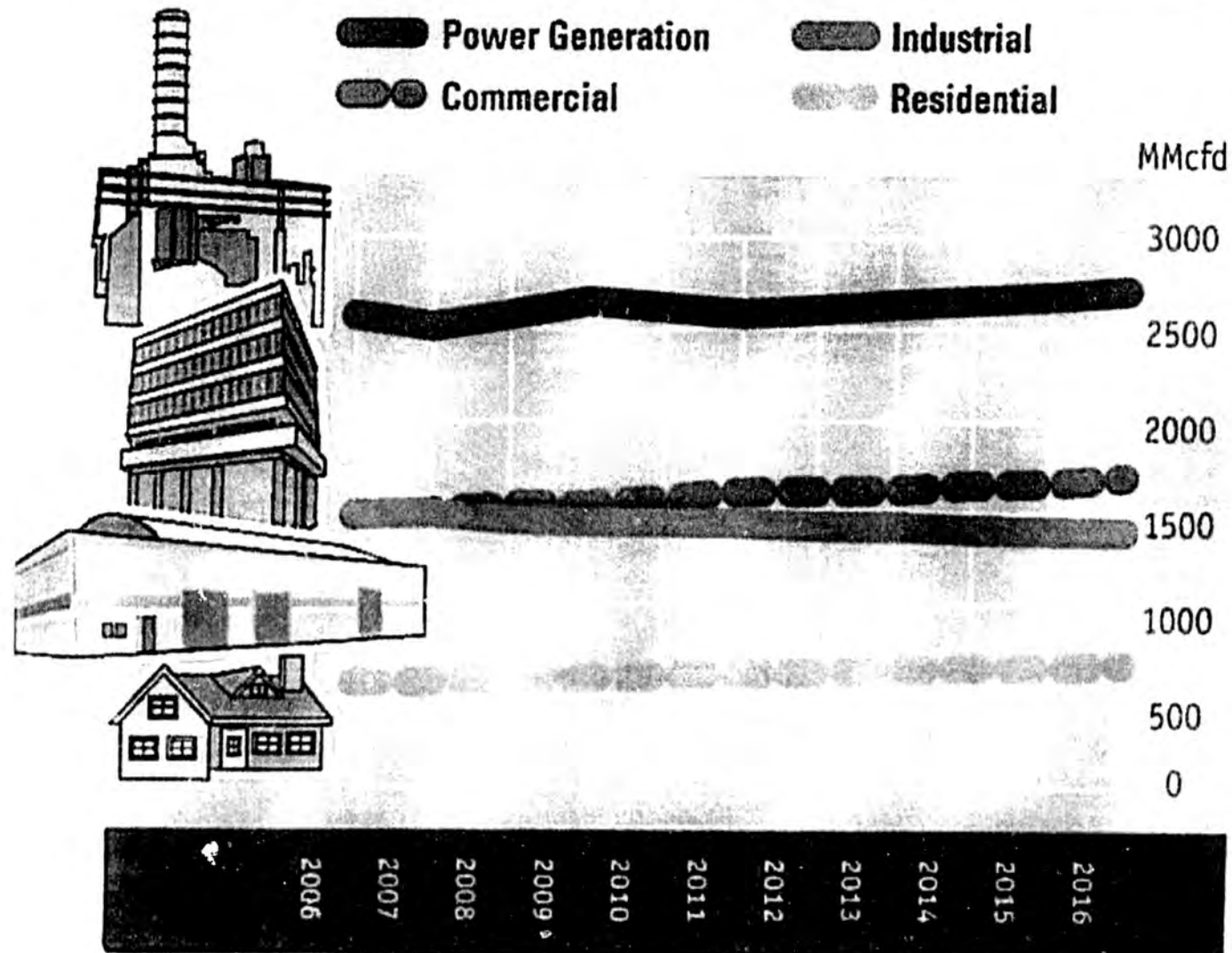
Options: Pipeline and LNG Economics

State of Alaska
August 4, 2006

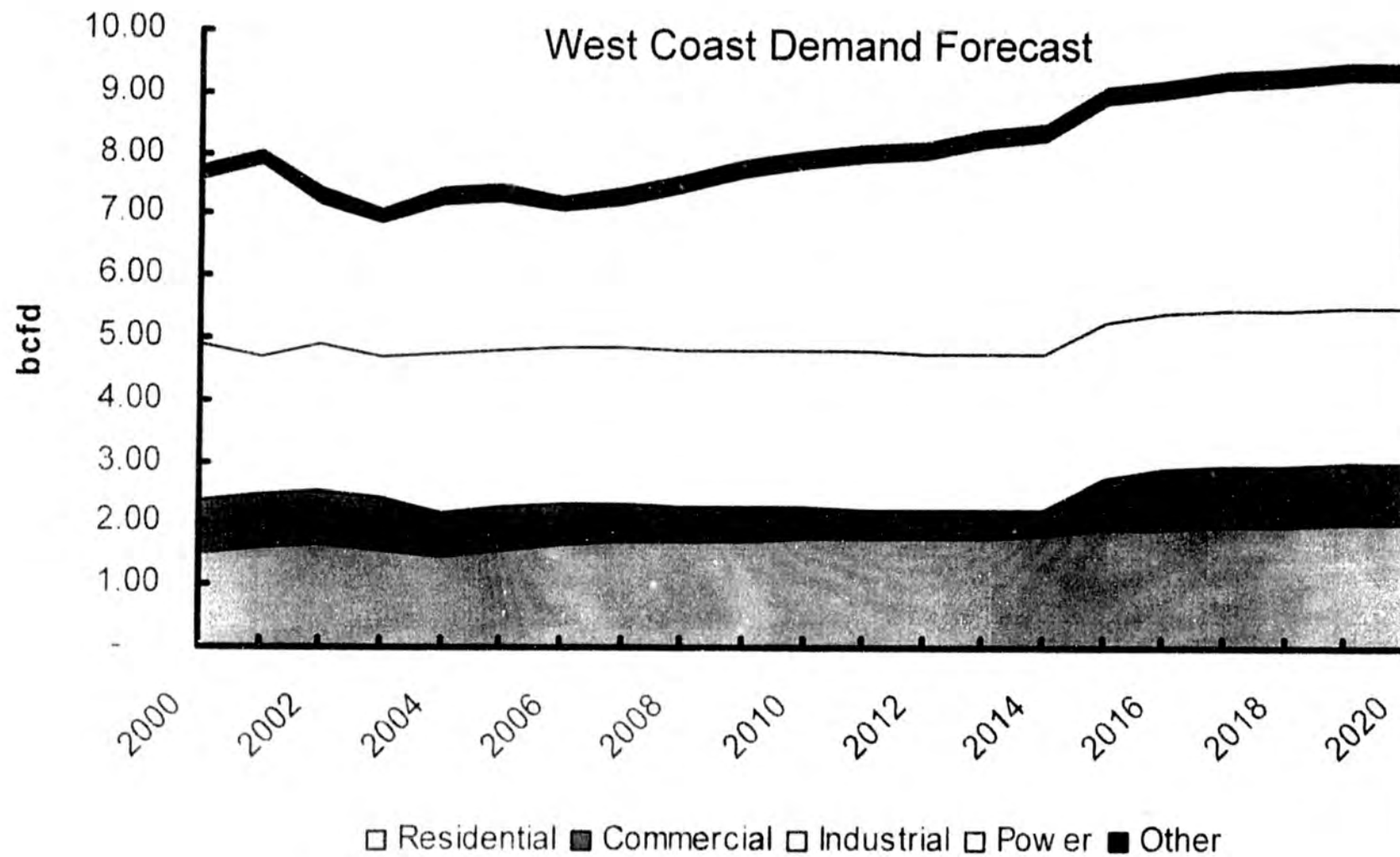
Price – West Coast Demand

- Small market (9 bcf/d) (U.S. = 65 bcf/d)
- Expected to grow 2%/year with population
- Plus 2 bcf/d over next 10-15 years (see next slides)
- Locked up by Sempra
- Reversing the flow of the pipelines would cause gas to back up in low demand areas

Figure 19: California Natural Gas Sector Demand Projection (by MMcfd)

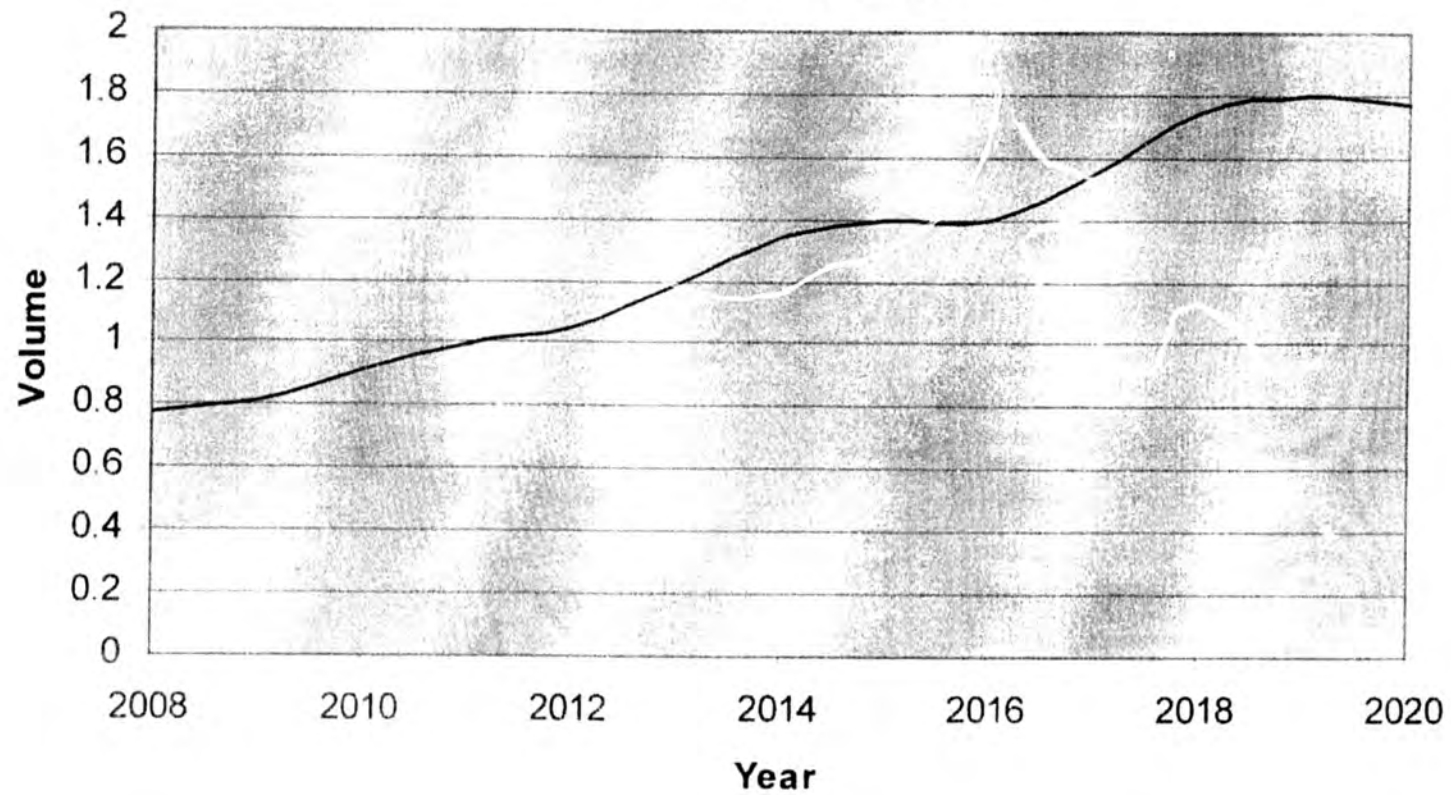


Source: California Energy Commission



Source: Wood Mackenzie

**Baha Imports
2008-2020 (bcf/d)**

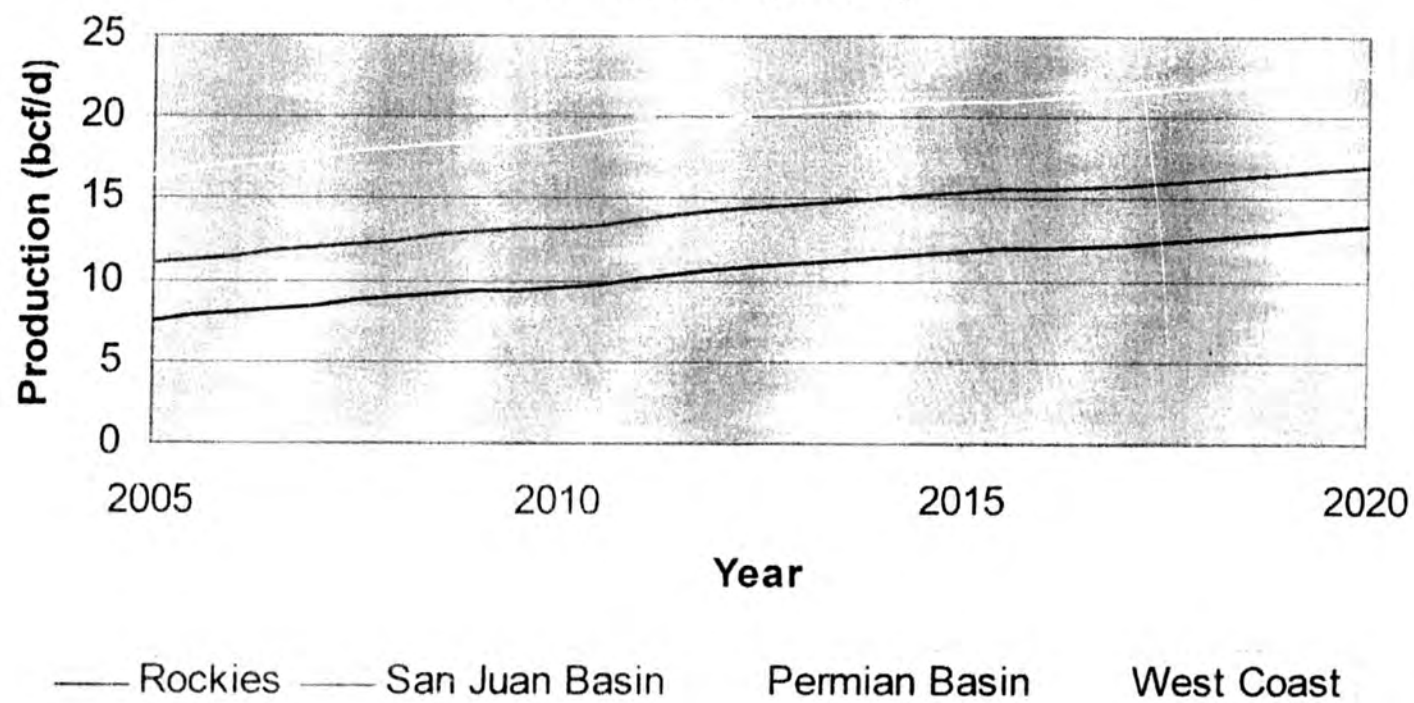


Source: Wood Mackenzie

Price – West Coast Supply

- West Coast is isolated market
- Gas from pipelines going East-West from the Rockies and Southwest, plus Canadian imports
- Also served by nuclear, hydro, coal, oil-fired power plants
- Supply areas expected to grow (see next 2 slides)
- Rockies Express pipeline
- Chicago is a very large very liquid market with access to many pipelines
- The West Coast has lower gas prices than Chicago (about 50 cents)
- AECO has lower price but lower cost

Production of West Coast Supply Areas 2005-2020 (bcf/d)

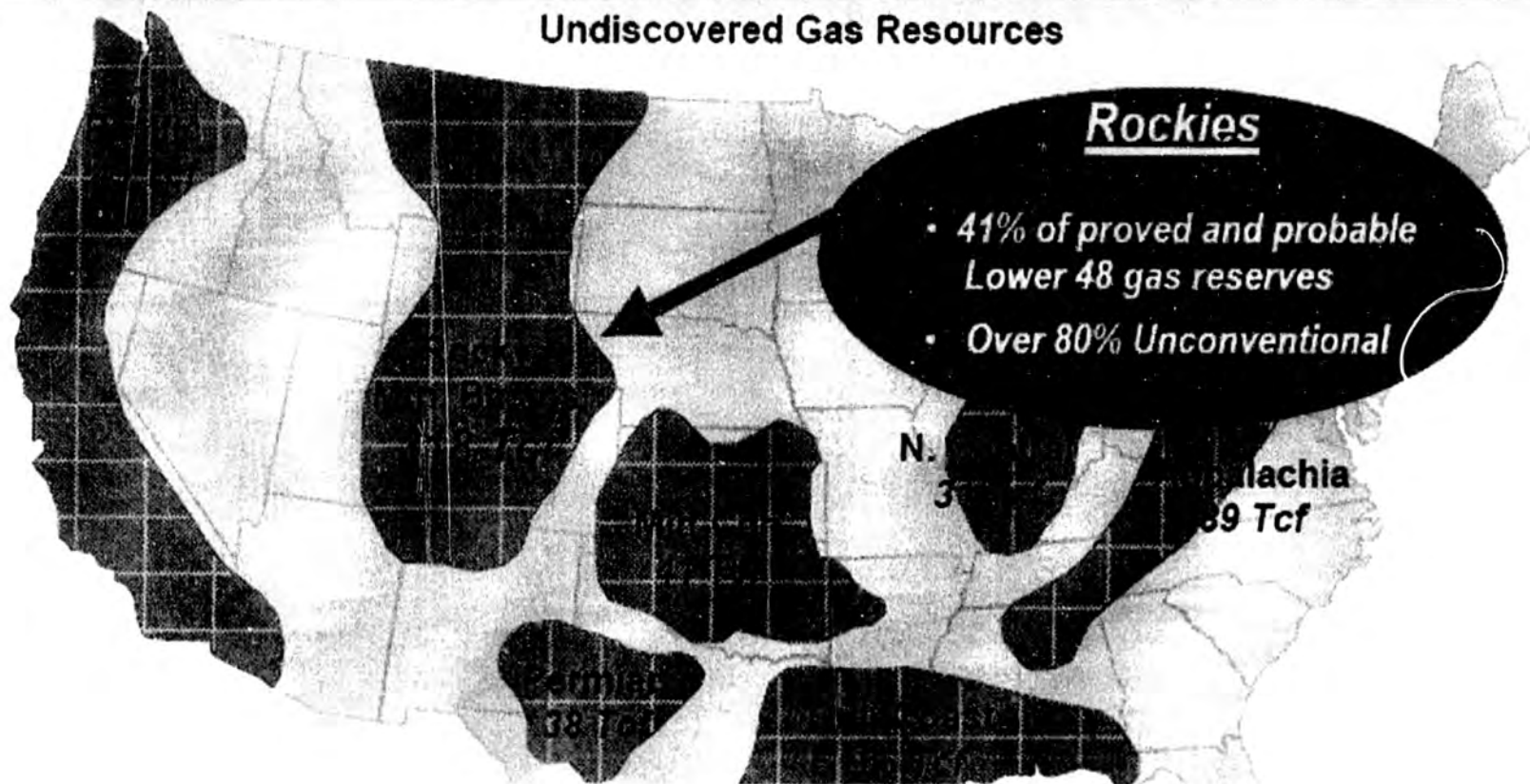


Source: Wood Mackenzie

Largest U.S. Gas Resource Opportunities

UCR Gas from Rockies – Our Principal Focus

Undiscovered Gas Resources



Source: USGS

Siting Issues for LNG Receiving Terminals

- Permitting
- Financing (underscores weak market)
- Marketing (underscores weak market)
- Community Resistance
- Environmental
- Safety

PFC Assessment

Likelihood of Construction in Next 10 Years*

- Kitimat (B.C.) Poor
- Northern Star (Bradford,OR) Poor
- Clearwater (Oxnard,CA) Poor
- Pt. Penguin (Pendleton,CA) Negligible

* Poor is less than 20% probability; negligible is less than 5% probability

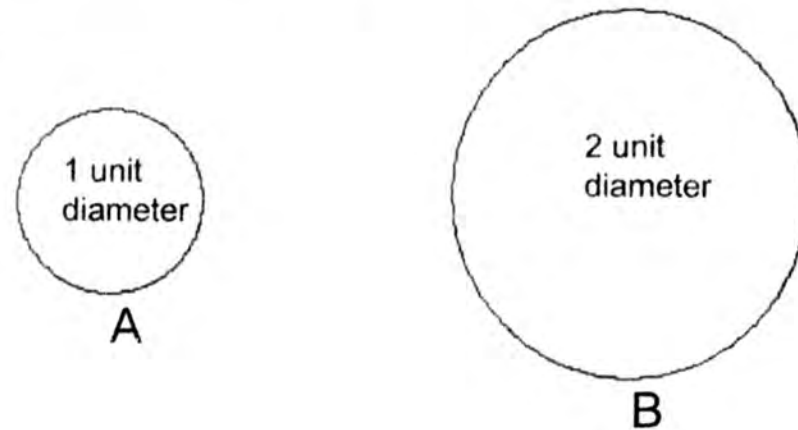
Cost – Pipe vs. LNG

- Conditioning
- Pipeline
- Liquefaction facilities
- Shipping
- Regasification
- Inland pipelines
- Operating costs
- Losses in transit
- Storage issues on West Coast

Y-Line

- Pipelines live and die with economies of scale
- Volume increases with square of diameter

How Volume Increases Proportionally With Diameter



Think of diameter as amount of steel (cost)
Think of area as volume of gas

$$\text{Area of circle} = \pi (d/2)^2$$

$$1 \text{ unit diameter} = 3.14 \times 1/2 \times 1/2 = 0.785$$

$$2 \text{ unit diameter} = 3.14 \times 2/2 \times 2/2 @ = 3.14$$

Diameter goes up **2-fold**; area goes up **4-fold**
(a little more steel, a lot more volume)

Y-Line

- The same thing works in reverse
 - Reduce the volume and the diameter decreases proportionally much less
- A 4 bcf/d line would be 48 inches
- A 3 bcf/d line would be 42 inches
 - Volume decreases 25%; cost decreases only 12%
 - **Tariff increases by 40 cents/mmbtu**
- A 1 bcf/d line would be 24 inches
 - Volume decreases 75%; cost decreases only 50%
 - **Tariff increases by 20 cents/mmbtu**
- **Together this raises the cost of 4 bcf/d by 20% (\$5B): Two pipelines cost more than one**

Jones Act

- Any vessels engaged in shipping from one U.S. location to another U.S. location must be in a ship which is U.S. built, U.S. flagged, and U.S. owned and operated
- Must be entirely assembled and fabricated in U.S.
- Required if gas goes to foreign port but gas ultimately goes to U.S.
- Once a ship re-flags it is ineligible for Jones Act service
- Potential temporary waivers available only for issues of national defense and passenger ships
- Very unlikely Congress would amend

Cost of Jones Act Ships

- No U.S shipyard has built an LNG tanker for several decades
- Steep learning curve
- High labor costs
- Low competition between yards
- Estimated costs 2 times greater than foreign built LNG tankers (3 - 4 ships @ \$400 million each)

Value of Tax Exemption

- Tariff is pass-through of costs – capital (deprec., r.o.d., r.o.e.), operating, property taxes, income taxes
- Taxes are only paid on income
- Only income element is return on equity (\$7 B)
- Unrecovered equity is higher in early years
- But volumes are lower in early years
- FERC usually levelizes tariffs to offset this

Value of Tax Exemption (con't.)

- Levelization defers recovery – carrier is made whole on a net present value basis
- Events that occur earlier carry more weight
- Accelerated tax depreciation much faster than book depreciation
- Difference between tax and book depreciation is a negative cost (\$6 B)
- It is very large and it occurs early on
- The benefits of tax depreciation reduce the tariff drastically
- With levelization, the tariff is actually lower with income taxes
- The income tax exemption has small value

Conclusion

- West Coast prices at least 50 cents less
- PFC Energy concluded that LNG based on 4 bcf/d would cost \$1.13 / mcf more using consistent assumptions
- The Y-Line approach leads to a directionally similar outcome
- Maximize value

AGPA Project Comments

August 4, 2006

Presentation to
The Senate Special Committee on
Natural Gas Development

Pedro van Meurs

Tax Comments

Reference was made to my comments on Federal taxation and aide-memoire for AGPA.

Federal income tax plays indeed a very important role in the overall government take distribution and project economics.

Tax Comments

Take Distribution

\$ 5.50 - Project to Alberta

	(\$ billion)
Corporate Income	93.7
Total Alaska	44.8
Canadian Gov	4.5
US Fed Tax Midstrear	2.0
US Fed Tax Upstream	47.8
Financial Inst	6.8
Total	199.6

Tax Comments

Under the Stranded Gas Contract proposal the State of Alaska will participate for 20%. It is assumed that the State will not be subject to corporate income tax. The saving in Federal CIT is about \$ 0.5 billion. If the State would own 100% of the pipeline system in Alaska the tax savings would be \$ 2.5 billion.

Tax Comments

In my aide memoire to AGPA I repeated the importance of these tax issues. I also indicated that AGPA could play a role in reducing tax under the following conditions:

- finds a way to lower the overall costs of the project,
- is able to create with other parties a financial and organizational configuration in which the project can proceed, and
- is able to create conditions under which this exemption can be effectively used to the benefit of the total project.

High Risk Nature of the Project

The AGPA presentation provided good background to illustrate the extreme gas price volatility in the North American market compared other gas markets and the significant cost escalation that has already occurred during the last five years. These are points which I have also emphasized repeatedly.

This is the reason for the stranded gas contract and the related fiscal stability provisions for the Sponsors.

Incremental Benefit of gas line to Alberta

The AGPA presentation illustrated how the AGPA project would greatly benefit from the gas line to Canada proposed by the Sponsors irrespective of whether 3.1 of 4.3 Bcf would be exported to Alberta.

Given this fact, one would expect AGPA to support the stranded gas contract with the Sponsors.

Time Line

AGPA claims that their project can deliver first gas based on Jan 2012 based on a start-up date of January 1, 2006.

The Sponsors plan provides for first gas Jan 2016 with a start up date of Jan 1, 2007.

So it seems that there is a **three year** difference in start up date rather than the **four years** claimed by AGPA.

Time Line

AGPA suggests that the GTP would be constructed by the producers. This seems rational.

The main function of the GTP is to eliminate CO₂ from the gas. However, this CO₂ would have to be re-injected. AGPA would not own suitable leases and fields to re-inject the gas. CO₂ also could play an increasingly important role in enhanced recovery of existing oil fields of the producers.

Time Line

The AGPA project therefore depends on a GTP to be constructed by the producers. This GTP is more costly and would have to have higher specifications because all CO₂ would have to be removed.

The producers have provided a rational and well documented time line why they believe that the preparatory front end engineering and the FERC process would take about four years. They contemplate the GTP FERC certificate to be granted January 2011.

How could AGPA have a project start up of 2013 when their own plan contemplates four years for construction?

Time Line

Alternatively, how does AGPA intend to do all the project engineering, the open season, the regulatory process, the preparation and leases for CO₂ injection for the GTP in two years in order to meet a Jan 2013 start up deadline?

Time Line

It is highly questionable that AGPA would have first gas by 2013 based on a Jan 2007 start up of activities.

First gas would be more likely by 2015 or 2016.

Gas Sales in California

AGPA did not provide any evidence that they would be capable of offering the lowest price in California compared to other LNG exporters.

Gas Sales in California

Most existing LNG export facilities in the Pacific are on tide water. This includes Australia, Indonesia, Malaysia and Brunei.

All countries have LNG expansion plans under way. Most projects relate to fields that have low production costs. Mr. Shipkoff indicated yesterday how easy it is to put in another "train" in Valdez if there would be more LNG demand and if the LNG export facilities already exist. This is easy for all competitors on tide water.

Gas Sales in California

Page 41 of the AGPA presentation illustrates the following capital cost estimates required just to get to Valdez:

- \$ 5.3 Billion for the pipeline
- a GTP aimed at removing all CO₂.

Given these conditions it would be extremely difficult for AGPA to compete on price with their competitors.

Gas Sales in California

AGPA claims that a benefit of their project is that it would diversify access for Alaska to both the East Coast and the West Coast markets.

This is incorrect.

The great advantage of building a gas line to the Alberta Hub is that this hub has access to both the East Coast and West Coast markets.

Financing of the Project

FERC would never approve the entire capital expenditure for a 48 inch line from Prudhoe Bay to Delta Junction in the rate base with an initial capability of 4.3 Bcf if such facilities is only used to transport 1.2 Bcf.

It is highly unlikely that the RCA would.

Financing of the Project

Therefore, about \$ 2 – 3 billion would have to be invested on pure speculation that a future project extension will occur.

This part can not be financed because FERC/RCA would not allocate the corresponding revenue stream. This amount has to be 100% equity.

It is highly unlikely that any investor in the world would be prepared to make such an investment.

Financing of the Project

AGPA claims that they can benefit from Federal Loan guarantees.

It are actually the lenders to AGPA that would receive the benefits under the loan guarantee in case AGPA defaults.

Under Federal Loan guarantees, however, the Federal Government would subsequently claim the money back from the borrower. The borrower therefore needs to have a credible financial position in order to be able to negotiate such a loan guarantee.

It is highly unlikely that the US Federal Government would provide a loan guarantee of \$ 18 billion to AGPA.

How would they ever get their money back if AGPA defaults?

Financing of the Project

The Federal loan guarantee would not cover completion risk. Nor would the lenders to AGPA be prepared to assume completion risk.

How would AGPA handle a situation where after having invested about \$ 5 billion a force majeure event occurs that stops the project and the lenders want their money back?

How is AGPA going to guarantee them their money back?

It is highly unlikely that construction firms would be willing to assume the full completion risk.

Financing of the Project

Conclusion

About \$ 2 -3 billion of excess capacity in the 48 inch line cannot be financed.

Without a Federal Loan guarantee and completion guarantee, AGPA will be unable to finance the project, even if AGPA has ship or pay contracts for all the gas with parties that have a strong balance sheet.

Ship or Pay commitment

Assume AGPA can overcome all financing problems.

In order to finance the project between PB and the LNG export point, AGPA needs a ship or pay contract from one or more parties. This could be a producer that is interested in using the project or it could be a buyer.

One would need a contract for about 8 Bcf over 20 years. Depending on the tariff this would be a \$ 10 - \$ 20 billion contract.

Who would be interested in concluding such a contract?

Ship or Pay commitment

The information provided by AGPA on page 44 of their presentation makes it clear that producers would very likely evaluate that the net back from the AGPA project is lower than the net back from their own project.

Why would the producers be interested in selling for a lower value to a 1.2 Bcf/day project?

At the same time they would increase the risk that their own 3.1 Bcf/day project would be more costly and would have a higher reserve risk.

It is highly unlikely that such a deal would come together.

Stranded Gas Contract

Even in the highly unlikely case that a producer would be interested in selling a share of their production as LNG, they would be unable to sign a contract with AGPA for ship or pay without a stranded gas contract.

The fiscal uncertainty would make it impossible to incur the risk of the ship or pay contracts. The lower net back would make the risk even higher.

Stranded Gas Contract

Therefore, no matter what:

The first step in either the AGPA project or the gas line to Alberta or any combination of the two is always a stranded gas contract.

Therefore, it is completely irrational for AGPA to oppose such a contract.

Stranded Gas Contract

From an economic perspective it is not sensible to consider the Alberta project incremental to the AGPA project because of the fact that such an option cannot be financed.

It is rational to potentially consider an AGPA project incremental to the Alberta project. This is the option included in the stranded gas contract.

Upstream economics

The upstream economics of the project on pages 65 and 67 of the AGPA presentation assume that a buyer would buy gas at the inlet of the pipeline.

These evaluations are not correct if the producers would have to assume the ship or pay commitments. The capitalized value of such commitments needs to be included in the evaluation.



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TITLE 15 > CHAPTER 15B > § 717a

§ 717a. Definitions

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Release date: 2005-08-01

When used in this chapter, unless the context otherwise requires—

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- ② (1) "Person" includes an individual or a corporation.
- ③ (2) "Corporation" includes any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, receiver or receivers, trustee or trustees of any of the foregoing, but shall not include municipalities as hereinafter defined.
- ④ (3) "Municipality" means a city, county, or other political subdivision or agency of a State.
- (4) "State" means a State admitted to the Union, the District of Columbia, and any organized Territory of the United States.
- (5) "Natural gas" means either natural gas unmixed, or any mixture of natural and artificial gas.
- ① (6) "Natural-gas company" means a person engaged in the transportation of natural gas in interstate commerce, or the sale in interstate commerce of such gas for resale.
- (7) "Interstate commerce" means commerce between any point in a State and any point outside thereof, or between points within the same State but through any place outside thereof, but only insofar as such commerce takes place within the United States.
- (8) "State commission" means the regulatory body of the State or municipality having jurisdiction to regulate rates and charges for the sale of natural gas to consumers within the State or municipality.
- (9) "Commission" and "Commissioner" means the Federal Power Commission, and a member thereof, respectively.
- (10) "Vehicular natural gas" means natural gas that is ultimately used as a fuel in a self-propelled vehicle.

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TITLE 15 > CHAPTER 15B > § 717f

§ 717f. Construction, extension, or abandonment of facilities

Release date: 2005-08-01

[Prev](#) | [Next](#)**(a) Extension or improvement of facilities on order of court; notice and hearing**

Whenever the Commission, after notice and opportunity for hearing, finds such action necessary or desirable in the public interest, it may by order direct a natural-gas company to extend or improve its transportation facilities, to establish physical connection of its transportation facilities with the facilities of, and sell natural gas to, any person or municipality engaged or legally authorized to engage in the local distribution of natural or artificial gas to the public, and for such purpose to extend its transportation facilities to communities immediately adjacent to such facilities or to territory served by such natural-gas company, if the Commission finds that no undue burden will be placed upon such natural-gas company thereby: Provided, That the Commission shall have no authority to compel the enlargement of transportation facilities for such purposes, or to compel such natural-gas company to establish physical connection or sell natural gas when to do so would impair its ability to render adequate service to its customers.

(b) Abandonment of facilities or services; approval of Commission

No natural-gas company shall abandon all or any portion of its facilities subject to the jurisdiction of the Commission, or any service rendered by means of such facilities, without the permission and approval of the Commission first had and obtained, after due hearing, and a finding by the Commission that the available supply of natural gas is depleted to the extent that the continuance of service is unwarranted, or that the present or future public convenience or necessity permit such abandonment.

(c) Certificate of public convenience and necessity**(1)**

(A) No natural-gas company or person which will be a natural-gas company upon completion of any proposed construction or extension shall engage in the transportation or sale of natural gas, subject to the jurisdiction of the Commission, or undertake the construction or extension of any facilities therefor, or acquire or operate any such facilities or extensions thereof, unless there is in force with respect to such natural-gas company a certificate of public convenience and necessity issued by the Commission authorizing such acts or operations: Provided, however, That if any such natural-gas company or predecessor in interest was bona fide engaged in transportation or sale of natural gas, subject to the jurisdiction of the Commission, on February 7, 1942, over the route or routes or within the area for which application is made and has so operated since that time, the Commission shall issue such certificate without requiring further proof that public convenience and necessity will be served by such operation, and without further proceedings, if application for such certificate is

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made to the Commission within ninety days after February 7, 1942. Pending the determination of any such application, the continuance of such operation shall be lawful.

(B) In all other cases the Commission shall set the matter for hearing and shall give such reasonable notice of the hearing thereon to all interested persons as in its judgment may be necessary under rules and regulations to be prescribed by the Commission; and the application shall be decided in accordance with the procedure provided in subsection (e) of this section and such certificate shall be issued or denied accordingly: Provided, however, That the Commission may issue a temporary certificate in cases of emergency, to assure maintenance of adequate service or to serve particular customers, without notice or hearing, pending the determination of an application for a certificate, and may by regulation exempt from the requirements of this section temporary acts or operations for which the issuance of a certificate will not be required in the public interest.

(2) The Commission may issue a certificate of public convenience and necessity to a natural-gas company for the transportation in interstate commerce of natural gas used by any person for one or more high-priority uses, as defined, by rule, by the Commission, in the case of—

(A) natural gas sold by the producer to such person; and

(B) natural gas produced by such person.

(d) Application for certificate of public convenience and necessity

Application for certificates shall be made in writing to the Commission, be verified under oath, and shall be in such form, contain such information, and notice thereof shall be served upon such interested parties and in such manner as the Commission shall, by regulation, require.

(e) Granting of certificate of public convenience and necessity

Except in the cases governed by the provisos contained in subsection (c)(1) of this section, a certificate shall be issued to any qualified applicant therefor, authorizing the whole or any part of the operation, sale, service, construction, extension, or acquisition covered by the application, if it is found that the applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of this chapter and the requirements, rules, and regulations of the Commission thereunder, and that the proposed service, sale, operation, construction, extension, or acquisition, to the extent authorized by the certificate, is or will be required by the present or future public convenience and necessity; otherwise such application shall be denied. The Commission shall have the power to attach to the issuance of the certificate and to the exercise of the rights granted thereunder such reasonable terms and conditions as the public convenience and necessity may require.

(f) Determination of service area; jurisdiction of transportation to ultimate consumers

(1) The Commission, after a hearing had upon its own motion or upon application, may determine the service area to which each authorization under this section is to be limited. Within such service area as determined by the Commission a natural-gas company may enlarge or extend its facilities for the purpose of supplying increased market demands in such service area without further authorization; and

(2) If the Commission has determined a service area pursuant to this subsection, transportation to ultimate consumers in such service area by the holder of such service area determination, even if across State lines, shall be

subject to the exclusive jurisdiction of the State commission in the State in which the gas is consumed. This section shall not apply to the transportation of natural gas to another natural gas company.

(g) Certificate of public convenience and necessity for service of area already being served

Nothing contained in this section shall be construed as a limitation upon the power of the Commission to grant certificates of public convenience and necessity for service of an area already being served by another natural-gas company.

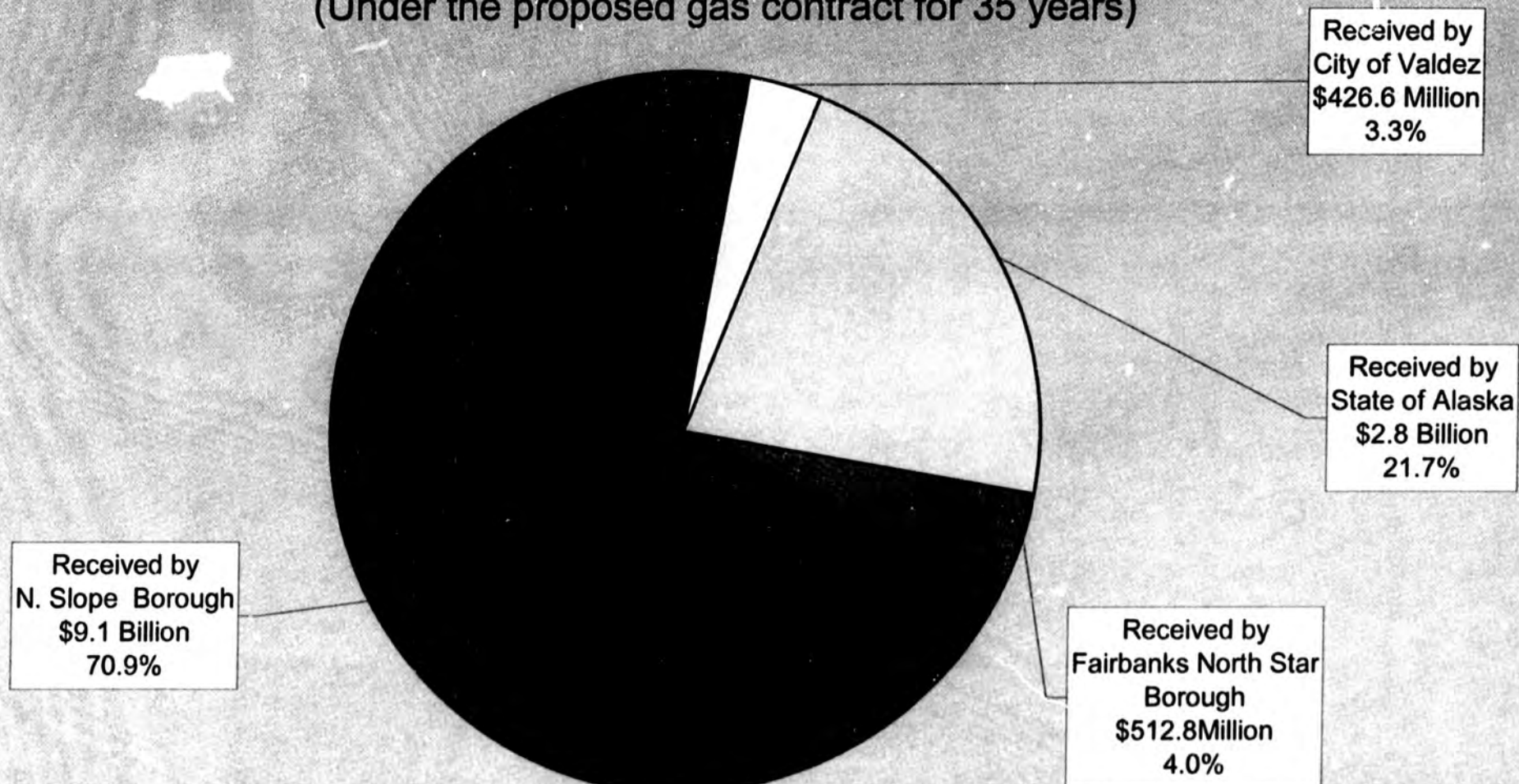
(h) Right of eminent domain for construction of pipelines, etc.

When any holder of a certificate of public convenience and necessity cannot acquire by contract, or is unable to agree with the owner of property to the compensation to be paid for, the necessary right-of-way to construct, operate, and maintain a pipe line or pipe lines for the transportation of natural gas, and the necessary land or other property, in addition to right-of-way, for the location of compressor stations, pressure apparatus, or other stations or equipment necessary to the proper operation of such pipe line or pipe lines, it may acquire the same by the exercise of the right of eminent domain in the district court of the United States for the district in which such property may be located, or in the State courts. The practice and procedure in any action or proceeding for that purpose in the district court of the United States shall conform as nearly as may be with the practice and procedure in similar action or proceeding in the courts of the State where the property is situated: Provided, That the United States district courts shall only have jurisdiction of cases when the amount claimed by the owner of the property to be condemned exceeds \$3,000.

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Proposed State Take
PILT Payments for Oil and Gas Pipeline & Facilities
(Under the proposed gas contract for 35 years)



Total - \$12.8 Billion

DRAFT - DRAFT

**Summary of Status Quo and PILT Payments
Negotiated under the Alaska Stranded Gas Act**
(The following amounts represent the total dollars paid over 35 years)

DRAFT - DRAFT**Oil Pipeline & Facilities** (Status Quo is based on actual property value)

	Total Amount			Pop	Per Capita		
	Status Quo* (20 mills)	PILT	Diff from Status Quo		Status Quo* (20 mills)	PILT	Diff from Status Quo
State of Alaska	\$ 1,196,512,439	\$ 1,278,881,152	\$ 82,368,713	626,932	\$ 1,909	\$ 2,040	\$ 131
North Slope Borough	\$ 3,940,177,114	\$ 5,386,487,413	\$ 1,446,310,299	6,894	\$ 571,537	\$ 781,330	\$ 209,793
Fairbanks North Star Borough	\$ 121,118,534	\$ 121,883,488	\$ 764,953	87,650	\$ 1,382	\$ 1,391	\$ 9
City of Valdez	\$ 423,914,870	\$ 426,592,206	\$ 2,677,337	4,454	\$ 95,176	\$ 95,777	\$ 601
TOTAL	\$ 5,631,722,958	\$ 7,213,844,260	\$ 1,532,121,302				

Gas Pipeline & Facilities (Status Quo is based on estimated property value)

	Total Amount			Pop	Per Capita		
	Status Quo* (20 mills)	PILT	Diff from Status Quo		Status Quo* (20 mills)	PILT	Diff from Status Quo
State of Alaska	\$ 2,178,996,801	\$ 1,490,903,791	\$ (688,093,009)	626,932	\$ 3,476	\$ 2,378	\$ (1,098)
North Slope Borough	\$ 2,174,462,468	\$ 3,671,669,328	\$ 1,497,206,861	6,894	\$ 315,414	\$ 332,589	\$ 217,175
Fairbanks North Star Borough	\$ 244,194,253	\$ 390,886,012	\$ 146,691,760	87,650	\$ 2,786	\$ 4,460	\$ 1,674
TOTAL	\$ 4,597,653,521	\$ 5,553,459,132	\$ 955,805,611				

Total Oil & Gas Pipeline & Facilities

	Total Amount			Pop	Per Capita		
	Status Quo* (20 mills)	PILT	Diff from Status Quo		Status Quo* (20 mills)	PILT	Diff from Status Quo
State of Alaska	\$ 3,375,509,240	\$ 2,769,784,944	\$ (605,724,296)	626,932	\$ 5,384	\$ 4,418	\$ (966)
North Slope Borough	\$ 6,114,639,582	\$ 9,058,156,742	\$ 2,943,517,159	6,894	\$ 886,951	\$ 1,313,919	\$ 426,968
Fairbanks North Star Borough	\$ 365,312,787	\$ 512,769,500	\$ 147,456,713	87,650	\$ 4,168	\$ 5,850	\$ 1,682
City of Valdez	\$ 423,914,870	\$ 426,592,206	\$ 2,677,336	4,454	\$ 95,176	\$ 95,777	\$ 601
TOTAL	\$ 10,279,376,479	\$ 12,767,303,392	\$ 2,487,926,912				

LEGAL SERVICES

DIVISION OF LEGAL AND RESEARCH SERVICES
LEGISLATIVE AFFAIRS AGENCY
STATE OF ALASKA

(907) 465-3867 or 465-2450
FAX (907) 465-2029
Mail Stop 3101

State Capitol
Juneau, Alaska 99801-1182
Deliveries to: 129 6th St., Rm. 329

MEMORANDUM

August 3, 2006

SUBJECT: Issues related to new CS (CSSB 3002(NGD), Draft version "F";
Work Order No. 24-GS2095\F)

TO: Senator Ralph Seekins
Attn: Brian Hove

FROM: Dennis C. Bailey *DCB*
Legislative Counsel

Please note the following.

Please review sec. 3 to make sure it expresses the committee's intent. It is in a slightly different format than the amendment.

In sec. 10 the meaning of "as may be modified as a result of the development of a contract under this chapter" is not clear to me. Does this refer to the implementation provisions or the plan approval under AS 43.82.140? And when would the modification occur?

Because of the addition of the last two lines of AS 43.82.270 in sec. 10, it appears that all future contracts under AS 43.82.020 will have to be with the sponsors of the project identified in AS 43.82.270(b), added by sec. 11. Should "applicable" be added before "requirements" in the last sentence of AS 43.82.270 in sec. 10? Also, sec. 11 may be challenged as local and special legislation, though the nature of this project is such that a law of general applicability may not be possible.

I did not know whether to make new secs. 3, 8, 9, 10 and 11 retroactive. I chose to treat them as retroactive. Let me know if you want something different.

In sec. 7 we substituted "(a)" for "(a)(1)(A)-(C)" because the section creating AS 43.82.220(a)(1)(A)-(C) was deleted. Please be sure that is what you intend.

Sec. 15 is modified to remove the reference to (c), which was deleted.

Sec. 16 is modified to conform with the deletion of former sec. 16 by removing the reference to grants.

If I may be of further assistance, please advise.

Senator Ralph Seekins
August 3, 2006
Page 2

DCB:ljw
06-289.ljw

Enclosure

Member Information



SENATE SPECIAL COMMITTEE ON NATURAL GAS DEV

No Time available

Special Committee

CHAIR: Senator Seekins

MEMBER: Senator Green
MEMBER: Senator Wilken
MEMBER: Senator Bunde
MEMBER: Senator Dyson
MEMBER: Senator Stedman
MEMBER: Senator Hoffman
MEMBER: Senator Olson
MEMBER: Senator Wagoner
MEMBER: Senator Stevens B
MEMBER: Senator Elton
MEMBER: Senator Kookesh

Bill Root:

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Internal Revenue Service

Department of the Treasury

Index Number: 103.02-01

Washington, DC 20224

Travis C. Gibbs
c/o O'Melveny & Myers LLP
400 South Hope Street
Los Angeles, California 90071-2899

Person to Contact:
David E. White I.D. #50-07793
Telephone Number:
(202) 622-3980
Refer Reply To:
CC:DOM:FI&P:5/PLR-118656-99
Date:

FEB 16 2000

FEB 16 2000

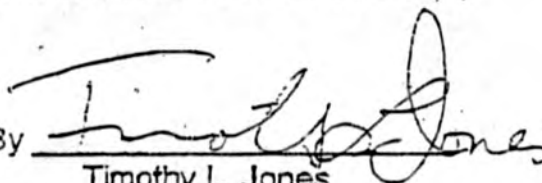
Dear Mr. Gibbs:

Attached is the corrected version of our letter in reply to your request for a ruling that the Authority qualifies as a political subdivision of the State under § 1.103-1(b) of the Income Tax Regulations, and is therefore exempt from federal income taxation. Please destroy the prior letter.

Sincerely yours, ..

Assistant Chief Counsel
(Financial Institutions & Products)

By



Timothy L. Jones

Assistant to the Chief, Branch 5

Internal Revenue Service

Department of the Treasury

Index Number: 103.02-01

Washington, DC 20224

Travis C. Gibbs
c/o O'Melveny & Myers LLP
400 South Hope Street
Los Angeles, California 90071-2899

Person to Contact
David E. White I.D. #50-07793
Telephone Number:
(202)622-3980
Refer Reply To:
CC:DOM:FI&P:5/PLR-118656-99
Date: JAN 24 2000

LEGEND:

Authority = Alaska Gasline Port Authority

State = Alaska

Date 1 = October 5, 1999

A = Fairbanks North Star Borough

B = North Slope Borough

C = City of Valdez

Port = Port of Valdez, Alaska

Location = North Slope of Alaska

Dear Mr. Gibbs:

This letter is in response to your request for a ruling that based on the definition of the term "political subdivision" in § 1.103-1(b) of the Income Tax Regulations, the Authority qualifies as a political subdivision of the State.

Facts and Representations

You make the following factual representations. The Authority was created on Date 1 pursuant to State law by the local governmental units A, B, and C. The Authority was created to provide for the development of ports in the State for transportation-related commerce. In accordance with this purpose, the Authority will

undertake various improvements and additions to certain existing port facilities located, and will construct new port facilities to be located, at the Port, and will acquire and develop the facilities necessary for the transportation, in state use, and sale of natural gas that is currently stranded at the Location (the "Project").

As a result of the availability of natural gas through the Project, the cost of electricity to the State's residents will be substantially reduced. Excess gas not used in-state will be available for other uses.

The Authority is governed by a board of directors appointed by its member governmental units A, B, and C. The Authority has the power to acquire, by purchase, lease, contribution, condemnation, or otherwise, real and personal property for the Project. State law provides that the Authority has the same power of eminent domain as that possessed by A, B, and C. Specifically, the Authority may commence eminent domain actions, in its own name, in the appropriate court of the State to acquire land or materials within its physical boundaries for Authority purposes, and may take possession of the property upon commencement of the proceedings.

The Authority's revenues will be derived primarily from the sale of natural gas to municipalities within the State and to other purchasers, which are expected to include governmental and private entities. These revenues will be used first generally to pay operating expenses and debt service and to fund necessary reserves for operation of the Project. Any net income will be shared with the State and all of its municipalities for use in their respective governmental purposes. Upon dissolution of the Authority, its assets will be distributed to its member governmental units.

In addition to contributions from the participating governmental units, the Authority is authorized to issue bonds or any other form of indebtedness to raise funds to finance the Project.

Law and Analysis

Section 103(a) of the Internal Revenue Code provides, in part, that except as provided in subsection (b), gross income does not include interest on any state or local bond. Section 103(c)(1) provides that the term "state or local bond" means an obligation of a state or political subdivision thereof.

Section 1.103-1(b) provides that the term "political subdivision" denotes any division of any state or local governmental unit that is a municipal corporation or that has been delegated the right to exercise part of the sovereign power of the unit. As thus defined, a political subdivision of any state or local governmental unit may or may not, for purposes of this section, include special assessment districts so created, such

as road, water, sewer, gas, light, reclamation, drainage, irrigation, levee, school, harbor, port improvement, and similar districts and divisions of these units. Rev. Rul. 78-276, 1978-2 C.B. 256, states that the term "political subdivision" has been defined consistently for all federal tax purposes as denoting either (1) a division of a state or local government that is a municipal corporation, or (2) a division of such state or local government that has been delegated the right to exercise sovereign power.

In determining whether an entity is a division of a state or local governmental unit, important considerations are the extent the entity is (1) controlled by the state or local government unit, and (2) motivated by a wholly public purpose. Revenue Ruling 83-131, 1983-2 C.B. 184.

The three generally acknowledged sovereign powers are the power to tax, the power of eminent domain, and the police power. See *Commissioner v. Estate of Alexander J. Shamburg*, 3 T.C. 131, (1944) *acq.*, 1945 C.B. 6, *aff'd* 144 F.2d 998 (2d Cir. 1944), *cert. denied*, 323 U.S. 792 (1945). It is not necessary that all three powers enumerated in *Shamburg* be delegated. Rev. Rul. 77-164, 1977-1 C.B. 20; Rev. Rul. 77-165, 1977-1 C.B. 21. However, possession of only an insubstantial amount of any or all sovereign powers is not sufficient. All of the facts and circumstances must be taken into consideration including the public purposes of the entity and its control by a government.

Indicia that the Authority is governmentally controlled are: (1) the Authority is governed by a board of directors appointed by its member governmental units A, B, and C; (2) the Authority's net revenues inure to the benefit of the State and its municipalities; and (3) the Authority's assets will be distributed to its member governmental units upon dissolution. The Authority is motivated by a wholly public purpose.

Under State law the Authority is granted broad powers of eminent domain within its physical boundaries. The Authority is authorized to commence actions in the appropriate court of the State to enforce this right and will be able to take possession of property upon commencement of the condemnation proceedings rather than after judgment. These exercises of the power of eminent domain are commensurate with a substantial exercise of that power.

Conclusion

Based solely on the representations made and the definition of the term "political subdivision" in § 1.103-1(b), we conclude that the Authority is a political subdivision. Accordingly, the Authority is not required to file federal income tax returns or pay federal income tax on its income.

4

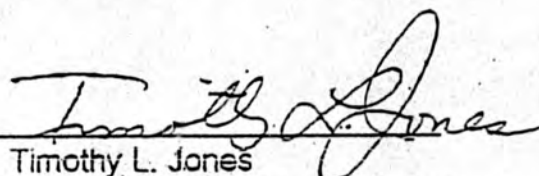
Except as specifically stated above, no opinion is expressed regarding the consequences of this transaction under any provision of the Code or regulations thereunder.

This ruling letter is directed only to the taxpayer who requested it. Section 6110(k)(3) provides that it may not be used or cited as precedent.

Sincerely yours,

Assistant Chief Counsel
(Financial Institutions & Products)

By:


Timothy L. Jones

Assistant to the Chief, Branch 5

Enclosure:

Copy of § 6110 purposes

cc: District Director, Pacific - Northwest District (Seattle)
Attn: Chief, Examination Division

Employee Plans & Exempt Organizations
Field Compliance Division
Attn: Joseph P. Grabowski, CP:E:EO:T:4
Room 6236

O
O'MELVENY & MYERS LLP

CENTURY CITY
NEWPORT BEACH
NEW YORK
SAN FRANCISCO
WASHINGTON, D.C.

400 South Hope Street
Los Angeles, California 90071-2899
TELEPHONE (213) 430-6000
FACSIMILE (213) 430-6407
INTERNET: www.omm.com

HONG KONG
LONDON
SHANGHAI
TOKYO

November 19, 1999

OUR FILE NUMBER
11,148-001

WRITER'S DIRECT DIAL
213-430-7402

Internal Revenue Service
Assistant Chief Counsel
Financial Institutions & Products
1111 Constitution Avenue, N.W.
Washington, D.C. 20224

WRITER'S E-MAIL ADDRESS
tgibbs@omm.com

Attn: CC:DOM:CORP:TSS, Room 6561

Re: Alaska Gasline Port Authority

Ladies and Gentlemen:

This letter ruling request is respectfully submitted on behalf of the Alaska Gasline Port Authority (the "Authority" or the "Alaska Gasline Port Authority").

In brief, a ruling is requested to the effect that, under the facts set forth herein, the Authority is a political subdivision of the State of Alaska (the "State"), and therefore, the Authority's income is exempt from federal income taxation.

Section I of this request outlines certain facts relating to the organization, operation and purpose of the Authority. Section II sets forth the specific ruling requested. Section III summarizes the authorities supporting such a ruling, analyzes their application to the relevant facts and sets forth the conclusion of that analysis. Section IV discusses certain taxpayer information and procedural matters.

By a separate letter attached hereto, the Authority is requesting expeditious handling of this request pursuant to Section 8.02(4) of *Revenue Procedure 99-1*.

ALASKA GASLINE PORT AUTHORITY
LETTER RULING REQUEST

I. STATEMENT OF FACTS

A. Information About the Authority

1. Creation and Legal Status of the Authority

The Authority is a port authority, which was established on October 5, 1999, in accordance with the Municipal Port Authority Act¹ of the Alaska Statutes (the "Act"). Pursuant to Section 29.35.605 of the Act,² the Fairbanks North Star Borough, the North Slope Borough and the City of Valdez (each an "Original Municipality") adopted parallel ordinances³ (each an "Ordinance," and together the "Ordinances") creating the Authority. Each of the Ordinances was approved by the respective voters of each Original Municipality on October 5, 1999. The Authority has been created pursuant to each of the Original Municipality's transportation system powers.⁴

2. Purpose of the Authority

The primary purpose of an authority created pursuant to the Act is to provide for the development of ports for transportation-related commerce.⁵ In accordance with this purpose and the State's constitutional mandate to utilize, develop and conserve its natural resources for the maximum benefit of its people,⁶ the Authority will undertake various improvements and additions to certain existing port facilities located, and will construct new port facilities to be located, at the Port of Valdez, Alaska, and acquire and develop the facilities necessary for the transportation, in state use, and sale of natural gas that is stranded on the North Slope of the State (the "Project"). See map attached hereto as Exhibit F.

3. Powers of the Authority

a. In General. The Authority has the power to acquire, by purchase, lease, contribution, condemnation or otherwise, real and personal property for the Project, and to construct, improve, maintain and operate, or to cause to be constructed, improved, maintained and operated, all or part of the Project.⁷

¹ ALASKA STAT. §§ 29.35.600 to 29.35.730. The Act is attached hereto as Exhibit D.

² ALASKA STAT. § 29.35.605(a)(2).

³ Fairbanks North Star Borough, Alaska, Ordinance, 99-059 (August 12, 1999) (attached hereto as Exhibit A); North Slope Borough, Alaska, Ordinance, 99-06 (August 3, 1999) (attached hereto as Exhibit B); Valdez, Alaska, Ordinance, 99-11 (July 19, 1999) (attached hereto as Exhibit C).

⁴ ALASKA STAT. § 29.35.605(d).

⁵ ALASKA STAT. § 29.35.600.

⁶ ALASKA CONST. art. VIII, § 2.

⁷ Ordinances, § 6.

b. **Eminent Domain.** The Authority is authorized to exercise the powers of eminent domain and declaration of taking to the same extent as such powers exists in the Participating Municipalities (as defined herein). Specifically, the Ordinances provide that the Authority may "exercise the powers of eminent domain and declaration of taking within its physical boundaries under [Section 29.35.030 of the Alaska Statutes] to acquire land or materials for [A]uthority purposes."⁸

c. **Additional Powers.** Additionally, the Authority is expressly authorized, in its own name, to do all acts necessary or convenient for the exercise of its power to achieve its purpose, including, but not limited to:

1. sue and be sued;
2. have a seal and alter it at pleasure;
3. acquire an interest in a project as necessary or appropriate to provide financing for the project, whether by purchase, gift or lease;
4. lease to others a project acquired by it upon the terms and conditions the Authority considers advisable, including, without limitation, provisions for purchase or renewal;
5. sell, by installment sale or otherwise, exchange, donate, convey or encumber in any manner by mortgage or by creation of another security interest, real or personal property owned by it, or in which it has an interest, including a project, when, in the judgment of the Authority, the action is in furtherance of its purpose;
6. accept gifts, grants or loans, under the terms and conditions imposed under the gift, grant or loan, and enter into contracts, conveyances or other transactions with a federal agency or an agency or instrumentality of the State, a municipality, private organization or other person;
7. deposit or invest its funds, subject to agreements with bondholders;
8. purchase or insure loans to finance the costs of projects;
9. provide for security within the boundaries of the Authority;

⁸ *Id.* The boundaries of the Authority are coterminous with the boundaries of the Participating Municipalities. Ordinances, § 3.

Section 29.35.030 of the Alaska Statute provides municipalities with the power of eminent domain. The extent of the Participating Municipalities' and the Authority's eminent domain powers is set forth in Section 09.55.250 of the Alaska Statutes, which is attached hereto as Exhibit E.

10. enter into loan agreements with respect to one or more projects upon the terms and conditions the Authority considers advisable;
11. acquire, manage and operate projects as the Authority considers necessary or appropriate to serve its purposes;
12. assist private lenders to make loans to finance the costs of projects through loan commitments, short-term financing or otherwise;
13. charge fees or other forms of remuneration for the use or possession of projects;
14. defend and indemnify a current or former member of the Board (as defined herein), employee or agent of the Authority against all costs, expenses, judgments and liabilities, including attorney fees, incurred by or imposed upon that person in connection with civil or criminal action in which the person is involved as a result of the person's affiliation with the Authority if the person acted in good faith on behalf of the Authority and within the scope of the person's official duties and powers;
15. purchase insurance to protect and hold harmless its employees, agents and Board members from any action, claim or proceeding arising out of the performance, purported performance or failure to perform in good faith, of duties for, or employment with, the Authority and to hold them harmless from expenses connected with the defense, settlement or monetary judgments from that action, claim or proceeding; and
16. protect its assets, services, and employees by purchasing insurance or providing for certain self-insurance retentions.⁹

4. Membership in the Authority

The Authority's members currently consist of the Fairbanks North Star Borough, the North Slope Borough and the City of Valdez, each a political subdivision of the State. Additional municipalities may join and become members of the Authority at a later date. The Fairbanks North Star Borough, the North Slope Borough and the City of Valdez, together with all municipalities that join the Authority prior to December 31, 1999, are hereinafter referred to as the "Original Municipalities." The Original Municipalities together with the municipalities that join the Authority after December 31, 1999, are hereinafter collectively referred to as the "Participating Municipalities."¹⁰

⁹ Ordinances, § 6.

¹⁰ Ordinances, § 5.

Prior to becoming a member in the Authority, the governing body of each existing Participating Municipality and the governing body of the new Participating Municipality must adopt parallel ordinances.¹¹ Pursuant to the Act, all municipalities that become members of the Authority must be political subdivisions of the State.¹²

5. Governance of the Authority

A governing board (the "Board") exercises the powers of the Authority.¹³ The Board is comprised of three members selected by each of the Original Municipalities. Board members were appointed by their respective municipalities; each serves a four-year term. The Original Municipalities selected their representatives pursuant to their own respective local procedures.

Each Board member must be a registered voter residing within the State and serves on the Board solely in his individual capacity at the pleasure of the governing body of the Original Municipality by which the member was appointed. A majority of the Board members constitutes a quorum of the Board for the transaction of business. A majority of Board members present at a meeting at which a quorum is present may act on behalf of the Board.¹⁴

6. Revenues of the Authority

The Authority's revenues will be derived primarily from the sale of natural gas to municipalities within the State and to other purchasers, which are expected to include governmental and private domestic and foreign entities. The Authority's revenues will be used first generally to pay operating expenses and debt service and to fund necessary reserves for operation of the Project. Any net income will be shared with the State and all its municipalities as described below for use in their respective governmental purposes.¹⁵ The funds will be distributed to the general funds of the State and each of the municipalities within the State in accordance with the following formula set forth in the Ordinances¹⁶:

1. Payment in Lieu of Tax. Each municipality that has Project facilities within its jurisdiction will receive a payment in lieu of tax to compensate the municipality for property taxes it would have received if the Authority were not tax exempt under the laws of the State. Such payment will be equal to 2 percent of the original cost of construction of the Project facility within its jurisdiction plus any subsequent capital costs added to the facilities within its jurisdiction.

2. Remaining Distribution. The remaining net income, if any, will be distributed as follows:

¹¹ ALASKA STAT. § 29.35.605(b); Ordinances, § 5.

¹² ALASKA STAT. § 29.35.605.

¹³ Ordinances, § 7.

¹⁴ By-laws of the Alaska Gasline Port Authority, art. 3, § 9 (August 11, 1999) (attached hereto as Exhibit G).

¹⁵ Ordinances, § 17.

¹⁶ Ordinances, § 17.

a. Sixty percent to the State.

b. Thirty percent to all municipalities within the State. A municipality's share will be calculated based on its population or, if it is a municipality within a borough, the ratio of its operating budget to the operating fund of the borough. Each municipality will receive a minimum annual payment of \$50,000.

c. Ten percent equally to the Original Municipalities.

7. Dissolution of the Authority

Upon dissolution of the Authority, all of its assets remaining after its debt is retired will be distributed to all the Participating Municipalities in proportion to their respective investment in the Authority at that time.¹⁷ Such proportion will be calculated "in proportion to the difference between their contributions to the [A]uthority and any outstanding debt or obligation of that municipality to the [A]uthority, provided that any obligation to bondholders then outstanding shall first be satisfied in full."¹⁸

B. Information About the Project

Approximately 35 trillion cubic feet of natural gas remains stranded on the North Slope of the State (the "Gas"). The Gas is not being commercially produced but is instead being used solely for purposes of reinjection into the ground, a process that facilitates the recovery of crude oil. While the Gas is stranded on the North Slope it is not available to the residents of the State without an 800-mile pipeline from the North Slope to Valdez.

Due to the State's small population, the in-state natural gas consumption alone could not financially support the Project. Therefore, a consequence of making the Gas available for use by Alaska residents is that excess Gas will be available for other uses. Accordingly, the Authority intends to provide facilities to condition the Gas in excess of Alaska's anticipated in-state use for export.

1. Benefits of the Project

The Project will help the State's residents to reduce their heating and electrical bills. Alaska has one of the nation's harshest climates and, therefore, a corresponding high cost of heating. This Project will enable the State's residents who are currently heating their homes with wood, coal or diesel fuel to use the State's own Gas for heating and power generation. Alaska residents also have among the highest, if not the highest, electric rates in the nation. The cost of electricity will be substantially reduced as a result of the availability of the Gas through this Project.

¹⁷ Ordinances, § 16. Cf. Ordinances, § 4.

¹⁸ ALASKA STAT. § 29.35.610(b).

Further, oil production has been a vital resource in the development of the State and its municipalities. For many years, the State has relied heavily on the production of oil to foster its livelihood, to provide opportunities and employment for its citizens and to generate revenue to ensure future prosperity. In recent years, however, lower oil prices, reduced production and potential field depletion have greatly affected the State's ability to generate revenues and provide a secure future for its citizens. This Project will generate much-needed revenues for the State, provide employment for its citizens and generally provide the State with the financial resources to prosper in the next century.

The benefits of the Project to the State and its residents are clear. Nevertheless, the obstacles to building the pipeline have been staggering. For thirty years private interests have investigated ways to build a pipeline to transport the Gas from the North Slope to market, but the scope, cost and practical difficulties of building it have thus far been financially and practically infeasible. Thus, the Original Municipalities believe that only a public entity has the requisite power and resources to build the pipeline and credibly deliver the Gas for use by Alaska residents and other purchasers.

2. Description of the Project

The Project consists of the acquisition, creation and improvement of all facilities and infrastructure necessary or useful for the purchase, conditioning, transportation, storage and sale of the Gas. It will include the acquisition, construction, financing, installation and improvement of new and existing port facilities located at the Port of Valdez and any other necessary facility, including compression stations, pipelines, spur lines and plants for conditioning the Gas for transport by commercial carriers (such plants are technically referred to as LNG Facilities). The Authority will deliver a development plan, which requires approval by each Participating Municipality prior to the construction or acquisition of the Project.¹⁹

As part of the Project, the Authority will be responsible for acquiring the Gas and other related commodities, whether by purchase or other conveyance or by exercising its eminent domain power, as well as for acquiring all necessary permits, licenses and related rights necessary for the operation of the Project.

The Authority expects that the Project will be operated by a professional gasline operator pursuant to a management contract. The Authority expects and intends that any such contract will meet the requirements of *Revenue Procedure 97-13*.²⁰

3. Financing of the Project

To finance the Project, the Participating Municipalities may contribute or advance public funds, personnel, equipment or property to the Authority.²¹ Such advances may be subject to

¹⁹ Ordinances, § 15.

²⁰ Rev. Proc. 97-13, 1997-1 C.B. 632.

²¹ Ordinances, § 13.

repayment in accordance with terms agreed upon at the time of the advance. As of the date hereof, the Original Municipalities have contributed funds to the Authority and there is no expectation that any such funds will be repaid in the future.

Additionally, the Authority is authorized to issue bonds or any other form of indebtedness to raise funds to finance the Project.²² Debt issued by the Authority may consist of senior as well as junior or subordinated debt. To the extent that the Authority issues debt, the debt instruments will require all parties to treat such instruments as debt for tax purposes. Further, all debt will have a noncontingent interest rate and will be due upon a fixed maturity date. The interest on and principal of any debt issued by the Authority will be due and payable in all events and failure to pay will be an event of default. Other than Participating Municipalities to the extent of their advances, any creditor of the Authority will be unrelated to the Authority and will possess customary creditor's rights; no such creditor will receive management rights as a direct result of lending money to the Authority. Finally, the Authority will have cash flow projections that reflect that there will be sufficient revenues to pay all debt, including subordinated debt.

The principal and interest on all debt issued by the Authority as well as the repayment of any advances will be payable exclusively from the income and receipts of, or other money derived from, the Project. Neither the State nor any of the Participating Municipalities will be liable for the debts, liabilities or obligations of the Authority.

II. RULINGS REQUESTED

The Authority requests a ruling that:

The Authority is a political subdivision of the State, whose income is exempt from federal income tax.

III. STATEMENT OF LAW AND ANALYSIS

Under the doctrine of intergovernmental tax immunity, "income earned by a . . . political subdivision of a state is generally not taxable in the absence of specific statutory authorization for taxing such income."²³ This doctrine ensures that the federal government does not impose taxes that would unduly burden the state in the performance of its functions.²⁴

For purposes of determining whether an entity qualifies for tax exemption under the doctrine of intergovernmental immunity, a "political subdivision" is defined as "any division of any State or local governmental unit which . . . has been delegated the right to exercise part of

²² Ordinances, § 11.

²³ Rev. Rul. 87-2, 1987-1 C.B. 18 (citing Rev. Rul. 71-131, 1971-1 C.B. 28) (emphasis added); see also Rev. Rul. 71-132, 1971-1 C.B. 29; Priv. Ltr. Rul. 88-20-030 (Feb. 16, 1988).

²⁴ Priv. Ltr. Rul. 88-20-030 (Feb. 16, 1988) (citing Rev. Rul. 71-131, 1971-1 C.B. 28; Rev. Rul. 71-132, 1971-1 C.B. 29).

the sovereign power of the government.²⁵ In considering whether an entity is a political subdivision, a two-part analysis must be taken.

First, in order to be a political subdivision, the entity must be a division of a state or local government (*i.e.*, the entity have close ties with a state or local government).²⁶ This determination is generally based upon all of the facts and circumstances.²⁷ Of particular importance are (1) the extent to which there is governmental control of the entity and (2) whether the entity has a public purpose.²⁸ In the case at hand, the Authority is governmentally controlled as it is managed by a governing board that is appointed by the Original Municipalities, and all of the Authority's assets and net revenues inure to the benefit of the State and its municipalities. Also, the Authority was established for the public purpose of promoting the development of the State's valuable natural resources, which would otherwise lie dormant but for public involvement. Such resource development will provide an alternative, more efficient fuel source to the citizens of the State, provide additional employment within the State and raise revenue for the State and its municipalities.

Second, a political subdivision must have a grant of sovereign power by the state. The primary sovereign powers are: (1) the power to tax, (2) the power of eminent domain, and (3) the police power.²⁹ "It is not necessary that all three of these powers be delegated. However, possession of only an insubstantial amount of any or all sovereign powers is not sufficient."³⁰ In this case, the Authority has been delegated broad and substantial powers, including the power of eminent domain. Moreover, the Authority has been delegated the eminent domain power by the Participating Municipalities, as permitted by the Act, to the same extent that such power exists in such municipalities.

A. The Authority is a "Division" of the Participating Municipalities

To be considered a political subdivision, an entity must be a division of the state or local government. "All the facts and circumstances must be taken into consideration in determining whether an entity is a political subdivision, including the public purposes of the entity and its control by government."³¹ The more indicia of "close ties" between government and the entity, the more likely the entity is a political subdivision.³² The Authority is closely related to the State and local government: (1) the Authority's Board is appointed by the Original Municipalities; (2) the Authority's net revenues inure to the benefit of the State and its municipalities; (3) the

²⁵ Treas. Reg. § 1.103-1(b). In General Counsel Memorandum 36,994, the Internal Revenue Service concluded that the definition of "political subdivision" under Section 103 should be used to interpret other provisions of the Code involving political subdivisions. Gen. Couns. Mem. 36,994 (Feb. 3, 1977).

²⁶ See *Philadelphia Nat'l Bank v. United States*, 666 F.2d 834, 835 (3d Cir. 1981).

²⁷ Rev. Rul. 77-174, 1977-1 C.B. 414; Gen. Couns. Mem. 37,629 (July 31, 1978).

²⁸ Rev. Rul. 77-174, 1977-1 C.B. 414.

²⁹ *Estate of Shamburg*, 3 T.C. 131 (1944), *acq.*, 1945 C.B. 6, *aff'd*, 144 F.2d 998 (2d Cir. 1944).

³⁰ See, e.g., *Texas Learning Tech. Group v. Commissioner*, 958 F.2d 122, 124 (5th Cir. 1992) (citing 30 Op. Atty. Gen. 252); Rev. Rul. 77-164, 1977-1 C.B. 20.

³¹ Rev. Rul. 77-164, 1977-1 C.B. 20.

³² See *Philadelphia Nat'l Bank*, 666 F.2d at 835.

Authority's assets will be distributed to the Participating Municipalities upon dissolution; and (4) the Authority is fulfilling a public purpose.

1. The Authority is Government Controlled

Control by the government is an important factor in determining whether an entity is a political subdivision. Rulings by the Internal Revenue Service (the "Service") have pointed to two indicia of governmental control: (1) whether the governing board of the entity is controlled by government and (2) whether the entity's revenue and assets inure to a public entity.

a. The Authority is Controlled by a Government-Appointed Governing Board

Public control via a government-appointed board indicates that an entity is a political subdivision.³³ There are several instances where the courts and the Service have determined that an entity is a political subdivision where the governing body of the entity is appointed by government or elected by the public.³⁴

In *Revenue Ruling 83-131*,³⁵ for example, the Service ruled that electric and telephone membership corporations, which had eminent domain power, were not political subdivisions because they were "not controlled directly or indirectly by a state or local government."³⁶ Instead, "the business and affairs of the corporations [were] controlled by a board of directors that [was] independent of such authority."³⁷ Accordingly, the membership corporations did not have close enough ties with government to be political subdivisions.

By contrast, the Authority is managed by a Governing Board that is entirely governmentally appointed. Each Original Municipality appoints three members to the Board. Each member of the Board shall "serve at the pleasure of the governing body of the Original Municipality by whom such member was appointed."³⁸ Moreover, any member "may be terminated at any time by a majority vote of the governing body of such Original Municipality which appointed such member."³⁹

³³ See *id.*; Rev. Rul. 83-131, 1983-2 C.B. 184. Cf. Rev. Rul. 77-164, 1977-1 C.B. 20.

In *Philadelphia Nat'l Bank* the court specifically noted that the majority of the entity's board was made up of private individuals, who were elected by the entity's board. The state only appointed a minority of the board members. See *Philadelphia Nat'l Bank*, 666 F.2d at 838.

³⁴ See, e.g., *Commissioner v. Shamberg*, 144 F.2d at 998, 1000 (2d Cir. 1944); *Commissioner v. White*, 144 F.2d 1019, 1020 (2d Cir. 1944); Priv. Ltr. Rul. 84-05-007 (Oct. 26, 1983); Priv. Ltr. Rul. 88-09-038 (Dec. 3, 1987); Priv. Ltr. Rul. 93-27-072 (April 12, 1993).

³⁵ Rev. Rul. 83-131, 1983-2 C.B. 184.

³⁶ *Id.*

³⁷ *Id.*

³⁸ Ordinances, § 7.

³⁹ *Id.*

b. The Authority's Assets and Net Revenues Inure to the Benefit of the State and its Municipalities

Another strong indicator that an entity is a "division" of a State or local government is the fact that the entity's assets and net revenue inure to the public benefit. For instance, a hospital district possessing only the power to tax was a political subdivision since no private individual or organization would benefit from the dissolution of the entity; the revenue and assets were to inure solely to the public benefit.⁴⁰

Here, the Authority will distribute its revenue only to the State and its municipalities.⁴¹ Generally, net revenues will be distributed sixty percent to the State, thirty percent to all municipalities in Alaska and ten percent to the Original Municipalities.

Furthermore, if the Authority is dissolved, the Act and Ordinances mandate that the Authority's assets are to be distributed to all Participating Municipalities.⁴² The assets will be distributed to the Participating Municipalities "in proportion to the difference between their contributions to the authority and any outstanding debt or obligation of that municipality to the [A]uthority."⁴³ Under no circumstances will private persons or entities receive asset distributions from the dissolution of the Authority.

2. The Authority is Fulfilling a Public Purpose

Whether an entity is serving a public purpose is also important in the determination of whether the entity has close ties with, or is a division of, the state or local government. The courts and the Service have given the term "public purpose" a broad interpretation. Not only has it included such traditional public purposes as education⁴⁴ and transportation⁴⁵ but also county humane societies with the purpose of preventing cruelty to children and animals,⁴⁶ utilities,⁴⁷ conservation and preservation of natural resources,⁴⁸ community development,⁴⁹ and even off-track betting⁵⁰ and the operation of liquor stores.⁵¹ In fact, we did not find a single opinion or

⁴⁰ Priv. Ltr. Rul. 88-20-030 (Feb. 16, 1988). The district argued that it also had the power of eminent domain, but the Service concluded that the district's power was too insubstantial since its condemnation decisions were subject to state approval. *Id.*; see also Priv. Ltr. Rul. 88-09-038 (Dec. 3, 1987); Priv. Ltr. Rul. 93-27-072 (April 12, 1993).

⁴¹ Ordinances, § 17.

⁴² Ordinances, § 16; ALASKA STAT. § 29.35.610.

⁴³ ALASKA STAT. § 29.35.610.

⁴⁴ *Michigan v. United States*, 40 F.3d 817, 819-20 (6th Cir. 1994); *Texas Learning*, 958 F.2d at 122.

⁴⁵ *Shamberg*, 144 F.2d at 959-1002; *White*, 144 F.2d at 119-20; Gen. Couns. Mem. 37,637 (1978).

⁴⁶ Gen. Couns. Mem. 38,713 (May 5, 1981).

⁴⁷ Gen. Couns. Mem. 37,629 (July 31, 1978); Gen. Couns. Mem. 37,771 (Nov. 30, 1978).

⁴⁸ Rev. Rul. 68-444, 1968-2 C.B. 430; Rev. Rul. 59-37, 1959-1 C.B. 384; Gen. Couns. Mem. 33,808 (April 29, 1968).

⁴⁹ Rev. Rul. 77-164, 1977-1 C.B. 20; Gen. Couns. Mem. 33,556 (July 8, 1967).

⁵⁰ Rev. Rul. 78-138, 1978-1 C.B. 314.

⁵¹ Rev. Rul. 71-131, 1971-1 C.B. 28.

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ruling where a court or the Service found that an entity was not a political subdivision based on an insufficient public purpose.

The Authority serves many of the above-mentioned purposes. Its primary function involves an exercise of the transportation powers of municipalities within the State. The public functions furthered by the exercise of those powers include the provision of natural gas for the use by its citizens, the development and preservation of the natural resources of the State, the development of jobs and commerce within the State and the raising of revenue to serve the general needs of the State, its municipalities and its citizens. Accordingly, the Authority's public purpose supports a determination that it is a political subdivision.

B. The Authority is a Political Subdivision as it Possesses a Substantial Amount of the Sovereign Power of Eminent Domain

1. The Power of Eminent Domain Is Sufficient

To be classified as a political subdivision, an entity must be authorized to exercise part of the sovereign powers of the government.⁵² There are three primary sovereign powers—the power to tax, the power of eminent domain and the police power; an entity need not possess all such powers to be a political subdivision.⁵³ In fact, possession of only one or two of these powers is sufficient as long as such powers are not insubstantial.⁵⁴

The seminal case that established the requirements for political subdivision status, *Commissioner v. Estate of Shamberg*,⁵⁵ also involved a port authority. In *Shamberg*, the court held that the Port of New York Authority (the "Port of New York") was a political subdivision because it possessed more than an insubstantial amount of the sovereign powers.⁵⁶

In *Shamberg* the Port of New York was established pursuant to a compact between the State of New York and the State of New Jersey and was vested with (i) all of the powers

⁵² *Shamberg*, 144 F.2d at 1005.

⁵³ *Id.*

⁵⁴ *Texas Learning*, 958 F.2d at 124 (citing 30 Op. Atty. Gen. 252); Rev. Rul. 77-164, 1977-1 C.B. 20. Three generally acknowledged sovereign powers of states are the powers to tax, the power of eminent domain, and the police power. . . . It is not necessary that all three of these powers be delegated. However, possession of only an insubstantial amount of any or all sovereign powers is not sufficient. All of the facts and circumstances must be taken into consideration, including the public purposes of the entity and its control by a government.

Id. (citations omitted).

⁵⁵ 144 F.2d 998 (2d Cir. 1944). Although decided under the statutory predecessor to section 103, *Shamberg* is still consistently cited as authority in this area. See *Texas Learning*, 958 F.2d at 125; *Michigan v. United States*, 40 F.3d 817, 824 (6th Cir. 1994); *Philadelphia Nat'l Bank*, 666 F.2d at 837 ("There is surprisingly little decisional law on what constitutes a political subdivision within the meaning of § 103. The Supreme Court has never addressed the issue, and the leading—and almost only—cases on point were decided by the Court of Appeals for the Second Cir.); *Commissioner v. Estate of White*, 144 F.2d 1019 (2d Cir. 1944).

⁵⁶ *Shamberg*, 144 F.2d at 1004; see also Rev. Rul. 77-164, 1977-1 C.B. 20.

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necessary to acquire and construct its projects;⁵⁷ (ii) the power to make and enforce the rules and regulations it deemed convenient for the operation of the bridges and tunnels it operates and to maintain a uniformed police force and (iii) the power of eminent domain. The Port of New York could only exercise its police power with the consent of the State, and rules and regulations made by the port authority were effective only if the legislatures of both states concurred. Nevertheless, the court held that the Port of New York was a political subdivision since it was not necessary that the Port of New York exercise all the functions of the state; it was sufficient that the Port only exercise a portion of those functions.⁵⁸

In relying on *Shamberg*, both the courts and the Service have consistently held that entities that possess but one of the three primary sovereign powers (e.g., the power of eminent domain) are political subdivisions so long as that power is more than insubstantial.⁵⁹ The House Ways and Means Committee stated: "an entity is a political subdivision . . . if it has more than an insubstantial amount of one or more of . . . the power to tax, the power of eminent domain, and the police power."⁶⁰

2. The Authority Possesses a Substantial Amount of Eminent Domain Power

The determination whether an entity possesses more than an insubstantial amount of sovereign power turns primarily on the extent to which the entity's power is similar to that of other governmental units within the state. As outlined below, the evaluation turns on (1) the extent to which such power rests with the entity that purports to be a political subdivision, as opposed to some other governmental unit or entity, and (2) the extent to which the entity's

⁵⁷ Specifically, under the compact the Port of New York was granted with the power to purchase, construct, lease and/or operate the terminal; to make charges for the use thereof; to own, hold, lease and/or operate real or personal property; to borrow money and secure the same by bond or by mortgages; and to make rules and regulations relating to navigation and commerce. *Shamberg*, 144 F.2d at 999-1001.

⁵⁸ *Id.* at 1004.

⁵⁹ Rev. Rul. 61-181, 1961-2 C.B. 21; Rev. Rul. 77-143, 1977-1 C.B. 340; Priv. Ltr. Rul. 77-52-065 (Sept. 29, 1977); Priv. Ltr. Rul. 78-07-069 (Nov. 18, 1977); Priv. Ltr. Rul. 84-05-007 (Oct. 26, 1984); Priv. Ltr. Rul. 89-09-038 (Dec. 3, 1987); Priv. Ltr. Rul. 88-20-030 (Feb. 16, 1988); Priv. Ltr. Rul. 93-27-072 (April 12, 1993); Priv. Ltr. Rul. 97-25-038 (March 25, 1997); Priv. Ltr. Rul. 97-30-001 (Oct. 4, 1997).

The Service has maintained that this is a facts-and-circumstances decision. Accordingly, the Service has been reluctant to state categorically that only one sovereign power is necessary. Gen. Couns. Mem. 36,994 (Feb. 3, 1977). The Service has a two-fold concern. First, a political subdivision must have close ties with the state or local government; a private company serving some public functions is not a political subdivision, even if it has certain sovereign powers. See Gen. Couns. Mem. 37,629 (July 31, 1978); see also Rev. Rul. 83-131, 1983-2 C.B. 184 (holding that electric and telephone membership corporations were not political subdivisions because they were not controlled by government). Second, an entity must possess a sufficient quantity of a sovereign power; the powers must be more than insubstantial in their effect as well as in their amount. Gen. Couns. Mem. 36,994 (Feb. 3, 1977).

The Authority has close ties to the State and the Participating Municipalities. It is governed by the Participating Municipalities; its net revenues inure to the State and its municipalities; its assets will be distributed to the Participating Municipalities upon dissolution; and it serves an important public purpose. The Authority also has more than an insubstantial amount of the eminent domain power; indeed, the Authority's eminent domain power is substantial in its effect and its amount.

⁶⁰ Committee Report on P.L. 99-514 (Tax Reform Act of 1986) (emphasis added).

sovereign power is similar substantively and procedurally to that of other governmental units within the state, including that of the governmental unit or units that created the entity.

a. The Power of Eminent Domain Rests with the Authority

In *Revenue Ruling 78-138*,⁶¹ the Service ruled that the determination of whether an entity possesses more than an insubstantial amount of one of the primary sovereign powers turns on whether the entity possesses the sovereign power in its own right. In *Revenue Ruling 78-138*, a corporation was established to operate an off-track betting system, which was designed to raise revenue and curb illegal bookmaking. The corporation possessed certain regulatory powers and it had the power of eminent domain; however, state law restricted its condemnation power by requiring the corporation to obtain the approval of the local chief elected official where the property was located. The Service held that for purposes of determining whether an entity possesses more than an insubstantial amount of sovereign power the "critical inquiry is not whether the power is restricted, but *with whom the actual power rests*."⁶² Consequently, the Service ruled that the corporation was a political subdivision because it possessed substantial, albeit restricted, powers of eminent domain and regulation in its own right.⁶³

Likewise, in similar situations the Service has determined that an entity possessing only the power of eminent domain will constitute a political subdivision if the entity can "exercise the condemnation power in its own right and by itself, and thereafter hold the acquired property in its own title."⁶⁴

Where the entity does not possess the eminent domain power in its own right, the entity may not be a political subdivision, absent possession of more than an insubstantial amount of one of the other primary sovereign powers. For example, in *Philadelphia National Bank v. United States*,⁶⁵ the court held that Temple University, a state university, was not a political subdivision because the university was required to obtain approval from the state to erect new facilities:

When it wishes to erect additional facilities, the university must request the General State Authority to procure the property. The power to condemn selected property is vested in the Authority, and the fact that it has cooperated with the university by accepting and implementing its suggestions does not constitute a grant of sovereign power to Temple.⁶⁶

⁶¹ Rev. Rul. 78-138, 178-1 C.B. 314.

⁶² *Id.* (emphasis added).

⁶³ *Id.* (emphasis added).

⁶⁴ Priv. Ltr. Rul. 84-05-007 (Oct. 26, 1983).

⁶⁵ 666 F.2d 834 (3d Cir. 1981).

⁶⁶ *Id.* at 840.

Although the state had cooperated with the university and had implemented the university's suggestions, the university was not a political subdivision because it did not possess a sovereign power in its own right.⁶⁷

The Alaska Gasline Port Authority is authorized to exercise the power of eminent domain and declaration of taking. The Authority does not need to seek the approval of any of the Participating Municipalities prior to exercising its eminent domain power. Section 6 of the Ordinances provides that:

The Authority is authorized, in its own name, to do all acts necessary or convenient for the exercise of said power for said purposes, including but not limited to . . . exercise the powers of eminent domain and declaration of taking within its physical boundaries . . . to acquire land or materials for authority purposes.⁶⁸

Moreover, the Authority is vested with eminent domain powers to the same extent that such powers exist in the Participating Municipalities.⁶⁹ Finally, upon the exercise of its power, the Authority will hold all property in its own name.⁷⁰ Thus, the Authority possesses full eminent domain power.

b. The Authority's Eminent Domain Power Is Identical Both Procedurally and Substantively to that of the Participating Municipalities

The scope of an entity's sovereign power and the procedures by which the entity must exercise that power has also been considered by the Service. For example, the Service has decided that health-care authorities, which had only eminent domain power,⁷¹ were political subdivisions because the entity "[had] the same power of eminent domain as [was] vested by law in any authorizing subdivision."⁷² Moreover, the Service has determined that a water district, possessing only the power of eminent domain, was a political subdivision because it could (1) commence condemnation actions in state court to enforce the right and (2) take possession of the property upon commencement of the proceedings, rather than after judgment.

⁶⁷ *Id.*

⁶⁸ Ordinances, § 6.

⁶⁹ ALASKA STAT. § 29.35.030.

⁷⁰ Section 6 of the Ordinances provides that: "The Authority shall have the power to acquire, by purchase, lease, contribution, condemnation, or otherwise, real property and personal property for the Project . . ."

Ordinances, § 6.

