

ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672

3110 SCOMM 143: SENATE SPEC.COMM.ON NATURAL GAS DEV. 2005-2006

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."

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- 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.

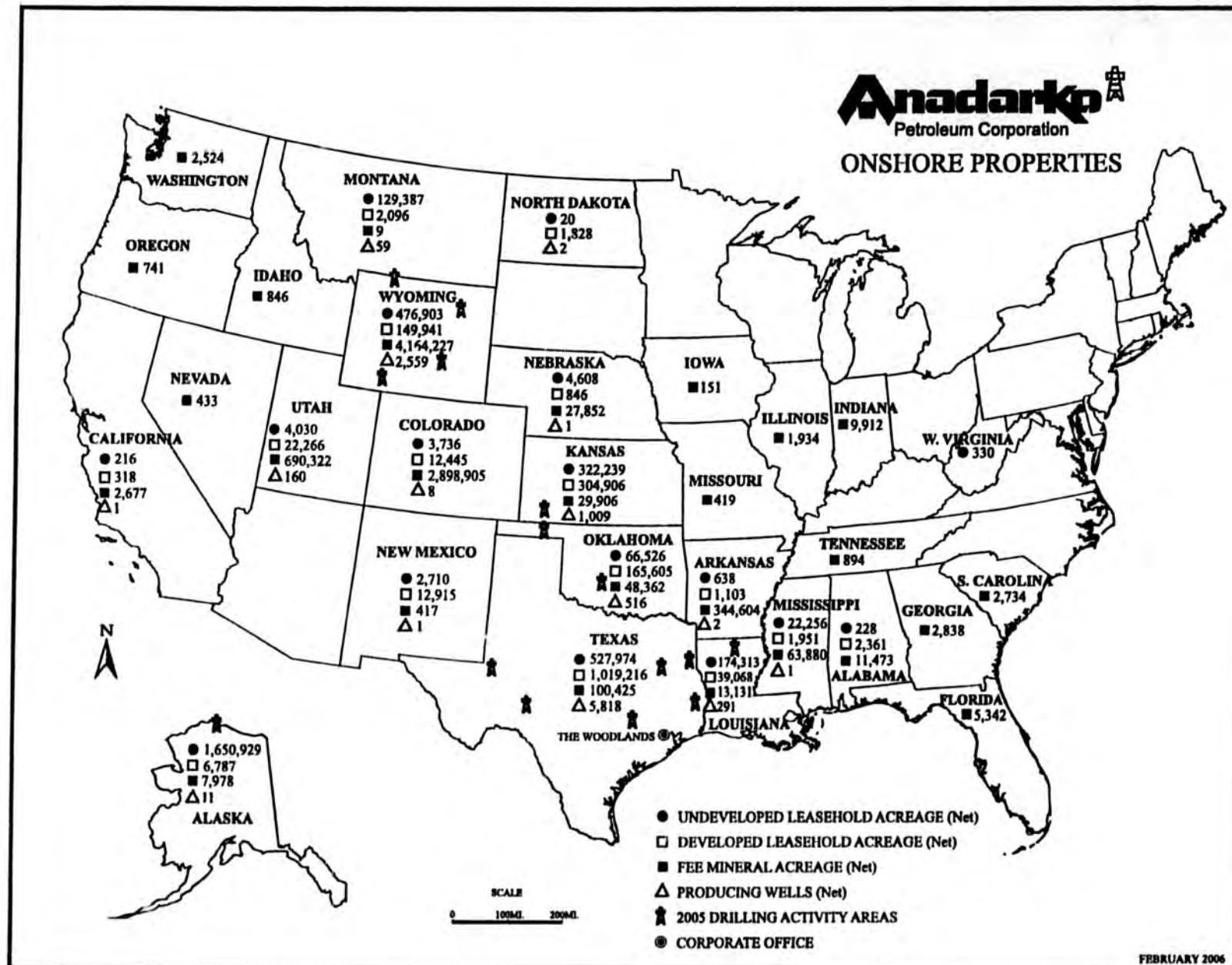
East Texas Development drilling and field extension of the Dowdy Ranch, Dew/Mimms Creek, Bald Prairie and Marquez fields are the primary focus in the east Texas tight gas Bossier play. Anadarko also continues to be active in its Cotton Valley infill drilling program in the Carthage area.