⁷¹ Priv. Ltr. Rul. 97-30-001 (Oct. 4, 1996). The eminent domain power of the health-care authorities was subject to a minor restriction: the authorities could not exercise their eminent domain power to provide "office facilities for the private practice of a health care professional." *Id.* Nevertheless, the Service determined that this power alone was sufficiently substantial to qualify the authorities as political subdivisions. *Id.*

⁷² *Id.*

In the present case, the Act and the Ordinances empower the Authority with full eminent domain power—the exact power that is vested in the Participating Municipalities and other municipalities within the state.⁷³ Moreover, the Authority is authorized by the Act and Ordinances to commence actions in its own name in Alaska superior court⁷⁴ and to take possession of the property upon commencement of the proceedings.⁷⁵

In sum, the Authority's broad eminent domain power is sufficient to qualify it as a political subdivision. First, the Authority can exercise condemnation power in its own right and by itself and can hold title to condemned property in its own name. Second, the Authority's power mirrors the eminent domain power of the Participating Municipalities. Third, the Authority can commence actions in state court to enforce its condemnation right and can take possession of the property upon commencement of the proceedings. Based on the Service's past positions, the such a grant of eminent domain power mandates that the Authority be treated as a political subdivision of the State.

C. Conclusion

For the reasons set forth above, we respectfully request that the Service issue a letter ruling that the Authority is a political subdivision of the State, whose income is exempt from federal income tax.

IV. TAXPAYER INFORMATION AND PROCEDURAL MATTERS

A. Names, Addresses, Telephone Numbers of All Interested Parties

Alaska Gasline Port Authority
c/o William M. Walker
550 West 7th Avenue
Suite 1850
Anchorage, Alaska 99501
(907) 278-7000

City of Valdez
c/o Dave Cobb, Mayor
P.O. Box 307
Valdez, Alaska 99686
(907) 835-4313

⁷³ The Act and Ordinances, each of which empower the Authority with eminent domain power, refer to Section 29.35.030 of the Alaska statutes, which is the source of eminent domain power for the Alaskan cities and boroughs. ALASKA STAT. § 29.35.030.

⁷⁴ ALASKA STAT. § 9.55.290.

⁷⁵ ALASKA STAT. § 9.55.380.

Fairbanks North Star Borough
c/o Hank Hove, Mayor
P.O. Box 71267
Fairbanks, Alaska 99707
(907) 459-1304

North Slope Borough
c/o George Ahmaogak, Mayor
P.O. Box 69
Barrow, Alaska 99723
(907) 852-2611

B. Taxpayer Identification Number

The Authority's Taxpayer Identification Number is 92-0169762.

C. Annual Accounting Period and Overall Method of Accounting

Not applicable.

D. Applicable District Office

The district having audit jurisdiction over the Authority is the Pacific Northwest District.

E. Identical or Similar Issues

To the best of the knowledge of the Authority and the Fairbanks North Star Borough, the North Slope Borough and the City of Valdez (the "Current Members") and their respective authorized representatives:

- a. Issues identical or similar to those discussed in this letter ruling request are not in any earlier return of the Authority, the Current Members or any taxpayer related to the Authority or the Current Members;
- b. The Service has not previously ruled on identical or similar issues for the Authority, the Current Members or any taxpayer related to the Authority or the Current Members;
- c. Neither of the Authority nor the Current Members or any taxpayer related to the Authority or the Current Members has submitted a request involving issues identical or similar to those raised in this letter ruling request and withdrawn it before a ruling was issued;
- d. Neither of the Authority nor the Current Members or any taxpayer related to the Authority or the Current Members or any predecessor of the

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Authority or the Current Members has previously submitted a request involving identical or similar issues that is currently pending with the Service; and

- e. Neither of the Authority nor the Current Members or any taxpayer related to the Authority, the Current Members or any predecessor of the is submitting to the Service another request involving identical or similar issues.

F. Certainty of the Law

The law in connection with the request is relatively certain and has been adequately addressed by relevant authorities. Beyond the authorities discussed in this request, the Authority, the Current Members and their authorized representatives are not aware of authorities contrary to the positions advocated therein.

G. Deletions Required by Section 6110(c) of the Code

The Authority desires to have certain information deleted from any documents made available for public inspection. A deletions statement is attached as **Exhibit H**.

H. Power of Attorney

An Internal Revenue Service Form 2848, Power of Attorney and Declaration of Representative, has been completed with respect to the Authority and said form is attached as **Exhibit I**.

I. Penalty of Perjury Declaration

The declaration required by Section 601.201(e)(1) of the Treasury Regulations is attached as **Exhibit J**.

J. Additional Information

If you have any questions or need further information in order for you to rule as requested, please contact Travis C. Gibbs at (213) 430-7402.

K. Request for a Conference

The Authority respectfully requests a conference at the National Office to discuss the issues involved in this letter ruling request.

L. Checklist

The checklist required by *Revenue Procedure 99-1* is attached as **Exhibit K**.

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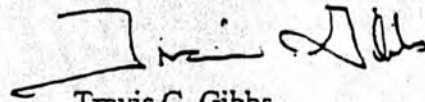
M. User Fee

Pursuant to Appendix A of *Revenue Procedure 99-1*, enclosed in a separate envelope is a check in the amount of \$5,000, payable to the Internal Revenue Service.

N. Facsimile Transmission

When a letter ruling is prepared, the Authority requests that an advance copy of the letter ruling be sent by facsimile transmission to Travis C. Gibbs; the fax number is (213) 430-6407. We agree to waive any disclosure violations resulting from the facsimile transmission.

Very truly yours,



Travis C. Gibbs
of O'MELVENY & MYERS LLP

TCG:mfm

LA3:889475.11

INDEX TO EXHIBITS

Exhibit A	Ordinance of Fairbanks North Star Borough
Exhibit B	Ordinance of North Slope Borough
Exhibit C	Ordinance of City of Valdez
Exhibit D	Municipal Port Authority Act
Exhibit E	Alaska Eminent Domain Statutes
Exhibit F	Map of the Project
Exhibit G	By-laws of the Alaska Gasline Port Authority
Exhibit H	Deletions Statement
Exhibit I	Power of Attorney and Declaration of Representative
Exhibit J	Declaration Under Penalties of Perjury
Exhibit K	<i>Revenue Procedure 99-1</i> Checklist

Alaska Gasline Port Authority

Presentation to Senate Special Committee on Natural Gas Development



Project Economics

August 3-4, 2006



Important Notice About Financial Projections

The purpose of this presentation is to provide background information and assist the recipients hereof in obtaining a general understanding of the Alaska Gasline Port Authority ("AGPA") and its project. This document is not intended to form a sole basis of any investment decision or other decision to participate in the AGPA project and should not be considered as a recommendation or invitation by AGPA to make such decision. Each recipient hereof must make (and will be deemed to have made) its own independent assessment and appraisal of AGPA and its project after making such investigation, as it deems necessary in order to determine its interest and independently (and at its own cost) to have formed its own opinions and views.

Although the information contained herein appears reasonable to AGPA on the basis of its present knowledge, neither AGPA nor any of its officers, directors, employees, or advisors accept liability or responsibility for the adequacy, accuracy or completeness of, nor make any representation or warranty, express or implied, with respect to the information contained in this document or on which this document is based or any other information or representations supplied or made in connection with this document. In addition, no representation, express or implied, is made that such information remains unchanged after receipt of this document.

This presentation includes certain estimates and projections of the anticipated future performance of the AGPA project. Such estimates and projections reflect various assumptions made by AGPA and its advisors, concerning anticipated results, which assumptions may or may not prove to be correct. The actual outcome may be affected by changes in economic and other circumstances that cannot be foreseen or have not been anticipated. The reliance that can be placed upon the projections and forecasts is a matter of commercial judgment. No representation is made by the AGPA or its advisors as to the accuracy of such estimates or projections or as to the reasonableness of any assumptions used. The financial projections contained herein have been prepared and set out for illustrative purposes only and should not be taken as a commitment as to future performance.



Overview

- Introduction of the Analysis
- Price Assumptions
- LNG Project Concept and Gas Volumes
- Cost Assumptions
- Netback Calculations
- Upstream Returns to the Producers
- PTU Case
- Comparison of State Revenues
- Conclusions / Questions



GREENGATE

Introduction of the Analysis



Project Component Terms

- Upstream
 - Lease production activities

- Midstream
 - Feeder lines
 - GCP
 - Alaska pipeline(s)
 - LNG Facility
 - Canadian pipeline(s)

- Downstream
 - LNG marine transportation
 - Regasification and takeaway pipelines to market
 - NGL extraction in Alberta



Project Component Terms (continued)

- AGPA project components: owned, built and financed by AGPA
 - Pipeline(s) from Prudhoe Bay to Valdez and possibly to Canadian Border
 - LNG Facility in Valdez
- Producer project components: owned, built and financed by Producers
 - GCP
 - Feeder pipelines
 - Upstream production activities
 - Canadian route components (if not provided by Third Parties)
- Third Party project components: provided by third parties
 - LNG marine transportation
 - Regasification and downstream takeaway pipelines to market
 - Canadian route components (if not provided by Producers)



GREENGATE

Price Assumptions

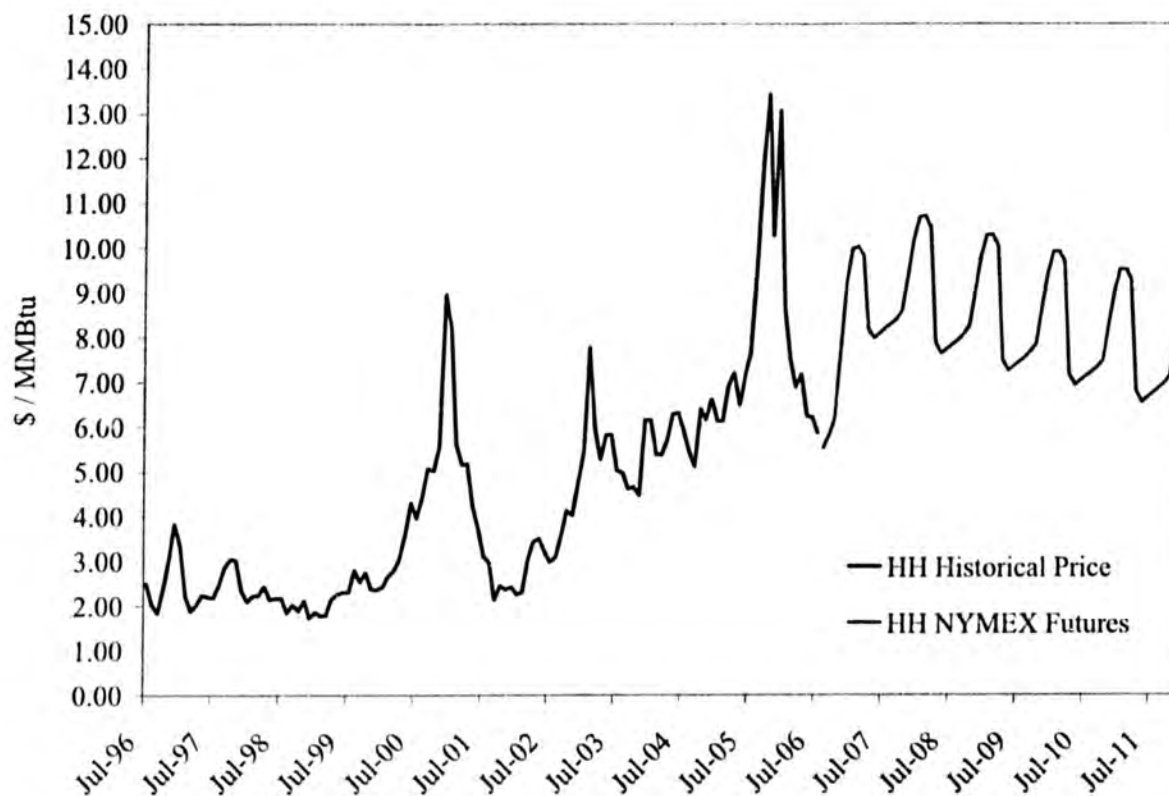


Gas Price Assumptions

- Henry Hub price:
 - considered the benchmark U.S. gas price
 - most forecasts for U.S. gas prices refer to Henry Hub pricing
 - used for the benchmark NYMEX physical and financial gas price futures contracts
- Regional gas prices are typically expressed as a differential above or below Henry Hub pricing (“basis”)

Henry Hub Price Assumption

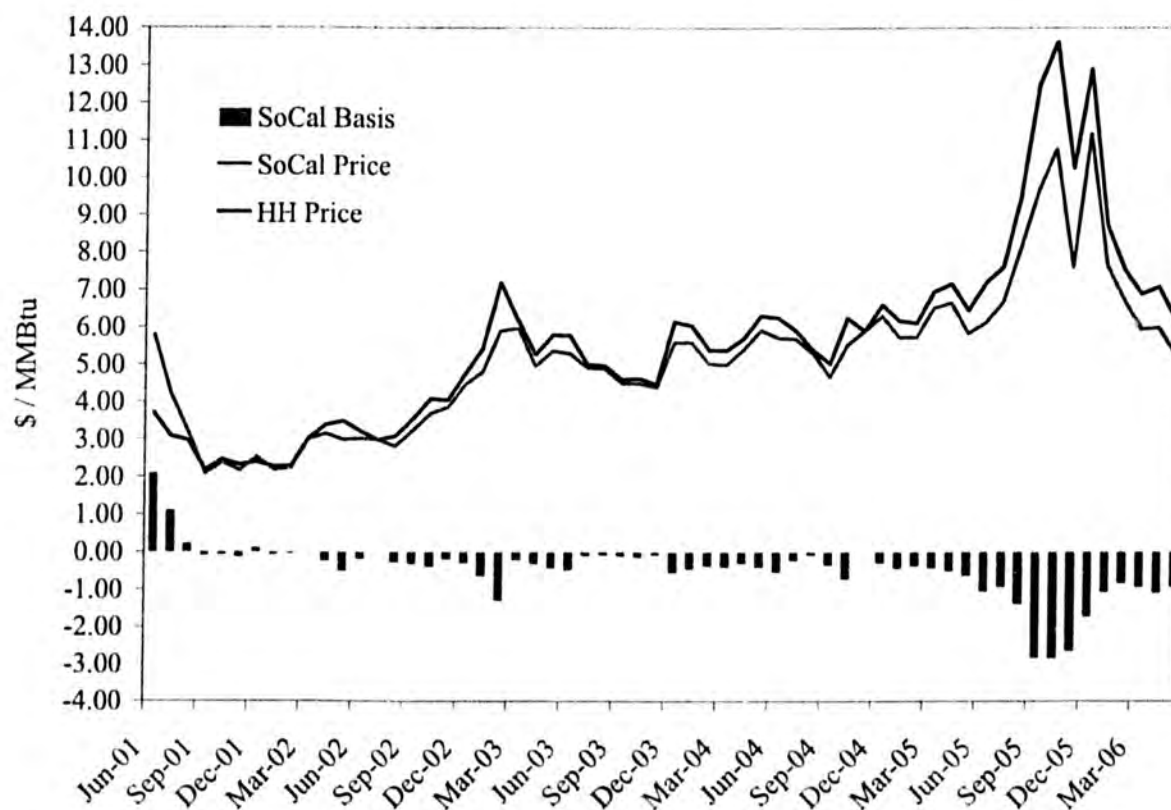
- Henry Hub historical 5-year average price: \$5.68 per MMBtu
- Current forward pricing on NYMEX: \$7.70 per MMBtu (average of distant 12 months)
- AGPA base case assumption: \$5.50 per MMBtu (constant 2005 dollars)



Source: Bloomberg, NYMEX

SoCal Gas Price Assumption

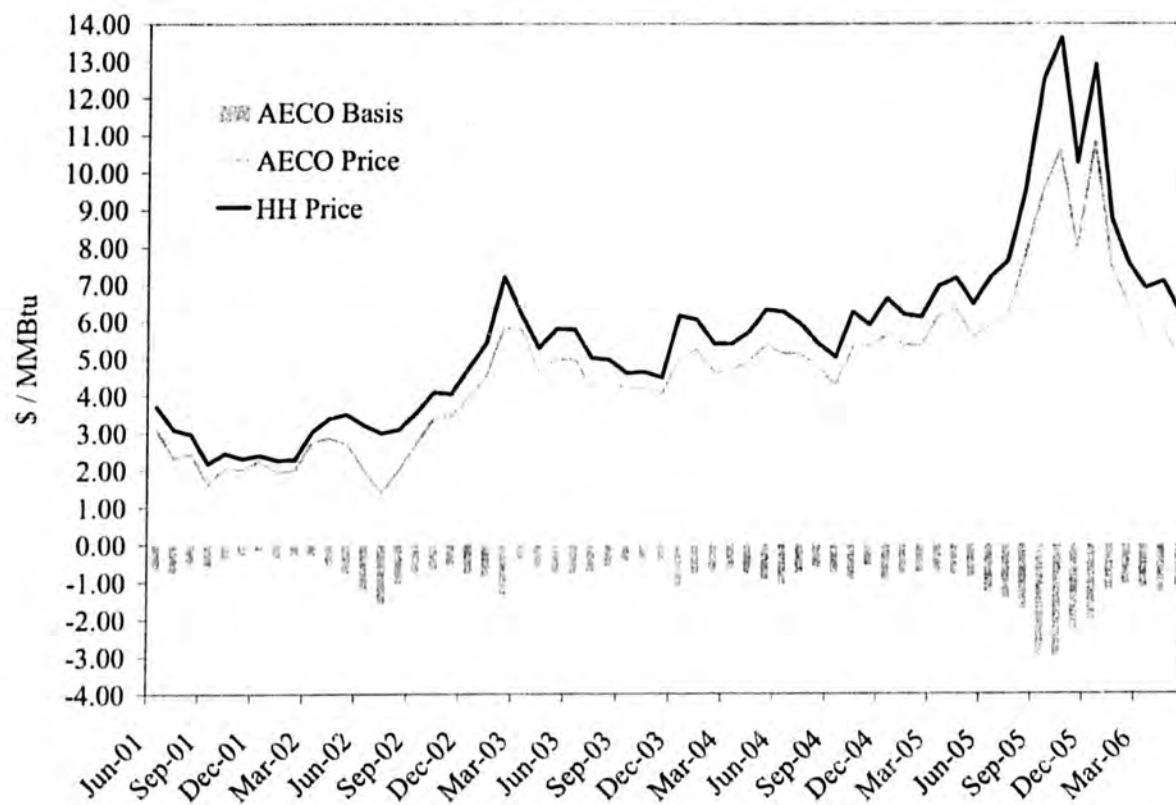
- 5-year average SoCal basis: \$(0.47) per MMBtu discount to HH
- After an increase to over \$(2.00)/MMBtu, SoCal basis has been narrowing and is expected to decrease further
- AGPA base case assumption: \$(0.47) per MMBtu discount (flat nominal terms)



Source: Bloomberg

Alberta Gas Price Assumption

- 5-year average AECO-C basis: \$(0.93) per MMBtu discount to HH
- AGPA base case assumption: \$(0.93) per MMBtu discount (flat nominal terms)

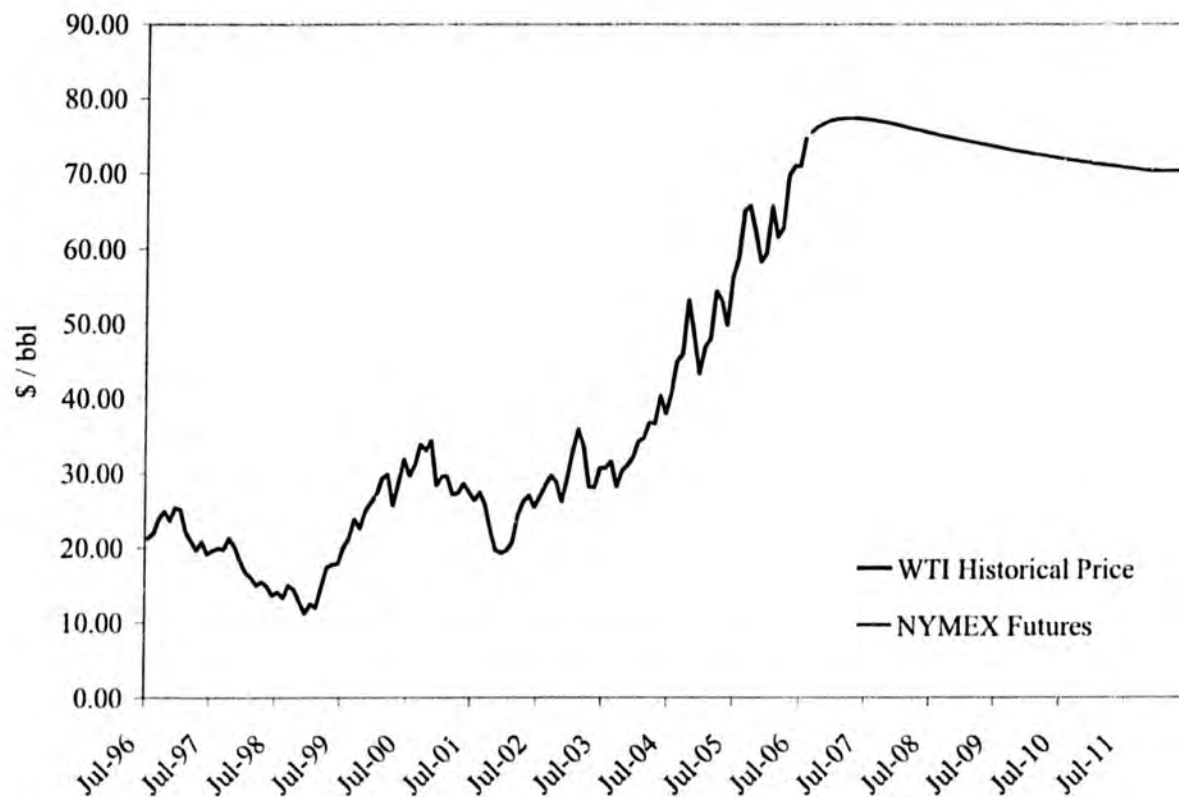


Source: Bloomberg

Crude Oil Prices

- WTI historical 5-year average price: \$40 per bbl
- Current forward pricing on NYMEX: ~ \$70 per bbl

- What is a reasonable WTI price assumption consistent with a certain Henry Hub gas price assumption?



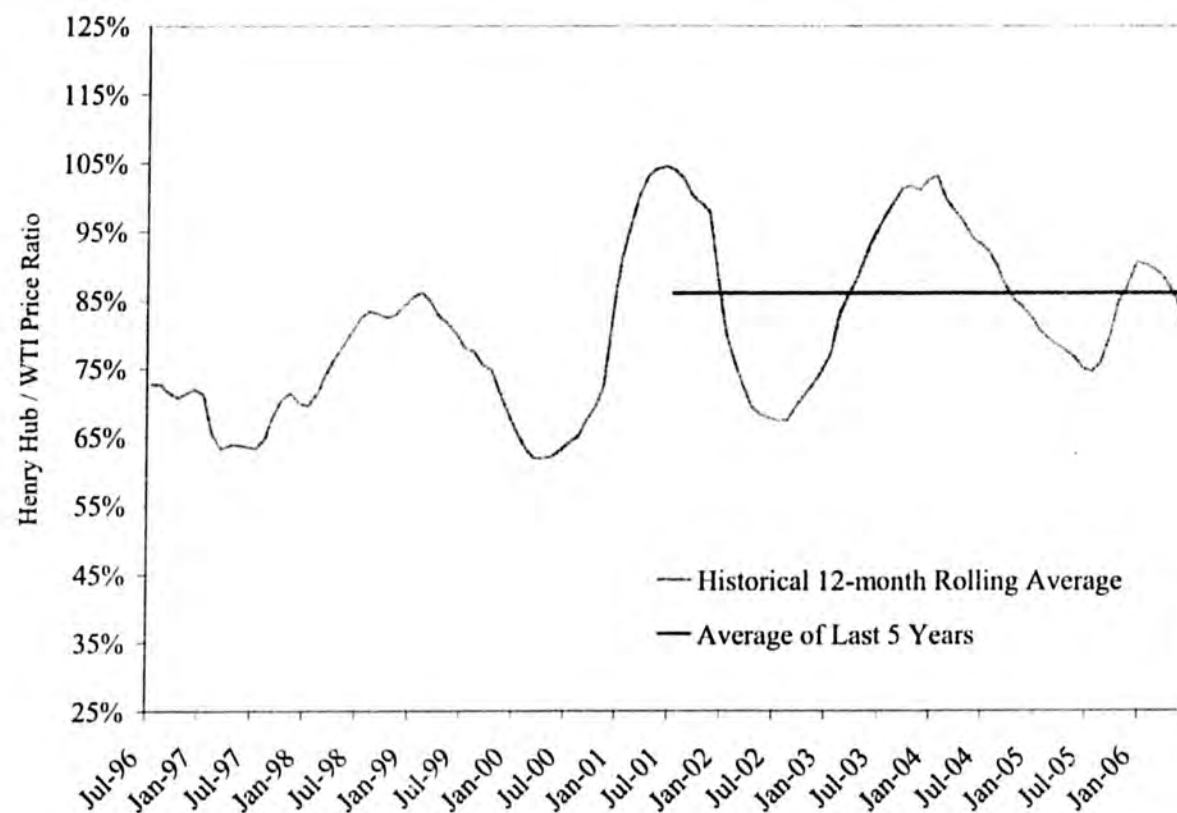
Source: Bloomberg, NYMEX

Crude Oil Prices (continued)

- Henry Hub prices and oil prices historically have not been closely correlated
- Henry Hub / WTI historical 5-year average price ratio: 86%

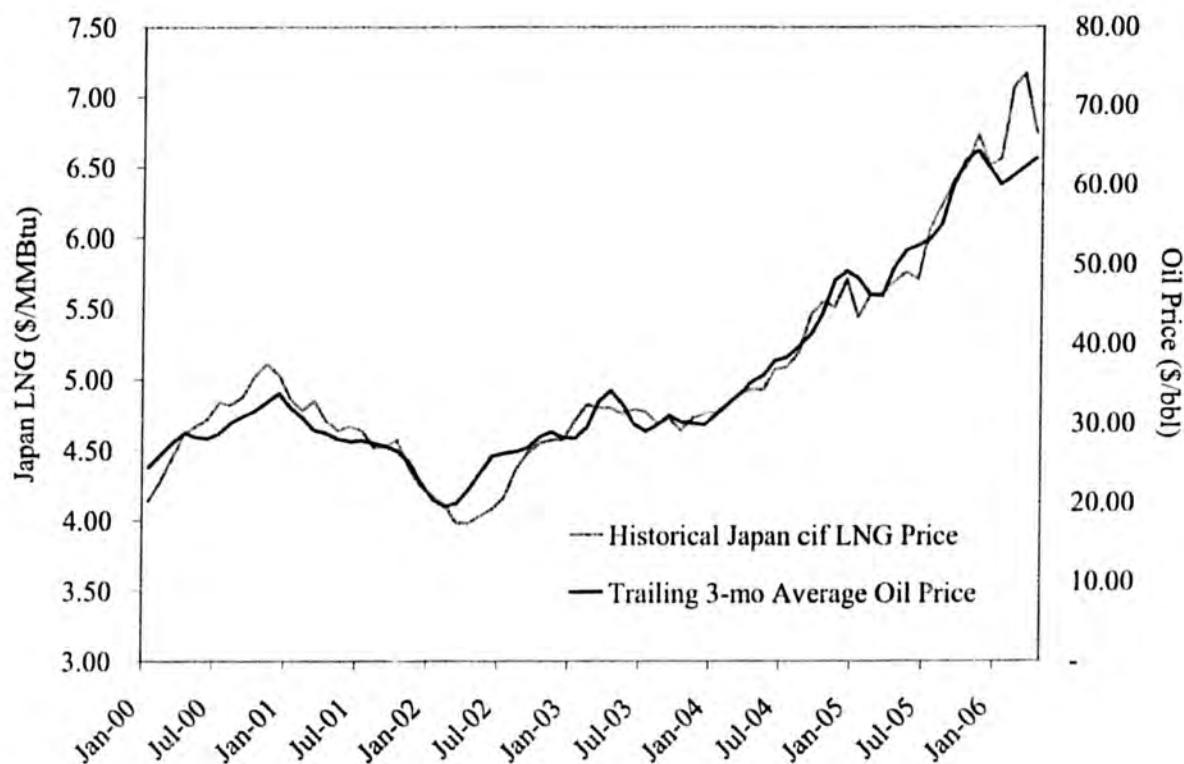
- A \$5.50/MMBtu Henry Hub assumption would be equivalent to a WTI assumption of \$37/bbl, assuming a 86% HH to WTI price ratio

- AGPA WTI base case assumption: \$36/bbl



Japan LNG Prices

- Japan LNG sales prices are typically expressed in contract formulas indexed to JCC (basket of crude oil imports to Japan)
- Japan LNG prices, therefore, are closely correlated with oil prices
- The AGPA model calculates Japan LNG prices on the basis of the assumed oil price and the historical price relationship



Source: Bloomberg

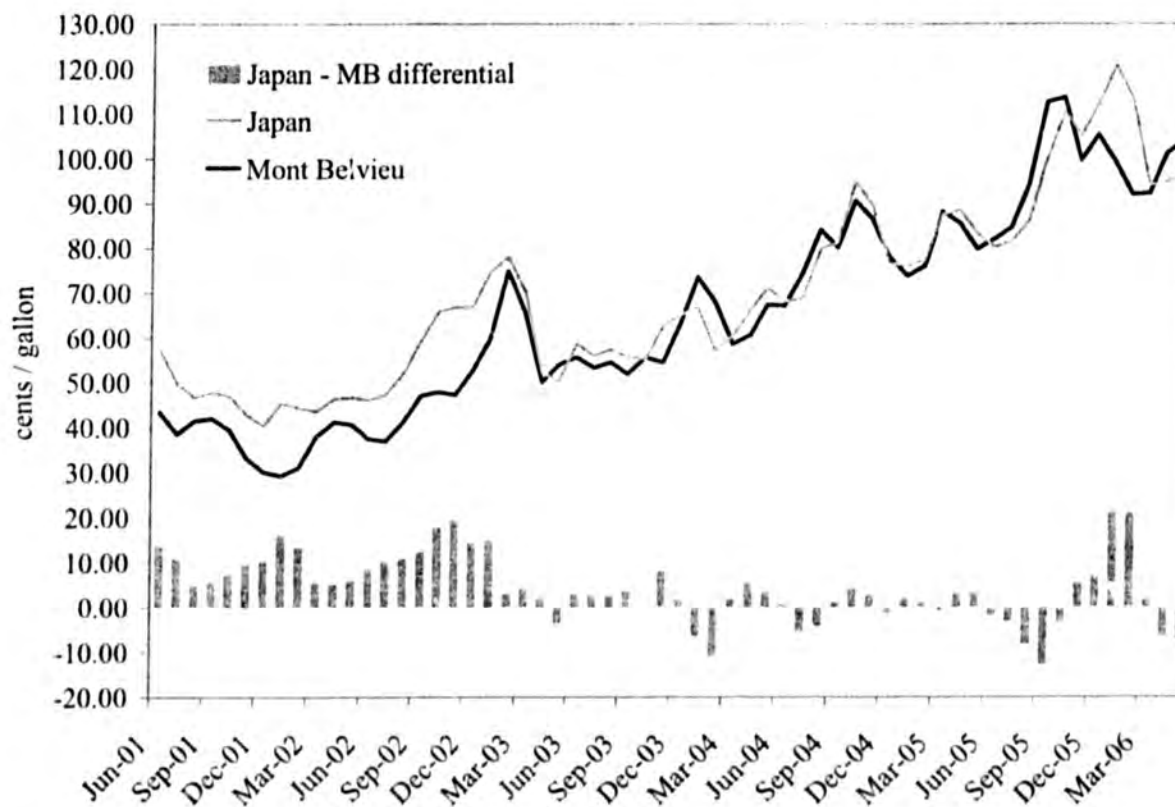


Propane Price Assumptions

- Mont Belvieu propane price:
 - benchmark U.S. Gulf Coast price
 - Mont Belvieu is the deepest propane market in the U.S.
 - used for the NYMEX propane futures contract
- MB propane prices have been historically correlated with both WTI and Henry Hub prices
- AGPA's financial model calculates Mont Belvieu propane prices on the basis of the assumed WTI and Henry Hub prices, using the historical price relationship
- Regional propane prices are assumed on the basis of historical premium/discount to Mont Belvieu

Propane Price Assumptions: Japan

- 5-year average Japan premium to MB: 4.4 cents/gallon
- AGPA assumption: 4.0 cents/gallon premium over MB

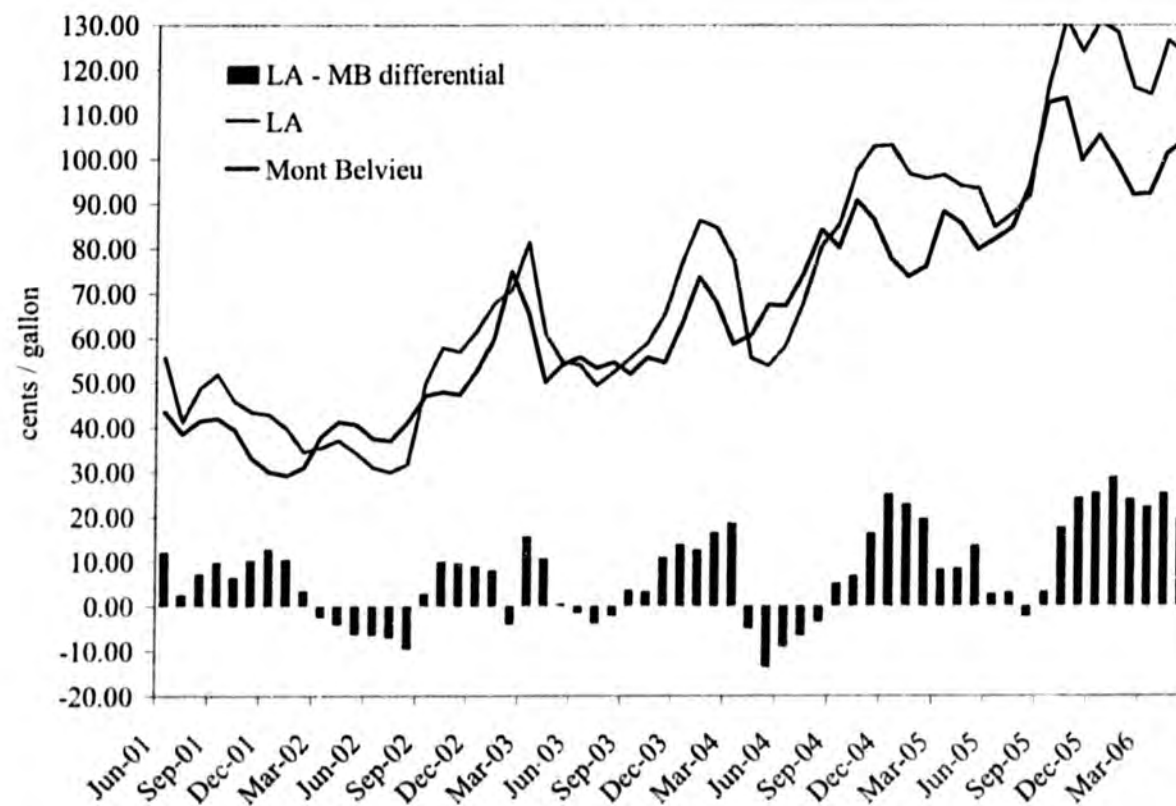


Source: Bloomberg



Propane Price Assumptions: LA

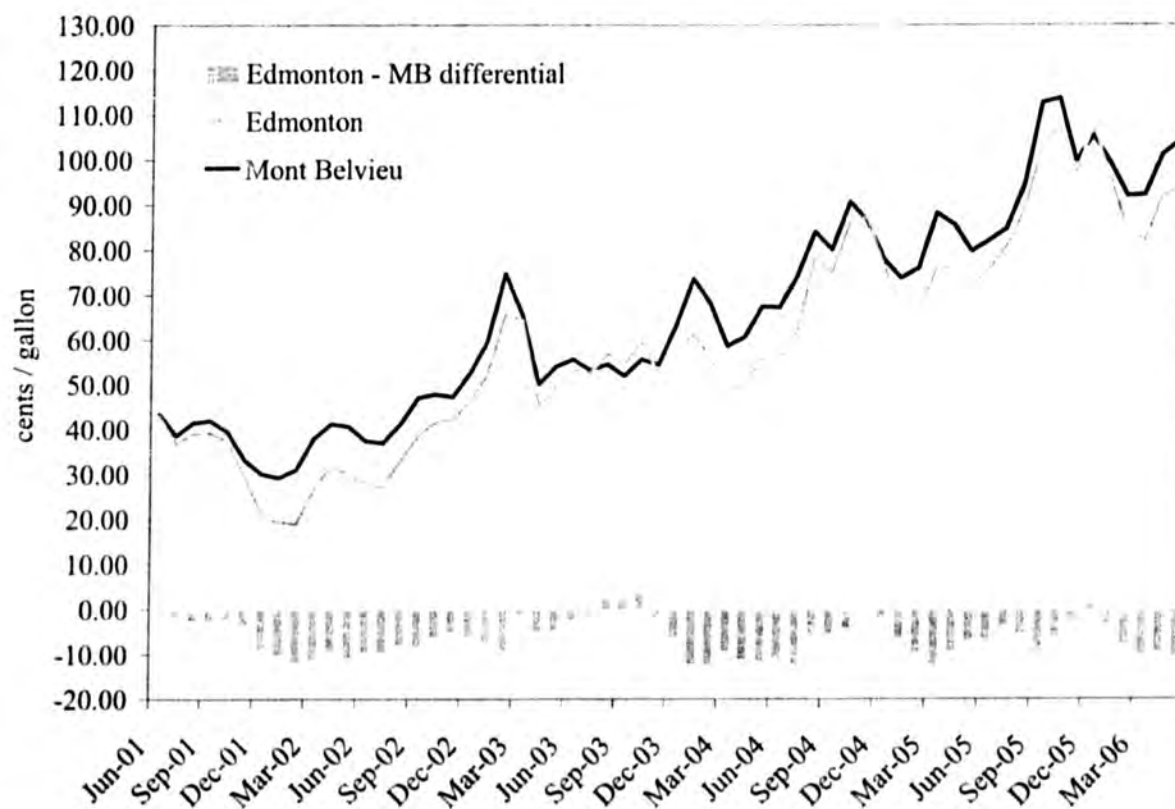
- 5-year average LA premium to MB: 7.6 cents/gallon (flat nominal terms)
- AGPA assumes most LPGs will go to East Asia, but there is opportunity for higher premium in LA market



Source: Bloomberg

Propane Price Assumptions: Alberta

- 5-year average Alberta discount to MB: (6.2) cents/gallon (flat nominal terms)
- AGPA assumption: (6.0) cents/gallon discount to MB



Source: Bloomberg, Duke Energy



Butane Prices

- Assumed on the basis of historical differential between butane and propane in respective markets (East Asia and Alberta)
- Japan butane – propane differential: 9 cents/gallon (flat nominal terms)
- Alberta butane – propane differential: 10 cents/gallon (flat nominal terms)



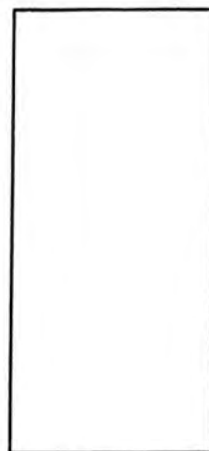
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LNG Project Concept and Gas Volumes

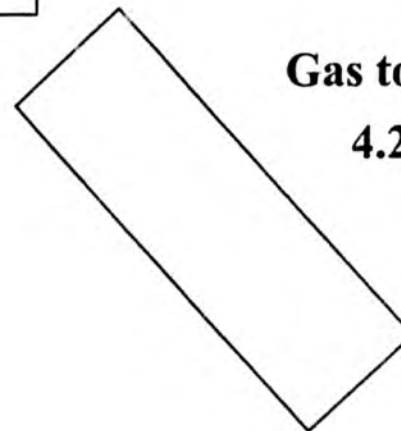
Highway Project Proposal

Year: 2016

4.3 Bcf/d



Pipeline from Prudhoe Bay



**Gas to Canada
4.2 Bcfd**

AGPA Proposal: Immediate Implementation

Year: 2012

1.2 Bcf/d

Pipeline from Prudhoe Bay



Alaska LNG

1.1 Bcfd





AGPA Proposal: Immediate Implementation (continued)

- The AGPA project can be implemented immediately
- Brings value to State and Producers during the period 2012 – 2016+ that would not be otherwise created
- The Highway Project can be implemented at a future date, when ready
- How will volumes be distributed if and when the Highway Project is ready to proceed?

AGPA Proposal: Y-Line Scenario A – Constrained Volume

Year: 2016

4.3 Bcf/d

No reason to limit total
volume to 4.3 Bcf/d

Pipeline from Prudhoe Bay

Reduction in volume
to Canada results in a
potential value
reduction due to loss
of economy of scale

**Alaska LNG
1.1 Bcfd**

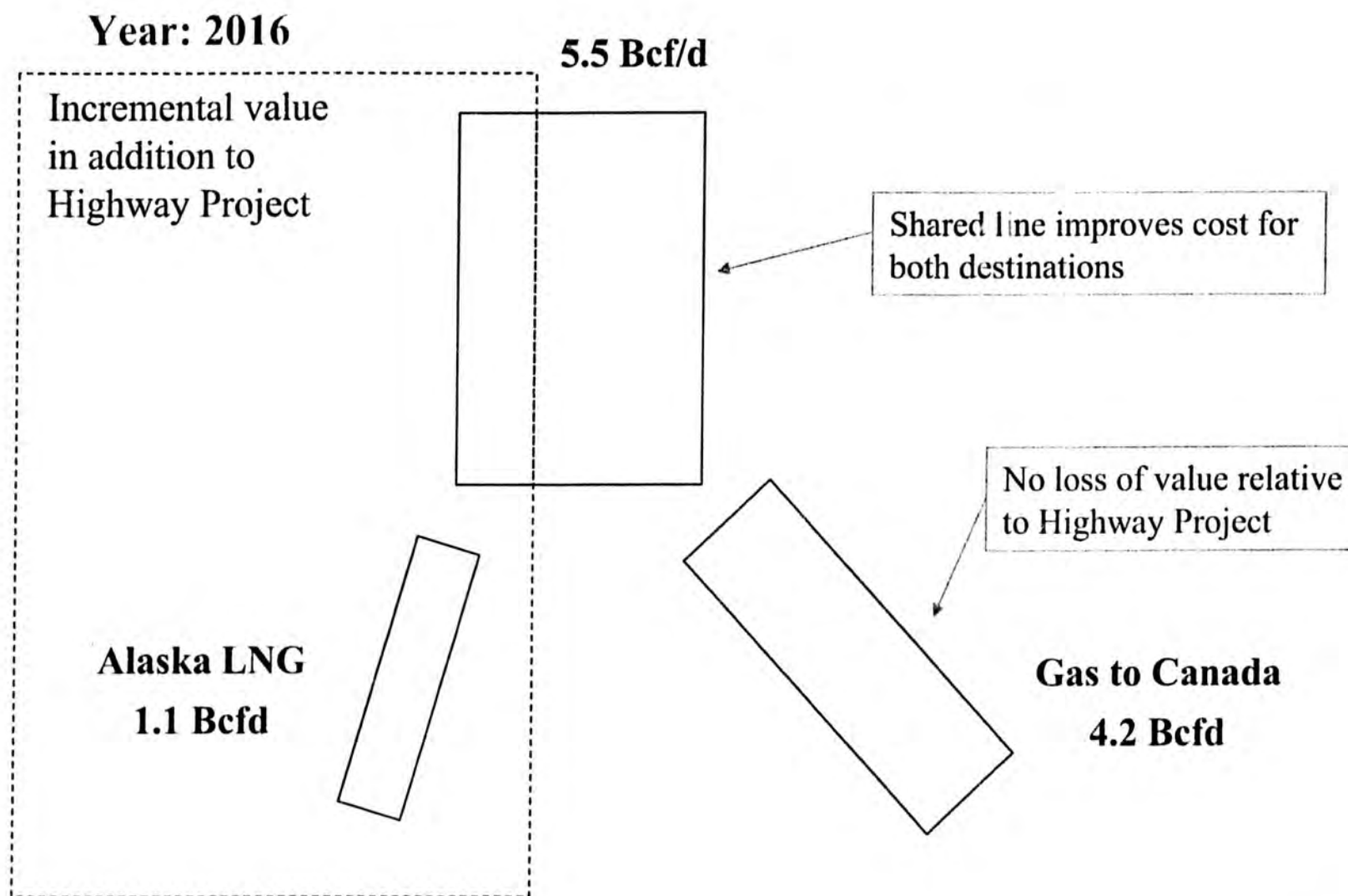
**Gas to Canada
3.1 Bcfd**



AGPA Proposal: Y-Line Scenario B – Incremental Volume

- It has been suggested that AGPA's Y-Line proposal is disadvantageous because the reduction of volume to Canada results in a loss of economies of scale, and hence, lower value for the gas
- This reasoning is premised on limiting total volume at the pipeline inlet to 4.3 Bcf/d (the same amount as under the Highway Project proposal)
- There is no reason to limit the total volume to 4.3 Bcf/d
 - LNG volumes could be in addition to the 4.3 Bcf/d to Canada
 - total volume at pipeline inlet in Prudhoe Bay: 5.5 Bcf/d
 - the Highway Project at 4.3 Bcf/d requires 49 Tcf over 30 years
 - a 5.5 Bcf/d Y-line project would require 62Tcf over 30 years
 - the known discovered resource on ANS is 35 Tcf
 - the Highway Project would require substantial new discoveries to proceed (both as a stand-alone project and part of a Y-line)
 - the stand-alone LNG project, however, can proceed immediately

AGPA Proposal: Y-Line Scenario B (continued)





Stand-Alone LNG Project Concept

- The issue is whether the AGPA project is economic on a stand-alone basis, as there will be no guarantee in 2012 that the expansion volumes from the Highway Project will ever materialize
- The subsequent sections elaborate on the economics of the stand-alone LNG project
- The projections show robust economics, with both high returns for the Producer and revenues for the State that would be incremental to the revenues from a potential Highway Project to be implemented later

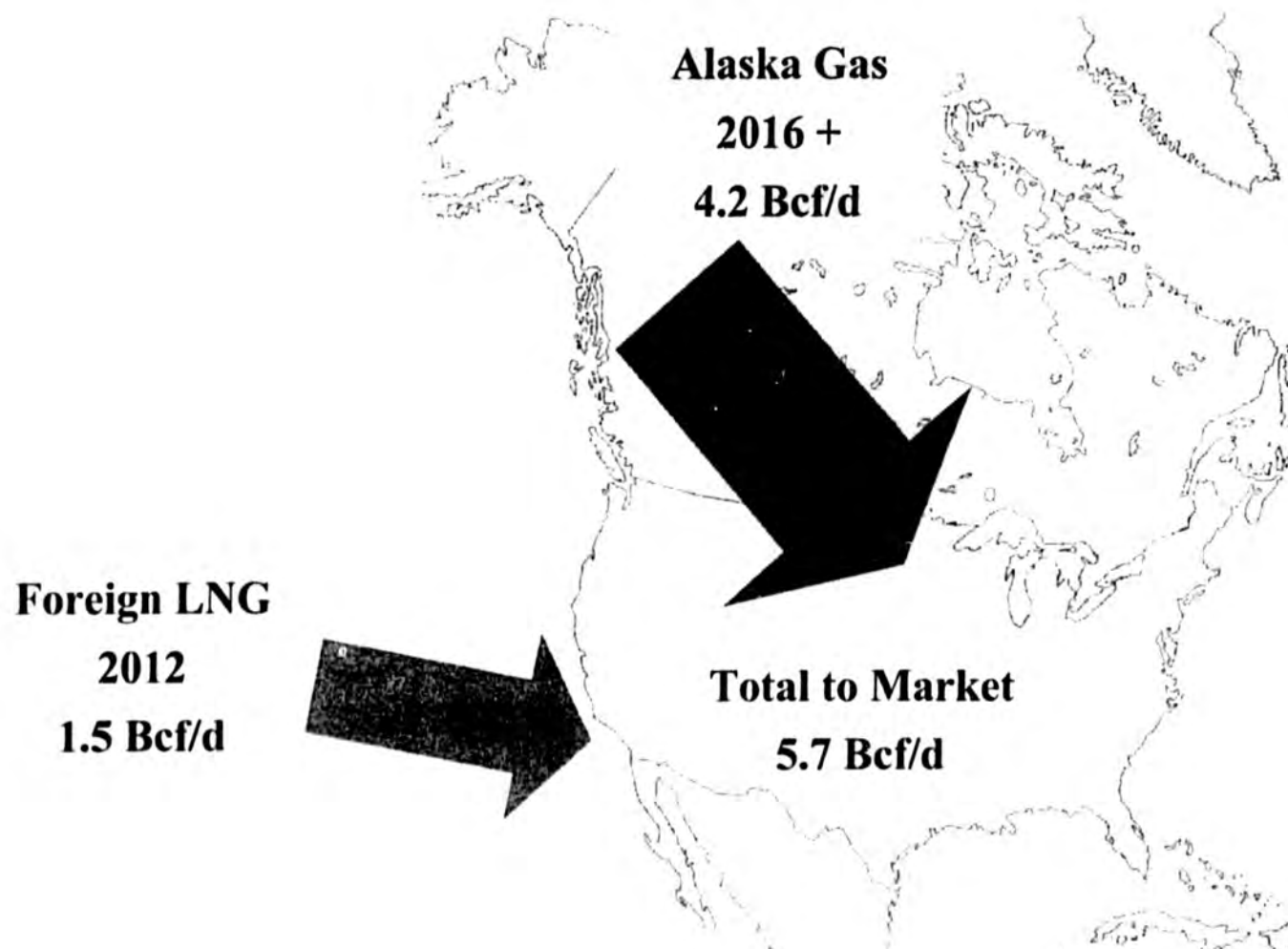


The Market Context

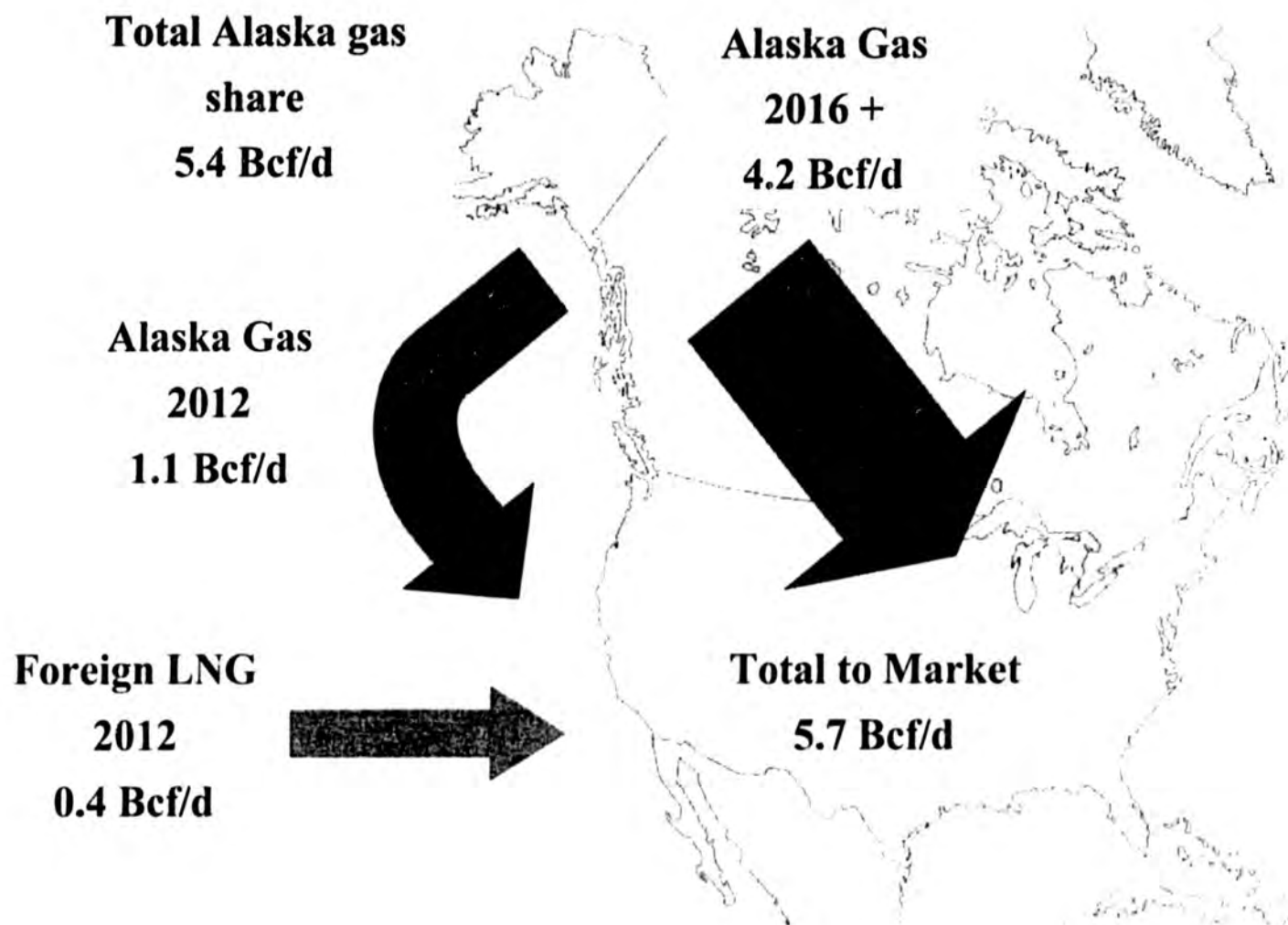
- Does a combined Y-Line of 5.5 Bcf/d deliver too much gas to market?
- The total gas to market is likely to be the same, but Alaska would capture a larger share, which would otherwise go to foreign LNG suppliers



Gas Flows to North America Under the Highway Proposal



Gas Flows to North America Under AGPA Proposal



Alaska's Risk: A Real Possibility?

Foreign LNG
2012
1.5 Bcf/d



Total to Market
5.7 Bcf/d

Foreign LNG
2016 +
4.2 Bcf/d





Additional Strategic Considerations

- Full commercialization of the Alaska gas resource requires a large scale project and additional exploration
- Independent explorers have expressed concern that they will be shut out of a potential Alaska gasline
- Without certainty as to whether pipeline capacity will be available, an explorer will not have an incentive to spend capital for exploration
- An AGPA line sized to accommodate future expansion and Y-line volumes will send a signal that there is free capacity and will spur exploration which will not occur otherwise



Additional Strategic Considerations (continued)

- The LNG project will make the implementation of the Highway Project more likely
- The Producers will have an incentive to participate in the value of the LNG Project and to take steps to fill the spare capacity of AGPA's pipeline
- The LNG project will give Alaska access to additional markets that would not be accessible to the Highway Project

Additional Markets for Alaska LNG

**LNG to
Japan/East Asia**

?

**LNG to West
Coast**

2012

1.1 Bcf/d

Foreign LNG

2012

0.4 Bcf/d

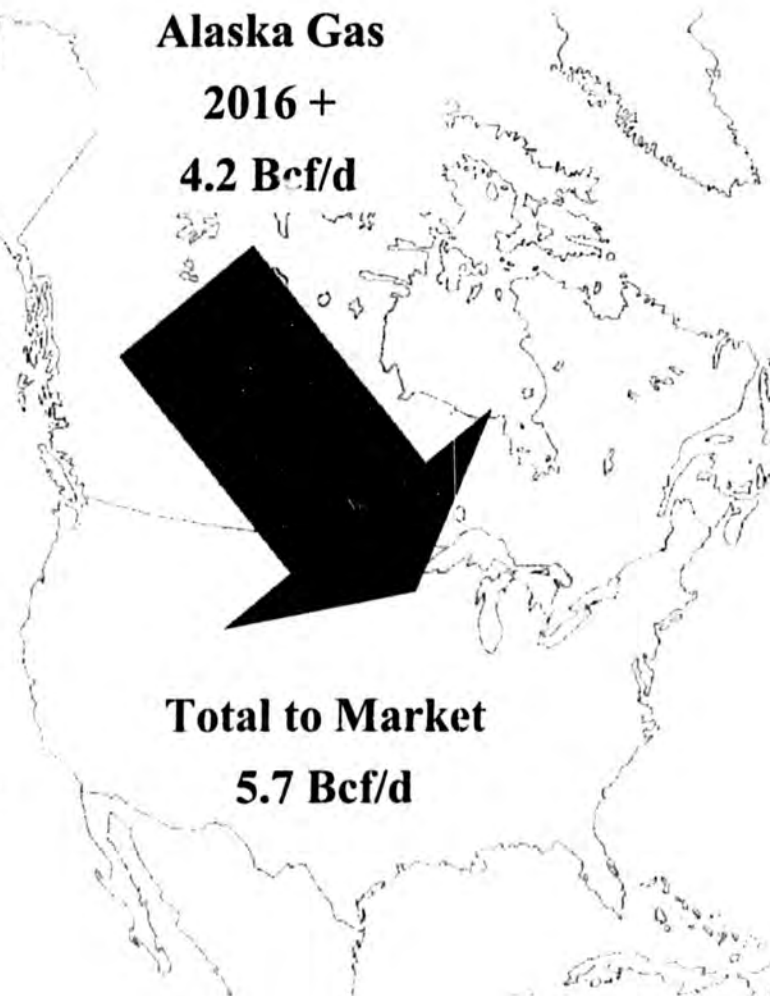
Alaska Gas

2016 +

4.2 Bcf/d

Total to Market

5.7 Bcf/d





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Cost Assumptions

Consistency of Capital Cost Assumptions

- Importance of consistency of capital cost numbers across project components
- Same components for different projects should have the same assumed costs in a comparison
- AGPA pipeline cost assumption in April 2005 (Sempra and AGPA proposal to State and Producers):
 - 3.0 Bcf/d, 48-inch diameter
 - \$8.4 billion EPC cost (2005 detailed cost update)
- FIF assumption (May 2006) for Alaska component of Highway line:
 - 4.3 Bcf/d, 52-inch
 - \$5.9 billion capex



Consistency of Capital Cost Assumptions (continued)

- Why are the capital costs estimates so different?
 - the mileage difference of Highway route vs. Valdez route of 8% clearly cannot alone explain the 42% higher cost of AGPA's *smaller* line
- Difference in methodology of estimate and cost inclusions
 - date of estimate
 - accuracy of estimate
 - contingencies included
- Some comparisons between the AGPA project and the proposed Highway Project (FIF, PFC) have failed to make an adjustment for consistency across capex numbers
- The following slides describe the appropriate adjustments that need to be made for a proper comparison of alternatives



Consistency of Capital Cost Assumptions (continued)

- AGPA's previously publicized capital cost figures include:
 - Contractor's contingencies ranging from 10% to 15%, depending on project component
 - Contractor's escalation allowance during construction period
 - Contractor's profit and risk premium
 - Owner's contingency in addition to Contractor's contingency
 - Owner's insurance cost during construction
- It appears that the above items have not been included in the capital cost estimates made public in the FIF
- A comparative analysis should use the same approach for both projects, as the risk mitigation and related cost premiums and contingencies associated with a given contracting strategy would be available to both projects



Consistency of Capital Cost Assumptions (continued)

- The magnitude of such consistency adjustments is significant:
- AGPA has previously used a \$2.1 billion estimate for the LNG Facility
- Stripping away the various risk premiums and allowances (both contractor's and owner's) that are not included in estimates for an alternative project reduces the capital cost assumption to \$1.5 billion

How Reliable are the Cost Estimates?

- AGPA's cost estimates are the result of extensive engineering work performed by Bechtel in 2000, with a detailed cost update study performed in 2005
- The technical details of Bechtel's work have been shared with the State's consultants
- There appears to be considerable uncertainty surrounding the publicized cost estimates for the proposed Highway project

Project Component	2001 Producer Estimate	2006 FIF Assumptions
GTP	\$2.6 billion	\$2.6 billion
Pipeline from Prudhoe Bay to Alberta	\$11.0 billion	\$11.6 billion

Source: Fiscal Interest Findings; Presentation titled "Alaska Producer Pipeline Presentation May 2002" and 2004 SGDA testimony by Producer group

AGPA Base Case Capital Cost Assumptions

- Midstream components (2005 dollars):
 - LNG Facility: \$1.5 billion
 - pipeline from PB to Valdez (initial 1.2 Bcf/d capacity): \$5.3 billion
 - expansion of PB-Delta Junction segment to accommodate incremental volume: \$0.9 billion
 - Delta Junction to Alberta pipeline: \$8.5 billion
 - GCP: based on the \$2.6 billion assumption in the FIF, adjusted for volume
 - all midstream components include a 10% capex contingency and a 5% owner's contingency
 - real 2005 numbers are escalated at 2.5% p.a.
- Upstream (PBU, PTU, other ANS fields and yet-to-find gas): \$8.4 billion



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Netback Results

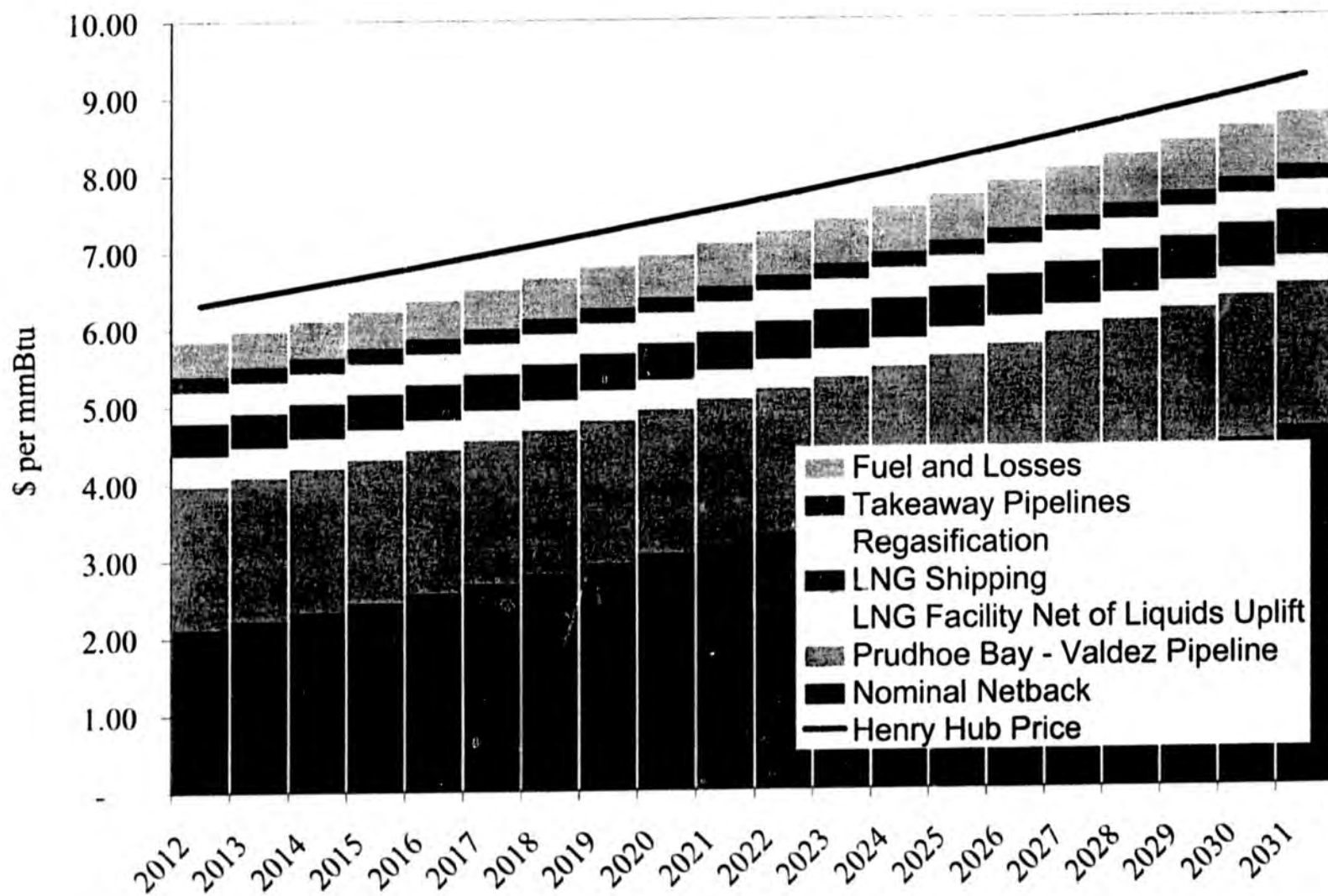
Netback Pricing

- Tariff Assumptions on midstream components
 - debt to equity ratio 80:20
 - interest on debt 5.50% (assumes Federal guarantee under ANGPA)
 - pipelines ROE 14%
 - LNG facility ROE 12%
- Combined pipeline and LNG facility tolls:
 - \$2.50 per mmBtu nominal terms in 2012
 - \$2.17 per mmBtu in real 2005 terms
- Downstream components plus total fuel consumption and losses:
 - \$1.50 per mmBtu nominal terms in 2012
 - \$1.30 per mmBtu in real 2005 terms

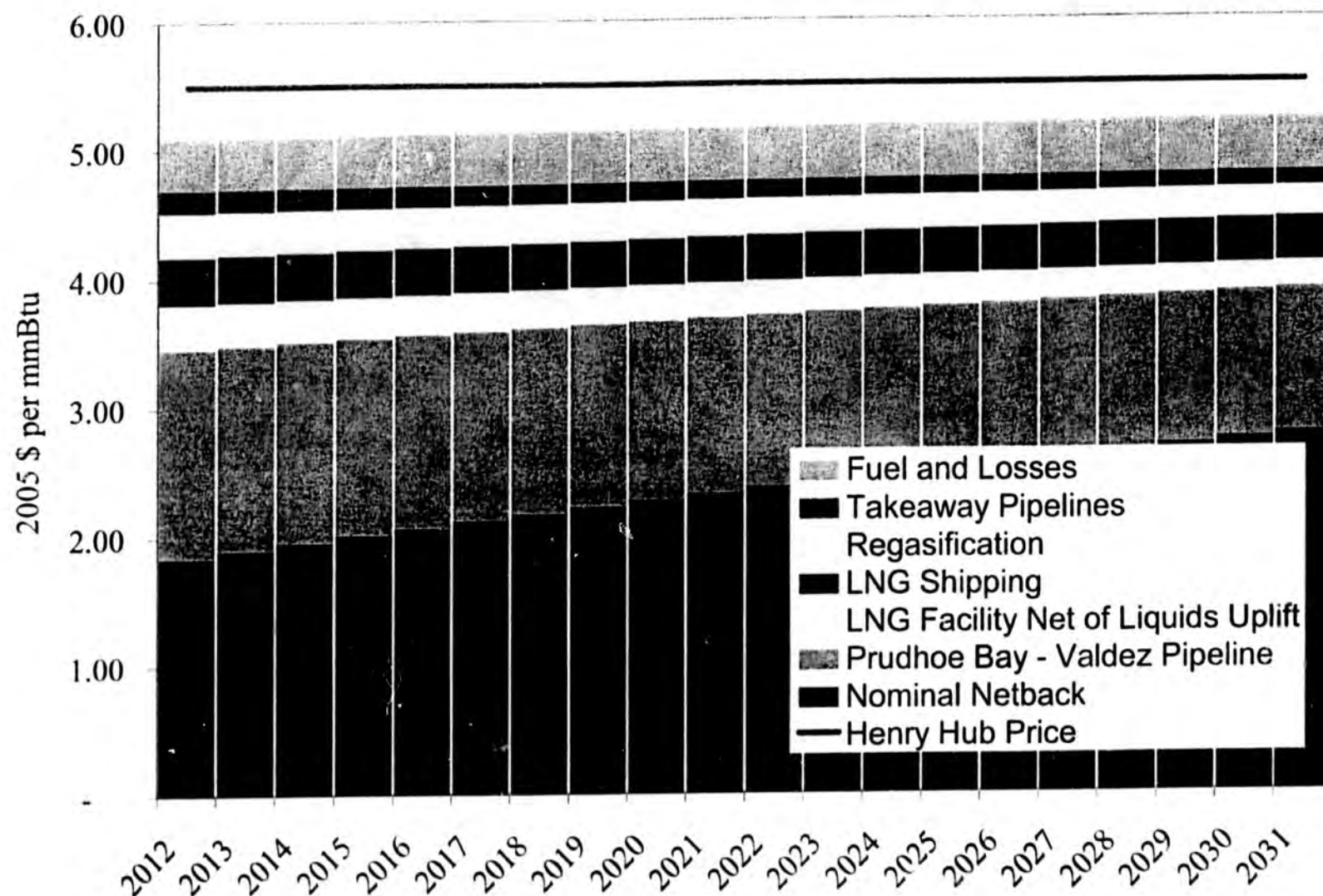
Netback Pricing (continued)

- Uplift from liquids extracted in Valdez:
 - \$0.23 per mmBtu nominal terms
 - \$0.20 per mmBtu in real 2005 terms
- Nominal netback prices at the pipeline inlet are in the range of \$2.11/mmBtu in 2012 to \$7.87/mmBtu in 2041
- Real at the pipeline inlet are in the range of \$1.84/mmBtu in 2012 to \$3.86/mmBtu in 2041
- Nominal prices at the point of production (net of GCP toll and shrinkage and feeder pipeline costs) are in the range of \$1.47/mcf to \$7.16/mcf

Nominal Netback at Pipeline Inlet



Real Netback at Pipeline Inlet (2005 \$)

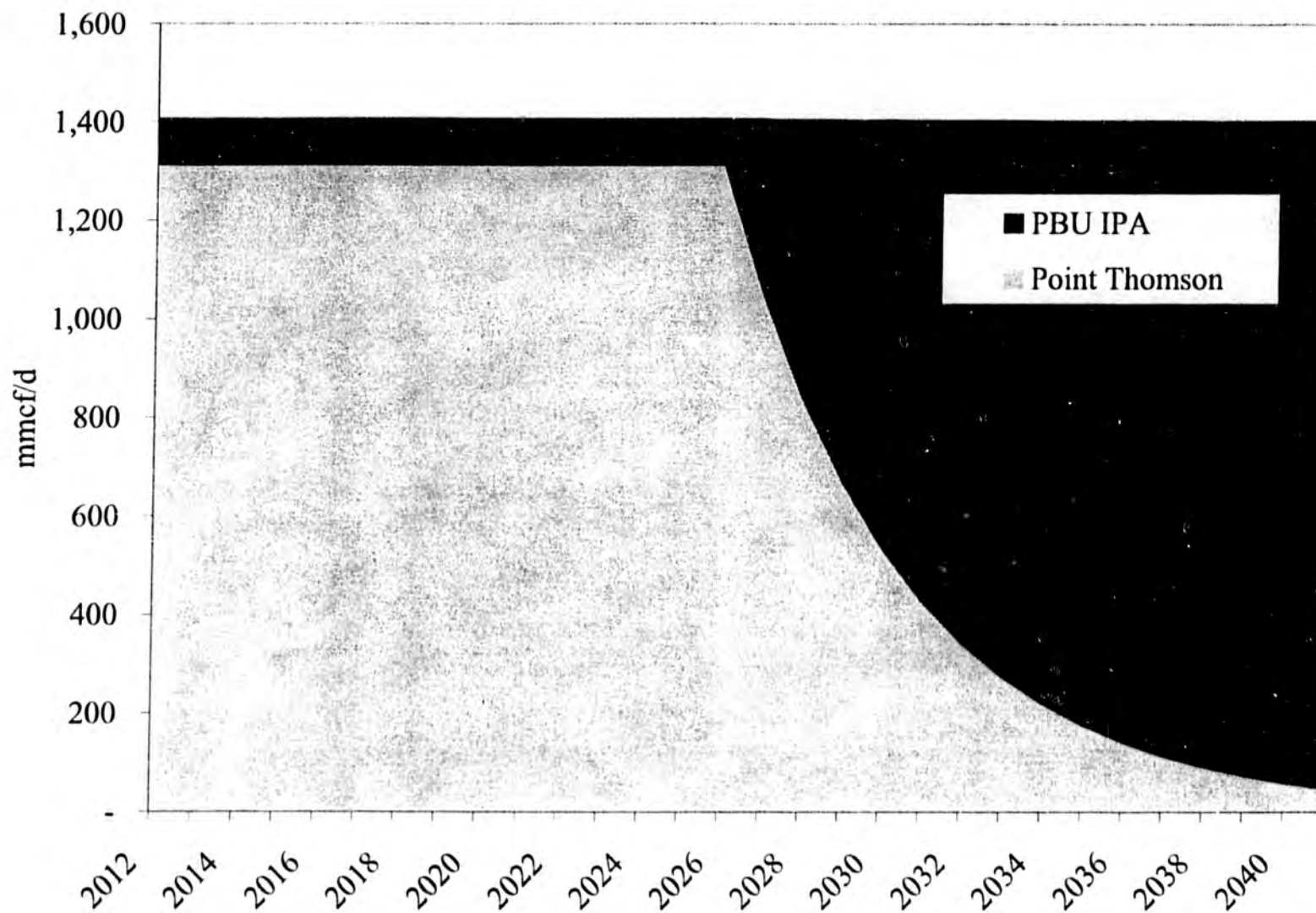




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Producer Results

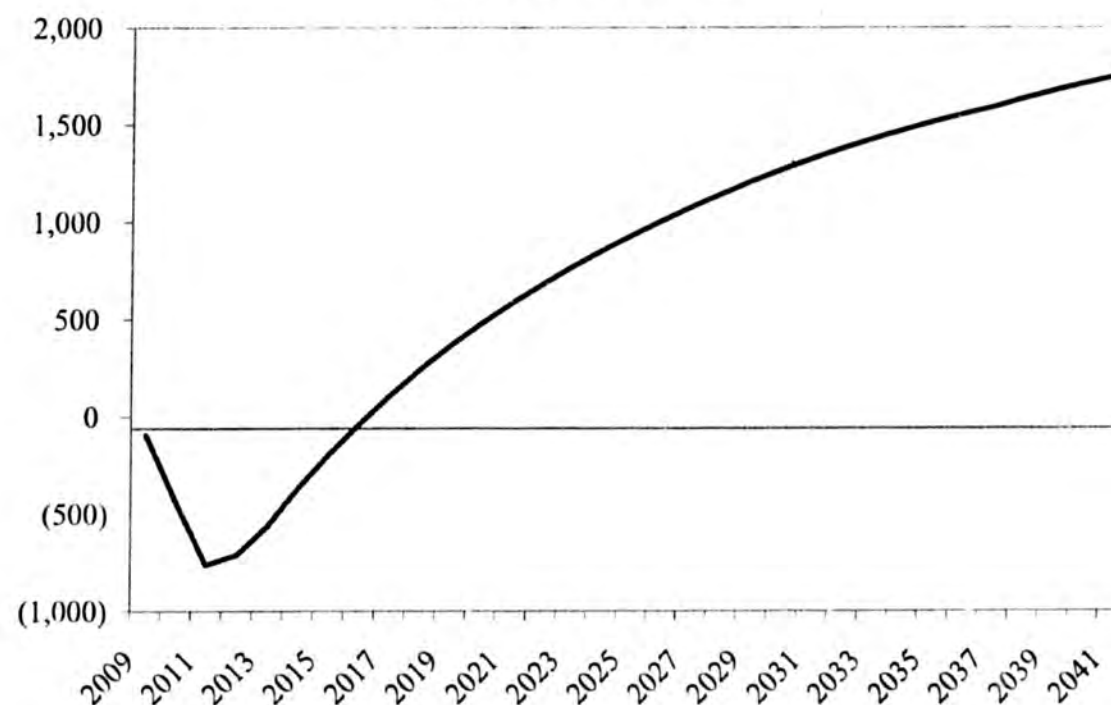
Assumed Upstream Production



Producer Returns

- Upstream Producer returns at the Base Case Henry Hub price of \$5.50/mmBtu
 - NPV @ 12% discount rate: \$1.7 billion
 - IRR: 27.4%

Producer Upstream NPV@12



- Discounted payback is achieved rapidly – within the first six years of operations

Sensitivity of Producer Returns

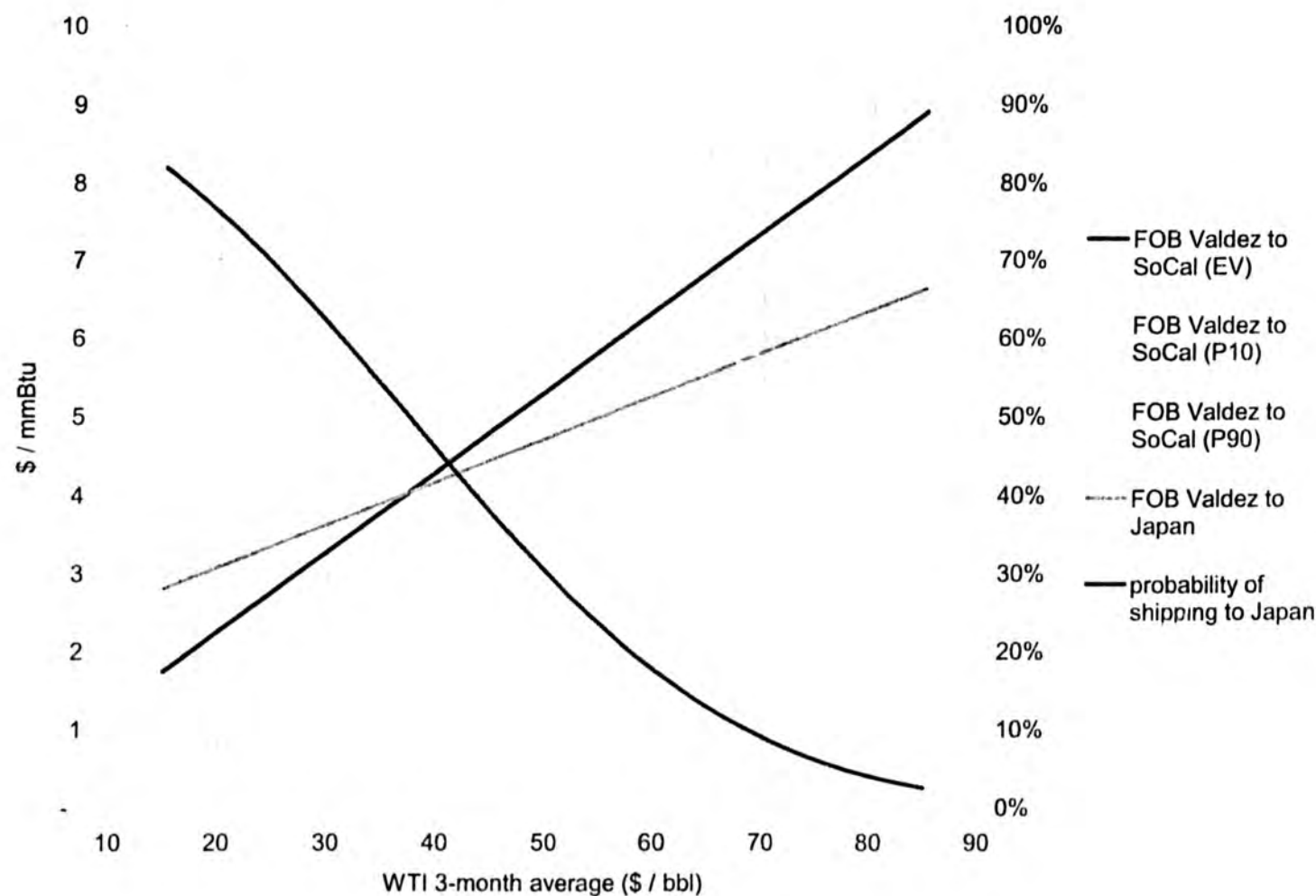
- Producer upstream returns at the high price scenario (\$7.70/mmBtu Henry Hub and \$70/bbl WTI):
 - NPV @ 12% discount rate: \$4.6 billion
 - IRR: 52.4%
- The breakeven Henry Hub price (at which the Producer IRR equals 12%) is \$4.30/mmBtu
- At the low prices scenario (stress case) (\$4.00/mmBtu Henry Hub and \$27/bbl WTI), the netback from Japan is significantly higher:
 - \$1.55/mmBtu at the pipeline inlet and \$0.95/mcf at the point of production in 2012 (nominal terms)
- The LNG project's option to divert production to higher value markets (e.g., Japan) has a significant value

Value of Diversion Option

- Japanese LNG c.i.f. prices are highly correlated with oil prices (R^2 of 0.96)
 - primarily due to contractual linkages to JCC
- US gas prices (including SoCal) are not highly correlated with oil prices, and by extension, Japanese LNG prices
- This low correlation gives increases the likelihood that prices in Japan will be high during periods of low U.S. prices, making it worthwhile to divert cargoes
- An analysis has been performed using both an algebraic approach and a Monte Carlo simulation to estimate the value of this option to divert cargoes to the high-prices market
- At AGPA's base case prices, the expected value of the diversion option is estimated to be \$0.49 per mmBtu of LNG produced

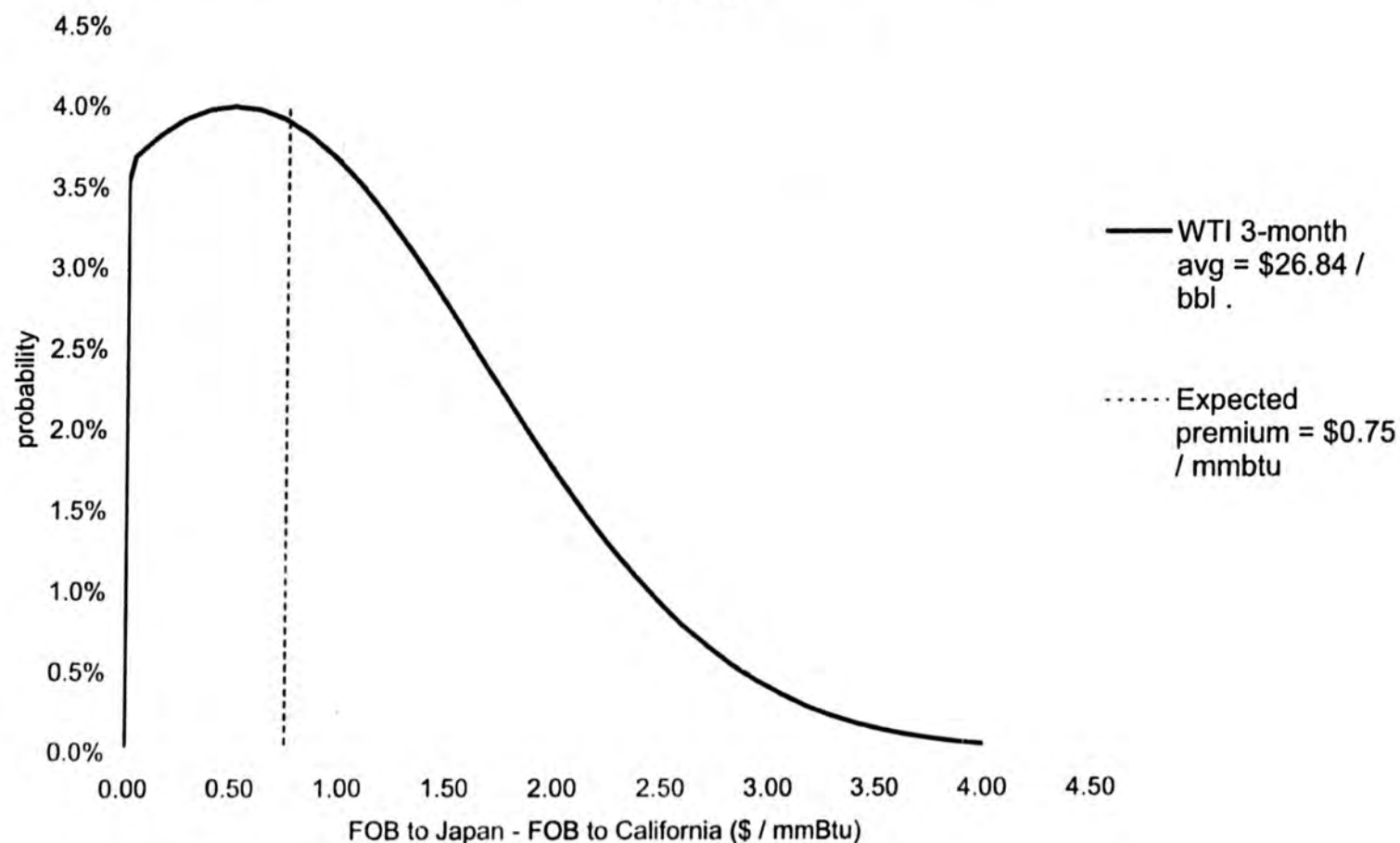


Value of Diversion Option (continued)

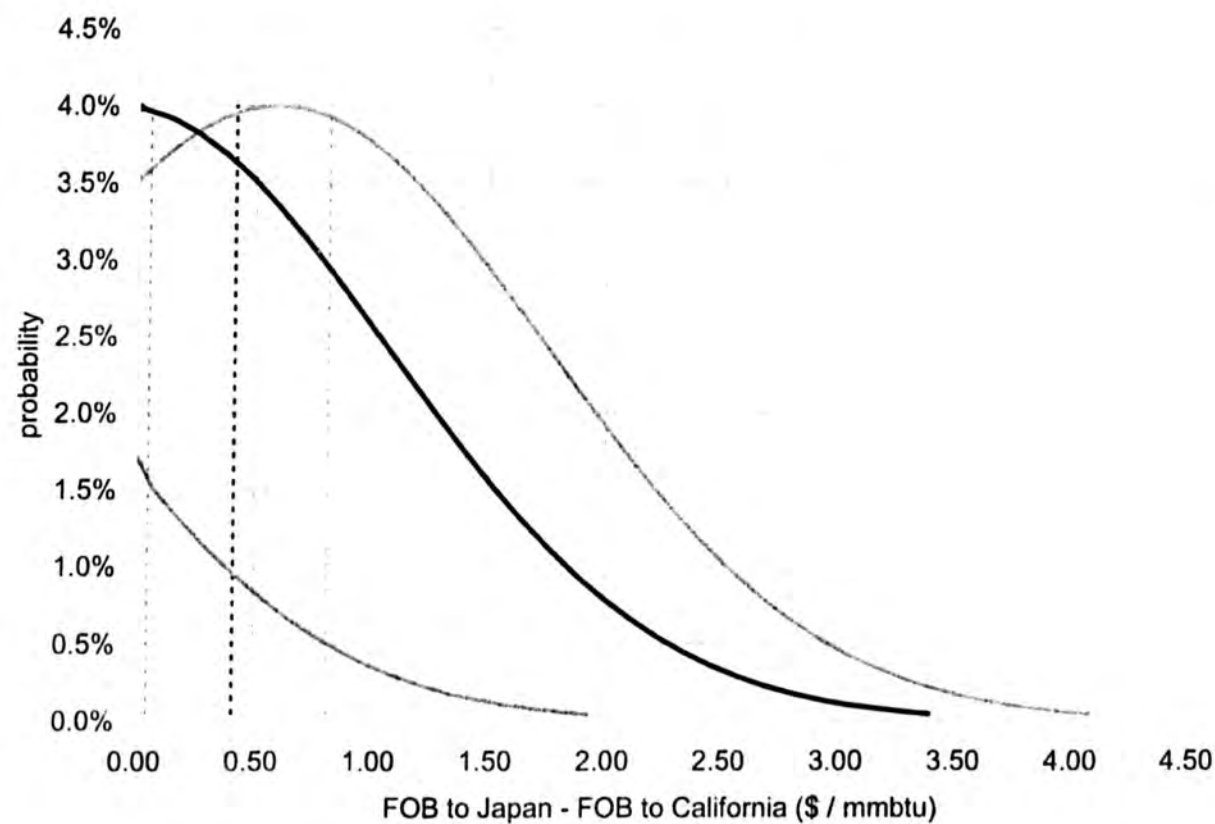


Value of Diversion Option (continued)

Example of diversion option value at a given oil price (\$26.84/bbl in this case)



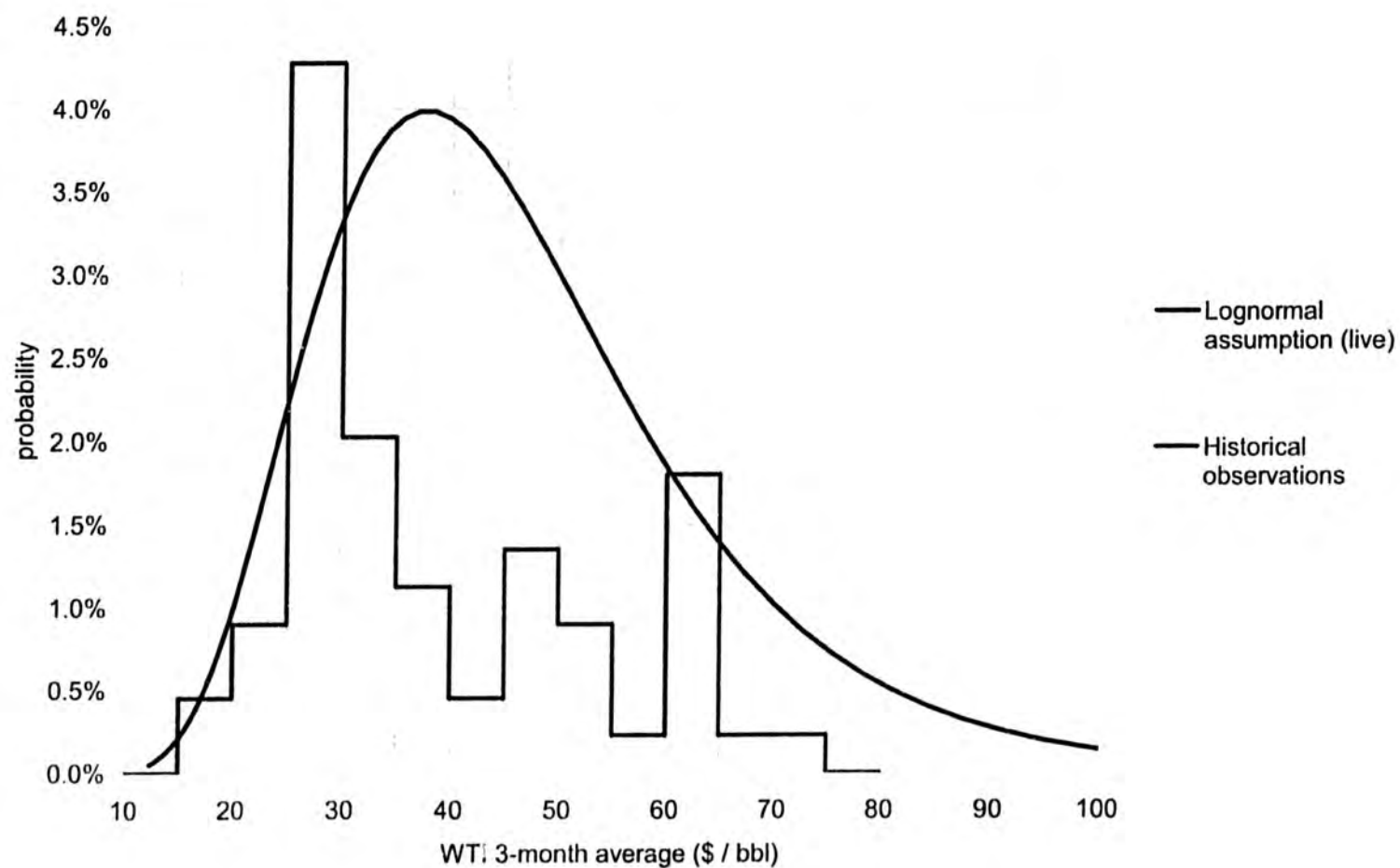
Value of Diversion Option (continued)



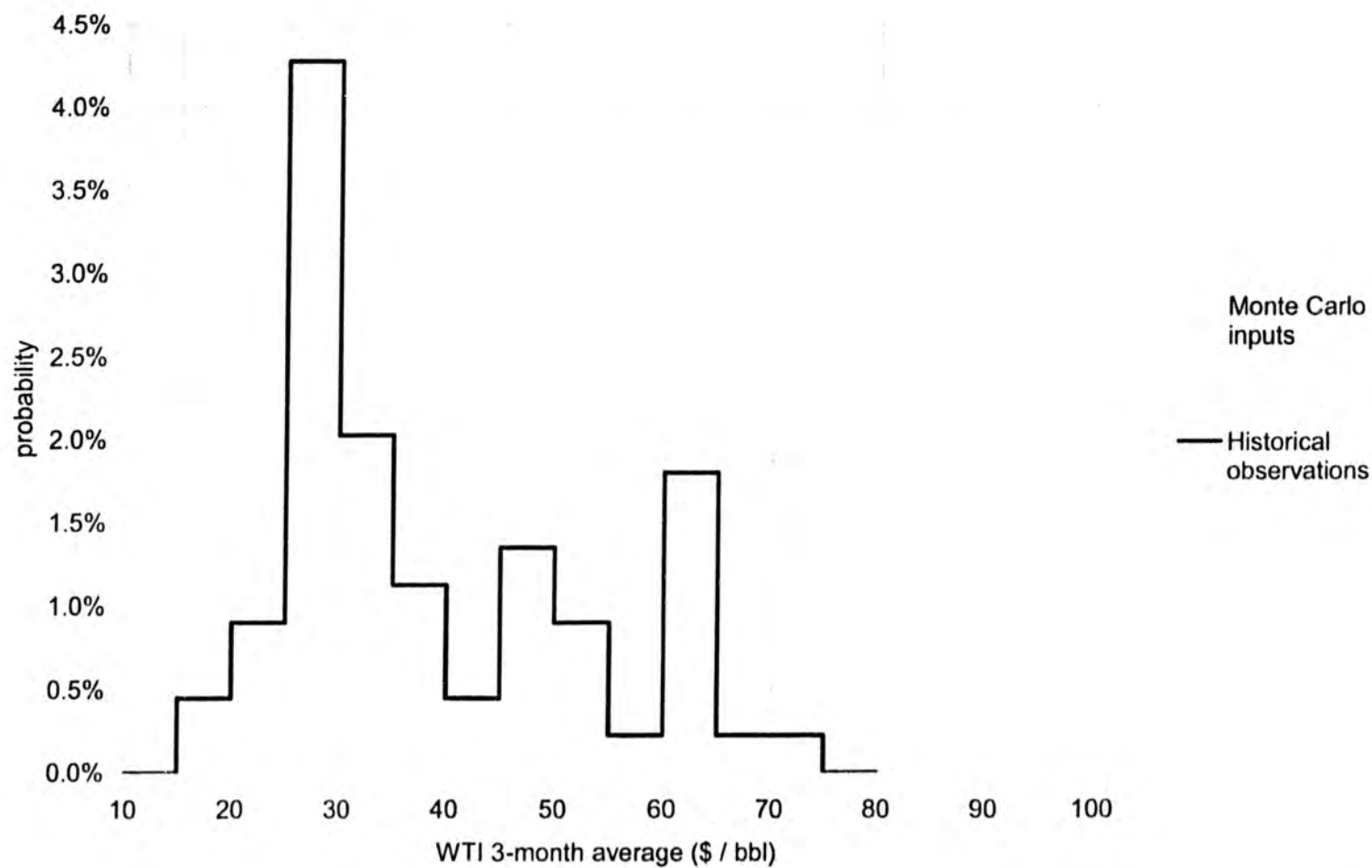
— WTI 3-month avg = \$25.00 / bbl .
 — WTI 3-month avg = \$39.36 / bbl .
 — WTI 3-month avg = \$70.00 / bbl .

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

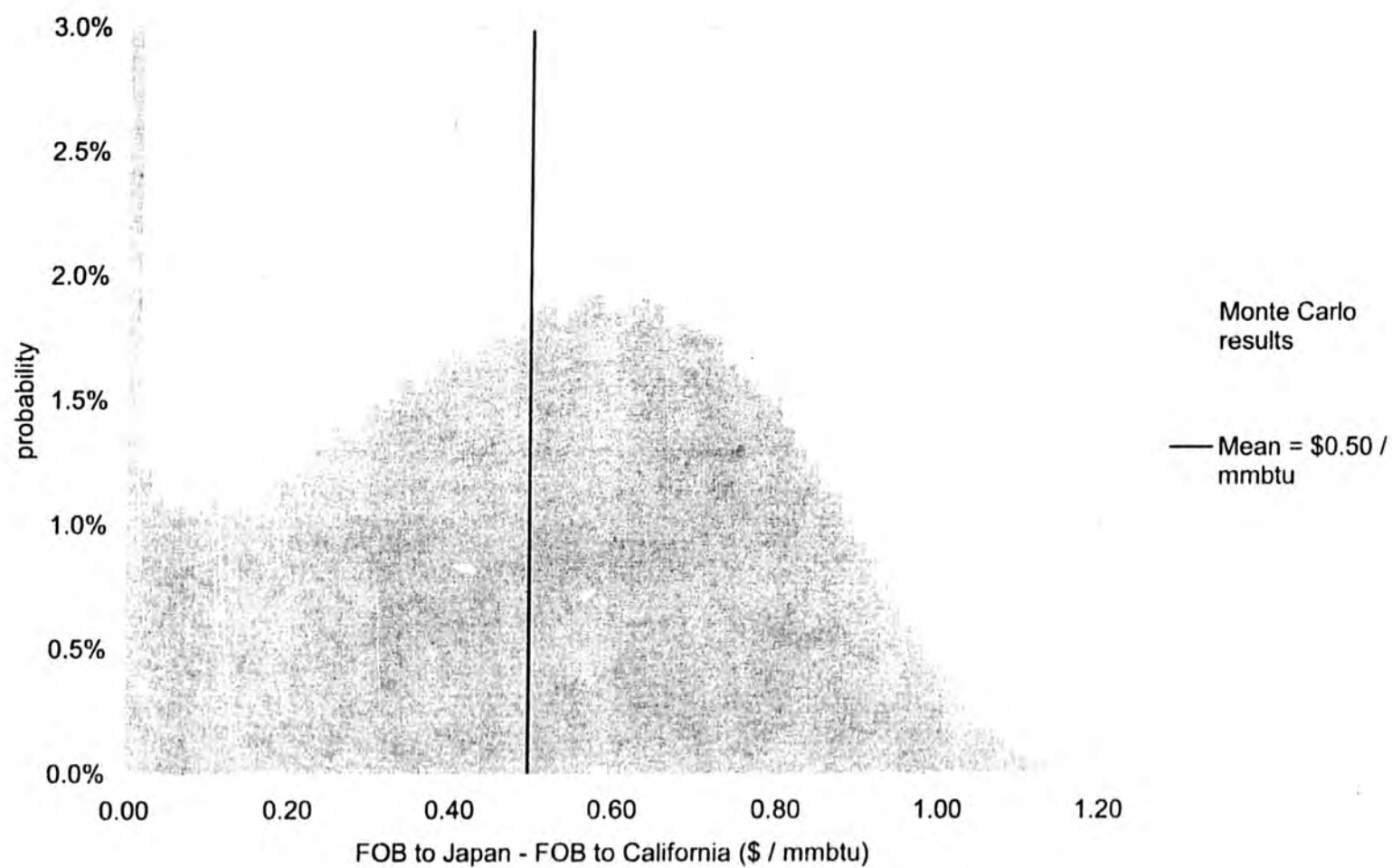
Value of Diversion Option (continued)



Value of Diversion Option (continued)

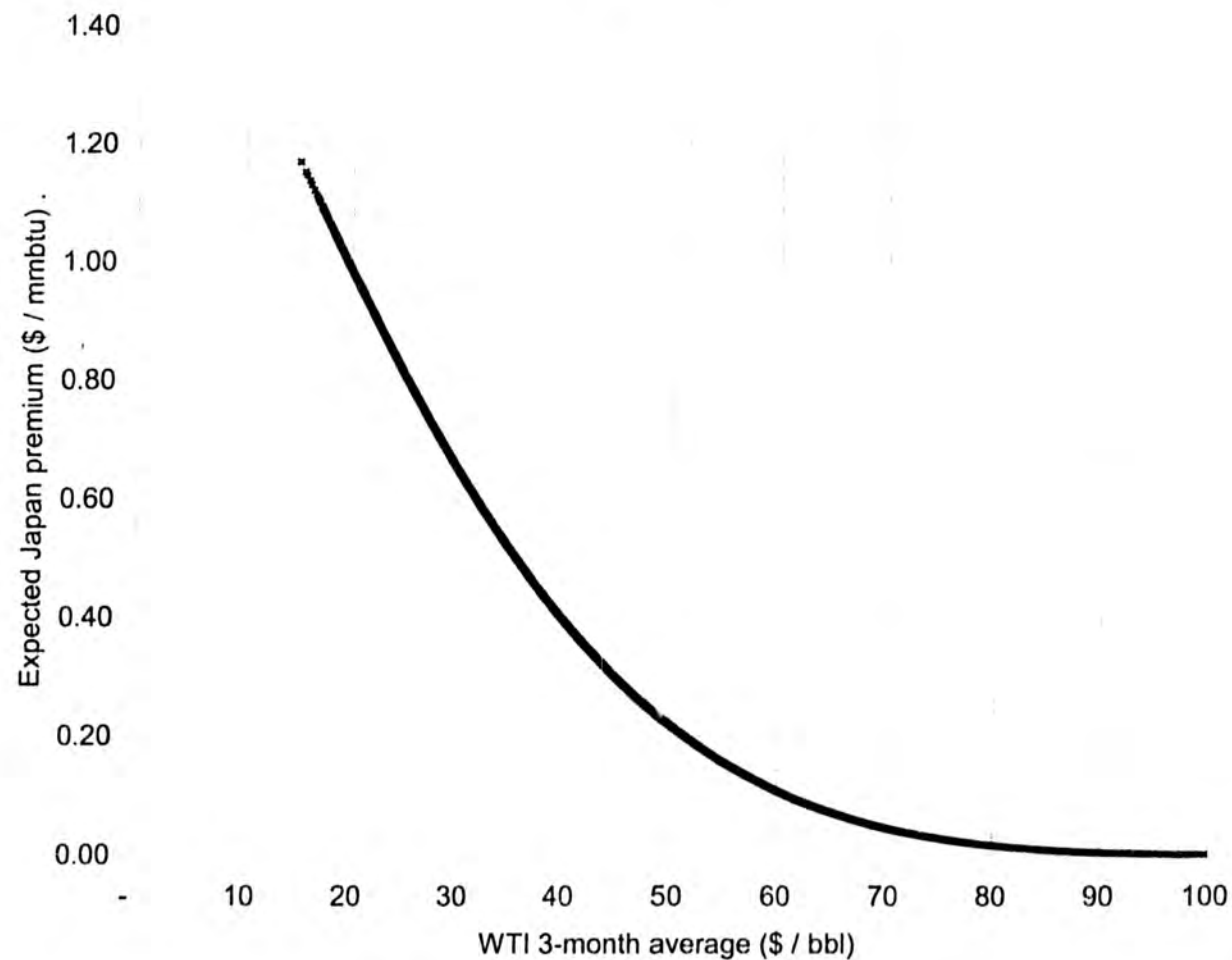


Value of Diversion Option (continued)



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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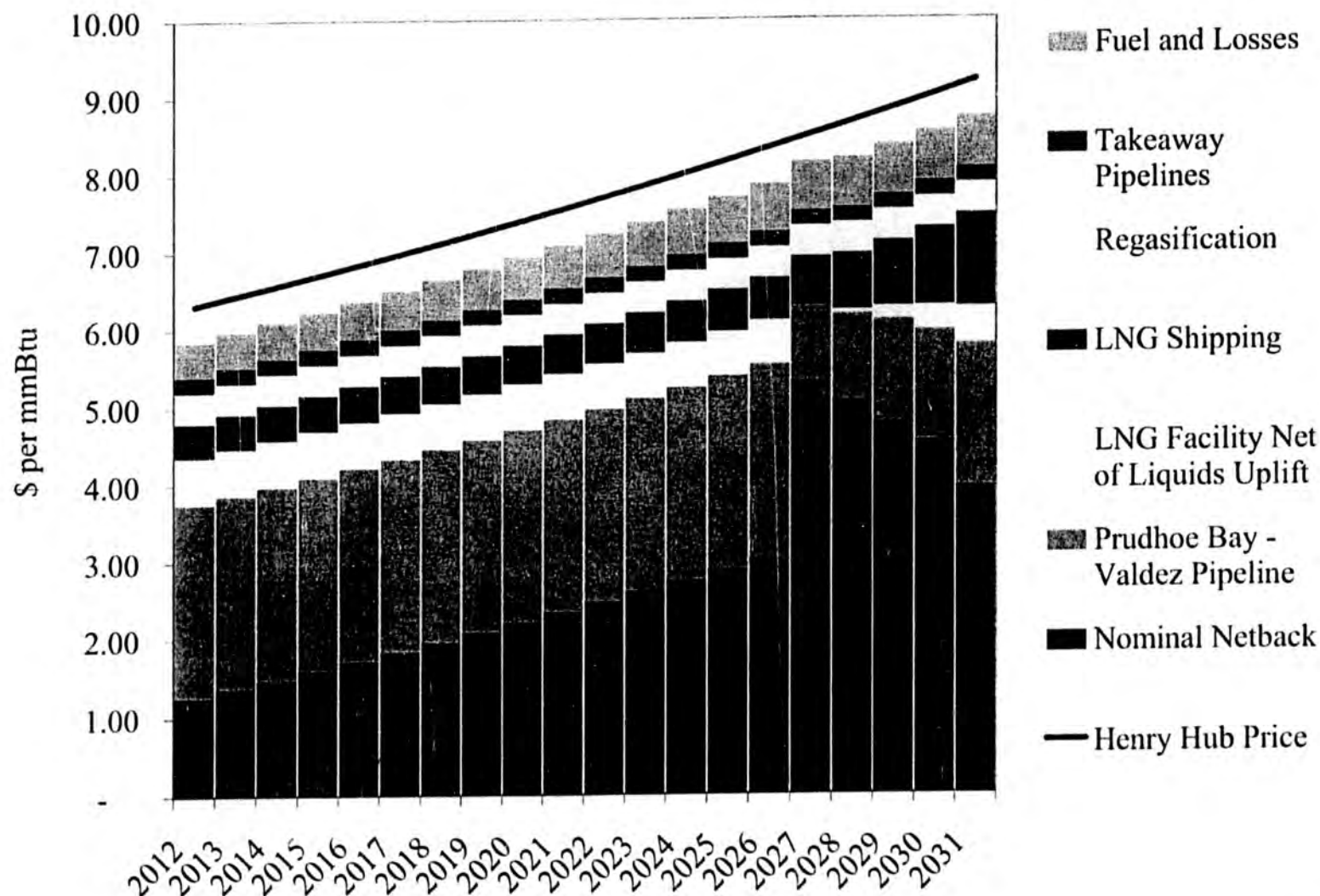
Sensitivity Case: Point Thomson Only

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



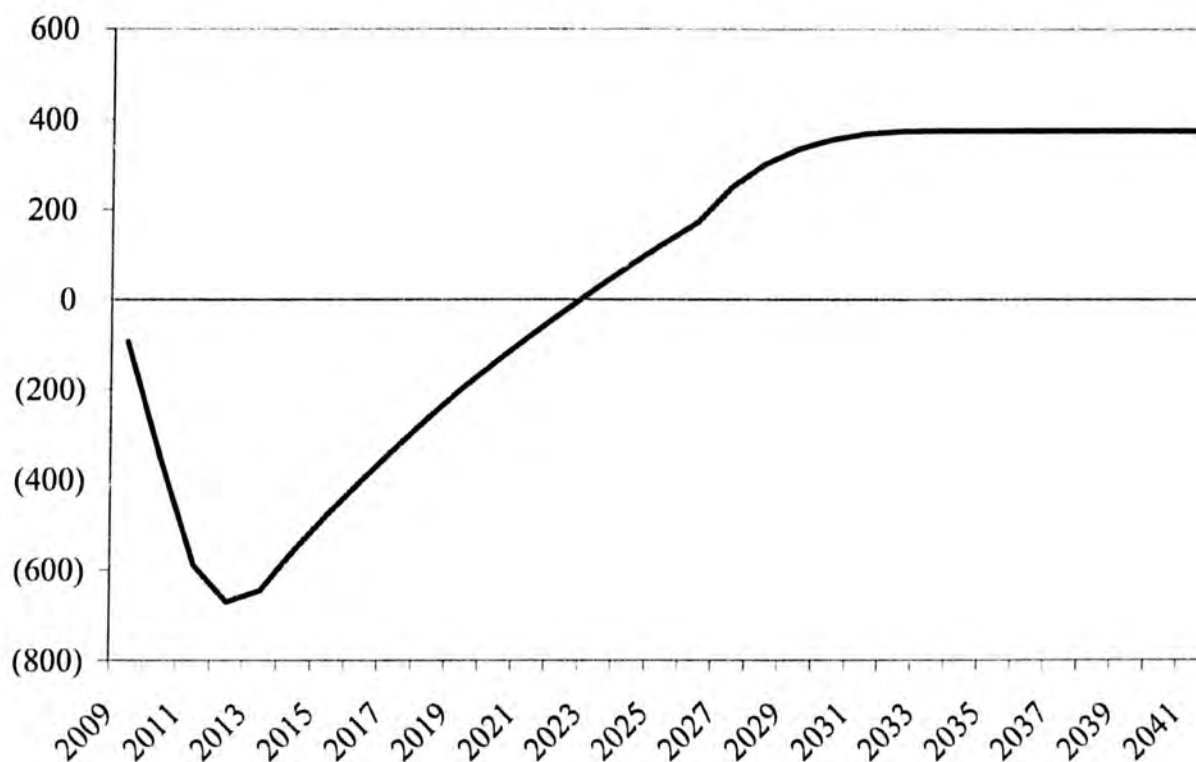
PTU Only: Nominal Netback Price at Pipeline Inlet (No Option)



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



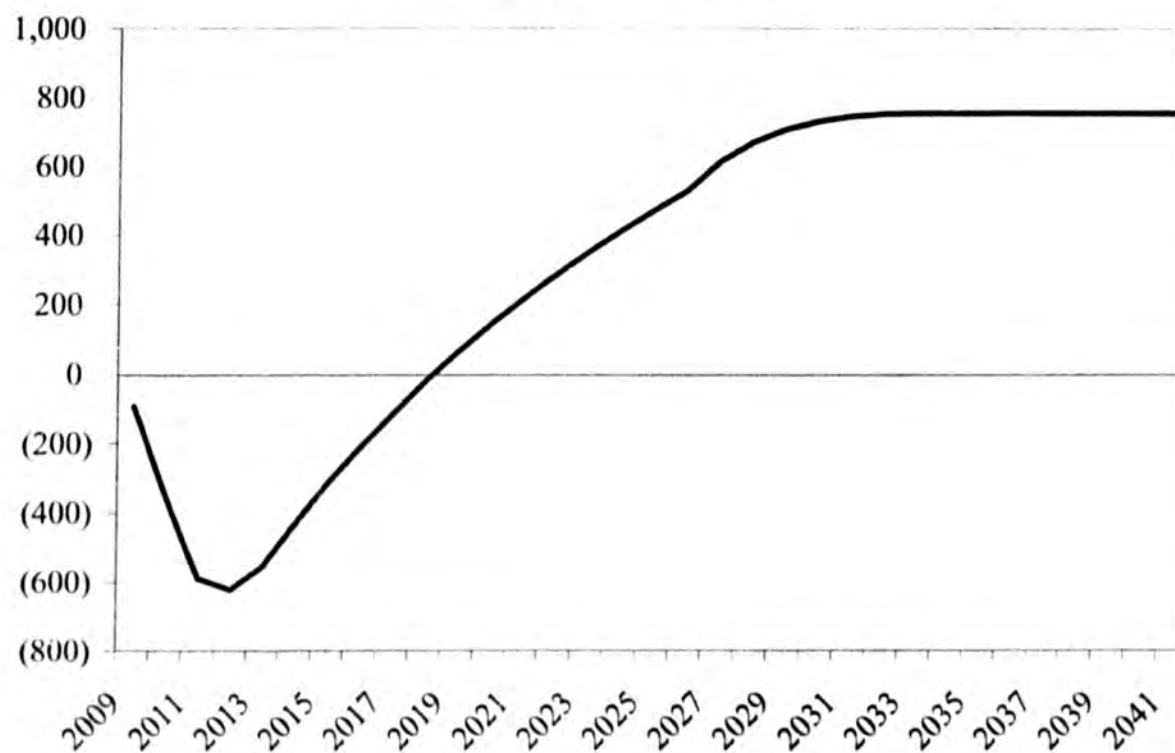
PTU Case: Sensitivity of Producer Returns (No Diversion Option Value)

- 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

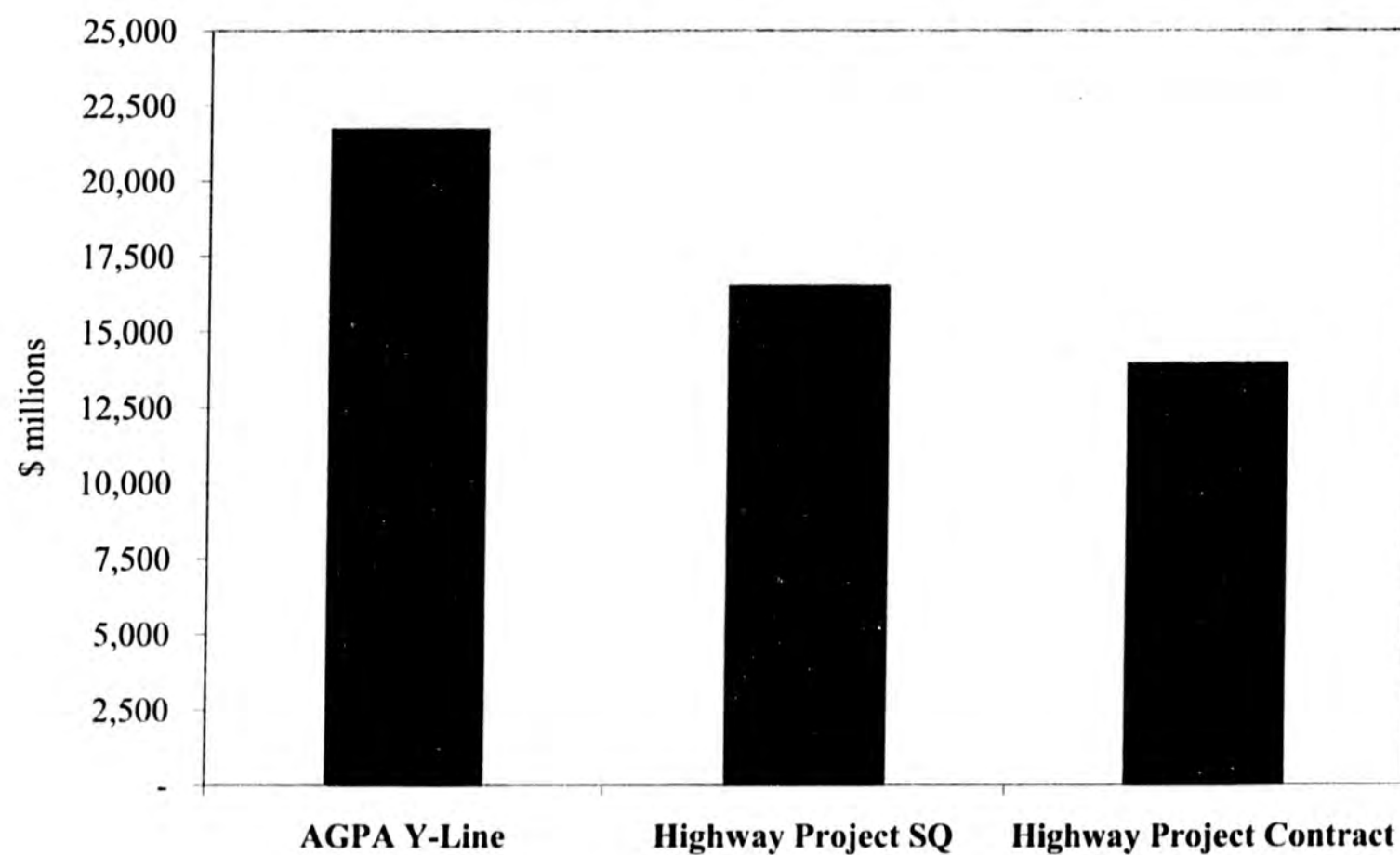


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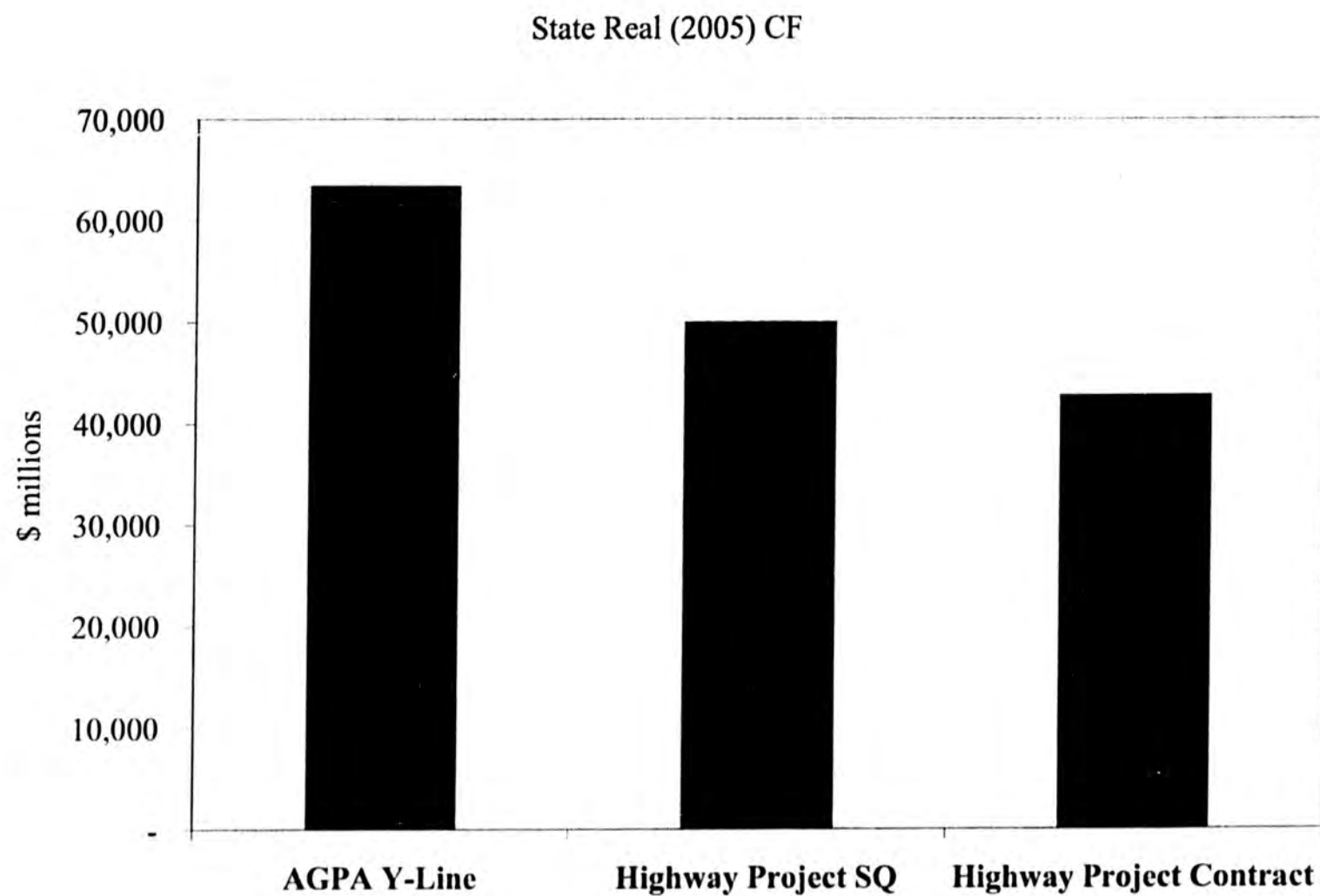
Comparison of State Revenues

Comparison of State NPV

State NPV@7%



Comparison of State Real Cash Flows (2005 dollars)





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Conclusions / Questions

LEGAL SERVICES

DIVISION OF LEGAL AND RESEARCH SERVICES
LEGISLATIVE AFFAIRS AGENCY
STATE OF ALASKA

(907) 465-3867 or 465-2450
FAX (907) 465-2029
Mail Stop 3101

State Capitol
Juneau, Alaska 99801-1182
Deliveries to: 129 6th St., Rm. 329

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.

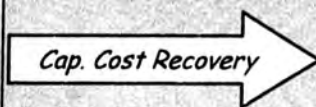
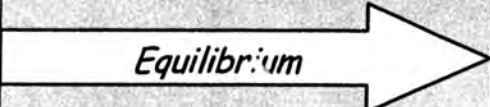
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Oil Tax Fiscal Certainty

SB 2004

Amendment #4

25 Years

		"4" years +/-	"5" Years +/-	9 years fixed			Remaining years <i>equals</i> 25 years <i>minus</i> ("Pre- build" years) <i>minus</i> ("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

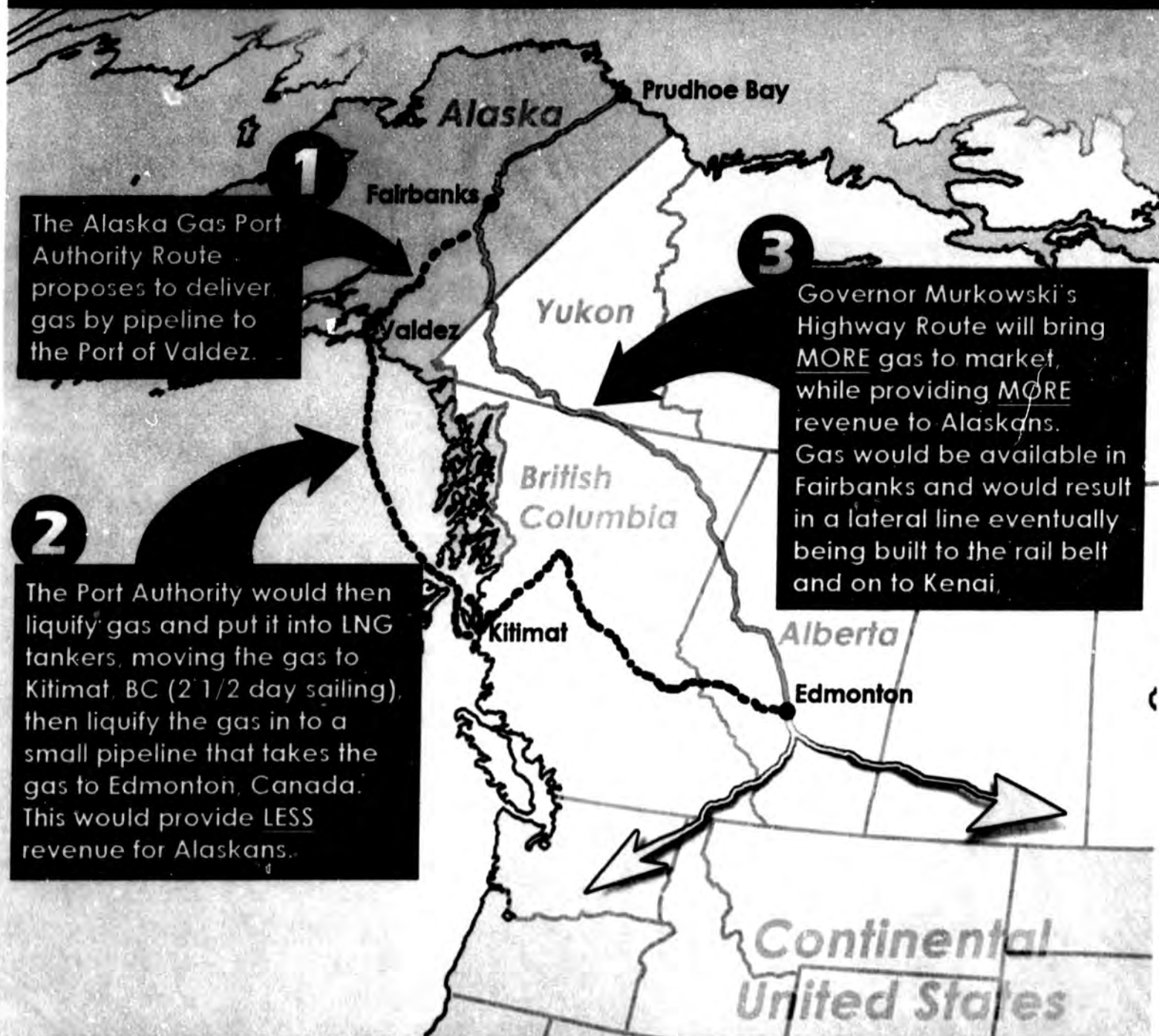
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A GAS PIPELINE FOR ALL ALASKANS



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.

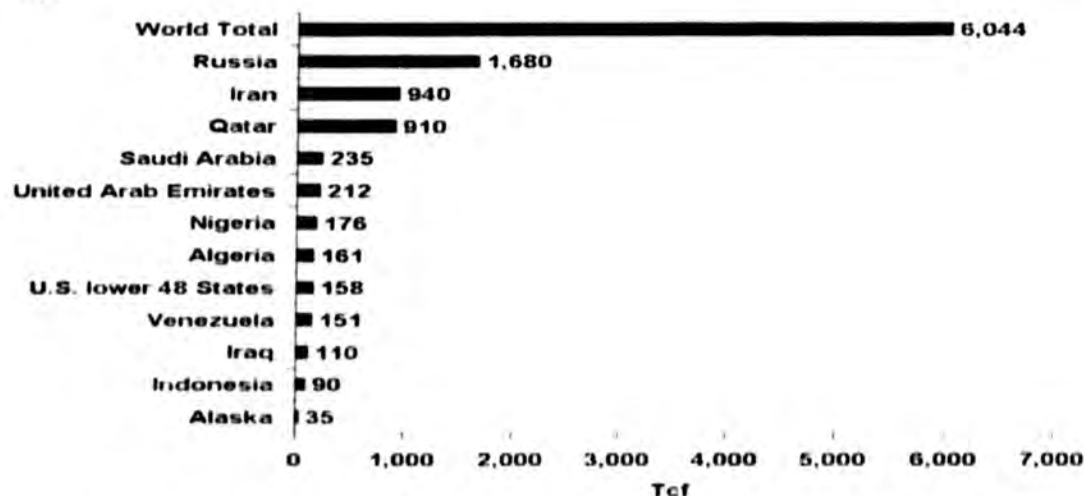
¹⁰ The Joint Review Panel for the Mackenzie Gas Project is a seven-member, independent body that will evaluate the potential impacts of the project on the environment and lives of the people in the project area.

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).

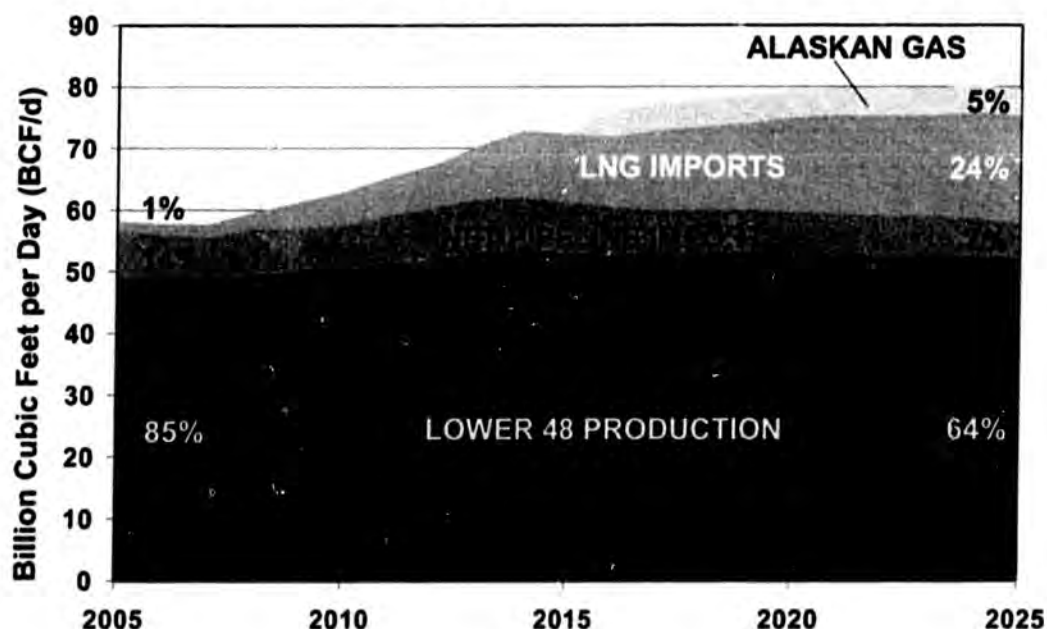
C. Alaska Gas's Potential Market Share

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

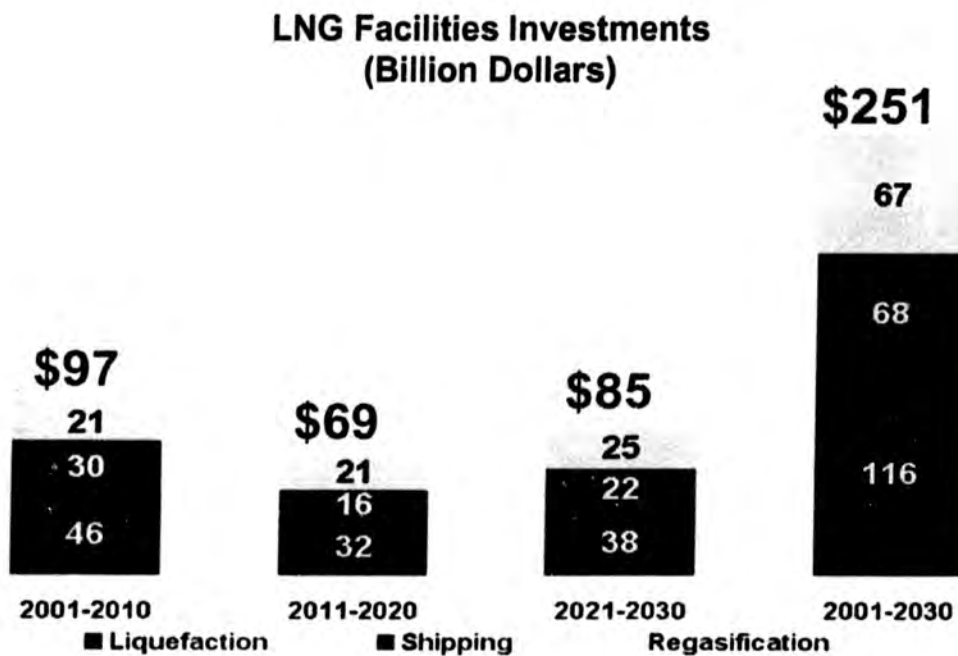
Therefore, the largest sources for growth in U.S. gas supply are Alaskan gas and LNG. As previously stated, gas flow from the Alaskan North Slope is expected to be 4.5 Bcf per day, a not inconsiderable amount. However, this amount pales in comparison to recent LNG infrastructure activity at the Commission. 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.

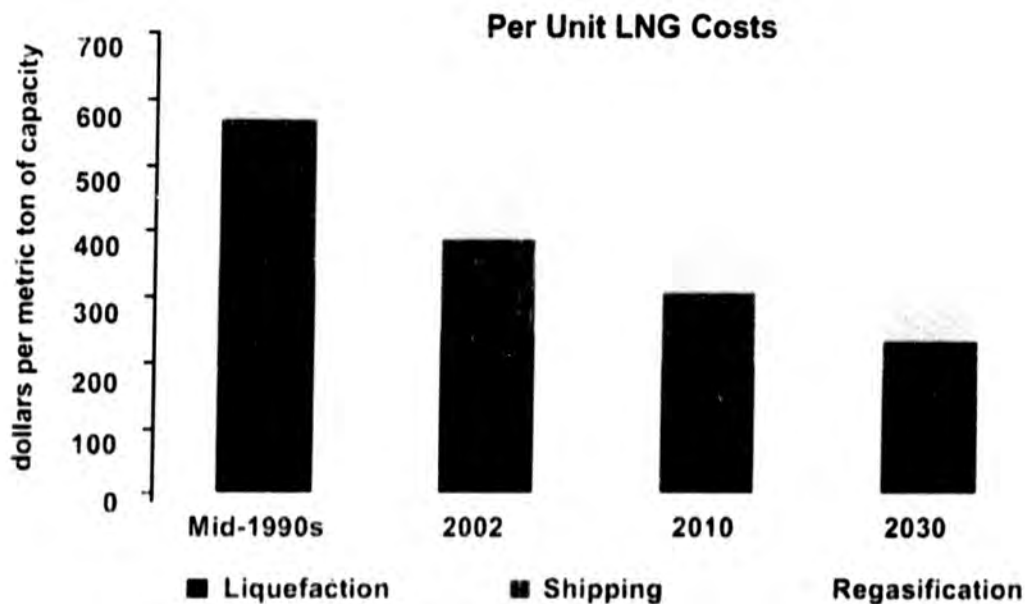
¹³ "Canada's Oil Sands, Opportunities and Challenges to 2015: An Update," National Energy Board, p. 16 (June 2006).

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

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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.

an Alaska natural gas transportation project. Indeed, the tremendous size, scope, and cost of an Alaskan pipeline, the long lead-time needed for such a project, environmental sensitivities, and the competitive conditions that are unique to such a project warrant special consideration and oversight. In addition, Congress specifically required that the open season regulations promote competition in the exploration, development, and production of Alaska natural gas and, as to any open season for expansion of the initial capacity of any Alaska natural gas transportation project, the Commission's regulations are to specifically provide the opportunity for gas other than Prudhoe Bay and Point Thomson production to have access to the pipeline.

10. As revealed in detail in the comments to the NOPR, there are complex, competitive conditions surrounding an Alaska natural gas transportation project, which are intensified by the generally agreed upon fact that there will be only one such pipeline for the foreseeable future. The North Slope Producers hold the proven reserves that may be able to support the initial construction of the project, and may now be in a position to make long-term capacity commitments to the project. Other producers and explorers, whose potential gas reserves are not yet commercially developed, may not currently be in a position to do so. Instead, they anticipate a need for capacity some time in the future, and express reluctance to make the large investment required to explore for and develop Alaska gas without being reasonably assured that they will have access to pipeline capacity when their gas is ready to move to market. Shippers seeking to move gas only within the State of Alaska for in-state uses may also seek pipeline capacity. While the North Slope Producers anticipate paying rates covering the costs of transportation through the entire project, shippers planning to make deliveries in Alaska likely will seek mileage-based or zone rates.

11. We have striven in this rule to balance the need to allow project sponsors the flexibility to develop and bring to market Alaska natural gas with the equally compelling needs to ensure fair competition in the transportation and sale of natural gas, promote the development of natural gas resources in addition to those in the North Slope, and consider Alaskan in-state requirements. As discussed in more detail below, we are not inclined to impose open season rules that prescribe such details as when open seasons must occur and precise criteria to be used in evaluating bids and allocating capacity. To do so could potentially unduly limit a prospective sponsor's ability to design and finance a viable project, and thereby add to the already-daunting challenges that face an Alaska natural gas transportation project sponsor.

12. At the same time, however, we are well aware of the risks to competition imposed by a project that is owned or primarily sponsored by a small group. Thus, we are imposing strict requirements on all proposals, and particularly on affiliate-owned projects, with respect to the public disclosure of information, to ensure that there is a level playing-field. As we discuss below, we will require applicants for an Alaska

pipeline project to provide detailed information as to project design, how capacity is to be allocated, and proposed rates, terms and conditions. This will allow us to be in a position to monitor whether competition for capacity is fair. In addition, while we are permitting pre-subscription for "anchor" shippers,⁸ we are requiring that contracts with such shippers be made publicly available, and that all shippers seeking the same type of capacity be offered service on the same terms and conditions. We will keep these considerations in mind, not only during an open season, but also during our consideration of any application for an Alaska natural gas transportation project placed before us.

13. Furthermore, we will bear in mind the concerns expressed by the non-North Slope producers in considering expansion issues. Thus, we will look to see whether a proposed pipeline is designed not only to meet immediate needs, but also to provide a reasonable opportunity for access to low-cost expansion capacity. Also, as discussed below, we will look, with the constraints of the Act in mind, to determine that rates for expansion capacity are set at levels that will promote competition in exploration and development of Alaska natural gas, not just protect the interests of initial shippers.

14. In addition to the careful scrutiny we will give to any Alaska pipeline proposal, the need to provide explorers and developers of Alaska natural gas with reasonable assurances that they will have access to capacity on any Alaska natural gas pipeline can be met through existing Commission oversight authority and certificate authorization authority, as supplemented, enhanced, and guided by the findings and requirements of this final rule, the NGA, and the Act. Any complaints regarding these Alaska project issues can be addressed through several ways, including the Commission's Dispute Resolution Service, the Enforcement Hotline, or the Commission's Fast Track complaint process which, under the final rule, will have automatic application to complaints involving any Alaska natural gas transportation open season.

15. Moreover, under section 157.33, any application for a certificate of public convenience and necessity for a proposed Alaska natural gas transportation project must include a demonstration that the applicant has conducted an open season for capacity on its proposed project in accordance with the requirements of this subpart, and failure to

⁸ Anchor shipper(s) as used in the natural gas industry means one or a very few shippers with very large, significant volumes of natural gas that will financially support the initial design and cost of a project.

provide the requisite demonstration will result in an application being rejected as incomplete. This provision will provide a strong disincentive to discriminatory or unduly preferential conduct. Finally, although not required, project sponsors have the option of seeking Commission pre-approval of a proposed notice of open season.

16. The Commission stated in the NOPR that its goal was to design an open season process that provides non-discriminatory access to capacity on any Alaska natural gas transportation project and, at the same time, allows sufficient economic certainty to support the construction of the pipeline and thereby provide a stimulus for exploration, development, and production of Alaska natural gas. It has been suggested that the Commission's stated goal improperly emphasizes the importance of providing certainty to project sponsors to facilitate construction of the project, when instead the Commission should focus on providing as much regulatory certainty as possible to natural gas explorers.⁹ However, providing the economic certainty to support the building of an Alaska natural gas transportation project and promoting competition in the exploration and development and production of Alaska natural gas are not mutually exclusive goals. We conclude that emphasizing economic certainty to explorers, without balancing the similar needs of potential project sponsors, would overlook the Act's overall objective of facilitating the timely development of an Alaska natural gas transportation project, and to bring Alaskan natural gas to markets in Alaska and in the lower 48 states. Thus, we believe that the balanced approach we are taking here is appropriate.

17. In the Commission's view, exploration, development, and production of Alaska natural gas are best served by having a pipeline built and by ensuring that all potential initial and future shippers are able to obtain access on that pipeline under non-discriminatory, non-preferential terms. This rule will provide the framework for an open season process that will provide reasonable flexibility to pipeline sponsors, while ensuring sufficient exchange of information and regulatory oversight to ensure that the goal of fair, open competition in the transportation and sale of natural gas is met.

⁹ See Comments of Shell USA, filed December 17, 2004, at 2. This belief is shared by a number of commenters aligned with the non-North Slope explorers and producers of Alaska gas.

Section-by-Section Analysis of Final Rule**A. Purpose - § 157.30**

18. Proposed section 157.30 sets out the purpose of subpart B. That purpose is to establish rules for the conduct of any open season on any Alaska natural gas transportation project. Section 103(e)(2) of the Act provides that these regulations must include the criteria for and timing of any open season, promote competition in the exploration, development, and production of Alaska natural gas, and, 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.¹⁰

19. The Commission is adopting section 157.30 with certain changes recommended by Alaska for purposes of clarity. Specifically, the revised section makes clear that the regulations apply to open seasons "for the purpose of making binding commitments for the acquisition of initial or voluntary expansion capacity" on any Alaska natural gas transportation project. We see no need to change the description of the purpose of the subpart from being "to establish the procedures for" an open season to being to "prescribe the rules," as recommended by Alaska.

B. Definitions - § 157.31

20. Proposed section 157.31 defines the terms "Alaska natural gas transportation project" and "Commission." ANGDA maintains that the definition of "Alaska natural gas transportation project" should be expanded to include a project involving "a liquid natural gas project to transport liquefiable natural gas from Southcentral Alaska to the West Coast states." ANGDA bases its proposed amendment on a November 18, 2004 amendment to section 116 of the Act whereby Congress included an entity determined to be qualified to construct and operate a liquefied natural gas project to transport liquefied natural gas from Southcentral Alaska to the West Coast states as a "qualified infrastructure project" for purposes of obtaining a loan guarantee. The amendment ANGDA relies on did not expand, much less refer to, the definition of an "Alaska natural gas transportation project." Consequently, the Commission finds no basis to conclude

¹⁰ The Prudhoe Bay and Point Thomson units are gas fields located on Alaska's North Slope with a total of approximately 35 Tcf of known gas reserves.

that Congress intended to include any liquefied natural gas project within the meaning of "Alaska natural gas transportation project."

21. While the NOPR's definition of "Alaska natural gas transportation project" is consistent with the Act's definition of that term, it does not fully define that term as it is defined in the Act. To be precise, the Commission is revising section 157.31 at section 157.31(a) to adopt the full statutory definition of that term. Additionally, the Commission is including for clarity new section 157.31(c), defining the term "voluntary expansion."

C. Applicability - § 157.32

22. The NOPR proposes that the open season regulations are to apply to any application to the Commission for a certificate of public convenience and necessity or other authorization for an Alaska natural gas transportation project, whether filed pursuant to the Natural Gas Act, the Alaska Natural Gas Transportation Act of 1976, or the Alaska Natural Gas Pipeline Act, and to applications for expansion of such projects. The proposed regulation also provides that the open season regulations do not apply to involuntary expansions pursuant to section 105, unless the Commission expressly so provides.

23. Alaska proposes language in the final rule that provides that the open season regulations will apply "to any Alaska Natural Gas Transportation Project for which a certificate of public convenience and necessity is sought pursuant to Section 7 of the NGA and section 103 of the Alaska Natural Gas Pipeline Act."¹¹ However, Alaska does not explain the basis for its proposed definition.

24. Section 102(2) of the Act defines an Alaska natural gas transportation project to include projects authorized under either the Alaska Natural Gas Transportation Act of 1976 or the Alaska Natural Gas Pipeline Act. Since the proposed regulation is consistent with this definition, the Commission sees no reason to amend it.

¹¹ See Comments of the State of Alaska regarding section 157.32.

D. Requirement for Open Season - § 157.33

25. Proposed section 157.33 requires that any application for a certificate of public convenience and necessity for a proposed Alaska natural gas transportation project include a showing that the applicant conducted an open season for capacity on its proposed project that fully complies with the requirements of this subpart. To ensure compliance with this requirement, proposed section 157.33 provides that any application lacking such a showing will be dismissed as deficient.
26. One of the questions that the Commission posed in its NOPR was whether the Commission should allow pre-subscribed, reserved capacity such as was allowed in connection with open seasons for certain new Outer Continental Shelf (OCS) pipeline facilities.
27. Several commenters, including TransCanada, Alliance, the North Slope Producers, Enbridge, Doyon, and MidAmerican/AGTA state that the Commission should allow pre-subscribed capacity for an Alaska natural gas transportation project. TransCanada and the North Slope Producers state that the open season rules should allow for options such as pre-subscription agreements that will encourage or facilitate the successful development of an Alaska pipeline project. They believe that pre-subscription might grant the flexibility to sponsors and shippers that is required in view of the size, expense, risk, and long lead time involved in an Alaska project. Enbridge is convinced that these factors call for pre-subscription.
28. However, the supporters of pre-subscription also comment that steps can or should be taken in order to ensure that other shippers have the opportunity to obtain capacity on a non-discriminatory basis through an open season process. TransCanada, for instance, describes a situation where the sponsor enters into binding prearranged precedent agreements with "backstop" or "transition" shippers who commit to sign firm transportation agreements if no other shipper comes forward, but who agree to lower their capacity commitments to pre-agreed levels to allow the inclusion of other shippers who tender qualifying bids during the open season. In a similar fashion, MidAmerican/AGTA states that the open season rules should permit transportation commitments allowing pre-subscribed capacity to be prorated down to a minimum threshold level to allow others to obtain capacity in the event the total requested capacity exceeds design capacity.
29. Enbridge is confident that, even with pre-subscription, an open season conducted under the safeguards and transparency provided by the Commission's proposed rules will result in a pipeline designed to enable every creditworthy shipper to obtain the long-term capacity it needs. However, Enbridge claims that there can be no Alaska natural gas transportation project without the full, binding commitment of the North Slope Producers. Alliance is also a strong believer in the potential usefulness of pre-subscribed

capacity in facilitating the development of an Alaska pipeline. However, also recognizing that the open season rules must promote competition in the exploration, development and production of Alaska gas, Alliance claims that limits could be placed on the amount of capacity available for pre-subscription, or that pre-subscription could be reserved for initial open seasons only.

30. Another group of commenters prefers that the Commission not allow pre-subscription of capacity and asks that if it is permitted, limitations and conditions be imposed in order to ensure that capacity is still available to prospective shippers which do not participate in pre-arranged agreements. These commenters include Anadarko, Alaska, Calpine and ChevronTexaco.

31. Anadarko argues that if the final rule approves the use of pre-subscription agreements, they must be subject to the outcome of the open season, and that potential bidders in the open season should be offered the same terms and conditions as the pre-subscribing shippers. Anadarko states that there are two distinct types of prospective shippers on an Alaska natural gas transportation project -- the North Slope Producers and the explorers and producers of unproven or undeveloped Alaska natural gas -- who are in long-term competition for the pipeline's capacity, and that pre-subscription favors the major producers to the detriment of those developing competing reserves. Second, Anadarko contends that there are circumstances that distinguish the situation in Alaska from that existing in the OCS cases cited in the NOPR, including the fact that the OCS cases involved the transportation of specific reserves and entailed unusual costs and risks, whereas the situation in Alaska calls for a pipeline that will access all Alaska gas, and that risk has been substantially reduced by a massive federal loan guarantee. Moreover, states Anadarko, the Act calls for mandatory open seasons for capacity on an Alaska natural gas transportation project. Consequently, Anadarko asserts that the final open season rules must require that pre-subscribed capacity must be subject to the outcome of the open season, and if the proposed project is oversubscribed, the project sponsors must either revise the project's capacity to accommodate all bids or fairly prorate all the capacity.

32. Alaska would also prefer that the final open season rules prohibit pre-subscribed capacity because of its potential to limit the amount of capacity in the open season. If pre-subscription is permitted, Alaska, like Anadarko, states that all parties should be able to obtain capacity on the same terms and conditions, and if the project is oversubscribed, all capacity should be pro-rated equally. ChevronTexaco has a similar view, stating that so long as the pre-subscription represents only a minimum commitment needed to construct a project, with the understanding that the project will be enlarged as a result of matching bids in the open season, and so long as pre-subscribed capacity and open season capacity are allocated on the same basis, the Act's open season goals are met. Calpine points out the same circumstances as Anadarko did in distinguishing an Alaska natural

gas transportation project from the OCS facilities referred to the NOPR. However, to facilitate the ultimate development of an Alaska natural gas transportation project, Calpine is agreeable to allowing pre-subscribed capacity that will be subject to an allocation procedure in the event capacity is oversubscribed.

33. Alaska Legislators and Arctic Slope oppose any pre-subscription. Arctic Slope asserts that 100 percent of the capacity of an Alaska natural gas transportation project must be made available on a non-discriminatory, open access basis to all potential shippers; therefore, the open season rules should prohibit pre-subscriptions. Alaska Legislators state that the Act requires the Commission alone to establish the open season procedures for awarding initial and expansion capacity on an Alaska natural gas transportation project. Moreover, since Congress mandates that these open season regulations promote competition in the exploration, development, and production of Alaska natural gas, Alaska Legislators contend that the project must be developed in a manner that maximizes the number of exploration and production companies able to participate in an open season and compete for capacity on the pipeline. The only way this can be done, according to Alaska Legislators, is by requiring that 100 percent of the initial and expansion capacity be awarded solely through a public open season. Alaska Legislators support their view by stating, like Anadarko and Calpine, that the OCS cases cited in the NOPR involved specific instances of individual pipeline construction proposals, and citing cases in which the Commission disapproved procedures outside of an open season and required transparent open seasons as the vehicle by which new pipeline capacity is obtained.¹²

34. The Commission recognizes that the expense, risk, and long lead time involved in developing an Alaska natural gas transportation project justify allowing project sponsors the flexibility to enter into pre-subscription agreements with the North Slope Producers and any other shippers who are currently in a position to support the project with long-term capacity commitments. We do not view the federal loan guarantees as reducing the risk of an Alaska project to a level where pre-subscription should not be allowed, nor do we see pre-subscription as inherently anti-competitive.

¹² *Wyoming-California Pipeline Co.*, 50 FERC ¶ 61,070 (1990); *TransColorado Pipeline Co.*, 53 FERC ¶ 61,421 (1991); and *Colorado Interstate Gas Co.*, 56 FERC ¶ 61,015 (1991).

35. Based on the foregoing, we will permit pre-subscription in order to facilitate the development of an Alaska natural gas transportation project. In order to ensure that all other potential shippers will have an equal opportunity to obtain access to capacity on the project in the open season, we are requiring in the final rule that any and all pre-subscription agreements be made public within ten days of their execution, and that capacity on the proposed project will be offered to all prospective qualifying shippers on the same rates, terms and conditions as contained in the pre-subscription agreements. In the event that there are pre-subscription agreements with varying rates, terms and conditions, all prospective qualifying shippers shall have the option of choosing among the several agreements which one they wish to accept. We note, however, that the justification for allowing pre-subscription may not be as compelling in the case of any expansion, since the major hurdles to developing the project in the first instance will have been overcome. Therefore, we will limit our authorization to provide for pre-subscribed initial capacity only.¹³

36. Much attention is given in the comments to concerns over potential discrimination and preference in allocating capacity in the event that the proposed Alaska pipeline project is oversubscribed, whether or not pre-subscription is allowed. While these concerns can best be addressed by designing a proposed project such that it meets the capacity needs of all shippers who are prepared to enter into binding agreements, we nonetheless will use our regulatory authority to protect against undue discrimination or undue preference in capacity allocation.

37. As discussed below, the Commission is holding to the regulatory approach taken in the NOPR which allows project sponsors to (subject to our subsequent review) develop the methodology by which they will allocate capacity in the event of oversubscription of a project not supported by precedent agreements. However, in the case of pre-subscribed capacity, the Commission will require that the project sponsors must either revise the project's capacity to accommodate all qualified bids or prorate only the capacity that was subject to the pre-subscription agreements or was bid for in the open season on the same

¹³ Future requests and open seasons for voluntary expansion capacity after the pipeline is in service will be controlled by procedures spelled out in the Alaska pipeline's approved FERC gas tariff, while involuntary expansion capacity will be controlled by the requirements of Section 105 of the Act and any rules that the Commission may issue in the future governing such expansions.

rates, terms and conditions as any of the pre-subscription agreements. The Commission has chosen this solution for several reasons. First, the parties most certain to be pre-subscription shippers are the North Slope Producers, who will be in a position of control over the proposed project's design, either as project sponsors or as owners of the reserves that support the project. Second, by their own estimate, the North Slope Producers assert that the initial pipeline can be designed to accommodate all qualified bids.¹⁴ Consequently, the Commission believes that it is appropriate that entities involved in pre-subscription bear the risk that their capacity will be reallocated in the event that the project is undersized.

38. Anadarko proposes to add to this section a provision that, when read in the context of its other proposed rules, would prohibit any pre-subscription agreements. Alaska also proposes language that would lead to that result. As discussed herein, the Commission is, with appropriate limitations, allowing pre-subscription, and is amending section 157.33 accordingly. Moreover, the Commission is satisfied that modifying section 157.33 to provide that any application lacking a showing that the open season regulations have been fully complied with will be rejected as deficient will ensure compliance with the open season requirements. Alaska proposes to also include in this section a provision requiring that open seasons be conducted without undue discrimination or preference in the rates, terms, or conditions of service. The Commission is expanding section 157.35 to include language similar to that suggested by Alaska.

E. Notice of Open Season - § 157.34

39. The criteria for and timing of Alaska natural gas transportation project open seasons are spelled out in proposed section 157.34. This proposed regulation received the most attention in comments. For clarity and convenience, the comments are broken down and grouped by the topics listed below.

¹⁴ As noted, *infra*, the North Slope Producers state that it will require 50 Tcf of gas to keep a 4 to 4.5 Bcf pipeline full for 30 years, and any Alaska pipeline will be designed to be economically expandable to 6 Bcf/d, which would accommodate an additional 15 Tcf over 30 years.

i. Open Season Timing and Duration

40. Proposed section 157.34 sets forth the criteria for and timing of Alaska project open seasons. Proposed section 157.34(a) provides for public notice of an open season at least 30 days prior to the commencement of the open season through methods including postings on Internet websites, press releases, direct mail solicitations, and other advertising. The Commission believes that such prior notice would serve several purposes. First, it would reduce, if not eliminate, any advantage that one potential shipper might have as a result of prior knowledge of the open season. Second, it would afford both project sponsors and prospective shippers a period of time prior to the actual open season period in which they could address and possibly resolve any questions or problems regarding the terms and conditions of the open season. Third, it would afford potential shippers time to prepare submissions in response to the open season.

41. Proposed section 157.34(c) provides that an open season for an Alaska natural gas transportation project must remain open for a period of at least 90 days. This minimum 90-day period for prospective shippers to examine the open season materials and make service requests to the pipeline is intended to establish some parity among shippers, given that certain shippers, primarily the "anchor" shippers, may have had advance information relating to the pipeline's proposed services, tariff provisions, and cost projections. Ninety days is proposed as an adequate amount of time in which to conduct a reasoned evaluation of the open season materials and to help level the playing field.

42. Alaska Legislators state that the notice period established in the NOPR needs clarification. Specifically, they state that the proposed regulations are unclear whether the 30-day notice period precedes and is computed separately from the 90-day open season period. In any event and for several reasons, state Alaska Legislators, an initial open season will require a duration of a minimum of six months, and any subsequent open seasons should remain open for a minimum of four months. First, Alaska Legislators assert that this additional time is needed to offset the fact that shippers affiliated with the pipeline will have advance information. Second, the substantial capital commitment that will be required of any prospective shipper warrants a much longer period within which to evaluate whether to contract for capacity on the project.

43. ANGDA agrees that a 180-day period to review and assess the open season information is required in order to account for the huge information gap between the information now available to potential intra-state shippers and the information they would need to make multi-year commitments for capacity on an Alaska natural gas transportation project. ANGDA states that such a commitment would equal or exceed the asset base of potential shippers on a spur line. Moreover, public hearings and Regulatory Commission of Alaska (RCA) approval of contract terms is required for several potential shippers. The due diligence and expert advice required to make decisions of this

magnitude require a minimum of 180 days, according to ANGDA. Additionally, ANGDA states that many shippers' contract terms require RCA approval, which could take one to two years. Anadarko also believes 180 days is required due to the magnitude of the commitment and to offset the informational advantages that the major producers have over other potential shippers. For example, Anadarko estimates that a 500 MMcf/d commitment for 20 years' capacity on an Alaska natural gas transportation project translates into a \$7 billion demand charge, and a 30-year contract would involve a \$10 billion commitment.

44. AOGCC, Shell, Pacific Star, Doyon, and Alaska share the belief that the NOPR's 90-day open season period should be extended. Pacific Star could support a 120-day open season, with a prior 90-day review period. Alaska recommends a "safe harbor" range of 90 to 120 days, with no preference given based on when bids are received.

45. MidAmerican/AGTA, Alliance and Enbridge find the 30-day notice and 90-day open seasons to be adequate. In particular, Enbridge and MidAmerican/AGTA find these time frames to strike an appropriate balance between meeting prospective shippers' informational needs and the need to expedite the development of an Alaska natural gas transportation project. Enbridge states that because there have been years of developmental work on an Alaskan natural gas pipeline, with many prior public hearings and discussions on the subject having occurred and continuing dialog between potential sponsors and shippers taking place, it is unnecessary to lengthen the proposed open season period.¹⁵ Enbridge adds that extending the open season could result in long delays in the project's overall schedule due to the narrow, seasonal windows associated with environmental studies and preliminary field work.

46. Another timing issue raised in comments involves when any open seasons for an Alaska natural gas transportation project should be held. The NOPR has no requirements on the subject of when project sponsors must hold the open season. According to Anadarko, the Commission's silence on this issue will allow sponsors to hold open

¹⁵ As support for the reasonableness of the 90-day open season period, Enbridge compares it to the 30-day and 53-day open seasons held in *Maritimes & Northeast Pipeline, LLC*, 80 FERC ¶ 61,346 at 62,174 (1997) and *Alliance Pipeline L.P.*, 80 FERC ¶ 61,149 at 61,591 (1997), both large, cross-border projects. Alliance too, refers to its own 53-day open season.

seasons early in the project's developmental process. As a result, explorers will be unable to commit to capacity on the project because of the present uncertainties surrounding their reserves. This sentiment is shared by others, including Arctic Slope, DOI, Doyon, and Shell. As a solution, these commenters state that the open season regulations should include a requirement that any open seasons must remain open until the last practical point in time, which according to Anadarko and Shell is the time when the sponsors must close on their financing arrangements. These commenters state that in this way, some potential shippers, other than the major producers who are in a better position to commit early in the process, might be able to resolve the uncertainties currently prohibiting them from participation. Shell also states that the open season regulations should preclude any open season for an expansion project prior to one calendar year after the in-service date of the pipeline unless the open season is specifically requested by a shipper other than a major producer.

47. In addition, some commenters urge the Commission to require that the study of in-state needs provided for in section 103(g) of the Act precede any open season. Although the language of the Act requires that "the holder of the certificate" demonstrate that it has conducted the required study, the Act does not state when such study should be conducted; nor does the Act require that the study be made public. Alaska states that contrary to the intent of the Act, the NOPR is silent on the subject of ensuring that in-state needs for gas are met.¹⁶ According to Alaska, the only logical way for this to be done is to require that the in-state study be conducted prior to the open season in order for the project sponsor to design the capacity, routing and expansibility of the project facilities to accommodate those needs. The Alaska Legislators argue that an in-state study is "virtually meaningless unless concluded and the results made public by the pipeline operator prior to any open season."¹⁷ Chevron Texaco, TransCanada, and ANGDA agree that, in order to determine where tie-in points are needed to meet Alaska's domestic gas needs, the studies should precede any open season.

48. The Alaska Legislators further argue that the Commission should spell out the type of study that the pipeline will be required to undertake. ANGDA's comments address the need for two major gas trunk-line interconnect points in Alaska, most

¹⁶ Governor Murkowski also made this point at the technical conference.

¹⁷ Joint Comments of the Legislative Budget and Audit Committee of the Alaska State Legislature and Indicated Alaska State Legislators at 48.

critically a spur line to make North Slope gas available to the Cook Inlet area, where two-thirds of the state's population resides, and which has less than a 10-year reserve life for current gas supply. United States Senator Murkowski, State Senator Therriault, and Mr. Izzo, representing Enstar, among others at the technical conference also stressed various in-state needs for natural gas. ChevronTexaco states that it could be a simple matter of identifying most logical tie-in points to address future needs and the most economic methods to expand the capacity to meet those needs when they arise. Alaska Legislators suggest that a January 2003 study conducted on behalf of Alaska's Department of Natural Resources might serve as a useful example to model in fashioning the requirements of the in-State study.¹⁸

49. The Commission is adopting the NOPR's 30-day notice period and 90-day open season period of "at least 90 days" for open seasons, and clarifies that the 30-day notice period will precede the 90-day open season and that the notice of open season is to contain all of the information detailed in section 157.34(b). Therefore, all interested persons will have a period of a minimum of 120 days in total to examine the information pertaining to any open season in order to assess whether they are willing and able to participate in the process and proffer bids. The Commission understands that on day one of the open season process, any shippers affiliated with the pipeline or who have entered into pre-subscription agreements may have certain information not available to other entities. However, that information is required to be disclosed at the beginning of the minimum 120-day period.

50. The Commission also appreciates that, due to the substantial capital commitment that will be required, any prospective shipper will need a sufficient period of time within which to evaluate whether to make multi-year commitments for capacity on the project. However, we also understand that in order to timely develop a pipeline proposal, size the facilities, secure financing and otherwise finalize the proposal in detail sufficient to file a certificate application, time is of the essence. This is accentuated by the fact that under section 109 the Act, if an application for an Alaska natural gas transportation project is not filed within 18 months after the October 2004 enactment of the Act, the Secretary of Energy is required to conduct a study of alternative approaches to an Alaska natural gas

¹⁸ This study can be found at:
http://www.dog.dnr.state.ak.us/oil/products/publications/otherreports/demand/instate_gas_v1.pdf.

transportation project.¹⁹ While the Act does not preclude the filing of an application after the 18-month period and the initiation of such a study, it is clear that the Act contemplates that an applicant will proceed with all deliberate speed.

51. The minimum 120-day open season period we are establishing is substantially longer than any open season heretofore held for a major pipeline project. While no other project equals or nears the size and complexity of an Alaska natural gas transportation project, this will be a project with many years of evaluation, information-gathering and private and public debate behind it. While there may currently be some disparity in the amount of information various interested parties have, most have been assessing their situations, at least conceptually, for many years. The Commission, on balance, believes a 120-day period is adequate to substantially level the playing field, particularly given the extensive information requirements imposed in the open season regulations. We are not convinced that an open season lasting as long as six months is necessary.

52. The Commission, for several reasons, will not impose a requirement that any open season must remain open until a particular point in time tied to other project activities. This requirement was requested in order to allow as much time as possible for potential shippers to put themselves in a position to bid for capacity. The Commission is providing that the effective date of this final rule shall be 90 days from its publication in the Federal Register, which will prevent any open seasons for the first three months. Any specific point in time that the Commission might select (such as a year before an application was filed) might not be suitable under all circumstances, and could, therefore, frustrate efforts in planning project proposals. However, we are adding a new provision in the final rule, section 157.34(d)(2), that a project sponsor must consider any bids tendered after the expiration of the open season by qualified bidders, and may reject them only if they cannot be accommodated due to economic, engineering, or operational constraints, in which case the project sponsor must provide a detailed explanation for the rejection. This

¹⁹ Congress' sense of urgency is demonstrated by a number of other provisions in the law, including those calling for expedited action in connection with the environmental review and the Commission's certificate approval processes, as well as expedited judicial review in connection with any environmental impact statement or final federal agency order issued under the Act. Moreover, the Act establishes an independent Office of Federal Coordinator who is empowered to oversee and coordinate the expeditious federal permitting processes in connection with any Alaska natural gas transportation project.

requirement is designed to allow reasonable access to those shippers whose circumstances prohibit them from participating during the established open season period. Nonetheless, our expectation is that the pipeline can and will be designed and built to accommodate all qualified shippers who are ready to sign firm agreements. On balance, this should be of benefit to late-developing shippers and at the same time provide the sponsor with flexibility in the timing of its open season.

53. In light of the concerns expressed by Alaska entities and Congress' mandate that Alaska in-state needs be given due consideration, we are adding to section 157.34 of the regulations a requirement that open season information include an assessment of in-state needs, based to the extent possible on any available study performed by Alaska, and a listing of prospective delivery points within Alaska. We are also adding a requirement that the open season information include a proposed in-state transportation rate, based on the costs of providing that service. This will give participants in an open season sufficient information to understand what capacity is proposed to be offered to entities within Alaska, where the project proponent proposes to make in-state deliveries, and what the rates for in-state service may be. To the extent possible, we intend that for this assessment to be made based on information provided by the state, so that we, project proponents, and other interested parties can have the benefits of the state's expertise.

54. We do not propose to set aside a specific amount of capacity for in-state service, because we do not now know how much capacity will be sought for that purpose. Similarly, although, as stated immediately above, in-state transportation rates must be based on the costs of providing that service, we cannot at this point determine the appropriate allocation of costs between services for in-state deliveries and for deliveries to the lower 48 States. We will deal with cost allocation issues occasioned by these matters as they arise.

55. We note that section 103(g) of the Act requires the holder of a certificate for an Alaska project to prepare a study of Alaska in-state needs. The open season information we are requiring does not obviate the need to comply with this provision, but the material provided during the open season could later be proffered as the post-certificate study, and, should we determine that there is sufficient agreement by interested parties that the open season information is sufficient, we may accept it as satisfying the statutory requirement.

ii. Open Season Technical Informational Requirements

56. Proposed section 157.34(b) lists the information that any notice of open season for an Alaska natural gas transportation project must contain. The listed information includes technical information such as the route, the proposed receipt and delivery points, the size and design capacity, estimated in-phase dates for expansion capacity, delivery

pressure, projected in-service date, estimated unbundled transportation rate, estimated cost of facilities and estimated cost of service, expected return on equity, negotiated rates and other rate options under consideration, quality specifications, terms and conditions of service. In addition, the list includes a detailed methodology for determining the value of bids, the methodology by which capacity will be awarded in the case of over-subscription, a clear statement of all terms that will be considered, including price and contract term, and required bid information. Other listed information includes the form of a precedent agreement and time of execution of the precedent agreement, and definition and treatment of non-conforming bids.

57. The Commission recognized in the NOPR that a potential applicant for an Alaska natural gas transportation project might find it necessary or appropriate to initiate an open season before some of the information can be determined. The NOPR also anticipated that in a given situation, such information cannot be reasonably determined until after an open season is held. As an example, the Commission described a situation where, for purpose of gathering information and assessing demand, a prospective project sponsor might first conduct a non-binding open season. Then, based on its evaluation of the response, the sponsor could conduct a second, binding open season containing information sufficiently detailed to permit prospective shippers to enter into binding precedent agreements.

58. To accommodate these situations, the NOPR provided that the sponsor would be required to include the listed information in the notice of open season "to the extent that such information is known or determined at the time the notice is issued."²⁰ Additionally, in order to level the playing field for all potential open season participants, the NOPR required that the sponsor include in the open season notice "[a]ll other information that may be relevant to the open season, including information pertaining to the proposed service to be offered, projected pipeline capacity and design, proposed tariff provision, and cost projections, made available to or in the hands of any potential shipper, including any affiliates of the project sponsor and any shippers with pre-subscribed capacity, prior to the issuance of the public notice of open season."²¹

²⁰ NOPR, proposed § 157.34(b).

²¹ *Id.*, § 157.34(b)(17).

59. Several commenters, including Anadarko, MidAmerican/AGTA, the North Slope Producers, Alliance, and Enbridge found the NOPR's listed information to be generally sufficient to provide prospective shippers the information needed to decide whether they to make binding, long-term commitments to purchase capacity on an Alaska natural gas transportation project. However, several aspects of the NOPR's informational requirements drew the attention of these commenters.

60. Anadarko and Shell state that limiting the sponsor's obligation to provide the information listed in the NOPR only "to the extent that such information is known or determined at the time the notice is issued" creates a loophole, and this qualifying language should be deleted from the regulations. According to Anadarko and Shell, a pipeline could avoid providing certain vital information simply by claiming that the information was not yet known or by holding the open season prematurely. These commenters state that the open season regulations should require that for any binding open season, pipelines include all the listed information in the notice. While certain physical characteristics of the pipeline will not be known until the pipeline is built, the pipeline can include in the notice the information upon which the open season proposal is based.

61. Alliance suggests that the Commission could reduce the risk of any dispute over the adequacy of the information contained in the notice by making clear that the information contained in the notice does not have to reflect the finalized positions on all elements at the time of notice of open season, and that a notice will not be invalidated by the absence of certain information. Additionally, Alliance recommends that the sponsors should be allowed to modify and update elements of their open season proposal if such modification is acceptable to prospective shippers. Alliance claims that this approach was useful in its own open season. MidAmerican/AGTA, on the other hand, feels that the above-mentioned qualifying language was reasonable.

62. However, MidAmerican/AGTA, together with the North Slope Producers and TransCanada, state that the catchall provision requiring "all other information that may be relevant..." is too broadly written. These commenters fear that the provision might be abused by those seeking either to delay the process or to obtain proprietary information. The North Slope Producers are also concerned over protecting proprietary or commercially sensitive information. They contend that this catchall provision is not in line with the Commission's policy against burdensome disclosure of commercially sensitive information. The North Slope Producers state that a notice containing the other sixteen types of information listed in the proposed regulations already provides more information than has been historically shared with shippers.

63. A number of comments on the proposed informational requirements focus on the need or desirability of including information that would inform all proposed shippers with respect to the expandability of the proposed project. Many commenters express, at one point or another in their comments, and all commenters implicitly agree, that it is extremely important to determine the original sizing and future expandability of an Alaska natural gas transportation project, as it will likely be the only pipeline built for the foreseeable future to transport Alaska natural gas for delivery to markets in the lower 48 states. Alaska, Calpine, and the Alaska Legislators all state that more information in the open season is needed to achieve optimal project design parameters. Alaska has proposed language to be included in the final regulations which includes feasibility and estimated cost of pipeline expansions, either through compression or looping, including any physical limitations.²² Calpine also states that the notice of open season should contain information on the expandability of the project's design capacity, including the design capacity per stage of each expansion and method of achieving expansions, and that rate estimates should cover rates for expansion stages (calculated on a rolled-in basis).

64. The North Slope Producers request that the Commission clarify that proposed section 157.34(b)(6) does not require that capacity must be awarded on an MMBtu basis. Their argument is that, because the gas transported may include higher-Btu components, such as ethanes, which will not ultimately show up as natural gas, Btu-based rates would be unfair. Instead, they state that capacity on an Mcf basis is typical for similar pipelines.

65. ANGDA contends that the open season information should include design requirements for two major gas trunkline interconnect points in Alaska. ANGDA adds that a single tariff clearly would unduly discriminate against intrastate Alaska shippers.

66. Looking beyond the initial open season, Alaska and Alaska Legislators address in their comments additional information requirements needed for potential shippers to evaluate either their own expansion needs or whether there is sufficient demand to support an economic expansion of an Alaska natural gas transportation project. Alaska asserts that in addition to the expanded information it proposes for initial expansions, a notice of open season for expansion capacity should also include specific information identifying the location of the natural gas reserves to which the pipeline relates, although

²² See Alaska's December 17 Comments, at Appendix, Proposed Open Season Regulations, § 157.34(a)(5)(ix).

Alaska would permit the pipeline to seek a waiver of any expansion information requirement it considers to be inapplicable. Alaska also states that the regulations should provide that any voluntary expansion design must either accommodate the capacity requests of all open season expansion bidders which are able to satisfy the Pipeline's creditworthiness requirements and willing to execute firm transportation agreements of reasonable duration at maximum recourse rates or demonstrate what technical or economic factors prevent such a design.

67. Alaska Legislators claim that ongoing collection and publication by the pipeline of real-time information necessary for non-pipeline owners to evaluate on an ongoing basis the potential for pipeline expansions is required. Alaska Legislators suggest alternative methods of accomplishing this. Either the pipeline should conduct periodic, non-binding open seasons, or it should maintain a publicly- available log or queue of capacity requests. In all events, Alaska Legislators state that the Commission should also require that the pipeline keep a regularly-updated schedule on its website that includes: (1) good faith estimates by the pipeline operator as to the possible and probable expansion increments to at least twice the original design capacity of the then-existing pipeline; (2) pipe characteristics of the then-existing pipeline, including wall thickness, diameter, and metallurgy; (3) compressor descriptions (manufacturer and model number, site rated horsepower and capacity, suction and discharge pressure and milepost locations of all existing and planned or prospective compressor stations); (4) an elevation profile of the then-existing pipeline; (5) known limitations on potential receipt and delivery points and a good-faith statement as to the bases for those limitations; (6) any other known limitations that would constrain or preclude expansions and a good-faith statement as to the bases for those limitations; and (7) any other expansion-related information of whatever nature which the pipeline owners or operators have made available to potential shippers (including any producing affiliates).

68. DOI states that the Commission should not allow decisions regarding the timing of open seasons to be left to the sole discretion of the pipeline and its affiliates. Instead, DOI requests that the Commission establish procedures for conducting future non-discriminatory open seasons that are reasonably responsive to ongoing exploration and development activities.

69. The Commission did not intend to provide project sponsors with a reason not to provide necessary information by qualifying their obligation to provide information in the open season "to the extent that such information is known or determined at the time the notice is issued." As noted above, this qualification was intended to recognize that a potential Alaska pipeline project applicant might find it necessary or appropriate to initiate an open season before some of the information can be determined. As an example, the Commission described in the NOPR a situation where a prospective project sponsor first conducts a non-binding open season in order to gather information and

assess demand, and thereafter, based on its evaluation of the response, conducts a second, binding open season containing information sufficiently detailed to permit prospective shippers to enter into binding precedent agreements.

70. The Commission's thinking at that time was that the open season rules would apply to "non-binding" open seasons, and the above qualification would have utility in such a situation. However, we understand that it may be difficult to draw distinctions between a "non-binding" open season and some other process of assessing interest in or need for capacity to assist the project sponsor in preparing a binding open season notice. Therefore, we are clarifying in the final rule that the open season regulations apply only to open seasons for binding commitments for capacity. The Commission sees no utility or need in imposing the full array of these open season regulations on activities leading up to a binding open season. There are adequate protections built into the open season rules, including the obligation to disclose information, to address any discriminatory and preferential practices through the Commission's oversight and enforcement capabilities.

71. Nonetheless, we understand that optimal design requirements are achieved as a result of an open season and not in advance of it, and we still foresee the possibility that a potential project sponsor might find it necessary or appropriate to conduct an open season before all the information required to be contained in the open season notice can be determined. Therefore, we will clarify in the final rule that the notice of open season must contain at a minimum, a good faith estimate based on the best information available of all items of required information and that the project sponsor must identify the source of information relied on, explain why such information is not presently known, and update the information when and if it is later determined during the open season period.

72. The Commission is also modifying proposed section 157.34(b)(17)²³ to address concerns that, as proposed, the regulations might be used to seek the disclosure of proprietary or commercially sensitive information. The purpose of the information-sharing requirement is to make sure that all interested parties are equally informed on matters essential to their decision whether to bid for capacity on the proposed project, with an eye toward leveling the playing field between affiliated shippers or others with prior knowledge of information to be contained in the open season notice and all other potential shippers. Between the specific information identified in proposed section

²³ See § 157.34(b)(18) of the final rule.

157.24(b)(17), namely, information pertaining to the proposed service to be offered, projected pipeline capacity and design, proposed tariff provision, and cost projections, and all the items of information enumerated in 157.34(b), the Commission has, in essence, defined the information that all shippers will need to participate in an open season for capacity on an Alaska natural gas transportation project. Accordingly, we will delete the reference to "all of information that may be relevant."

73. However, following review of the comments, the Commission is concerned that the informational requirements of section 157.34(b) alone might not be sufficient to prevent the possibility of discrimination by a project applicant in favor of an affiliate of that applicant. The Commission's goal is to prevent unduly discriminatory behavior and limit the ability of a project applicant to unduly favor its affiliate.

74. Therefore, in order to further the Commission's goal of a non-discriminatory open season, the Commission is applying certain of the Standards of Conduct requirements of Order No. 2004²⁴ to all project applicants conducting open seasons for an Alaska natural gas transportation project because this will minimize the risk that an affiliate of a project applicant would have an advantage over non-affiliates in obtaining capacity through the open season. The Commission is requiring project applicants to create/designate a unit or division to conduct the open season. The unit or division will be required to function independent of the other non-regulated divisions of the project applicant as well as the project applicant's Marketing and Energy Affiliates and subject to certain provisions of the Standards of Conduct. Specifically, the following provisions of Order No. 2004 will apply to project applicants conducting an open season: separation of functions (18 C.F.R. §§ 358.4(a)(1), (3), (4), (5) and (6) and (b)(e)(3),(5) and (6) (2004)); information access

²⁴ *Standards of Conduct for Transmission Providers*, Order No. 2004, FERC Stats. & Regs., Regulations Preambles ¶ 31,155 (2003), *order on reh'g*, Order No. 2004-A, III FERC Stats. & Regs. ¶ 31,161 (2004), 107 FERC ¶ 61,032 (2004), *order on reh'g*, Order No. 2004-B, III FERC Stats. & Regs. ¶ 31,166 (2004), 108 FERC ¶ 61,118 (2004), *order on reh'g*, Order No. 2004-C, 109 FERC ¶ 61,325 (2004) (Order No. 2004). Under Order No. 2004, for a natural gas pipeline Transmission Provider, the Standards of Conduct requirements do not apply until 30 days after the Commission issues a certificate allowing a project applicant to commence construction of an interstate natural gas pipeline.

(18 C.F.R. § 358.5(a) (2004)); information disclosure (18 C.F.R. § 358.5(b) (2004)); prohibitions against discrimination (18 C.F.R. 358.5(c)(5)(2004)) and discounts (18 C.F.R. § 358.4(d)(2004).

75. Under section 358.4(a)(1) of the Commission's regulations, the transmission function employees of a transmission provider must function independent of the transmission provider's Marketing affiliate or Energy Affiliates' employees. The employees who are part of the unit/division conducting the open season will be treated as transmission function employees and must function independently. Applying the separation of functions requirement would entail that employees of a project applicant who are involved in the open season may not also perform duties for the Energy Affiliates or Marketing Affiliates (as defined in 18 C.F.R. §§358.3(d) and (k) (2004)) of that project applicant. This would prevent Energy Affiliates of the project applicant who participate in the open season from having the advantage of information or strategy that non-affiliated open season participants do not have.

76. The applicable exemptions from the separation of functions would also apply to permit the project applicant to share various categories of employees, including: support, field and maintenance employees (section 358.4(a)(4)); senior officers and directors who are not "Transmission Function Employees" (as defined by 18 C.F.R. § 358.3(j)), provided that they do not participate in directing, organizing, or executing transmission system operations or market functions or act as conduits for sharing prohibited information with a Marketing or Energy Affiliate (Section 358.4(a)(5)); and risk management employees who are not engaged in transmission functions or sales or commodity functions.

77. Consistent with section 358.4(e)(3) of the Standards of Conduct, the Commission will require each project applicant to post on its internet website its written procedures describing how it comply with the applicable provisions of Order No. 2004. The Commission also will require each project applicant to train its employees involved in the open season or part of the open season unit/division, officers, directors and employees with access to transportation information or information concerning gas purchases, sales or marketing functions under section 358.4(e)(5). The project applicant must also designate a Chief Compliance Officer who will be responsible for Standards of Conduct compliance, as required by section 358.4(e)(6). In order to reduce the burden on project applicants, the Commission will not apply some of the posting requirements of Order No. 2004 to the open season (e.g., posting organizational charts and transfers of employees). However, project applicants must be able to verify that they have followed the organizational separation requirements.

78. The application of the information access (18 C.F.R. § 358.5(a)) and disclosure (18 C.F.R. § 358.5(b)) requirements will ensure that employees of Marketing/Energy Affiliates participating in the Open Season would not have access to any transmission information that is not publicly available to non-affiliated participants and require that any disclosure of non-public transmission information to a Marketing/Energy Affiliate be immediately disclosed to all other actual and potential open season participants by posting that information on the project applicant's internet website. *See* 18 C.F.R. § 358.5(b)(3). The requirements for written consent before releasing non-affiliated customer information to a Marketing or Energy Affiliate and posting that consent on the Internet would also apply for project applicants. *See* Section 358.5(b)(4).

79. The application of some of the non-discrimination requirements of Order No. 2004 will broadly prohibit discrimination by a project applicant conducting an open season and limiting its ability to unduly favor a Marketing/Energy Affiliate. The applicable non-discrimination provisions include: (1) section 358.5(c)(3), which requires a Transmission Provider to process all similar requests for transmission in the same manner and within the same period of time; and (2) section 358.5(c)(5), which prohibits transmission providers from giving their Marketing or Energy Affiliates any preference over any other wholesale customer in matters relating to the sale or purchase of transmission service. In the context of an open season, these provisions ensure a project applicant will not provide any preferences to affiliated participants.

80. Finally, the application of the discount provision of Section 358.5(d), which requires a Transmission Provider to post an offer of a discount for transmission service at the time an offer is contractually binding, will ensure the transparency of the open season process and discourage undue preferences. We note that if an offer of a discount becomes contractually binding through the execution of a precedent agreement, the offer must be posted at that time, not at the time of the final agreement.²⁵

81. Applying many of the functional separation, information access, disclosure and non-discrimination provisions of Order No. 2004 to this open season process will ensure that it is conducted in a manner that is non-discriminatory and provides equal access to all participants, particularly those not affiliated with the project applicants. If during or following the open season the Commission determines that the project applicant has violated the terms of the Order No. 2004 requirements that we are making applicable to

²⁵Order No. 2004-A, III FERC Stats. & Regs. ¶ 31,161 at p 227.

the open season, the results of the open season with regard to the Energy Affiliates of that project applicant may be voided and a new open season held for that capacity.

82. As noted above, a number of commenters discuss the need for or desirability of requiring disclosure of information relevant to the expandability of the project, both as proposed and on an ongoing basis. In overseeing the open season process and in processing and application for a certificate or other authority to construct and operate an Alaska natural gas transportation project, we will require that every reasonable effort be made to design a project that meets current needs for capacity, and accommodates future needs for capacity through low-cost expansion. The information identified in section 157.34(b)(2), together with the design and engineering information required as part of any application for a certificate, should be sufficient to reasonably inform all interested parties on matters involving the expandability of the project.