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.

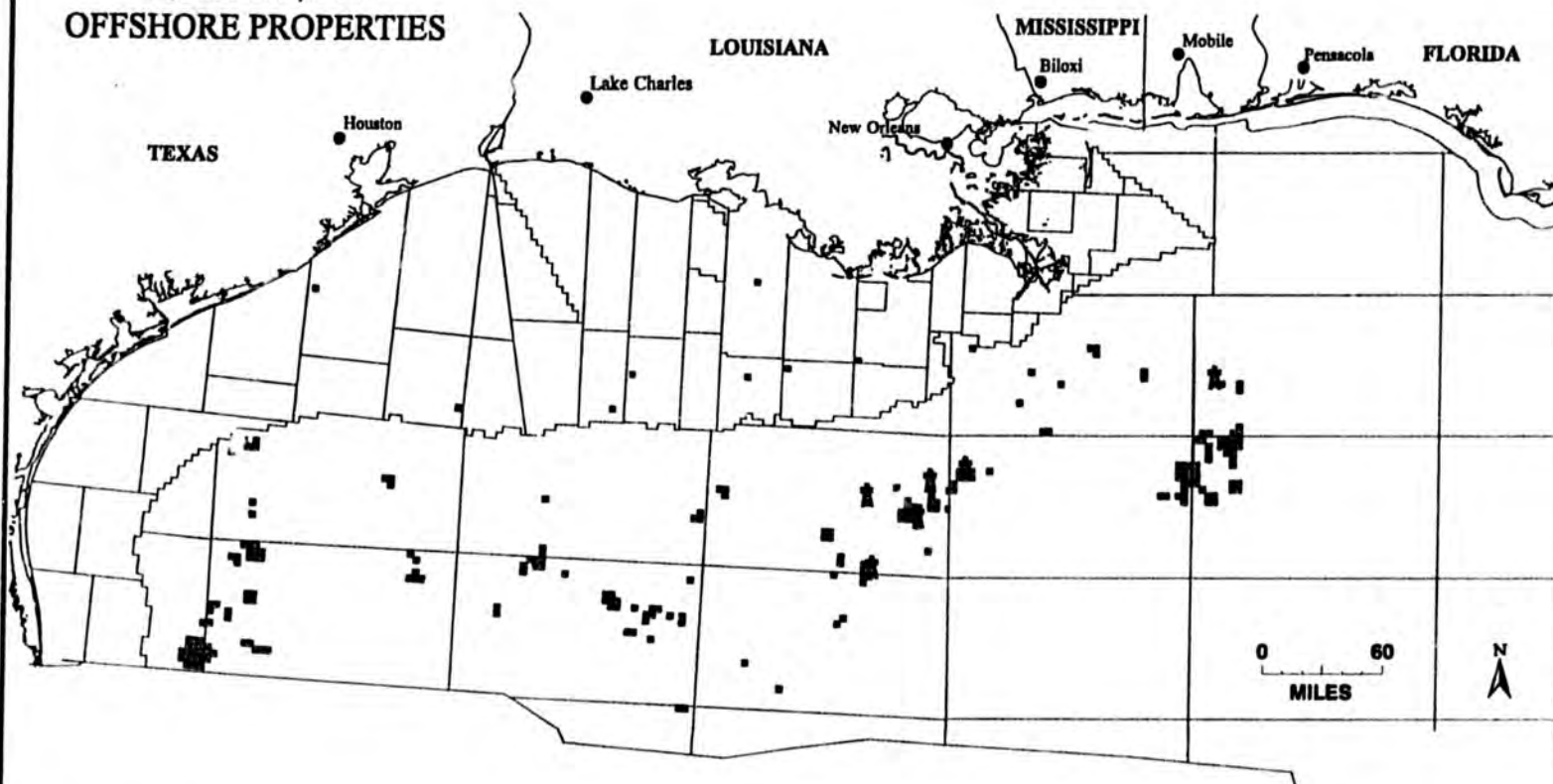
Development plans for a gas processing hub, Independence Hub, and gas export pipeline in the eastern Gulf of Mexico were approved in late 2004. The Company, along with a group of other producers, contracted with a third party to design, construct and own the facility. Anadarko will operate Independence 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

UNDEVELOPED (Net)

DEVELOPED (Net)

PRODUCING WELLS (Net)

GULF OF MEXICO

WESTERN	CENTRAL	EASTERN	CALIFORNIA
426,581	293,243	177,984	2,785
—	14,366	—	—
—	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.