83. As noted above, we are providing that the open season information include an assessment of in-state needs, based to the extent possible on any available study performed by Alaska, and a listing of prospective delivery points within Alaska. Moreover, we are requiring that a proposed in-state transportation rate, based on the costs of providing that service, also be included. This should address ANGDA's contention that the open season information should include design requirements for two major gas trunkline interconnect points in Alaska and that a single tariff clearly would unduly discriminate against intrastate Alaska shippers.

84. Also as noted above, the North Slope Producers request that proposed section 157.34(b)(6) clarify that it does not require that capacity must be awarded on an MMBtu basis. The Commission clarifies that this provision was intended to be a mandate that rates for an Alaskan pipeline will eventually have to be stated on a thermal basis, as is long-standing Commission policy. However, the Commission understands that at this stage of project development for an Alaskan pipeline, it will be significantly more complex for project sponsors to estimate rates and award capacity on that basis given the unique features of this project. Thus during the open season process, capacity may be described and rates may be estimated on a volumetric basis. However, as was the case in the two orders cited by the North Slope Producers,²⁶ the Commission has found that pipelines can meet the Commission's objectives concerning the statement of rates on

²⁶ Alliance Pipeline L.P., 84 FERC ¶61,239 (1998); *Kern River Gas Transmission Co.*, 79 FERC ¶ 61,299 (1997).

a thermal basis by proposing methods of rate adjustment at a later time. If during the open season process, a project sponsor chooses that capacity will be described and has its rates estimated on a volumetric basis, then it must notify bidders that final pro forma service agreements and the sponsors proposed tariff will have to be submitted with rate calculated on a thermal basis.

iii. Open Season Bid/Capacity Allocation Methodology

85. As stated above, the NOPR required that the notice of open season contain a detailed methodology for determining the value of bids,²⁷ and the methodology by which capacity will be awarded in the case of over-subscription, clearly stating all terms that will be considered, including price and contract term.²⁸ In addition, the NOPR required that capacity allocated as a result of any open season be awarded without undue discrimination or preference of any kind.²⁹

86. The North Slope Producers contend that the combination of the mandatory non-discrimination/undue preference standard contained in the NOPR's section 157.35, the information disclosure requirements of section 157.34 (b), and section 157.33's provision that any application for a certificate of public convenience and necessity for a proposed Alaska natural gas transportation project must show that the applicant has conducted an open season for capacity in accordance with the open season rules fulfills the Commission's responsibilities under the Act to establish the criteria for conducting an open season, including the procedures for the allocation of capacity. Northwest Industrials, TransCanada, MidAmerican/AGTA, and the AGA all agree that the NOPR's proposed rules are appropriately flexible and provide a reasonably fair and open process that is consistent with the Act's directives.

87. The North Slope Producers stress that the most important, and first step to promoting competition in the exploration, development and production of Alaska natural gas is to get the Alaska natural gas transportation project built. They maintain that the Commission's current policies of allocating capacity in an open season to customers who

²⁷ FERC Stats. & Regs., Proposed Regulations, ¶ 32,577(2004), §157.34(b)(13).

²⁸ *Id.*, §157.34(b)(14).

²⁹ *Id.*, §157.35.

value it most, and of favoring net present value (NPV) as a basis for awarding capacity will ensure that capacity will be awarded in a non-discriminatory and economically efficient manner. The North Slope Producers assert that through these policies, pipelines and shippers will also be assured that only capacity that is supported by the market and that is economically viable will be constructed.

88. Additionally, the North Slope Producers assert that based on preliminary assessments, there will be enough initial pipeline capacity to accommodate all near-term production from other producers and explorers, in addition to all production from Prudhoe Bay and Point Thomson. Specifically, they state that it will require 50 Tcf of gas to keep a 4 to 4.5 Bcf pipeline full for 30 years. Moreover, the North Slope Producers expect that any Alaska pipeline will be designed to be economically expandable to 6 Bcf/d, which would accommodate an additional 15 Tcf over 30 years.

89. At the same time, the North Slope Producers contend that while it is in a pipeline's interest to build a pipeline designed to carry all the gas shippers are willing to pay to transport, the costs of unused new capacity imposes certain limitations on just how much initial capacity the pipeline can build for a project to be economically viable. In response to suggestions made at the technical conference that, regarding capacity allocation in the event of oversubscription, small shippers should be favored, the North Slope Producers argue that any preferential capacity allocation methodology would be discriminatory, anti-competitive, and contrary to the NGA. The North Slope Producers state that shipper support for the project could be adversely affected if prospective shippers thought their commitments could be reduced. Moreover, they claim that any such undue preference or discriminatory treatment to particular shippers or sources of gas is unnecessary since an expansion under section 105 of the Act is available as a backstop for any shipper.

90. On the other hand, a number of comments are critical of the Commission's approach to addressing bid evaluations and allocation of capacity as represented in the NOPR. Pacific Star, Alaska Legislators, Shell, ChevronTexaco, Anadarko, Alaska, Calpine, Arctic Slope, Alaska Venture Capital/Brook Range, and Doyon all fault the Commission for not taking a pro-active approach in developing the capacity allocation methodologies, and instead leaving it to the pipeline to develop them. These commenters contend that Congress specifically instructed the Commission to detail the criteria to be used in awarding capacity, and to do so in a manner which will promote competition in exploration, development and production of Alaska gas.

91. In the NOPR, the Commission required that the notice of open season contain a detailed methodology for determining the value of bids,³⁰ and that capacity allocated as result of any open season be awarded without undue discrimination or preference of any kind.³¹ We do not read section 103 of the Act to require that we define the methodology with the precision urged by those commenters who advocate a prescriptive regulatory approach. We remain confident, even more so now that we have the expanded scope of the regulatory text prohibiting undue discrimination and undue preference, that the regulations being promulgated in this order fully comply with the directives as well as the intent of the Act. Although the Commission is permitting prospective applicants the flexibility to establish the details of the bid evaluation methodology, any such methodology must meet the criteria imposed in this rule prohibiting undue discrimination, and it is the Commission, not the pipeline applicant who will apply that criteria to any open season claimed not to be in compliance with this rule. In this regard, the Commission notes that NPV has been the standard, but not required, methodology for evaluating bids in open seasons under current Commission policy. Although we are not mandating that methodology here, we will examine carefully any methodology that varies from those heretofore approved by the Commission to ensure that such variations respond to the unique circumstances of an open season for an Alaska project, and that they do not discriminate against any shipper or class of shippers in the evaluation of bids. We will now address specific issues.

a. Caps on contract terms

92. The Alaska Legislators, ChevronTexaco, Alaska, Anadarko, and Calpine all urge the Commission to establish some uniform cap on the term by which, under the NPV methodology, bids are evaluated. Calpine, for instance, proposes that the contract term for purposes of bid evaluation be 30 years. Anadarko states that any bid term or other terms and conditions that are difficult, if not impossible, for all but a few preferred shippers to meet, should be prohibited if they are not critically required to secure financing. Accordingly, Anadarko proposes a bid cap of 20 years or the length of the financing instrument. Chevron Texaco and Alaska concur that a 20-year cap would be appropriate.

³⁰ *Id.*, §157.34(b)(13).

³¹ *Id.*, §157.35.

93. The Alaska Legislators also argue that a uniform cap should be placed on the term by which bids are evaluated. Although they do not have a specific cap term in mind, they claim that the Commission should impose some bid evaluation to prevent the major producers from bidding unduly long contract terms in order to squeeze out competitors. Recognizing that previous efforts by the Commission to limit the duration of contracts awarded in Tennessee Gas Pipeline Company's open season did not survive judicial scrutiny, Alaska Legislators state that the circumstances surrounding an open season for an Alaska natural gas transportation project are quite different from the circumstances associated with Tennessee, a pipeline in the lower 48 states. These distinctions, they assert, satisfy the concerns that the Court had in *Process Gas Consumers Group v. FERC (Process Gas)*.³²

94. The Alaska Legislators point out that in the case of an Alaska natural gas transportation project open season, it would be the bid evaluation that is being limited, not the contract term itself, as was the case in *Process Gas*. Second, they assert that the parties in *Process Gas* were debating the duration of the cap, not the need for any cap to counter affiliates' attempts to obtain capacity through unjustifiably long bids. Third, they say, the Commission, on remand, concluded that open season caps in Tennessee's tariff were not required to protect captive customers because market forces dictate that pipelines have greater incentive to build new capacity to serve all demand, than to create scarcity by withholding capacity. On this point, Alaska Legislators contend that monopoly forces rather than market forces control the climate in Alaska, and that a producer-owned pipeline would indeed be disinclined to assist competing producers by affording them capacity on the pipeline.

95. The Commission is not persuaded that any cap on contract term bids is necessary or appropriate at this time. Other than general concerns of affiliate abuse, the comments have provided no factual predicate which would warrant the Commission to deviate from current Commission policy, which is to not impose limits on bid terms. However, the Commission will be reviewing the results of any open season processes to determine the appropriateness of any unusually long contract terms (*e.g.*, a term exceeding the projected life of the pipe) to determine whether shippers incorporated them in their bids to obtain capacity allocation. For example, it would be in a prospective shipper's economic interest to seek a contract term that would be sufficient to allow the recovery of its revenues. However, it would not be in a shipper's economic interest to bid for capacity

³² 177 F.3d 995 (D.C. Cir. 1999).

beyond its projected reserve's life because it would expose the shipper to reservation charges it may not be able to recover.

b. In-state capacity bids

96. The Alaska Legislators state that bids for in-state capacity, with lower NPV as a consequence of mileage-based rates, cannot fairly compete with bids for transportation over the full length of the pipeline. Consequently, in order for bids for Alaska deliveries to compete with deliveries to the lower 48 states, Alaska Legislators contend that the final open season rules should contain a mileage-based multiplier to bids for in-state capacity. Alaska Venture Capital also recognizes this potential problem, but offers no solution other than calling on the Commission to address the problem with specific rules.

97. Concerns over length-of-the-pipe versus in-state bids are misplaced in the context of NPV for a new pipeline such as any Alaska natural gas transportation project. The primary purpose of the open season process is to determine the appropriate size of the initial pipeline. In-state capacity bids will not result in stranded capacity, as can be the case with capacity sales on an existing pipeline. We agree with the Alaska Legislators. The purpose of the in-state capacity bids will be to determine whether and to what extent there is interest in developing a telescoped pipeline to service Alaskan needs in the initial capacity allocation. The revised regulations require that the open season include an estimated transportation rate for in-state deliveries, as well as a methodology for determining the value of bids for in-state deliveries and for deliveries outside of the State of Alaska.

98. Other topics raised in the comments include Anadarko's suggestion that prepayments are unnecessary since the pipeline sponsor may already be the recipient of an \$18 billion loan guarantee. Anadarko also claims that since prepayments would be much less burdensome to the major North Slope producers than to others, they are unduly preferential and should be prohibited. ChevronTexaco requests that the regulations expressly provide that, in the event more than one sponsor group conducts an open season for an Alaska natural gas transportation project, bidders may bid on the competing proposals. Calpine adds that bids should not exceed the amount of the proposal's design capacity, and that affiliates should be prohibited from making multiple bids, so that there is only one bid from each entity.

99. Although the loan guarantee under the Act will certainly facilitate the sponsor's ability to obtain financing, it cannot be said that such guarantee obviates the need for creditworthiness standards or prepayment requirements where reasonably necessary. Consequently, we will not prohibit prepayments as urged by Anadarko. Such standards must be included in the information contained in the notice, and as such, are subject to the requirement that there be no undue discrimination or undue preference in the terms or

conditions of service. ChevronTexaco's request that the regulations expressly provide that, in the event more than one than one sponsor group conducts an open season for an Alaska natural gas transportation project, bidders may bid on the competing proposals is a reasonable one. We have included appropriate language in the regulations. Finally, the Commission takes note of Calpine's requests regarding limitations on the amount of capacity bid and multiple bids from affiliates. Although we are not prohibiting all such bids, we will examine closely any such bids to determine whether they are soundly based on satisfying the legitimate needs of the bidder, or whether they are made to "game" the open season process.

c. Capacity allocation in case of oversubscription

100. On the subject of allocating capacity in the event qualified bids for capacity exceed the amount of design capacity, a number of comments fault the Commission for not proposing requirements that will encourage exploration and development for yet to be discovered Alaska gas resources. This group includes Pacific Star, the Alaska Legislators, ChevronTexaco, Alaska Venture Capital/Brook Range, Alaska, Anadarko, Shell and Doyon. Consistent with their view that the Commission must take a pro-active approach and adopt detailed rules regarding critical elements of open season, Alaska Legislators contend that the rules governing capacity allocation in the event of oversubscription must provide that small shippers will not be subject to proration. Alaska Legislators claim that a pro rata basis of capacity allocation is not appropriate for an Alaska pipeline, especially a producer-owned pipeline. They assert that the producers' control over the pipeline must be countered by regulations favoring access to capacity by multiple, smaller-volume shippers over single, large-volume shippers. Alaska Legislators state that by providing as many shippers as possible all of the capacity they request, those with market power will be encouraged to ensure that there is enough capacity for their requirements as well.

101. ChevronTexaco claims that in order for any open season to be fairly and reasonably conducted, any project that is too small to accommodate all nominated volumes should be redesigned, if possible. ChevronTexaco states that if the project cannot be redesigned upward, the next step would require that the bidders prove their access to gas supply to support their bids. After that, any unsupported bids would be allocated on a pro rata basis. Doyon also recommends as a first step that the sponsor upwardly revise the project's proposed capacity to accommodate all, and if it cannot be done, all shippers would receive a pro rated minimum volume of capacity. Similarly, Anadarko suggests that in case of oversubscription, the sponsor should either revise upward the proposed capacity to accommodate all shippers or the pipeline should be required to prorate capacity requests in a manner that does not disproportionately affect those shippers who do not have pre-subscribed capacity. Finally, Alaska states that the Commission should require that all bids for 20 or more years at the maximum rate be

treated equally and pro rated if necessary. If all such bids can be accommodated but bids under 20 years cannot, then NPV should be applied to award capacity to those bidders.³³

102. Just as the Commission required that the notice of open season contain a detailed methodology for determining the value of bids, the Commission also required in the NOPR that the prospective applicant state the methodology by which capacity will be awarded, clearly stating all the terms that will be considered,³⁴ and that capacity allocated as a result of any open season be awarded without undue discrimination or preference of any kind.³⁵ Our justification and reasoning in support of our approach to establishing criteria for purposes of bid evaluation applies here as well. Moreover, to further meet the concerns expressed by parties who are worried about obtaining access to an Alaska pipeline, we have added new sections 157.36 and 157.37, which make clear that the Commission will examine proposed pipeline designs, as well as expansion proposals, to ensure that all interested shippers are given a fair opportunity to obtain capacity both on an initial project and on any voluntary expansion. As stated elsewhere in this order, we believe it is in both the sponsor's and shippers' best interests to build the pipeline to accommodate all qualified shippers who are ready to sign firm agreements. We will carefully review project design and the documentation relating to the allocation of capacity, with the goal of promoting our open access and pro-competition policies.

F. Prefiling Procedures

103. Another specific issue on which the Commission sought comment was whether it should require that prospective applicants for Alaska natural gas transportation projects, before conducting open seasons, file with the Commission proposals for how the open seasons will be conducted. If so, the Commission asked whether the proposals be filed for notice and comment, or for a decision or pre-determination by the Commission that

³³ See Alaska's comments, Appendix at § 157.34(a)(3). As noted *infra*, Alaska also urges that the regulations include a requirement that a sponsor must justify in its application the technical or economic factors that prevented it from designing the project to accommodate all qualified bidders.

³⁴ See FERC Stats. & Regs., Proposed Regulations, ¶ 32,577(2004), § 157.34(b)(14).

³⁵ *Id.*, § 157.35.

such proposals conform to the regulations. The Commission concluded its inquiry on this subject by inviting suggestions on what other procedures would be suitable to facilitate the expeditious resolution of objections or concerns regarding any open season for an Alaska natural gas transportation project.

104. The majority of commenters who addressed the subject of requiring that all open season proposals be pre-filed with the Commission were of the opinion that such a requirement is unnecessary and could potentially delay or disrupt the whole open season process. MidAmerican/AGTA and TransCanada propose that, instead, the sponsor should have the option of requesting Commission preapproval, adding that such option should include a 45-day comment period. ChevronTexaco prefers that instead of mandatory prefiling requirements, sponsors should be free to seek informal guidance from the Commission. Neither Alliance, nor Anadarko, nor the North Slope Producers supports any advance pre-approval filing requirement or procedure.

105. Alaska, on the other hand, believes that it is better to resolve any disputes involving the open season process beforehand. To accomplish this, Alaska proposes that the entire proposed open season package be filed with the Commission three months prior to opening date, and the Commission should notice the filing for comments prior to a Commission determination on the sufficiency of the open season notice.

106. Anadarko, ChevronTexaco, Alliance, Enbridge, the North Slope Producers, and MidAmerican/AGTA all stress the need for some form of dispute resolution during the opens season process. Anadarko states that the open season rules should specify that the Commission's Fast Track Processing (18 C.F.R. § 385.206(h)) will apply to all complaints regarding non-compliance with open season regulations. Moreover, Anadarko maintains that the open season process should be suspended during pendency of the fast track complaint procedures in order to preserve the complainant's rights to acquire capacity. MidAmerican/AGTA and Alliance also refer to the Commission's Fast Track procedures as well as the Enforcement Hotline as useful, available procedures for resolving open season complaints. In addition to expedited complaint procedures, ChevronTexaco states that open season disputes could be resolved by way of a declaratory order.

107. ChevronTexaco also states that the Commission should consider imposing Standards of Conduct-like requirements, such as guidelines for interstate transporters in Order No. 2004. Enbridge and the North Slope Producers are also satisfied that the Commission's existing procedures are sufficient to expeditiously resolve and complaints or disputes over the open season process. Alliance asserts that the best way to address disputes is to minimize them through clear and unambiguous, yet flexible, rules.

108. DOI believes that some form of oversight is needed and suggests that all proposals be filed and publicly reviewed by the Commission or other independent regulatory group. DOI states that the proposed rules are vague and some process should be developed to modify the rules to accommodate changing circumstances in the future as they may arise.

109. On balance, we conclude that it is in the public interest to require pre-approval of open season procedures. This will allow issues to be identified and resolved at the earliest possible time, and, ideally, reduce the possibility of dissatisfaction with open seasons, as well as the risk that the Commission will have to require that deficient open seasons be conducted again. Therefore, the regulations will require that project proponents file open season plans for Commission approval.

110. As detailed above, various approaches to resolving disputes over the open season process are suggested. On review, the Commission believes that its current processes and procedures, combined with the pre-approval requirement, are sufficient to resolve any disputes arising out of the open season process, and in light of the sense of urgency expressed in the provisions of the Act, the Commission is providing in the final rule that any complaints alleging non-compliance with this subpart shall be processed under the Commission's Fast Track procedures.³⁶ However, the Commission does not find it necessary or appropriate as a rule to suspend the open season process during pendency of a Fast Track complaint in order to preserve the complainant's rights to acquire capacity, as requested by Anadarko. The Commission anticipates that in most cases that might arise, the project sponsor will be able to comply with a Commission order directing that it provide the capacity requested by a prospective shipper who is found to be entitled to capacity. However, just as we will not require that the open season be suspended, nothing in this rule prohibits a complainant from requesting, or the Commission granting, such relief if necessary.

³⁶ See 18 C.F.R. § 385.206(h)(2004). Normally, Fast Track complaint processing must be requested and supported by an explanation why expedited processing is required. The Fast Track procedures include expedited filing of responsive pleadings, an order spelling out the schedule and procedures to be followed, including expedited action on the pleadings, an expedited hearing before an administrative law judge, or expedited action on any particular relief sought.

G. Rate Treatment for Expansions

111. As noted above, one of the issues that received substantial attention in the pre-NOPR comments is whether the Commission should require rolled-in rate treatment for Alaska pipeline expansions. Although the NOPR's proposed regulations are silent on this subject, the NOPR requested comment on whether, in the event the Commission issues regulations with respect to the Commission's authority to require expansion of any Alaska natural gas transportation project, those regulations should address the rate treatment (rolled-in or incremental) of any such expansion.

112. Other than the North Slope Producers and Alliance, there is much support for rolling-in the costs of both voluntary and involuntary expansions, although there is disagreement about when the issue should be resolved. ChevronTexaco states that the subject of appropriate rate treatment for expansions is a subject deserving of substantial, detailed consideration that should be addressed after dealing with the more pressing task of issuing the open season rules. Northwest Industrial Gas Users also believes that the issue can be addressed later. Alaska agrees that expansion pricing is a complex subject that should be examined thoroughly, and asserts that instead of addressing the issue in this rulemaking, the Commission should issue a notice regarding expansion rate treatment for Alaska natural gas transportation projects in early 2005. Alaska observes that the arguments in support of rolled-in pricing are strong, but suggests that rolled-in pricing might not be appropriate in all circumstances. Alliance believes that because the appropriateness of rolled-in or incremental rate treatment for any expansion should be made on a fact-specific basis, and not by rule that predetermines, before the circumstances of a given expansion are even known, how that expansion should be priced.

113. Pacific Star and Alaska Venture Capital state that the Commission should give an early indication that it will support rolled-in rates for expansions of any Alaska natural gas transportation project. Pacific Star states that it agrees with the statement at the technical conference by TransCanada, ANGDA, Anadarko, BLM, and MMS that rate uncertainty will discourage exploration and development and that expansions of the pipeline could present widely varying rate consequences. Pacific Star also states that concerns over existing shippers' subsidizing rolled-in expansions should be weighed against the facts that initial shippers are benefiting from substantial subsidies through the \$18 billion loan guarantee and a 7-year accelerated depreciation. Alaska Venture Capital/Brook Range similarly believes that the Commission should give an early indication that it will support rolled-in pricing under scenarios outside the Commission's existing policy, under which the Commission approves rolled-in rates only where the rolled-in rate is equal to or less than the existing recourse rate. According to Alaska Venture Capital/Brook Range, a policy calling for different rates for similar services

would place explorers and smaller producers at a competitive disadvantage. This would, in turn, discourage exploration and development of Alaska natural gas, contrary to the mandate of the Act.

114. TransCanada, MidAmerican/AGTA, and DOI encourage the Commission to adopt a rebuttable presumption favoring rolled-in rates. TransCanada states that any shippers concerned about the effect of such treatment can seek to avoid it through negotiated rates. MidAmerican/AGTA qualifies its support for this presumption by stating that the presumption should apply only to reasonably-engineered increments of mainline expansions supported by long-term contracts similar to those supporting the initial project. DOI states that rolled-in rate treatment is more equitable to future shippers, and that, because Canada has adopted rolled-in rates for expansions, it would provide rate consistency for the entire system.

115. Alaska Legislators, Anadarko, Shell, Calpine, Arctic Slope, and Doyon all contend that rolled-in pricing should be required for pipeline expansions. Alaska Legislators contend that incremental treatment for expansions would discriminate against expansion shippers who, merely because of the timing of their capacity needs, may pay higher rates than initial shippers. This, according to the Alaska Legislators, ignores the fact that the need for expansion is the consequence of the demands of all shippers. Alaska Legislators state that the Commission must balance the interests of the existing customers against interests of other stakeholders in determining whether or not pre-existing shippers should get the benefit of rate decreases for expansions that lower the average per unit cost of transportation, but face the possibility of rate increases that increase the average per unit cost of transportation. Alaska Legislators also note that the current Commission policy on expansion pricing was developed to address pipeline to pipeline competition, which will not arise in Alaska.

116. In addition to arguing that incremental rates operate to discriminate against expansion shippers, Alaska Legislators argue that the prospect of incremental rates will also act to reduce competition and impede the development of Alaska natural gas. Alaska Legislators state that exploration and development of Alaska reserves requires a long lead-time due to seasonal restrictions and the remoteness of the resource.³⁷ Alaska

³⁷ Alaska Legislators refers to a statement made at the technical conference by Jeff Walker, of DOI's Mineral Management Service that it takes at least nine years for an exploration project to mature into production.

Legislators contend that this long lead time makes it difficult for an explorer to judge when it is feasible to commit to capacity on the pipeline. The result, state Alaska Legislators, is that the explorers and developers may be deterred from investing the large sums required to drill for Alaska natural gas, when they are unsure whether their future capacity needs will be met at a time when inexpensive expansion through increased compression will be available, or whether the expansion they require would involve costly looping. The Alaska Legislators also argue that Canada has a long-standing policy of requiring rolled-in rates for expansions which could make exploration in Canada much more attractive to exploration and production companies.

117. Anadarko, also convinced that expansions under section 103 of the Act must be priced on a rolled-in basis, argues that this is critical to avoid a rate structure or policy that discriminates on the basis of time of entry onto the pipeline. Anadarko maintains that it is important to establish this requirement in the initial open season process in order to inform those prospective shippers that their rates might increase as expansions are rolled-in. Alaska Legislators provide a history of the Commission's expansion rate policy, varying over time in order to address different goals as deemed necessary to address changing market dynamics. In short, Alaska Legislators assert that the current Commission policy favoring incremental expansion rates seeks to address issues of competing pipelines, competitive markets, optimal construction, and protecting captive customers, all valid considerations of the market setting in the lower 48 states, but wholly inapplicable to an Alaska natural gas transportation project or the Alaska market. According to Alaska Legislators, the Act instructs the Commission, through its open season regulations, to focus on reducing barriers, not to competitive markets, but rather, to entry in exploration and development of Alaska natural gas. Alaska Legislators conclude that to achieve this mandated goal, the open season regulations must be revised to include rolled-in pricing as one of the criteria for open seasons for pipeline expansions

118. Shell and Calpine also argue that Commission's 1999 pricing policy for expansions has no application to the circumstances of an Alaska natural gas transportation project where there is no element of pipeline competition or preventing overbuilding. Shell is concerned that companies might not invest hundreds of millions in exploration and development costs if they may have to pay for expansions on an incremental basis, while competitors benefited from earlier, inexpensive expansion. Calpine stresses that since an Alaska natural gas transportation project will be called to transport all Alaska gas, not just gas from Prudhoe Bay and Point Thomson reserves, a larger picture is required in assessing any policy against subsidization. Calpine maintains that an Alaska pipeline should be viewed as a 10 Bcf/d pipeline that will be built, in phases, over time, as opposed to a 4.5 Bcf pipeline that might be expanded from time to time. Under this picture, shippers on the first phase facilities will benefit from lower initial rates due to the Act's loan guarantees, however the Act was not only concerned

with facilitating the development of a project that carries Prudhoe Bay and Point Thomson production to market, but also the development and transportation of Alaska's unproven reserves.

119. Arctic Slope is also concerned that unless rolled-in rates are mandated, there may never be an expansion of the pipeline beyond capacity created through infill compression and added compression horsepower. Arctic Slope estimates that rolled-in rates for expansions would probably be only a little higher than the initial rates since expansion costs would be borne by the entire pipeline throughput. However, the impact of incrementally-priced expansions on the incremental shippers, which would be based entirely on the incremental throughput quantities, would be very severe.

120. Alliance and the North Slope Producers assert that rates for expansion should be determined on a fact-specific, case-by-case basis, not on a pre-determined, rolled-in basis under the open season rules. The North Slope Producers stress that absent information regarding design, timing, and other project attributes, it would be inappropriate either to require or to favor rolled-in rates. In addition, the North Slope Producers point to section 105(b)(1) of the Act wherein, they state, Congress identified either rolled-in or incremental rates as appropriate for mandatory expansions. They add that if rolled-in rates were made applicable to voluntary expansions in the final open season rule, the result would be that such expansions would become involuntary and they would be discouraged.

121. Additionally, the North Slope Producers state that the Commission's existing, fact-specific policy recognizes the risks inherent in major infrastructure projects and seeks to prevent uneconomic pipeline expansions, as well as subsidization by existing customers, and should not be lightly discarded. Responding to the assertion that the NEB requires rolled-in rates for Canadian expansions, the North Slope Producers state that although NEB has adopted rolled-in rates in expansion cases, NEB addresses the issue on a case-by-case basis.

122. Finally, the North Slope Producers claim that explorers do not require absolute rate certainty in order to decide whether to participate in open seasons; an anticipated range that supports future economics is sufficient. On the other hand, the North Slope Producers state that initial shippers who fear that they may be called on to subsidize future shippers may not bid for initial capacity. In this connection, the North Slope

Producers contend that one of the Commission's goals is to protect captive customers from rate increases arising from costs unrelated to their service, resulting in rate uncertainty and increased contractual risk.³⁸

123. In this rule, the Commission does not adopt a firm pricing policy for future expansions of an Alaska natural gas transportation project, but we do take this opportunity to provide guidance on this important issue, as it will assist participants in the initial open season. We conclude that there should be a rebuttable presumption in favor of rolled-in pricing for project expansions. Our existing lower-48 states policy favoring incremental rates for expansions does not apply in the case of an Alaska natural gas transportation project. There is likely to be only one Alaska pipeline, so there will be little or no opportunity for competition between pipelines. Incremental pricing of expansion could put expansion shippers at a significant rate disadvantage compared with initial shippers, and accordingly could discourage exploration, development and production of Alaska natural gas. Having markedly different rates for similar service could be in conflict with one of the chief objectives of the statute, which is to encourage further exploration and development of Alaska natural gas. On the other hand, consistent with the arguments of a number of commenters, a presumption in favor of rolled-in pricing may spur investment in and development of Alaska reserves, and the ultimate delivery of that gas to the lower 48 states.

124. We cannot at this point, without a specific project proposal or the facts surrounding a proposed expansion before us, define exactly what will be required to overcome the presumption. As a general matter, we have historically not favored requiring existing shippers to subsidize the rates of new shippers. We do not intend to discard this principle, but rather to indicate that we will not lightly authorize expansion rates that would have an unduly negative impact on the exploration and development of Alaska reserves. Witnesses at the technical conference acknowledged that defining subsidization is difficult without specific facts to review, and that fact was restated in several of the comments filed. We agree. But a basic observation may be useful here. For example, a rolled-in expansion rate that is less than or equal to the rate paid by the initial shippers would not be considered a subsidy. Whether a rolled-in expansion rate that is higher than original rates is a "subsidy" is a question that necessarily would have to be reviewed in the context of a future NGA section 7 filing. At that time, Pacific

³⁸ See, e.g., *Transcontinental Gas Pipe Line Corp.* 106 FERC ¶ 61,299 (2004).

Star's arguments relating to whether the federal government's loan guarantees and accelerated depreciation amount to a "subsidy" of initial shippers' rates may be raised.

125. In conclusion, to provide guidance to potential shippers in advance of the initial open season that is the subject of this rule, the Commission intends to harmonize both objectives (rate predictability for initial shippers and reduction of barriers to future exploration and production) in designing rates for future expansions of any Alaska natural gas transportation project. It is consistent with our guiding principle that competition favors all of the Commission's customers, as well as with the objectives of the Act, to adopt rolled-in rate treatment up to the point that would cause there to be a subsidy of expansion shippers by initial shippers, if any subsidy were to be found.

126. Anadarko states that the open season regulations must prohibit pipelines from bundling ancillary services with transportation. In particular, Anadarko is concerned that sponsors might include in a tariff and an open season the bundled cost of a gas conditioning plant that would extract CO₂ despite the fact that such extraction would not be required of gas from many new Alaska gas fields which likely will be of pipeline quality. MidAmerican/AGTA and Enbridge agree that the open season process should preclude applicants from tying receipt of capacity to taking ancillary services, such as gas conditioning, treating, or processing. TransCanada simply states that it has no objection to proscription of tying.

127. DOI and MidAmerican/AGTA agree that rates for ancillary services should not be bundled with transportation rates. However, DOI contends that the State of Alaska should address the need for rules concerning non-discriminatory access to gathering and other production-related facilities, whereas MidAmerican/AGTA claims that the Commission should assert jurisdiction over gas treatment plants and require separate open seasons and cost-based tariff structures for gas processing. On the other hand, the North Slope Producers contend issues of tying or bundling of services can be dealt with through established Commission processes and policies at the appropriate time, and need not be addressed in the open season. Alliance views the tying issue in the context of requiring designated downstream capacity, and suggests that as a practical matter, that should not be prohibited.

128. The Commission is stating in the final rule at section 157.34(c)(6) that the open season notice must contain an unbundled transportation rate. Moreover, section 157.34(c)(10) prohibits a prospective applicant from requiring prospective shippers to process or treat their gas at any designated facility. The Commission is satisfied that it can address any other discriminatory conduct in connection with gas quality requirements or other ancillary services through the provisions of section 157.35 in conjunction with existing Commission policies and procedures.

INFORMATION COLLECTION STATEMENT

129. The Office of Management and Budget (OMB) regulations require that OMB approve certain reporting, record keeping, and public disclosure (collections of information) imposed by an agency.³⁹ The following information collection requirements contained in this Final Rule are being submitted to the Office of Management and Budget (OMB) for review under section 3507(d) of the Paperwork Reduction Act of 1995.⁴⁰ The Commission identifies the information disclosed under Part 157 as FERC-537. The Commission has submitted this information collection to OMB for review and clearance under emergency processing procedures.⁴¹

130. The Commission did not receive specific comments concerning its burden estimates and uses the same estimates here in the Final Rule. Comments on the substantive issues raised in the NOPR are addressed elsewhere in the Final Rule.

Data Collecti on	No. of Resp onde nts	No. of Res pon ses	Hours Per Respo nse	Total Annua l Hours
FERC-537	0	1	80	2400
Totals				2400

Total Annual Hours for Collection: 2400 hrs. These are mandatory information collection requirements.

³⁹ 5 C.F.R. § 1320.11.

⁴⁰ 44 U.S.C. § 3507(d).

⁴¹ 5 C.F.R. §1320.13.

Information Collection Costs: The Commission sought comments on the cost to comply with these requirements. No comments were received. The Commission is projecting the average annualized cost for all respondents to be \$139,000 (2400 x \$58.00).

Title: FERC-537 "Gas Pipeline Certificates: Construction, Acquisition and Abandonment."

Action: Proposed Information Collection

OMB Control Nos.: 1902-0060. The applicant shall not be penalized for failure to respond to this collection of information unless the collection of information displays a valid OMB control number.

Respondents: Business or other for profit.

Frequency of Responses: One-time implementation.

131. *Necessity of Information:* On October 13, 2004, Congress enacted the Alaska Natural Gas Pipeline Act. Section 103(e) (1) of the Act directs the Commission to issue regulations within 120 days from the enactment of the Act. Congress and the Commission consider the issuance of these regulations to be of critical importance to the construction and development of and access to Alaska natural gas transportation projects. The Commission must issue a Final Rule by February 10, 2005.

132. Interested person may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE, Washington, D.C. 20426 (Attention: Michael Miller, Office of the Executive Director, 202- 502-8415, fax: (202)273-0873), e-mail: michael.miller@ferc.gov. For submitting comments concerning the collection of information and the associated burden estimate(s) including suggestions for reducing this burden, please send your comments to the contact listed above and to the Office of Management and Budget, Room 10202 NEOB, 725 17th Street, N.W., Washington, D.C. 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission, 202-395-4650, fax: 202-395-7285).

ENVIRONMENTAL ANALYSIS

133. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.⁴² No environmental consideration is raised by the promulgation of a rule that is procedural in nature or does not substantially change the effect of legislation or regulations being amended.⁴³ The Final Rule establishes requirements governing the conduct of open seasons for proposals to construct Alaska natural gas transportation projects and does not substantially change the effect of the underlying legislation or regulations being revised.

REGULATORY FLEXIBILITY ACT CERTIFICATION

134. The Regulatory Flexibility Act of 1980 (RFA)⁴⁴ generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. The Commission is not required to make such an analysis if a rule would not have such an effect.

135. The Commission concludes that this Final Rule would not have such an impact on small entities. Most companies regulated by the Commission do not fall within the RFA's definition of a small entity.⁴⁵

⁴² Order No. 486, Regulations Implementing the National Environmental Policy Act, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Preambles 1986-1990 ¶ 30,783 (1987).

⁴³ 18 C.F.R. § 380.4(a)(2)(ii) (2004).

⁴⁴ 5 U.S.C. § 601-612.

⁴⁵ 5 U.S.C. § 601(3), citing to section 3 of the Small Business Act, 15 U.S.C. § 623. Section 3 of the Small Business Act defines a "small-business concern" as a business which is independently-owned and operated and which is not dominant in its field of operation.

DOCUMENT AVAILABILITY

136. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (<http://www.ferc.gov>) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, N.E., Room 2A, Washington D.C. 20426.

137. From FERC's Home Page on the Internet, this information is available in the Commission's document management system, eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

138. User assistance is available for eLibrary and the FERC's website during normal business hours. For assistance, please contact FERC Online Support at 1-866-208-3676 (toll free) or 202-502-6652 (e-mail at FERCOnlineSupport@FERC.gov), or the Public Reference Room at 202-502-8371, TTY (202)502-8659 (e-mail at public.referenceroom@ferc.gov)

EFFECTIVE DATE

139. These regulations are effective 90 days after publication in the FEDERAL REGISTER.

140. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this Final Rule is not a major rule as defined in Section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

List of subjects in 18 CFR Part 157

Administrative practice and procedure

Natural gas

Reporting and recordkeeping requirements.

By the Commission.

(S E A L)

Magalie R. Salas,
Secretary.

In consideration of the foregoing, the Commission amends Part 157, Chapter I, Title 18, Code of Federal Regulations, as follows.

PART 157 - APPLICATIONS FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND FOR ORDERS PERMITTING AND APPROVING ABANDONMENT UNDER SECTION 7 OF THE NATURAL GAS ACT

AUTHORITY: 15 U.S.C. §§ 717 -717w.

SUBPART B – OPEN SEASONS FOR ALASKA NATURAL GAS TRANSPORTATION PROJECTS

1. Subpart B is added to Part 157 to read as follows:

§ 157.30 Purpose

This subpart establishes the procedures for conducting open seasons for the purpose of making binding commitments for the acquisition of initial or voluntary expansion capacity on Alaska natural gas transportation projects, as defined herein.

§ 157.31 Definitions.

(a) "Alaska natural gas transportation project" means any natural gas pipeline system that carries Alaska natural gas to the international border between Alaska and Canada (including related facilities subject to the jurisdiction of the Commission) that is authorized under the Alaska Natural Gas Transportation Act of 1976 or section 103 of the Alaska Natural Gas Pipeline Act.

(b) "Commission" means the Federal Energy Regulatory Commission.

(c) "Voluntary expansion" means any expansion in capacity of an Alaska natural gas transportation project above the initial certificated capacity, including any increase in mainline capacity, any extension of mainline pipeline facilities, and any lateral pipeline facilities beyond those certificated in the initial certificate order, voluntarily made by the pipeline. An expansion done pursuant to section 105 of the Alaska Natural Gas Pipeline Act is not a voluntary expansion.

§ 157.32 Applicability.

These regulations shall apply to any application to the Commission for a certificate of public convenience and necessity or other authorization for an Alaska natural gas transportation project, whether filed pursuant to the Natural Gas Act, the

Alaska Natural Gas Transportation Act of 1976, or the Alaska Natural Gas Pipeline Act, and to applications for expansion of such projects. Absent a Commission order to the contrary, these regulations are not applicable in the case of an expansion ordered by the Commission pursuant to section 105 of the Alaska Natural Gas Pipeline Act.

§ 157.33 Requirement for open season.

(a) Any application for a certificate of public convenience and necessity or other authorization for a proposed Alaska natural gas transportation project must include a demonstration that the applicant has conducted an open season for capacity on its proposed project, in accordance with the requirements of this subpart. Failure to provide the requisite demonstration will result in an application being rejected as incomplete.

(b) Initial capacity on a proposed Alaska natural gas transportation project may be acquired prior to an open season through pre-subscription agreements, provided that in any open season as required in (a) above, capacity is offered to all prospective bidders at the same rates and on the same terms and conditions as contained in the pre-subscription agreements. All pre-subscription agreements shall be made public by posting on Internet websites and press releases within ten days of their execution. In the event there is more than one such agreement, all prospective bidders shall be allowed the option of selecting the terms rates, terms and conditions contained in any one of the several agreements.

§ 157.34 Notice of open season.

(a) Notice. A prospective applicant must provide reasonable public notice of an open season, at least 30 days prior to the commencement of the open season, through methods including postings on Internet websites, press releases, direct mail solicitations, and other advertising. In addition, a prospective applicant must provide actual notice of an open season to the State of Alaska and to the Federal Coordinator for Alaska Natural Gas Transportation Projects.

(b) In-State Needs Study. A prospective applicant must conduct or adopt a study of gas consumption needs and prospective points of delivery within the State of Alaska and rely upon such study to develop the contents of the notice required in (a) above. Such study shall be identified in the notice and if practicable, shall include or consist of a study conducted, approved, or otherwise sanctioned by an appropriate governmental agency, office or commission of the State of Alaska. In its open season proposal, a prospective applicant shall include an estimate based upon the study, of how much capacity will be used in-state.

(c) Contents of Notice. Notice of the open season required in (a) above, shall contain at least the following information; however, to the extent that any item of such information is not known or determined at the time the notice is issued, the prospective applicant shall make a good faith estimate based on the best information available of all such unknown or undetermined items of required information and further, must identify the source of information relied on, explain why such information is not presently known, and update the information when and if it is later determined during the open season period:

(1) The general route of the proposed project, including receipt and delivery points, and any alternative routes under consideration; delivery points must include those within the State of Alaska as determined by the In-State Study in (b) above.

(2) Size and design capacity (including proposed certificate capacity at the delivery points named in (1) above to the extent that it differs from design capacity), a description of possible designs for expanded capacity beyond initial capacity, together with any estimated date when such expansions designs may be considered;

(3) Maximum allowable operating pressure and expected actual operating pressure;

(4) Delivery pressure at all delivery points named in (1) above;

(5) Projected in-service date;

(6) An estimated unbundled transportation rate for each delivery point named in (1) above, stated on a volumetric or thermal basis, for each service offered, including reservation rates for pipeline capacity, interruptible transportation rates, usage rates, fuel retention percentages, and other applicable charges, or surcharges, such as ACA; (if rates are estimated on a volumetric basis then the notice must inform bidders that final pro forma service agreements and the sponsor's proposed FERC tariff will have to be submitted with rates based on a thermal basis.)

(7) The estimated cost of service (i.e., estimated cost of facilities, depreciation, rate of return and capitalization, taxes and operational and maintenance expenses), and estimated cost allocations, rate design volumes and rate design;

(8) Based on the In-State Study and the delivery points within the State of Alaska identified in (1) above, there must be an estimated transportation rate for such deliveries, based on the amount of in-state needs shown in the study. Such estimated transportation rate must be based on the costs to make such in-state deliveries and shall not include costs to make deliveries outside the State of Alaska;

(9) Negotiated rate and other rate options under consideration, including any rate amounts and terms of any precedent agreements with prospective anchor shippers that have been negotiated or agreed to outside of the open season process proscribed herein;

(10) Quality specifications and any other requirements applicable to gas to be delivered to the project; provided that a prospective applicant shall not require that potential shippers process or treat their gas at any designated plant or facility;

(11) Terms and conditions for each service offered;

(12) Creditworthiness standards to be applied to, and any collateral requirements for, prospective shippers;

(13) The date, if any, by which potential shippers and the prospective applicant must execute precedent agreements;

(14) A detailed methodology for determining the value of bids for deliveries within the State of Alaska and for deliveries outside the State of Alaska;

(15) The methodology by which capacity will be awarded, in the case of over-subscription, clearly stating all terms that will be considered, including price and contract term. If capacity is oversubscribed and the prospective applicant does not redesign the project to accommodate all capacity requests, only capacity that has been acquired through pre-subscription or was bid in the open season on the same rates, terms, and conditions as any of the pre-subscription agreements shall be subject to allocation on a pro rata basis; no capacity acquired through the open season shall be allocated.

(16) Required bid information, whether bids are binding or non-binding, receipt and delivery point requirements, the form of a precedent agreement and time of execution of the precedent agreement, definition and treatment of non-conforming bids;

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

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

(19) A list of the names and addresses of the prospective applicant's affiliated sales and marketing units and Energy Affiliates involved in the production of natural gas in the State of Alaska. Affiliated unit means "Affiliate" as applicably defined in section

358.3(b) of the Commission's Regulations. Energy Affiliate means "Energy Affiliate" as applicably defined in section 358.3(d) of the Commission's Regulations;

(20) A comprehensive organizational charts showing:

- (i) The organizational structure of the prospective applicant's parent corporation(s) with the relative position in the corporate structure of marketing and sales units and any Energy Affiliates involved in the production of natural gas in the State of Alaska.
- (ii) The job titles and descriptions, and chain of command for all officers and directors of the prospective applicant's marketing and sales units and any Energy Affiliates involved in the production of natural gas in the State of Alaska; and

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

(d) Timing.

(1) A prospective applicant must provide prospective shippers at least 90 days from the date on which notice of the open season is given within which to submit requests for transportation services. No bid shall be rejected because a prospective shipper has submitted another bid in another open season conducted under this subpart.

(2) A prospective applicant must consider any bids tendered after the expiration of the open season by qualifying bidders and may reject them only if they cannot be accommodated due to economic, engineering or operational constraints, and a detailed explanation must accompany the rejection.

(3) Within 10 days after precedent agreements have been executed for capacity allocated in the open season, the prospective applicant shall make public on the Internet and through press releases the results of the open season, at least including the name of the prospective shipper, amount of capacity awarded, and term of agreement.

(4) Within 20 days after precedent agreements have been executed for capacity allocated in the open season, the prospective applicant must submit copies of all such precedent agreements to the Commission and copies of any relevant correspondence with bidders for capacity who were not allocated capacity that identifies why such bids were not accepted (all documents in this subsection may be filed under confidential treatment pursuant to section 388.112 of the Commission's regulations if desired).

§ 157.35 Undue Discrimination or Preference.

(a) All binding open seasons shall be conducted without undue discrimination or preference in the rates, terms or conditions of service and all capacity allocated as a result of any open season shall be awarded without undue discrimination or preference of any kind.

(b) Any complaint filed pursuant to section 385.206 of the Commission's regulations alleging non-compliance with any of the requirements of this subpart shall be processed under the Commission's Fast Track Processing procedures contained in section 385.206(h).

(c) Each project applicant conducting an open season under this subpart must create or designate a unit or division to conduct the open season that must function independent of the other divisions of the project applicant as well as the project applicant's Marketing and Energy affiliates as those terms are defined in §§ 358.(d) and (k) of the Commission's regulations.

(d) Each project applicant conducting an open season under this subpart that is not otherwise subject to the provisions of Part 358 of the Commission's regulations must comply with the following sections of that Part: §§ 258.4(a)(1) and (2); 358.4(c)(3), (4), (5), and (6); 358.5(a), (b), (c)(3) and (5); and 358.5(d). The exemptions from §§ 358.4(a)(1) and (3) set forth in §§ 358.4(a)(4), (5), and (6) of the Commission's regulations also apply to each project applicant conducting an open season under this subpart.

§ 157.36 Open seasons for expansions.

Any open season for capacity exceeding the initial capacity of an Alaska natural gas transportation project must provide the opportunity for the transportation of gas other than Prudhoe Bay or Point Thomson production. In considering a proposed voluntary expansion of an Alaska natural gas pipeline project, the Commission will consider the extent to which the expansion will be utilized by shippers other than those who are the initial shippers on the project and, in order to promote competition and open access to the project, may require design changes to ensure that all who are willing to sign long-term

firm transportation contracts that some portion of the expansion capacity be allocated to new shippers or shippers seeking to transport natural gas from areas other than Prudhoe Bay and Point Thomson.

§ 157.37 Project Design.

In reviewing any application for an Alaska natural gas pipeline project, the Commission will consider the extent to which a proposed project has been designed to accommodate the needs of shippers who have made conforming bids during an open season, as well as the extent to which the project can accommodate low-cost expansion, and may require changes in project design necessity to promote competition and offer a reasonable opportunity for access to the project.

§ 157.38 Prefiling Procedures

No later than 90 days prior to providing the notice of open season required by section 157.34(a), a prospective applicant must file, for Commission approval, a detailed plan for conducting an open season in conformance with these regulations. Upon receipt of a request for such a determination, the Secretary of the Commission shall issue a notice of the request, which will then be published in the Federal Register. The notice shall establish a date on which comments from interested persons are due and a date, which shall be within 60 days of receipt of the prospective applicant's request unless otherwise directed by the Commission, by which the Commission will act on the plan.

§ 157.39 Rate Treatment of Pipeline Expansions

There shall be a rebuttable presumption that rates for any expansion of an Alaska natural gas transportation project shall be determined on a rolled-in basis.

Appendix

Technical Conference Commenters

Governor Frank H. Murkowski
U.S. Senator Lisa Murkowski
State Representative Ralph Samuels
State Senator Gene Therriault
Tony Palmer, TransCanada
Richard Guerrant, ExxonMobil
Ken Konrad, BP Alaska
Joe Marushack, ConocoPhillips
Ron Brintnell, Enbridge
Bill Corbus, Commissioner, Alaska Department of Revenue
Mark Handley/Dave Anderson, Anadarko
Tony Izzo, Enstar
Rick Mott, ConocoPhillips (as a shipper)
Tom Irwin, Commissioner, Alaska Department of Natural Resources
Jeff Walker, Minerals Management Service, Department of Interior
Colleen McCarthy, Bureau of Land Management(BLM), Department of Interior
David Houseknecht, U.S. Geological Survey
Harold Heinze, ANGDA
Jerry Isaac, Upper Tanana Intertribal Coalition
Bob Sattler, Tanana Chiefs Conference

Commenters in response to NOPR

Alaska Natural Gas Development Authority (ANGDA)
Alaska Oil and Gas Conservation Commission (AOGCC)
Alaska Venture Capital Group LLC and Brook Range Petroleum Corporation (Alaska Venture Capital/Brook Range)
Alliance Pipeline, LP (Alliance)
American Gas Association (AGA)
Anadarko Petroleum Corporation (Anadarko)
Nels Anderson, Jr. (individual)

Arctic Slope Regional Corporation (Arctic Slope)
Ken Baker⁴⁶
Alaska Representative Ethan Berkowitz
BP Exploration (Alaska) Inc., ConocoPhillips Company, and Exxon Mobil
Corporation (North Slope Producers)
Calpine Corporation (Calpine)
ChevronTexaco Natural Gas, a Division of Chevron U.S.A. Inc.
(ChevronTexaco)
Doyon Limited
Enbridge, Inc. (Enbridge)
Legislative Budget and Audit Committee and Indicated State Legislators
(Alaska Legislators) ⁴⁷
MidAmerican Energy Holdings Company and Alaska Gas Transmission
Company (MidAmerican/AGTA)
Northwest Industrial Gas Users (Northwest Industrials)
Pacific Star Energy LLC (Pacific Star)
B. Sachau, aka Jean Public (individual)
Shell USA (Shell)
State of Alaska (Alaska)
TransCanada Pipeline Limited (TransCanada)
U.S. Department of Interior (DOI)
U.S. Geological Survey ⁴⁸

⁴⁶ New River Community and Technical College, Greenbrier Valley Campus

⁴⁷ Representative Ralph Samuels, Chairman of the Alaska Legislative Budget & Audit Committee (separately)

⁴⁸ Brenda Johnson, Office of Environmental Affairs Program

111 FERC ¶ 61,332
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 157

(Docket No. RM05-1-001; Order No. 2005-A)

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

(Issued June 1, 2005)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule; Order on Rehearing.

SUMMARY: The Federal Energy Regulatory Commission (Commission) generally reaffirms its determinations in Order No. 2005. Order No. 2005 establishes requirements governing the conduct of open seasons for proposals to construct Alaska natural gas transportation projects, including procedures for allocation of capacity. Pursuant to the directive of section 103(e)(2) of the Alaska Natural Gas Pipeline Act, enacted on October 13, 2004, the regulations promulgated in Order No. 2005 (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.

In this order, the Commission addresses the requests for rehearing and or clarification of Order No. 2005. Here, we grant rehearing in part, deny rehearing in part, and provide clarification of Order No. 2005. In specific, we: (1) clarify that the

Commission may require design changes necessary to ensure that some portion of a proposed voluntary expansion will be allocated to new shippers or shippers seeking to transport gas from areas other than Prudhoe Bay or Point Thomson, provided such shippers are willing to sign qualifying long-term firm transportation agreements;

(2) codify the expanded criteria for evaluating late bids for capacity and the requirement that any late bid contain a good faith showing; (3) in the case of the mandatory pre-review, codify that the plan to be filed by the Commission must contain the open season notice, and eliminates the 30-day prior notice requirement; (4) discuss how the open season rules may apply to jurisdictional gas treatment plants; (5) clarify that capacity bid for in the open season is exempt from allocation only in a case where there is also presubscribed capacity, and that in the event there are more than one pre-subscription agreement, bidders in the open season may not cherry-pick among the provisions of the several agreements; (6) clarify the project applicant's obligation to establish a separate entity to conduct the open season; and (7) further codify the requirements of the catchall provision regarding information to be include in an open season notice.

EFFECTIVE DATE: Revisions in this order on rehearing will become effective on the date this order is published 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:

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

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

Docket No. RM05-1-001

ORDER NO. 2005-A

ORDER ON REHEARING AND CLARIFICATION

(Issued June 1, 2005)

1. On February 9, 2005, the Federal Energy Regulatory Commission (Commission) issued a Final Rule, Order No. 2005,¹ amending its regulations by adding Subpart B to Part 157 to establish requirements governing the conduct of open seasons for capacity on proposals to construct Alaska natural gas transportation projects. Order No. 2005 fulfilled the Commission's responsibilities to issue open season regulations under section 103 of the Alaska Natural Gas Pipeline Act (ANGPA or 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, the regulations promulgated in Order No. 2005 (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

¹ *Regulations Governing the Conduct of Open Seasons for Alaska Natural Gas Transportation Projects*, RM05-1-000, Order No. 2005, FERC Stats. and Regs.

¶ 31,174 (2005).

opportunity for the transportation of natural gas other than from the Prudhoe Bay and Point Thomson units.

2. The Commission affirms here the legal and policy conclusions on which Order No. 2005 was based. As stated in Order No. 2005, the goal of the open season regulations is to design an open season process that provides non-discriminatory access to capacity on any Alaska natural gas transportation project and, at the same time, allows sufficient economic certainty to support the construction of the pipeline and thereby provide a stimulus for exploration, development, and production of Alaska natural gas. We find that Order No. 2005's open season rules as revised and clarified herein, satisfy that goal and, therefore, are in the public interest.

Background

3. ANGPA mandates the expedited processing by the Commission of any application for an Alaska natural gas transportation project. To this end, as stated above, section 103(e)(1) of the Act specifically directs the Commission to prescribe the rules which shall apply to any open season held for the purpose of soliciting interest in, or making binding commitments to the acquisition of capacity on, any Alaska natural gas transportation project, including the criteria for allocating capacity among competing bidders. In this regard, Congress instructed the Commission to include in its regulations the criteria for, and timing of, any open season, and to design its open season regulations to promote competition in the exploration, development, and production of Alaska natural gas and, as to any open season for the voluntary expansion² of the initial capacity of any Alaska natural gas transportation project, to specifically provide the opportunity for gas other than Prudhoe Bay and Point Thomson production to have access to the pipeline.

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 (NPR) in this proceeding

² Excluded from the scope of the open season rules are expansions compelled by the Commission pursuant to section 105 of the Act. Section 105 authorizes the Commission to order these "involuntary" expansions upon the request of one or more persons, and upon the satisfaction of certain statutory criteria.

containing the Commission's proposed Alaska natural gas transportation project open season regulations. Also, the Commission held a public technical conference in Anchorage, Alaska on December 3, 2004 to develop a record in this proceeding. The Commission received 25 comments in response to the NOPR.

5. On February 9, 2005, the Commission issued Order No. 2005. The open season regulations contained in Order No. 2005 apply to any application for a certificate or other Commission authorization for an Alaska natural gas transportation project, whether filed pursuant to the NGA, the Alaska Natural Gas Transportation Act of 1976, or ANGPA, as well as to any voluntary applications for expansions of such a project.

6. The Final Rule adopted the NOPR's proposed requirements that the applicant provide a 30-day prior public notice containing extensive information intended to allow all interested persons to decide whether to participate in the open season, followed by an actual open season period of at least 90 days. The regulations in the Final Rule also adopted the NOPR's approach of allowing prospective applicants to develop and state in detail the methodologies for determining the value of bids and for allocating capacity, subject to the requirement that all capacity be awarded without undue discrimination or preference of any kind. In addition, the Final Rule required that at least 90 days prior to providing the open season notice, the prospective applicant must file its open season plan with the Commission for approval, and that the Commission will act on the plan within 60 days of its filing.

7. The Final Rule provided that prospective applicants must conduct or adopt a study of Alaska's in-state needs, and use the study results to design capacity needs for use within the state, and design in-state delivery points and in-state transportation rates as part of an open season. Moreover, bidding on in-state capacity must be conducted independent of out-of-state deliveries during a prospective applicant's open season.

8. In order to further the Commission's goal of a non-discriminatory open season, the Final Rule applied certain of the Standards of Conduct requirements of Order No. 2004, including the establishment of an independent, functionally-separate unit to conduct the open season. In addition, the open season notice must identify the prospective applicant's affiliates involved in the production of natural gas in the state of Alaska, and all information about the open season disclosed to any potential shippers must be made available to all potential shippers.

9. The Final Rule permitted pre-subscription by anchor shippers, limited to initial capacity only, in order to facilitate the development of an Alaska pipeline project. However, to ensure that all other potential shippers have an equal opportunity to obtain

access to capacity on the project in the open season, all pre-subscription agreements must be made public within ten days of their execution, and capacity on the proposed project must be offered to all prospective qualifying shippers under the same terms and conditions and at the same rates as the pre-subscription agreements. In addition, if capacity is oversubscribed in the open season and it is not feasible to redesign the proposed project to meet both the pre-subscription shippers' and the open season shippers' capacity needs, then capacity bid for in the open season will not be reduced, but all capacity subject to the terms and conditions of pre-subscription agreements will be allocated pro rata.

10. In an effort to allow as many potential shippers as possible the opportunity to acquire capacity in the initial open season, the Final Rule required that the project sponsor must consider any qualifying bids tendered after the expiration of the open season, and reject them only if they cannot be accommodated due to economic, engineering, or operational constraints.

11. The Final Rule stated that, within ten days after precedent agreements have been executed for capacity acquired in the open season, the prospective applicant shall make public the results of the open season, including the names of the prospective shippers, amount of capacity awarded, and the terms of the agreements. Within 20 days after precedent agreements have been executed, copies of all precedent agreements, as well as copies of any correspondence with bidders whose bids were not accepted, must be filed with the Commission.

12. In another provision, the Final Rule stated that, as a part of the Commission's review of any application for an Alaska natural gas transportation project, it will consider the extent to which the proposed project has been designed to accommodate the needs of shippers who have made conforming bids during an open season, as well as the extent to which the project can accommodate low-cost expansion, and the Commission may require changes in the project's design necessary to promote competition and offer a reasonable opportunity for access to the project.

13. Finally, to provide guidance to interested parties on the important subject of expansion rate treatment, the Final Rule establishes a presumption in favor of rolled-in pricing for expansions up to the point that it would cause there to be a subsidy of expansion shippers by initial shippers.

14. Requests for rehearing and/or clarification were filed jointly by BP Exploration (Alaska), Inc., ConocoPhillips Company and Exxon Mobile Corporation (the North Slope Producers), by Enbridge, Inc. (Enbridge), by ChevronTexaco Natural Gas, a division of

Chevron U.S.A. Inc. (ChevronTexaco), and by the State of Alaska. In addition, Anadarko Petroleum Corporation (Anadarko) and the Legislative Budget and Audit Committee of the Alaska State Legislature (Alaska Legislators) filed responses to the rehearing requests.³

Discussion

I. Mandating Pipeline Design

A. The Final Rule - §§ 157.36 and 157.37

15. Section 157.36 requires that any open season for expansion capacity of an Alaska natural gas transportation project must provide the opportunity for the transportation of gas other than Prudhoe Bay or Point Thomson production, and that the Commission, in considering any proposed voluntary expansion of an Alaska natural gas pipeline project, "may require design changes to ensure that all who are willing to sign long-term firm transportation contracts that some portion of the expansion capacity be allocated to new shippers or shippers seeking to transport natural gas from areas other than Prudhoe Bay and Point Thomson." Section 157.37 states that, in reviewing any application for an Alaska natural gas pipeline project, the Commission "may require changes in the project design necess[ary] to promote competition and offer a reasonable opportunity for access

³ Under Rule 213 of the Commission's Rules of Practice and Procedure, answers to rehearing requests are not permitted. However, the Commission has discretion to waive this rule when it finds that the answers will help provide a complete record in the proceeding or allow a better understanding of the issues. This proceeding involves the establishment of open season rules for capacity on an Alaska natural gas transportation project, and is critical to the development of Alaska's vast natural gas resources to meet anticipated national demand for natural gas, thereby enhancing national security. The Commission finds that the answers will provide necessary information to provide a full and complete record, which will assist the Commission in addressing the issues on rehearing pertaining to the complex and unique circumstances surrounding the development of an Alaska natural gas transportation project. Therefore, Anadarko's and the State of Alaska's answers to the rehearing requests are accepted. See 18 C.F.R. § 385.213 (2004).

to the project, taking into account the extent to which the proposed project design accommodates the open season's conforming bids as well as low-cost expansion."⁴ These provisions were included in the Final Rule in response to concerns of non-North Slope producers that they have access to capacity on an Alaska natural gas transportation project when their potential gas reserves are commercially developed.

B. Rehearing/clarification requests

16. The North Slope Producers and ChevronTexaco object to the provisions contained in sections 157.36 and 157.37 to the extent that they authorize the Commission to require changes in the design of an Alaska natural gas transportation project. The North Slope Producers object to these provisions on a number of grounds. First, they contend that it is beyond the Commission's NGA authority to mandate changes in the design of a pipeline, either to provide additional capacity or to enhance future expandability. The North Slope Producers contend that, in either case, the result is a mandatory expansion of the project, which according to section 7(a) of the NGA, is outside the Commission's authority to require.⁵ The North Slope Producers maintain that this limitation on the Commission's authority is reflected in the Commission's regulations providing that open access pipelines are "not required to provide any requested transportation service for which capacity is not available or that would require the construction or acquisition of any new facilities,"⁶ and in judicial precedent.⁷ According to the North Slope Producers, the Commission has acted unreasonably in "morphing" ANGPA's vague and undefined open

⁴ "Necessity" in section 157.37 is revised to read "necessary."

⁵ Section 7(a) of the NGA provides "[t]hat the Commission shall have no authority to compel the enlargement of transportation facilities..." 15 U.S.C. 717f(a).

⁶ 18 C.F.R. §284.7(f).

⁷ The North Slope Producers cite *Panhandle Eastern Pipe Line Co.*, 204 F.2d 675 (3rd Cir. 1953) in which the court stated that "[i]n light of Section 7(a) we are compelled to conclude that Congress meant to leave the question whether to employ additional capital in the enlargement of its pipeline facilities to the unfettered judgment of the stockholders and directors of each natural gas company involved." 204 F.2d at 680.

season requirements pertaining to competition in the exploration, development, and production of Alaska gas and sufficient opportunity for future access for the transportation of non-Prudhoe Bay/Point Thomson gas into factors to be considered by the Commission in its NGA section 7 review of a certificate applications for Alaska natural gas transportation projects.

17. Second, the North Slope Producers assert that ANGPA section 105 further limits the Commission's authority to require an expansion of an Alaska natural gas transportation project sections. The North Slope Producers state that before an involuntary expansion can be ordered by the Commission, section 105 lists a number of statutory requirements that must be met which are designed to balance potential future shippers' interests with the need to protect the pipeline and existing shippers and to protect against uneconomic overbuilding. The North Slope Producers state that none of these statutory requirements are referenced in or satisfied by section 157.36 or 157.37.

18. Third, the North Slope Producers argue that the Commission appears to mistakenly "assume that a pipeline can, in all circumstances, be efficiently designed to accommodate all qualifying bids." The North Slope Producers assert that the most efficient and economic pipeline design might not be one which can accommodate 100 percent of the capacity bid for in the open season. In fact, according to the North Slope Producers, it is possible that a pipeline designed to accommodate all the capacity bid in the open season "could result in a design that is inefficient and/or negatively impacts future expansion design alternatives."

19. Fourth, the North Slope Producers maintain that to the extent that it authorizes a set-aside of capacity, section 157.36 violates the Order No. 636's goal of eliminating impediments to the transmission of proper pricing signals between producers and consumers, as well as the Commission's non-discrimination policies. The North Slope Producers point to the second sentence of section 157.36, which states:

"In considering a proposed voluntary expansion of an Alaska natural gas pipeline project, the Commission will consider the extent to which the expansion will be utilized by shippers other than those who are the initial shippers on the project, and in order to promote competition and open access on the project, *may require design changes to ensure that all who are willing to sign long-term firm transportation contracts to some portion of the expansion capacity be allocated to new shippers or shipper's seeking to transport natural gas from areas other than Prudhoe Bay and Point Thomson.*" (Emphasis added).

The North Slope Producers assert that if this "indecipherable" language is intended to set aside capacity for new shippers or shippers of gas from areas other than Prudhoe Bay and Point Thomson, then the Commission is favoring one shipper's bid over another bid that otherwise meets all of the bid criteria. The North Slope Producers assert that ANGPA's section 103(e)(2)(C) requirement that open season regulations for voluntary expansions are to "provide an opportunity for the transportation of gas other than Prudhoe Bay and Point Thomson gas" does not support section 157.36's apparent set-aside or preference. The North Slope Producers state that not only is such a preference inconsistent with the Commission's open access policies, it is patently discriminatory and anti-competitive and unlawful under the NGA. The North Slope Producers contend that allocating pipeline capacity in an open season to customers who value it most, *i.e.*, through the use of the Commission-favored net present value capacity allocation methodology, ensures pipelines and shippers that capacity will be allocated in a non-discriminatory and economically efficient manner. The North Slope Producers also assert that development of multi-owner fields could be delayed or hampered if one group of shipper/owners had a competitive advantage over another shipper/owner group due to a capacity allocation advantage or preference.

20. Finally, the North Slope Producers maintain that sections 157.36 and 157.37 are contrary to the Commission's reliance on market forces, on which its existing policies are based. Specifically, the North Slope Producers claim that Order No. 2005 fails to reconcile Subparts 157.36 and 157.37 with current Commission policies in favor of "facilitate[ing] the unimpeded operation of market forces to stimulate the production of natural gas,"⁸ and against the subsidization of new services by existing shippers. The North Slope Producers state that it would be unreasonable to expect that the pipeline sponsors would simply assume the financial risk for significant amounts of uncontracted capacity on such an enormous project, yet Order No. 2005 fails to address cost recovery issues associated with any mandated design changes that might be ordered.

21. ChevronTexaco claims that the regulations promulgated in Order No. 2005 apply to open seasons for initial or voluntary expansion capacity; therefore, the idea of post-open season Commission-mandated design changes is inconsistent with and outside the

⁸ Order No. 636, FERC Stats. and Regs. ¶ 30,939 at 30,393 (1992), *quoting* S.Rep. No. 309, 101st Cong., 1st Sess. at p.2 (1989).

scope of this rulemaking. Moreover, ChevronTexaco asserts that the design change provisions of sections 157.36 and 157.37 should be deleted from the open season regulations because the subject was not included in the Notice of Proposed Rulemaking. ChevronTexaco states that absent removing sections 157.36 and 157.37 from the open season regulations, the Commission should provide that it would not require project design changes if doing so would negatively impact the rates, terms or conditions of service for initial shippers or otherwise adversely affect pipeline operations of efficiency.

22. In its response to the rehearing requests, Anadarko argues that ANGPA and the NGA provide the Commission with ample authority to require changes in the design of an initial or expanded Alaska natural gas transportation project necessary to meet the statutory objectives of promoting competition and provide a reasonable opportunity for access to all shippers who have made conforming bids during the open season. Anadarko states that clearly there is interplay between the NGA and ANGPA. Specifically, states Anadarko, section 7(e) of the NGA provides that a "certificate shall be issued ... if it is found that proposed service, sale, operation, construction... to the extent authorized by the certificate, is or will be required by the present or future public convenience and necessity." Anadarko states that the Commission considers many factors in making this public convenience and necessity finding, and, in the case of an Alaska natural gas transportation project, should consider the requirements of ANGPA.

23. Anadarko asserts that the Commission often imposes conditions to its certificates requiring routing or design modifications in order to support a finding that a particular project is in the public convenience and necessity. In any event, sections 157.36 and 157.37 do not mandate an expansion, according to Anadarko, because the applicant may choose not to accept a certificate that requires that the project be redesigned. Anadarko states that the regulations merely put the applicant on notice that its proposed project design might be rejected as failing to meet the objectives of ANGPA, and consequently, not being required by the public convenience and necessity.

24. In response to the North Slope Producers' charge that section 157.36 provides for discriminatory reallocation of capacity contrary to existing Commission policy, Anadarko contends that the Commission is merely following the mandate of ANGPA section 103(e)(2)(C). Anadarko states that under section 103(e)(2)(C), the Commission's regulations must ensure that any open season for expansion capacity provides the opportunity for the transportation of natural gas other than from Prudhoe Bay/Point Thomson, and section 157.36 seeks to do just that.

25. Anadarko also disputes the North Slope Producers' claim that parties were not adequately notified in the NOPR that pipeline design would be a subject of the

rulemaking. Anadarko maintains that the regulations contained in sections 157.36 and 157.37 reasonably respond to many concerns expressed throughout the rulemaking process.⁹ Anadarko contends that under the Administrative Procedure Act (APA), the Commission was required in this informal rulemaking proceeding to provide either the terms or substance of the proposed rule or a description of the subjects and issues involved.¹⁰ Moreover, Anadarko points out that the courts have held that "even if the final rule deviates from the proposed rule, '[s]o long as the final rule promulgated by the agency is a 'logical outgrowth' of the proposed rule... the purposes of the notice and comment have been adequately served.'" ¹¹ Anadarko states that Order No. 2005's pipeline design provisions were a "logical outgrowth" of the NOPR and the issues discussed therein, *e.g.*, the major goals of ANGPA, concerns over potential discrimination, producer/sponsor preferences, the role of pre-subscriptions, and tensions between ANGPA's goals and the application of existing policies to an Alaska project.

26. Lastly, Anadarko contends that the Commission provided ample support for not following current Commission policies that favor reliance on market forces. Anadarko states that the rulemaking record in Order No. 2005 thoroughly discusses the conditions and circumstances in Alaska that are much different than those found in the lower 48 states, requiring the appropriate regulatory action taken in sections 157.36 and 157.37. In conclusion, Anadarko disagrees that 157.36 is "indecipherable" as claimed by the North Slope Producers.

27. The Alaska Legislators maintain that sections 157.36 and 157.37 are well within the Commission's broad power to attach to certificates any conditions that may be found to be required by the public convenience and necessity. They claim that the "forced expansion" argument fails to acknowledge that ANGPA has injected into the public convenience and necessity standard of the NGA a new statutory standard, *i.e.*, the promotion of competition in the exploration, development and production of Alaska

⁹ Anadarko identifies comments addressing pipeline size both at the technical conference and written. See Anadarko's March 29, 2005 response at 15 -16.

¹⁰ See 5 U.S.C.A. 553(b)(3).

¹¹ *Appalachian Power Co. v. EPA*, 135 F.3d 791, 804 n.22 (D.C. Cir. 1998).

natural gas with respect to Alaska natural gas transportation projects. Moreover, the Alaska Legislators contend that the Commission's pipeline design concerns are required not only by the mandate of ANGPA, but also by the economic realities in Alaska, where virtually all of the proven reserves are held by the North Slope Producers. The Alaska Legislators state that the Commission is simply announcing in sections 157.36 and 157.37 that it may condition the approval of the certificate upon the applicant's making necessary design changes required to satisfy the public convenience and necessity standard, including the "promote competition" standard, which is uniquely applicable to an Alaska natural gas transportation project.

28. Addressing the North Slope Producers' claim that section 157.36 provides for an unduly discriminatory set aside of capacity for non-North Slope shippers, the Alaska Legislators agree with Anadarko that ANGPA mandates that in the case of an expansion of an Alaska natural gas transportation project, the Commission must provide an opportunity for the transportation of natural gas other than from Prudhoe Bay and Point Thomson units in its open season rules. Alaska Legislators state that section 157.36 is consistent with that mandate.

29. The Alaska Legislators also defend the Commission's "proactive" approach through which it fashioned the open season rules in recognition of the recognized differences between competitive forces in the lower 48 states and the lack of competition in Alaska. Given these differences, the Alaska Legislators maintain that the Commission was right to depart from existing Commission policy. They assert that the fact that Congress required the Commission to promulgate the Alaska open season rules in place of the Commission's long-standing policy of evaluating open seasons on a case-by-case, after-the-fact basis, is an illustration of the need for different approach based on the unique circumstances surrounding an Alaska pipeline. The Alaska Legislators conclude that, unlike the situation in the lower 48 states, there is no existing or foreseeable competitive environment in Alaska, where the North Slope Produces not only control all the known gas reserves, but also may become the sponsors of the Alaska pipeline. Therefore, the Commission was right to not rely on market forces in Alaska to ensure the development, routing, sizing and timing of an Alaska pipeline.

30. Finally, the State of Alaska suggests that section 157.36 be expanded to better reflect its intent. According to the State of Alaska, section 157.36 should read:

"In considering a proposed voluntary expansion of an Alaska natural gas transportation project, the Commission will consider the extent to which the expansion will be utilized by shippers other than those who are the initial shippers on the project and, in order to promote competition and open

access to the project, may require design changes to ensure that new shippers willing to sign long-term firm transportation contracts or shippers

seeking to transport natural gas from areas other than Prudhoe Bay or Point Thomson who are willing to sign long-term contracts can have access to some portion of the expansion capacity."

C. Commission Response

31. The North Slope Producers' assertion that the Commission has no authority under the NGA to require changes in the design of an proposed Alaska natural gas transportation project in connection with an application for authorization either to construct the project, or to expand the project is inconsistent with law and precedent. At the outset, we reject the notion that any design change that might be required under either section 157.36 or 157.37 would constitute a mandatory expansion of the project. First, in every case in which the section 7(a) limitation has been addressed, the facilities involved were existing facilities subject to existing certificate authorization. The reasoning behind this limitation is clear. Once a natural gas company accepts a certificate and in reliance thereof expends resources to construct the facilities authorized therein, the pipeline and its customers should have the right to rely on the authorizations contained in that certificate. It is quite another thing where the Commission tells a certificate applicant that unless it agrees to certain changes (including cost allocations and the design of initial service rates), its proposal will not be found to be in the public convenience and necessity. In such case, if the applicant does not want to change its proposed project design, it is not required to accept the certificate. Furthermore, because design changes under either 157.36 or 157.37 would not constitute a mandatory project expansion, the statutory requirements of ANGPA section 105 have no application.

32. In considering an application for a certificate of public convenience and necessity under section 7 of the NGA, the Commission has the authority to consider all factors

bearing on the public interest,¹² and in particular, the Commission "certainly has the right to consider a congressional expression of fundamental national policy as bearing upon the question whether a particular certificate is required by the public convenience and necessity."¹³ In the case of an Alaska natural gas transportation project, these factors would properly include the requirements of ANGPA, including the statutory objectives of promoting competition and provide a reasonable opportunity for access to all shippers who have made conforming bids during the open season.

33. The Commission has authority under NGA section 7(e) to attach to a certificate of public convenience and necessity any conditions it deems necessary to meet the public interest.¹⁴ The Commission has exercised this conditioning authority to require routing or design modifications in order to support a finding that a particular project is in the public convenience and necessity.¹⁵ Sections 157.36 and 157.37 merely codify our existing authority and practice.

34. The North Slope Producers' claim that sections 157.36 and 157.37 are predicated on the Commission's erroneous assumption "that a pipeline can, in all circumstances, be efficiently designed to accommodate all qualifying bids." This is inaccurate. We noted in Order No. 2005 that both the North Slope Producers and Enbridge maintained that an Alaska pipeline could be designed and built with sufficient capacity to accommodate the

¹² See, e.g., *FPC v. Transcontinental Gas Pipe Line Corporation*, 365 U.S. 1, 81 S.Ct. 435 (1961); *Office of Consumers' Counsel v. FERC*, 655 F.2d 1132, 210 U.S.App. D.C. 315 (1980).

¹³ *City of Pittsburgh v. FPC*, 237 F.2d 741 at 754 (D.C. Cir. 1965).

¹⁴ See, e.g., *FPC v. Hunt*, 376 U.S. 515, 525 -527, 84 S.Ct. 861 (1964); *Atlantic Refining Co. v. Public Service Commission of New York*, 360 U.S. 378 (1959).

¹⁵ See, e.g., *Vector Pipeline, L.P.*, 87 FERC ¶ 61,225 at 61,892-893 (1999); *Maritimes & Northeast Pipelines, L.L.C.*, 80 FERC ¶ 61,345 (1997); *NE Hub Partners, L.P.*, 83 FERC ¶ 61,043 (1998); see also, *Transcontinental Gas Pipe Line Corp v. FERC*, 589 F.2d 186 (5th Cir.), cert. denied, 445 U.S. 915 (1979).

needs of every qualified shipper.¹⁶ Our expectation is that an Alaska natural gas transportation project will be designed and built, to the extent possible, to accommodate all qualified shippers who are ready to sign firm transportation agreements. Nonetheless, in Order No. 2005 we certainly did not rule out the possibility that a project, with or without pre-subscription agreements, might be oversubscribed.¹⁷ On this note, we should emphasize that in our review of any application for initial Alaska project or any expansion thereof, our consideration of the project design will be driven by our need to find that the proposal is in the public convenience and necessity. Any conditions we impose must be required by the public interest, and be based on substantial evidence.

35. The North Slope Producers' claim that section 157.36 provides for an unduly discriminatory set-aside of capacity for non-North Slope shippers discounts, if not ignores, the Congressional mandate of ANGPA section 103(e)(2)(C) that requires our open season regulations to ensure that any open season for expansion capacity provides the opportunity for the transportation of natural gas other than from Prudhoe Bay/Point Thomson. Section 157.36 does so in a reasonable manner. In any event, our regulations do not require that an expansion proposal must, regardless of economic and technical considerations, provide transportation of gas other than Prudhoe Bay/Point Thomson volumes. The regulations simply require that an opportunity for such transportation be provided.

36. As pointed out elsewhere in this order, and throughout Order No. 2005, a number of existing Commission policies predicated on competitive conditions in the lower 48 states are ill-suited for application in the case of an Alaska natural gas transportation project, particularly in view of ANGPA's directives. As we stated in Order No. 2005, a successful Alaska natural gas transportation project will have to overcome a variety of significant obstacles, including unique and complex competitive conditions. Those competitive conditions, we said, are intensified by the generally agreed-upon fact that

¹⁶ See, e.g., Order No. 2005 at P 29, 37, and 88.

¹⁷ See *id.* at P 37; see also § 157.34(c)(15).

there will be only one such Alaska pipeline for the foreseeable future.¹⁸ Against that backdrop, we affirm the conclusions of Order No. 2005, which serve as the underpinnings of the Final Rule's regulations, including the need in certain instances to accommodate existing Commission policy to the unique circumstances surrounding the exploration, production, development, and transportation to market of Alaska natural gas.

37. Finally, while due process and the APA impose an obligation on agencies to provide adequate notice of issues to be considered,¹⁹ that obligation is satisfied in this informal rulemaking by providing either the terms or substance of the proposed rule or a description of the subjects and issues involved.²⁰ Order No. 2005's pipeline design provisions were a logical outgrowth of the NOPR and the issues discussed therein, *e.g.*, major goals of ANGPA, concerns over potential discrimination, producer/sponsor preferences, potential role of pre-subscriptions, tensions between ANGPA's goals, and application of existing policies to the circumstances of an Alaska project. Indeed, the critical importance of properly sizing the pipeline was a recurring theme throughout this proceeding, and was raised by several parties at the technical conference, and in later comments and reply comments.²¹ Thus, Order No. 2005 does not unduly change the scope of this proceeding. In any event, the parties' ability to seek rehearing resolves any due process issues.

38. Although the North Slope Producers describe section 157.36 to be "indecipherable," their comments demonstrate that they understand its intent.

¹⁸ The North Slope Producers, in their rehearing request, claim that it is too early to conclude that only one Alaska pipeline will ever be built. We find nothing in the record to support a contrary conclusion.

¹⁹ *Public Service Commission of the Commonwealth of Kentucky v. FERC*, 397 F.3d 1004 (D.C. Cir. 2005), citing *Williston Basin Interstate Pipeline Co. v. FERC*, 165 F.3d 54 (D.C. Cir. 1999); see 5 U.S.C. § 554(b)(3).

²⁰ See 5 U.S.C. 553(b)(3).

²¹ See n. 8, *supra*.

Section 157.36 is intended to provide that the Commission may require design changes necessary to ensure that some portion of a proposed voluntary expansion will be allocated to new shippers or shippers seeking to transport gas from areas other than Prudhoe Bay or Point Thomson, provided such shippers are willing to sign qualifying long-term firm transportation agreements. To ensure clarity, we will revise section 157.36 to read as follows:

“In considering a proposed voluntary expansion of an Alaska natural gas transportation project, the Commission will consider the extent to which the expansion will be utilized by shippers other than those who are the initial shippers on the project and, in order to promote competition and open access to the project, may require design changes to ensure that some portion of the expansion capacity will be allocated to new shippers willing to sign qualifying long-term firm transportation contracts, including shippers seeking to transport natural gas from areas other than Prudhoe Bay or Point Thomson.”

II. Presumption of Rolled-in Rates for Expansions

A. Final Rule - § 157.39

39. Section 157.39 states that “[t]here shall be a rebuttable presumption that rates for any expansion of an Alaska natural gas transportation project shall be determined on a rolled-in basis.” The Commission stated in Order No. 2005 that by providing for this presumption, the Commission is advising potential shippers, in advance of any initial Alaska natural gas transportation project open season, of its intention to harmonize the objective of rate predictability for initial shippers with the objective of reducing barriers to future exploration and production in designing rates for future expansions of any Alaska natural gas transportation project. The Commission concluded in Order No. 2005 that section 157.39 is consistent with “our guiding principle that competition favors all of the Commission’s customers, as well as with the objectives of the Act, to adopt rolled-in rate treatment up to the point that would cause there to be a subsidy of expansion shippers by initial shippers, if any subsidy were to be found.”

B. Rehearing/Clarification Requests

40. The North Slope Producers, Enbridge, and ChevronTexaco assert that the presumption in favor of rolled-in rates for voluntary expansions established in section 157.39 creates uncertainty for shippers and project sponsors, and, therefore, section 157.39 should be eliminated from the regulations or substantially revised. The

North Slope Producers and Enbridge claim that prospective initial shippers, fearing that in the future their rates may be increased to subsidize the cost of expansion facilities, will be less willing to make the long-term commitments necessary to support an Alaska project. This uncertainty, they predict, will discourage rather than advance the development of an Alaska pipeline or any voluntary expansion thereof – a result clearly inconsistent with ANGPA's primary goal. Moreover, the North Slope Producers and Enbridge suggest that mandatory expansions pursuant to ANGPA section 105 will become more attractive than voluntary expansions because of the explicit rate protection for existing shippers in section 105.

41. The North Slope Producers contend that section 157.39 is unjustifiably inconsistent with the Commission's current policy regarding rate treatment of expansions, which is to discourage uneconomic expansions and assure that expansions will not be subsidized by existing shippers. They assert that even if, as claimed by the Commission, only one pipeline will be built in Alaska, that distinction does not justify deviating from the Commission's current policy.

42. The North Slope Producers charge that the Commission acted arbitrarily and capriciously in relying on ANGPA section 103(e) to justify its conclusion to provide for a presumption of rolled-in rates for expansions. Although the North Slope Producers concede that the Commission clearly has the authority under ANGPA and the NGA to approve rates for Alaska natural gas transportation projects, they claim that ANGPA section 103(e) has nothing to do with rate regulation. Furthermore, state the North Slope Producers, even if section 103 could be read to give the Commission authority to include rate regulations in its open season rules, the proper course would be to remove section 157.39 from the open season rules and instead address rate policy issues only after the parties have the opportunity of developing a complete factual record. Failing this, the North Slope Producers state that the Commission should revise section 157.39 to provide that the Commission's current rate policies will apply to Alaska projects.

43. Enbridge also argues that the Commission acted arbitrarily and capriciously by imposing a rebuttable rolled-in presumption, even where rolled-in pricing would increase existing shippers' rates. According to Enbridge, Order No. 2005 identifies two considerations, namely the Commission's disfavor of existing shippers subsidizing the rates of new shippers, and the Commission's reluctance to authorize an expansion rate that would have an unduly negative impact on the exploration and development of Alaska reserves. Enbridge contends that the presumption should be "scaled back" to apply only to cases where expansion rates are no higher than pre-existing rates. Enbridge points to the Commission's acknowledgement in Order No. 2005 that it "cannot at this point, without a specific project proposal or the facts surrounding a proposed expansion before

us, define exactly what will be required to overcome the presumption." Enbridge contends that the Commission's inability to explain how the presumption can be rebutted renders rolled-in pricing mandatory, leaving the question of whether a rolled-in expansion rate that is higher than original rates is a subsidy to be resolved in a future NGA section 7 filing.

44. ChevronTexaco stresses that because the text of Order No. 2005 recognizes that "without a specific project proposal or the facts surrounding a proposed expansion" the Commission cannot determine what is needed to overcome the presumption favoring rolled-in rates, the Commission should defer any determination of rate treatment for expansions until a record can be developed after a specific proposal is made. According to ChevronTexaco, this inability to articulate when the presumption will be applied creates uncertainty that inhibits the development of any Alaska project.

45. ChevronTexaco states that inconsistency between the text of order and the text of the regulations creates further uncertainty. ChevronTexaco states that while the regulations state that the presumption applies to "any expansion," Order No. 2005's text, at paragraphs 124 and 125, suggests that rolled-in rates are appropriate only if there is no increase in rates for existing shippers. ChevronTexaco urges the Commission to clarify section 157.39 to state that no cross-subsidy is intended. Otherwise, the Commission should consider issuing, in lieu of a regulation, a policy statement which outlines the general direction that the Commission intends to take.

46. The Alaska Legislators and Anadarko contend that rolled-in pricing is essential and justified. Anadarko asserts that the Commission clearly has the statutory authority to establish a presumption of rolled-in pricing for future expansions in the open season regulations. Both Anadarko and the Alaska Legislators contend that the significant differences identified in the record between an Alaskan pipeline project and a pipeline in the lower 48 states provide ample justification for departing from the current pricing policy. The Alaska Legislators contend that even if there were some factual reason for applying the current policy, that policy cannot be reconciled with the policy considerations stated in ANGPA. Both Anadarko and the Alaska Legislators state that incremental pricing of expansions cannot be reconciled with ANGPA's goals of promoting competition in the exploration, development, and production of Alaska natural gas, and providing for the transportation of natural gas other than from the Prudhoe Bay and Point Thomson units in any expansions of the Alaska pipeline facilities. The Alaska Legislators estimate that expanding a pipeline, through looping, to a capacity of 7 billion cubic feet (Bcf), would result in an expansion rate 50 percent higher than existing rates if incrementally priced. Anadarko predicts that incremental pricing of expansions of an Alaskan pipeline beyond 6 Bcf would cause the pipeline to be capped at 6 Bcf.

C. Commission Response

47. ANGPA section 103(i) gives the Commission broad authority to establish "such regulations as are necessary" for the conduct of open seasons. In this regard, the Commission believes that it is appropriate to establish rate criteria that will assist potential shippers to make informed open season bids, and will promote competition, as required by ANGPA. As discussed in detail in Order No. 2005, these criteria include projected rates for in-state deliveries of gas, as well as a presumption for rolled-in rate treatment for future pipeline expansions.

48. In adopting the presumption for rolled-in rate treatment, the Commission balanced rate predictability for initial shippers with the objective of reducing barriers to future exploration, development and production of Alaska natural gas. The Commission was concerned that the prospect of high incremental transportation rates might increase risks to Alaskan producers and serve as a disincentive to future exploration and development of potentially valuable natural gas resources. On the other hand, the Commission does not wish to discourage voluntary capacity expansions.

49. The rolled-in rate presumption was not an abandonment of our current policy of not favoring rate subsidization by existing customers of capacity expansions as suggested in the requests for rehearing. The Commission did, however, suggest that because of the likelihood of a single Alaskan pipeline project, it would consider alternatives to our current policy on how to define or quantify subsidization by current customers. Current policy primarily considers whether the expansion project will result in a rate higher than the existing transportation rate for existing customers. An alternative consideration or definition of subsidization could be whether the expansion rate is no higher than the actual initial rate or of an initial rate without built-in subsidies. The Commission believed and continues to believe that the appropriate place to review this issue is in the context of a future NGA section 7 filing. In such a proceeding, if the pipeline owners can show that the initial pipeline was sized appropriately, *i.e.*, it was uneconomic or inefficient to build a larger capacity pipeline, the Commission would consider this in overcoming the rolled-in rate presumption.

50. The text of Order No. 2005 referred to by ChevronTexaco does not simply state that rolled-in rates are appropriate only if there is no increase in rates for existing shippers; it suggests that a rolled-in expansion rate that is higher than the original rate is not necessarily a subsidy. As noted above, we will determine whether a particular rate amounts to a subsidy when the issue is presented to us.

51. Nothing in the requests for rehearing causes us to question our conclusion that a rebuttal presumption of rolled-in treatment for the expansion of an Alaska Project is a reasonable approach to the difficult issues we, and prospective pipeline proponents and shippers, may face on the future. We think that the signal we are sending is a positive one that will help spur natural gas exploration and development in Alaska. At the same time, we have not prejudged how we will resolve future proceedings, and all parties will have the opportunity to convince us of appropriate rate treatment if and when expansion proposals for an Alaska project are developed. We therefore will not change the rule on this matter.

III. Late Bids

A. The Final Rule - § 157.34(d)(2)

52. Order No. 2005 added a new provision in the Final Rule, section 157.34(d)(2), that a project sponsor must consider any bids tendered after the expiration of the open season by qualified bidders, and may reject them only if they cannot be accommodated due to economic, engineering, or operational constraints, in which case the project sponsor must provide a detailed explanation for the rejection. The Commission explained that this requirement is designed to allow reasonable access to those shippers who may not be ready to participate during the established open season period, and at the same time provide the sponsor with flexibility in the timing of its open season.

B. Rehearing/Clarification Requests

53. The North Slope Producers and Enbridge contend that it is important for the timely development of any project that the project sponsors be able to rely on an open season that has a definite term. They state that the open season results are needed to permit the project sponsor to gauge demand and in turn finalize pipeline design. They assert that the late bid provisions of section 157.34(d)(2) will result in unreasonable risks and costs to the project sponsor by creating a never-ending, open-ended open season in which the project sponsor will be required, for each and every late bid received, to divert resources and incur additional costs to evaluate whether bid can be accommodated. In addition, they state that there is tremendous potential for delay at each step of the development of the project, if the project sponsor must stop and make design changes at every stage to accommodate a late bid. Thus, they state, section 157.34(d)(2) would frustrate the Commission's stated goal of adopting open season regulations that ensure sufficient economic certainty to support the construction of a pipeline.

54. The North Slope Producers add that financing cannot be secured until pipeline design and development costs are known and precedent agreements are in place. Consequently, they claim, the prospect of having to make changes to key project components to accommodate late bids jeopardizes the project sponsor's ability to obtain financing in a timely manner.

55. Both Enbridge and the North Slope Producers also state that section 157.34(d)(2) fails to provide a clear standard under which the project sponsor must evaluate late bids. This failure, they claim, presents another risk of uncertainty and delay. Enbridge argues that, even if it is necessary to significantly re-design a project in order to satisfy a late bid, the regulation would require that such a bid be accepted if the re-designed project remains feasible from an "economic, engineering or operational" perspective.

56. The North Slope Producers state that another effect of the late bid provision is that potential shippers will be discouraged from participating in an open season if they can submit a late bid. They worry that this would diminish the open season's ability to accurately demonstrate the demand for pipeline capacity. Enbridge also claims that, absent a good faith requirement in connection with submitting late bids, section 157.34(d)(2) permits such gamesmanship. Enbridge states that at a minimum, section 157.34(d)(2) should put "the burden on the bidder to demonstrate compelling circumstances that prevented participation in open season, and that the bid can be accommodated without changing system design, requiring capacity to be allocated away from other shippers, or otherwise adversely impacting the project's development and timing." In this regard, the State of Alaska maintains the Commission should include language in section 157.34(d)(2) that requires late bidders to provide adequate justification for their late bids.

57. Additionally, the North Slope Producers assert that, to the extent a project sponsor would be required to expand the project to accommodate late bids, the Commission is in effect ordering an expansion of the pipeline. In such a case, section 157.34(d)(2) raises the same issues regarding forced expansions as are raised by sections 157.36 and 157.37. The North Slope Producers contend that whereas the Commission may require an expansion under section 105, that section places the burden on the party seeking such expansion to establish that specific conditions are met, section 157.34(d)(2) appears to place the burden on the pipeline to justify why it cannot expand the project to accommodate a late bid.

58. Enbridge states that in any event there is little or no reason for section 157.34(d)(2) "given the other measures instituted by Order No. 2005 to protect the interests of late developing shippers." Specifically, Enbridge refers to the

unprecedented level of information required in the open season notice on which bidders will be able to base their long-term capacity decisions, Order No. 2005's emphasis on requiring that the project's design demonstrate a capability for low-cost expansion, and, finally, the mandatory expansion provisions of ANGPA 105. Enbridge contends that to the extent late bids can be accommodated without adversely impacting the project's development, it is in the project sponsor's economic interests to do so.

59. ChevronTexaco requests that the Commission clarify that project sponsors will be required to consider late bids only if there is excess capacity after capacity is allocated to those open who bid in the open season. ChevronTexaco states that one of the major purposes of the open season is provide a level playing field for all participants, thereby eliminating the advantages of possessing superior or advance information. ChevronTexaco cannot understand the Commission's reasoning in giving special consideration to one specific parameter of a conforming bid, namely, the timing of the bid. According to ChevronTexaco, late bidders should not be allowed to put new burdens on the project or to adversely affect timely open season bidders.

60. Anadarko states that section 157.34(d)(2) is a reasonable compromise balancing concerns that the open season could be held prematurely with a project sponsor's desire to control open season timing. Anadarko also states that it is possible to accommodate all qualified bidders up to the time the pipeline design is finalized.

C. Commission Response

61. Under the Commission's open access policy and rules, all operating interstate pipelines have an obligation to receive and respond to new requests for service, even if no capacity is available. All operating pipelines have provisions in their FERC tariffs governing the procedures that the pipeline will use in evaluating requests for service. Absent an expansion,²² capacity could still be made available to a prospective shipper via capacity release or the capacity turnback provisions of an interstate pipeline's FERC

²² Interstate pipelines, other than an Alaska pipeline, cannot be required to expand their systems, but pipelines are required to respond to those who request service, even when none is available.

tariff. During the several years between the time that the open season ends and an Alaskan pipeline goes into service, there will be no tariff with provisions like those described above in effect for that pipeline. Without the late bidder provisions of section 157.34(d), late-developing prospective shippers would have no formal way of seeking capacity on the pipeline after the open season ends. As revised herein, the Commission believes that the late bidder provision is a fair and necessary addition to the open season process for an Alaska natural gas transportation project.

62. The project sponsor's obligation under section 157.34(d)(2) is not "unbounded" or "open-ended," as North Slope Producers contend. We added this requirement in recognition of the possibility that an appreciable amount of time might pass between the close of the open season and the project sponsor's finalizing the details of the proposed pipeline design and associated development costs, given the size and scope of an Alaska natural gas pipeline project. During that time, it is possible that producers of Alaska natural gas who were not in a position to commit to long-term capacity commitments during the open season, might then be in a position to request capacity consistent with the open season notice (except, of course, that the bid is tendered out of time). We felt it proper to require the project sponsor to consider such a request. At the same time, we appreciated that at some point in time, either before or after the proposed pipeline design is finalized, the project sponsor might not be able to accommodate reasonably a late request. For that reason, we provided that late requests could be rejected on the basis of "economic, engineering or operational constraints." This is far from an unbounded, open-ended obligation. Indeed, as noted above, Enbridge points out that to the extent that late bids can be accommodated without adversely impacting the project's development, it is in the project sponsor's economic interest to do so. We see no harm in requiring that result.

63. We will however, revise the requirements of section 157.34(d)(2) in response to the complaints that the "economic, engineering or operational constraints" standard for rejecting late bids is too vague. Specifically, we are clarifying the criteria for rejecting late bids in section 157.34(d)(2) to be "economic, engineering, design, capacity or operational constraints, or accommodating the request would otherwise adversely impact

the timely development of the project.”²³ Additionally, we are adding a provision to the section which will enable the project sponsor, at the appropriate time in the development of its project and subject to Commission approval, to determine, based on the above criteria, that no further bids can be accepted. We will also revise section 157.34(d)(2) to provide that any bid tendered after the expiration of an open season must contain a good faith showing, including a statement of the circumstances which prevented the bidder from tendering a timely bid, and how those circumstances have changed. This requirement is consistent with the underlying premise of section 157.34(d)(2) in the Final Rule, and should serve to protect against “gamesmanship.” With these revisions and clarifications, we believe that the late bid provision will permit late-developing shippers to obtain capacity after the expiration of the open season, while also providing the prospective applicant the assurance that it will be able to design and develop its project according to its own schedule.

V. Mandatory Pre-Approval

A. The Final Rule - § 157.38

64. Section 157.38 requires that, at least 90 days prior to providing its notice of open season, an applicant must file, for Commission approval, a detailed plan for conducting the open season in conformance with the regulations. The Commission will establish a date by which comments on the request for approval are due, and the Commission, unless it directs otherwise, will act on the request within 60 days of its filing. The Commission concluded in Order No. 2005 that this requirement would allow for the resolution of disputes or dissatisfaction with an open season at the earliest possible time, thereby reducing the risk of having to require a second remedial open season because the first one did not conform to the regulations.

²³ We are retaining the requirement that the prospective applicant must provide a detailed explanation for its rejection, at least until such time as it has determined, subject to Commission approval, that no further late bids can be accepted. We find that, based on the prospective applicant’s position, it is easier for it to evaluate why a late bid cannot be accepted, than it is for a later bidder to explain why its bid can be accommodated.

B. Rehearing/Clarification Requests

65. The North Slope Producers and Enbridge urge the Commission to eliminate the mandatory pre-review process set out in section 157.38, calculating that with the addition of this mandatory review, the open season process will take at least 210 days, instead of the 120-day open season period proposed in the NOPR and established in section 157.34. They state that this additional 90 days does not include further delays that could result from disputes arising during the pre-review process, including the need to consider requests for rehearing of any orders pre-approving an open season or the Commission's inability to adhere to its 90-day window. The result, they claim, is that the open season process will be delayed, not expedited. Enbridge states that the 210-day period is longer than the 180-day open season period which the Commission rejected as inconsistent with Congress' sense of urgency, as well as the Commission's conclusion in Order No. 2005 that "timing is of the essence."

66. The North Slope Producers maintain that the Commission's justification for this requirement is that a successful open season is more likely to occur if issues are identified and resolved at the earliest time. The North Slope Producers disagree, claiming that, instead of reducing the chance of post-bid disputes, this layer of review will provide those who would gain commercial leverage by delaying the open season process "with an additional bite at the apple, first by objecting to the bid package, then by objecting to the results of the open season."

67. Both the North Slope Producers and Enbridge contend that the mandatory pre-review process is unnecessary and duplicative of other protections provided in Order No. 2005, including the transparency and specificity of the open season information, the 30-day prior notice requirement, the prohibition against undue discrimination or preference in rates, terms or conditions of service, and the imposition of Order No. 2004 standards of conduct. They contend that the effects of any delay of the open season can be profound, due to narrow, seasonal windows for environmental studies and preliminary field work, which cannot take place until the open season has been held. These risks, they claim, far outweigh any utility of a mandatory pre-review. In conclusion, the North Slope Producers contend that any pre-review of the open season notice should be voluntary, shortened, and that the Commission decision on the sufficiency should be deemed a pre-decisional, non-reviewable determination, similar to the Commission's action in rejecting a deficient certificate application under section 157.8 of the Commission's regulations.

68. Anadarko defends the mandatory pre-review requirement as striking an "appropriate balance between granting project sponsors flexibility in designing open seasons and providing regulatory supervision to potential bidders by requiring project sponsors to file and obtain approval of the open season plan." Anadarko and the Alaska Legislators state that pre-approval will reduce any risk of having to hold a second open season to correct one done improperly. Anadarko states that this will, as the Commission believes, promote rather than hinder a timely and successful open season. The Alaska Legislators agree with this assessment, contending that adding 90 days to the front end of the open season process, even with the prospect of a rehearing, is better than having an open season called back by an order on rehearing or on appeal from the results of an open season, and then having to hold another open season. Moreover, they state that once the open season is approved, parties may rely on those terms being controlling throughout the bidding and contracting process.

C. Commission Response

69. The North Slope Producers and Enbridge correctly state that, by virtue of the mandatory pre-approval established in section 157.38, the minimum duration of the whole open season process would be 210 days. However, the concept of a mandatory pre-approval and the attendant additional time that such review will add is not inconsistent with our concern that "time is of the essence" that caused us to reject a 180-day open season period, and instead provide for a 120-day open season.²⁴ Our focus in establishing this 120-day period was to arrive at a time period such that all prospective bidders reasonably could review the open season information and evaluate whether to make multi-year capacity commitments, thereby leveling the playing field.

70. When discussing the duration of the whole "open season process," we must consider the potential for delays due to disputes arising during the open season. In this regard, we found in Order No. 2005 that pre-approval of open season procedures would "allow issues to be identified and resolved at the earliest possible time and, ideally, reduce the possibility of dissatisfaction with open seasons, as well as the risk that the

²⁴ The 120 days consists of the 30-day prior notice period (section 157.34(a)), followed by a 90-day open season (section 157.34(d)(1)).

Commission will have to require that deficient open seasons be conducted again.”²⁵ The North Slope Producers’ and Enbridge’s disagreement with this assessment is based on arguments that the transparency and specificity of the information required in the open season and other protections provided in the open season rules render pre-approval unnecessary, and that the pre-approval process itself invites delay.

71. We are not as optimistic as the North Slope Producers and Enbridge that there is little likelihood that disputes might arise over the conduct of an open season and its conformance with the open season rules. While the transparency and specificity of the open season rules might lead to a clearer identification of any issues in dispute, they do not change the fact that in any open season there will be a universe of potential bidders with starkly different, competing needs and interests, and the potential for dispute is real. We continue to believe that getting it right the first time is the best approach.

72. Nonetheless, in revisiting the requirement for mandatory pre-approval as a result of these rehearing requests, we find that it is appropriate to make some changes. First, we are revising section 157.38 to make clear that the plan to be filed by a prospective applicant shall include the information required in a notice of open season under section 157.34. Second, we are eliminating the 30-day prior notice requirement in section 157.34(a). Since the public will have actual notice of a prospective applicant proposed open season notice at least 90 days prior to the open season, there is no reason to provide for an additional prior notice period. By this change, we are reducing the 210-day period to 180 days. It also our conclusion that, given the fact that participants in an open season will have the opportunity to object to the conduct of the open season after a certificate application is filed, as is our current practice, as well as the ability to seek rehearing and obtain appellate review of any Commission certificate orders, orders approving open season procedures will be interlocutory and not subject to rehearing.

V. In-State Study

A. The Final Rule - §157.34(b)

²⁵ Order No. 2005 at P 109.

73. In response to concerns expressed by Alaska entities and in recognition of Congress' mandate that Alaska in-state needs be given due consideration, the Final Rule added in section 157.34(b) a requirement not contained in the proposed regulations that the open season information include an assessment of Alaska's in-state needs and prospective points of delivery within the State of Alaska, based to the extent possible on any available study performed or otherwise approved by an appropriate Alaska governmental entity.

B. Rehearing/Clarification Requests

74. While the North Slope Producers find reasonable a requirement that a study of in-state needs be completed prior to any open season, they object to section 157.34(b)'s requirement that the contents of the open season notice rely on an in-state study, if practicable. They assert that ANGPA does not require a pipeline sponsor's study to "include or consist" of a state-sanctioned study. The North Slope Producers contend that this requirement invites disputes as to whether it is "practicable" to include a state study, or whether "appropriate" state officials were involved. Consequently, the North Slope Producers request that the Commission revise section 157.34(b) to require that a project sponsor consult with the State regarding the study for in-state needs.

75. The Alaska Legislators state that the Commission has avoided the problem of "dueling studies" by deferring the study to the State of Alaska. In this regard, the Alaska legislators advise the Commission that the State of Alaska has undertaken to designate an appropriate agency to conduct or sanction the required study, and the Alaska House of Representatives has passed a resolution urging the Administration to conduct, approve, or sanction the required study prior to the effective date of the opens season rules.

C. Commission Response

76. Section 157.34(b) does not mandate the use of a particular study but rather is premised on the common-sense notion that information provided by the State of Alaska likely will be valuable to potential shippers. We trust that the State and prospective pipeline applicants can agree on the manner in which such information can be provided. If questions arise as to the extent to which it is possible to include a state study, we will resolve them. Our regulations offer several options that the prospective applicant and the State of Alaska could take to ensure the adequate involvement of the State. Accordingly, we will not revise section 157.34(b).

VI. In-State Rates

A. The Final Rule - § 157.34 (c)(8)

77. In addition to the requirement that in-state gas needs be addressed in the open season, the Commission also required, in section 157.34(c)(8), that, based on in-state needs and the delivery points identified in the study, open season information include a proposed in-state transportation rate, based on the costs of providing that service.

B. Rehearing/Clarification Requests

78. The North Slope Producers ask the Commission to clarify that estimating rates for in-state service does not create a requirement to offer such a service at that rate (or at all) if the open season does not yield firm commitments for in-State deliveries. They assert that the ultimate indicator of any market for in-state service is the willingness of shippers to make firm commitments to purchase capacity for in-state use during the open season, not a study. They also request that the Commission clarify that the estimated in-state service rates are merely illustrative and subject to adjustment.

79. Enbridge requests that the Commission make clear that the "estimated transportation rate" referred to in section 157.34 (c)(8) is one based on project sponsor's estimated costs to make in-state deliveries, not upon any rates assumed by the study. Additionally, Enbridge states that the Commission clarify that bids for in-state service should be subjected to the same requirements for creditworthiness, collateral and execution of binding contractual commitments as apply to any other open season bidder.

80. The State of Alaska asks the Commission to clearly state that the in-state rates are to be distance-sensitive in order to ensure that the cost of in-state service is calculated properly.

C. Commission Response

81. During the open season process, qualified bidders must successfully bid upon and arrange to consummate service agreements for transportation service. Projected rates for in-state deliveries must be based on estimates of costs for providing service to the in-state delivery points. While prospective applicants will estimate rates during an open season, the Commission's review of proposed rates will be guided by section 284.10(c)(3) of our regulations, which states in part that "[a]ny rate filed for service ... must reasonably reflect any material variation in the cost of providing the service due to ... the distance over which the transportation is provided."

82. All shippers on any new interstate pipeline have a right to pay only the initial rate on file as approved in the NGA section 7 certificate of public convenience and necessity. Those initial rates, approved under section 7 as part of the certificate, would be paid unless changed under section 4 or 5 of the NGA after appropriate regulatory proceedings and upon the Commission's order. However, under the Commission's negotiated rate policy,²⁶ pipelines and shippers are free to make an agreement to "dispense with cost-of-service regulation" and agree to any mutually agreeable rate. A recourse rate found in the pipeline's tariff would be available for those shippers preferring traditional cost-of-service rates. Thus, if an in-state service is successfully bid upon, filed for and approved, an in-state cost-of-service recourse rate would be set in an Alaskan pipeline's tariff, but in-state shippers would also be free to seek a negotiated in-state rate with an Alaskan pipeline. Negotiated rates can be used to lock in transportation costs and pipeline revenues to the mutual benefit of both the shippers and the pipeline, without the risks of later changes to rates and revenues under the NGA.

83. If there are no successful bids for in-state service, the prospective applicant would nonetheless have to include the in-state service as part of its proposed initial tariff. An opportunity to have in-state service might arise if the pipeline voluntarily accepts a request for it at a later time, or if the Commission acts under section 103(h) of ANGPA and section 5 of the NGA to require the pipeline to make such in-state deliveries. The actual in-state rate for in-state service would be an issue for such future proceedings. Based on the foregoing, we see no need to further clarify the regulations.

VII. Tying Arrangements

A. The Final Rule - §§ 157.34(c)(6), 157.34(c)(10), and 157.35(a)

84. The Commission addressed the matter of tying access to pipeline capacity on an Alaska project to ancillary services in two sections of the Final Rule. First, section 157.34(c)(6) requires that the open season notice must contain an unbundled

²⁶ Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines, Docket No. RM95-6-000, Regulation of Negotiated Transportation Services of Natural Gas Pipelines, Docket No. RM96-7-000, 74 FERC ¶ 61,076, (Jan. 31, 1996).

transportation rate. Second, section 157.34 (c)(10) prohibits a prospective applicant from requiring prospective shippers to process or treat their gas at any designated facility. We explained elsewhere in Order No. 2005 "that [we] can address any other discriminatory conduct in connection with gas quality requirements or other ancillary services through the provisions of section 157.35 in conjunction with existing Commission policies and procedures." Relevant to this explanation, section 157.35(a) provides that "[a]ll binding open seasons shall be conducted without undue discrimination or preference in the rates, terms, or conditions of service and all capacity awarded as a result of any open season shall be awarded without undue discrimination or preference of any kind."

B. Rehearing/Clarification Requests

85. The State of Alaska states that the Commission should more explicitly explain the prohibition against tying arrangements, and explain how the open season rules will apply to gas treatment plants. The State believes that the open season rules should do more than require an applicant to use an unbundled transportation rate, prohibit tying of capacity on the pipeline to the use of a designated plant or facility, and merely refer to the existing regulations and policies prohibiting undue discrimination or preference. Rather, Alaska states that the open season rules should make clear that any tying arrangements will be subject to an exacting inquiry by the Commission and will require a compelling justification, and even offers recommended language to this end.

86. Alaska also states that since ANGPA includes gas treatment plants in its definition of an Alaska natural gas transportation project,²⁷ treatment plants should be subject to the open season regulations. Alaska points out that the effect of the unbundling requirement of section 157.34(c)(6) is to exclude gas treatment plants from the requirements of the open season. As a possible solution, Alaska suggests that the open season rules be clarified to provide that the applicant must separately offer gas treatment plant capacity and pipeline capacity in the open season notice, and give bidders an opportunity to bid on

²⁷ ANGPA §102(2) defines the term 'Alaska natural gas transportation project' as "any natural gas pipeline system that carries Alaska natural gas to the border between Alaska and Canada (including related facilities subject to the jurisdiction of the Commission) ..."

either or both, as they choose. ChevronTexaco contends that because gas treatment plants are jurisdictional facilities,²⁸ Order No. 2005's approach of deferring consideration of any discriminatory conduct as to necessary such ancillary facilities and services to a later day does not satisfy the requirements of the ANGPA. Chevron Texaco maintains that it is particularly important that access to treatment facilities be subject to the same open season, non-discriminatory requirement as the pipeline because pipeline capacity without access to gas treatment facilities that maybe a part of the pipeline system is meaningless.

C. Commission Response

87. The Commission did not intend to preclude the inclusion of jurisdictional natural gas conditioning facilities from the open season. If, pursuant to ANGPA section 103, a project sponsor intends to file an application under section 7 of the NGA for authorization of a project that includes a jurisdictional natural gas conditioning service, we will review the open season plan and notice to ensure that such service is offered in its open season notice, subject to the same requirements as apply to transportation service. However, the prospective applicant must offer a separate rate for the gas treatment service and separate rate for the transportation service. Furthermore, the prospective applicant can neither require bidders to bid on both services, nor evaluate the bids based on whether bidders requested one or both services. Moreover, while the prospective applicant can require specific natural gas quality specifications such as would be met by using the conditioning services of the pipeline, it cannot reject an otherwise qualified bidder that states that it will deliver to the pipeline facilities gas that meets the stated quality specifications.

88. On the other hand, if a prospective applicant is proposing to apply to revise the Alaska Natural Gas Transportation System (ANGTS) application now held in abeyance, then a conditioning service will have to be included as a part of the open season but again, with all services offered priced separately. Specifically, in 1981, President Reagan submitted a Waiver of Law to Congress for the purpose of clearing away certain government-imposed obstacles to the private financing of the ANGTS. The Commission

²⁸ See *Venice Gathering Co.*, 97 FERC ¶ 61,045 at 61,255 (2001) (Treatment of gas to enhance its safe and efficient transportation is subject to Commission jurisdiction).

implemented that portion of the Presidential waiver that required the Commission to include within the ANGTS the gas conditioning plant at Prudhoe Bay.²⁹

VIII. Pre-Subscribed Capacity

A. The Final Rule - §§ 157.33(b) and 157.34(c)(15)

89. Under section 157.33(b), pre-subscription agreements for initial capacity on a proposed Alaska natural gas transportation project are permitted, provided that capacity is offered to all open season prospective bidders at the same rates and on the same terms and conditions as contained in the pre-subscription agreements. In addition, if there is more than one pre-subscription agreement, open season prospective bidders are given the option of selecting the rates, terms and conditions contained in any one of the several agreements. However, section 157.34(c)(15) states that "[i]f capacity is oversubscribed and the prospective applicant does not redesign the project to accommodate all capacity requests, only capacity that has been acquired through pre-subscription shall be subject to allocation on a *pro rata* basis; no capacity acquired through the open season shall be allocated."

B. Rehearing/Clarification Requests

90. The North Slope Producers assert that the provision in section 157.34(c)(15) subjecting only presubscribed capacity to *pro rata* allocation, will dissuade any shippers from signing up for the presubscribed capacity, thereby "wholly negating" the recognized benefits of allowing pre-subscription agreements to facilitate the development of an Alaska natural gas transportation project. They predict that prospective shippers would rather wait for the open season than risk proration. The North Slope Producers maintain that this selective proration unduly discriminates against those shippers who are willing to make early commitments for firm capacity in order to support the project, in violation

²⁹ See *Alaskan Northwest Natural Gas Transportation Co.*, 18 FERC ¶ 61,002 (1982).

of the NGA and Commission policy. They add that since section 157.33(b) allows all open season participants to enjoy the same benefits as contained in the pre-subscription agreements, such discrimination is particularly unjustified. The North Slope Producers add that this is another example where the Commission is attempting to compel the project sponsor to make design changes in order to accommodate all bids.

91. The North Slope Producers also state that the final clause of section 157.34(c)(15) is not consistent with the Commission's presumed intent not to foreclose proration among open season bidders where there is no presubscribed capacity. They suggest that the final clause of that provision, which states "no capacity acquired through the open season shall be allocated," should be clarified.

92. In addition to agreeing that proration renders pre-subscription an unattractive option for prospective shippers, Enbridge adds that the additional requirement that the terms and conditions of any pre-subscription agreements be made public prior to the open season notice renders pre-subscription even less desirable because it put anchors shippers at a competitive disadvantage to open season bidders who would have prior knowledge of the pre-subscription bids. At the same time, Enbridge concedes that it would be highly unlikely that project would not be re-designed to accommodate capacity of all qualified bids at the incipient, open season stage.

93. Enbridge raises again the claim that the "numerous and overlapping protections" of Order No. 2005, in particular the level of information provided in open season notice and measures provided to ensure against discrimination, are sufficient to ensure a fair, open and non-discriminatory open season process. Enbridge also states that the Commission should clarify that open season shippers who in the open season elect to select the terms and conditions of a pre-subscription agreement may not cherry-pick terms and conditions from several agreements but must accept any one agreement in its entirety.

94. The State of Alaska seeks clarification that, in the case of capacity allocation on an oversubscribed pipeline that cannot reasonably be redesigned, both presubscribed capacity and capacity later acquired on the same rates, terms and conditions will be subject to allocation, for the reason that the final words of section 157.34 (c)(15) stating that "no capacity acquired through the open season shall be allocated," suggests otherwise.

95. ChevronTexaco maintains that the Commission failed to consider and provide for the various circumstances that could trigger the pro-rationing of pre-subscribed capacity. ChevronTexaco states that bidders in the open season could outbid pre-subscribing

shippers on the basis of any of the qualifying conditions: for instance, an open season bidder might outbid pre-subscribing shippers whose agreements are at less than maximum rates, or whose agreements are of shorter terms. ChevronTexaco is concerned that pre-subscribing shippers might lose their capacity to open season bidders who outbid them because they know the salient terms of the pre-subscription agreements. Therefore, ChevronTexaco submits that the Commission should expand the requirement of pro-rationing by establishing that all bids eligible to be allocated capacity in an open season where pre-subscribing shippers will be prorated should be treated as having equal value to the pre-subscription precedent agreement for purposes of pro-rationing. In this way, later qualifying bidders would be prevented from outbidding pre-subscribing shippers.

96. In response to the claims on rehearing that the capacity allocation provisions of section 157.34(c)(15) are counterproductive because they will deter potential anchor shippers from entering into pre-subscription agreements, Anadarko contends that the Commission's finding that the North Slope Producers' unique position of control over pipeline design amply justifies putting the consequences of any decision not to redesign pipeline to accommodate all bidders on them. Anadarko also questions the importance placed on pre-subscription agreements in connection with an Alaska pipeline project. According to Anadarko, the only justification for a pre-subscription agreement is to facilitate financing and to provide the project sponsor with assurances that it has the commitments to justify development and construction expenses. However, states Anadarko, there is little doubt that any Alaska natural gas transportation project will be fully committed, even without pre-subscription agreements.

97. The Alaska Legislators support the pre-subscription rules of Order No. 2005, claiming that the rules make sense given the unique nature and circumstances of an Alaska natural gas transportation project and the need to balance concerns "that pre-subscription is essential to finance the pipeline with concerns of those who feared that such arrangements would favor affiliates of the pipeline or otherwise undermine the objectives of conducting public open seasons for capacity."

C. Commission Response

98. Although we allowed pre-subscription agreements in the belief that they could have utility in facilitating the development of an Alaska natural gas transportation project, we cannot quantify how beneficial such arrangements are. Our paramount consideration in allowing pre-subscription was that it should not impact in any way the capacity obtained through the open season process. For this reason, we provided that any capacity acquired by reason of agreements entered into prior to the open season would have to yield to capacity bid for in the open season in the case of oversubscription. We

believe our reasons for this selective proration, as stated in Order No. 2005 and reaffirmed here, are sound.

99. The argument that anchor shippers will be dissuaded from entering into pre-subscription agreements if they risk losing capacity as a result of open season bidding, and that the "recognized benefits" of pre-subscription will be lost, is unpersuasive. The North Slope producers and other potential project sponsors have developed a plethora of information in recent years regarding the viability of an Alaska project. They are fully capable of deciding whether they wish to execute pre-subscription agreements. If they do not, capacity will be allocated in an open season. There has been no showing that an Alaska project cannot be financed, as are many major projects, based on commitments made in an open season. While we have concluded that the public interest permits pre-subscription, under the conditions established by the rule, we do not find that the public interest requires pre-subscription. It does require competition and open-access. We leave it to potential project sponsors and shippers whether pre-subscription makes sense to them.

100. We will, however, clarify section 157.34(c)(15) in two respects, first to eliminate confusion over the last sentence of that section which concludes "no capacity acquired through the open season shall be allocated," and second to make clear that in the event there is more than one pre-subscription agreement, bidders in the open season may not cherry-pick among the provisions of the several agreements. The North Slope Producers contend that the last clause of section 157.34(c)(15) might be read to provide that proration is foreclosed among open season bidders even where there is no subscribed capacity. We will clarify the language of the rule to avoid such a misreading. Capacity bid for in the open season is exempt from allocation only in a case where there is also subscribed capacity, as explained in the text of Order No. 2005. The State of Alaska reads that clause to suggest that capacity acquired by bidders in the open season who elect to acquire their capacity on the same rates, terms and conditions as contained in a pre-subscription agreement will not be subject to pro rata allocation along with the pre-subscription shippers. Such an interpretation also misreads the intent of section 157.34(c)(15), and we will clarify the language of the rule accordingly. Finally, we will clarify section 157.33 to make clear that open season bidders may not cherry pick among the provisions of several precedent agreements, as was our intent in the Final Rule.

IX. Other Issues

101. The North Slope Producers request that the open season rules be clarified in certain respects. First, they request that the Commission clarify the open season

regulations by replacing references to "prospective points of delivery within the State of Alaska" or "delivery points" in several subsections of the regulation with the term "tie-in points."³⁰ The North Slope Producers assert that the term "delivery point" implies an obligation that the pipeline will be finally designed to deliver gas all the way to in-State markets and that ANGPA does not contemplate or impose such an obligation.

102. The Commission understands the terms "prospective points of delivery within the State of Alaska" or "delivery points" to mean those points on the interstate Alaskan pipeline where custody of the gas would be transferred to the facilities of an intrastate pipeline, local distribution company, or end-user whose facilities are not otherwise under the Commission's jurisdiction, assuming that shippers on an Alaska pipeline requested such deliveries. The term "tie-in points" as used only once in ANGPA is used in reference to the study of in-state needs in section 103(g) and as a familiar natural gas industry phrase is not as familiar to the Commission as the terms "points of delivery" or "delivery points."³¹

103. As part of the open season, the prospective applicant is in fact obligated to offer to deliver gas at least at certain prospective in-state delivery points identified in the study of in-state needs. However, the open season notice's initial design of the pipeline need only match the prospective applicant's open season business proposal to deliver at least the amount of gas identified in the study of in-state needs at those prospective in-state delivery points. Bidders may seek alternative delivery points (such as ones closer to their market) as part of their bids, and as part of the open season the prospective applicant may consider building additional facilities to such alternate points, but has no obligation to do so as long as it treats similar requests the same. As discussed above, if the open season ends without any successful bids for in-state deliveries, then there is a continuing obligation for the prospective applicant to leave provision for such in-state service available in its tariff, but it would not have to voluntarily propose such service as part of its initial application. Also, as used in section 157.34, the term "delivery point(s)" also refers to the location at the border between Alaska and Canada where presumably

³⁰ These sections include §§ 157.34(b) and 157.34(c)(1), (2), (3), (6), (8), and (16).

³¹ Although tie-in point is used in some Commission documents, the most common use is to identify the point where a pipeline's loop ties back into the mainline.

prospective bidders will seek to have their volumes delivered. It would be much more confusing if the regulations were revised to refer to "tie-in points" for points inside Alaska and "delivery points" for locations at the border between Alaska and Canada. Therefore, we will not clarify the rules as requested by the North Slope Producers in this regard.

104. Second, the North Slope Producers state that the "catch-all" language in section 157.34(c)(18) was not scaled back enough from the language proposed in the NOPR. Specifically, they state that as written, the final regulation requires a pipeline applicant to provide all bidders, not only with information the applicant has provided to any bidder, but also with information "in the hands of" any bidder. The North Slope Producers claim that the applicant cannot know what information identified in section 157.34(c)(18) is "in the hands of a potential shipper." Moreover, they contend that while the text of Order No. 2005 does not discuss the intent of this subsection, the Commission's press release and the Commission staff's PowerPoint presentation at the February 9, 2005 Commission Open Meeting presentation refer to information that the applicant has in some way made available to a potential shipper, and the regulations should be clarified to be consistent with this intent. The North Slope Producers add that, read literally, this language would call for protected information. Enbridge, on the other hand, claims that section 157.34(c)(18) should be eliminated as unnecessary due to the transparency assured by the rest of the numbered subsections of section 157.34(c).

105. Anadarko objects to this requested clarification, pointing out that the North Slope Producers are likely already to possess relevant project-related information as a result of discussions with other possible project sponsors, and if the North Slope Producers becomes the project sponsor, this information is already in their hands and was not made available to them by an applicant.

106. The "catchall" provision addresses the difficult issue of separation of functions between a prospective applicant and its affiliates who produce, sell or market Alaska gas, and as such are potential bidders for capacity on an Alaska natural gas transportation project. It has been targeted as a problem since it appeared in the NOPR and it was discussed extensively in the Final Rule.³² The North Slope Producers have undertaken

³² See Order No. 2005 at P 72 -83.

millions of dollars of due diligence "homework" on the design, cost, operation and feasibility of an Alaska pipeline. If they are not affiliated with the prospective applicant for an Alaska pipeline, then all that knowledge and information is theirs and, presumably, would give them an informational advantage in the open season bidding. However, if the North Slope Producers are affiliated with the prospective applicant, then the Commission and other potential bidders must be assured that any relevant information about the design, cost, operation and feasibility of an Alaska pipeline that the North Slope Producers transfers to an affiliated prospective applicant is available to everyone. The Commission desires to make this very important part of the Final Rule as clear as possible. Thus, we will revise section 157.34(c)(18) to read as follows:

All information that the prospective applicant has in its possession pertaining to the proposed service to be offered, projected pipeline capacity and design, proposed tariff provisions, and cost projections, or that the prospective applicant has made available to, or obtained from, any potential shipper, including any affiliates of the project sponsor and any shippers with pre-subscribed capacity, prior to the issuance of the public notice of open season;

The Commission understands that the scope of this information is extensive. Therefore, we will not require that the contents of the open season notice to be published by the prospective applicant must contain copies of all the documents which would be covered under section 157.34(c)(18), but that the notice identify a "public reading room" where such information is available, for copying at the reader's expense. Further, as the North Slope Producers point out, dealing with potential "protected information" will have to be addressed as it is in any commercial situation. The Commission expects that all parties will cooperate in dealing with "protected information," but as in all matters pertaining to the open season process, the Commission and its staff stand ready to assist in resolving any disputes.

107. Third, the North Slope Producers request that the Commission clarify the requirement in section 157.35(c) that the project applicant "create or designate a unit or division to conduct the open season that must function independent of the other divisions of the project applicant as well as the applicant's Marketing and Energy affiliates." They claim that they intend to create a separate entity to be the project sponsor and to conduct the open season, and that this section would require them to establish yet another separate entity to conduct the opens season, and that section 157.35(c) should be revised to reflect that this is sufficient. Specifically, the North Slope Producers propose to delete from the regulations the language requiring that a project applicant must designate a separate unit

or division to conduct the open season. Anadarko claims that this requested clarification would largely nullify the purpose of section 157.35(c).

108. The Commission denies the North Slope Producers' proposed change to section 157.35(c). However, the Commission will amend the section to take into account situations in which a project applicant is an entity that has been separately created for the purpose of conducting an open season. In such cases, the separate entity would comply with the provisions of section 157.35(c) if that project applicant functioned and operated independently from the project applicant's Marketing and Energy Affiliates, as well as the other divisions of the project applicant. The purpose of section 157.35(c) is to ensure that the project applicant conducting the open season is independent of, and does not favor, its affiliates. If the project applicant was created to comply with section 157.35(c) and does, in fact, comply with the regulation, the project applicant is not required to create a further subdivision to achieve compliance.

109. The North Slope Producers identify several other non-substantive clarifications to the regulatory language that should be made to avoid confusion.³³ These corrections will be made.

110. Enbridge argues that since the open season regulations require that the project design criteria include a requirement that the project be capable of "low-cost expansion,"³⁴ the Commission should explain that the threshold for satisfying the low-cost expansion" standard is any expansion that does not increase rates to initial shippers. However, as Enbridge recognizes, any certificate application for an Alaska natural gas

³³ These include typographical errors in section 157.35(d) (references to sections 258.4(a)(1) and (3) should be to sections 358.4(a)(1) and (3)), Order No. 2005, P 74 (should cite to §§ 358.5(d) and 358.4(e)(3) rather than §§ 358.4(d) and 358.(b)(e)(3)); section 157.34(c)(9) ("proscribed" should be changed to "prescribed"); and section 157.33(b) ("terms, rates, terms and conditions" should be changed to "duration, rates, terms and conditions"). The North Slope Producers also suggest that the term "rate amounts" in section 157.34(c)(9) should be changed to "rates" as the latter term is more commonly used in the industry.

³⁴ See, e.g., Order No. 2005 at P 82; section 157.37.

transportation project might provide detail regarding several expansion scenarios depending on and in response to the results of the open season. The project design review that the Commission will undertake focuses on the proposed project's ability to accommodate the capacity bid for in the open season, as well as the extent to which the project can accommodate "low-cost" expansion. All expansions will involve cost. Obviously, as recognized by virtually all stakeholders, capacity that can be gained by compression alone would typically be the lowest-cost expansion. At the other end of the spectrum would be a pipeline that has no compression-only expansion potential, necessitating the need for looping in the first instance. The operative word in connection with any "low-cost" standard in section 157.37, is the *extent* of the design's expandability, and that standard is not tied to the cost impact of a given expansion. Consequently we will not clarify section 157.37 as requested by Enbridge.

111. ChevronTexaco claims that the Final Rule contains a conflict about how the contract term might be used by the prospective applicant in establishing its methodologies for the evaluation of bids and the allocation of capacity due to oversubscription, should that be necessary. It states that this confusion is caused because contract term is not mentioned in section 157.34(c)(14) regarding evaluation of bids, but is mentioned in section 157.34(c)(15) regarding allocation of capacity due to oversubscription. ChevronTexaco also complains that the Commission's stated intention to rely on after the fact enforcement of issues that might be caused by unusual contract terms, rather than set a cap on contract term for the purpose of bidding and allocation review methodologies, does not satisfy ANGPA's mandate that the Commission's open season rules are fully prescriptive. ChevronTexaco requests that the Commission clarify the open season regulations to require that open season notices to include a cap on the contract term for capacity bids.

112. First, our intention to rely on after-the-fact enforcement of open season issues that might be caused by unusual contract terms, or by any other aspect of the open season process that is not specifically enumerated in the open season regulations, completely satisfies the intent of Congress as stated in ANGPA. Moreover, as explained in Order No. 2005, it is consistent with our existing policy. However, we do agree that the discrepancy in language between section 157.34(c)(14) and section 157.34(c)(15) should be clarified to provide consistency between the methodologies for the evaluation of bids and the allocation of capacity due to oversubscription. To be consistent and avoid confusion, we will delete the phrase "including price and contract term" from section 157.34(c)(15). Furthermore, we will look carefully at this issue in our review of any open season plan and notice under section 157.38.

113. ChevronTexaco claims that the only way to assure that an open season was conducted fairly and in accordance with the open season rules is by making the precedent agreements publicly available. Therefore, ChevronTexaco objects to the provision in section 157.34(d)(4) which provides that all precedent agreements and correspondence with bidders who were not allocated capacity must be filed with the Commission, but that they may be filed under a request for confidential treatment pursuant to section 388.112 of the Commission's regulations. ChevronTexaco claims that since precedent agreements will become agreements that will appear in a pro forma tariff or an effective tariff, there is little chance that the information in the precedent agreements should be confidential for any prolonged period of time, or that any of the information would fall under a Freedom of Information Act exemption. ChevronTexaco states that the precedent agreements could be filed in a public and non-public version in the event parts of the agreements do contain protected information.

114. We deny ChevronTexaco's request. Under section 388.112 of the Commission's regulations, any person submitting a document to the Commission may request privileged treatment by claiming that some or all other information is exempt from the Freedom of Information Act's disclosure requirements. We are not conferring any special confidential status to the agreements. The party requesting privileged treatment must support that claim. It may be, as ChevronTexaco claims, that precedent agreements are not likely to be exempt from disclosure. Neither section 157.35(d)(4) nor section 388.112 predetermines whether privileged treatment will be granted.

Document Availability

115. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (<http://www.ferc.gov>) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, N.E., Room 2A, Washington D.C. 20426.

116. From FERC's Home Page on the Internet, this information is available in the Federal Energy Regulatory Records Information System (FERRIS). The full text of this document is available on FERRIS in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in FERRIS, type the docket number excluding the last three digits of this document in the docket number field.

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(202) 502-8371 Press 0, TTY (202)502-8659. E-Mail the Public Reference Room at public.referenceroom@ferc.gov

Effective Date

118. These regulations are effective as of the date of publication in the FEDERAL REGISTER.

List of subjects in 18 CFR Part 157

Administrative practice and procedure; natural gas; reporting and recordkeeping requirements

By the Commission.

(S E A L)

Linda Mitry,
Deputy Secretary.

In consideration of the foregoing, the Commission amends Part 157, Chapter I, Title 18, Code of Federal Regulations, as follows.

**PART 157 - APPLICATIONS FOR CERTIFICATES OF PUBLIC CONVENIENCE
AND NECESSITY AND FOR ORDERS PERMITTING AND
APPROVING ABANDONMENT UNDER SECTION 7 OF THE
NATURAL GAS ACT**

1. The authority citation for Part 157 continues to read as follows:

AUTHORITY: 15 U.S.C. §§ 717 -717w.

**SUBPART B – OPEN SEASONS FOR ALASKA NATURAL GAS
TRANSPORTION PROJECTS**

2. In section § 157.33, paragraph (b) is revised to read as follows:

§ 157.33 Requirements for Open Seasons.

(a) * * *

(b) Initial capacity on a proposed Alaska natural gas transportation project may be acquired prior to an open season through pre-subscription agreements, provided that in any open season as required in (a) above, capacity is offered to all prospective bidders at the same rates and on the same terms and conditions as contained in the pre-subscription agreements. All pre-subscription agreements shall be made public by posting on Internet websites and press releases within ten days of their execution. In the event there is more than one such agreement, all prospective bidders shall be allowed the option of selecting among the several agreements all of the rates, terms and conditions contained in any one such agreement.

3. In section 157.34, paragraphs (a), (c)(9), (c)(15) and (c)(18), and (d)(2) are revised to read as follows:

§ 157.34 Notice of open season.

(a) Notice. A prospective applicant must provide reasonable public notice of an open season through methods including postings on Internet websites, press releases, direct mail solicitations, and other advertising. In addition, a prospective applicant must provide actual notice of an open season to the State of Alaska and to the Federal

Coordinator for Alaska Natural Gas Transportation Projects.

* * * * *

(c) * * *

(9) Negotiated rate and other rate options under consideration, including any rates and terms of any precedent agreements with prospective anchor shippers that have been negotiated or agreed to outside of the open season process prescribed herein;

* * * * *

(15) The methodology by which capacity will be awarded, in the case of over-subscription, clearly stating all terms that will be considered, except that if any capacity is acquired through pre-subscription agreements as provided in §157.33(b) above and the prospective applicant does not redesign the project to accommodate all capacity requests, only that capacity that was acquired through pre-subscription or was bid in the open season on the same rates, terms, and conditions as any one of the pre-subscription agreements shall be allocated on a pro rata basis and no other capacity acquired through the open season shall be allocated.

* * * * *

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

* * * * *

(d) * * *

(2) A prospective applicant must consider any bids tendered after the expiration of the open season by qualifying bidders and may reject them only if they cannot be accommodated due to economic, engineering, design, capacity or operational constraints, or accommodating the request would otherwise adversely impact the timely development of the project, and a detailed explanation must accompany the rejection. Any bids tendered after the expiration of the open season must contain a good faith showing, including a statement of the circumstances which prevented the late bidder from

tendering a timely bid and how those circumstances have changed. If a prospective applicant determines at any time that, based on the criteria stated above, no further late bids for capacity can be accommodated, it may request Commission approval to summarily reject any further requests.

* * * * *

4. In section 157.35, paragraph (c) is revised to read as follows and paragraph (d), the word "258.4(a)(1)" is removed and the word "358.4(a)(1)" is inserted in its place.

§ 157.35 Undue Discrimination or Preference.

(a) * * *

(b) * * *

(c) Each prospective applicant conducting an open season under this subpart must function independent of the other divisions of the prospective applicant as well as the prospective applicant's Marketing and Energy affiliates as those terms are defined in §§ 358.3(d) and (k) of the Commission's regulations. In instances in which the prospective applicant is not an entity created specifically to conduct an open season under this Subpart, the prospective applicant must create or designate a unit or division to conduct the open season that must function independent of the other divisions of the project applicant as well as the project applicant's Marketing and Energy affiliates as those terms are defined in sections 358.3(d) and (k) of the Commission's regulations.

* * * * *

5. Section 157.36 is revised to read as follows:

§ 157.36 Open seasons for expansions.

Any open season for capacity exceeding the initial capacity of an Alaska natural gas transportation project must provide the opportunity for the transportation of gas other than Prudhoe Bay or Point Thomson production. In considering a proposed voluntary expansion of an Alaska natural gas pipeline project, the Commission will consider the extent to which the expansion will be utilized by shippers other than those who are the initial shippers on the project and, in order to promote competition and open access to the project, may require design changes to ensure that some portion of the expansion capacity be allocated to new shippers willing to sign long-term firm transportation contracts, including shippers seeking to transport natural gas from areas other than Prudhoe Bay and Point Thomson.

6. Section 157.38 is revised to read as follows:

§ 157.38 Pre-Approval Procedures.

No later than 90 days prior to providing the notice of open season required by section 157.34(a), a prospective applicant must file, for Commission approval, a detailed plan for conducting an open season in conformance with these regulations. The prospective applicant's plan shall include the proposed notice of open season. Upon receipt of a request for such a determination, the Secretary of the Commission shall issue a notice of the request, which will then be published in the Federal Register. The notice shall establish a date on which comments from interested persons are due and a date, which shall be within 60 days of receipt of the prospective applicant's request unless otherwise directed by the Commission, by which the Commission will act on the proposed plan.

CHAPTER 83

Natural Gas Transportation

Jonathan D. Schneider*

Richard M. Lorenzo**

Aryeh B. Fishman***

Huber Lawrence & Abell

Washington, D.C.

Scope

The natural gas industry has undergone a radical, albeit evolutionary, transformation since 1985. Culminating in Order No. 636, the effect of this change has been to shift the matter of buying and selling natural gas supplies almost completely into the competitive marketplace, while the focus of much recent regulatory activity has been to ensure that the interstate pipeline system serves as a barrier-free conduit for these transactions.

The discussion that follows begins with a review of the jurisdictional framework for federal natural gas regulation. Following that is a review of the events leading up to and those immediately following the issuance of the FERC's Order No. 436, which was the first major stage in the assault on the bastion of bundled pipeline sales service. Reviewed in some detail after that are the provisions of Order No. 636, the associated regulations and certain of the many orders through which the provisions of Order No. 636 were implemented. That review describes in depth the nature of services under which the natural gas industry is currently operating.

* Jonathan D. Schneider, a partner in the law firm of Huber Lawrence & Abell, chairs the firm's natural gas regulation practice and heads the firm's Washington, D.C. office. Co-gate University (B.A. 1978); Albany Law School of Union University (J.D. 1982).

** Richard M. Lorenzo is a partner in the law firm of Huber Lawrence & Abell. State University of New York at Albany (B.A. 1972); Case Western Reserve University (J.D. 1975); Columbia University (L.L.M. 1981). Columbia University, Center for Law and Economic Studies (Fellow 1979-1980); Columbia University School of Law (Associate in Law 1979-80).

*** Aryeh B. Fishman is an attorney in the Washington, D.C. office of Huber Lawrence & Abell. Brown University (B.A. 1991); Georgetown University Law Center (J.D. 1996).

crediting, distributing or allocating amounts previously collected."

Order No. 528 did not specify a general rule concerning the method to be adopted by individual pipelines, instead allowing individual pipelines and their customers to devise allocation methods suited to the various individual pipeline systems through individual Section 4 proceedings under the National Gas Act.³⁴ Order No. 528 retained Order No. 500's equitable sharing requirement and provided that pipelines must continue to absorb the same amount of costs as they had under Order No. 500. (Pipelines were permitted, however, to file to recover through a volumetric surcharge costs originally included in fixed charges.) In addition, the Commission concluded that, absent agreement of interested parties, it would retain Order No. 500's 50% cap on volumetric surcharge recovery for costs included in prior Order No. 500 filings, but would allow pipelines to seek to recover up to 75% of costs not included in a prior Order No. 500 filing through a volumetric surcharge.³⁵ Further, to mitigate the impact on small customers, the Commission allocated 50% of the costs otherwise allocated to these customers to other, larger customers, noting that small customers are often treated differently than other customers because of their special characteristics.³⁶ The Commission also indicated that the parties should include true-up provisions, and should consider adopting mileage-sensitive volumetric surcharges.

[2] Restructuring Under Order No. 636

[a] Introduction

On April 8, 1992, FERC issued Order No. 636,³⁷ reflecting the latest iteration in FERC's thinking on the nature of

³⁴ Order No. 528 at 61,595-96.

³⁵ Order No. 528-A at 61,299-300.

³⁶ *Id.* at 61,300-01.

³⁷ Order No. 636, *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations; and Regulation of Natural Gas Pipeline After Partial Wellhead Decontrol*, III F.E.R.C. Stats. & Regs. (CCH) ¶ 30,939, order on reh'g, Order No. 636-A, III F.E.R.C. Stats. & Regs. (CCH) ¶ 30,950 (1992); reh'g denied, Order No. 636-B, 61 F.E.R.C. (CCH) ¶ 61,272 (1992), appeal pending, *Atlanta Gas Light Co. and Chattanooga Gas Co. v. FERC*, No. 94-1171 (D.C. Cir.).

services that interstate pipelines must offer in order to enable consumers to take advantage of the competitive market for natural gas supplies resulting from the Natural Gas Policy Act of 1978,³⁸ the Commission's open-access program under Order No. 436 and the Natural Gas Well-head Decontrol Act of 1979.³⁹

Order No. 636 reflected the logical extension of Order No. 436, that consumer welfare is maximized when the interstate pipeline network provides a conduit for transporting natural gas purchased and sold in an open market. Order No. 636 states:

The Commission must create a regulatory environment in which no gas seller has a competitive advantage over another gas seller. In particular, the Commission must regulate the pipeline transportation system and pipeline sales for resale in a manner that ensures that pipeline control of the transportation system—a natural monopoly—does not give a competitive advantage to pipelines over other sellers in the sale of natural gas.⁴⁰

The Commission further characterized the competitive harm under status quo prior to Order No. 636 as resulting from "an unlawful restraint of trade."⁴¹ According to the Commission:

The bundled, city-gate, firm sales service provides the pipelines with an undue advantage and subjects other gas merchants to an undue disadvantage. It maintains an unreasonable difference in service between classes of service (bundled, city-gate, firm sales and open-access; firm transportation) because the firm transportation embedded within the firm sales is superior in quality. . . . The

³⁸ 15 U.S.C. §§ 3301-3432.

³⁹ 15 U.S.C. § 3331.

⁴⁰ Order No. 636 at 30,393. In a number of cases preceding Order No. 636, parties had litigated, and the Commission had approved settlements addressing, the "comparability of service" between transportation and sales rate schedules. In these cases, parties endeavored to ensure that parties purchasing gas from non-pipeline merchants enjoyed the same features of service, other than the gas itself, offered by pipelines to their bundled sales service customers. See, e.g., *Tennessee Gas Pipeline Co.*, 57 F.E.R.C. (CCH) ¶ 61,360 (1991); *Order on Rehearing Approving Settlement as Modified*, 59 F.E.R.C. (CCH) ¶ 61,045 (1992); *Order on Rehearing*, 59 F.E.R.C. (CCH) ¶ 61,318 (1992); *Transcontinental Gas Pipe Line Co.* went so far as to fully unbundle its sales and transportation services in a settlement approved by the Commission prior to Order No. 636. See *Transcontinental Gas Pipeline Co.*, 55 F.E.R.C. (CCH) ¶ 61,446 (1991).

⁴¹ Order No. 636 at 30,405.

Commission therefore finds and concludes that pipelines' bundled, city-gate firm sales service violates NGA Sections 4(b) and 5(a).

To remedy the harm so identified, the Commission chose from among the suggestions offered in response to its Notice of Proposed Rulemaking in Docket No. RM91-11⁴², the relatively dramatic remedy of prohibiting interstate pipelines from offering their sales service on a bundled basis, thereby requiring all customers to convert their previously bundled sales contracts to transportation and transportation-related services, and to purchase natural gas independently, whether from independent vendors or pipeline suppliers. The Commission provided a basis to allow conversion of each pipeline's bundled city-gate, firm sales service into unbundled firm transportation service.⁴³ In addition, the Commission authorized all interstate pipelines to provide unbundled sales service under new blanket certificates issued under Part 284 of Title 18 of the Code of Federal Regulations.⁴⁴

In an appendix to Order No. 636, the Commission published regulations, now appearing in Part 284 of the FERC regulations,⁴⁵ governing the terms of service with which all pipelines were directed to comply, although the Commission has allowed for a substantial degree of deviation among the features of service across pipelines.

[b] Order No. 636 Implementation

Working under a schedule for filing deadlines imposed in Order No. 636,⁴⁶ all pipelines were required to file their plans for compliance with Order No. 636 not later than the end of December 1992. Compliance filings were to include tariff sheets governing all services and pro forma rates reflecting the service-related changes, along with the rate design changes mandated by Order No. 636⁴⁷ and related

⁴² 56 Fed. Reg. 38,372 (1991).

⁴³ *Id.* at 30,409. The Commission rejected arguments that the remedy prescribed by Order No. 636 required modified certificate authority under § 7 of the Natural Gas Act, an argument upon which certain parties have rested the view that the Commission's Order is unlawful. *Id.* at 30,422.

⁴⁴ *Id.* at 30,409.

⁴⁵ 18 C.F.R. § 284, *et seq.*

⁴⁶ Order No. 636 at 30,462.

⁴⁷ While Order No. 636 addressed pipeline services principally, it raised rate design issues to the extent it required pipelines to implement

regulations under Part 284 of Title 18 of the Code of Federal Regulations (C.F.R.). Preceding these filings, pipelines were required to negotiate the terms of Order No. 636 compliance with their customers and other interested parties in settlement discussions initiated when each pipeline filed a restructuring proposal. Following the compliance filings, completed by December 1992, parties filed responsive comments on issues left unsettled following the negotiations, after which the Commission issued implementation orders governing each pipeline.⁴⁸

[c] Nature of Service Under Order No. 636

[i] The Unbundling Requirement and the Equality Principle

Although the regulations under Order No. 436 required that pipelines provide transportation services on a non-discriminatory basis,⁴⁹ thereby preventing pipelines from favoring their sales customers over transportation customers,⁵⁰ the Commission concluded in Order No. 636 that it was further necessary to prohibit pipelines from providing bundled sales service in order to ensure that customers would have equal access to all natural gas sellers, whether affiliated with a pipeline or independent. Accordingly, the Commission required all pipelines to convert customers' bundled city-gate, firm sales service into unbundled firm transportation service.⁵¹ In addition, the Commission required pipelines to make available so-called "no-notice" transportation, permitting certain customers to transport supplies to meet market needs fluctuating daily, without the need to nominate service or risk incurring a penalty.⁵²

Among the features left open to negotiations in individual pipeline proceedings was the place of unbundling in the

a "straight fixed variable" method for cost allocation and rate design, discussed further below.

⁴⁸ The Commission expressly determined that the record it had created through comments on the NOPR was sufficient in order to require industry-wide restructuring, thus rejecting the arguments of those insisting on evidentiary hearings. Order No. 636-A at 61,528.

⁴⁹ 18 C.F.R. §§ 284.8(b) and 284.9(b).

⁵⁰ Order No. 636 at 30,413.

⁵¹ *Id.* at 30,409.

⁵² *Id.* at 30,410.

pipelines' supply area, downstream of which customers would take control of their transportation services on an unbundled basis.⁵³ The options available to parties in individual proceedings have ranged from systems whereby customers control their transportation service back to the wellhead and those where customers take title to gas at centrally located pooling points, upstream of which suppliers are responsible for transporting supplies.⁵⁴ The Commission also left open to debate in individual proceedings the development of market centers and pooling points, although the Commission encouraged both.⁵⁵

Embodied in Sections 284.8(b)(2) and 284.9(b)(2) of Title 18 of the C.F.R. is the guiding principle behind the Commission's unbundling requirement and its approach to evaluating all pipeline services in the wake of Order No. 636, *i.e.*, that pipelines must offer its transportation services "on a basis that is equal in quality for all gas supplies, whether purchased from the pipeline or elsewhere."⁵⁶ According to the Commission:

This equality principle will ensure that a pipeline cannot impose unreasonable restrictions on a shipper's ability to be served by other gas sellers. Any such restrictions would render transportation of gas sold by the pipeline or an affiliate superior in quality to transportation of gas of other merchants. Such a quality preference would result in undue discrimination under NGA Sections 4 and 5 and is prohibited by the equality principle.⁵⁷

[ii] Transportation Service Terms and Conditions

[A] No-Notice Service

Based on comments received in response to the "Mega-NOPR,"⁵⁸ the Commission concluded that providing customers converting to transportation in pipeline restructuring with so-called "no-notice" transportation service was a key to enabling the customers to replicate in an unbundled environment those services previously enjoyed as part of bundled sales service.⁵⁹ On the central role envisioned by this new service in restructuring, the Commission opined:

⁵³ Order No. 636, at 30,410.

⁵⁴ 18 C.F.R. § 284.283.

⁵⁵ Order No. 636, at 30,027-28.

⁵⁶ Order No. 636, at 30,414.

⁵⁷ Order No. 636, at 30,414.

⁵⁸ 56 Fed. Reg. 38,372 (1991).

⁵⁹ See 18 C.F.R. § 284.8(a)(4). Order No. 636 required pipelines to make this service available in restructuring only to shippers that were firm city-gate bundled sales customers on May 18, 1992, the effective date of Order No. 636, on the theory that only these customers required the new service in order to replicate the service altered through Order No. 636. Pipelines were encouraged to make the service available more widely, if possible. See Order No. 636-B at 62,006.

The requirement that a pipeline provide "no-notice" transportation service will enable a customer to receive its natural gas supplies in a fashion as reliable as the customer had been receiving under a bundled, city-gate service, with the added advantage of providing greater opportunities to purchase that supply at competitive prices.⁶⁰

The Commission defined no-notice service as the "service pursuant to which firm shippers can receive delivery of gas on demand up to their firm entitlements on a daily basis without incurring daily balancing and scheduling penalties."⁶¹ In other words, the Commission intended no-notice service to be a surrogate for the sort of service-on-demand previously provided by bundled sales service. In order to ensure that customers had sufficient information to evaluate this more expensive option, as against other options, including storage service and other peak shaving opportunities, the Commission required pipelines to delineate the cost components of the service and to allow customers to nominate the service freely.⁶² Also, the Commission noted that pipelines would have varying operational requirements in order to perform this service, including the retention of a certain amount of system storage and the imposition of operating protocols on the use of unbundled storage.⁶³

Following the D.C. Circuit's remand of Order No. 636, in *United Distribution Cos. v. FERC*,⁶⁴ the Commission issued Order No. 636-C,⁶⁵ determining that pipelines offering no-notice service must offer that service on a non-discriminatory basis to all requesting customers on a prospective basis. The Commission also held that a pipeline offering no-notice service must only do so to the extent the pipeline has capacity available, but such pipelines are not obligated to expand their capacity or acquire additional facilities to provide service.⁶⁶

[B] Flexible Receipt and Delivery Points

Order No. 636 required pipelines to provide customers with the flexibility to take advantage of all receipt and delivery points on a pipeline system, subject to the proviso that customers may transport gas only within the transportation capacity they have under contract and the availability of capacity at the desired points.⁶⁷ Section 284.14(b)(1)(v) of the FERC regulations prescribes new

⁶⁰ Order No. at 636, at 30,424-425.

⁶¹ Order No. at 636, at 30,421.

⁶² Order No. at 636, at 30,421.

⁶³ Order No. at 636, at 30,424.

⁶⁴ 88 F.3d 1105 (D.C. Cir. 1996).

⁶⁵ 78 F.E.R.C. ¶ 61,186 (1997).

⁶⁶ 78 F.E.R.C. ¶ 61,186 (1997).

⁶⁷ Order No. 636, at 30,428-29. Since Order No. 636, pipelines have provided "extended delivery service" outside their contractual path, subject to availability and further payment to account for distance-related costs. See *Tennessee Gas Pipeline Co.*, 66 F.E.R.C. ¶ 61,317 (1994).

procedures for the allocation of receipt and delivery points. As things have developed in individual restructuring proceedings, customers have secured the rights to transport gas on a firm basis through so-called "primary" receipt and delivery points and to use other points on a "secondary," or interruptible, basis.⁶⁸

In *Transcontinental Gas Pipe Line*,⁶⁹ the Commission found that Part 157 shippers that convert to Part 284 service and pay Part 284 rates are entitled to the same flexibility as other Part 284 customers. However, subsequently, in *Tennessee Gas Pipeline Co.*,⁷⁰ the Commission stated that Part 157 shippers are not entitled to flexible receipt and delivery points.

In *Northwest Pipeline Corp.*,⁷¹ the Commission found that shippers may change, without additional payment, their primary receipt and delivery points to other points within their capacity path when capacity at those points is available. According to the Commission, firm shippers may use other points on a secondary basis, without changing their primary point. The Commission also stated that shippers using points on a secondary basis have priority superior to interruptible shippers, but inferior to firm shippers holding that point as a primary point. Additionally, the Commission allowed pipelines to implement right of first refusal (ROFR) and flexible receipt and delivery point procedures that enabled new bidders for capacity under the expiring contracts to have priority for the receipt or delivery points in the contract over existing shippers seeking to change primary receipt or delivery points. As such, the current shippers would be allowed to make receipt or delivery point changes 30 days after the bidding period ends, if no bid is accepted for that capacity.

In *Questar Pipeline Co.*,⁷² the Commission found that a pipeline cannot restrict primary receipt or delivery point changes when capacity becomes available through means other than a contract expiration, unless the change would impair the pipeline's ability to provide firm service to other shippers. Later, in *Questar Pipeline Co.*,⁷³ the Commission clarified that firm shippers receiving discounted rates do not have the right to use alternate receipt and delivery points at the discounted rate, unless their contract so provides. Further, in *Questar Pipeline v. PacifiCorp.*,⁷⁴ the Commission found that if an agreement between a pipeline and shipper is ambiguous, then the pipeline is free to charge the maximum rate.

⁶⁸ See, e.g., *Tennessee Gas Pipeline Co.*, 62 F.E.R.C. ¶ 61,250, at 62,645; *Texas E. Transmission Corp.*, 62 F.E.R.C. ¶ 61,015, at 61,109.

⁶⁹ 73 F.E.R.C. ¶ 61,024 (1995).

⁷⁰ 78 F.E.R.C. ¶ 61,340 (1997).

⁷¹ 66 F.E.R.C. ¶ 61,304 (1994).

⁷² 68 F.E.R.C. ¶ 61,269 (1994).

⁷³ 69 F.E.R.C. ¶ 61,119 (1994).

⁷⁴ 70 F.E.R.C. ¶ 61,328 (1995).

In *Tennessee Gas Pipeline Co., (Tennessee)*,⁷⁵ the Commission found those shippers paying the same zone rate should receive the same priority for secondary points within that zone. However, in Order No. 637-A, the Commission established an equal priority for secondary points within the zone of the shipper's contract path of delivery, thereby reversing the policy established in *Tennessee*.⁷⁶

[C] Abandonment upon Contract Termination and the Right of First Refusal

Resolving a controversy that had been on its doorstep since the court's decision in *AGA II*,⁷⁷ the Commission promulgated in Order No. 636 new Section 284.221(d) of its regulations, revising rules previously providing that pipelines would receive pre-granted, or automatic, abandonment authority terminating their obligation to serve Part 284 transportation customers upon the expiration of their contracts.⁷⁸ With Order No. 636, the Commission replaced its prior regulations with a rule providing customers with transportation contracts⁷⁹ for one year and longer⁸⁰ with the right to renew their contracts upon expiration, so long as they agreed to match the price bid for the capacity by any other interested customer and to sign a contract for as long a term as offered by the competing customer.⁸¹

In Order No. 636, the Commission also clarified that the maximum price customers are required to offer under the regulations in order to take advantage of the protection provided by the rule is the pipeline's maximum lawful price, while in Order No. 636-A, the Commission modified its regulations to require

⁷⁵ 73 F.E.R.C. ¶ 61,399 (1995).

⁷⁶ Order No. 637-A at 31,597.

⁷⁷ *American Gas Ass'n v. FERC*, 912 F.2d 1469 (D.C. Cir. 1990).

⁷⁸ Following the *AGA II* decision, the Commission stayed the operation of former Section 284.221(d), pending reconsideration on remand, in Order No. 500-J. FERC Stats. & Regs. ¶ 30,915 (1991). In *AGA II*, the court determined that the Commission failed to provide adequate protection to customers under Section 7 of the Natural Gas Act by providing pipelines with the authority to abandon customers upon the expiration of their contracts. In view of the court's decision in *AGA II*, the Commission determined in Order No. 636 that customers that converted their bundled sales contracts to transportation following the stay implemented after the *AGA II* remand (February 13, 1991) and prior to the effective date of Order No. 636 would have full abandonment protection. Order No. 636, at 30,452.

⁷⁹ The protection of the revised rules applies also to 18 C.F.R. pt. 284 storage, since the Commission has defined transportation to include storage service. See Order No. 636-A at 30,636.

⁸⁰ Order No. 636-A clarified that the right of first refusal would adhere only to contracts of one year or longer, while in Order No. 637, Regulation of Short-Term Natural Gas Transportation Services, and Regulation of Interstate Natural Gas Transportation Service, 65 Fed. Reg. 10156 (2/25/00), FERC Stats. & Regs. ¶ 31,091 (2/9/00), the Commission further clarified that this right attached only to contracts for 12 or more consecutive months of service. Order No. 637, at 31,337.

⁸¹ In Order No. 636-A, the Commission clarified that a pipeline would not be required to serve a customer at discounted rates where there were no competing offers driving prices up to levels deemed acceptable by the pipeline. Order No. 636-A at 30,629.

an existing customer to go so far only as to offer a contract term of 20 years in order to take advantage of the new protection.⁸² In Order No. 636-A,⁸³ the Commission further clarified that if customers pay maximum rate, they may renew for any term of their choosing, so long as there are no competitive offers.

In Order No. 637,⁸⁴ the Commission further modified its approach in order to provide that in the limited instance in which a pipeline is fully subscribed, there is an incremental rate schedule providing for firm transportation service above system average rates, and a customer interested in renewing capacity is vying with other shippers for available capacity, the renewing customer may be required to pay up to the incremental rate on the system in order to take advantage of the right of first refusal.⁸⁵

[D] Capacity Release and Buy-Sell Mechanisms

Order No. 636 and Section 284.243 of the FERC regulations provide relatively detailed guidelines on the mechanism pursuant to which the Commission has authorized parties to assign to others the interstate pipeline capacity (transportation and storage) they hold under contract. While the Commission's approach reflects precedent rejecting parties' efforts to broker their capacity,⁸⁶ the Commission's new approach ensures that the parties' efforts to assign capacity remain in full view of the Commission.⁸⁷ Accordingly, while authorizing capacity assignment under the new regulations, the Commission simultaneously amended all previously existing capacity brokering certificates in order to ensure conformity.⁸⁸ In addition, the Commission prohibited parties from entering into

⁸² The Commission left to parties in individual restructuring proceedings the detail of adjudging best offers when faced with offers of varying price and duration. Order No. 636, at 30,451.

⁸³ Order No. 636-A at 30,633.

⁸⁴ Order No. 637, at 31,297.

⁸⁵ Order No. 637, at 31,338-39.

⁸⁶ See *El Paso Natural Gas Co.*, 35 F.E.R.C. ¶ 61,440, at 62,065-66, *reh'g denied*, 38 F.E.R.C. ¶ 61,008 (1987); *Texas E. Transmission Corp.*, 37 F.E.R.C. ¶ 61,260, at 61,684 (1986).

⁸⁷ Addressing its need for consistency in these programs in order to preserve its oversight, the Commission opined: "[t]he Commission no longer believes that it can adequately monitor capacity brokering under existing certificates to ensure that all allocations are non-discriminatory. Simply put, there are too many potential assignors of capacity and too many different programs for the Commission to oversee capacity brokering as it now exists." Order No. 636, at 30,416.

⁸⁸ Order No. 636, at 30,416. See also *Algonquin Gas Transmission Co.*, 59 F.E.R.C. ¶ 61,032 (1992), amending on all capacity brokering certificates existing prior to Order No. 636. The Commission has distinguished capacity brokering from capacity assignment in that brokering has taken place through private arrangements entered into between capacity holders and others, without the involvement of the pipeline or the Commission.

The Commission has, in various orders, rejected arguments that capacity brokering by LDCs is a non-jurisdictional matter equal or akin to local distribution exempt from Commission oversight. See *Texas E. Transmission Corp.*, 51 F.E.R.C. ¶ 61,170, at 61,452. Accordingly, in Order No.

new "buy/sell" arrangements, as of the effective date of the new capacity assignment programs in restructuring.⁸⁰ The Commission grandfathered all such arrangements entered into through the date of restructuring on each pipeline.

In Section 284.243 of the regulations, the defining characteristic of the Commission's rules governing capacity assignment is that available capacity is to be posted for bid on electronic bulletin boards (EBBs) maintained by each of the pipelines.⁸⁰ A pipeline's Part 284 firm shippers⁸¹ may release the capacity to, and the pipeline will thereby be obliged to contract with, bidders extending the best offer for the capacity, up to a ceiling price of the pipeline's maximum transportation rate.⁸²

In *Tennessee Gas Pipeline Co.*,⁸³ the Commission approved net present value (NPV) criteria for evaluating competing bids for capacity available for general subscription. The Commission also found that NPV criteria may be applied to requests for changes in receipt and delivery points. Furthermore, in *Tennessee Gas Pipeline Co.*,⁸⁴ the FERC found that NPV analyses may include revenue from minimum throughput guarantees, provided that the NPV used in such analyses does not exceed the NPV equal to the maximum reservation rate available to recourse shippers, in cases where one or more bidders in an open season is willing to pay only the maximum recourse reservation rate.

Consistent with its rejection of buy-sell arrangements, the Commission has, since the publication of Order No. 436, consistently rebuffed efforts to modify on a generic basis its requirement that shippers must have title to the gas they

636, the Commission issued on a generic basis blanket NGA Section 7 certificates to all shippers holding firm interstate pipeline capacity rights enabling them to assign pipeline capacity pursuant to the new regulations. Order No. 636, at 30,421. See also Order No. 636-A at 30,551-52.

⁸⁰ Order No. 636, at 30,416. See also *El Paso Natural Gas Co.*, 59 F.E.R.C. ¶ 61,031 (1992), issued simultaneously with Order No. 636, in which the Commission addressed existing buy/sell programs. The Commission defined such programs as those whereby an LDC would purchase gas in the production area on behalf of an end user, transport the gas under its transportation contract and sell the gas to the end user at its retail delivery point. Order No. 636, at 30,416. See Carter, *Buy/Sell Transactions in The Natural Gas Industry: What's Prohibited and What Isn't?*, 15 Energy L.J. 427 (1994).

⁸¹ See generally Order No. 636, at 30,418-21. See Mishkin & Adelman, *Gas Industry Standards Board: Legal Considerations in the Standard Setting Process*, 15 Energy L.J. 73 (1994).

⁸² The Commission has expressly excluded shippers under individually certificated Section 7 transportation arrangements to release their capacity. Order No. 636-A at 30,565. These shippers may, however, convert to 18 C.F.R. pt. 284 service.

⁸³ Releasing shippers will remain ultimately liable for reservation charges under original contracts, unless the pipeline agrees otherwise. Usage charges and penalties are solely the responsibility of the replacement shipper. Order No. 636-A at 30,561-62.

⁸⁴ 76 F.E.R.C. ¶ 61,101 (1996), order on reh'g, 79 F.E.R.C. ¶ 61,297 (1997), order on reh'g, 82 F.E.R.C. ¶ 61,008 (1998).

⁸⁵ 82 F.E.R.C. ¶ 61,011 (1998).

ship under an open access transportation agreement.⁹⁵ The Commission again held fast to this "shipper must have title rule" in Order No. 637,⁹⁶ over the objection that it had become antiquated in view of gray market transactions bundling transportation and sales gas that avoid the Commission's capacity release oversight. Nevertheless, waivers of the rule have been granted in limited instances. In *Atlanta Gas Light Co.*,⁹⁷ the Commission waived for one year the "shipper must have title" rule in order to facilitate a retail service unbundling program. The Commission stated that in considering waiver requests the Commission must weigh the need for the waiver to accomplish the unbundling at the state level against any potential negative effect a waiver may have on the interstate gas market. Similarly, in *National Fuel*,⁹⁸ the Commissions temporarily waived the rule for one year in order to implement a unique customer choice program.

In Order No. 637, the Commission removed the price cap for capacity released for a term of less than one year, while retaining the cap for longer-term transactions.⁹⁹ The Commission reasoned that it had already lost meaningful control of the market for released capacity through operation of the "grey" market for bundled sales and transportation service, and that by allowing prices to rise to a market-clearing level would be good economics and competition in the secondary market from regulated pipeline interruptible service would help constrain prices for released capacity.¹⁰⁰

The Commission has further permitted parties to include the length of the assignment to which an assignee will agree as among the factors in determining the best bid.¹⁰¹ The rules further permit releasing customers to specify certain terms governing the release, including provisions limiting the release to those days on which weather conditions permit.¹⁰² In an effort to reflect some of the flexibility certain parties saw in previously existing capacity brokering programs, Order No. 636-A exempted from the requirement for EBB posting the assignment

⁹⁵ See *Texas Eastern Transmission Corp.*, 37 F.E.R.C. ¶ 61,260, at 61,684 (1986).

⁹⁶ Order No. 637, at 31,300.

⁹⁷ 84 F.E.R.C. ¶ 61,119, *reh'g denied*, 84 F.E.R.C. ¶ 61,323 (1998).

⁹⁸ 86 F.E.R.C. ¶ 61,179 (1999).

⁹⁹ Regulation of Short-Term Natural Gas Transportation Services, and Regulation of Interstate Natural Gas Transportation Service, 65 Fed. Reg. 10156 (2/25/00), FERC Stats. & Regs. ¶ 31,091, at 31,279 (2/9/00).

¹⁰⁰ Order No. 637, at 31,281-83.

¹⁰¹ Order No. 636-A at 30,558.

¹⁰² The Commission clarified in Order No. 636-A that releasing shippers may specify minimum acceptable prices. Order No. 636-A at 30,558. The Order further stipulates that all conditions governing releases must be posted and non-discriminatory, and that releasing shippers are prohibited from tying releases to any conditions (such as a requirement that assignees purchase gas from the releasing shipper) unrelated to the capacity to be assigned. Order No. 636-A at 30,559.

of capacity for less than thirty days.¹⁰³ This exemption was subsequently expanded to include transactions for one full calendar month.¹⁰⁴ In addition, the Commission permitted capacity holders to "pre-arrange" capacity releases for specific assignees, provided that these arrangements were posted in advance on the pipelines' EBBs and competing assignees were permitted to extend a superior offer, in the event the capacity were to be released for less than the maximum price.¹⁰⁵

Finally, in regulations implemented with Order No. 637,¹⁰⁶ the Commission has promulgated Section 284.12(c)(1)(ii), providing that purchasers of released capacity, like purchasers of capacity directly from a pipeline, will have the opportunity to submit nominations at the earliest opportunity after consummation of their deal. The regulation is designed to ensure the competitiveness and free substitution of capacity in the secondary market and capacity available directly from a pipeline.¹⁰⁷

[E] Upstream Pipeline Capacity

Section 284.242 of the regulations, promulgated under Order No. 636, requires open-access upstream pipelines to permit capacity under contract to downstream pipelines to be assigned by the downstream pipeline to its customers.¹⁰⁸ The regulations further require downstream pipelines to assign this capacity to their customers, to the extent required, to enable customers converting customers in restructuring to preserve their previous daily entitlements.¹⁰⁹ In Order No. 636-A, the Commission further indicated¹¹⁰ that it would permit downstream pipelines to retain upstream capacity upstream under contract to the extent needed for

¹⁰³ Order No. 636-A at 30,554; 18 C.F.R. § 284.243(h).

¹⁰⁴ Order No. 577, FERC Stats. & Regs. ¶ 31,017 (Mar. 29, 1995).

¹⁰⁵ See generally Order No. 636, at 30,418-20. Individual pipeline tariffs and the Commission's implementation orders on each pipeline must be consulted for specific features of the capacity assignment programs, including details relating to the procedures whereby bidders' offers will be compared in order to determine the best offer. In Order No. 636-A, the Commission clarified that pipeline tariffs must specify objective features by which bids would be evaluated, unless non-discriminatory standards are posted by releasing shippers on pipeline EBBs, along with the release posting. Order No. 636-A at 30,557.

¹⁰⁶ Order No. 637, at 31,343.

¹⁰⁷ Order No. 637, at 31,297.

¹⁰⁸ Order No. 636, at 30,417-18. "Upstream pipelines" are those pipelines which are connected to the supply area and which deliver a substantial portion of the gas transported to so-called "downstream pipelines," rather than to individual customers or distributors. Downstream pipelines do not access directly the market rates, but instead receive gas delivered from upstream pipelines.

¹⁰⁹ Order No. 636-B at 62,004.

¹¹⁰ Order No. 636-A at 30,566-67.

operational management and balancing services and the performance of no-notice service.¹¹¹

In *Texas Eastern Transmission Corp.*,¹¹² the Commission confirmed that Order No. 636 did not create a *per se* rule prohibiting pipelines from entering into contracts for transportation or storage capacity on other interstate pipelines, but rather that the Commission would decide this issue on a case-by-case basis. On rehearing, in *Texas Eastern Transmission Corp.*,¹¹³ the Commission clarified that its analysis would focus on whether the cost impacts of acquiring off-system capacity compared to the benefits to the acquiring pipeline's shippers justifies rolling-in the acquisition costs.

[F] Curtailment

In Order No. 636, the Commission hewed to its prior determination¹¹⁴ that the curtailment priorities stated in Title IV of the Natural Gas Policy Act of 1978 (NGPA)¹¹⁵ only authorize the Commission to apportion gas among a pipeline's sales customers and not its transportation customers.¹¹⁶ With respect to capacity-related curtailments, the Commission adhered to precedent¹¹⁷ approving apportionment among customers on a *pro rata* basis, unless parties in the individual restructuring proceedings agreed to another basis for allocating shortages. The Commission observed that capacity-related curtailments would affect all parties equally, whether pipeline sales customers or not, since after restructuring all customers would become pipeline transportation customers downstream of the point of unbundling.¹¹⁸ It further noted that the NGPA authorized it to apply the statutorily mandated priorities only to shortages of pipeline sales gas, although parties to the restructuring proceedings were encouraged to agree upon protocols that would protect high priority needs in the event of capacity related shortages.¹¹⁹

The clear distinction articulated by the Commission between capacity and supply curtailments was subsequently blurred, however, by the D.C. Circuit's

¹¹¹ The Commission has been fairly rigorous in policing pipelines arguing that they require upstream capacity for this purpose. *CNG Transmission Corp.*, 64 F.E.R.C. ¶ 61,303, at 63,215 (1993).

¹¹² 74 F.E.R.C. ¶ 61,074 (1996).

¹¹³ 78 F.E.R.C. ¶ 61,277 (1997).

¹¹⁴ See, e.g., Order No. 436, at 31,515; Order No. 436-A at 31,652-53; *Sebring Utils. Comm'n v. FERC*, 591 F.2d 1003 (5th Cir. 1979), *cert. denied*, 444 U.S. 879 (1979). See discussion of Order Nos. 436 and 436-A in § 83.03[1].

¹¹⁵ 15 U.S.C. § 3301 *et seq.*

¹¹⁶ Order No. 636, at 30,429; Order No. 636-A at 30,586.

¹¹⁷ See *Texas E. Transmission Corp.*, 37 F.E.R.C. ¶ 61,260 (1986); *Southern Natural Gas Co.*, 41 F.E.R.C. ¶ 61,218 (1987).

¹¹⁸ See *Texas E. Transmission Corp.*, 37 F.E.R.C. ¶ 61,260 (1986); *Southern Natural Gas Co.*, 41 F.E.R.C. ¶ 61,218 (1987).

¹¹⁹ Order No. 636-A at 30,586-94; Order No. 636, at 30,429.

1993 *City of Mesa* decision.¹²⁰ In *City of Mesa*, the court reaffirmed that the traditional NGPA end-use curtailment priorities applied only to supply curtailments, but held that the consumer protection mandate of the NGA requires that the Commission assure that high-priority end-users have continuous access to natural gas, which may require departure from strict *pro rata* capacity curtailments. The court did not rule on a specific mechanism to protect certain end-uses, but rather remanded the case for further explanation and support for the Commission's determination that the pipeline's proposed curtailment provision provided adequate protections. As a result, the precise features of the mechanism necessary to meet the NGA standard are yet to be determined.

[G] Storage Service

Recognizing that a pipeline's control of its storage facilities in order to perform daily and seasonal balancing provided pipeline sales service with an important advantage over competitive service, Order No. 636 also required pipelines to unbundle their storage facilities and to provide storage service on an open-access non-discriminatory basis.¹²¹ Part 284.1(a) of the FERC regulations was amended by Order No. 636 to define transportation to include storage service.¹²² Under Order No. 636, pipelines were permitted to retain part of their storage capacity for system management purposes and to perform no-notice service. Pipelines also were permitted to reserve storage capacity upstream of the point of unbundling in order to perform unbundled sales service, although the Commission further provided that the pipeline must allocate storage between its sales function and other interested parties on a non-discriminatory basis.¹²³

While Order No. 636 refrained from specifying a generic method for allocating storage capacity, leaving that matter to individual restructuring proceedings, the Commission clarified in Order No. 636-A that pipeline sales customers prior to restructuring would have a priority to storage service to the extent needed to preserve their pre-restructuring daily entitlements.¹²⁴ In Order No. 636-B it was held that this priority extended to storage of upstream pipelines, again to the extent necessary to preserve pre-restructuring entitlements.¹²⁵

[H] Capacity Segmentation

Building on earlier decisions,¹²⁶ the Commission made clear in Order No.

¹²⁰ *City of Mesa, Arizona v. FERC*, 993 F.2d 888 (D.C. Cir. 1993).

¹²¹ Order No. 636, at 30,425-27.

¹²² 18 C.F.R. § 284.1(a) defines "transportation" to include "storage, exchange backhaul, displacement, or other methods of transportation."

¹²³ Order No. 636, at 30,427.

¹²⁴ Order No. 636-A at 30,578.

¹²⁵ Order No. 636-B at 62,004.

¹²⁶ See *Texas Eastern Transmission Corp.*, 63 F.E.R.C. ¶ 61,100 (1994), in which the releasing

637 and 637-A that pipelines are required, in the absence of operational infeasibility, to permit customers to segment their capacity in a fashion enabling the original shipper and replacement shippers to employ as severable contractual rights pipeline segments of the pipeline system included within primary receipt and delivery point paths.¹²⁷ Nevertheless, the Commission identified highly reticulated pipeline systems as those on which segmentation may pose particular difficulty. In such cases, the Commission has persisted in requiring segmentation where operations permit.¹²⁸

[I] Capacity Auctions

Building on the Commission's earlier decisions promoting the concept of an auction mechanism for the sale of long-term capacity¹²⁹ the Commission, in Order No. 637 promulgated a series of minimum standards governing auctions for pipeline capacity.¹³⁰ Although the Commission did not insist on any particular auction format for pipelines or third-parties, the Commission set forth some basic principles to which auctions must adhere. In particular, the Commission established six principles:

- The timing of the auction should be predictable, and shippers potentially offering or bidding on capacity should have notice of when the auction will be held and what capacity will be included.
- The auction should be open to all potential bidders on a non-discriminatory basis.
- The auction should be user-friendly with information on the rules and procedures easily accessible to all.
- The bidding procedures as well as the methods for selecting the best bid should be fully disclosed prior to the auction.
- There should be no favoritism in the determination of the winning bidder and mechanisms should be included to permit monitoring of how the

shippers and replacement shippers are treated as separate shippers with separate contract demands. Similarly, in *ANR Pipeline Co.*, 73 F.E.R.C. ¶ 61,288 (1995), customers were permitted to segment capacity and release a portion of its contract path even if the total amount of gas delivered exceeds its total reservation quantity. Segmentation was limited in *Florida Gas Transmission Co.*, 67 F.E.R.C. ¶ 61,008 (1994), in which the Commission allowed a pipeline to refuse a complete segmented release transaction when such a transaction would reduce the firm primary receipt point to firm primary delivery point capacity rights of an existing shipper.

¹²⁷ See Order No. 637, FERC Stats. and Regs. ¶ 31,091, at 31,304 *et seq.*; Order No. 637-A, FERC Stats. and Regs. ¶ 31,099, at 31,590 *et seq.*

¹²⁸ See Order No. 637, FERC Stats. and Regs. ¶ 31,091, at 31,304 *et seq.*; Order No. 637-A, FERC Stats. and Regs. ¶ 31,099, at 31,590 *et seq.*

¹²⁹ See *Natural Gas Pipeline Co. of Am.*, 82 F.E.R.C. ¶ 61,036 (1998).

¹³⁰ See Order No. 637, at 31,296.

selection criteria were applied. This would include methods of verifying any reserve price applied in an auction.

- Transaction information (such as prices, volumes, and receipt and delivery points) should be disclosed so that shippers can ascertain the value of transportation. The names of shippers may not be disclosed or could be disclosed at a later date if the auction results are verifiable and free from potential affiliate favoritism.¹³¹

[iii] Electronic Bulletin Boards

In Order No. 636, the Commission required pipelines to establish Electronic Bulletin Boards (EBBs) upon which parties would post capacity available for release.¹³² The Commission held that the EBBs would be operative as of the effective date of each pipeline's capacity assignment program (generally, the date of restructuring) and further mandated that the terms and conditions governing pipeline EBBs would be included in pipeline tariffs and must be just and reasonable. Further, the Commission expressed a strong preference for having the bulletin boards operate interactively in order to effectuate transactions. In addition, the Commission agreed with those parties arguing that the EBBs should be standardized to facilitate operation and encouraged the industry to work cooperatively in order to implement that goal.¹³³

Operating on the strength of recommendations from the Natural Gas Industry Working Group, convened to consider industrywide protocols for standardizing the operation of the EBBs, the Commission issued Order No. 563, requiring pipeline compliance with specified standard EBB procedures.¹³⁴ In Order No. 563, the Commission adopted the Working Group's recommendations for developing a common code database that would identify pipeline transaction points, including receipt and delivery points. Additional modifications to the Commission's approach were made upon further recommendations of the Working Group in Order No. 563-C.¹³⁵

¹³¹ See Order No. 637, FERC Stats. and Regs., ¶ 31,091, at 31,304 *et seq.*; Order No. 637-A, FERC Stats. and Regs. ¶ 31,099, at 31,590 *et seq.*

¹³² Order No. 636, at 30,419. See Mishkin & Adelman, *Gas Industry Standards Board: Legal Considerations in the Standard Setting Process*, 15 Energy L.J. 73 (1994).

¹³³ Order No. 636-A at 30,549-50.

¹³⁴ Standards for Electronic Bulletin Boards Required Under Part 284 of the Commission's Regulations, [Regulations Preambles] III FERC Stats. & Regs. ¶ 30,988 (1993), *order on reh'g*, Order No. 563-A, [Regulations Preambles] III FERC Stats. & Regs. ¶ 30,994, *reh'g denied*, Order No. 563-B, 68 F.E.R.C. ¶ 61,002 (1994).

¹³⁵ 68 F.E.R.C. ¶ 61,362 (1994).

[iv] Standardization of Business Practices

In Docket No. RM96-1-000,¹³⁶ the Commission solicited proposals designed to standardize business practices for all interstate pipelines in order to facilitate interstate transactions. Building on the outline of priorities for standardization identified by the Natural Gas Industry Working Group (*see* § 83.03[2][c][iii]), the Commission sought comments in the following areas: nominations; confirmations; allocated gas flows; customer and contract imbalances; gas flow at metered points; transportation invoices; pre-determined allocation methodologies; gas payment remittance statements; gas sales invoices; and uploads of capacity release prearranged deals.

[d] Transition Costs Under Order No. 636**[i] Introduction**

Order No. 636 recognized that pipelines were likely to incur certain transition costs as a result of the move to restructured services. The Commission identified four basic categories of these costs:

- (1) gas supply realignment (GSR) costs;
- (2) costs associated with the elimination of the purchase gas adjustment (PGA) mechanism;
- (3) costs associated with unneeded upstream capacity; and
- (4) stranded facilities costs.¹³⁷

Under Order No. 636 pipelines are authorized to file a separate Section 4 proceeding to recover these costs, while parties opposing recovery of such costs are permitted to challenge the eligibility and prudence of the costs in the individual Section 4 cases.

[ii] Gas Supply Realignment (GSR) Costs

GSR costs are costs which result from the pipelines having to reform their existing supply contracts as a result of the implementation of Order No. 636. In order to recover contract reformation costs as GSR costs, pipelines must satisfy a two-part test specified by Order No. 636. First, the costs must be found to be eligible as costs that are attributable to the implementation of Order No. 636.¹³⁸ The test for eligibility is that the pipeline must determine that realignment costs are directly attributable to the implementation of Order No. 636 and not a result of events which occurred independently of Order No. 636.¹³⁹ Elaborating

¹³⁶ 73 F.E.R.C. ¶ 61,104 (1995).

¹³⁷ *See* Order No. 636, at 30,457-62.

¹³⁸ Order No. 636, at 30,459.

¹³⁹ Order No. 636, at 30,459. *See also* Texas E. Transmission Co., 62 F.E.R.C. ¶ 61,015, at 61,124 (1993).

on this standard in Order No. 636-A, the Commission stipulated that pipelines only are permitted to recover as GSR costs, those costs incurred to reform gas supply contracts in response to customer purchasing decisions during restructuring.¹⁴⁰ Second, all eligible costs must have been prudently incurred. Order No. 636 provided that the pipeline requesting recovery bears the burden of proof with regard to both the eligibility and prudence of its GSR costs.

Building on the basic eligibility criteria established in Order Nos. 636, *et al.*, the Commission further held in *Texas Eastern Transmission Corp.*¹⁴¹ that:

Eligibility depends on the facts of each case but certain standards of eligibility must be met under any circumstance:

(1) prior to the issuance of Order No. 636, the contracts must have been part of an overall gas supply portfolio that was commensurate with the pipelines' merchant obligation; (2) the cost must have been incurred after the issuance of Order No. 636 on April 8, 1992; (3) the pipeline's contract sales obligations must have decreased as a result of Order No. 636 restructuring, thus necessitating the reduction or elimination of gas supplies under contract; (4) the cost must be known and measurable.

In addition, some pipelines, such as Texas Eastern, had GICs under which they were to recover gas contract reformation costs. To prevent pipelines from recovering transition costs twice, the Commission will also apply a fifth eligibility standard in all cases in which a pipeline had a GIC: if the obligation to pay contract reformation costs was incurred during the effectiveness of a GIC, such obligation cannot be recovered as GSR costs. *Texas Eastern Transmission Corp.*, 65 FERC ¶ 61,608 (1993).

On a case-by-case basis, the Commission has determined that the parties have raised sufficiently serious eligibility and prudence issues to warrant full evidentiary hearings.¹⁴² For example, Columbia Gas Transmission Corporation's (Columbia) request for GSR cost recovery was rejected by the Commission on eligibility grounds.¹⁴³ Columbia argued for the recovery as GSR costs of liability it accrued prior to restructuring as a result of having rejected its gas supply contracts while it was in bankruptcy. The Commission dismissed Columbia's

¹⁴⁰ Order No. 636-A at 30,642.

¹⁴¹ 65 F.E.R.C. ¶ 61,246 (1994).

¹⁴² See *Texas E. Transmission Corp.*, 65 F.E.R.C. ¶ 61,363 (1993); *Tennessee Gas Pipeline Co.*, 66 F.E.R.C. ¶ 61,029 (1994).

¹⁴³ *Columbia Gas Transmission Corp.*, 64 F.E.R.C. ¶ 61,060, at 61,572 (1993). The Commission stated, "Thus, while the Commission has not determined eligibility in other restructuring cases, the Columbia case is unique." *Id.*

arguments and stated that the costs in question were associated with the bankruptcy proceedings and ineligible for recovery of GSR costs.¹⁴⁴

In addition to contract reformation costs, pipelines also have been permitted to recover so-called "pricing differential" costs as GSR costs. A pricing differential is calculated by taking the difference between the price of gas purchased under above-market contracts and a price established by an objective index of spot market prices. In the Commission's view, the pricing differential mechanism holds out the hope that it may be less expensive for a pipeline to continue purchasing gas under certain contracts, even at above-market levels, than to buy out the supply, at least for some interim period of time.¹⁴⁵ Consequently, in order for a pipeline to use a pricing differential, it must demonstrate that the potential costs incurred can be minimized on the competitive market rather than continuing to purchase gas under existing contract prices.¹⁴⁶ Moreover, the Commission has held that to be recoverable through a pricing differential mechanism, pipelines must also demonstrate that they have met the Commission's eligibility and prudence standards.¹⁴⁷ To enable the Commission to evaluate the pricing differential mechanism, the Commission has required pipelines using the pricing differential mechanism to identify specific contracts, keep strict accounting, and separate costs by contract.¹⁴⁸ Further, in *Tennessee Gas Pipeline Company (Tennessee)*,¹⁴⁹ the Commission required Tennessee to make quarterly filings that would identify costs that are known, measurable, and actually incurred in the previous quarter. The Commission approved pricing differential costs for a period of two years, three months prior to the expiration of which Tennessee would have to show support for the continuation of using the pricing differential mechanism or use an alternate mechanism.¹⁵⁰

¹⁴⁴ 64 F.E.R.C. at 65,582. Columbia argued that these contracts were entered into in anticipation of Order No. 636 and renegotiated during its restructuring proceedings. The Commission rejected this argument and stated that: (1) Columbia could have had "no meaningful knowledge of the effect of Order No. 636 on its system or what actions its customers would take"; (2) Columbia previously attempted to make these contracts marketable under its Global Settlement and failed; (3) a § 4 filing was unnecessary since Columbia's arguments for recovery raised a legal question, and the Commission had all the facts necessary to make a determination. As for Columbia's argument that it had been penalized for realigning these contracts early, the Commission has consistently held that even though a contract is terminated during restructuring, the pipeline still bears the burden of proving that the termination was attributable to the implementation of Order No. 636. *Id.*

¹⁴⁵ Texas E. Transmission Corp., 62 F.E.R.C. ¶ 61,015, at 61,124 n.130 (1993).

¹⁴⁶ See Texas E. Transmission Corp., 63 F.E.R.C. ¶ 61,100 (1993).

¹⁴⁷ Thus, the pipeline must prove that: (1) it negotiated in good faith to reduce or terminate contracts; and, (2) transition costs were minimized by vigorous arms-length negotiations with suppliers. 63 F.E.R.C. ¶ 61,100, at 61,507. See Texas E. Transmission Corp., 63 F.E.R.C. ¶ 61,100 (1993). See also *Tennessee Gas Pipeline Co.*, 64 F.E.R.C. ¶ 61,020 (1993).

¹⁴⁸ Texas E. Transmission Corp., 63 F.E.R.C. ¶ 61,100 (1993).

¹⁴⁹ 64 F.E.R.C. ¶ 61,020 (1993).

¹⁵⁰ *Tennessee Gas Pipeline Co.*, 62 F.E.R.C. ¶ 61,250 (1993).

As to the prudence criterion for recovering GSR costs, the Commission has stated that it will follow traditional prudency standards,¹⁵¹ examining such questions as:

- (1) whether contract terms are reasonable in light of the market conditions when contract negotiated, renegotiated or terminated;
- (2) whether the contract realignment costs resulted from vigorous arm's length negotiations; and
- (3) whether there was a bona fide effort on the part of both parties to the contract to arrive at settlement.¹⁵²

Ninety percent of the eligible costs may be recovered from Part 284 firm shippers, whether through a reservation fee, a surcharge or an exit fee, while ten percent of the costs can be recovered from interruptible transportation customers.¹⁵³ The Commission specifically exempted, from the obligation to fund GSR costs, transportation services under individual Section 7(c) certificates, on the theory that these services are not directly affected by Order No. 636.¹⁵⁴

[iii] Account No. 191

In Order No. 636, the Commission permitted pipelines to direct bill positive purchase gas adjustment (PGA) balances left in Account No. 191¹⁵⁵ as of July 31, 1991, to their former firm sales customers, whether or not they continued as firm sales customers. However, direct billed customers were granted the right to challenge the prudency of any related gas contracts.¹⁵⁶ The Commission restricted recovery of Account No. 191 costs to the costs that a pipeline had incurred prior to the issuance of the Notice of Proposed Rulemaking (NOPR) of Order No. 636 on July 31, 1991, reasoning that the NOPR established adequate notice for the pipelines to plan for the changing market.¹⁵⁷

Although the Commission left the allocation of Account No. 191 costs to determination of the individual restructuring proceedings, it indicated in Order

¹⁵¹ Order No. 636, at 30,459.

¹⁵² Order No. 636, at 30,459. The Commission later added that if pipelines had collected GIC charges, these costs would be precluded as transition costs. An exception would be made if the pipeline could prove that certain transition costs were anticipated and not recovered in designing the GIC. Order No. 636-A at 30,654.

¹⁵³ Order No. 636, at 30,458; Order No. 636-A at 30,641. Order No. 636-B at 62,032. The Commission noted that if a pipeline cannot recover 10% of its GSR costs from interruptible customers because it has no interruptible customers or a *de minimis* level, the Commission would consider in a § 4 filing, a request for another form of recovery. Order No. 636-B at 62,034.

¹⁵⁴ Order No. 636-A at 30,650.

¹⁵⁵ Account No. 191 refers to certain unrecovered gas costs. See Order No. 636, at 30,457-58.

¹⁵⁶ Order No. 636, at 30,458.

¹⁵⁷ For purposes of determining the date on which costs were deemed incurred, the Commission required use of the date on which the associated gas was taken.

No. 636 that commodity costs could be allocated based upon customers' gas purchases for the 12 months preceding the effective date of service under the pipeline's unbundled sales certificates. The Commission further indicated that demand costs could be allocated upon relative contract entitlements on the day preceding the effective date of service under the pipeline's unbundled sales certificate.¹⁵⁸ The Commission also directed the pipeline to flow through any over-recoveries to its customers.¹⁵⁹ In *Columbia Gas Transmission Corp.*,¹⁶⁰ the Commission rejected Columbia's effort to allocate all Account No. 191 costs based on customers' contract demand.

Customer payments to the pipeline may be made in a lump sum, over a 12-month period or any reasonable period of time at the customer's discretion.¹⁶¹ If the customer chooses to pay the assessment over time, however, the Commission permits the pipeline to collect carrying charges on the unrecovered balance.¹⁶² Thus, for example, in Texas Eastern's initial restructuring filing the pipeline determined its customers' liability for Account No. 191 costs on a *pro rata* basis, according to each buyer's total annual sales contract demand level to the aggregate sales annual contract demand level on the Texas Eastern system. Texas Eastern's methodology, while not in strict accord with the Commission's guidelines, was determined to be consistent with the Commission's overall policy goals. Furthermore, the Commission stated under Order No. 636, parties can suggest alternate consistent methodologies.¹⁶³ In subsequent restructuring orders, the Commission upheld Texas Eastern's methodology, but clarified that only "costs that are known and measurable" may be direct billed as transition costs subject to Commission approval.¹⁶⁴

[iv] Stranded Investment Costs

The third type of cost that drew Commission concern under the new competitive market proposed by Order No. 636 is stranded investment costs. These costs eligible for recovery are those incurred by a pipeline after implementation of Order No. 636 in connection with their bundled sales services that cannot be directly allocated to customers of the unbundled services. The Commission suggested that these costs may entail retention of unclaimed or unneeded

¹⁵⁸ Order No. 636, at 30,458.

¹⁵⁹ Order No. 636, at 30,458.

¹⁶⁰ 64 F.E.R.C. ¶ 61,060, at 61,564 (1993). The Commission reiterated this holding in subsequent Columbia restructuring orders, insisting that Columbia disregard its use of AENs and base demand costs on those costs that are actually billed and to account for commodity costs as well. 64 F.E.R.C. ¶ 61,365, at 63,574 (1993).

¹⁶¹ Order No. 636, at 30,458.

¹⁶² Order No. 636-A at 30,652.

¹⁶³ 62 F.E.R.C. ¶ 61,015 (1993).

¹⁶⁴ 63 F.E.R.C. ¶ 61,100 (1993).

upstream capacity, unbooked open-access, and contract storage beyond contract needs for balancing and system management,¹⁶⁵ as well as costs associated with unneeded gathering facilities.¹⁶⁶

The Commission directed pipelines to file a general rate filing under Section 4 of the NGA to recover stranded investment costs, upon which the Commission indicated it would make case-by-case determinations.¹⁶⁷ Further, the pipelines were required to meet eligibility and prudence criteria, as with GSR cost recovery. Pipelines must prove that the facilities for which they are seeking stranded cost recovery were "used and useful" before restructuring, but are no longer as a result of the implementation of Order No. 636.¹⁶⁸

[v] Facilities Costs

Facilities costs are defined as those capital costs and other costs incurred for and in connection with new facilities needed to implement Order No. 636.¹⁶⁹ Costs associated with stranded facilities costs are typically capital costs associated with the installation of electronic data exchanges, electronic meters, and other equipment needed to function in the competitive market.¹⁷⁰

For a pipeline to recover stranded facilities costs it must make a Section 4 filing and justify the prudence in which these costs are incurred.¹⁷¹ As of December 1994, Tennessee sought recovery of an estimated \$10-20 million for the installation of electronic meter and communications systems.¹⁷² Although Texas Eastern did not estimate any particular dollar amounts, it reserved the right to recover any new facilities costs incurred under a general Section 4 case.¹⁷³

However, Columbia's request for facilities costs warranted Commission criticism when it claimed that its costs would be highly speculative and it requested permission to build these costs into its rate base with an amortization period of five years.¹⁷⁴ The Commission denied Columbia's request to amortize

¹⁶⁵ Order No. 636, at 30,460.

¹⁶⁶ Order No. 636-A at 30,662 (explaining that certain facilities may no longer be needed in the restructured market as a result of capacity reallocation).

¹⁶⁷ Order No. 636, at 30,460.

¹⁶⁸ Order No. 636-A at 30,662. *See, e.g.*, Trunkline Gas Co., 66 F.E.R.C. ¶ 61,158 (1994).

¹⁶⁹ 62 F.E.R.C. ¶ 61,015 (1993).

¹⁷⁰ 62 F.E.R.C. ¶ 61,015 (1993).

¹⁷¹ 62 F.E.R.C. ¶ 61,250 (1993).

¹⁷² 62 F.E.R.C. ¶ 61,250 (1993).

¹⁷³ 62 F.E.R.C. ¶ 61,015, at 61,217. The Commission replied to Texas Eastern's request stating that "Order No. 636 anticipates such section 4 filings to recover costs associated with new facilities" and the Commission "will not prejudge Texas Eastern's right to recover such costs until Texas Eastern files a section 4 case to recover facility costs." *Id.*

¹⁷⁴ 64 F.E.R.C. ¶ 61,060, at 61,565.

these costs and directed Columbia to file for cost recovery in a general Section 4 rate case after the costs are actually incurred.¹⁷⁵

[3] Interconnection Policy

Responding to the court's remand in *Panhandle Eastern Pipe Line Co. v. FERC*,¹⁷⁶ the Commission announced in *Panhandle Eastern Pipe Line Co.*,¹⁷⁷ a new set of generic rules requiring pipelines to provide applicants with physical interconnection upon application. Reinforced by its decision in *ANR Pipeline Co.*,¹⁷⁸ the Commission held that its authority under NGA Section 5 to remedy undue discrimination is sufficient to mandate interconnection when the following five conditions are met:

- (1) the applicant must agree to bear the cost of interconnection;
- (2) the interconnection must not adversely affect existing operations;
- (3) the proposed interconnection must not diminish existing service;
- (4) the proposed interconnection must not cause the pipeline to be in violation of applicable environmental or safety laws or regulations; and
- (5) the proposed interconnection must not cause the pipeline to be in violation of its right of way agreements or other contractual obligations.

§ 83.04 Transportation Rate Issues

[1] Introduction

Considered below are several rate issues of interest in connection with transportation service. Issues of more general interest in connection with pipeline ratemaking, including a review of cost of service rate setting, and other rate design and cost allocation principles are reviewed elsewhere in this treatise.

[2] Incremental Versus Rolled-In Rates

The Commission's approach to the question of whether the cost of new facilities and service should be treated on an incremental basis, and thereby assessed to new customers individually, or rolled into general pipeline system rates is the subject of the decision in *TransCanada Gas Pipeline v. FERC*.¹ In *TransCanada*, the court remanded to the Commission for further consideration the decision in *Great Lakes Transmission L.P.*² In *Great Lakes*, the Commission

¹⁷⁵ 64 F.E.R.C. ¶ 61,060, at 61,565.

¹⁷⁶ 196 F.2d 1273 (D.C. Cir. 1999).

¹⁷⁷ 91 F.E.R.C. ¶ 61,037 (2000).

¹⁷⁸ 91 F.E.R.C. ¶ 61,066 (2000).

¹ 24 F.3d 305 (D.C. Cir. 1994).

² 57 F.E.R.C. ¶ 61,140, 61,512 (1991) (Opinion 367), *reh'g denied*, 62 F.E.R.C. ¶ 61,101, 61,713

had adopted a "commensurate benefits" test for determining whether the cost of new facilities should be rolled into system rates. Under this test, as explained by the Commission, parties seeking to roll the cost of new facilities into system rates must demonstrate that the benefits accruing to system customers are at least commensurate with costs. Of the showing made by the proponents seeking roll-in in the *Great Lakes* case, the Commission stated:

Even assuming, arguendo, that all those systemwide benefits asserted by the parties advocating rolled-in pricing have or will come to fruition, based on our review of the record, the new facilities were not needed to ensure continued service to existing customers at the same level of reliability. In return for these benefits, existing customers would, under the rolled-in methodology, pay significantly higher rates for the same service. This result would be inequitable based upon the record evidence in these proceedings . . . Simply put, existing customers would not, under rolled-in pricing, receive system-wide benefits "commensurate with the increase in rates."³

In *TransCanada*, the court faulted the Commission for failing adequately to explain its reliance on the commensurate benefits test, in preference to the approach taken in other precedent holding that the cost of new facilities would be rolled into system rates upon a showing that the facilities are integrated with the existing system and that the facilities would produce systemwide benefits.⁴ Importantly, the *TransCanada* decision does not prejudice the outcome of the Commission's reconsideration, instead it requires the Commission to rethink its approach and provide further explanation for its departure from precedent.⁵

Responding to the *TransCanada* remand, and perhaps because not all hands at the Commission are fully supportive of the approach in *Great Lakes*, the Commission issued on August 3, 1994, a Notice of Public Conference in Docket No. PL94-4 seeking industrywide comments on an appropriate approach for handling the incremental/rolled-in issue.⁶

(1993) (Opinion 367-A); *Great Lakes Gas Transmission L.P.*, 57 F.E.R.C. ¶ 61,141, 61,534 (1991) (Opinion 368), *reh'g denied*, 62 F.E.R.C. ¶ 61,102, 61,731 (1993) (Opinion 368-A). See Spulber, *Pricing and the Incentive to Invest in Pipelines After Great Lakes*, 15 *Energy L.J.* 377 (1994).

³ 57 F.E.R.C. ¶ 61,141, at 61,541-52 (citing *Colorado Interstate Gas Co.*, 56 F.E.R.C. ¶ 61,015, at 61,074 (1991)).

⁴ See *Battle Creek Gas Co. v. FPC*, 281 F.2d 42 (D.C. Cir. 1960).

⁵ Of relevance is the court's decision in *Algonquin Gas Transmission Corp. v. FERC*, 948 F.2d 1305 (D.C. Cir. 1991). There, the court held that in order to support a decision authorizing the roll-in of the cost of new facilities, the Commission must at least: (1) define and address the cost impact, and (2) describe with reasonable particularity the specific benefits provided by the facilities. 948 F.2d at 1313, 1315.

⁶ *Pricing Policy for New and Existing Facilities Constructed by Interstate Natural Gas Pipelines*, 68 F.E.R.C. ¶ 61,140 (1994).

Following a public conference on November 4, 1994, the Commission issued in May 1995 its long-awaited policy statement addressing the question whether the cost of new facilities should be treated on a rolled-in or an incremental basis.⁷ The Policy Statement signals the Commission's preference for rolled-in pricing, especially for projects that evidence a cost impact on existing customers of five percent or less. The Policy Statement establishes a presumption favoring rolled-in rate treatment in cases where the rate impact on existing customers of rolling in new facilities is no more than five percent and the pipeline makes a "showing of system benefits." Opponents of roll-in may overcome this presumption only if they demonstrate that "the benefits [of the new service] are so insignificant that rolled-in rates are not justified." In cases where the rate impact exceeds five percent, pipelines proposing to roll-in the costs of new facilities must show that the rate impact on existing customers is "proportionate" to the claimed benefits. The Policy Statement offers a detailed listing of potential operational and financial benefits, and wisely discounts so-called societal benefits. The Commission notes that it will not permit pipelines to break projects into small increments simply to qualify for the presumption applicable to projects with an impact smaller than five percent.

To provide greater rate certainty at the time new facilities or services are designed and placed in service, the Policy Statement provides that the Commission will reflect its pricing determination in a declaratory order to be issued in the Section 7 certificate proceeding together with the certificate authorizing construction. The initial pricing determination contained in the declaratory order will be controlling in the pipeline's next-filed rate case absent a showing of changed circumstances.

The mechanics of the five percent threshold are unclear. The Policy Statement explains that to determine the rate impact of a proposed roll-in "the pipeline should calculate the effect on revenue responsibility for each Firm Rate Schedule under its currently effective rate design and under the pipeline's preferred rolled-in rate design." The Policy Statement does not explain, however, how to address cases where the rate impact exceeds five percent for some customers but not for others. Moreover, the Policy Statement does not consider cases in which the initial estimate of costs may be less than five percent, and thereby qualify for the presumption, while the actual costs may exceed the threshold. Further, while the Policy Statement admonishes applicants against splitting larger projects into smaller parts to stay below the five percent threshold, it offers no mechanism for preventing such abuses. Indeed, the very existence of the threshold encourages such gaming of the system.

In a separate order on remand of the *TransCanada* case, the Commission declined to apply the new policy statement, instead holding that the pricing

⁷ Pricing Policy for New and Existing Facilities Constructed By Interstate Natural Gas Pipelines, Docket No. PL94-4-000, 71 F.E.R.C. ¶ 61,241 (1995).

treatment of the project should be determined on the basis of the traditional *Battle Creek* policy in place when Great Lakes initially planned its expansions. The Commission asserted it would be inappropriate to apply retroactively its new pricing policy, whose "hallmark is up-front assurance at the certificate stage" to facilities certificated years prior to the issuance of the Policy Statement. Applying *Battle Creek*, the Commission concluded that the new additions satisfied both prongs of the test and ordered rolled-in rates.

The Commission changed course yet again with the issuance of a new Statement of Policy in Docket No. PL93-3-000 on September 15, 1999.⁹ Reversing altogether its presumption favoring rolled-in rates where the rate impact of the proposed new facilities is less than 5%, the Commission now indicates that it will require proposals for new service be predicated upon incremental rates, unless incremental rates would be below the generally applicable Part 284 rate, or projects are designed to improve existing services. The Commission explained that a policy encouraging incremental pricing for facilities (1) sends the proper price signals to the market; (2) leaves the pipeline responsible for the costs of new capacity that is not fully utilized; and (3) obviates the need for an "at risk" condition because it accomplishes that same purpose. To implement this policy, the Commission established a two-part test for determining whether proposed NGA Section 7(c) projects serve public convenience and necessity by requiring an applicant to show that: (1) its proposal can proceed without financial subsidies, and (2) that the balance of benefits outweighs the adverse impacts to all relevant interests associated with the proposal.¹⁰

Under the Commission's new policy, to establish that a project serves public convenience and necessity, an existing pipeline must demonstrate that it is prepared to financially support the project without relying on subsidization from its existing customers.¹⁰ In addition, the Commission's public convenience and necessity analysis requires the certificate applicant to show that its proposed project will produce public benefits in excess of the adverse effects to all the relevant interests. The Commission identified three major interests that must be balanced: (1) the interests of the applicant's existing customers, (2) the interests of competing existing pipelines and their captive customers, and (3) the interests

⁹ Certification of New Interstate Natural Gas Pipeline Facilities, 88 F.E.R.C. ¶ 61,227 (1999) (Statement of Policy).

¹⁰ 88 F.E.R.C. at 61,745-46.

¹⁰ The Commission noted that projects designed to improve existing service for existing customers, by replacing existing capacity, improving reliability or providing flexibility, are for the benefit of existing customers. As such, increasing rates of existing customers to pay for these improvements is not a subsidy. Under the Commission's current policy, these kinds of projects are permitted to be rolled-in and are not covered by the presumption of the current pricing policy. See *Great Lakes Gas Transmission Ltd. Partnership*, 80 F.E.R.C. ¶ 61,105 (1997) (pricing policy statement not applicable to facilities constructed solely for flexibility and reliability).

of landowners and surrounding communities. The Commission stated that, in this balancing step, it will consider all relevant factors reflecting on the need for the project, including but not limited to, demand projections, potential cost savings to consumers, or a comparison of projected demand with the amount of capacity currently serving the market.¹¹ In *Williston Basin Interstate Pipeline Co.*,¹² one of the first cases decided under the Commission's new Policy Statement, the Commission permitted rolled-in rates upon a showing that the project would likely produce revenues exceeding costs, and that public benefits were provided through the addition of new gas supply sources. Similarly, in *Tennessee Gas Pipeline Co.*,¹³ the Commission granted NGA Section 7(c) authority and roll-in of costs under the new Policy Statement on the ground that the project would not be subsidized by Tennessee's existing customers because project revenues would exceed costs, and would not cause adverse impacts. The Commission also required the pipeline to execute firm contracts equal to the project shippers' committed capacity prior to commencing construction of the project. In *Transwestern Pipeline Co.*,¹⁴ the Commission also ordered rolled-in rate treatment under the new Policy Statement because such treatment would effectuate a rate decrease to existing customers.

In a theme elaborated upon in Order No. 637,^{14.1} a shipper exercising a right of first refusal in renewing a long-term contract would be required to match a competing shipper's bid rate for the same capacity in the event the pipeline system is fully subscribed and an incremental rate has been previously approved for the system. The incremental rate caps the required matching price.^{14.2}

[3] Market-Based Rates

While the Commission has yet to issue a decision approving a proposal for market-based transportation rates, it has approved several proposals for market-based storage rates.^{14.3} For example, in *Avoca Natural Gas Storage*,^{14.4} the

¹¹ 88 F.E.R.C. at 61,747-49.

¹² 89 F.E.R.C. ¶ 61,021 (1999).

¹³ 89 F.E.R.C. ¶ 61,129 (1999).

¹⁴ 90 F.E.R.C. ¶ 61,032 (2000).

^{14.1} See discussion at § 83.03[2][c][ii][C]; see also discussion of Order No. 637 in § 83.04[8].

^{14.2} 88 F.E.R.C. at 61,646.

^{14.3} See, e.g., *Avoca Natural Gas Storage*, 68 F.E.R.C. ¶ 61,045 (1994); *Koch Gateway Pipeline Co.*, 66 F.E.R.C. ¶ 61,385 (1994); *Bay Gas Storage Co., Ltd.*, 66 F.E.R.C. ¶ 61,354 (1994); *Petal Gas Storage Co.*, 64 F.E.R.C. ¶ 61,190 (1993); *Richfield Gas Storage Sys.*, 59 F.E.R.C. ¶ 61,316 (1992). See also *Koch Gateway Pipeline Co.*, 72 F.E.R.C. ¶ 61,216 (1995) (The Commission set for hearing a proposal to establish market-based rates for firm and interruptible transportation services. The Commission commented that the outcome of the litigation would be made subject to the guidelines it expected to issue in generic docket no. RM95-6-000).

^{14.4} 68 F.E.R.C. ¶ 61,045 (1994).

Commission granted an application to provide market-area storage services at negotiated, market-based rates. The Commission concluded that market-based rates were appropriate because Avoca lacked "market power" in its market.

Of relevance to the Commission's authority to implement market-based storage and transportation rates is *Elizabethtown Gas v. FERC (Transco)*.^{14.5} There, the court upheld a Commission order approving a settlement under which a pipeline would offer unbundled sales at market-based rates, opining that the Commission was within its statutory authority in relying on the competitive market in order to establish just and reasonable rates under the Natural Gas Act.^{14.6} In *Elizabethtown*, the court specifically rejected petitioners' claim that the NGA mandates that the Commission approve only cost-based rates:

[T]he Supreme Court "has repeatedly held that the just and reasonable standard does not compel the Commission to use any single pricing formula . . .," and we have indicated that when there is a competitive market the FERC may rely upon market-based prices in lieu of cost-of-service regulation to assure a "just and reasonable" result.

In *New York State Electric & Gas Corp. (NYSEG)*,^{14.7} the Commission approved a request for market-based rates for interstate storage services, applying its Alternative Rate Policy Statement^{14.8} for evaluating proposals for market-based rates.^{14.9} The Alternative Rate Policy Statement requires finding either (1) that there is a lack of market power because customers have sufficient good alternatives or (2) that market power has been mitigated.^{14.10} The Commission indicated its three-step analysis required it to: (1) define the relevant markets; (2) measure a firm's market share and market concentration; and (3) evaluate other relevant factors.^{14.11} Relying on *Avoca Natural Gas Storage (Avoca)*,^{14.12} and *Steuben Gas Storage Co. (Steuben)*,^{14.13} the Commission held that NYSEG's market share of 0.3 percent for working gas capacity and 1.44 percent for deliverability was relatively small compared to the overall market which has 339 times the capacity, and 70 times the deliverability of NYSEG.^{14.14} While the Commission found that market concentration was high in the market areas served

^{14.5} 10 F.3d 866 (D.C. Cir. 1993).

^{14.6} 10 F.3d at 870-71.

^{14.7} 81 F.E.R.C. ¶ 61,020 (1997).

^{14.8} Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines, 74 F.E.R.C. ¶ 61,076 (1996), *reh'g denied*, 75 F.E.R.C. ¶ 61,024 (1996).

^{14.9} 81 F.E.R.C. ¶ 61,132.

^{14.10} 76 F.E.R.C. ¶ 61,230.

^{14.11} 76 F.E.R.C. ¶ 61,231.

^{14.12} 68 F.E.R.C. ¶ 61,045 (1994).

^{14.13} 72 F.E.R.C. ¶ 61,102 (1995).

^{14.14} 72 F.E.R.C. ¶ 61,102 (1995).

by NYSEG (4692 HHIs for working gas capacity and 4196 for deliverability), the Commission stated that this was mitigated for the following factors: (1) NYSEG's market share for working gas capacity and deliverability are too small to permit an exercise of market power; (2) NYSEG could not exercise market power as a new entrant that must offer better deals to obtain customers; (3) there was ease of entry and anticipation of many new entrants in the market; (4) rates of existing interstate storage providers in New York and Pennsylvania are regulated.^{14.15}

[4] Straight-Fixed Variable Rate Design

While the Commission in Order No. 636 concerned itself largely with unbundling and service-related issues, in one significant departure from that rule it required on a generic basis the implementation of a straight-fixed variable (SFV) format for rate design and cost allocation purposes, allowing for only limited deviations.^{14.16} Under SFV, pipelines are required to include all fixed costs in demand charges and to limit the costs included in commodity rates to variable costs.^{14.17} In contrast, most pipelines have employed a modified-fixed variable format, whereby the pipelines' revenue requirement associated with return to equity and taxes was assigned to commodity rates.^{14.18}

In the Commission's view in its adoption of SFV, it was necessary to level pipeline commodity rates across various

(Text continued on page 83-59)

^{14.15} 72 F.E.R.C. ¶ 61,136-137. See NE Hub Partners, L.P., 83 F.E.R.C. ¶ 61,043 (1998); CNG Transmission Corp., 81 F.E.R.C. ¶ 61,031 (1997); CNG Transmission Corp., 83 F.E.R.C. ¶ 61,134 (1998); Clear Creek Storage Co., 84 F.E.R.C. ¶ 61,210 (1998); Petal Gas Storage Co., 86 F.E.R.C. ¶ 61,224 (1999).

^{14.16} Order No. 636, at 30,431-37.

^{14.17} See 18 C.F.R. § 284.8(d).

^{14.18} See Natural Gas Pipeline Co. of Am., 25 F.E.R.C. ¶ 61,176 (1983), *order on reh'g*, 26 F.E.R.C. ¶ 61,203 (1984), *aff'd in part*, Northern Ind. Pub. Serv. Co., 782 F.2d 730 (7th Cir. 1986).

pipeline systems in order to eliminate deviations in pipeline costs as a factor in determining which supplies to purchase.¹⁵ According to the Commission:

Under MFV, or any method other than SFV, pipeline usage charges vary depending upon the amount of fixed costs recovered in the usage charge. If customers can choose to take gas from two or more pipelines, they will minimize their transportation costs by baseload-ing the pipeline with the lowest usage rate and swinging on pipelines with higher usage rates. . . . Producers whose gas moves to market over pipelines with low usage charges would be able to have higher sales and/or higher prices than otherwise equally efficient producers whose gas moves over pipelines with higher usage charges. Equally efficient producers whose gas gets to market on pipelines with equal total cost would not be on an equal footing because of the differing rate designs of the pipelines. This is inefficient and creates artificial barriers to the production of gas from one basin as compared to another.¹⁶

The Commission left open the potential for limited exceptions to the application of its general rule by providing that it would consider allowing parties to individual cases to agree upon alternative rate design methodologies. In cases where such deviation was agreed to by the pipeline but opposed by other parties, the Commission provided that parties advocating a departure from SFV would bear a "heavy burden of persuasion."¹⁷ In addition, the Commission stated that it would require pipelines to mitigate the impact of the cost shifts among pipeline services due to SFV implementation, where parties demonstrated that historic customers (those existing as of the effective date of Order No. 636) experienced an increase in cost responsibility greater than 10%.¹⁸ In such cases, the Commission stated it would require pipelines to implement measures to phase in the implementation of SFV over a period not longer than four years, using methodologies tailored to individual cases.¹⁹

¹⁵ Order No. 636-A at 30,596.

¹⁶ *Id.*

¹⁷ Order No. 636 at 30,434.

¹⁸ While the Commission first chose to measure the impact on customer classes, in Order No. 636-B, it clarified that it would look to the impact on individual customers. Order No. 636-B at 62,016.

¹⁹ Order No. 636 at 30,435-36.

[5] Interruptible Transportation Rate Design and Revenue Crediting

[a] Rate Design

It has been the Commission's practice to establish maximum rates for interruptible transportation (IT) based on the rate for firm transportation. Prior to the issuance of the Commission's 1989 Statement of Policy on Rate Design,²⁰ the Commission routinely calculated the IT rate as a 100% load factor derivative of the firm transportation (FT) rate. That is to say, IT volumetric rates were set by adding to the FT commodity rate a derivative of the firm demand rate based on the assumption that transportation was moved on a 100% load factor. This practice was upheld by the Court of Appeals for the D.C. Circuit in *Elizabethtown Gas Company v. FERC*.²¹ Responding to the argument of the parties that the 100% IT load factor rate overvalued the service, the court commented that this was a misconception, since IT rates only would equal firm rates in circumstances when firm customers moved their gas at a 100% load factor, i.e., at their maximum entitlement, 365 days each year. According to the court, the argument of the opponents of the 100% load factor rate "proceeds on the erroneous premise." In the court's view, firm customers:

are in fact charged a higher rate than interruptible customers. . . reflecting the cost and quality differentials between the two classes of customers. The 100% load factor is only the lowest per unit rate that a firm customer can in principle pay, i.e., if it takes 100% of its demand entitlements. Because many firm customers do not take all of their entitlements, firm customers overall end up paying a greater load factor than interruptible customers, who never pay more than the 100% load factor.²²

Picking up a thread of doubt the Commission had earlier raised over the propriety of the 100% IT load factor rate,²³ the Commission in the Policy Statement on Rate Design

²⁰ Policy Statement Providing Guidance With Respect to the Designing of Rates, 47 F.E.R.C. (CCH) ¶ 61,295 (1989); Order on Rehearing and Clarifying Policy Statement Providing Guidance with Respect to the Designing of Rates, 48 F.E.R.C. (CCH) ¶ 61,122 (1989).

²¹ 10 F.3d 866 (D.C. Cir. 1993).

²² *Id.* at p. 873.

²³ See, e.g., Transcontinental Gas Pipe Line Corp., 46 F.E.R.C. (CCH) ¶ 61,364, at 62,143 (1989).

invited parties to debate in individual proceedings whether the rate should be reduced through the imputation of a higher load factor.²⁴ The Commission focused its concern principally on whether the 100% load factor rate yielded a rate too high to maximize throughput and, in the Commission's view, allocate capacity efficiently. The Commission further made clear that it would consider this issue only in the context of individual cases. According to the Commission:

The issue is whether the 100 percent load factor rate yields a maximum interruptible rate which is too high to efficiently maximize throughput and is therefore an inefficient allocation of costs or revenue responsibility to interruptible service. The answer depends on an analysis of the pipeline's package of rates and services and not merely on an examination of the 100% load factor method by itself. For example, the 100% load factor method may be an appropriate way to set a maximum rate which acts as a cap on a pipeline's market power where it is efficiently discounting to maximize throughput or where the pipeline is using peak and off-peak rates.²⁵

In addition, the Commission commented that it would judge the appropriate level of rates in view of the relative quality of the services.²⁶

In the many pipeline rate cases following the issuance of the Policy Statement, the parties considered the application of the Commission's stated predilection for altering its approach to setting IT rates, in the context of individual proceedings. These cases were, by and large, settled on the basis of agreements reached by the parties in which IT rates were generally decreased, in varying degrees. In, for example, *CNG Transmission Corp.*,²⁷ the Commission approved a settlement establishing IT rates for the winter season set on a 110% load factor basis, while summer rates were set on a 150% load factor basis. Taking a somewhat different tack in *Tennessee Gas Pipeline Company*,²⁸ the

²⁴ Consistent with applicable precedent, the Commission clarified in its Order on Rehearing of the Policy Statement, the Statement did not shift the burden or proof away from parties seeking to change the status quo on individual pipelines, although it plainly suggested the Commission's sympathy would be with those parties seeking to do so. See *Order on Rehearing and Clarifying Policy Statement Providing Guidance with Respect to the Designing of Rates*, 48 F.E.R.C. (CCH) ¶ 61,122 at 61,444.

²⁵ 47 F.E.R.C. at 62,058.

²⁶ *Id.* at 62,059.

²⁷ 55 F.E.R.C. (CCH) ¶ 61,189 at 61,628 (1991).

²⁸ 59 F.E.R.C. (CCH) ¶ 61,045 at 61,194 (1992).

Commission approved a settlement establishing a 125% load factor rate for IT service.

In what may be a general shift in direction, the Commission in *South Georgia Natural Gas Company*,^{28.1} approved an initial decision rejecting a proposal to reduce the pipeline's IT rate from one set on a 100% load factor to 125%, holding that the 100% load factor rate would best ration capacity, while protecting customers. The Commission further noted that decreasing the IT rate would provide it with a price advantage over released capacity. Similarly, in *Southern Natural Gas Company*,^{28.2} the Commission approved a settlement implementing a 100% load factor IT rate, rejecting claims that the rate failed to recognize the inferior quality of IT service. Nevertheless, the Commission approved a reduced maximum IT rate for certain production area transportation subject to intense competition.

[b] Revenue Crediting

In Order No. 636-A, the Commission recognized that the implementation of its capacity release program would create a great deal of uncertainty over the level of IT service that a pipeline would perform after restructuring. Responding to comments arguing that establishing a representative level of throughput for IT service in order to allocate costs in this environment would be a difficult task, the Commission encouraged parties to consider some type of revenue crediting mechanism in lieu of the traditional mechanism for allocating costs.²⁹

In the restructuring cases following the Commission's comments, many pipelines have implemented revenue crediting mechanisms for IT service. In general, these mechanisms call for crediting to firm services 90% of the revenues derived from IT throughput once a pipeline has recovered a specified level of cost associated with an assumed level of IT throughput.³⁰ Pipelines have generally been allowed to retain ten percent of these revenues as an incentive to perform this service. For example, in *Viking Gas Transmission Corp.*,³¹ the Commission approved

^{28.1} 72 F.E.R.C. (CCH) ¶ —, Dec. 20, 1995.

^{28.2} 72 F.E.R.C. (CCH) ¶ 61,322, *mimeo* at 28, *et seq.* (1995).

²⁹ Order No. 636-A at 30,563.

³⁰ See, e.g., *Paiute Pipeline Co.*, 63 F.E.R.C. (CCH) ¶ 61,189 (1993); *Colorado Interstate Gas Co.*, 63 F.E.R.C. (CCH) ¶ 61,101 (1993).

³¹ 65 F.E.R.C. (CCH) ¶ 61,058 at 61,463-64.

a 90/10 IT revenue crediting system, once the pipeline recouped costs associated with a designated level of throughput. Explaining the interplay between the revenue crediting mechanism and the attribution of costs to IT service, the Commission commented,

Viking is required to credit excess interruptible revenues, but only to the extent that Viking's allocation of costs to interruptible service is less than the revenues it receives from interruptible service. The crediting requirement does not apply to situations where Viking's allocation of costs to interruptible service equals or exceeds the revenues from interruptible service.³²

In *CNG Transmission Corporation*,³³ the Commission permitted a modest departure from the 90/10 rule, authorizing the pipeline in approving the parties' settlement to retain twenty percent of IT revenues in excess of allocated costs. Similarly, in *Southern Natural Gas Company*,³⁴ the Commission approved a settlement allowing the pipeline to retain 25% of its IT revenues.

In a series of more recent orders, the Commission has authorized the elimination of the 90/10 interruptible revenue crediting mechanism, at least in certain circumstances. The Commission has stated it will permit a pipeline to eliminate the IT revenue crediting if the pipeline has had substantial actual post-Order No. 636 experience representative of the full range of annual operating conditions and allocated a representative percentage of its fixed cost of service to interruptible transportation service.³⁵ Previously, the Commission had rejected pipeline requests to eliminate the 90/10 mechanism, noting that the pipelines had not had sufficient operating experience to be able to make known and measurable projections of interruptible service levels and had not allocated a sufficient portion of fixed costs to interruptible service.³⁶ Elimination of the 90/10 crediting was approved where the pipeline had at least twelve months of operating experience post-Order No. 636, had supplied sufficient support through data and testimony for its projected interruptible transportation levels, and

³² *Id.* at 61,464-65. See also, *Tennessee Gas Pipeline Co.*, 62 F.E.R.C. (CCH) ¶ 61,250 at 62,654 (1993); *Order on Rsh'g*, 64 F.E.R.C. (CCH) ¶ 61,020 at 61,226 (1993).

³³ 66 F.E.R.C. (CCH) ¶ 61,144 (1994).

³⁴ 72 F.E.R.C. (CCH) ¶ 61,322, *mimeo* at 28, *et seq.* (1995).

³⁵ See *Transcontinental Gas Pipe Line Corp.*, 70 F.E.R.C. (CCH) ¶ 61,384, at 62,130 (1995); *KN Interstate Gas Transmission Co.*, 66 F.E.R.C. (CCH) ¶ 61,138, at 61,253 (1994).

³⁶ See *ANR Pipeline Co.*, 66 F.E.R.C. ¶ 61,335, at 62,105 (1994); *KN Interstate*, 66 F.E.R.C. at 61,253 (1994).

had demonstrated that a sufficient portion of fixed costs would be allocated to interruptible service.³⁷

[6] Transportation Rate Discounts

Section 284.7(d) of the Commission's Regulations, 18 C.F.R. § 284.7(d) (1995), permits pipelines operating under Part 284 open access blanket certificates to discount transportation rates to a level not less than average variable cost. Through a variety of methodologies, pipelines have generally projected their level of discounted service and allocated the cost shortfall between the discounted rate and maximum rate to remaining customers.³⁸ Although, in *Associated Gas Distributors v. FERC*,³⁹ the court appeared generally to approve the Commission's Order No. 436 regulations permitting discounting for Part 284 service in order to meet competition, the court recently suggested in *Mississippi Valley Gas Co. v. FERC*⁴⁰ that selective discounting to meet "gas-on-gas" competition between pipelines may be discriminatory. The controversy in that case was nevertheless dismissed for lack of ripeness.

³⁷ See *Ozark Gas Transmission Sys.*, 73 F.E.R.C. ¶ 61,129 (1995) (IT revenue crediting mechanism eliminated because pipeline no longer has any firm shippers); *Questar Pipeline Co.*, 72 F.E.R.C. (CCH) ¶ 61,195, at 61,928 (1995) (IT crediting mechanism eliminated because pipeline had over one and one-half years' post-636 operating experience and provided testimony and exhibits to support its projected IT throughput); *Transcontinental*, 70 F.E.R.C. at 62,130 (IT revenue crediting mechanism eliminated where pipeline had 12 months' operating experience and sufficiently explained IT throughput levels in its filing); *Florida Gas Transmission Co.*, 70 F.E.R.C. (CCH) ¶ 61,116, at 61,306 (1995) (pipeline's analysis of IT throughput comparing test period volumes to total entitlements sufficient to permit elimination of crediting mechanism); *High Island Offshore Sys.*, 66 F.E.R.C. (CCH) ¶ 61,378, at 62,269 (1994) (revenue crediting mechanism eliminated where pipeline allocated 93% of total cost of service to IT service and IT projection based on expiration of firm contracts); *U-T Offshore Sys.*, 66 F.E.R.C. (CCH) ¶ 61,377, at 62,264 (1994) (revenue crediting mechanism eliminated where pipeline allocated 53% of costs to IT service and projections of interruptible service levels based on expiring firm contracts).

³⁸ See *Interstate Natural for Pipeline Rate Design*, 47 F.E.R.C. (CCH) ¶ 61,295, at 62,056-58, *reh'g*, 48 F.E.R.C. ¶ 61,122 (1989).

³⁹ 824 F.2d 981 (D.C. Cir. 1987).

⁴⁰ D.C. Cir. No. 94-1486, issued Oct. 20, 1995.

[7] Allocation of Costs Associated with "turned-back" Capacity

In a series of recent orders, the Commission has been grappling with the cost allocation issues arising when long-term firm contracts are not renewed at the end of the contract term and the pipeline is unable to secure replacement shippers. In the clearest signal of its approach to date, in *Natural Gas Pipeline Co.*,⁴¹ the Commission rejected the pipeline's proposal to reallocate costs that would have been recovered from the departing customers from the remainder of the pipeline system. The Commission commented that it would "not permit a pipeline losing customers simply to shift the costs of resulting unsubscribed capacity to the remaining customers without regard to the adverse effects on those customers."⁴² Accordingly, the Commission rejected the pipeline's alternative proposals to reallocate its costs or to book the excess costs for subsequent recovery.

The decision in *Natural Gas Pipeline Co.* builds on prior decisions in *El Paso Natural Gas Co.*⁴³ and *Transwestern Gas Pipeline Co.*⁴⁴ In *El Paso*, the Commission rejected the pipeline's proposal to institute an exit fee allocating system capacity costs to customers failing to renew or substantially maintain their contract entitlements. The Commission found that such an exit fee would violate its exit fee policy set forth in Order Nos. 636 and 636-A.⁴⁵ In *Transwestern*, the Commission approved a settlement including a mechanism for sharing costs associated with departing customers between shareholders and customers. The settlement provided that the pipeline's firm customers pay a demand surcharge equal to approximately thirty percent of the costs associated with the capacity relinquished for five years. In approving the settlement, the Commission expressed the hope that its structure would serve as a model on other systems.

In a related development, in *Southern Natural Gas Co.*,⁴⁶ the Commission approved a settlement agreement requiring the pipeline to accept prospective demand reductions in two circumstances: (1) where elected by local distribution company customers in response to a public service commission order to reduce interstate pipeline capacity; and (2) where the reduction is necessitated by loss of the LDC's market due to pipeline bypass. The Commission rejected challenges that these provisions were discriminatory and anti-competitive, in the context of a settlement.

⁴¹ 73 F.E.R.C. ¶ 61,050 (1995).

⁴² 73 F.E.R.C. at 61,129.

⁴³ 72 F.E.R.C. ¶ 61,083 (1995).

⁴⁴ 72 F.E.R.C. ¶ 61,085, *reh'g denied*, 72 F.E.R.C. (CCH) ¶ 61,089 (1995).

⁴⁵ The Commission rejected the pipeline's argument that such a unilateral fee was appropriate in light of the FERC Electric Utility Open Access Rulemaking (RM95-8) where exit fees were one of the Commission's proposed methods of dealing with electric utility stranded costs.

⁴⁶ 72 F.E.R.C. (CCH) ¶ 61,322 (1995).

[8] Order No. 637

In Order No. 637,⁴⁷ the Commission promulgated a series of changes governing released capacity, peak and off-peak pricing and term-differentiated rates for pipeline services, voluntary auctions for pipeline capacity, proposals for imbalance service, and the right of first refusal for firm contract holders upon expiration of their contract terms. Contained here is a report on the Commission's new provisions on peak and off-peak pricing, term-differentiated rates, auctions, imbalance services and a review of the Commission's thinking on negotiated terms and conditions of service.⁴⁸

[a] Peak and Off-Peak Rates

Order No. 637 invites interstate pipelines to file proposals for varying rates for peak and off-peak service that would enable the price of peak service to rise toward a market clearing level. The Commission asserts that such seasonally differentiated rates will serve the dual goals of more efficiently allocating a scarce service during peak periods to the highest valued uses, while providing a pool of additional revenues available to reduce the rates for captive long-term customers.⁴⁹ The Commission has further indicated that it will be receptive to a variety of proposals for seasonal pricing, but has commented: (1) that it will allow peak rates to rise on a "value of service" basis, and will not reject such pricing based on arguments that such rates are not cost-based; and (2) that it will require reductions to off-peak prices corresponding to increases for peak pricing in order to keep revenues within a filing pipeline's approved revenue requirement.⁵⁰

Pipelines have been permitted to file for approval of such pricing either in the context of a general section 4 rate case, or through the implementation of *pro forma* tariff sheets. In the event the latter mechanism is used, the Commission has required pipelines to propose a mechanism for sharing increased peak revenues with long-term customers. Pipelines are further required to file within 15 months of implementing peak and off-peak rates a cost/revenue study, following which the Commission comments it will determine whether further rate adjustments are necessary prospectively.⁵¹

⁴⁷ *Regulation of Short-Term Natural Gas Transportation Services, and Regulation of Interstate Natural Gas Transportation Service*, 65 Fed. Reg. 10156 (2/25/00), — FERC Stats. & Regs. ¶ 31,091 (2/9/00).

⁴⁸ A discussion of the provisions in Order No. 637 governing capacity release and the right of first refusal is found at § 83.03[2][c][ii][C] and [D], respectively.

⁴⁹ Order No. 637, at 31,287-90.

⁵⁰ Order No. 637, at 31,290-91.

⁵¹ Order No. 637, at 31,290-91.

[b] Term-Differentiated Rates

Order No. 637 also permits pipelines to apply in a Section 4 rate proceeding for authority to implement term-differentiated rates designed to increase rates for shorter-term transactions, while extending offsetting decreases to customers entering into longer-term transactions.⁵² The Commission has commented that it believes pipelines are justified in charging more for short term, rather than for longer-term transactions, on the ground that longer-term shippers assume more financial risk than their shorter-term counterparts and provide an assured source of revenues for the pipeline. As with seasonally differentiated rates, the Commission has determined to limit rates in the aggregate to the pipeline's revenue requirement.⁵³

[c] Auctions

Retreating from a proposal in the NOPR for mandatory auctions of available pipeline capacity, the Commission has promulgated in Order No. 637 a series of basic principles governing procedures for auctions the Commission is now encouraging on a voluntary basis, both by pipelines and third parties. The guidelines governing such auctions include that:

- (1) the timing of the auctions be predictable and provide sufficient notice to bidders;
- (2) the auctions should be open to all potential bidders on a non-discriminatory basis;
- (3) the auctions be user friendly with information on the rules and procedures easily accessible;
- (4) the bidding procedures, as well as methods for selecting the best bids should be fully disclosed prior to the auctions;
- (5) there should be no favoritism in the determination of the winning bidders;
- (6) transaction information be disclosed so that shippers may determine the value of the transportation.⁵⁴

Within these guidelines, the Commission is encouraging experimentation that may include auctions of capacity establishing a transportation path over a series of pipelines in a given region.⁵⁵

[d] Imbalance Services, Operational Flow Orders and Penalties

Concerned that the existing regulatory approach to the imposition of penalties upon shippers for exceeding their contractual rights has encouraged shippers to

⁵² Order No. 637, at 31,292-94.

⁵³ Order No. 637, at 31,292-94.

⁵⁴ Order No. 637, at 31,294-96.

⁵⁵ Order No. 637, at 31,294-96.

engage in service arbitrage across pipeline system and to commit intentional violations of service restrictions as a means of managing imbalances,⁵⁶ the Commission has promulgated new rules in three areas. First, through new Section 284.12(c)(2)(iii) of its regulations, the Commission has required pipelines to provide, to the extent practicable, a new range of services enabling shippers to manage their imbalances more efficiently. Such services may include parking and lending, and the creative provision of additional storage rights, and must include provision for imbalance trading and netting in order to enable customers to minimize their imbalances. Further, the new regulation requires that provision must be made to enable third party vendors to provide such services, and that transportation customers will be treated on a non-discriminatory basis when they employ such third-party suppliers.⁵⁷

Second, through new Section 284.12(c)(2) of the regulations, the Commission has required pipelines to take all reasonable steps to minimize the impact and issuance of Operational Flow Orders (OFOs) and to set forth in their tariffs standards governing the circumstances in which OFOs will issue and when they will end. Pipelines are further obligated to provide timely information to shippers enabling them to minimize the adverse impact of an OFO. These new measures are designed to provide a level of predictability in the issuance of OFOs and to minimize their incidence.⁵⁸

Finally, new Section 284.12(c)(2)(v) of the Commission's rules requires that: (1) a pipeline may include penalties in its tariff only to the extent necessary to prevent the impairment of reliable service; (2) pipelines must credit penalty revenues to shippers' rates; and (3) pipelines must provide shippers as much information as is available on the status of their imbalances and overruns in order to assist them in avoiding penalties. The aim of these new regulations is to minimize the imposition of penalties and to remove any incentive for pipelines to assess penalties where they may otherwise assist customers in managing their imbalances.⁵⁹

[e] Negotiated Terms and Conditions of Service

Rejecting a proposal made in the earlier NOPR, the Commission decided in Order No. 637 not to extend blanket authority to pipelines to enter into negotiations with customers over the terms and conditions of their service.⁶⁰ While the Commission previously granted permission to pipelines to negotiate

⁵⁶ Order No. 637, at 31,307-09.

⁵⁷ Order No. 637, at 31,310.

⁵⁸ Order No. 637, at 31,312-13.

⁵⁹ Order No. 637, at 31,314-19.

⁶⁰ Order No. 637, at 31,342-43.

rates,⁶¹ the Commission refrained from extending this authority to features of natural gas transportation service other than rates, including provisions regarding scheduling, imbalances or operational obligations. The Commission has indicated an interest in continuing to discuss this concept in connection with what it anticipates will be an ongoing dialogue with the natural gas industry over the potential for two-track regulation, with one track reserved for services directed to traditional captive pipeline markets, with another track permitting individuated agreements aimed at customers with a range of service options.⁶² Pending that discussion, the Commission comments that it will continue to permit pipelines to submit non-conforming, negotiated agreements that will be subject to review on an individual basis against claims of discrimination or preferential treatment.⁶³

§ 83.05 Conclusion

With the FERC's issuance of Order Nos. 636, *et al.*, the natural gas industry may have reached a relatively stable stage in which natural gas supplies are purchased and sold freely in an open market. Looking to the future, the Commission has yet to resolve a host of issues relating to, among other things, the rate treatment for capacity built to serve new markets and the challenges raised by those recommending the application of market-based rates to transportation service. The Commission also has not put to bed issues relating to the transition costs resulting from industry restructuring under Order No. 636. What further issues arise will very much depend on the durability of the competitive framework engineered by the Commission.

⁶¹ See *Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines, and Regulation of Negotiated Transportation Services of Natural Gas Pipeline*, 74 F.E.R.C. ¶ 61,076 (1996).

⁶² Order No. 637, at 31,343.

⁶³ Order No. 637, at 31,343.

Access to Alaska Gas Pipeline and "Basin Control"

Robert H. Loeffler
Partner
Morrison and Foerster LLP

July 13, 2006

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ACCESS AND BASIN CONTROL OVERVIEW

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

2

ACCESS AND BASIN CONTROL PRODUCER PIPELINE OWNERSHIP

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

3

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

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

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

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ACCESS AND BASIN CONTROL

THE PERVASIVE NATURE OF FERC REGULATION OF INTERSTATE GAS PIPELINES

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

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ACCESS AND BASIN CONTROL

THE LEGAL FRAMEWORK

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

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ACCESS AND BASIN CONTROL

PHASES OF FERC REGULATION

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

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PART II

EVOLUTION OF FERC'S AFFILIATE/SEPARATION OF FUNCTIONS REGULATIONS

8

NATURAL GAS RESTRUCTURING – OPEN ACCESS/ORDER 436

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

NATURAL GAS RESTRUCTURING – ORDER 636/UNBUNDLING

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

NATURAL GAS RESTRUCTURING – ORDER 636/CAPACITY

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

NATURAL GAS RESTRUCTURING – ORDER 637

FERC's issuance of Order 637 enhanced Order 636:

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

PART III

FERC'S ENFORCEMENT POWERS DURING PIPELINE OPERATIONS

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

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

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

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

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

EX-456710

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FERC'S NEW ENFORCEMENT TOOLS UNDER EPAc

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

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

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

DC 456710

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CONCLUSION

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

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ORDER 670: PROHIBITION OF ENERGY MARKET MANIPULATION

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

DC 456710

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

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

DC 456710

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PART IV

THE ALASKA OPEN SEASON REGULATIONS

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OPEN SEASON REGULATIONS FOR THE ALASKA PIPELINE OVERVIEW

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

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OPEN SEASON REGULATIONS FOR THE ALASKA PIPELINE

OVERVIEW...cont.

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

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INFORMATION AVAILABILITY

18 CFR 157.34

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

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CERTIFICATION BY SALES AND MARKETING UNITS
18 CFR 157.34

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

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

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

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**UNDUE DISCRIMINATION OR PREFERENCE
PROHIBITIONS**

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

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

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**UNDUE DISCRIMINATION OR PREFERENCE
PROHIBITIONS**

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

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

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BID TERMS – FERC ORDER 2005

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

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PART V

BASIN CONTROL AND BASIN MASTERY

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BASIN CONTROL AND BASIN MASTERY

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

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FERC TOOLS TO ADDRESS BASIN CONTROL, SUMMARY

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

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

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

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

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APPENDIX

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

The regulations provide the following:

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

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

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

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

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

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

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

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the Year Ended December 31, 2005
Commission File No. 1-8968

ANADARKO PETROLEUM CORPORATION

1201 Lake Robbins Drive, The Woodlands, Texas 77380-1046
(832) 636-1000

Incorporated in the State of Delaware Employer Identification No. 76-0146568

Securities registered pursuant to Section 12(b) of the Act:

Common Stock, par value \$0.10 per share
Preferred Stock Purchase Rights

The above Securities are listed on the New York Stock Exchange.

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐.

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒.

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐.

Indicate by check mark if the disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐.

Indicate by check mark whether the registrant is a shell company. Yes ☐ No ☒.

The aggregate market value of the Company's common stock held by non-affiliates of the registrant on June 30, 2005 was \$19.4 billion based on the average bid and asked price as reported on the New York Stock Exchange.

The number of shares outstanding of the Company's common stock as of January 31, 2006 is shown below:

Title of Class	Number of Shares Outstanding
Common Stock, par value \$0.10 per share	230,441,223

Part of
Form 10-K

Documents Incorporated By Reference

- Part II Portions of the Anadarko Petroleum Corporation 2005 Annual Report to Stockholders.
- Part III Portions of the Proxy Statement for the Annual Meeting of Stockholders of Anadarko Petroleum Corporation to be held May 11, 2006 (to be filed with the Securities and Exchange Commission prior to April 3, 2006).

The following table presents selected 2005 U.S. operating data by area.

	Sales Volumes			Producing Wells ⁽¹⁾	Drilling Statistics	
	Natural Gas (MMcf/d)	Oil and NGLs (MMbbls/d)	Total (MBOE/d)		Wells Drilled ⁽²⁾	Success Rate
North Louisiana - Vernon/Ansley	217	—	36	316	78	100%
East Texas - Bossier	211	—	35	761	46	100%
- Carthage	95	4	20	1,259	28	100%
Central Texas - Austin Chalk	95	21	37	1,817	54	100%
West Texas - Haley	73	—	12	30	19	95%
- Ozona	45	—	8	2,082	50	100%
- EOR	6	5	7	2,117	66	100%
Mid-Continent - Kansas/Oklahoma	84	10	24	1,453	5	100%
Western States - Tight gas and conventional	196	14	46	2,120	187	100%
- Coalbed Methane	72	—	12	871	91	100%
- EOR	10	13	15	1,553	13	100%
Other	27	6	9	598	—	
Total Onshore — Lower 48 States	1,131	73	261	14,977	637	
Alaska	—	22	22	48	7 ⁽³⁾	
Gulf of Mexico	5	8	9	8	11	64%
Total United States	1,136	103	292	15,033	655	99.2%

(1) Gross number of wells in which Anadarko has an interest.

(2) Includes 631 gross development wells with a 99.8% success rate and 24 gross exploration wells with an 83% success rate.

(3) The results of these wells are held confidential for competitive reasons.

Onshore — Lower 48 States At the end of 2005, about 60% of the Company's proved reserves were located onshore in the Lower 48 states. The Company's 2006 capital budget for this area is about \$2 billion and is expected to largely focus on unconventional tight gas plays throughout the region.

North Louisiana The Company's tight gas drilling program in the Vernon and Ansley areas are focused on development drilling with an increased effort on extending field boundaries. Additionally, a pilot program is underway to test for increased infill drilling opportunities. The Company also has tight gas exploration programs underway in north Louisiana and is encouraged by preliminary results in the Vixen and Liberty Hills prospect areas.

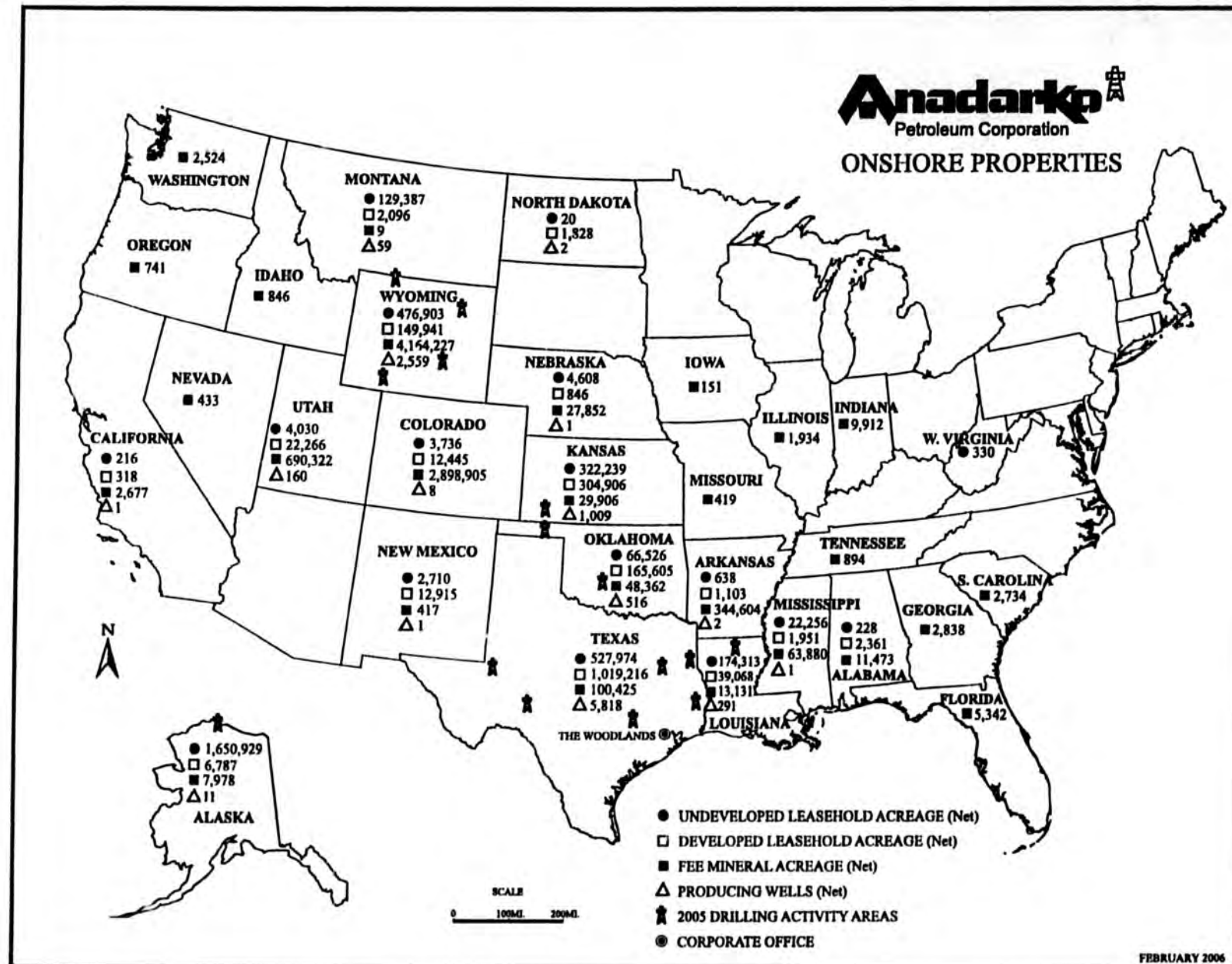
East Texas Development drilling and field extension of the Dowdy Ranch, Dew/Mimms Creek, Bald Prairie and Marquez fields are the primary focus in the east Texas tight gas Bossier play. Anadarko also continues to be active in its Cotton Valley infill drilling program in the Carthage area.

Central Texas Anadarko's horizontal drilling program continues to be the focus in central Texas where the objective is to exploit the multiple pay zones and extend field boundaries in the Austin Chalk formation of the Giddings and Brookeland fields. In addition, a successful re-entry program is in place. Anadarko's exploration activities in the area are currently evaluating the potential of the deep Bossier and Woodbine formations.

West Texas Operations in west Texas are concentrated on increasing production and reserves in the tight gas play of the Haley field where early activity levels and performance is ramping up at a pace comparable to what was achieved in the Company's two largest domestic gas fields, the Bossier and Vernon. The Company's efforts also include continued development in the Ozona field and waterflood projects in the Permian basin.

Mid-Continent The Company's operations in the mid-continent continue to focus on production and development of its long-life, high-margin assets in the Hugoton and Golden Trend fields as well as enhanced oil recovery (EOR) activities in the Norge Marchand field.

ONSHORE PROPERTIES



Western States The majority of the activity in the western states area is associated with developing conventional reservoirs, tight gas, coalbed methane (CBM) and EOR projects. Increased activity is expected in Wamsutter, among other areas in the Land Grant, where the Company's non-operated positions benefit from net revenue interests greater than its working interest due to Anadarko's additional royalty interest. The Company operates multiple full-scale CBM properties, as well as active pilot programs. The Company's operations at the Salt Creek, Monell and Sussex EOR projects (98%-100% working interest (WI)) in Wyoming continue to demonstrate year-over-year increases in oil response due to CO₂ injection.

Alaska Anadarko's activity in Alaska is concentrated primarily on the North Slope. About 3% of the Company's proved reserves at year-end 2005 were in Alaska. The Company's capital budget is expected to be about \$70 million for Alaska in 2006, which will focus primarily on development activities and preparation for future exploration.

At the Alpine field (22% WI) on Alaska's North Slope, a capacity expansion project was completed in 2005 that increased capacity of the Alpine oil processing facility to 140 MBbls/d gross.

Development of the Nanuq and Fiord satellite fields (both 22% WI) is underway. First production is scheduled for late 2006, with expected peak production of approximately 35 MBbls/d in 2008. Anadarko and the operator are continuing to pursue the state, local and federal permits for three additional Alpine satellites. During the 2004-2005 winter drilling season, the Company participated in exploration wells located in the National Petroleum Reserve-Alaska. Commerciality and potential development scenarios are currently being evaluated.

Gulf of Mexico At year-end 2005, about 11% of the Company's proved reserves were located offshore in the deepwater of the Gulf of Mexico where Anadarko owns an average 71% interest in 231 blocks and has access to an additional 33 blocks through participation agreements. Anadarko has budgeted about \$850 million for capital spending in the deepwater Gulf of Mexico for 2006. In the eastern Gulf of Mexico, facilities will be installed to link several Anadarko-operated natural gas discoveries with the Independence Hub. In the central Gulf of Mexico, the Company expects to bring several high-volume wells on-line at the Marco Polo hub facility and participate in exploration or delineation wells in the foldbelt area.

Anadarko operates, and a third party owns, the platform and production facilities for the Marco Polo (100% WI) deepwater development project. During 2005, the K2 (52.5% WI) and K2 North (100% WI) fields were tied back subsea to the Marco Polo platform. Production from the K2 field began in 2005. Due to the active 2005 hurricane season, production startup at the K2 North field was delayed several months to January 2006.

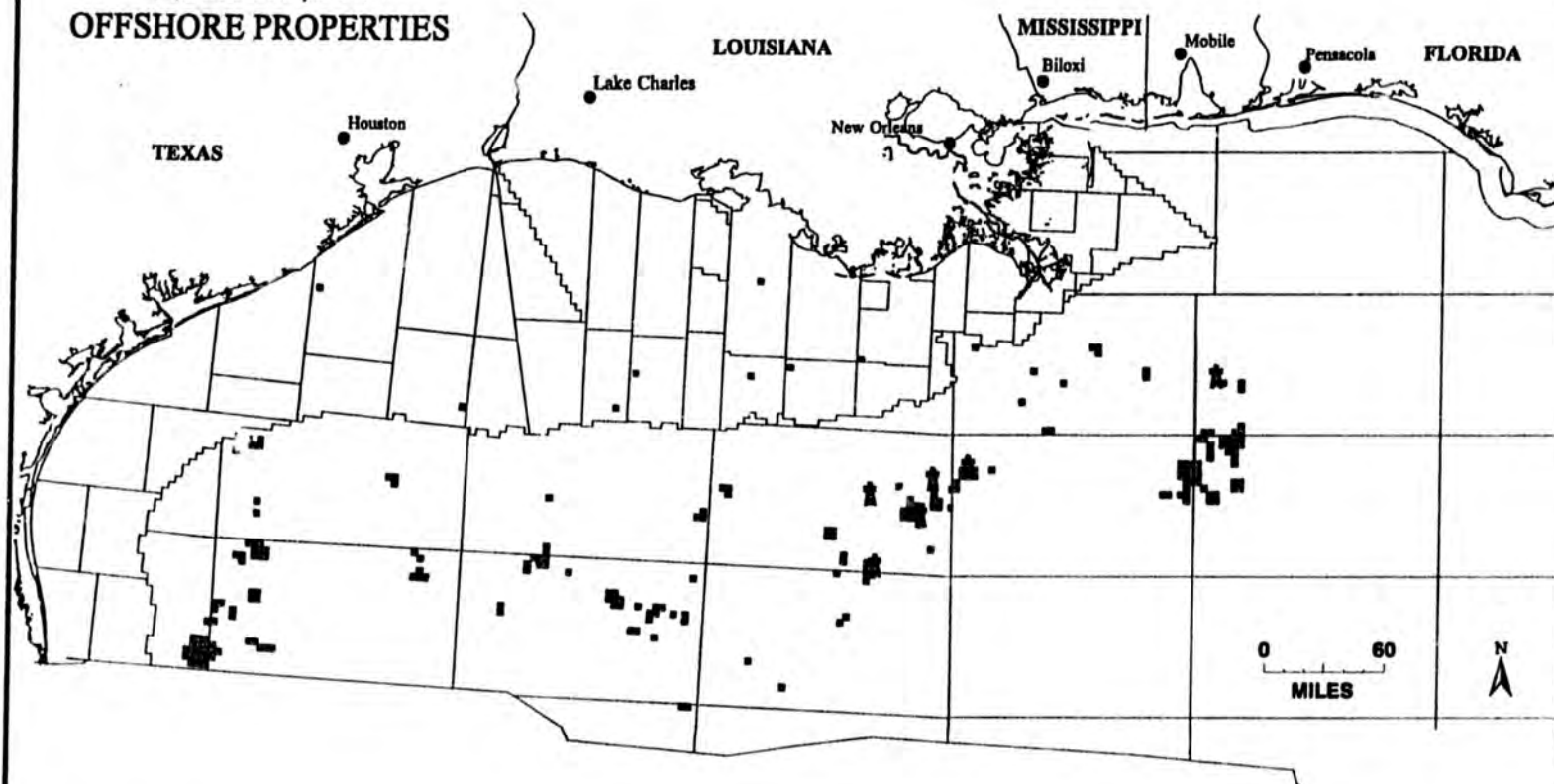
Development plans for a gas processing hub, Independence Hub, and gas export pipeline in the eastern Gulf of Mexico were approved in late 2004. The Company, along with a group of other producers, contracted with a third party to design, construct and own the facility. Anadarko will operate Independence Hub. The facility, capable of processing 1 Bcf of gas per day, will serve several ultra-deepwater natural gas fields, including seven discoveries operated by Anadarko. During 2006, the Company plans to install subsea infrastructure and start the downhole completion phase of previously drilled and suspended wells. Production from Independence Hub is expected to commence in the second half of 2007.

Anadarko has participation agreements to explore deepwater blocks in the central and western Gulf of Mexico. Anadarko's exploration program in this area is currently focused on the extensive middle-to-lower Miocene play within the foldbelt area. During 2005, the Company was successful in three out of four exploration wells in this play. The Knotty Head (25% WI) and Big Foot (15% WI) discoveries are outside operated. The Company-operated Genghis Khan (100% WI) discovery and appraisal well is expected to be tied into the Marco Polo complex and on production by the end of 2006. Anadarko expects to remain very active in the region in 2006.

Gas Processing The Company processes gas at various third-party plants under agreements generally structured to provide for the extraction and sale of NGLs in cost efficient plants with flexible volume commitments. The Company has agreements with eight plants in Texas, four plants in the western states area, five plants in the mid-continent area and one plant in the gulf coast area. Anadarko also processes gas and has interests in two Company-operated plants in the western states. Anadarko's strategy to aggregate gas through Company-owned and third-party gathering systems allows Anadarko to secure processing arrangements in each of the regions where the Company has significant production.



OFFSHORE PROPERTIES



- ▲ 2005 DRILLING ACTIVITY
- PRODUCTION BLOCKS
- EXPLORATORY BLOCKS
- ⊠ 2005 LEASE ACQUISITIONS

OFFSHORE ACREAGE	GULF OF MEXICO				CALIFORNIA
	WESTERN	CENTRAL	EASTERN		
UNDEVELOPED (Net)	426,581	293,243	177,984		2,785
DEVELOPED (Net)	—	14,366	—		—
PRODUCING WELLS (Net)	—	7	—		—

FEBRUARY 2006

Properties and Activities — Canada

Overview At the end of 2005, about 11% of the Company's proved reserves were located in Canada. In 2005, net sales volumes from the Company's properties in Canada accounted for 13% of the Company's total sales volumes. During 2005, drilling activity in Canada included 40 exploration wells with a success rate of 85% and 108 development wells with a success rate of 98%. The Company's 2006 capital budget for Canada is expected to be about \$450 million and is allocated about 70% to development and 30% to exploration activity. The accompanying map illustrates the Company's net developed and undeveloped lease and fee mineral acreage, number of net producing wells and other data relevant to its Canadian properties.

Fort St. John During 2005, additional compression was added, increasing capacity in the Buckinghorse area where the Company continues to pursue multi-zone, deep natural gas targets in the area. Anadarko also continues to increase its land holdings in the Buckinghorse and Adsett areas of British Columbia where it holds approximately 1 million net acres.

Grande Prairie In the Peace River Arch area of Northern Alberta, the Company continues to have exploration success in a number of conventional gas plays. In addition, an evolving unconventional gas project is expected to provide future growth opportunity. The Company also has the benefit of operating two gas plants in the region.

Edson The Wild River/Cecilia drilling program continues to be the most active development area for the Company in Canada. Wild River represents about 30% of Anadarko's Canadian production and reserve base. This multi-zone area is expected to continue to provide growth opportunities in 2006. Additionally in central Alberta, the Company is evaluating a portion of its acreage for CBM production potential.

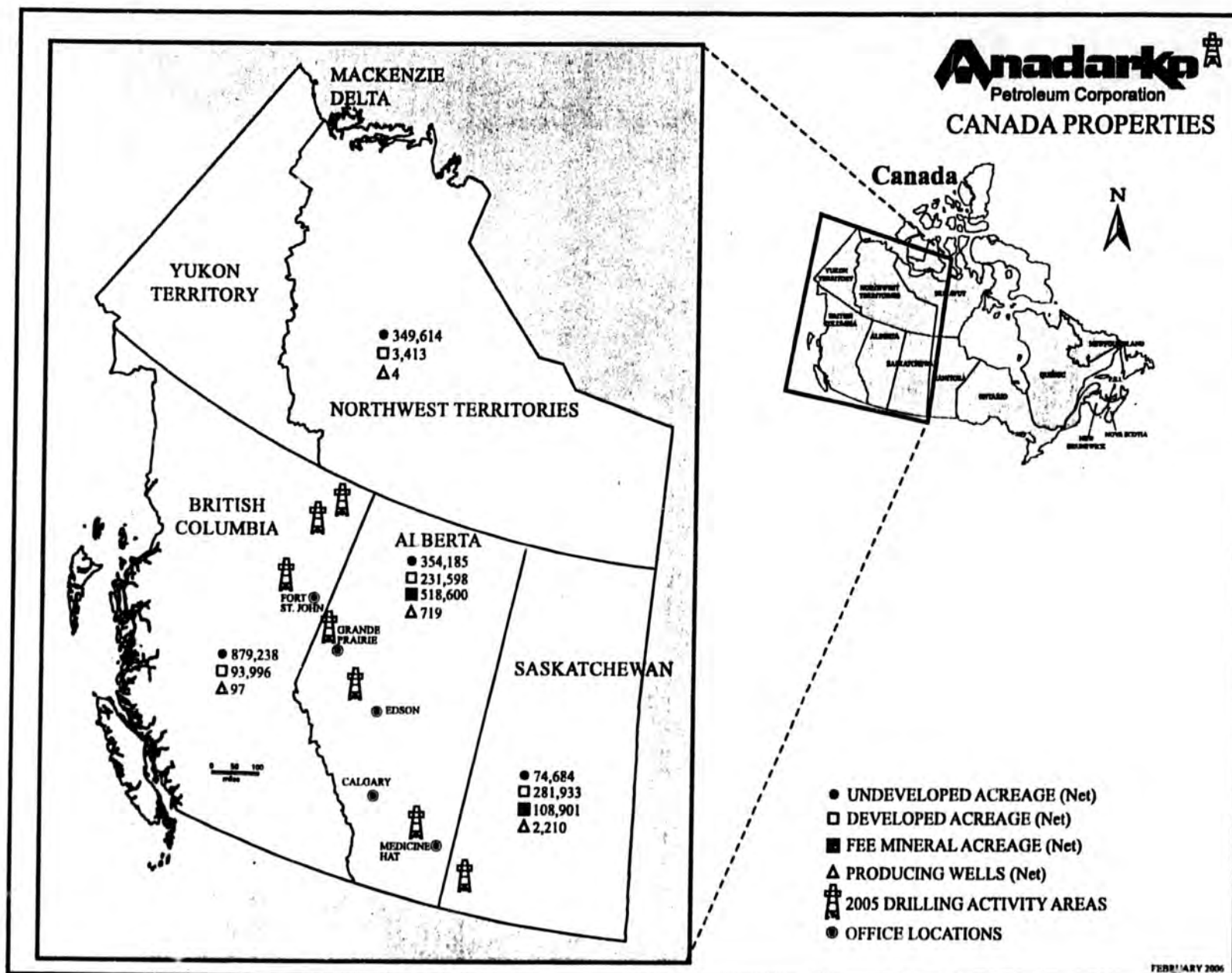
Medicine Hat In southern Alberta, Anadarko continues to develop a CO₂ pilot project near the Company's Hays gas plant. In southwest Saskatchewan, the Company began the second of three phases of its 115-well Crane Lake North shallow gas program. With use of new drilling and completion technologies, this mature area continues to provide steady production and exploitation opportunities that can be brought on-line quickly.

Other In the Mackenzie Delta, Anadarko continues its evaluation of encouraging Burnt Lake discoveries on Block EL-384. The Company is closely monitoring development related to the Mackenzie Valley pipeline.

Properties and Activities — Algeria

Overview Anadarko is engaged in exploration, development and production activities in Algeria's Sahara Desert. At the end of 2005, about 13% of the Company's proved reserves were located in Algeria where a total of eight fields discovered by the Company were on production. In 2005, net sales volumes from the Company's properties in Algeria represented 15% of the Company's total sales volumes. In 2005, Anadarko participated in 20 wells with a success rate of 90%. In addition, the Company participated in nine injection or service wells during the year. The Company's 2006 capital budget for Algeria is expected to be about \$130 million and the budget provides for drilling about 30 development and service wells and four exploration wells, as well as engineering design for a production facility on Block 208.

Contracts and Partners Anadarko's interest in the Production Sharing Agreement (PSA) for Blocks 404, 208 and 211 is 50% before participation at the exploitation stage by Sonatrach, the national oil and gas enterprise of Algeria. The Company has two partners, each with a 25% interest, also prior to participation by Sonatrach. Under the terms of the PSA, oil reserves that are discovered, developed and produced are shared by Sonatrach, Anadarko and its two partners. Sonatrach is responsible for 51% of the development and production costs. Anadarko and its partners also have an exploration program underway on Blocks 404, 208 and 211 and have exploration licenses, under separate PSAs, for Block 406b (60% interest) and Block 403c/e (33% interest). Anadarko and its joint venture partners fund Sonatrach's share of exploration costs and are entitled to recover these exploration costs out of production in the exploitation phase.



Production and Development On Block 404, production from the HBNS field averaged 125 MBbls/d of oil (gross) and production from five of the satellite fields averaged 31 MBbls/d of oil (gross) in 2005. Production from the HBN field, which extends from Block 404 into Block 403 and is unitized with other companies, averaged 77 MBbls/d of oil (gross) in 2005. Anadarko is also actively involved in the unitized Ourhoud field which is located in the southern portion of Block 404 and extends into Block 406a and Block 405. Production from the Ourhoud field averaged 224 MBbls/d of oil (gross) in 2005. Anadarko has several fields farther south on Block 208. Development of the Block 208 fields is progressing and the new facility is expected to be operational in late 2008 with over 150 MBbls/d of oil production capacity.

Exploration During 2005, the Company participated in two exploration wells on Block 404, one of which was successful. Anadarko's first exploration well in Block 403c/e was drilled in 2005 and is currently pending testing. During 2006, the Company plans to continue exploratory drilling on Blocks 404 and 406b and evaluate the prospect on Block 403c/e for commerciality.

Anadarko continually monitors the political situation in Algeria and has taken steps to help ensure the safety of employees and the security of its facilities in the remote regions of the Sahara Desert. Anadarko is unable to predict with certainty any effect political events may have on activity planned for 2006 and beyond. However, no material effect has been experienced to date on the Company's operations in Algeria, where the Company has had activities since 1989.

Properties and Activities — Other International

Overview The Company's other international oil and gas production and development operations are located primarily in Venezuela and Qatar. The Company has exploration acreage in Qatar, Indonesia and other selected areas. About 2% of the Company's total proved reserves were located in other international locations at year-end 2005. During 2005, net sales volumes from the Company's other international properties accounted for 5% of the Company's total volumes. In 2006, the Company's capital budget is expected to range from \$200 million to \$250 million for other international projects and provides for drilling about 20 development and 20 exploration wells.

Venezuela The Company's operations consist of the Oritupano-Leona contract area, in which the Company has a non-operated 45% participating interest. The Company's net oil sales volumes from this 395,000 acre area totaled 5 MMBbls during 2005. The development program in 2005 included drilling ten wells with a 100% success rate and workover activity.

Anadarko's operations in Venezuela have been governed by an Operating Service Agreement (OSA) that was entered into between the Company and an affiliate of Petroleos de Venezuela, S.A. (PDVSA), the national oil company of Venezuela. In accordance with the 2005 announcement by the Venezuelan Ministry of Energy and Petroleum, the OSA is under renegotiation. The Company and its operating partner, Petrobras Energia Venezuela (Petrobras), recently signed a Transitory Agreement with PDVSA. For additional information see *Other Developments* under Item 7 of this Form 10-K.

Qatar The Company had interests in 1,549,000 undeveloped lease acres and 19,000 developed acres in Qatar at year-end 2005. Anadarko is the operator and has a 92.5% interest in the Al Rayyan field, which is part of an Exploration and Production Sharing Agreement covering Blocks 12 and 13. Production from the Al Rayyan field, located on Block 12, totaled 3 MMBbls of oil (net) in 2005. An exploration well is scheduled for 2006 in offshore Block 13, which will be the first well drilled in this block. In Block 4 (100% interest), the Company plans to acquire seismic data in 2006 as partial fulfillment of an exploration work program. Anadarko also has a non-operated interest in an Exploration and Production Sharing Agreement covering offshore Block 11 (49% interest). The exploration period for Block 11 has recently been extended until 2007 to evaluate the commerciality of a prospect drilled on the block in 2005 and to further assess exploration potential.

Indonesia In 2005, Anadarko entered into an outside operated exploration joint venture agreement, under which the Company gained access to 12 Production Sharing Contracts (PSCs) covering about 7,400,000 gross acres onshore and offshore Indonesia. Anadarko has committed to a three-year, \$80 million work program to fund exploration activities. The Company has the opportunity to earn up to a 40% interest in each of the PSCs where a successful exploration well is drilled and upon the approval of a plan of development. In 2004, the Company entered into a PSC for exploration and production rights to the nearly 1,000,000 acre North East Madura III Block (100% interest) offshore Indonesia. Under the terms of the PSC, Anadarko will undertake a three-year exploration phase. Anadarko has purchased 3-D seismic data and plans to drill up to four wells on this block in 2006.

Other Anadarko also has active exploration projects in Tunisia and West Africa, as well as activities in other potential new venture areas overseas.

Drilling Programs

The Company's 2005 drilling program focused on known oil and gas provinces in the United States (Lower 48, Alaska and Gulf of Mexico), Canada and Algeria. Exploration activity consisted of 67 wells, including 13 wells in the Lower 48, three wells in Alaska, eight wells offshore in the Gulf of Mexico, 40 wells in Canada, two wells in Algeria and one well in other international locations. Development activity consisted of 769 wells, which included 624 wells in the Lower 48, four wells in Alaska, three wells offshore in the Gulf of Mexico, 108 wells in Canada, 18 wells in Algeria and 12 wells in other international locations.

Drilling Statistics

The following table shows the results of the oil and gas wells drilled and tested:

	Net Exploratory			Net Development			Total
	Productive	Dry Holes	Total	Productive	Dry Holes	Total	
2005							
United States	10.9	3.2	14.1	375.9	1.0	376.9	391.0
Canada	15.7	4.7	20.4	78.5	0.6	79.1	99.5
Algeria	0.5	0.2	0.7	2.9	0.3	3.2	3.9
Other International	0.5	—	0.5	5.4	—	5.4	5.9
Total	27.6	8.1	35.7	462.7	1.9	464.6	500.3
2004							
United States	25.2	9.4	34.6	484.2	4.7	488.9	523.5
Canada	25.5	6.0	31.5	159.9	3.6	163.5	195.0
Algeria	1.1	1.5	2.6	2.1	—	2.1	4.7
Other International	—	—	—	8.1	—	8.1	8.1
Total	51.8	16.9	68.7	654.3	8.3	662.6	731.3
2003							
United States	22.2	16.3	38.5	452.1	14.4	466.5	505.0
Canada	64.6	7.3	71.9	183.7	5.5	189.2	261.1
Algeria	1.5	1.5	3.0	4.0	0.3	4.3	7.3
Other International	1.0	2.2	3.2	3.5	1.0	4.5	7.7
Total	89.3	27.3	116.6	643.3	21.2	664.5	781.1

State North Slope/Beaufort Sea Oil & Gas Lease Acreages

Independents	Net Acreage*	Percent
Anadarko Petroleum Corporation	203,516.68	10.0%
Union Oil Company Of California	184,117.41	9.0%
Pioneer Natural Resources Alaska	151,160.41	7.4%
AVCG, LLC	139,878.64	6.9%
ENI Petroleum US LLC	137,711.33	6.7%
FEX L.P.	94,745.79	4.6%
BG Alaska E&P, Inc	82,840.40	4.1%
All Others	174,662.20	8.6%
Total "Independents"	1,168,632.86	57.3%
 Major Alaska Producers	 Net Acreage*	 Percent
ConocoPhillips	482,534.07	23.6%
BP Exploration	264,919.38	13.0%
Exxon	124,901.54	6.1%
Total Major Alaska Producers	872,354.99	42.7%
Total	2,040,987.85	100.0%

*Acreage is calculated as gross acreage held times the working interest ownership for each

July 26, 2005

Federal Alaska Leasehold Acreage Held

July 26, 2006

BLM on shore (NPR-A):

Anadarko Petroleum Corp	
ConocoPhillips AK Inc	
Pioneer Natural Resources AK Inc	980,437.98
Anadarko Petroleum Corp	
ConocoPhillips Alaska Inc	522,264.45
ConocoPhillips Alaska Inc.	
Pioneer Natural Resources AK Inc	390,355.00
FEX LP	304,504.00
Petro-Canada Alaska Inc	277,182.00
Petro-Canada Alaska Inc	
Pioneer Natural Resources AK Inc	74,596.00
Anadarko Petroleum Corp.	
Petro-Canada Alaska Inc	48,481.00
Peter G Zamarello	11,500.00
Arctic Falcon Exploration LLC	6,672.41
Total Acres	2,615,992.84

MMS Offshore:

Shell Oil	565,262
ConocoPhillips AK Inc	149,540
BP Exploration	20,733
Anadarko Petroleum Corp	7,490
ENI	3,761
ChevronUSA	2,892
Forest Oil	2,442
Murphy Exploration	524
Total Acres	752,644

**Senate Special Gas Committee
Written Comments of Ken Sheffield, President
Pioneer Natural Resources Alaska, Inc.
Re: Draft Alaska Stranded Gas Fiscal Contract
July 27, 2006**

Pioneer strongly supports the timely construction of a gas pipeline to tap the existing gas reserves and the vast gas resources on the North Slope of Alaska. Although Pioneer is not specifically targeting gas in its current exploration efforts, it is likely that gas will be encountered in our search for oil. As the certainty and timing of a gas pipeline becomes clearer, we may in the future shift our exploration efforts to partially focus on gas. Reasonably certain availability to pipeline capacity to access gas markets is critical for explorers to risk exploration dollars. Even with the development of oil reservoirs, such as our Oooguruk oil project, the ability to sell the gas produced in conjunction with the oil at some future date will provide operational flexibility and revenues for the project and the state.

Pioneer's primary concerns with any gas contract are simply:

- 1) Pioneer and other explorers should have fair access to capacity at the initial open season and timely and reasonable mechanisms for future expansions,
- 2) the pipeline and related services should be regulated such that the fees for services are fair and transparent, and
- 3) the Uniform Upstream Fiscal Contract should be fair for both producers and explorers.

Pioneer believes a gas line with reasonable and fair access will stimulate significant, new exploration activity for gas with a positive impact on oil exploration economics. New gas infrastructure over time will lower the economic threshold of lower tier resources. The real challenge is in the details of the contract and we salute the efforts of the administration and the legislature in this important work for the future of Alaska.

AMENDMENT

OFFERED IN THE SENATE

BY SENATOR BEN STEVENS

TO: SB 3002 24-GS2095\C

1 AS 43.82 is amended by adding a new section to read:

2 **Sec. 43.82.255. Term of contract provisions related to oil.** (a) The
3 provisions of this section apply to a contract developed under AS 43.82.020 that
4 provides for periodic payment in lieu of taxes on oil under AS 43.55.

5
6 (b) For the part of the contract term beginning immediately after the date
7 of full project funding or the date of issuance of a certificate of public convenience
8 and necessity for construction and initial operation of the Alaska Natural Gas pipeline,
9 whichever date is later, and ending 14 years after that date, the commissioner may
10 develop a term for the contract that provides for payments in lieu of the taxes on oil
11 set out in AS 43.55. For the part of the contract term established with as much
12 certainty as the Constitution of the State of Alaska allows.

13
14 (c) For the part of the contract term beginning immediately after the period
15 described in (b) of this section, and ending on a date not later than 25 years after the
16 effective date of the contract, the amount of the payment in lieu of tax on oil under
17 AS 43.55 must be equal to the amount of the tax levied by the law. However, the
18 commissioner may develop a contract term that, in the event of a material change in
19 the taxes enacted after the effective date of the contract, establishes a procedure for
20 restoring the parties to substantially the same economic position they had as of the
21 end of the period described in (b) of this section immediately before the change.

22
23 (d) Implementation of a contract provision authorized in this section may
24 be made subject to the dispute resolution procedures of the contract.

Aspects of Fiscal Certainty

May 16, 2006

Presentation to
The Alaska Legislature

Pedro van Meurs

Fiscal Certainty

In the May 11 presentations it was illustrated why it was absolutely essential to have fiscal certainty.

In this presentation the nature, timing and characteristics of fiscal certainty will be discussed in more detail.

Fiscal Certainty

Six aspects of fiscal certainty will be discussed:

- Project vs non-project applications
- The type of taxes included in fiscal certainty
- Application to new leases
- Fiscal certainty for oil and gas
- The duration of fiscal certainty
- The mechanisms to implement fiscal certainty.

Project vs Non-Project application

The SGDA permits the granting of fiscal certainty as follows in Sec.43.82.010(2):

- (2) *Allow the fiscal terms applicable to a qualified sponsor or the members of a qualified sponsor group, with respect to a qualified project, to be tailored to the particular economic conditions of the project and to establish **those** fiscal terms in advance with as much certainty as the Constitution of the State of Alaska allows*

Project vs Non-Project application

The proposed contract goes beyond establishing fiscal certainty for the qualified project only. The contract with respect to some items establishes fiscal certainty on a state wide basis. This is primarily done for reasons of practicality or to enhance the strength of the fiscal certainty.

Project vs Non-Project application

For instance:

- Fiscal certainty is provided with respect to all state corporate income tax, related to the project as well as oil and gas income from other sources, such as Cook Inlet.
- “Capped Taxes” which include sales or use tax on the purchase or use of goods or services, gravel severance or mining license tax, excise tax, including bed or motor fuel tax are capped for each sponsor at a State wide level.

Type of taxes

The SGDA permits the granting of fiscal certainty through payments in lieu of taxes.

The SGDA also permits granting fiscal stability on “like” taxes which are similar to the taxes that are being replaced in order to avoid that the State or municipalities would simply levy similar taxes in addition to the taxes subject to fiscal certainty.

Type of taxes

In fiscal certainty arrangements in the world it is generally understood that the fiscal certainty does not apply to certain taxes which are of general application and do not discriminate against the investor.

Examples are personal income taxes or withholding taxes on contractors and other payments such as fines or fees.

The proposed contract includes similar exclusions from fiscal stability.

Type of taxes

In fiscal contract provides a very detailed description of which taxes need to be paid and from which taxes the sponsors are exempt.

In general, under the agreement, the sponsors the sponsors are exempt from all taxes which would be a replacement of the taxes paid under the agreement, would be similar or would be specifically targeted to the sponsors. A detailed discussion of these classes of taxes will take place later in the week.

New leases

Exhibit D to the contract lists the leases that will contribute gas to the project. These are the leases that will benefit from fiscal certainty.

New leases

Article 31.4 of the proposed contract contemplates the addition of possible new leases to Exhibit D. New leases have to produce gas for the project within a specified period of time. New leases cannot be added unless a new law of general applicability has been passed providing for a Uniform Upstream Fiscal Contract.

New leases

The restriction on adding new leases is to create a “level playing field”, otherwise companies would be placed in different economic positions when bidding for new acreage. The Uniform Upstream Fiscal Contract would give a company that commits to capacity on the gas line the right to the same upstream fiscal terms as the sponsors.

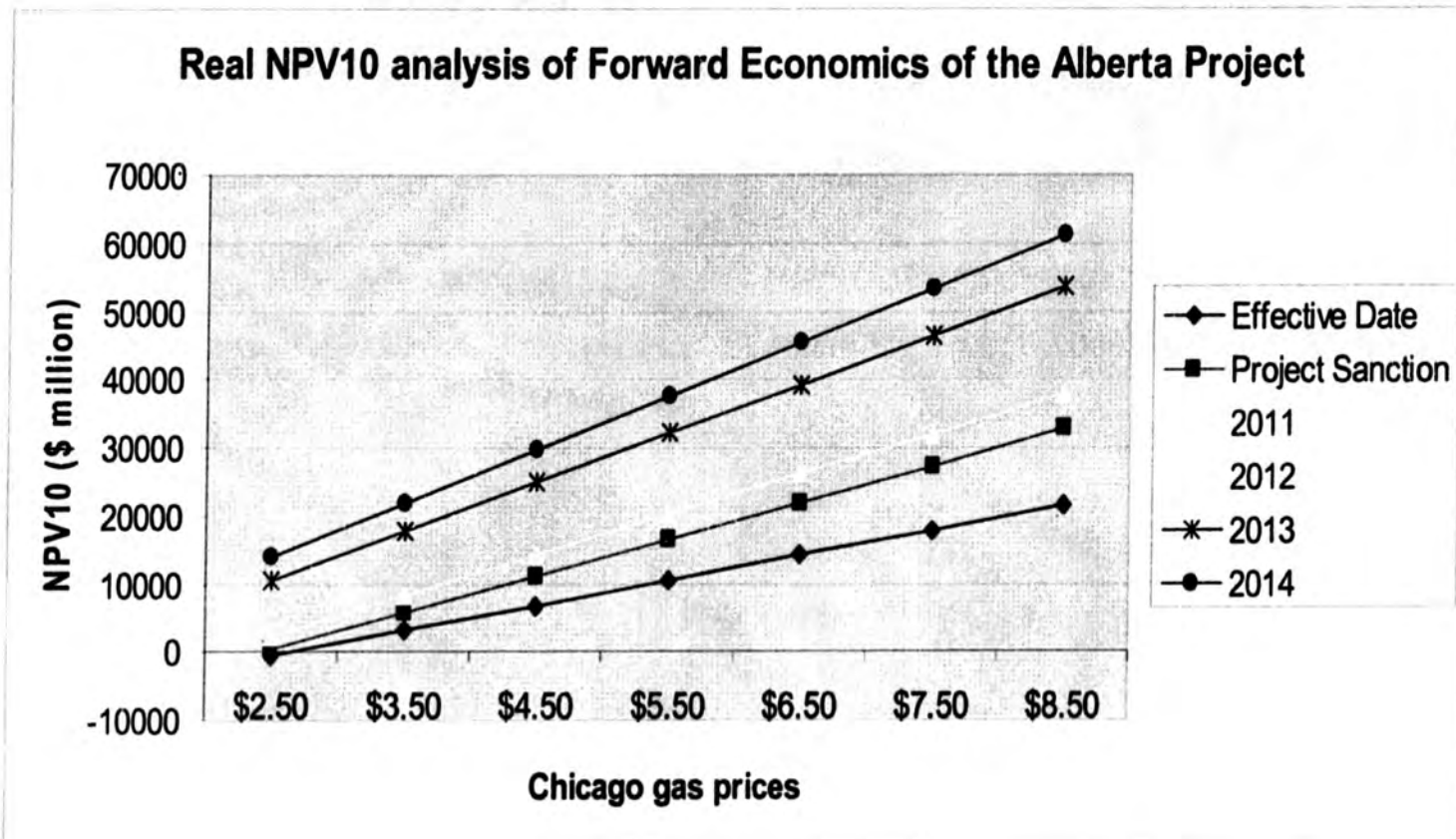
Fiscal certainty for Oil

In previous presentations the absolute need for fiscal stability with respect to the reserve tax and with respect to fiscal change for gas was discussed. Why is there fiscal stability for oil?

Fiscal certainty for Oil

As was illustrated in a previous presentation, the NPV10 of the project changes dramatically over time, as capital expenditures are being made and these become sunk costs. In fact, the NPV10 increases by a factor 4 between the effective date and the date of commencement of operations.

Fiscal certainty for Oil



Repeat slide: The NPV10 improves dramatically towards project sanction. After that, the NPV10 continues to improve as capital expenditures become sunk costs.

Fiscal certainty for Oil

The rapidly increasing NPV10 as the capital invested in the project becomes sunk cost creates an unusual fiscal risk exposure, since it becomes increasingly attractive to a Legislature to increase taxes on these profits.

However, fiscal stability for gas would prevent this. As a result, it is plausible that a Legislature would increase oil taxes as compensation for the inability to increase taxes on gas.

Fiscal certainty for Oil

It is for this reason that the Sponsors considered the matter of fiscal stability for oil a “deal breaker”.

Therefore, the PPT bill was introduced in order to be able to enshrine fiscal stability for oil in the overall package on the basis of new tax legislation that is favorable for Alaska.

Fiscal certainty for oil

It should be noted, however, that a fiscal certainty provision for oil would also be very favorable to stimulate further heavy oil development.

It would be a strong platform for the companies to take a long term view and invest in the development of new technology for heavy oil development.

Fiscal certainty for oil

Fiscal certainty for oil would also be a strong incentive to do the exploration for gas to in order to initially expand and subsequently fill the gas line. This is because condensates are treated as oil.

Typically one million cubic feet of gas comes with 50 barrels of condensate. Therefore condensate terms very much influence exploration for gas.

Furthermore, often exploration is for both oil and gas.

Therefore, fiscal certainty for oil will stimulate exploration for oil, condensates and gas.

Fiscal certainty for oil

More exploration will help fill the gas line

Current reserves - 35 Tcf

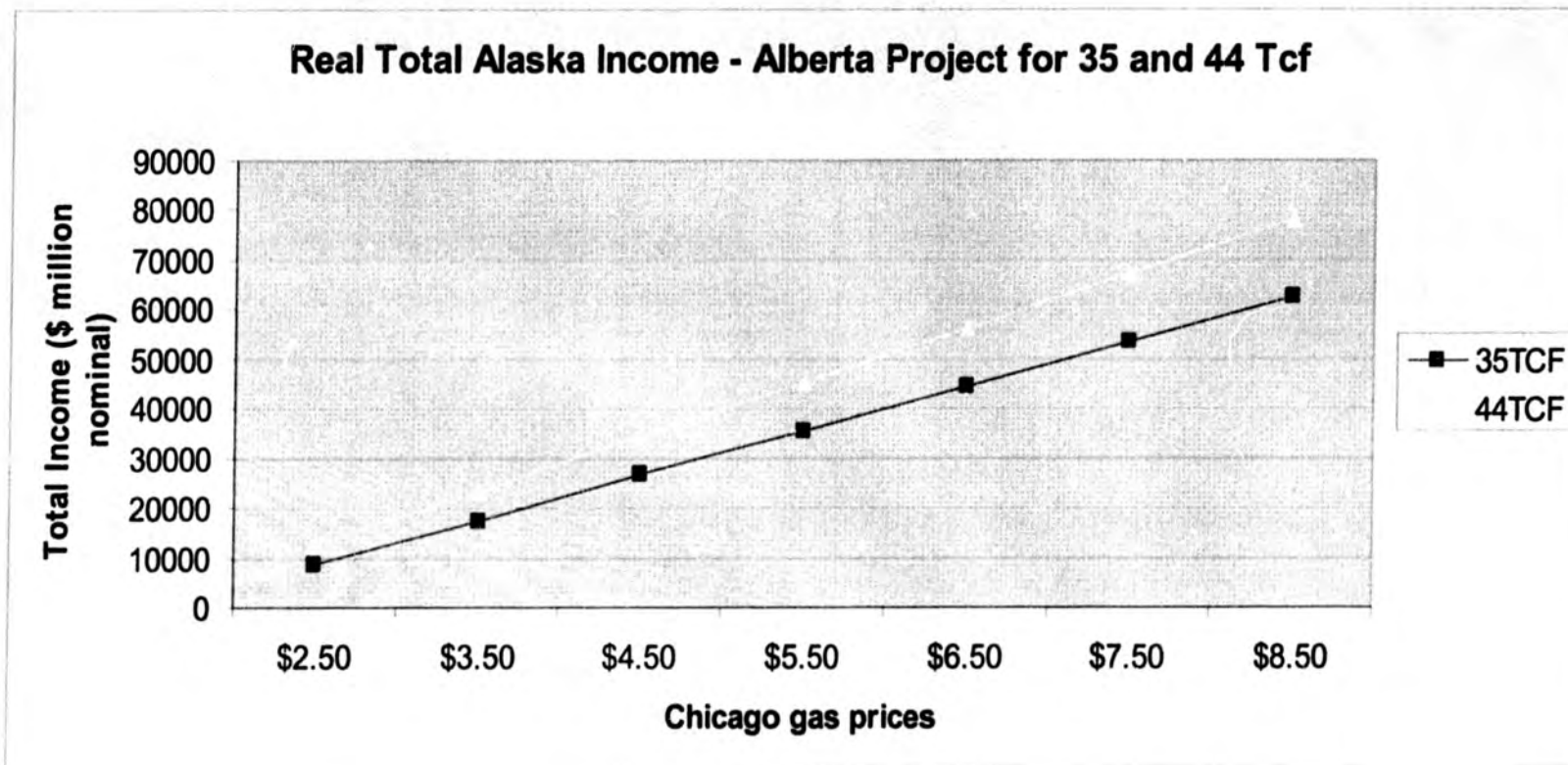
30 year full line - 44 Tcf

35 year full line - 51 Tcf

35 year full expanded line - 70-77 Tcf

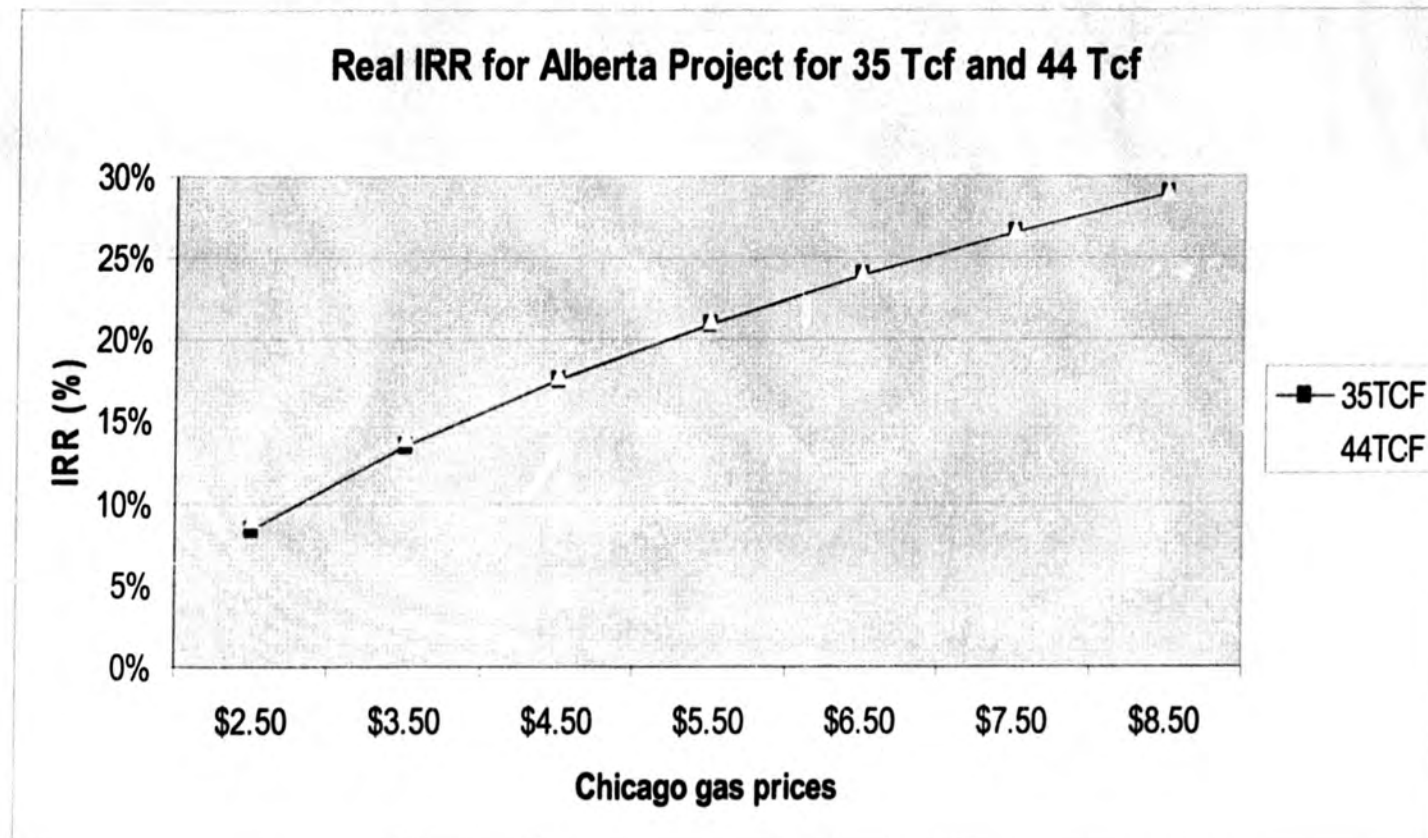
In order to study the economic impact an analysis was done of a 35 Tcf and 44 Tcf case.

Fiscal certainty for Oil



Filling the gas line even for just 30 years would have a very beneficial effect on the Total Alaska Revenues because of the larger volume and the lower average transport tariffs.

Fiscal certainty for Oil



The increased pipeline use has in general only a modest impact on the IRR for average or high prices, since the additional cash is at tail end of the cash flow.

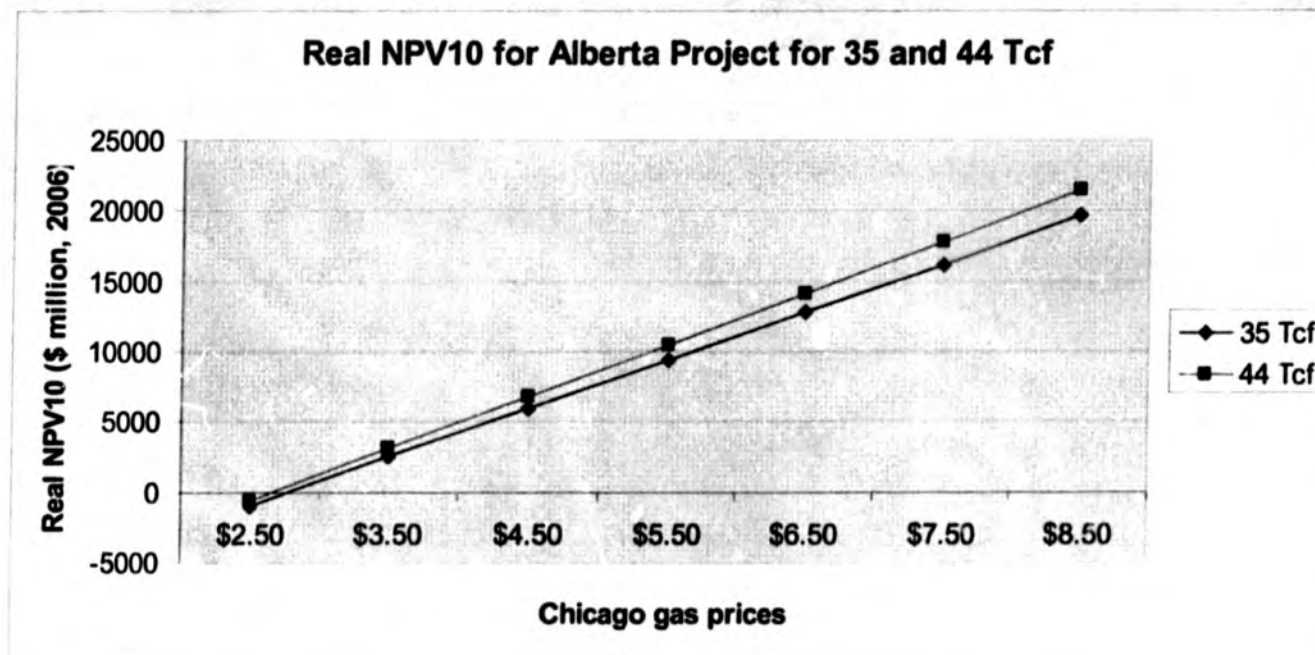
Fiscal certainty for Oil

Real IRR for Alberta Project for 35 and 44 Tcf

	35 Tcf	44 Tcf	Target
\$2.50	8.4%	9.1%	10.0%
\$3.50	13.5%	14.0%	13.0%
\$4.50	17.6%	17.8%	16.5%
\$5.50	21.0%	21.2%	19.5%
\$6.50	23.9%	24.1%	22.0%
\$7.50	26.6%	26.7%	24.0%
\$8.50	29.0%	29.1%	25.0%

However, increased pipeline use has a beneficial impact on the IRR at the stress price. This will help in making the pipeline a lower risk venture.

Fiscal certainty for Oil



The NPV10 improves only slightly as a result of the increase from 35 Tcf to 44 Tcf.

Fiscal certainty for Oil

The main beneficiaries of an increase in throughput from 35 Tcf to 44 Tcf are the State and the affected municipalities because they receive income from a higher volume of gas that is transported for lower tariffs.

The IRR improvement is important to the Sponsors at low prices. Otherwise the profitability improvement for the Sponsors is very modest because the improvement takes place at the tail end of the cash flow.

Also there would only be a significant improvement for the Sponsors if the new gas actually belongs to them. If the gas belongs to other producers the improvement in Sponsor economics is negligible.

Duration of fiscal certainty

Given the beneficial impact of more exploration on filling the gas pipeline for the State and the affected municipalities, the fiscal stability for oil was structured in such a way to encourage new exploration for gas.

A survey was done of 46 countries with production sharing contracts which typically provide for fiscal stability for exploration and production in order to determine what a reasonable international competitive contract term would be for gas.

Duration of fiscal certainty

COUNTRY	CONTRACT	
Albania	Chevron	25
Algeria	Model	30
Angola	Ultra-Deep Water	31
Aruba	Maraven	30
Azerbaijan	Union-Texas	25
Bahrain	Kufpec	35
Bangladesh	Cairn	42
Belize	RSM	33
Cambodia	Enterprise	40
China	Shell	30
Cote d'Ivoire	UMIC	43
Croatia	Model	25
Cuba	Model	20
Dominican Rep	Canadian Superior	26
Egypt	Apache	44
Equatorial Guinea	Triton	48
Eritrea	Anadarko	33
Ethiopia	Afar Exploration	34
Gabon	Vanco	35
Guatemala	Shell	25
Guyana	Maxus	30
India	Shell	35
Indonesia	Vico	20

Duration of fiscal certainty

COUNTRY	CONTRACT	
Jordan	Anadarko	46
Kazakhstan	Oryx	49
Kenya	Total/Amoco	33
Liberia	Henry Resources	43
Libya	Model	32
Malaysia	Model	34
Malta	Model	30
Mauritania	Hardman	48
Mongolia	Model	29
Mozambique	Model	30
Myanmar	Model	25
Nigeria	Model	30
Oman	Triton	41
Philippines	Model	36
Qatar	Model	25
Russia	Marathon	35
Sudan	CNPC	25
Syria	Shell/Deminex	45
Trinidad&Tobago	Exxon	37
Turkmenistan	Model	35
Vietnam	Occidental	25
Yemen	Mayfair	41
Zambia	Placid	33

Duration of fiscal certainty

20 – 24 years	2	contracts
25 – 29 years	10	contracts
30 – 34 years	15	contracts
35 - 39 years	7	contracts
40 – 44 years	7	contracts
45 – 49 years	5	contracts

Average duration: 34 years

Duration of fiscal certainty

Based on the above evaluation a 30 year period of fiscal stability for oil in order to encourage gas exploration to fill the line is a reasonable period.

Duration of fiscal certainty

The total duration of 45 years for gas was not based on economic criteria. The economic impact of plausible fiscal change on the IRR and NPV10 after 30 years is minimal.

Duration of fiscal certainty

Furthermore the period of 30 years is essential for gas because this is the period consisting of 10 year construction and 20 years operations.

It is anticipated that the FT commitments and the financing will be for this 20 year period. Therefore the initial period of 30 years is also essential in order to finance the pipeline.

Duration of fiscal certainty

As indicated before exploration for additional gas will be oriented at participating in an open season for the expansion of the line.

However, such exploration is risky. It may be that discoveries will be too late to participate in an expansion open season or the discoveries may be too small to make initial FT commitments viable. This means that such companies will have to wait until space becomes available in the line. Therefore, it is only fair that companies which are in such a situation will at least retain their fiscal stability for gas. This is an important reason why the 45 year period for gas was introduced.

Duration of fiscal certainty

It should be noted that it is not unusual that international production sharing contract or concession contracts have a longer period for gas than for oil. The marketing and pipeline access problems are widely recognized as justification for such longer duration. Several major (potential) LNG exporters have such provisions, including Bangladesh, Egypt, Equatorial Guinea, Libya, Malaysia, Oman and Trinidad and Tobago.

Duration of fiscal certainty

Furthermore, the duration of 45 years for gas was based on three strategic criteria:

1. FERC may approve a 35 year depreciation period. This is beneficial for new explorers. In this context a 35 year fiscal stability from the commencement of operations is reasonable.
2. A total period of 45 years will add considerably to a possible long secure cash flow. This adds to the strategic desirability of the contract to the investors.
3. A period of longer than 30 years will create more confidence that financing can be restructured in the case of unforeseen circumstances.

Mechanisms to ensure fiscal certainty

Two methods are being used in the proposed contract to ensure fiscal stability under the contract:

1. The Sponsors are exempt from taxation and therefore do not need to pay certain taxes.
2. The Sponsor under certain circumstances will pay the tax, for instance in case of certain municipal taxes, but will then recover the payments through offsets against obligations by the State. This offset system is known as the "waterfall" and is contained in Article 22 of the contract. In case the State owes to the Sponsors and there is no fiscal offset available, the Sponsors can take a part of the State Gas instead.

These methods will be discussed in much more detail in the coming days.

Session:
State Capitol - Room 125
Juneau, Alaska 99801-1182
(907) 465-2327
(907) 465-5241 Fax
(800) 336-7383 Toll Free



Brian wants this archived with file.

Interim:
119 N. Cushman Street - Suite 201
Fairbanks, Alaska 99701
(907) 456-8161
Senator.Ralph.Seekins@legis.state.ak.us

Alaska State Legislature
Senator Ralph Seekins
District D

talk w/ Brian after this

Chair: Senate Judiciary Committee
Vice Chair: Senate Labor and Commerce Committee; Member: Senate Resources Committee
Senate Special Committee on World Trade and State/Federal Relations

July 20, 2006

Chairman Joseph T. Kelliher
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Dear Chairman Kelliher:

I am Chairman of the Alaska State Legislature's Senate Special Committee on Natural Gas Development. We request that the Commission make available appropriate staff members to speak to our committee about the general topics enumerated below. I understand that the Commission has already been contacted by a representative of Governor Murkowski about testifying and I am authorized to state that his Administration joins in this request.

By way of background, let me explain that our Committee has held several weeks of hearings concerning Governor Murkowski's proposed Fiscal Contract and related issues. We have heard testimony on various FERC issues from the State's representatives, North Slope producer representatives, and independent consultants to the Alaska Legislature. We have also received and appreciate the Commission's Second Report to Congress on Progress Made in Licensing and Constructing the Alaska Natural Gas Pipeline.

Ideally, we would hear from the FERC on the morning of July 25, starting at 9 AM Alaska Time. The testimony could be presented telephonically. We hope that the Commission's representatives would be available to answer questions on the following topics:

- 1) The subject matter of the Commission's July 10 Report to Congress;
- 2) The Commission's pre-filing and application process;
- 3) The Commission's powers to ensure access to capacity on the pipeline for shippers and prospective shippers not affiliated with the owners of the pipeline;

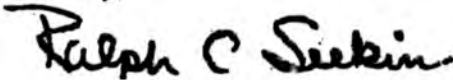
4) The Commission's review of competition issues as part of its processing of a certificate application;

5) The Commission's enforcement powers and procedures with respect to affiliate relationships in a producer owned Alaska gas pipeline, including the response time of the Enforcement Hotline;

6) The Commission's review, if any, of the operations of a certificate pipeline for anticompetitive behavior, including the concept of basin control.

Please feel free to call me at 907-388-8454 or Bob Loeffler, the State's counsel, at 202-887-1506. We appreciate the Commission's willingness to provide information to the Alaska Legislature and the public on FERC's relationship to an Alaska Gas Pipeline.

Sincerely,

A handwritten signature in cursive script that reads "Ralph C. Seekins".

Senator Ralph C. Seekins
Serving District "D"
Alaska State Legislature

cc: Mark Robinson, FERC
John Katz, FERC

Greenberg Traurig

Memorandum

TO: Senator Gene Therriault, Chair, Legislative Budget and Audit Committee;
Representative Ralph Samuels, Vice-Chair, Legislative Budget and Audit
Committee; and
Senator Ralph Seekins, Chair, Senate Special Committee on Natural Gas
Development
FROM: Donald C. Shepler
DATE: July 31, 2006
RE: Basin Control Issues Arising From SGDA Contract

EXECUTIVE SUMMARY

Protection against the possibility of "Basin Control" should be a fundamental goal for a Stranded Gas Development Act ("SGDA") Contract. If there is reasonable certainty that: (1) the line will be expanded to meet new demand; and (2) the pricing of expansion capacity will be appropriate, most of the concerns about Basin Control will be resolved.

The State of Alaska is now in a unique and unprecedented position. It is negotiating substantial benefits to be provided to the Sponsor Group in exchange for commitments to pursue a pipeline. Including reasonable commitments to pursue voluntary expansions of that pipeline as part of the Contract will effectively mimic the incentives that independent pipeline owners have to expand to satisfy new demand. This will provide the explorer-producers with sufficient certainty about future access to support their exploration and development activities which are clearly a key to unlocking the value of the resources on the North Slope.

In contrast, relying on FERC's extensive enforcement powers to prevent anti-competitive behavior will result in costly, uncertain litigation and will not satisfy the explorers' needs for new

capacity on a predictable time line. There are also material legal risks and timing uncertainties associated with parties' seeking expansions under the FERC-mandated process contained in § 105 of the Alaska Natural Gas Pipeline Act ("ANGPA"). These risks and uncertainties make § 105 an unworkable vehicle to obtain capacity when it is needed. Likewise, the Article 8.7 "State-initiated expansion" provisions of the Contract does not provide a viable means for independent explorer producers to obtain needed capacity on a timely basis.

Such commitments will not impede the flexibility of the Producer-owners in their efforts to design and build the initial pipeline upon which future expansions will depend. Thus, it is recommended that the Contract be expanded to include commitments under which voluntary expansions will be pursued by the owners as a remedy to the Basin Control issue and as a vehicle to maximize the timely development of the State's gas resources.

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INTRODUCTION

It should be assumed that each party to the contract will act in its own self-interest.

Economics 101 explains how the Producers would benefit from controlling competition on the North Slope by imposing barriers to entry by independent explorer producers, and by limiting the supply of gas placed on the market (collectively, "Basin Control"). Assuming that each Producer will rationally employ all available tools to maximize their return, reasonable contractual protections should be put in place to eliminate the risk of such control.

The key is *balance*. The legitimate business interests of the Producer-owners must be recognized and rationalized with the interests of the State and the independent explorers. The Producer-owners must not be impeded in their efforts to complete a successful pipeline project that will open the region to all producers—including the independents. However, protection must be put in place to defeat potentially anti-competitive behavior.

During the Senate hearings and roundtable discussions, Administration and Producer representatives have recognized the *potential* for anti-competitive behavior and the need for *protection* against such behavior. The discussion has centered on the question of the appropriate measures to provide that protection. The Administration and Producer representatives have suggested that the FERC regulatory regime provides ample and sufficient protection. The Legislature's consultants have suggested that in addition to relying on FERC, contractual protections against anti-competitive behavior should be put in place under the theory that by such method the State can take charge of its own destiny without having to rely on potentially lengthy, expensive, and unpredictable FERC proceedings. To use a baseball analogy, the FERC works well as a backstop to protect the fans from the occasional wild pitch or foul ball, but an umpire right

behind the catcher is necessary to maintain fair play between the teams. Contractual protections can operate as that umpire since the Producers risk losing some or all of the benefits of the Contract if they are found to violate the terms of the Contract and can be compelled under the Contract to undertake appropriate actions to comply with the provisions of the agreement.

The State and the Producers cannot be perfectly aligned on competition in the production of ANS gas.

Much has been said in the discussion of the Contract about the importance of *alignment* between the State and the Producers as owners of and shippers on the line. Certainly such alignment is strongly to be encouraged. However, it must be recognized that the State, as the sovereign, has unique interests that are probably not shared by the Producers. The State is clearly best served by the development of a vibrantly competitive gas production industry on the North Slope, but such development is probably not welcomed by the Producers who will have to compete with new explorers for leases, gas sales and ultimately pipeline capacity.

The fact that the State is well served by new exploration and development activity is repeatedly acknowledged by the Administration. The Fiscal Interest Finding ("FIF") makes clear that the Administration recognizes and supports the necessity to ensure that the competition in production of ANS gas is robust:

- "Exploration and development opportunities for new market entrants are critical for Alaska's future, and without access to the gas pipeline there may not be enough new explorers and exploration activity to find the gas resources that are necessary to fully operate the pipeline for the 35-year contract term." (FIF at 97).
- "[I]t is important that explorers have assurance that the pipeline will be expanded to accommodate their gas. Access to pipeline capacity will provide incentive for explorers to find and develop additional gas resources." (FIF at 98).
- "Despite these [FERC regulatory] competitive safeguards, the state sought additional protection because of its concern for independent exploration." (FIF at 99).

- The LLC for the mainline contains a procedure for the members of the LLC to determine whether to expand it. Any member of it may deliver a written proposal for a proposed expansion. There follows a sequence of steps beginning with a management committee vote on whether to conduct a feasibility study, followed by the preparation of such a study, and then a decision on whether to proceed with a FERC application for expansion authority. If and when an expansion is authorized by the FERC, the steps to accomplish the expansion are laid out." (FIF at 101).

Thus, there is no policy debate as to the value of fostering competition. The only question seems to be how best to ensure that control of the pipeline cannot be used to stifle development of that competitive environment.

Normally there is no choice—the FERC rules and the federal anti-trust laws are all that parties can rely upon to protect against competitive abuse in the Lower-48. Here, however, Alaska is in an enviable and unique position. It is negotiating to provide substantial tax and other benefits in exchange for commitments to pursue a pipeline. Thus, Alaska has the opportunity to include specific and focused protections against the risks of Basin Control into its Contract.

In light of this specific opportunity, the question becomes whether it is better for the State to address Basin Control directly, through the Contract, or forego that unique opportunity and rely on litigation to pursue FERC-mandated expansions or pursue FERC enforcement regulation, or rely upon the much-criticized § 8.7 to defend against the risks of Basin Control. The answer seems clear—appropriate contractual commitments for voluntary expansion should be preferred over any scenario that involves litigation. Further, affirmative commitments to expand under appropriate (and defined) circumstances should be preferred over reliance on the current § 8.7 "State-initiated expansion" provision of the Contract.

What is "Basin Control"

The first matter to be considered in analyzing how best to protect against "Basin Control" is to define the term so that all parties are comparing apples to apples. All agree that "Basin Control" connotes anti-competitive behavior to the detriment of independent explorer producers. At the July 13 roundtable discussion the Administration (Mr. Loeffler) presented one definition: "Producer-owned pipeline would favor production affiliates to the exclusion of independents in decisions on operation and expansion of the pipeline so as to control development on the North Slope."¹

This succinctly defines a major component of anti-competitive behavior. It may, however, present too terse of a definition. A more appropriate definition of the issue would expand on the foregoing concept and read: "The Producers favoring production affiliates, and otherwise using ownership of the pipeline to disadvantage competitors, including initial sizing and design of the pipeline project, timing of pipeline development decisions, manipulation of the expansion decision-making process, operation of the pipeline, and tariff control, so as to devalue competitors' leases, reserves and production and thus controlling competition on the North Slope."

This expanded definition reveals the additional levels of potential anti-competitive behavior to be protected against. These additional levels deal with questions of manipulation of pipeline capacity decisions at each step in the development, operation and expansion of the pipeline project, acknowledging that the question of timely pipeline capacity availability for growing demand starts with initial design decisions, includes expansion decisions during construction of the pipeline, and continues with expansion decisions once the initial project is completed.

¹ Loeffler July 13, 2006, slide No. 31.

As the old adage goes, "time is money." Adding the element of time manipulation to the Basin Control definition exposes at least one anti-competitive behavior that the FERC, as a backstop, cannot effectively remedy. This is because if explorer producers do not have reasonable, up-front assurance that capacity for their new production will be available *when* their new production comes on line, and not several years later after FERC hearings and appeals are exhausted, they will not make that initial decision to invest in Alaskan exploration and development. This alone may result in the gas line becoming essentially a proprietary line for the Producers reserves and may impede finding the additional reserves necessary to support the pipeline after 20-25 years.

This is an issue that concerns the explorer-producers. Certainly, Anadarko has concerns about access to the line—initially and (more importantly) through future expansions. BG has similar concerns. Shell raises the issue as does Tesoro. Through their written comments these independent producers confirm that the access issues are real and not theoretical. They deserve resolution by whatever means are appropriate.

Dealing with such issues head-on, in the Contract, is much more efficient, effective and economic than ignoring them now and leaving them to be resolved later, through FERC litigation.

A brief history of "Basin Control" in Alaska confirms that the issue is real and significant.

ANGTA and the Attorney General's Report

The issue of Basin Control by the Producers has arisen before. President Carter's 1977 Decision regarding the Alaska Natural Gas Transportation Act ("ANGTA") prohibited any producer ownership in any line authorized under ANGTA:

The successful [ANGTA certificate] applicant shall exclude and prohibit producers of significant amounts of Alaskan gas, or their subsidiaries and affiliates from participating in

the ownership of the Alaska natural gas transportation system, except that such producer may provide guarantees for project debt. The aforesaid producers of Alaska gas may not be equity members of the sponsor consortium, have any voting power in the project, have any role in the management or operations of the project, have any continuing financial obligation in relation to debt guarantees associated with initial project financing after the project is completed and the tariff is put into effect, or impose conditions on the guarantees of project debt permitted above which may give rise to competitive abuse, including power to veto pro-competitive policies. (Presidential Decision at 38-39, printed as part of S. Rpt. No. 95-567, November 1, 1977, by the Senate Committee on Energy and Natural Resources, emphasis added).

This prohibition was based on 1977 Attorney General Report that found:

A nonintegrated owner cannot earn upstream profits – he has no upstream operations; he is motivated by pipeline profits only. Regulation forces him to expand throughput with the result that, absent market power in production, a properly designed Federal Power Commission tariff would eliminate all excess profits – upstream, downstream and in the pipeline. The clean solution to the vertical integration problem is to place all pipelines in the position of the nonintegrated owner – prohibit producer-ownership of the pipeline. (Report at 42, emphasis added)

The Report continued:

“... vertically integrated producer-owners could circumvent pipeline tariff and city gate regulation by restricting pipeline capacity (and consequently access) while achieving monopoly profits in their upstream operations. Initial sizing of the pipe for large capacity does not necessarily solve this problem, since it will be in the interests of producer-owners to resist future expansion and thus discourage future entry into Alaskan gas production.” (Report at 43, emphasis added).

The 1981 waiver

In 1981, this prohibition on producer participation in the ownership of the ANGTS system was waived in order to facilitate financing the project. However, that waiver still required that the FERC consider the views of the Department of Justice on any producer-ownership interest in any ANGTA project; and that the FERC must specifically find that the producer participation will not, “(a) create or maintain a situation inconsistent with the antitrust laws or (b) in and of itself create restrictions on access to the Alaska segment of the [proposed pipeline]”.

Have circumstances changed?

While it may be claimed that the industry has changed markedly since the days of Presidents Carter and Reagan, that is really not the case. True, pipelines then bought and sold gas flowing through their systems, but now are largely prohibited from the gas ownership or marketing functions. This change alone does not materially impact the issue of Basin Control.

Certainly, though, as a result of this structural change in the gas industry the FERC has established its market-affiliate rules. In addition, Congress has enacted the Energy Policy Act of 2005 ("EPAct") and has enacted the Alaska Natural Gas Pipeline Act of 2004. FERC has issued regulations implementing both of these statutes. However, at the end of the day there are still legitimate concerns about Basin Control. This can be seen from the correspondence between then-FERC Chairman Wood and State Representative Berkowitz.

Chairman Wood's letter to Representative Berkowitz

On January 28, 2005, then-FERC Chairman Pat Wood recognized the concern over Basin Control, responding to a letter from Representative Berkowitz that had inquired about the status of the 1970s-1980s findings and waivers discussed above. Chairman Wood stated:

In authorizing an Alaskan gas pipeline under the [Natural Gas Act], the Commission will seek to promote investment in and the development of Alaskan gas reserves to expedite the delivery of these reserves to markets in and out of Alaska, in conformity with antitrust laws. In doing so, *we will be mindful of the congressional and presidential pronouncements you referenced in your letter.* (Emphasis added).

Chairman Wood's letter continued:

In response to your immediate concern, *it would be prudent to conclude that the antitrust issues which concerned Congress and the President over twenty years ago are still valid and will be addressed by our Commission in our proceedings.* (Emphasis added).

The State has a unique opportunity at this time to guard against Basin Control.

The legislature can assume that FERC will do its job. It will enforce its own regulations and the Federal statutes that it administers. However, one must ask whether exclusive reliance on these regulations and statutes is prudent, especially in light of the fact that the State is now negotiating substantial concessions with the Producers. This presents a unique opportunity for the State to put in place specific contractual protections that supplement and reinforce the FERC regulations. This can be characterized as a "belt and suspenders" approach, or as a "trust-but-verify" approach. Whatever it is called, though, it is prudent to take the steps necessary to guard against the risk of Basin Control which, if unchecked, could require expensive litigation to correct (with an uncertain outcome) and more significantly could largely thwart the State's efforts discussed in the Fiscal Interest Findings to maximize the timely development of its gas resource base.

The concern that a Producer-owned pipeline will not aggressively expand the pipeline to meet new, incremental demand can be illustrated by comparing a producer-owner group's apparent economic motivations with an independent pipeline owner's economic motivations.

Independent pipeline expansion incentives compared to a producer-owned pipeline's expansion incentive

An "independent pipeline" (which may or may not have some ancillary affiliated gas producers, shippers or marketers) makes its profit through a regulated rate of return that is set by the FERC.² Since the pipeline has monopoly characteristics with a relatively assured customer base, the rate of return reflects a lower risk profile. Because the profit that the pipeline makes is

² FERC's Order No. 2004-A contains a table showing that of 87 interstate natural gas pipelines, 57 have producer or marketing affiliates. Only 16 have gas producer affiliates, though. Of those 16 the production affiliates hold on average, only 37% of the pipeline capacity and only 9% when the average is volume-weighted. In Alaska, it is anticipated that the producer affiliates will own upwards of 80% of the pipe's capacity.

based upon the size of its rate base (*i.e.*, its equity investment in the project), and because pipeline expansions add rate base, thus *increasing profits*, independent pipeline owners have great incentive to expand the size of their rate base by expanding the pipeline.

Because independent pipeline owners have a profit motive to expand the pipeline; they also have the incentive to assure their expansion capacity is as market-friendly to new shippers as possible. This typically implies the use of rolled-in pricing for expansion capacity. Obviously, in the Lower-48, under FERC's current policy, rolled-in pricing cannot be expected when it will result in a rate increase to existing shippers, but that policy is not applicable in Alaska. FERC's policy here is to presume the appropriateness of rolled-in pricing for an Alaska pipeline. Thus, an independent owner of the Alaskan pipeline would have every incentive to expand an Alaskan pipeline whenever demand would support the addition of capacity. An Alaskan independent pipeline could also be expected to seek and defend the use of rolled-in pricing for all capacity additions—regardless of the impact on its existing shippers' rates.³

These same motivations cannot be assumed to exist in the context of a Producer-owned line. The Producers' principle business is the production and sale of petroleum products. This business has significant business risks and accordingly requires significantly higher rates of return on investment than a regulated pipeline company does. Holders of the Producers' stock did not invest their money for regulated pipeline returns, they invested for returns attendant to successful petroleum products businesses.

³ This is because incremental pricing, placing all expansion costs on new shippers, would discourage expansions. It would make expansions harder to market whereas rolled-in pricing lowers the cost of expansions to new shippers, making expansion capacity easier to market.

To put this in perspective, in my June 2, 2006, Memorandum to the Legislature I noted that the Producer's equity return on the *pipeline* (i.e., their profit) is estimated to be in the 20- to 25-cent range based on a \$2.50 tariff. This profit level is insignificant compared to the \$3.00 netback the producers expect to see at a \$5.50 market price (assuming the \$2.50 tariff).

Because the additional pipeline profit the owners will receive for expansion capacity will be much less than even the 20- 25-cents they can expect on the entire pipeline investment, expansion returns will not be a significant factor in the Producer-owners' overall economics. One can even question whether such expansion-investment returns would even satisfy their internal hurdle rates unless the new capacity was related to the Producers' own new production.

Rational economic behavior by producer owners of the pipeline would thus be expected to limit expansions unless needed for *their* own capacity growth needs. Certainly rational behavior on the part of the Producers would be to pursue incremental pricing on any expansion they might undertake because that pricing approach would discourage expansions and would raise the cost for their competitors—thus protecting the Producers ability to control the gas reserves on the North Slope. These economic motivations are almost 180 degrees from the incentives of an independent pipeline owner. That point was made in 1977 by the Attorney General's report and it is just as true today.

Delay and uncertainty will arise by exclusive reliance on FERC, whereas the State can assure timely expansion if provided under the Contract.

Pursuit of remedies at FERC has always been expensive, time consuming and uncertain. While the FERC has a veritable arsenal of weapons at its control to prevent Basin Control, it is nonetheless required to act upon a legal record, with administrative due process, make decisions that are supported by that record, and afford appellate due process. This translates into

"administrative litigation" which is never speedy or cheap, nor are results of such processes ever guaranteed.⁴ In the context of ensuring any expansion of the pipeline, reliance on FERC's tools is patently inadequate and would appear to be far too uncertain to justify explorers' commencement of drilling activities. Perhaps more importantly, though, is that the timing of any expansion that could be expected to arise out of such proceedings would likewise be far too uncertain for those parties' needs. Just as BP, ConocoPhillips and Exxon Mobil have demanded certainty from the State as a condition to commencing the pipeline project, so, too, do the independent explorer-producers require certainty with respect to expansions. That certainty can best come from linking the State's fiscal and other valuable commitments to the Producers that are contained in the SGDA Contract to the Producers' reciprocal commitment to reasonable expansion and expansion-pricing terms.

Of the three ways to expand, only "voluntary expansion" addresses Basin Control concerns.

There have been many references to the fact that there are "three ways to obtain expansion" of the pipeline. The first of these is a "voluntary expansion." If the Producer-owners agree to an expansion, then the expansion occurs. However, the Contract has no provision for such expansion. The other two methods come with substantial drawbacks and risks and do not adequately protect the State's interest in ensuring the construction of new capacity *when it is needed*.

First, the "FERC-mandated" expansion that was created by § 105 of the 2004 ANGPA legislation comes with a number of difficult hurdles as identified below. Further, this is a new

⁴ At the roundtable discussion on July 14, 2006, Mr. Kiethley, counsel for BP, referred to the FERC "hotline" as being available to anyone with a complaint. The FERC "hotline" came up in other discussions before the Senate Committee. However, as noted there, the "hotline" typically addresses relatively minor issues, where a phone call or two can clear up a misunderstanding. It has no administrative authority and does not address major competitive issues. The FERC website itself notes that if the hotline mediation-type services are not capable of resolving issues, matters must be referred to the formal "investigation" (*i.e.*, litigation).

statute. It gives FERC powers that it has never before exercised. Since the statute has not been judicially tested, the possibility of a challenge to FERC's authority under the statute to compel the owners to invest new capital to expand the pipeline is very real and the outcome unknown. There is the further legal uncertainty arising out of any substantive order that the FERC might issue under this authority. As shown below FERC can only require an expansion if eight criteria are met. Some of these criteria (such as "no rate subsidy") are potentially subject to extensive litigation, with uncertain outcomes. And, any FERC order will almost certainly be appealed to the courts with the ensuing delays attendant to federal appeals.⁵

Aside from these judicial concerns, this expansion vehicle comes with a number of conditions (listed below).

- Rates must ensure recovery of the costs (including return) of the expansion;
- FERC must ensure that rates do not require existing shippers to subsidize expansion shippers;
- FERC must find the new shippers will comply with the tariff;
- FERC must find the new facilities will not adversely affect the financial or economic viability of the pipeline project;
- FERC must find that the new facilities will not adversely affect the overall operation of the system;
- FERC must find that the new facilities will not diminish the contract rights of existing shippers to previously subscribed certificated capacity;
- FERC must ensure that all necessary environmental reviews have been completed; and

⁵ Notably, although appeals under the 2004 federal statute are required to be expedited, the one pending appeal of FERC's open season rulemaking is only now in the briefing stage with no date set for oral argument even though FERC's last order was issued June 1, 2005—almost 18 months ago. There is no deadline by which the court has to decide the case even after briefing and oral argument are completed.

- FERC must find that adequate downstream facilities exist or are expected to exist to delivery incremental Alaska natural gas to market.

These conditions can probably be satisfied in the context of a compression-based expansion (*i.e.*, up to about 6 Bcf/day of capacity). However, once any expansion involves substantial looping then the "no subsidy of expansion customers by existing shippers" requirement becomes problematic (so long as rolled-in pricing is used). Unless such expansion capacity is priced on an incremental basis the obvious question that will arise is what constitutes a "subsidy." The FERC has not established rules for administering this section of the law, so no one can say with certainty whether any particular level of rate increase to existing shippers (as could occur in certain expansion scenarios involving rolled-in pricing) would be found to be an unacceptable "subsidy." This ambiguity alone invites prolonged litigation at the Commission with an uncertain outcome there and in the courts.

The third expansion tool is the State-initiated expansion (set forth in § 8.7 of the Contract). This vehicle comes with all of the conditions listed above with respect to a FERC-mandated expansion, but also includes the following additional limitations that gut its effectiveness:

- It can only be exercised once every 5 years;
- Expansion must be for a minimum of 50,000 Mcf/day on a Gas Transmission Pipeline and 125,000 Mmbtu/day on the mainline or the GTP
- Such minimum amounts must exclude any Producer or Producer-affiliate volumes but expansion facilities must be designed to include incremental volumes from a Producer or Producer-affiliate;
- Expansion does not require any lateral pipeline facilities;
- Expansion does not require installation of any loops in excess of 100 miles;

- New shippers must pay its proportionate share (as determined by the *Project Entity*) of all cost related to the filing of the application and to activities required to complete the application, including engineering studies and design and environmental reviews, "which costs may be recoverable under Article 8.7(a)(iv)(A)";
- New shippers are required to bid for new capacity in a new open season and are subject to proration or displacement under the open season process;
- New shippers must enter into "negotiated rate" agreements;
- Expansion must not require any existing shipper to pay a higher rate than it would have to pay absent the expansion;
- Expansion must not require any existing shipper to be assessed a higher fuel retention percentage than would have been assessed absent the expansion;⁶

Probably the most notable of these additional conditions are the prohibitions on any rate increase to existing shippers or any increase in fuel retention resulting from any expansion. The range of potential expansions that could possibly fit within these criteria will be very narrow, and even those narrow possibilities will be fraught with uncertainty of execution, implementation, and most importantly, timing. Here as well, once an expansion involves looping (even up to the 100-mile limit contained in § 8.7) these factors will effectively preclude any ability to obtain expansion capacity.

In addition, the requirements that a party trying to obtain capacity via Section 8.7 will have to pay all the up-front costs associated with obtaining an expansion certificate (which are not insignificant) will have a chilling effect upon potential new shippers. Similarly, the fact that an explorer producer seeking to avail itself of this provision will have to compete in an open season for any expansion capacity that is proposed by the owners, and may well only obtain a pro-rated share of the expansion that the party initially sought diminishes substantially the value of this

⁶ Compression fuel is typically stated as a percentage of throughput per contract rather than a dollar and cents item in most pipeline tariffs.

provision in terms of facilitating expansion of the system on a timely basis to accommodate new shippers.

Section 8.7 further states that it is effective unless FERC determines that any provisions are contrary to law. Moreover, this section also provides that, "If *FERC* issues a certificate on a basis different than the expansion proposal filed by the *Project Entity*, then the *Project Entity* shall reject the certificate unless any such difference is minor or all of the members of the *Project Entity* vote otherwise." (Emphasis added). Finally, the Fiscal Interest Finding (at 115) suggests that the Producers may be given rights of first refusal for capacity created under any such expansion, which itself defeats the purpose of an expansion to assist independent explorer producers – and is inconsistent with FERC policies as well. Taken together, these provisions strip Section 8.7 of any substantial value in terms of obtaining expansion capacity at reasonable rates on a timely basis.

Thus, while as a technical matter three expansion options do exist, only aggressive voluntary expansion policies will protect against anti-competitive behavior in a manner that will provide certainty to independent explorer producers. Such expansion policies can best be assured by the addition of appropriate contract provisions addressing voluntary expansions.

The point has been made that the State, through its membership in the LLC, will "be watching" the Producer-owners as expansion decisions are made. It was suggested that through such a "seat at the table" the State could effectively keep an eye on the Producers' activities and "blow the whistle" as needed. It was also suggested that as an "insider" the State would have documents in its hands, thus expediting any administrative litigation by shortening the discovery process. This is indeed a plus, but the FERC would still have to go through the administrative

hearing and decision process based on the evidence put into a litigated record. Thus, the time saving from a shortened discovery process may or may not be material.⁷

It should be asked, though, if reliance on enforcement litigation (*i.e.*, a “big stick”) should be the preferred approach at the outset. Providing the benefits of the Contract to the Producers (*i.e.*, “carrots”) in exchange for pre-agreed expansion terms is simpler and much faster. It also produces the desired result—timely voluntary expansion of the line mimicking what one would expect from an independent pipeline. Thus, State participation is helpful but not dispositive with respect to Basin Control litigation.

Agreement on some level of expansion may already exist.

At the roundtable discussions comments have been made that the Contract is “not expansion friendly.” Those remarks have been challenged or questioned by both the Producers and the Administration. Representations have been made that the pipeline will be expanded if necessary; certainly up to the level of about almost 6 Bcf/day at which point expensive looping will be required. Indeed, compression based expansions up to the 6 Bcf/day range should be expected since expansion to this level will have downward pressure on the pipeline’s rates—thus increasing the Producers’ netback for all volumes shipped and increasing the State’s RIK value as well.

If expansion to this level is indeed planned or intended, there should be no meaningful objection to putting such a commitment into the Contract. An expansion from 4- 4.5Bcf/day to the 5.9- 6 Bcf/day level would reflect a significant addition to the system’s capability. Since such expansion could be achieved in a manner that would generally reduce (or certainly not materially

⁷ Moreover, it must be asked whether the LLC agreements will contain confidentiality provisions that would impede the State in providing documents to litigants in any such FERC proceedings.

increase) rates, it would generally be in the interest of the State, the Producers and independent explorer shippers for such expansions to be undertaken. The Contract should so provide.⁸

Expansion above the 6 Bcf/day level appears to require more expensive pipeline looping. Under incremental pricing no such expansion will be supported by the market since the price for such service will substantially exceed the price that pre-existing shippers will be paying. Under rolled-in pricing this type of expansion would be economic but would increase rates to existing shippers. However, the rate to all shippers would be the same (*i.e.*, a "level playing field"), and the rate level for the existing shippers would not be nearly as high as the rate level for new shippers had the expansion been priced incrementally. Thus, there is no reason why the Mainline Entity as a pipeline owner would not want to pursue such expansion, nor why the State would not want to pursue such expansion as both a pipeline owner and as the sovereign.

The only downside to looping expansions that are priced on a rolled-in basis relates to increased rates to the existing shippers. The objection of the Producers to such an expansion thus relates to their interests as producers and shippers, and not to their interests as pipeline owners. Indeed, as pipeline owners they will benefit through increased rate base that results in increased equity return! There is no reason why, as pipeline owners the Producers should object to the use of rolled-in pricing for the expansion. Thus, in the context of a contract providing for the Producers

⁸ The assumption that expansion to the 6 Bcf range is economic is predicated upon the 52-inch design. That design is not a contract term as noted by Anadarko, and the Producers objected to its being put into the Contract. So, there is reason to question whether the pipeline that is built will in fact be capable of expansion to the 6 Bcf/day level. As noted by Anadarko the FIF indicates that only the sponsor group proposed using the larger diameter pipeline. It may be that the other companies that discussed the project with the State had a more realistic handle on the design issue and the Sponsors will eventually come around to the smaller design. In that case, of course, the economics of expansion will be much different than has been presented to date.

to become pipeline owners it would be entirely appropriate to provide for such expansions to take place using rolled-in pricing.

From the State's perspective expansions to capacities in excess of 6 Bcf/day should be a stated objective. Such expansions necessarily imply significant new gas supplies being found—supplies that will benefit the State in terms of additional royalty gas being produced or at a minimum of additional tax gas being produced. Additional jobs are also implied in potential expansions beyond 6 Bcf/day. Expansions at this level should be strongly supported by the State *even if* they would result in some increase in rates being paid by existing shippers and *even if* such expansions would result in a modest reduction in the State's own netback related to its in-kind volumes.⁹

Thus, to support pro-competitive behavior and to mimic the behavior of an independent pipeline owner, contract language should be developed to require "voluntary expansion" to meet growing market demand. The Contract should also require that all expansion proposals be made on a rolled-in pricing basis. By such means the risk of untoward Basin Control by the Producer-owners is materially reduced or even eliminated. Specific suggestions to accomplish these goals are set forth below:

- a) Require that the Project Entity conduct periodic open seasons (either binding or non-binding) at least every three-to-five years to determine the existence of market demand for expansion capacity.
- b) Provide the State (and any Producer) with authority to initiate expansions (including during the initial construction of the pipeline) upon request by creditworthy shippers in reasonable

⁹ In this regard it should be noted that rate increases occur for any number of reasons. Inflation causes pipelines to increase rates to maintain their equity return. Reductions in shipping commitments can result in rate increases to existing customers. Moreover, as a new pipeline FERC will probably require that the Mainline Entity file to justify its rates within 3-years after service commences—this could also result in a rate increase. Unless a shipper has a "negotiated rate" contract, FERC tariffs normally require shippers to pay the higher rates once the FERC has approved them.

engineering increments while requiring the Pipeline Entity to propose and defend the use of rolled-in pricing for such expansion capacity.

- c) Provide the State (and any Producer) with authority to initiate expansions requested by creditworthy shippers in less than reasonable engineering increments to the extent the new shippers make an appropriate contribution in aid of construction such that the expansion will not adversely affect the economics of the pipeline system.
- d) Provide the State (and any Producer) with authority to initiate open seasons without time limitations and to veto open season timing decisions as it believes necessary to foster full and fair competition.
- e) Replace Article 8.7 with the above provisions.

CONCLUSION

The Alaska gas pipeline will be a *basin opening* project. The fundamental concern is whether potential anti-competitive behavior arising out the vertical ownership of the pipeline by the Producers raises unacceptable risks that in opening the basin for some producers the basin can effectively be closed to others.

Remedying anti-competitive behavior can be dealt with in at least two ways. First, the matter can be deferred until the issue actually arises and then litigated at the FERC (and through the Courts on appeal). Second, the issue can be dealt with in the Contract, by putting in place mechanisms that will prevent the behavior from taking place in the first instance. The first approach creates uncertainty and time delay that could result in deterring explorer producers from seeking new Alaskan resources. The better solution is to forestall anti-competitive behavior before it occurs, by building competitive protections (addressing voluntary expansion terms and conditions) into the SGDA Contract, with the FERC as a backstop. Requiring voluntary expansion terms to be added to the contract as a *quid-pro-quo* for the State providing fiscal certainty to the

Producers, will provide fiscal certainty for the independent explorer producers and level the playing field to the benefit of State.

Greenberg Traurig

Memorandum

TO: Senator Ralph Seekins, Chair, Senate Special Committee on Natural Gas Development;
Senator Gene Therriault, Chair, Legislative Budget and Audit Committee;
and
Representative Ralph Samuels, Vice-Chair, Legislative Budget and Audit Committee

FROM: Donald C. Shepler

DATE: July 31, 2006

RE: Data on Producer-affiliate capacity holdings on Lower-48 pipelines and capacity of producer-owned pipelines

In the Special Senate Committee on Natural Gas Development hearings last week the point was made by one presenter that "there are no independent pipeline companies" in the Lower-48. This was a reference to the claim that all Lower-48 pipelines have producer-affiliates and/or marketing-affiliates. Attached is a table which appears as Attachment B to FERC's Order No. 2004-A relating to its rules regarding marketing and producer affiliates of interstate pipelines. This table lists all gas pipelines that are subject to the FERC's rule and shows the percent of capacity held by the pipeline company's marketing affiliate, its producer affiliate and its storage affiliate.

Significantly, only 16 pipelines have producer affiliates and on a weighted average basis the producer-affiliates hold only about 9% of the capacity on their affiliate pipelines. Even looking at an a simple, unweighted average, the percentage of capacity held by producer affiliates on those 16 pipelines is only about 37 percent. By comparison, it is anticipated that the production affiliates of the owners of the Alaskan pipeline will hold upwards of 80% of the system's capacity.

Also attached is a Department of Energy report showing reported system capacity for a number of gas gathering companies, pipeline companies and others. From this report it can be seen that the six "producer-owned pipelines" that were identified at last week's hearings are very small entities. The six companies listed at the hearings were:

- | | |
|----------------------------|----------------------------------|
| 1. Garden Banks | capacity shown as 1,000 MMcf/day |
| 2. Green Canyon | capacity shown as 200 MMcf/day |
| 3. Destin | capacity shown as 1,200 MMcf/day |
| 4. Discovery | capacity shown as 793 MMcf/day |
| 5. Maritimes and Northeast | capacity shown as 428 MMcf/day |
| 6. Nautilus | capacity shown as 600 MMcf/day. |

Thus, the average capacity of the "producer owned pipelines" listed at the hearing is about 600 MMcf/day.

This can be compared to five of the largest interstate pipelines listed below:

- | | |
|---------------------|-----------------------------------|
| 1. Transcontinental | capacity shown as 8,203 MMcf/day |
| 2. ANR | capacity shown as 6,785 MMcf/day |
| 3. Tennessee | capacity shown as 6,644 MMcf/day |
| 4. El Paso | capacity shown as 6,292 MMcf/day |
| 5. Texas Eastern | capacity shown as 6,196 MMcf/day. |

Thus, the producer-owned pipelines are clearly very small compared to the major, long-line pipelines and compared to the 4,000-4,500 MMcf/day capacity envisioned for the Alaskan pipeline.

I wanted to provide these official data to ensure that the Special Committee on Natural Gas Development and the rest of the Alaska Legislature was fully informed on this matter. As always, should you have any questions on this matter please let me know.

ATTACHMENT B

Staff Analysis of Interstate Natural Gas Pipeline Index of Customers Data

Staff compiled index of customers data from all 87 pipelines for which it was available for the October 1, 2003 filing.

Staff identified 63 pipelines which had reported affiliated transactions. Staff noted that 5 of these pipelines had contracts only with Transmission Provider affiliates and removed these from the study as a special category. The remaining 58 pipelines were then examined in more detail.

Staff then identified the type of affiliation, e.g., marketer, LDC, producer, for each customer from publicly available information.

The table "Summary of Natural Gas Pipeline Affiliate Information" shows summary affiliate information by pipeline and type of affiliation. Totals are shown also for all 58 pipelines examined. The information was derived from the detailed affiliated customer data as follows:

- Table rows labeled "Affil Vols (MMBtu)" are simply total volumes by affiliation type for individual pipelines or the group of 58 pipelines aggregated from the data for individual affiliated customers
- Table rows for each pipeline labeled "Pct of P/L Total Vols" are the affiliate volumes shown divided by the total contracted volumes for the pipeline
- The table row labeled "Pct of Relevant PL Tot Vols (WA)" for the group of 58 pipelines are the affiliate volumes shown divided by the total contracted volumes only for those pipelines that have affiliated customers of the type shown in that column of the table. This is a weighted average.
- The Table row labeled "Pct of Relevant PL Tot Vols (SA)" is the simple average of the "% of P/L Total Vols" figures for each pipeline with data in that column.

Some pipelines have more than one type of affiliate, and would be included in the summary information compiled under each affiliate type.

Summary of Natural Gas Pipeline Affiliate Information
Source: Oct 2003 Index of Customers

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Pipeline	Item	Transportation Affiliate	Storage Affiliate	Transpo Marketing Affiliate	Storage Marketing Affiliate	Transpo Producer Affiliate	Storage Producer Affiliate	Transpo LDC Affiliate	Storage LDC Affiliate
All Pipelines (58 PLs)	Affil Vols (MMBtu)	21,842,719	345,328,545	6,737,835	102,025,929	2,695,111	7,436,818	13,246,318	252,286,681
	% of Relevant PL Tot Vols (SA)	38	57	19	44	37	11	46	48
	% of Relevant PL Tot Vols (WA)	17	34	6	15	9	8	35	32
ALLIANCE PIPELINE L.P.	Affil Vols (MMBtu)	188,559	.	188,559	.	.	.	.	.
	% of P/L Total Vols	13	.	13	.	.	.	.	.
ANR PIPELINE COMPANY	Affil Vols (MMBtu)	78,000	.	21,000	.	.	.	.	.
	% of P/L Total Vols	1	.	0	.	.	.	.	.
CARNEGIE INTERSTATE PIPELINE CO.	Affil Vols (MMBtu)	13,000	.	.	.	.	.	13,000	.
	% of P/L Total Vols	57	.	.	.	.	.	57	.
CENTERPOINT ENERGY GAS TRANSMISSI	Affil Vols (MMBtu)	1,249,309	17,543,333	32,929	.	20,000	.	1,196,380	17,543,333
	% of P/L Total Vols	39	100	1	.	1	.	37	100
CENTRAL NEW YORK OIL AND GAS COMP	Affil Vols (MMBtu)	.	11,900,000	.	11,900,000	.	.	.	.
	% of P/L Total Vols	.	100	.	100	.	.	.	.
CHANDELEUR PIPE LINE COMPANY	Affil Vols (MMBtu)	210,000	.	.	.	210,000	.	.	.
	% of P/L Total Vols	77	.	.	.	77	.	.	.
CLEAR CREEK STORAGE COMPANY L.L.	Affil Vols (MMBtu)	.	8,000,000	.	8,000,000	.	.	.	.
	% of P/L Total Vols	.	100	.	100	.	.	.	.
COLORADO INTERSTATE GAS COMPANY	Affil Vols (MMBtu)	100,000	.	100,000	.	.	.	.	.
	% of P/L Total Vols	3	.	3	.	.	.	.	.
COLUMBIA GAS TRANSMISSION CORPORA	Affil Vols (MMBtu)	5,411,834	126,689,688	3,338	.	567	.	5,395,929	126,689,688
	% of P/L Total Vols	42	51	0	.	0	.	42	51
COLUMBIA GULF TRANSMISSION COMPAN	Affil Vols (MMBtu)	587,039	.	10,000	.	.	.	577,039	.
	% of P/L Total Vols	18	.	0	.	.	.	17	.
CROSSROADS PIPELINE COMPANY	Affil Vols (MMBtu)	8,700	.	8,700	.	.	.	.	.
	% of P/L Total Vols	9	.	9	.	.	.	.	.
DAUPHIN ISLAND GATHERING PARTNERS	Affil Vols (MMBtu)	28,440	.	28,440	.	28,440	.	.	.
	% of P/L Total Vols	14	.	14	.	14	.	.	.
DESTIN PIPELINE COMPANY L.L.C.	Affil Vols (MMBtu)	301,800	.	.	.	301,800	.	.	.
	% of P/L Total Vols	63	.	.	.	63	.	.	.
DOMINION COVE POINT LNG LP	Affil Vols (MMBtu)	95,000	.	95,000	.	.	.	.	.
	% of P/L Total Vols	7	.	.	.	.	.	.	.

Summary of Natural Gas Pipeline Affiliate Information
Source: Oct 2003 Index of Customers

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Pipeline	Item	Transportation Affiliate	Storage Affiliate	Transpo Marketing Affiliate	Storage Marketing Affiliate	Transpo Producer Affiliate	Storage Producer Affiliate	Transpo LDC Affiliate	Storage LDC Affiliate
DOMINION TRANSMISSION INC.	Affil Vols (MMBtu)	1,515,633	44,749,533	211,630	5,970,000	.	.	1,368,503	38,779,533
	% of P/L Total Vols	28	16	4	2	.	.	25	14
EASTERN SHORE NATURAL GAS COMPANY	Affil Vols (MMBtu)	45,465	255,803	.	.	.	.	45,465	255,803
	% of P/L Total Vols	41	74	.	.	.	.	41	74
EGAN HUB PARTNERS L.P.	Affil Vols (MMBtu)	.	3,000,000	.	3,000,000	.	.	.	.
	% of P/L Total Vols	.	18	.	18	.	.	.	.
EL PASO NATURAL GAS COMPANY	Affil Vols (MMBtu)	132,112	.	132,112	.	.	.	.	.
	% of P/L Total Vols	2	.	2	.	.	.	.	.
ENBRIDGE PIPELINES (ALATENN) L.L.	Affil Vols (MMBtu)	700	.	700	.	.	.	.	.
	% of P/L Total Vols	1	.	1	.	.	.	.	.
EQUITRANS L.P.	Affil Vols (MMBtu)	579,920	15,006,619	34,985	3,859,049	206,000	4,181,818	338,935	6,965,752
	% of P/L Total Vols	89	63	5	16	31	18	52	29
FLORIDA GAS TRANSMISSION	Affil Vols (MMBtu)	21,000	.	21,000	.	.	.	.	.
	% of P/L Total Vols	1	.	1	.	.	.	.	.
GARDEN BANKS GAS PIPELINE LLC	Affil Vols (MMBtu)	209,102	.	.	.	209,102	.	.	.
	% of P/L Total Vols	76	.	.	.	76	.	.	.
GRANITE STATE GAS TRANSMISSION I	Affil Vols (MMBtu)	105,400	.	.	.	.	.	105,400	.
	% of P/L Total Vols	92	.	.	.	.	.	92	.
GREAT LAKES GAS TRANSMISSION LIMI	Affil Vols (MMBtu)	93,540	.	93,540	.	.	.	.	.
	% of P/L Total Vols	2	.	2	.	.	.	.	.
GUARDIAN PIPELINE L.L.C.	Affil Vols (MMBtu)	1,302,500	.	2,500	.	.	.	1,300,000	.
	% of P/L Total Vols	99	.	0	.	.	.	99	.
GULF SOUTH PIPELINE COMPANY LP	Affil Vols (MMBtu)	340,000	26,865,998	340,000	26,865,998	.	.	.	.
	% of P/L Total Vols	14	90	14	90	.	.	.	.
KINDER MORGAN INTERSTATE GAS TRAN	Affil Vols (MMBtu)	171,470	2,179,485	.	.	.	.	5,086	.
	% of P/L Total Vols	21	54	.	.	.	.	1	.
KO TRANSMISSION COMPANY	Affil Vols (MMBtu)	218,000	.	218,000	.	.	.	.	.
	% of P/L Total Vols	80	.	80	.	.	.	.	.
MARITIMES & NORTHEAST PIPELINE L	Affil Vols (MMBtu)	199,335	.	199,335	.	185,335	.	.	.
	% of P/L Total Vols	30	.	30	.	28	.	.	.

Summary of Natural Gas Pipeline Affiliate Information
Source: Oct 2003 Index of Customers

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Pipeline	Item	Transportation Affiliate	Storage Affiliate	Transpo Marketing Affiliate	Storage Marketing Affiliate	Transpo Producer Affiliate	Storage Producer Affiliate	Transpo LDC Affiliate	Storage LDC Affiliate
MIDWESTERN GAS TRANSMISSION	Affil Vols (MMBtu)	1,600	.	1,600	.	.	.	.	.
	% of P/L Total Vols	0	.	0	.	.	.	.	.
MIGC INC.	Affil Vols (MMBtu)	90,000	.	90,000	.	.	.	.	.
	% of P/L Total Vols	69	.	69	.	.	.	.	.
MISSISSIPPI CANYON GAS PIPELINE	Affil Vols (MMBtu)	558,518	.	.	.	558,518	.	.	.
	% of P/L Total Vols	85	.	.	.	85	.	.	.
MISSISSIPPI RIVER TRANSMISSION CO	Affil Vols (MMBtu)	53,710	1,725,989	12,887	650,444	.	.	40,823	1,075,545
	% of P/L Total Vols	3	5	1	2	.	.	2	3
MOJAVE PIPELINE COMPANY	Affil Vols (MMBtu)	24,000	.	24,000	.	.	.	.	.
	% of P/L Total Vols	6	.	6	.	.	.	.	.
NATIONAL FUEL GAS SUPPLY CORPORAT	Affil Vols (MMBtu)	1,252,530	34,650,281	73,882	3,255,000	73,882	3,255,000	1,178,648	31,395,281
	% of P/L Total Vols	57	51	3	5	3	5	53	46
NAUTILUS PIPELINE COMPANY LLC	Affil Vols (MMBtu)	277,648	.	.	.	277,648	.	.	.
	% of P/L Total Vols	74	.	.	.	74	.	.	.
NORTHERN NATURAL GAS COMPANY	Affil Vols (MMBtu)	1,660,004	11,314,460	1,660,004	11,314,460	.	.	.	.
	% of P/L Total Vols	10	17	10	17	.	.	.	.
NORTHWEST PIPELINE CORPORATION	Affil Vols (MMBtu)	15,635	.	15,635	.	15,635	.	.	.
	% of P/L Total Vols	0	.	0	.	0	.	.	.
OZARK GAS TRANSMISSION L.L.C.	Affil Vols (MMBtu)	197,380	.	197,380	.	.	.	.	.
	% of P/L Total Vols	85	.	85	.	.	.	.	.
PATUTE PIPELINE COMPANY	Affil Vols (MMBtu)	81,100	400,571	.	.	.	.	81,100	400,571
	% of P/L Total Vols	51	82	.	.	.	.	51	82
PANHANDLE EASTERN PIPE LINE COMPA	Affil Vols (MMBtu)	27,880	1,471,800	.	.	.	.	27,880	1,471,800
	% of P/L Total Vols	1	2	.	.	.	.	1	2
PG&E GAS TRANSMISSION NORTHWEST CO	Affil Vols (MMBtu)	654,668	.	609,968	.	.	.	.	.
	% of P/L Total Vols	21	.	20	.	.	.	.	.
PINE NEEDLE LNG COMPANY LLC	Affil Vols (MMBtu)	.	3,255,000	.	3,255,000	.	.	.	.
	% of P/L Total Vols	.	79	.	79	.	.	.	.
PORTLAND NATURAL GAS TRANSMISSION	Affil Vols (MMBtu)	60,000	.	15,000	.	.	.	.	.
	% of P/L Total Vols	28	.	7	.	.	.	.	.

Summary of Natural Gas Pipeline Affiliate Information
Source: Oct 2003 Index of Customers

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Pipeline	Item	Transportation Affiliate	Storage Affiliate	Transpo Marketing Affiliate	Storage Marketing Affiliate	Transpo Producer Affiliate	Storage Producer Affiliate	Transpo LDC Affiliate	Storage LDC Affiliate
QUESTAR PIPELINE COMPANY	Affil Vols (MMBtu)	929,080	16,412,368	929,080	16,412,368	.	.	898,902	15,347,368
	% of P/L Total Vols	61	31	61	31	.	.	59	29
SABINE PIPE LINE LLC	Affil Vols (MMBtu)	64,000	.	64,000	.	60,000	.	.	.
	% of P/L Total Vols	72	.	72	.	67	.	.	.
TENNESSEE GAS PIPELINE COMPANY	Affil Vols (MMBtu)	213,565	6,403,610	161,500	6,403,610	.	.	.	.
	% of P/L Total Vols	3	8	2	8	.	.	.	.
TEXAS EASTERN TRANSMISSION LP	Affil Vols (MMBtu)	40,400	.	35,400	.	.	.	.	.
	% of P/L Total Vols	1	.	1	.	.	.	.	.
TOTAL PEAKING SERVICES LLC	Affil Vols (MMBtu)	72,000	1,140,000	72,000	1,140,000	.	.	.	.
	% of P/L Total Vols	100	100	100	100	.	.	.	.
TRANSCOLORADO GAS TRANSMISSION CO	Affil Vols (MMBtu)	125,000	.	.	.	125,000	.	.	.
	% of P/L Total Vols	18	.	.	.	18	.	.	.
TRANSCONTINENTAL GAS PIPELINE COR	Affil Vols (MMBtu)	457,630	.	457,630	.	.	.	.	.
	% of P/L Total Vols	7	.	7	.	.	.	.	.
TRANSWESTERN PIPELINE COMPANY	Affil Vols (MMBtu)	25,000	.	25,000	.	.	.	.	.
	% of P/L Total Vols	0	.	0	.	.	.	.	.
TUSCARORA GAS TRANSMISSION COMPAN	Affil Vols (MMBtu)	127,101	.	127,101	.	.	.	.	.
	% of P/L Total Vols	77	.	77	.	.	.	.	.
VECTOR PIPELINE L.P.	Affil Vols (MMBtu)	768,000	.	405,000	.	.	.	255,000	.
	% of P/L Total Vols	64	.	34	.	.	.	21	.
VENICE GATHERING SYSTEM L.L.C.	Affil Vols (MMBtu)	297,010	.	.	.	297,010	.	.	.
	% of P/L Total Vols	40	.	.	.	40	.	.	.
WESTGAS INTERSTATE INC.	Affil Vols (MMBtu)	11,372	.	.	.	.	.	11,372	.
	% of P/L Total Vols	85	.	.	.	.	.	85	.
WILLISTON BASIN INTERSTATE PIPELI	Affil Vols (MMBtu)	425,856	12,364,007	19,000	.	.	.	406,856	12,364,007
	% of P/L Total Vols	92	100	4	.	.	.	87	100
WYOMING INTERSTATE COMPANY LTD.	Affil Vols (MMBtu)	126,174	.	.	.	126,174	.	.	.
	% of P/L Total Vols	7	.	.	.	7	.	.	.

Natural Gas Pipeline Systems Database - as of April 24, 2006

<u>Pipeline Name</u>	<u>Reported Capacity (MMcf/d) - 2006(To date)</u>	
Tyler County Gathering System	0	REPORTED SYSTEM CAPACITY
Acadian Gas Gathering System	0	
Ada Gathering System	80	
Anaconda Pipeline System	400	
Anadarko Gathering System	0	
Antelope Valley Delivery Line	50	
Appleby Gathering System	40	
Arkoma Basin Gathering System	0	
Bastian Bay Pipeline Co	0	
Big Thicket Gathering System	0	
Bighorn Gas Gathering Co	250	
Blue Water Gathering System	1800	
Bonepile Gathering System	9	
Brigepoint Gathering System	650	
Brookland/Masters Creek Gathering System	100	
Canyon Chief Pipeline Co	350	
Canyon Express Pipeline Co	500	
Cardinal Gas Gathering System	145	
Carlsbad Natural Gas Gathering System	0	
Carthage Gas Gathering System	310	
Casper and Douglas Gathering Systems	210	
Chalk and Madison Gas Gathering Systems	0	
Chalkley/Rusk/Whiskey Bay/Vantex/Ranger/Dorado Sys	556	
Cleopatra Gathering System	500	
Conroe Gathering System & Gas Plant	65	
Constitution Gathering System	0	
Copano Pipelines Co	0	
Copano ScissorTail Gathering	0	
Cowtown Gathering System	75	
Crosstex Alabama Gathering System	70	
Crosstex Arkoma Gas Gathering System	30	
Crosstex Mississippi Pipeline System	175	
Dauphin Island Gathering System	1155	
Denton Gathering System	35	
Duke Energy Field Services LP (LA)	250	
Duke Energy Field Services LP (TX)	0	
East Breaks Gathering Co	400	
Elk City Gathering System	410	
Enbridge Pipelines (Fort Worth System)	81	
Enbridge Pipelines (North Texas)	170	
Enbridge Pipelines (Texas Gathering)	345	
Energy Bridge Connection	690	
Falcon Gas Gathering System	400	
Fort Union Gathering Header	634	
Foss Lake Gathering System	65	
FrontRunner Gathering Pipeline	100	
Gap Gathering System	18	

Garden Banks Gas Pipeline LLC	1000
Gas Gathering Enterprises System	15
Green Canyon System	220
Gregory Gathering System & Gas Plant	200
Harrison System	15
Indian Springs Gathering System	140
Jonah Gas Gathering Co	1500
Jupiter Pipeline Co	50
KN Wattenberg LLC	254
Keyes Gas Gathering System	0
Kinta Gas Gathering System	145
Lost Creek Gathering Co	275
Madison Gathering System	18
Magnolia Gathering System	275
Manta Ray Gathering System	755
Matagorda Texas Offshore Pipeline System	150
Minden Gathering System	115
Mississippi Canyon Gathering System	800
Mobile Area Gathering System	75
Mulhall Gathering System	150
Mulhall-Drumright Gathering Header	750
Nemo Pipeline Co	300
Northeast Spotted Horse System	0
OGC Pipeline Co	0
Okeanos Deepwater System	1200
Ozark Gas Gathering Co	0
Pandale Gathering System	40
Panther Interstate Pipeline Co	115
Pelican Gas Gathering System	50
Permian Basin System	0
Phoenix Gathering System	450
Piceance Basin Gas Gathering System	360
Ram Powell Pipeline Co	0
Raptor Intrastate Pipeline System	0
Red Cedar Gathering Co	700
Regency Dubach/Calhoun/Lisbon Gathering System	0
Regency MidContinent Gathering System	0
Regency WAHA Gathering System	125
Rendezvous Gathering Pipeline Co	275
Rimrock Gathering System	350
Saginaw Bay Pipeline North	135
San Juan Gathering System	1100
Seahawk Gathering System	0
SemKan Gathering System	0
Sonora Pipeline System	0
South Kitty Delivery Line	10
Southeast Texas Pipeline System	1245
Spectrum Golden Trend Gas Gathering System	0
Stone Mountain Gathering System	26
Superior Pipeline Co	122
TOP Gathering System	8
TPC Offshore System	0

Gas Transmission Northwest Co	2502
Granite State Gas Transmission Co	146
Great Lakes Gas Transmission Ltd	2796
Guardian Pipeline Co	773
Gulf South Pipeline Co	3863
Gulf States Transmission Corp	100
Gulfstream Natural Gas System	1241
Harve Pipeline Co	0
High Island Offshore System	1800
Horizon Pipeline Co	370
Iroquois Gas Transmission Co	1271
KO Transmission Co	356
Kelso-Beaver Pipeline Co	310
Kern River Gas Transmission Co	1833
Kinder Morgan Border Pipeline LP	300
Kinder Morgan Interstate Gas Co	1137
MIGC Pipeline Co	130
Maritimes & Northeast Pipeline Co	428
Michcon Gas Co	0
Michigan Gas Storage Co	0
Midwestern Gas Transmission Co	660
Mojave Pipeline Co	407
NGO Transmission Co	77
National Fuel Gas Supply Co	2215
Natural Gas PL Co of America	4485
Nautilus Pipeline Co	600
Norteno Pipeline Co	0
North Baja Pipeline Co -- US	512
North Country Pipeline Co	56
Northern Border Pipeline Co	2496
Northern Natural Gas Co	4625
Northwest Pipeline Corp	3509
OkTex Pipeline Co	1123
Ozark Gas Transmission LLC	321
Paiute Pipeline Co	680
Panhandle Eastern PL Co	2765
Penn York Energy Corp	0
Portland Gas Transmission Co	214
Questar Overthrust Pipeline Co	875
Questar Pipeline Co	2631
Regent Border Pipeline	20
SCG Pipeline Inc	0
Sabine Pipeline Co	1348
Sea Robin Pipeline Co	1038
Shoshone Pipeline	14
Sierra Border Pipeline	24
South Georgia Natural Gas Co	145
Southern Natural Gas Co	3340
Southern Star Central Gas PL Co	2450
Southern Trails Pipeline Co	85
Southwest Gas Transmission Co	294
St Lawrence Gas Co	62

Empire Pipeline Co	525
Enbridge Pipelines (Alabama Intra)	0
Enbridge Pipelines (East Texas)	500
Enbridge Pipelines (Louisiana Intrastate)	115
Enbridge Pipelines (Palo Duro)	75
Energy Transfer - Oasis Pipeline	1200
Enogex Inc	0
Enterprise Texas Pipeline LP	4040
Evangeline Gas Pipeline Co	0
Fort Worth Basin Pipeline	400
Fort Worth Basin Pipeline	250
Guadalupe Pipeline Co	0
Gulf Coast Pipeline System	250
Hallmark Laterals System	0
Heartland Pipeline	80
Houston Gas Pipeline System	2400
KM North Texas Pipeline	365
KM Rancho Pipeline	320
KM Tejas Pipeline System	3500
Kentucky-West Virginia Gas Co	100
KeySpan Energy Delivery (NH)	0
KeySpan Energy Delivery Co (NY)	0
KeySpan LNG LP	0
Kinder Morgan Texas Pipeline Co	0
Louisiana System	600
MarkWest Intrastate Pipeline Co	70
MarkWest New Mexico LP	162
Matagorda Island Pipeline Co	0
Mississippi Fuel Co	0
Missouri Gas Co	0
Missouri Interstate Pipeline Co	0
Missouri Public Service Co	0
Monterey Pipeline Co	0
Mustang Fuel Co	0
NORA Gas Transmission Co	50
National Fuel Gas Distribution Co	0
Ninilchik Pipeline Co	120
Norse Pipeline Co	0
North Coast Gas Transmission Co	82
North Penn Gas Co	0
North Side Loop Line	200
North Texas Pipeline	325
NorthWestern Energy Co	73
Northern Illinois Gas Co	0
Northern Utilities Inc (ME)	0
Northwest Natural Gas Co	0
Oklahoma Natural Gas Co	2000
Oklahoma Texas Gas Co	0
Overland Trail Transmission Co	0
PG&E Transmission Co	3200
Peoples Gas Co (TX)	0
Pub Svc Co of North Carolina	0

Public Service Co of New Mexico	0
Red River Pipeline Co	0
Regency Intrastate Pipeline System	615
River Gas Co	0
Rocky Mountain Natural Gas Co	0
Saginaw Bay Pipeline South	135
San Diego Gas & Electric Co	900
Sandhill Pipeline Co	300
South Shore Pipeline Co	10
Southern California Gas Co	4050
Southern Union Intrastate Pipelines	0
Southwest Gas Co	0
Southwestern Energy Pipeline Co	34
Tengasco Pipeline Co	25
Tidelands Pipeline System	0
Tuscaloosa Pipeline Co	0
Union Light Heat & Power	0
Vanderbuilt Pipeline System	60
West Texas Gas Pipeline Co	134
Westex Pipeline Co	0

Stingray Pipeline Co	1031
Tennessee Gas Pipeline Co	6644
Texas Eastern Transmission Corp	6190
Texas Gas Transmission LLC	3018
Trailblazer Pipeline Co	844
Trans-Union Pipeline Co	427
TransColorado Gas Transmission Co	933
Transcontinental Gas PL Co	8203
Transwestern Pipeline Co	3211
Trunkline Gas Co	1636
Tuscarora Gas Transmission Co	190
Vector Pipeline Co	983
Vermont Gas System Inc	49
Viking Gas Transmission Co	530
WTG Hugoton System	0
WestGas Interstate Pipeline Co	13
Western Gas Interstate Pipeline	50
Williston Basin Interstate PL Co	606
Wyoming Interstate Co	2331
	
AGL/Elizabethtown Gas Division	0
Acadian Gas Pipeline System	0
Alaska Pipeline Co	0
Amoco Pipeline Co	0
Arkansas Western Pipeline Co	27
Atmos Energy - Mississippi	0
Atmos Pipeline - Texas	1300
Barnett-Texoma Pipeline	700
Battle Creek Pipeline Co	0
Bossier Pipeline	500
Bridgeline Gas Systems Inc	1500
Buffalo Wallow System	0
CCNG Transmission System	350
Calpine Texas Pipeline	0
Cardinal Pipeline Co	263
Cardinal Pipeline System	100
Channel Industries Gas Pipeline Co	1300
Coos Bay Pipeline Co	70
Cornerstone Pipeline Co	0
Cranberry Pipeline Corp	0
Cypress Gas Pipeline Co	100
Dominion East Ohio Gas Co	0
Dominion Hope Gas co	0
Dominion West Ohio Gas Co	0
Dow Pipeline Co (LA)	0
Dow Pipeline Co (TX)	0
Duke Energy Intrastate Pipeline Co	0
Duke Energy Virginia Pipeline Co	0
ET Fuel System	1300
Eastern North Carolina Gas Pipeline Co	72
El Paso Intrastate-Alabama	200

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BASIN CONTROL

I am providing the following observations as a supplement to my prior written and oral comments concerning various issues related to the Draft Alaska Stranded Gas Fiscal Contract ("Contract"). I have recently had the benefit of reviewing both written comments and/or testimony by The Administration; BP, ExxonMobil, and ConocoPhillips ("Producers"); independent producers (i.e. Shell, British Gas, and Anadarko et al); and other Legislative Consultants on a variety of matters related to the issue of "basin control".

It remains my professional opinion that basin control is a significant concern should the Contract receive Legislative approval and become executed by the existing parties in its present form.

It is my understanding that under The Alaska Stranded Gas Development Act, there may be further negotiations between The State and the Producer participants and that a material revision of the current Contract may be developed and submitted for approval soon. It is also my understanding that an LLC currently being finalized may contain provisions that would substantially affect the issues of concern regarding basin control. The issues that I have highlighted (both here and previously) may be mitigated through those processes. The Governor's Chief of Staff and key members of his team have indicated that they have heard my comments and those offered by other stake holders and will be taking them into account in finalization of the LLC and in further negotiations of the Contract. I am particularly appreciative of his apparent openness and receptivity in that regard.

OBSERVATIONS:

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The Producers, as parties to the Contract", control the majority of the existing proved reserves necessary to support the firm transportation ("FT") commitments associated construction of a natural gas pipeline project from the North Slope to markets in the Lower 48 States and Alaska ("gasline"). To that extent, they have basin control in their position as majority owners and operators of the key fields (Prudhoe Bay, Point Thompson, and Kuparuk most particularly). The primary issue is to insure an environment is created where other independents will have timely and economic access to the gasline to support additional exploration in these and other basins across Alaska. Unlike the oil and products industries, the natural gas industry in North America has not traditionally been vertically integrated where major producers have owned or controlled interstate pipelines. Historically, there were legal prohibitions to this. Today, these Producers are fully entitled to own natural gas pipelines and FT shipping rights associated with those systems. The point is that industry custom and practice, along with both State and Federal regulatory regimens, arose over a long period of time under a different presumption of industry ownership and structure.

Consequently, it is my opinion that extraordinary care should be taken to protect the interests of independent producers through the Contract, LLC, and legislation. Further, the State should err on the side of caution and include to the fullest extent possible though explicit contract language in the LLC and Contract on gasline expansion; remedies and penalties; regulatory oversight; and access to State and Federal courts. I recommend not presuming that existing FERC regulations and policies will protect the State's interest and prevent basin control, either overtly or through subtle device.

It is apparent that the Producers have purposely limited ownership to the current participants and have rebuffed overtures from interested independents. They have indicated that they may now be open to ownership participation from those with interests in other prospective basins. This would be highly desirable in my opinion in helping to insure proper alignment of the interests of the broader industry in Alaska.

A critical element in minimizing the risks of basin control is for the gasline to be expansion friendly both explicitly and implicitly. The contract should be no less restrictive than FERC policy in establishing and administering expansions. The current draft of the Contract is not expansion friendly as previously indicated and as expressed at length by both Anadarko and British Gas ("BG Alaska E & P, Inc.") in written and oral comments.

The Contract could contain specific design parameters that are consistent with the project described in the Application. Short of that, specific design criteria could be specified to insure that both the initial design and expansion methodologies support ease of timely access at the lowest reasonable cost. Reasonable engineering increments and credit demands (and alternative financial mechanisms, ie. aid in construction) are important elements to moving towards an expansion friendly protocol.

Article 10 Capacity Management Program is causing considerable consternation among independents. As mentioned previously, this is a section that the Administration worked extremely hard on to mitigate the effects on the State's share of production given that the receipt point is on the upstream side of the gasline. I continue to urge that the State negotiate, if at all possible, to receive it's take in kind share at the terminus of the gasline system both in-state and out of state.

The Contract should insure regulatory oversight should FERC jurisdiction be limited or constrained now or in the future. The Contract currently seeks to preclude State regulatory oversight by the RCA or otherwise should FERC jurisdiction not apply. The gasline and related facilities constitute a natural monopoly and existing commercial terms would not protect the interests of independents in my opinion.

Proposed tariff provisions should be open to comment and review at the earliest possible juncture. The Administration has indicated that draft provisions are currently part of the LLC.

The draft Contract is available only for leases north of 68 degrees. Gas prone regions such as the "Foothills" would be eliminated.

The Contract does not offer identical terms to the independents as those afforded the Producer participants. Independents must make transportation commitments not required of the Producers before receiving the benefits of the Contract [AS 43.82.437(d)(4)(ii) in Section 1 of the proposed Act]. In addition, independents are only entitled to "substantially similar" terms in Articles 11, 16, 22, 23, 28 and 30 as contrasted with the same terms the Producers are entitled to.

As previously reported, the Contract specifically precludes seeking the protection and remedies of State and Federal Courts except for the enforcement of an award pursuant to arbitration under the Contract. The Contract completely limits liability for loss associated with consequential or incidental damages, including lost profits, or any special or punitive damages. Diligence is a weak standard that is defined in the Contract and is the basis for measuring certain important duties of performance. There has been Producer testimony that the penalties under existing law are a sufficient deterrent to anti-competitive behaviors and outcomes. I respectfully disagree. At this time, for instance, one of the Producers (BP) has a wholly owned affiliate which has been sued recently by the Commodities Futures Trading Commission after a months long investigation. The complaint is reported to accuse BP of unleashing a speculative trading strategy that cornered up to 88% of the U.S. propane market by late 2004. The Company has denied the allegations. Separate, but related, the U.S. Justice department announced very recently that a senior professional at BP had pleaded guilty to felony charges of conspiring to drive up propane prices. According to a press report, this individual said he "understood that the scheme was approved by senior executives at BP, and that steps were taken to avoid detection by market participants and others". Additional indictments are apparently expected.

In conclusion, I re-urge that every attempt to put belts and suspenders on the Contract be made and that reliance on oral statements and commitments by counter-parties

not be relied upon when evaluating the overall merits of of this massive transaction and all of its components.

Respectfully Submitted,

RICK HARPER

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7/31/2006 Session Expanded Table

	Last	Open High	Open Low	High	Low	Most Recent Settle	Change	Open Interest	Volume	L
Sep 2006	8.185	7.790	7.750	8.250	7.220	7.184	+1.001	120457	4279	0
Oct 2006	8.470	8.000	7.980	8.500	7.430	7.424	+1.046	80396	2426	0
Nov 2006	9.880	9.400	9.330	9.800	8.834	8.804	+996	41494	780	0
Dec 2006	10.800	n/a	n/a	11.100	10.184	10.159	+741	38340	571	0
Jan 2007	11.050	11.250	11.250	11.700	11.240	10.764	+886	51531	2147	0
Feb 2007	11.050	n/a	n/a	11.650	10.772	10.774	+876	29526	295	0
Mar 2007	11.430	n/a	n/a	11.430	10.550	10.534	+896	64009	5259	0
April 2007	8.800	n/a	n/a	8.800	8.594	8.644	+156	36845	4922	0
May 2007	8.800	n/a	n/a	8.640	8.520	8.464	+136	23939	477	0
June 2007	8.780	n/a	n/a	8.750	8.550	8.546	+204	12963	1	0
July 2007	8.800	n/a	n/a	8.800	8.730	8.649	+151	9785	n/a	0
Aug 2007	8.860	n/a	n/a	8.860	8.860	8.729	+131	9256	n/a	0
Sep 2007	8.960	n/a	n/a	8.960	8.900	8.829	+131	10039	n/a	0
Oct 2007	9.060	n/a	n/a	9.060	9.040	8.989	+071	27728	n/a	0
Nov 2007	9.830	n/a	n/a	9.900	9.830	9.769	+061	15260	n/a	0
Dec 2007	10.644	n/a	n/a	10.720	10.644	10.574	+070	28046	n/a	0
Jan 2008	11.144	n/a	n/a	11.144	11.090	11.074	+070	30338	61	0
Feb 2008	11.149	n/a	n/a	11.200	11.149	11.079	+070	11795	n/a	0
Mar 2008	10.980	n/a	n/a	10.980	10.880	10.814	+166	26032	n/a	0
April 2008	8.109	n/a	n/a	8.200	8.109	8.089	+020	19404	n/a	0
May 2008	7.864	n/a	n/a	7.900	7.864	7.844	+020	12339	n/a	0
June 2008	7.954	n/a	n/a	8.050	7.954	7.934	+020	4079	n/a	0
July 2008	8.024	n/a	n/a	8.150	8.024	8.024	+0	3140	n/a	0
Aug 2008	8.104	n/a	n/a	8.104	8.104	8.104	+0	3042	n/a	0
Sep 2008	8.219	n/a	n/a	8.219	8.219	8.219	+0	3364	n/a	0
Oct 2008	n/a	n/a	n/a	n/a	n/a	8.394	+0	14626	n/a	0
Nov 2008	n/a	n/a	n/a	n/a	n/a	9.154	+0	4683	n/a	0
Dec 2008	n/a	n/a	n/a	n/a	n/a	9.929	+0	8654	n/a	0
Jan 2009	10.450	n/a	n/a	10.450	10.450	10.399	+051	16171	n/a	0
Feb 2009	n/a	n/a	n/a	n/a	n/a	10.399	+0	1489	n/a	0
Mar 2009	n/a	n/a	n/a	n/a	n/a	10.139	+0	13341	n/a	0

April 2009	n/a	n/a	n/a	n/a	n/a	7.649	+0	13775	n/a	0
May 2009	n/a	n/a	n/a	n/a	n/a	7.404	+0	5830	n/a	0
June 2009	7.550	n/a	n/a	7.550	7.550	7.489	+0.061	2004	n/a	0
July 2009	n/a	n/a	n/a	n/a	n/a	7.579	+0	1622	n/a	0
Aug 2009	n/a	n/a	n/a	n/a	n/a	7.674	+0	2074	n/a	0
Sep 2009	n/a	n/a	n/a	n/a	n/a	7.789	+0	2628	n/a	0
Oct 2009	7.969	n/a	n/a	7.969	7.969	7.969	+0	5625	3	0
Nov 2009	n/a	n/a	n/a	n/a	n/a	8.719	+0	1306	n/a	0
Dec 2009	n/a	n/a	n/a	n/a	n/a	9.479	+0	4075	n/a	0
Jan 2010	n/a	n/a	n/a	n/a	n/a	9.964	+0	4135	n/a	0
Feb 2010	n/a	n/a	n/a	n/a	n/a	9.964	+0	1465	n/a	0
Mar 2010	n/a	n/a	n/a	n/a	n/a	9.739	+0	9341	n/a	0
April 2010	n/a	n/a	n/a	n/a	n/a	7.269	+0	11966	n/a	0
May 2010	n/a	n/a	n/a	n/a	n/a	7.029	+0	2142	n/a	0
June 2010	n/a	n/a	n/a	n/a	n/a	7.129	+0	2291	n/a	0
July 2010	n/a	n/a	n/a	n/a	n/a	7.224	+0	1309	n/a	0
Aug 2010	n/a	n/a	n/a	n/a	n/a	7.319	+0	1992	n/a	0
Sep 2010	n/a	n/a	n/a	n/a	n/a	7.414	+0	1537	n/a	0
Oct 2010	n/a	n/a	n/a	n/a	n/a	7.569	+0	4104	n/a	0
Nov 2010	n/a	n/a	n/a	n/a	n/a	8.324	+0	2266	n/a	0
Dec 2010	n/a	n/a	n/a	n/a	n/a	9.094	+0	8135	n/a	0
Jan 2011	n/a	n/a	n/a	n/a	n/a	9.584	+0	1811	n/a	0
Feb 2011	n/a	n/a	n/a	n/a	n/a	9.584	+0	1391	n/a	0
Mar 2011	n/a	n/a	n/a	n/a	n/a	9.359	+0	6328	n/a	0
April 2011	n/a	n/a	n/a	n/a	n/a	6.919	+0	3292	n/a	0
May 2011	n/a	n/a	n/a	n/a	n/a	6.679	+0	1288	n/a	0
June 2011	n/a	n/a	n/a	n/a	n/a	6.779	+0	747	n/a	0
July 2011	n/a	n/a	n/a	n/a	n/a	6.879	+0	703	n/a	0
Aug 2011	n/a	n/a	n/a	n/a	n/a	6.979	+0	648	n/a	0
Sep 2011	n/a	n/a	n/a	n/a	n/a	7.074	+0	669	n/a	0
Oct 2011	n/a	n/a	n/a	n/a	n/a	7.234	+0	2164	n/a	0
Nov 2011	n/a	n/a	n/a	n/a	n/a	7.979	+0	972	n/a	0
Dec 2011	n/a	n/a	n/a	n/a	n/a	8.744	+0	2436	n/a	0

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Natural Gas Development
COMMITTEE
Amendment # #2
To Bill Number: SB 3002
Sponsor: B Stevens
Date: 7/28/02 logged by: Mindy

AMENDMENT

OFFERED IN THE SENATE SPECIAL

BY B. STEVENS

COMMITTEE ON NATURAL GAS DEVELOPMENT

TO: CSSB 3002(NGD)(24-GS2095\G)

1 Page 8, following line 8:

2 Insert new bill sections to read:

3 ** Sec. 14. AS 43.82.430(b) is amended to read:

4 (b) After considering the material described in (a) of this section and securing the
5 agreement of the other parties to the proposed contract regarding any proposed
6 amendments prepared under (a) of this section, if the commissioner determines that the
7 contract is in the long-term fiscal interests of the state, the commissioner may execute
8 [SHALL SUBMIT] the contract [TO THE GOVERNOR].

9 * Sec. 15. AS 43.82.430(c) is amended to read:

10 (c) The commissioner's final findings and determination under (a) of this section
11 and decision regarding whether to execute the contract under (b) of this section are
12 final agency decisions under this chapter.

13 * Sec. 16. AS 43.82.440 is amended to read:

14 Sec. 43.82.440. Judicial review. An [A PERSON MAY NOT BRING AN]
15 action challenging the constitutionality of a law authorizing a contract developed under
16 this chapter [ENACTED UNDER AS 43.82.435] or the enforceability of a contract
17 executed under a process authorized by [A] law may not be brought [AUTHORIZING
18 A CONTRACT ENACTED UNDER AS 43.82.435] unless the action is commenced
19 within 120 days after the date that the contract was executed by the state and the other
20 parties to the contract."
21

1 Renumber the following bill sections accordingly.

2

3 Page 11, following line 30:

4 Insert new bill sections to read:

5 **"* Sec. 24.** The uncoded law of the State of Alaska is amended by adding a new section to
6 read:

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

11 *** Sec. 25.** The uncoded law of the State of Alaska is amended by adding a new section to
12 read:

13 **SUSPENSION OF OTHER LAW.** The provisions of the Alaska Stranded Gas Fiscal
14 Contract between the State of Alaska and BP Exploration (Alaska) Incorporated, ConocoPhillips
15 Alaska, Incorporated, and ExxonMobil Alaska Production, Incorporated, as amended to conform
16 to the provisions of this Act, are effective notwithstanding the provisions of any other law,
17 including AS 43.82.200 - 43.82.270. Any inconsistency between the Alaska Stranded Gas
18 Development Act (AS 43.82) and the fiscal contract executed under AS 43.82 are cured and
19 authorized by this section.

20 *** Sec. 26.** The uncoded law of the State of Alaska is amended by adding a new section to
21 read:

22 **ADVISORY VOTE.** At the 2006 general election to be held on November 7, 2006, in
23 substantial compliance with the election laws of the state, the lieutenant governor shall place
24 before the qualified voters of the state a question advisory to the governor and the commissioner
25 of revenue. Notwithstanding other laws relating to preparation of the ballot proposition, the
26 question shall appear on the ballot in the following form:

27 **Q U E S T I O N**

28 Shall the commissioner of revenue sign and make binding upon the State of Alaska the Alaska
29 Stranded Gas Fiscal Contract between the State of Alaska and BP Exploration (Alaska)
30 Incorporated, ConocoPhillips Alaska, Incorporated, and ExxonMobil Alaska Production,
31 Incorporated ?

1 Yes [] No []

2 * Sec. 27. If secs. 14 - 16 and 25 of this Act take effect, they take effect on the date that the
3 director of elections certifies the results of the 2006 general election at which a majority of the
4 votes cast on the proposition favor execution by the commissioner of revenue and binding effect
5 on the State of Alaska of the Alaska Stranded Gas Fiscal Contract between the State of Alaska
6 and BP Exploration (Alaska) Incorporated, ConocoPhillips Alaska, Incorporated, and
7 ExxonMobil Alaska Production, Incorporated."

8

9 Renumber the following bill sections accordingly.

10

11 Page 12, line 7:

12 Delete "Sections 2 - 14 and 17 - 20"

13 Insert "Sections 2 - 13, 17, and 20 - 23"

14

15 Page 12, following line 9:

16 Insert a new bill section to read:

17 "** Sec. 30. Sections 24, 25, and 26 of this Act take effect immediately under
18 AS 01.10.070(c)."

19

20 Page 12, line 10:

21 Delete "This"

22 Insert "Except as provided in sec. 30 of this Act, this"

Natural Gas Development
COMMITTEE #1
Amendment #
To Bill Number: SB 3002
24-GS2095\GSponsor: B. Stevens
7/28/06 Date: 7/29/06 logged by: Mindy

AMENDMENT

OFFERED IN THE SENATE

BY SENATOR BEN STEVENS

TO: CSSB 3002(NGD) -Version G

- 1 Page 6, line 6:
- 2 Delete "35"
- 3 Insert "25"
- 4
- 7 Page 6, line 10:
- 8 Delete "45"
- 9 Insert "35"
- 10
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CS FOR SENATE BILL NO. 3002(NGD)

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-FOURTH LEGISLATURE - THIRD SPECIAL SESSION

BY THE SENATE SPECIAL COMMITTEE ON NATURAL GAS DEVELOPMENT

Offered:
Referred:

Sponsor(s): SENATE RULES COMMITTEE BY REQUEST OF THE GOVERNOR

A BILL

FOR AN ACT ENTITLED

1 "An Act relating to the Alaska Stranded Gas Development Act, including clarifications
2 or provision of additional authority for the development of stranded gas fiscal contract
3 terms; making a conforming amendment to the Revised Uniform Arbitration Act;
4 relating to municipal impact money received under the terms of a stranded gas fiscal
5 contract; relating to determination of full and true value of property and required
6 contributions for education in municipalities affected by stranded gas fiscal contracts;
7 and providing for an effective date."

8 BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

9 * Section 1. AS 09.43.300(a) is amended to read:

10 (a) AS 09.43.300 - 09.43.595 govern an agreement to arbitrate made on or
11 after January 1, 2005, except as otherwise provided in a contract term developed
12 under AS 43.82.200(a)(5) and (b).

13 * Sec. 2. AS 43.82.010 is amended to read:

1 **Sec. 43.82.010. Purpose.** The purpose of this chapter is to

2 (1) encourage new investment to develop the state's stranded gas
3 resources by authorizing establishment of fiscal terms related to oil and gas
4 agreements and taxes for a qualified sponsor, the members of a qualified sponsor
5 group, or a related party and related to their oil and gas business activity in the
6 state, including gas pipeline expansion pricing that encourages further gas
7 exploration [THAT NEW INVESTMENT WITHOUT SIGNIFICANTLY
8 ALTERING TAX AND ROYALTY METHODOLOGIES AND RATES ON
9 EXISTING OIL AND GAS INFRASTRUCTURE AND PRODUCTION];

10 (2) allow the fiscal terms applicable to a qualified sponsor or the
11 members of a qualified sponsor group, or a related party, with respect to a qualified
12 project, to be tailored to the particular economic conditions of the project and to
13 establish those fiscal terms in advance with as much certainty as the Constitution of
14 the State of Alaska allows; and

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

17 * **Sec. 3.** AS 43.82.020 is amended to read:

18 **Sec. 43.82.020. Negotiation of contract terms** [CONTRACTS FOR
19 **PAYMENTS IN LIEU OF OTHER TAXES AND FOR ROYALTY**
20 **ADJUSTMENTS**]. The commissioner may, under this chapter, negotiate terms for
21 inclusion in a proposed contract with a qualified sponsor or qualified sponsor group
22 providing for

23 (1) periodic payment in lieu of one or more taxes that otherwise would
24 be imposed by the state or a municipality on the qualified sponsor, [OR] members of
25 the qualified sponsor group, or a related party; [AS A CONSEQUENCE OF THE
26 SPONSOR'S OR GROUP'S PARTICIPATION IN AN APPROVED QUALIFIED
27 PROJECT UNDER THIS CHAPTER; AND]

28 (2) certain adjustments regarding oil and gas lease agreements, unit
29 agreements, and other agreements [ROYALTY] under AS 43.82.220; in this
30 paragraph, "oil and gas lease agreements" includes royalty provisions of those
31 agreements; and

(3) payment of the gas production tax under AS 43.55, or payment in lieu of the gas production tax, by delivery of gas.

* Sec. 4. AS 43.82.200 is amended to read:

Sec. 43.82.200. Contract development. If the commissioner approves an application and proposed project plan under AS 43.82.140, the commissioner may develop a contract that may include

(1) terms concerning periodic payment in lieu of one or more taxes on oil or gas or both as provided in AS 43.82.210, and terms related to credits for investment in a project that is the subject of a contract developed under this chapter;

(2) terms developed under AS 43.82.220 concerning oil and gas leases, unit agreements, and other agreements under AS 38, including terms relating to

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

(B) royalty value;

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

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

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

(6) terms and conditions for [ADMINISTRATIVE] termination of a contract [UNDER AS 43.82.445]; and

(7) other terms or conditions that the commissioner determines are

(A) reasonable and promote [NECESSARY TO FURTHER] the purposes of this chapter, including the implementation of AS 43.82.020 - 43.82.270; or

(B) in the long-term fiscal [BEST] interests of the state.

* Sec. 5. AS 43.82.200 is amended by adding a new subsection to read:

(b) Terms relating to arbitration and alternate dispute resolution may provide

1 for a waiver, with the concurrence of the attorney general, of the state's immunity from
2 suit. The waiver may include waiver of the state's sovereign or other immunity and
3 consent to entrance and enforcement of an arbitration award in any state court in the
4 United States that has jurisdiction over the State of Alaska. The authority granted in
5 this subsection is effective only after the arbitration award is entered and enforcement
6 is sought in the superior court of the state.

7 * Sec. 6. AS 43.82.210(a) is amended to read:

8 (a) If the commissioner approves an application and proposed project plan
9 under AS 43.82.140, the commissioner may develop proposed terms for inclusion in a
10 contract under AS 43.82.020 for periodic payment in lieu of one or more of the
11 following taxes that otherwise would be imposed by the state or a municipality on the
12 qualified sponsor, a [OR] member of a qualified sponsor group, or a related party
13 [AS A CONSEQUENCE OF PARTICIPATING IN AN APPROVED QUALIFIED
14 PROJECT]:

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

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

18 (3) [REPEALED

19 (4)] Alaska net income tax under AS 43.20;

20 (4) [(5)] municipal sales and use tax under AS 29.45.650 - 29.45.710;

21 (5) [(6)] municipal property tax under AS 29.45.010 - 29.45.250 or
22 29.45.550 - 29.45.600;

23 (6) [(7)] municipal special assessments under AS 29.46;

24 (7) [(8)] a comparable tax or levy imposed by the state or a
25 municipality after June 18, 1998;

26 (8) [(9)] other state or municipal taxes or categories of taxes identified
27 by the commissioner.

28 * Sec. 7. AS 43.82.220(a) is amended to read:

29 (a) Notwithstanding any contrary provisions of AS 38 or regulations adopted
30 under that title, the commissioner of natural resources, with the concurrence of the
31 commissioner of revenue and, if necessary, the affected parties holding a state lease or

unit agreement, may develop proposed terms for inclusion in a contract under AS 43.82.020 that modify [THE TIMING AND NOTICE] provisions of the applicable oil and gas leases, [AND] unit agreements, and other agreements under AS 38, including provisions

(1) pertaining to the state's rights to receive its royalty on gas in kind or in value if

(A) [(1)] the viability of the approved qualified project depends on long-term gas shipping commitments [PURCHASE AND SALE AGREEMENTS];

(B) [(2)] certainty over time regarding the quantity of royalty gas that the state may be taking in kind is needed to enter into long-term gas shipping commitments or marketing agreements [SECURE THE LONG-TERM PURCHASE AND SALE AGREEMENTS];

(3) THE SPECIFIED PERIOD OF THE STATE'S COMMITMENT TO TAKE ITS ROYALTY SHARE IN VALUE OR IN KIND DOES NOT EXCEED THE TERM OF THE PURCHASE AND SALE AGREEMENTS]; and

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

(2) relating to lease or unit expenses for separation, cleaning, dehydration, gathering, salt water disposal, and preparation for transportation on or off the lease.

* Sec. 8. AS 43.82.220(c) is amended to read:

(c) The commissioner of revenue shall include any proposed terms [RELATING TO ROYALTY] developed in accordance with this section in the proposed contract under AS 43.82.400.

* Sec. 9. AS 43.82.220 is amended by adding a new subsection to read:

(e) An agreement by the state to take royalty gas in kind as part of a contract developed under this chapter that satisfies (a)(1)(A) - (C) of this section is not subject to the provisions of AS 38, or regulations adopted under that title, relating to decisions

1 to take royalty in kind.

2 * Sec. 10. AS 43.82.250 is amended to read:

3 Sec. 43.82.250. Term of contract; effective date. The term of a contract
4 developed under AS 43.82.020 [MAY BE FOR NO LONGER THAN IS
5 NECESSARY TO DEVELOP THE STRANDED GAS THAT IS SUBJECT TO THE
6 CONTRACT; HOWEVER, THE TERM OF THE CONTRACT] may not exceed 35
7 years from the commencement of commercial operations of the approved qualified
8 project, excluding suspensions of contract obligations that are covered by the
9 force majeure terms of any contract developed under this chapter. However, the
10 term of contract may not exceed 45 years from the effective date of a contract
11 approved under AS 43.82.435.

12 * Sec. 11. AS 43.82 is amended by adding a new section to read:

13 Sec. 43.82.255. Terms of contract provisions related to oil. (a) The
14 provisions of this section apply to a contract developed under AS 43.82.020 that
15 provides for periodic payment in lieu of taxes on oil under AS 43.55.

16 (b) For the period of the contract term beginning immediately after the date of
17 full project funding or the date of issuance of a certificate of public convenience and
18 necessity for construction and initial operation of the Alaska Natural Gas Pipeline,
19 whichever date is later, and ending 14 years after that date, the commissioner may
20 modify those terms of the contract relating to payments in lieu of the taxes on oil set
21 out in AS 43.55. For the period of the contract term covered by this subsection, the
22 payments in lieu of taxes may be established with as much certainty as the
23 Constitution of the State of Alaska allows.

24 (c) For the period of the contract term beginning immediately after the period
25 described in (b) of this section, and ending on a date not later than 25 years after the
26 effective date of the contract, the amount of the payment in lieu of tax on oil under
27 AS 43.55 must be equal to the amount of the tax levied by law. However, the
28 commissioner may develop a contract term that, in the event of a material change in
29 the taxes enacted after the effective date of the contract, establishes a procedure for
30 restoring the parties to substantially the same economic position they had as of the end
31 of the period described in (b) of this section immediately before the change.

(d) Implementation of a contract provision authorized in (c) of this section may be made subject to the dispute resolution procedures of the contract.

* Sec. 12. AS 43.82.270 is amended to read:

Sec. 43.82.270. Project plans and work commitments. A contract under AS 43.82.020 must include provisions for implementation of the qualified project plan approved under AS 43.82.140, as may be modified as a result of the development of a contract under this chapter, and provisions for updating the plan at reasonable intervals until the commencement of commercial operations of the approved qualified project. The commissioner of revenue, in consultation with the commissioner of natural resources, may, as a term in a contract under AS 43.82.020, include work commitments or other obligations in the contract to be accomplished before the commencement of commercial operations of the approved qualified project.

* Sec. 13. AS 43.82.410 is amended to read:

Sec. 43.82.410. Notice and comment regarding the contract. The commissioner shall

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

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

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

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

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

(3) offer to appear before the Legislative Budget and Audit Committee to provide the committee a review of the commissioner's preliminary findings and determination, the proposed contract, and the supporting financial, technical, and market data; if the Legislative Budget and Audit Committee accepts the

1 commissioner's offer, the committee shall give notice of the committee's meeting to
2 the public and all members of the legislature; if the financial, technical, and market
3 data that is to be provided must be kept confidential under AS 43.82.310, the
4 commissioner may not release the confidential information during a public portion of
5 a committee meeting; and

6 (4) establish a period of at least 60 [30] days for the public and
7 members of the legislature to comment on the proposed contract and the preliminary
8 findings and determination made under AS 43.82.400.

9 * Sec. 14. AS 43.82.500 is amended to read:

10 **Sec. 43.82.500. Obligation to share payments with municipalities.** If the
11 commissioner develops a contract under AS 43.82.020 that includes terms that exempt
12 a qualified sponsor, the members of a qualified sponsor group, or a related party
13 to the contract, and the property, gas, products, and activities associated with the
14 approved qualified project that is subject to the contract, from a municipal tax or
15 assessment in accordance with AS 29.45.810 or AS 29.46.010(b), or AS 43.82.200
16 and 43.82.210, the commissioner shall include a term in the contract that provides for
17 [THE PARTY PAY] a portion of the periodic payments to be made payable [DUE
18 UNDER THE CONTRACT] to the revenue-affected municipality.

19 * Sec. 15. AS 43.82.505 is amended to read:

20 **Sec. 43.82.505. Payments to economically affected municipalities.** If the
21 commissioner executes a contract under AS 43.82.020 that will produce one or more
22 economically affected municipalities, the commissioner shall include a term in the
23 contract that provides for [A PORTION OF THE] periodic impact payments to the
24 state that may be appropriated to the Alaska natural gas pipeline construction
25 impact fund established in (c) of this section to benefit the economically affected
26 municipalities under the principles in AS 43.82.520.

27 * Sec. 16. AS 43.82.505 is amended by adding new subsections to read:

28 (b) A special account is established in the general fund into which the
29 Department of Revenue shall deposit impact payments received by the state under (a)
30 of this section.

31 (c) The Alaska natural gas pipeline construction impact fund is established in

1 the Department of Commerce, Community, and Economic Development. The
2 legislature may appropriate money deposited in the special account established in (b)
3 of this section, as well as any additional money considered necessary, to the Alaska
4 natural gas pipeline construction impact fund to address the economic and social
5 impacts incurred by an economically affected municipality, or incurred by a nonprofit
6 organization serving the unorganized borough, during the construction of a project that
7 is the subject of a proposed contract developed under this chapter.

8 (d) The Department of Commerce, Community, and Economic Development
9 shall adopt regulations under which economically affected municipalities and
10 nonprofit organizations may apply for and be eligible to receive grants to alleviate
11 impact caused by construction of a gas pipeline. The department shall give priority in
12 the allocation of grants to municipalities and organizations that are experiencing or
13 will experience the most direct or severe impact from gas pipeline construction. The
14 department shall finance, under (e) of this section, all meritorious grant applications
15 each year, to the extent money is available in the Alaska natural gas pipeline
16 construction impact fund. Within 10 days after the convening of each regular session
17 of the legislature, the department shall submit to the legislature a list of all
18 municipalities and organizations that have received grants, a list of all municipalities
19 and organizations determined by the department to be eligible for further grants, a
20 recommendation of the amount of money to be granted for those additional
21 applications, and written justification of each past and potential grant.

22 (e) The commissioner of commerce, community, and economic development,
23 in consultation with the relevant municipal advisory group established under
24 AS 43.82.510, shall use money appropriated to the Alaska natural gas pipeline
25 construction impact fund to make grants to municipalities, and to nonprofit
26 organizations serving the unorganized borough, for impacts on transportation,
27 infrastructure, law enforcement, emergency services, health and human services,
28 education, the labor force, population, wages, and subsistence and for socio-cultural
29 impacts, brought about by the construction of the gas pipeline. In determining whether
30 an expenditure or proposed expenditure by a municipality or nonprofit organization is
31 eligible for a grant under this subsection and in allocating available money among

1 grant proposals, the commissioner shall consider the recommendations of the relevant
2 municipal advisory group established under AS 43.82.510 and whether the proposed
3 expenditure meets the purposes of this section.

4 (f) Before making awards of grants under this section for a fiscal year, the
5 commissioner of commerce, community, and economic development shall provide
6 reasonable public notice of all grant applications received, the recommendations of the
7 relevant municipal advisory group, preliminary determinations made concerning the
8 eligibility of each municipality or organization for a grant, the eligibility of each
9 expenditure or proposed expenditure for a grant, and the proposed allocation of
10 available money among grant proposals. The public notice must specify a time and
11 place for a public hearing during which the commissioner will receive comments
12 concerning the preliminary determinations and allocations of the department. The
13 commissioner shall give reasonable public notice of the final awards of grants made
14 under this section. Thirty days after such public notice is given, final awards take
15 effect and may be paid to the grantees according to procedures established by
16 regulation.

17 (g) Grant money received under this section may not be used for the
18 retirement of municipal debt.

19 (h) Amounts appropriated to the Alaska natural gas pipeline construction
20 impact fund under (c) of this section for a fiscal year that are not used for grants to
21 municipalities and organizations under (d) and (e) of this section shall be retained in
22 the Alaska natural gas pipeline construction impact fund and remain available for
23 distribution as grants under this section in succeeding fiscal years.

24 (i) Nothing in this chapter exempts money deposited into the special account
25 in the general fund established in (b) of this section from the requirements of AS 37.07
26 (Executive Budget Act) or dedicates that money, or money appropriated to the Alaska
27 natural gas pipeline construction impact fund, for a specific purpose.

28 (j) In this section, "direct or severe impact" means a clearly demonstrable
29 effect on a community that proximately contributes to a material change to
30 transportation, infrastructure, law enforcement, emergency services, health and human
31 services, education, the labor force, population, wages, subsistence, or for socio-

1 cultural impacts brought about by the construction of a gas pipeline.

2 * Sec. 17. AS 43.82.510(c) is amended to read:

3 (c) Each municipal advisory group serves until the later of 90 days after
4 final distribution of impact payment money under AS 43.82.505, or
5 commencement of operations of the qualified project. Expenses of a municipal
6 advisory group are eligible for reimbursement under a grant made under
7 AS 43.82.505 [A FINAL ACTION IS TAKEN ON THE APPLICATION FOR
8 WHICH THE GROUP WAS APPOINTED].

9 * Sec. 18. AS 43.82 is amended by adding a new section to article 7 to read:

10 **Sec. 43.82.650. Calculations of education funding.** To determine the amount
11 of required local contribution under AS 14.17.410(b)(2) and (c) for a school district in
12 a revenue-affected municipality, and to perform its duties under AS 14.17.510, the
13 Department of Commerce, Community, and Economic Development shall adopt
14 regulations. The regulations must establish assessment standards for any property that
15 would have been assessed under AS 43.56 but is instead generating a payment to a
16 revenue-affected municipality in lieu of a municipal property tax as provided in a
17 contract developed under this chapter. The regulations must ensure that the property is
18 included in the full and true value of the city or borough school district for the purpose
19 of determining required local contributions for education funding under
20 AS 14.17.410(b)(2) and (c).

21 * Sec. 19. AS 43.82.900 is amended by adding a new paragraph to read:

22 (14) "related party" means an entity, including a limited liability
23 company or similar incorporated or unincorporated entity, that

24 (A) is affiliated with a qualified sponsor or qualified sponsor
25 group;

26 (B) owns or operates a qualified project or any segment of a
27 qualified project; and

28 (C) is an intended beneficiary of the fiscal terms included in a
29 contract developed under this chapter.

30 * Sec. 20. AS 43.82.445 is repealed.

31 * Sec. 21. The uncodified law of the State of Alaska is amended by adding a new section to

1 read:

2 REVISOR'S INSTRUCTION. The revisor of statutes is instructed to change the
3 section heading of AS 43.82.220 from "Contract terms relating to royalty" to "Contract terms
4 relating to oil and gas lease, royalty provisions, and other agreements."

5 * Sec. 22. The uncodified law of the State of Alaska is amended by adding a new section to
6 read:

7 RETROACTIVITY. (a) Sections 2 - 14 and 17 - 20 of this Act are retroactive to
8 January 1, 2004.

9 (b) Section 1 of this Act is retroactive to January 1, 2005.

10 * Sec. 23. This Act takes effect immediately under AS 01.10.070(c).

DIRECT (832) 636-8808 • MAIN (832) 636-1000 • FAX (832) 636-8234 • E-MAIL bob_daniels@anadarko.com
ANADARKO PETROLEUM CORPORATION

1201 LAKE ROBBINS DRIVE • THE WOODLANDS, TX 77380
P.O. BOX 1330 • HOUSTON, TEXAS 77251-1330



ROBERT P. DANIELS
SENIOR VICE PRESIDENT
EXPLORATION AND PRODUCTION

July 24, 2006

The Honorable Frank Murkowski
Governor, State of Alaska
State Capitol
Juneau, AK 99801

Dear Governor Murkowski:

We would like to begin our comments on the draft gas line contract by thanking you for your longstanding and strong personal support for oil and gas explorers in Alaska, both as a U.S. Senator and as Governor. Your leadership as Senator resulted in FERC's expanded authority to help ensure fair access on reasonable terms to any gas line built out of Alaska. As Governor you have helped encourage new investment through exploration incentives, reduced and expedited permitting, extended tundra travel seasons and other improvements.

One of Anadarko's top Alaska priorities is to have a gas line built as soon as possible, which will stimulate new gas exploration and improve oil exploration economics. As you are keenly aware, another priority regarding the gas line continues to be fair access to the line with reasonable and equitable terms and conditions.

We appreciate your efforts to move a project forward, and we appreciate this opportunity to provide you with input and suggested changes that we believe will improve the contract and encourage a new wave of gas exploration in Alaska. Thank you again for all of your support for explorers, and we look forward to continuing our productive relationship with you and your administration.

Please do not hesitate to contact us if you or members of your administration have questions about our comments or would like additional information.

Sincerely,

A handwritten signature in dark ink, appearing to read "Robert P. Daniels".

Robert P. Daniels

Cc: Commissioner Bill Corbus, Department of Revenue
Commissioner Mike Menge, Department of Natural Resources

**COMMENTS OF
ANADARKO PETROLEUM CORPORATION
ON
DRAFT ALASKA STRANDED GAS FISCAL
CONTRACT**

Dated: July 24, 2006

**ANADARKO PETROLEUM
CORPORATION**

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**COMMENTS OF
ANADARKO PETROLEUM CORPORATION
ON
DRAFT ALASKA STRANDED GAS FISCAL CONTRACT**

On May 10, 2006, the Draft Stranded Gas Fiscal Contract ("Contract") between the State of Alaska and BP Exploration (Alaska) Inc., ConocoPhillips Alaska, Inc. and ExxonMobil Alaska Production Inc. (the "Project Sponsors") was released for public comment. In accordance with the established schedule, Anadarko Petroleum Corporation ("Anadarko") hereby submits these comments.

INTRODUCTION

Anadarko believes that constructing the Alaska natural gas pipeline as soon as possible is critical to the State of Alaska and to explorers looking to develop Alaska's undiscovered natural gas resources. A pipeline will facilitate the production of existing reserves and the exploration of gas prone acreage, resulting in new capital investment and jobs, natural gas for Alaskan communities, and significant revenue for the State.

But it is not the mere existence of a pipeline that will encourage exploration. The pipeline must be properly designed and operated to ensure access for explorers and ease of expansion – two of Governor Murkowski's "guiding principles" for the development of the Alaska pipeline. And, if access for future explorers and expansions to accommodate future natural gas discoveries are to be meaningful, they must be timely, sufficient in quantity, and reasonable in price. Capacity which is not available when needed, or which is only available in insufficient quantities or at excessive prices, does little to encourage companies like Anadarko to invest hundreds of millions of dollars in Alaska natural gas development programs.

SPECIFIC CONCERNS

A. The Contract Could Inhibit Access By Allowing A Premature Open Season

The owners of any proposed pipeline project determine when to hold an open season for purposes of allocating capacity in the project, and in this respect, the Alaska pipeline will be no different.¹ Deciding when to hold that open season is one of the most important decisions the owners can make.

Generally speaking, if the pipeline holds its open season before explorers in a production region have identified their reserves, the pipeline will either be undersubscribed or undersized. An undersubscribed pipeline will not be built. An undersized pipeline will face significant competition from future pipeline developers for newly-discovered reserves unless the pipeline has been designed for easy expansion. Therefore, in the lower 48, the risk of future competition from other pipeline developers usually ensures that a pipeline will not be undersized, that it will be designed with expansion in mind, and that it will be expanded any time there are sufficient developed reserves to justify the expansion.

Here, with the Alaska pipeline being developed by the producers who own the discovered reserves and are competitors of explorers who looking for undiscovered reserves, the point in time when the open season is held takes on added significance. With the Alaska pipeline, 35 Tcf of reserves have already been discovered and are owned by the pipeline's project developers. Therefore, the pipeline can be built to accommodate *only* the project developers' reserves, at deliverability levels that are determined by the

¹ 18 C.F.R. § 157.38 (2006).

pipeline developers. Therefore, even if there are expectations that reserves available to the pipeline by the in-service date would justify a 4 or 5 Bcf/d pipeline, the project sponsors might decide to build a 3 Bcf/d pipeline. The pipeline would not be undersubscribed, but it would be undersized.

Unlike a lower 48 pipeline project developer that faces potential competition from other pipelines, the Alaska pipeline project developers do not face that risk. Undersizing the Alaska pipeline to exclude competition from explorers does not create competitive risk for the pipeline. The availability of the open season process required by the Alaska Natural Gas Pipeline Act and the regulations promulgated by the Federal Energy Regulatory Commission does not ensure access to the pipeline if the open season is held too early, before it is necessary for project development. A premature open season will ensure that only the project developers can bid for capacity on the pipeline. For this reason, the Contract should allow the State – whose interests on this issue are aligned with explorers – to have the power to veto the holding of a premature binding open season.

As written, the Contract seems to accept that the pipeline's initial capacity will be committed exclusively to its owners. The Preliminary Fiscal Interest Findings ("FIF") speaks in terms of the initial capacity of the pipeline being allocated proportionately to the pipeline's owners – 20% to a state-owned entity and 80% to entities created by the Producers. (FIF-ES-14). This, of course, is the likely outcome of a premature open season, but is not the likely outcome of an open season held at a time that will both facilitate timely project development and access by explorers. The primary concern of explorers like Anadarko is that the decision as to *when* to hold the open season will be

driven by the interests of the Project Sponsors as producers, rather than the interests of the Project Sponsors as pipeline project developers. Because the outcome of the initial open season will serve as a basis for the project's design capacity, it should be held no sooner than necessary to advance the project. Project Summaries that are currently available indicate that the initial open season will be held within 2 years of the Effective Date of the Contract. If the Contract is executed this fall, an open season could be held before year-end 2008, which seems to be premature.

**A.1. AOGCC Authorizations For Prudhoe Bay/Point Thomson Gas Offtake
Should Be Required Before An Open Season Can Be Held**

In December of 2004, the Alaska Oil and Gas Conservation Commission ("AOGCC") advised FERC that AOGCC approval of reservoir offtake (depletion plans), in excess of current limits, will be required before hydrocarbons may be taken from Prudhoe Bay and Point Thomson. The purpose of the AOGCC review is to avoid premature gas withdrawal resulting in waste of liquid hydrocarbons. The AOGCC informed FERC that preliminary reservoir study results it received in 2002 from the Prudhoe Bay Producers indicated that significant liquid hydrocarbons (up to several hundred million barrels) could be lost if the pipeline project is initiated prematurely. AOGCC further informed FERC that it did not have sufficient information to make informed conservation decisions with respect to major gas sales that may occur in the future and, for it to perform an analysis of that magnitude would require up to three years following the filing of applications by the Producers.²

² Letter from John K. Norman, Chairman, Alaska Oil and Gas Conservation Commission, and Dan Seamount, Commissioner, Alaska Oil and Gas Conservation Commission, to Commissioners, Federal Energy Regulatory Commission, Dec. 16, 2004.

The FIF recognizes the need for AOGCC off-take authorizations for both Prudhoe Bay and Point Thomson and the Contract requires the Point Thomson producers to apply to the AOGCC for the issuance of pool rules to authorize the rate of gas extraction within six months of the effective date of the Contract. (FIF-ES-12). At the present time, the, Prudhoe Bay gas offtake is limited to 2.7 Bcf/d and offtake authorizations for Point Thomson have yet to be issued. If new offtake authorizations are to be sought for Prudhoe Bay, AOGCC will have to review the new proposed plan and issue new authorizations. (FIF-15).

To the best of Anadarko's knowledge, applications have yet to be filed with the AOGCC by the Prudhoe Bay or Point Thomson unit holders. Accordingly, there can be no meaningful open season and commitment of volumes to the pipeline until the AOGCC rules on the allowable gas off-take from those units, unless, of course, the pipeline is to be sized to accommodate only the currently authorized 2.7 Bcf/d from Prudhoe Bay and the Contract-required 0.5 Bcf/d from Point Thomson for a total initial capacity of 3.2 Bcf/d.

A. 2. Front End Engineering Design (FEED) Must Be Completed Before An Open Season Can Be Held

Under regulations promulgated by FERC,³ the Notice of the Open Season must include, among other things, the following information:

- The general route, including receipt and delivery points
- Alternate routes under consideration
- Size and design capacity
- Capacity at delivery points
- Designs for expansions

³ *Regulations Governing the Conduct of Open Seasons for Alaska Natural Gas Transportation Projects*, Order No. 2005, 110 FERC ¶ 61,095; Order No. 2005-A, 111 FERC ¶ 1,332 (2005).

- Estimated dates for consideration of expansion
- Maximum allowable operating pressure
- Expected actual operating pressure
- Pressure at all delivery points
- Projected in-service date
- Estimated unbundled transportation rate for each delivery point for each service offered including reservation rates, usage rates, fuel retention percentages, and any other charges
- Estimated cost of service including cost of facilities, depreciation, rate of return and capitalization, taxes, operating and maintenance expenses, cost allocation, rate design volumes, and rate design
- Estimated transportation rate for in-state deliveries, based upon the completed study of in-state needs
- Negotiated rate and other rate options
- Quality specifications

Based upon the May 10, 2006 Project Summary, Front End Engineering Design (FEED) is the "Preliminary Engineering" that must be undertaken in order to develop project definition and analyze project economics. The FIF acknowledges that this "Preliminary Engineering" is a necessary prerequisite to the holding of a meaningful open season that will lead to the execution of binding precedent agreements: "As FEED is completed, the next major step may be the holding of the open season for the project." (FIF-230). Indeed, it is difficult to see how the pipeline could provide prospective shippers with the kind of information required by the Notice and expect prospective shippers to submit binding, non-contingent bids until it has at least completed the Preliminary Engineering for the project.

The most recent Project Summary shows that this Preliminary Engineering, an essential pre-requisite to the holding of a binding open season, is not expected to be

completed until some time between 2009 and 2011. If that is the case, holding a binding open season in 2008 would be premature.

A. 3. A Premature Open Season Will Restrict Access To The Pipeline

For the Alaska pipeline, Congress directed, and the FERC requires, that any open season be conducted in a manner that encourages competition in the exploration, development, and production of Alaska natural gas. The ability to obtain pipeline capacity is essential to the achievement of this objective. Holding the open season at a time when no one other than the pipeline's owners can bid precludes competition for project capacity and inhibits competition in the exploration, development, and production of Alaska natural gas.

Anadarko is currently planning to drill its first natural gas exploration wells in the Foothills Region of Alaska's North Slope this winter. Therefore, the earliest Anadarko is likely to be positioned to bid on capacity for gas from the Foothills is in 2009 or 2010. Yet, despite the fact that "the state and the producers will not be in a position to make a decision to proceed with construction of the project until four or five years after the effective date of the contract" (FIF-115), the Project Sponsors have indicated that the open season will be held in 2008, at a time when it is not likely that Anadarko, or any other explorer, will be positioned to bid on the pipeline's initial capacity.

An independent pipeline company is neutral as to which entities secure capacity on the line and is normally eager to expand to accommodate additional demand for capacity. Anadarko is concerned that the Project Sponsors' economic interest as *producers* will outweigh the economic interest they may have as *pipeline owners*. It is, therefore, critically important that the State, as the pipeline owner whose interests are

most likely aligned with explorers, have the ability to ensure that a binding open season is not held before it is necessary for project advancement.

Suggested Changes

- Provide the State with the authority to veto the premature holding of a binding open season for the initial capacity.
- Require that the Project Sponsors provide the State with information to make determinations regarding when to hold the open season.
- Prohibit a binding open season for the initial capacity of the pipeline from being held prior to the later of (1) the AOGCC setting offtake rates from Prudhoe Bay and Point Thomson; or (2) the date on which the pipeline has completed its Preliminary Engineering/FEED.

B. The Contract Should Reflect The Design of The Project Described In The Application And The Preliminary Findings And Determination

A pipeline designed with adequate initial capacity and expansion capability is crucial in encouraging the gas exploration in Alaska by new market entrants.⁴ The Application filed by the Project Sponsors in their efforts to obtain the Contract represented that the design reflected an *expandable pipeline that accommodates the State's objectives of promoting exploration in Alaska*. That pipeline was described in relatively clear detail, being the result of a 2-year, \$125 million study, and encompasses:

1. A design capacity of approximately 4 Bcf/d (Application at 4,6, 7, 8,16);
2. 52-inch pipe operating at approximately 2500 psi (Application at 7);
3. Compressor stations located at regular intervals (Application at 7);
4. Ability to accommodate new discoveries during the initial open season (Application at 15, A-1-3);
5. Ability to accommodate new discoveries through expansions (Application at 15, A-3);
6. Ability to increase capacity by 1 Bcf/d through infill compression (Application at A-3); and

⁴ "Exploration and development opportunities for new market entrants are critical for the State's future." (FIF-248).

7. Ability to increase capacity by looping all or portions of the line
(Application at A-3).

Yet, the Contract contains none of this detail. The State seems to assume that this is the pipeline that will be built. However, the Project Sponsors' willingness to adhere to this pipeline design, or to any design or expansion which may be necessary to accommodate the needs of explorers, has become increasingly unclear.

Most recently, the Project Sponsors have advised the Senate in hearings being conducted on the Contract that there is no commitment to construct a pipeline, much less a pipeline of any particular design. In addition, the Project Sponsors have sought judicial review in the United States Court of Appeals for the District of Columbia Circuit of FERC's Order Nos. 2005 and 2005-A, challenging the FERC's statutory authority to require design changes in the initial pipeline or any proposed expansion. Reading this in the light of the Application's statements that "details" of the pipeline project are likely to change, and that the feasibility of any expansion will have to be evaluated at the time the expansion is considered elevates Anadarko's concern that the pipeline that is ultimately designed by the Project Sponsors will not be the pipeline described in the Application on which the Contract is premised.

It seems clear that the State relied heavily on the project description reflected in the Application as a key reason to negotiate with the North Slope Producers rather than other potential project sponsors. The Preliminary Fiscal Interest Finding ("FIF") describes the pipeline project as including, as a critical component, the expandability of the base design, with the base design consisting of a 52-inch pipeline, an operating pressure of 2500 psi, and an initial capacity of between 4Bcf/d and 4.5Bcf/d, expandable

through compression to 6 Bcf/d. (FIF-100). The importance of the initial size of the pipeline being as represented in the Application and its ease of expansion is clear:

"Building a 52-inch line is riskier and more expensive than building a smaller line, and for this reason the pipeline companies that state officials talked to said that they would build a smaller-diameter line. Not so the sponsor group. They were willing to take this 52-inch risk in order to take maximum advantage of the economies of scale associated with gas pipelines. This large-diameter pipeline not only allows a large volume of gas to be transmitted through the line while limiting fuel loss, it also allows for a relatively inexpensive and attractive large increment of expansion. In fact, the average capital cost per unit decreases for an almost 50 percent expansion of the line. This decreasing cost function means that expansions not only will be in the pipeline entity's best interest (through more tariff revenue), but will also benefit existing shippers as well as expansion shippers through lower per-unit tariffs. Apart from the FERC access regulations, or the SGDA contract provisions, the 52-inch decision is a concrete way of telling explorers that if the gas is there, the pipe capacity will be there to take it to market."

(FIF-100-101, footnotes omitted).

The Contract, however, contains no specificity at all regarding the initial design or its expandability. It does not require that the Project Sponsors build a 52-inch pipeline, that the pipeline be designed to operate at 2500 psi, that the pipeline have daily deliverability of between 4 and 4.5 Bcf/d, or that the pipeline be designed for easy expansion to 6 Bcf/d through relatively inexpensive infill compression. Anadarko submits that the Contract should require adherence to the project design upon which the Administration committed to negotiate with the Project Sponsors.

Suggested Change:

- Include an Appendix to the Contract specifying the project design for the "Qualified Project" as a pipeline capable of transporting between 4

and 4.5 Bcf/d; initially expandable through infill compression to 6 Bcf/d.

C. The Contract Inhibits Access To The Initial Capacity By Non-Owner Shippers Through The Capacity Acquisition Provisions of Article 10

The Open Season that is required by federal law is intended to give all qualified shippers the opportunity to bid on capacity on the pipeline in the initial open season and in any expansion open season. Bids, almost certainly, will be valued on an NPV basis taking into account the contract term, the contract volume, and the price to be paid by the shipper for transportation service. This valuation process becomes important if a non-owner shipper bids on the capacity at a volume level that is equal to the volume level bid by one of the owner shippers. In that case, an owner-shipper could be outbid by a higher bid price for the same term contract.

To protect against a scenario where an owner-shipper can always outbid a non-owner shipper, the Contract should clearly preclude the Producers from bidding the State's volumes in a single capacity bid. Otherwise, the State's volume will inflate the Producer's bid volume for purposes of the NPV calculation and will also ensure, all other things being equal, that no owner-shipper can be outbid by a non-owner shipper. In fact, even if the Producer/State bid were priced lower than a non-owner shipper bid, it might still prevail due solely to the volume inflation. While the State's purpose in negotiating this provision was, presumably, to ensure that it is not charged more to transport its royalty gas than the pipeline charges for the transportation of the producer's production from the same lease, the structure of this provision is unfair to non-owner shippers.

Suggested Change

- Replace the option for the State to elect to have its capacity bid by the Producer Capacity Holder with a most favored nations clause that ensures

that the State is not charged more to ship its volumes than the pipeline charges the producer from whose leases the State's royalty derives.

- To the extent that the State is concerned with having different "terms and conditions" of service from those granted to the Producer/Shippers, include a provision to the effect that "all terms and conditions of service shall be set out in the FERC tariff." This is current FERC policy and should ensure that the affiliates of the owner-shippers do not receive preferential treatment over any shipper not affiliated with the pipeline.

D. The Contract Inhibits Access To Initial And Expansion Capacity Through Article 10's Capacity Management Program

Article 10 requires the Producers to accommodate any additional capacity needs of the State. This is to be accomplished by releasing a portion of the producer's capacity to the State, acquiring additional capacity for the State in the producer's name and then releasing that capacity to the State, or acquiring additional capacity with the State's proportional interest being acquired "on behalf of" the State, in the State's name, and the balance in the name of the producer. Alternatively, the producer may purchase the excess State gas at the AECO price less the Alaska to Alberta Tariff, or, simply reduce the amount of delivered gas, overall.

Article 10 also requires the State to acquiesce in the Producer's control over the management of any of the State's excess capacity. If the producer itself has excess capacity and seeks to purchase additional gas or release capacity to offset that excess capacity, then, it must give the State the opportunity to participate in the transaction to offset any excess capacity the State may hold. These transactions, and the related required reciprocal "Put" arrangements, are the *sole means* for the owner-shippers to manage their excess capacity. The terms under which they take place are subject to a Confidentiality requirement and are not subject to dispute by the State, except in the case of fraud; nor may they be challenged in any administrative proceeding or court of law.

Article 10 is complex but appears to be structured to ensure that as between the producers and the State, State capacity will be managed under these mechanisms before any capacity can otherwise be made available to or purchased from third parties. Not only does this provision restrict the ability of non-owner shippers to gain access to excess capacity from owner-shippers but, because every capacity release or capacity acquisition arrangement necessarily involves the State, all capacity release and capacity acquisition arrangements on the pipeline will take place behind the screen of this confidential "managed access" program. There will be no transparency due to the confidentiality requirement, there will be no bidding for capacity under FERC's capacity release rules, and disputes are to be handled outside of the purview of FERC, even in the case of suspected fraud. In short, Article 10 attempts to remove the trading of interstate pipeline capacity on the Alaska pipeline from FERC's jurisdiction and have it governed, instead, by private contract.

The State's Preliminary Fiscal Interest Finding describes the Capacity Management provisions as necessary to ensure that the State's gas can always be transported, and to mitigate the risk associated with making a long-term commitment for firm capacity. But if the State is to commit to take its gas in kind and, therefore, to purchase firm transportation capacity on the Alaska Pipeline in its own name, it cannot, by private contract, grant itself preferential terms and conditions to eliminate the business risks faced by all other shippers in committing to long-term firm capacity on the pipeline. Current FERC rules for transferring capacity on interstate pipelines do not allow the structure envisioned by Article 10.

In fact, Article 10 does not even appear to be in the best interest of the State. For, to receive these "advantages" the State must agree that all of the information involved in the transactions is confidential, that it will not challenge any producer decision on how to structure these capacity transactions, that it will not purchase or release capacity other than under the terms of the Contract, that it will not purchase or sell gas on the ANS from anyone other than through the producers, and that it will not allocate in-state capacity other than proportionately to the producers' interests in the relevant leaseholds.

Moreover, the State must agree that in the event that a producer breaches its obligations under this Article, the State's sole remedy is specific performance. The State must also indemnify, hold harmless, and defend each Producer Capacity Holder against any Loss arising out of the Producer's performance of its obligations under this Article. The term "Loss," as used here, includes any fine, fee, penalty, or other charge, settlement, and litigation expense incurred should the Producer Capacity Holder be found to have violated federal law in engaging in these activities.

Suggested Change

- Eliminate the capacity management program. Instead, the State should bid on its own capacity, and, to the extent that it is concerned that it will be disadvantaged vis-à-vis the producers which own the leases from which its royalty gas derives, it can insist on a most favored nations clause with respect to that particular producer's bid. Other than that, it should be required to abide by the Commission's rules on capacity release. It should not enter into any agreement that restricts its ability to sell gas, buy gas, sell capacity, or purchase capacity from any other shipper.

E. The Contract's Restrictions On Access For Non-Owner Shippers Will Be Exacerbated If The ROFR Provisions Discussed In The FIF Are Included In The Precedent Agreements For The Initial Capacity

According to the FIF, it is contemplated that the initial contracting parties, which, more likely than not will be the affiliates of the owners, may be granted rollover rights as

to their existing capacity and rights of first refusal to any expansion capacity in the initial open season. (FIF-115-116). If this is allowed, the owner-shippers will have *guaranteed* access over any explorer, not only for their existing reserves but also for any new reserves they may discover. Non-owner shippers, on the other hand, will be even more skeptical of their ability to obtain capacity in either the initial open season or any expansion open season if these rights are granted. The obvious purpose of granting such right is to lock up capacity for the life of the project for the project owners, should they desire to keep it. This will severely undercut the ability of Anadarko and other explorers to compete with the North Slope Producers in Alaska.

The FIF makes much of the fact that additional reserves will have to be found in order to keep the pipeline full for its expected 35-year regulatory depreciable life. (FIF-97, 115). But, if the Precedent Agreements grant rights of first refusal to the initial shippers for expansion capacity, no explorer will have assurance that it will be able to obtain capacity in a future open season, even if it submits a qualifying bid. FERC does not allow pipelines to grant shippers rights of first refusal over expansion capacity. And, while FERC may ultimately determine the terms and conditions of any open season, and is expected to preclude rights of first refusal to expansion capacity, the State should not support this provision; in fact, the State should affirmatively oppose any effort by the Project Sponsors to grant preferential capacity rights to expansion capacity in the initial open season.

Finally, any such provision will make it even less likely that the pipeline will accommodate requests for voluntary expansion. This is because with rollovers and rights of first refusal, the owner-shippers will be positioned to capture all of the initial capacity

and all of the first expansion capacity, leaving only expensive expansions for the non-owner shippers.

Suggested Change

- Specifically provide that the pipeline may not grant rights of first refusal for expansion capacity on the Alaska pipeline in the initial open season.

F. The "State-Initiated" Expansions Provisions Adversely Impact Non-Owner Shippers' Access To Expansion Capacity And Diminish The Progress Made At FERC

In its comments to FERC regarding the open season regulations, the State stressed the importance that the Alaska pipeline be built to realize the full potential of Alaska's natural gas resources. The State also emphasized the need for reasonable certainty to explorers that they will have access to the pipeline "when they successfully discover new gas supplies." (Comments of the State of Alaska at 10). Acknowledging that "more competition in exploration and development should lead to the discovery and exploitation of more gas reserves," and noting that the Prudhoe Bay and Point Thomson units represent but a fraction of the total possible gas supplies from Alaska, the State pressed the FERC hard for rules that would ensure the adequate initial sizing and expandability of the pipeline. As the State explained to FERC:

"North Slope and arctic offshore conventionally recoverable gas potential exceeds 225 Tcf. In addition, North Slope gas hydrate potential in the Prudhoe Bay/Kuparuk River/Milne Point area alone exceeds 100Tcf. Further, Alaska's Interior basins are for the most part unexplored, but some data indicates that they also have significant gas resource potential. The pipeline will pass very near some of those basins, and in order to motivate explorers to drill for and develop at least some of the yet to be discovered gas sooner rather than much later, the pipeline likely will have to be expanded in its early life. Explorers will not explore today if the pipeline is undersized or cannot be expanded early and easily, or both. It is simply unacceptable to explorers to have to wait for the decline in gas production at Prudhoe Bay and Point Thomson in order to monetize their gas; as Alaska's Commissioner of Natural

Resources testified, that decline in pipeline throughput may not occur until some 15 years after startup of the flow of gas."

(Comments of the State of Alaska at 11).

In its comments, the State asked FERC to require that the pipeline, in its open season, include information showing the "feasibility and estimated cost of pipeline expansions, either through compression or looping, including any physical limitations." (Comments of the State of Alaska at 13). FERC's regulations, as adopted, only require that the pipeline include in its open season package a description of possible designs for expansions of the pipeline together with an estimated date as to when an expansion would be considered.

In the Contract, the State has the opportunity to require that the project sponsors voluntarily provide to the FERC and to all prospective shippers, information showing the feasibility and cost of expansions, whether compression or looping. It also has the opportunity to require that the Project Sponsors hold periodic open seasons to test the market for an expansion and file for an expansion when economically and technologically feasible. In this way, the State can ensure that the pipeline will be expanded to meet the needs of explorers anytime there was market support for an expansion.

In the Legislative hearings on the Contract, the Administration expressed the view that the provisions of Article 8.7 - "State-Initiated Expansion" - were intended to provide a third avenue for pursuing an expansion of the pipeline. Although well-intentioned, Article 8.7 can actually hurt explorers in their efforts to obtain expansions of the pipeline. Of particular concern to Anadarko is the view that Article 8.7 somehow follows what Congress did in Section 105 of ANGPA - the mandatory expansion provision.

Moreover, because of its onerous requirements, its lack of certainty, and its limited availability, it is unclear how, or when the process would be used to assist explorers in obtaining capacity.

First, from a shipper's perspective, the terms and conditions of Article 8.7 are far more onerous than those required under ANGPA for a mandatory expansion. For example, instead of requiring that the rates to the existing shippers not subsidize expansion shippers, Article 8.7(a)(iv)(B) requires that the rates to the existing shippers must not be *increased*. In addition, it provides that fuel retention percentages may not be increased, referring to both increases as subsidies of expansion shippers by existing shippers.

In Order Nos. 2005 and 2005-A, FERC made it clear that whether or not an increase in rates to existing shippers due to an expansion constitutes a "subsidy" is a factual matter for the FERC to decide in the context of a particular Section 105 proceeding. This Article purports to define a "subsidy" and suggests that the Administration has already taken the position that any increase in the rate to exiting shippers, and any increase in the fuel percentages paid by existing shippers will constitute a "subsidy." Additionally, Article 8.7(a)(iii), requires that all contracts resulting from the open season be "negotiated rate" agreements. FERC regulations and policies do not allow any pipeline to require a shipper to enter into a negotiated rate agreement as a condition to receiving any service on a pipeline – even expansion service. *Natural Gas Pipeline Company of America*, 101 FERC ¶61,125 (2002).

Second, there is a lack of certainty in the process, even if a shipper were willing to choose this route. Any Article 8.7 expansion will require a FERC certificate. Yet, under

the Contract, "If FERC issues a certificate on a basis different than the expansion proposal filed by the Project Entity, then the *Project Entity shall reject the certificate* unless any such difference is minor or all the members of the *Project Entity* vote otherwise." (Contract, § 8.7(a)(iv)(H), emphasis added). Even the initiation of the process is subject to being disputed and the entire process is put on hold until the dispute is resolved through the arbitration provisions of the Contract.

Third, the state-initiated expansion is only available *after* service has commenced on the pipeline, and may only occur once every five years. This is unduly restrictive as the first expansion may be required *before* the in-service date and subsequent expansions may well be required earlier than five years after the first expansion, depending on the success of explorers' drilling programs.

Finally, the mere "availability" of this process could be used by FERC to delay action on a Section 105 request for mandatory expansion. The fewer impediments standing in the way of a final FERC decision on a mandatory expansion, the better off the explorer is.

For all of these reasons, Article 8.7 is not only unnecessary but detrimental to the interests of explorers in their efforts to obtain expansions of the pipeline. And, it undercuts the progress that the State and explorers have already made at FERC.

In Anadarko's view, a better way to assist explorers is for the Contract to require that open seasons be held periodically, or for the Contract to allow the State to require that the pipeline hold an open season at any time. This will provide the State with a real opportunity to ensure that expansions are timely pursued by the pipeline. Explorers need the State as an active ally in their efforts to gain access to capacity on this pipeline. The

State should not allow its ownership interest in the pipeline to compromise its role as an advocate for the development of competition in the exploration, development, and production of Alaska natural gas resources.

Suggested Changes

- Eliminate Article 8.7.
- Include a provision that allows the State, as an owner of the pipeline to propose expansions and/or hold a non-binding open seasons at any time.
- Include a provision to require the pipeline to hold periodic open seasons to assess the market's interest in an expansion.
- Include a provision that requires the pipeline to hold a binding open season, consistent with FERC regulations, if the results of any non-binding open season demonstrate a requisite level of interest.
- Include a provision that requires the pipeline to file a voluntary expansion in cases where the outcome of the binding open season is sufficient to support the expansion.
- Include a provision that requires the pipeline to include in its tariff a provision articulating the criteria it will use to in determining whether or not to voluntarily expand the pipeline. This will provide the opportunity for protest, comment, and advance determination by FERC as to whether the parameters satisfy regulatory requirements.

G. The Contract Should Not Eliminate Regulatory Protections for Shippers and Consumers

The Alaska pipeline and the facilities encompassing the Project will all be part of a natural monopoly that must be regulated, either at the federal or state level. For, absent effective regulation there is nothing to prevent the exercise of monopoly power through unreasonable access terms, conditions and rates to the detriment of shippers.

Articles 8.1, 8.2, and 8.3 of the Contract provide that the contracting parties (including the State) intend that access to and regulation of all of the Project facilities will be governed exclusively by federal law; and, to the extent that federal law does not apply, or if federal regulators elect not to regulate, then access and regulation of the relevant

facilities will be governed exclusively by commercial agreements. (Article 8.1) This Article also bars the Parties from seeking any additional, different, or supplemental regulatory requirements for the regulation of or *access to* any of the Project facilities. (Article 8.1)

Article 8.2 requires the Parties to affirmatively seek and support the exclusivity of FERC's jurisdiction over the facilities and provides that if FERC does not assert jurisdiction over any Midstream Element within 15 months after submitting an application, then that entity may enter into commercial arrangements to govern and control rates, terms, and conditions of access.

Finally, Article 8.3 bars the State from seeking or supporting jurisdiction of the Regulatory Commission of Alaska ("RCA") over any of the Project facilities and provides that if the RCA exercises jurisdiction over any aspect of the project facilities in a manner that results in a "Loss" to any Participant, that the State will reimburse that Participant for its "Loss." This raises serious concerns for shippers not affiliated with the owners.

The State should not agree to preclude itself from seeking or supporting regulation over any Project entity by the RCA. In the event that FERC does not have jurisdiction over particular facilities, access to the main transmission line or to other essential facilities can be blocked by whatever vote of the project entity is required if the RCA does not have jurisdiction. This can leave non-owner shippers at the mercy of their competitors both in terms of obtaining access to the facilities and in terms of the rates, terms and conditions of service. If they are not regulated, there is nothing to stop the pipeline from denying access or extracting monopoly rents from shippers. Regulation of

and access to any of the Project facilities should be required, either at the federal or state level.

Second, there is no certainty that every aspect of this Project will, in fact, be subject to federal regulation. This is particularly true with respect to the Gas Transmission Pipelines and the GTP. Without a final court determination as to the extent of FERC's jurisdiction, the State cannot be certain that federal regulation will apply to each of these facilities. To ensure that there is no regulatory gap, the State should eliminate this provision so that it is not precluded from taking action it deems necessary to ensure access to or regulation of any part of the Project.

Finally, similar concerns exist with respect to the facilities to be located in Canada. The State should not agree that if existing regulatory law does not regulate all necessary aspects of this pipeline that terms and conditions for access will be controlled by private contract and that it will not seek any additional, different, or supplementary requirements for regulation of or access to these facilities.

Suggested Changes

- Remove Articles 8.1, 8.2 & 8.3, but still require that the Parties request FERC jurisdiction over all parts of the Alaska pipeline project.
- Ensure that RCA has jurisdiction over the rates, terms and conditions of service on any facilities that will not be regulated by FERC and which are a part of the Project. This will eliminate the ability of the monopoly pipeline to control access directly or indirectly by private contract and will ensure that monopoly rents are not extracted from shippers as a condition of such access.

H. The Uniform Upstream Fiscal Contract Should be Modified

In analyzing the Contract, the FIF states that the benefits of the Stranded Gas Fiscal Contract should be made available to "other North Slope leaseholders" and that the purpose of the Uniform Upstream Fiscal Contract is to "create a level playing field for

explorers and producers not affiliated with the project." (FIF-98). Anadarko agrees with the need for a level playing field and appreciates the State's effort to make equal benefits available to explorers.

One improvement to Section 43.82.437(d)(4)(ii) and (iii) would be to ensure that the sale of leasehold gas production to a capacity holder on the pipeline qualifies the leaseholder for the benefits of the Uniform Upstream Fiscal Contract.

Suggested Change

- Revise Sec. 43.82.437(d)(4)(ii) to read: "the execution of a letter of intent from the person, an affiliate of that person, or a prospective purchaser of gas from that person to make a firm commitment that a minimum volume of gas that is discovered or yet to be discovered from the oil and gas lease interests committed to the uniform upstream fiscal contract will be transported on the *Project* for a minimum term, as specified by the Commissioner of Revenue with the concurrence of the Commissioner of Natural Resources."
- Revise Sec. 43.82.437(d)(4)(iii) to read: "termination if the work commitment is not diligently performed or the commitment specified in Sec. 43.82.437(d)(4)(ii) is not maintained or kept."

I. The Contract Should Specify The Rate Treatment To Be Accorded To Previously Used Assets To Eliminate A Write Up Of The Asset For Ratemaking Purposes

Article 8.6 provides that each Participant shall follow FERC policy regarding the treatment of previously used assets for ratemaking purposes. Anadarko assumes that the State contemplated that these assets would be valued at their depreciated original cost for ratemaking purposes rather than at their acquisition price. However, that is not necessarily the outcome under current FERC policy. FERC allows a write up of assets to include the full purchase price if (1) the acquired facility is being put to new use, and (2) the purchase price is less than the cost of constructing a comparable facility.

Suggested Change

- Require that any previously used assets being acquired for use in the Project be valued at depreciate original cost for ratemaking purposes.

J. Absent Disclosure Of The Project Entity Agreements It Is Impossible To Fully Evaluate The Impact On The Value Of Having The State "At The Table"

Part of the justification for the State's participation as an owner is its ability to be a party "at the table" and its ability to influence decisions of the Project Entities. Given that the State's interest is only 20%, it is not likely that this will be a real benefit to the State or to non-Project Sponsors seeking access to the project facilities under reasonable and nondiscriminatory terms and conditions. There are likely restrictions on the State's ability to take positions that are contrary to those advocated by the Project Sponsors in various provisions of the Contract. Further restrictions may well exist under the Project Entity documents. Substantial concern exists that the State's ability to have any influence over the Project Sponsors will be severely restricted through these documents.

Suggested Change

- Make the Project Entity Agreements public so that the entire package can be reviewed, commented on, and fully evaluated before the Contract is approved by the Legislature.

CONCLUSION

Anadarko respectfully requests that, in reviewing the Contract for purposes of making the necessary Fiscal Interest Finding required by the Stranded Gas Development Act, that the Commissioner of Revenue adopt the Suggested Changes proposed in these Comments.

DATE: 072506

UPDATE #:

Y or N

[illegible]

**Excerpts of Attorney General's
Presentation to the Legislature at
Centennial Hall Regarding the
May 10, 2006 Attorney General's
Opinion on the
Authority to Provide Fiscal
Certainty Under Article IX,
Sections 1 And 4 Of The Alaska
Constitution**

THE QUESTION PRESENTED:

Whether sections 1 and 4 of article IX of Alaska's Constitution permit the state to enter into a long term fiscal contract under the Stranded Gas Development Act ("SGDA"), AS 43.82.010 et seq.?

Can states enter into binding fiscal contracts that cannot be modified by subsequent legislative enactments?

- The federal contract clause (Art. I, § 10) provides that no state shall pass any law impairing the obligation of contracts.
- In a series of cases, starting in the 1800s, the United States Supreme Court held that the contract clause applied to contracts in which state legislatures agreed to specific tax obligations.

- Although the Court found that there are certain inherent and essential elements of sovereignty – referred to as “reserved powers” – that can never be contracted away, the Court also held that the power of taxation is not a reserved power.
- Rather, the taxation power is “alienable” and can be bargained away for consideration because it is incidental to the exercise of governmental functions and exists to facilitate inherent and legitimate governmental functions.
- Any such alienation must be allowable under the state’s constitution and must be expressed in a clear and unequivocal manner, i.e. it must be unmistakable.
- A state can therefore be held to a contract despite subsequent state legislation that alters the fiscal terms in a manner that substantially impairs the contract and is not otherwise justified as reasonable and necessary to serve an important public purpose.

Sections 1 and 4 of Article IX of the Alaska Constitution read together provide the authority to enter into a fiscal contract that would be enforceable under the federal contract clause.

- Art. IX, § 1 provides: “The power of taxation shall never be surrendered. This power shall not be suspended or contracted away, *except as provided in this article.*”
- Art. IX, § 4 provides for specific exemptions from taxes – such as for properties owned by state and local governments and nonprofits – and also provides: “*Other exemptions of like or different kind may be granted by general law.*”

The history of §§ 1 and 4 shows that the Framers chose to give the Legislature the flexibility to provide for tax exemptions by general law to develop industries in Alaska.

- The Framers rejected stricter language.
- The Framers endorsed economic development incentives.
- The Framers were familiar with contemporaneous industrial incentive acts.

- The Framers specifically considered and rejected a Model Provision put forward by the National Municipal League that stated that “[t]he power of taxation shall never be surrendered, suspended or contracted away.”
- Instead, the Framers adopted the language in Art. IX, § 1 which states: “The power of taxation shall never be surrendered. This power shall not be suspended or contracted away, except as provided in this article.”
- The Model Provision arose from concerns that some states had restricted their power to tax businesses through approval of long term tax rates in corporate charters which were later upheld by the U.S. Supreme Court under the contracts clause.
- Consultants to the Framers noted that, without the Model Provision, Alaska could be bound by the types of fiscal contracts other states had authorized.
- Nonetheless, the Framers rejected the Model Provision in light of Alaska’s unique circumstances as a resource-rich but sparsely populated state without the local capital available to develop its resources.

What did the Framers mean in § 1 when they stated that the power of taxation “shall not be suspended or contracted away, *except as provided in this article*”?

- The Official Commentary about § 1 explained that “[t]he power to tax is never to be surrendered, but under terms that may be established by the legislature, it may be suspended or temporarily contracted away. This could include industrial incentives, for example.”
- The Convention history demonstrates that the Framers were referencing the tax exemption power provided in § 4 of Article IX, which states that “*Other exemptions of like or different kind may be granted by general law. ...*”
- The Official Commentary to § 4 explained that “the legislature is authorized to make further tax exemptions to encourage, among other purposes, new industry....”

- Delegate White stated: “And then in the last paragraph of that section [4] it provides that other exemptions may be provided by general law. This would allow for, *among other things*, for a granting of tax incentives to new industries.”
- Delegate Nerland stated “...this is the provision that allows for some exemption or inducement to industries or similar things.”

- Delegate Smith asked: “Isn’t that, in effect, saying that exemptions of any kind may be granted? Delegate Nerland responded: “Yes, that was the purpose of it.”
- Such archival history demonstrates that although the prohibition against surrendering taxation power may be absolute, the prohibition against suspending or contracting away taxing power is not absolute, but is qualified by the permissible exemption provision in § 4.

Consistent with the Framers' intent, the SGDA provides fiscal certainty for the length of the Project in order to realize the State's long term goal of an ANS gas line necessary to monetize our vast gas resources.

- The Finance and Taxation Committee expressly considered but chose not to include any time limit on tax exemptions provided for in § 4.

- If tax liability could constitutionally be entirely extinguished by granting an exemption for a particular industry, it follows that tax liability could also constitutionally be extinguished in favor of fixed payments in lieu of those taxes for a set term.
- In short, the proposed SGDA Contract is within the parameters established by the Framers in §§ 1 and 4 to use the State's tax structure to encourage development for the maximum benefit of the people.

- To address the need for an economic base, Congress granted 103 million acres of federal land to Alaska – including land containing the North Slope oil and gas fields – as an endowment that would yield income to meet the costs associated with becoming a State.
- The Framers recognized that developing Alaska's resources according to the mandate of Article VIII might require an innovative tax regime, as reflected in their rejection of the highly restrictive Model Provision in favor of § 1 of Article IX and the adoption of the "like or different" exemption language in § 4 of Article IX.

Finally, it is significant that fiscal contracts have been employed in Alaska to attract new industries since Territorial days.

- In 1949, the Territory authorized the tax commissioner to enter into fiscal contracts for new industrial enterprises.
- In 1957, after the Alaska Constitution was ratified, the Territory enacted an industrial incentive act that permitted businesses to apply for fiscal contracts to encourage new investments in Alaska.

- In 1968, the Legislature enacted the Alaska Industrial Incentive Tax Credits Act.
 - In 1971, the Alaska Supreme Court held that the grant of tax relief provided for in the 1968 Act was “in the broadest possible form and that the legislature intended that a credit could be provided for almost any tax within the State of Alaska.”
- The proposed SGDA Contract is more favorable to the State than the tax exemptions previously required to attract industry to Alaska.
 - It is not a complete exemption from payment of taxes.
 - It requires continuous payments in lieu of taxes.
 - It will provide a steady source of revenue to Alaska at the same time that it provides an incentive to the Sponsor Group to build a gas line in order to develop Alaska's gas resources.

IN CONCLUSION:

- There is always a degree of uncertainty in trying to anticipate what action a future legislature might take and how a court might rule on that action.
- The proposed SGDA Contract is within the parameters established by the Framers in §§ 1 and 4 to use the State's tax structure to encourage development for the maximum benefit of the people.
- Additionally, Article 11.1 of the proposed contract coupled with a legislative act authorizing the Governor to sign the contract will constitute a clear and unequivocal statement of intent to alienate the power to change taxes for the terms established in the contract, and thus, the contract will be enforceable under the contracts clause.

July 25, 2006

The Honorable Thomas Wagoner
Alaska State Senate
State Capital
Juneau, Alaska

Re: 2001 Production Tax proposal

Dear Senator Wagoner:

Please find attached the report which I prepared April 29, 2001 for Governor Knowles regarding changes to the ELF. Jim Clark asked me to send this to you in view of your interest in a gross based production tax.

The 2001 report recommended major changes to the ELF based production tax. However, the main concept remained a production tax based on the gross value of the production.

The changes included:

- Adjustments to the ELF formula,
- Making the production tax price progressive,
- A special tax credit in order to encourage re-investment, and
- Special provisions for heavy oil.

My recommendation was endorsed by Revenue Commissioner Wilson Condon. Unfortunately, Governor Knowles decided at the time against any changes to the production tax.

I still regret that Governor Knowles decided not adopt my recommendations at the time. If my proposal had passed the Legislature, Alaska would have been \$6 billion better off today on a cumulative basis.

I re-introduced my recommendation in 2003 for Governor Murkowski. However, the Governor indicated that he was willing to consider fundamental change to the production tax. This induced me to propose to the Governor the PPT concept. I recommended the PPT concept over my earlier production tax proposal based on gross because this system has many advantages.

However, prior to explaining these advantages it is important to emphasize the critical role tax credits play in the future of Alaska.

Already in 2001 it was clear that the production tax system was outdated and that production was declining and therefore it was important to induce more investment.

In the 2003 version of the production tax based on gross, it was suggested to include up to a 40% tax credit.

These tax credits play a fundamental role in significantly increasing investment in the State.

In a system without such tax credits, investors count a \$ 1 million capital expenditure as \$ 1 million, as far as production tax is concerned.

If there are tax credits of 40%, investors count a \$ 1 million capital expenditure only as a \$ 600,000 expenditure, because they get \$ 400,000 back in tax credits. In other words they perceive the **net investment** as a \$ 600,000 expenditure.

Needless to say an investment based on a net investment of \$ 600,000 rather than a gross investment of \$ 1 million is far more profitable. This is the basic reason why such tax credits make investments in the State significantly more attractive and the result is a much higher level of investment and therefore production decline can be slowed down or halted.

What is very important is that governments do not loose revenues relative to the revenue targets by providing tax credits. All government do is first increase taxes to a somewhat higher level than their revenue target. Then they simply give some of it back to the investors if they re-invest in their jurisdiction. In the end governments end up with the total revenues they want. But investors see this as a reduction of tax payable.

The choice is therefore very simple:

1. Either Alaska collects tax based on a revenue target, without tax credits, and ends up with a low level of investor interest in re-investment, or
2. Alaska collects somewhat more tax and then provides tax credits ending up with the same revenue target, but creates a high level of investor interest in re-investment.

Most governments recognize that option two is the best. They get the revenues they want and strong investment.

All important oil and gas producing OECD jurisdictions have adopted this broad concept in different forms, including Norway, the UK, Denmark, the Netherlands, Alberta, Newfoundland, Canada (NWT) and Australia. Furthermore, there are at least 60 other nations which have profit or profit oil based systems.

Assuming that Alaska adopts tax credits, the question then arises why did I recommend the PPT to the Governor rather than an updated 2001 recommendation based on gross with tax credits. There are very important reasons for my recommendation to the Governor to adopt the PPT concept rather than a production tax based on gross with credits as I proposed in 2001 and 2003.

Firstly, Alaska has already a fiscal feature based on gross, which is the royalty. The royalties provide about half the Alaska revenues from oil and gas. Combining a royalty with a tax that is also on gross is a complex economic task because the two features together have to fit a wide spectrum of economic conditions from marginal to profitable fields. This is the reason why the current production tax is based on an ELF formula.

However, such economic formulas have a relatively short "shelf" life. The current ELF formula worked well for about 10 years and then became outdated. Now it has taken already more than five years to try to replace this system. The "shelf" life is short because the formulas are quickly overtaken by new economic and technical developments. It is not possible to design formulas based on gross that are so sophisticated that they automatically adjust to a wide range of new circumstances. The petroleum industry is changing too rapidly and the future is too uncertain. The international experience is that systems based on net revenues adjust better to new and unexpected circumstances. Therefore, they are more durable as well.

Secondly, in order to be flexible, production tax systems based on gross have to be "field" based. In order to extract the maximum benefit for the State, the formula has to adjust downward for marginal fields and upward for profitable fields. The problem is that it becomes increasingly difficult to define what a "field" is on the North Slope. Most of the new developments today are not new field developments. They relate to deeper and shallower reservoirs, reservoir extensions, satellite fields, EOR in existing reservoirs, etc. This creates significant problems in "field" definition. It also creates serious distortions between the application of the formulas to different type of investments. These distortions create administrative difficulties and require significant administrative discretion. Alaska has already experienced problems in this regard and the Governor already took action earlier to avoid the related negative effects for the State. A "field" based system requires separate tax calculations for each "field". It is much simpler to have a State wide system that is based on net revenues, based on a single tax return per company.

Thirdly, any system based on gross has to consider heavy oil separately. The system has to be more generous for heavy oil than for light oil since the production costs of heavy oil are much higher. This creates a wide range of problems as follows:

- It is rather difficult to define what heavy oil is in the first place. There are no separate clearly defined "light" oil and "heavy" oil fields on the North Slope. There is a full spectrum of reservoirs with different gravities ranging from 25 to 14 degrees API and also with different viscosities. In fact, in the same reservoir lighter and heavier oils could occur in different parts of the reservoir. Apart from heavy oils there are also viscous light oils in shallow formations which behave from a production perspective as heavy oils.

- There is a considerable problem in defining the economic differences in order to determine a formula based on gross. We really do not know and therefore have no economic basis for judging the cost differences between 25, 20, 18 or 14 degree API crude oils in different style reservoirs. We can only make guesstimates of this. It is precisely heavy oil development that will be subject to very considerable technological changes over the next decade. What appears to be costly oil today may be relatively cheap ten years from now. Therefore, providing incentives for heavy oil today on a gross formula basis may well be perceived as a "give away" within a few years. This is a very significant problem because most of the future oil developments on the North Slope will be heavy or viscous oils.
- Finally, it would be difficult to administer a system that provides sliding scales or different formulas for heavy oil. There could be considerable disputes as to how and where the gravity of the oil would be determined. In order to be effective in stimulating heavy oil development, the measurement should preferably be as differentiated as possible among reservoirs, etc. The more crude blended before measurement, the less effective the fiscal feature would be.

For all these reasons a system based on net revenues is far more preferable. A profit based system deals effectively with heavy oil. It does not matter what the gravity or viscosity of the oil is or whether costs are high or low—a profit based system accommodates both. Therefore, profit based systems ensure that under a much wider range of conditions the State will receive its fair share. It is for this reason that Alberta is developing the oil sands as well as a large heavy oil field called Cold Lake very successfully with a profit based system.

Finally, most other important oil producing countries have adopted profit based systems either with or without a royalty. Therefore these systems are well known around the world. For instance in the OECD area, Norway, the UK, Denmark, the Netherlands, Alberta (oil sands and heavy oils), Newfoundland, Nova Scotia, Canada (NWT) and Australia have operated these systems successfully since the early 1980's. In addition there are more than 60 other jurisdictions with profit based or profit oil based systems. Therefore, there is ample experience around the world that profit based systems work well for governments.

I understand that the interest in a production tax based on gross revenues is largely based on the concern that cost control under a net revenue based system will be difficult for Alaska to implement. There is concern that Alaska may be "cheated" out of the taxes that are due through inappropriate high cost declarations or other practices.

The international experience is that the matter of cost control is always an issue and need to be taken seriously. Inappropriate deductions do slip through. Tax collection is never perfect. It is therefore, that the PPT bill already contains a variety of features that deny certain cost deductions and make administration easier.

The PPT bill contains a highly up to date list of costs that are not deductible in order to make cost control easier, these include:

1. Depreciation, depletion, amortization
2. Financing charges and costs of raising equity
3. Acquisition costs of leases
4. Costs of litigation and arbitration
5. Partnership, joint-venture and other organizational costs
6. Any expenditures in excess of fair market value
7. Expenditures to purchase a company or business
8. Certain abandonment costs
9. Losses and damages related to oil discharges.

However, cost control should be considered in perspective. Typical costs on the Alaska North Slope today may be \$ 6 per barrel (50% capital and 50% operating costs). If a certain unscrupulous oil company would over-declare these costs by 30% and the administration would not identify this, the total extra deduction would still only be \$ 1.80 per barrel resulting in a tax loss (at a 20% tax) of \$ 0.36 per barrel and the undeserved tax credit under the PPT would be \$ 0.18 per barrel for a total of \$ 0.54 per barrel. In a world with \$ 30 to \$ 60 per barrel oil at the North Slope this is a modest problem. Therefore, even a significant failure in proper cost control would not cause significant damage to Alaska PPT tax collection.

However, compared to most other countries in the world Alaska has a highly competent administration. Today they are controlling and auditing already billions of costs related to transportation and also net profits leases are being administered. The chance therefore the entire oil industry would on a significant scale fraudulently declare cost deductions without this being noted by the administration is nearly nil.

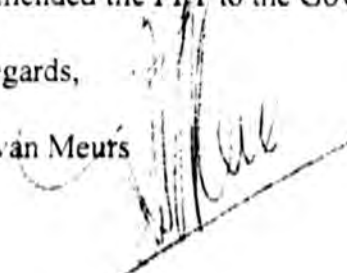
From my perspective, in comparing my 2001 recommendation of a gross based production tax with the PPT proposal I took the following factors into account:

- The PPT has a manageable cost control problem, which international experience indicates other similar jurisdictions are quite capable of handling. A State wide PPT based on a single tax return per company is a relatively simple system.
- A production tax based on gross, requires formulas which are likely to have a short "shelf" life, requires the definition of "fields" and requires to define fiscal conditions for heavy oil for which there is insufficient information to properly design these features and such conditions would probably be outdated rather quickly.

Therefore, I believe strongly that a PPT based system is easier to administer and will be more durable than a gross revenue based production tax with tax credits. It was therefore, that I recommended the PPT to the Governor.

Best regards,

Pedro van Meurs



FRANK H. MURKOWSKI
GOVERNOR
GOVERNOR@GOV.STATE.AK.US



STATE OF ALASKA
OFFICE OF THE GOVERNOR
JUNEAU

P.O. Box 110001
JUNEAU, ALASKA 99811-0001
(907) 465-3500
FAX (907) 465-3532
WWW.GOV.STATE.AK.US

SB3002

July 12, 2006

The Honorable Ben Stevens
President of the Senate
Alaska State Legislature
State Capitol, Room 111
Juneau, AK 99801-1182

Dear President Stevens:

Under the authority of article III, section 18, of the Alaska Constitution, I am transmitting a bill relating to the Alaska Stranded Gas Development Act. This bill is a shorter version of SB 2004, which was introduced at my request during the Second Special Session of the Twenty-Fourth Alaska State Legislature. The provisions of the present bill are based largely on certain amendments to SB 2004 that were reflected in CSSB 2004(NGD). The bill I am transmitting would authorize the commissioner of revenue to negotiate fiscal terms relating to oil, and includes provisions relating to certain payments to municipalities and nonprofit organizations.

I continue to believe that the proposed fiscal contract originally negotiated with the producers would be in the public interest. However, it is my intent to be responsive to the concerns expressed by the Legislature and members of the public concerning the provisions in the fiscal contract that provide for fiscal certainty for certain taxes levied on the production of oil. I encourage the Legislature to continue its review of the fiscal contract and consider amendments to the Stranded Gas Development Act that will provide a sound foundation throughout the duration of the contract. I pledge the full cooperation of my administration to assist you in this effort, which is in the long-term fiscal interest of the state.

I urge your prompt and favorable consideration of this bill.

Sincerely yours,

A handwritten signature in dark ink, appearing to read "Frank H. Murkowski".

Frank H. Murkowski
Governor

Enclosure

COMMITTEE COPY