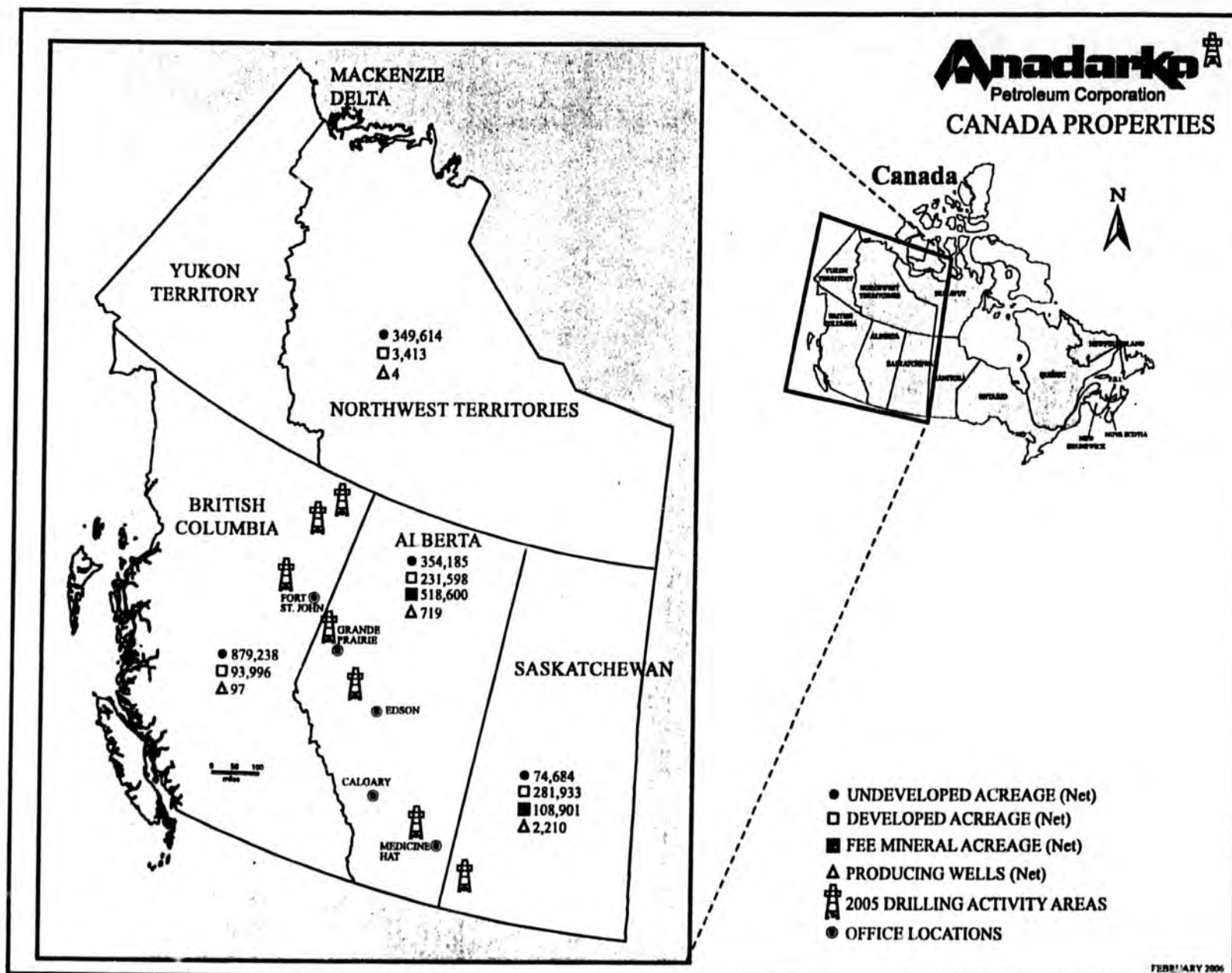
Medicine Hat In southern Alberta, Anadarko continues to develop a CO₂ pilot project near the Company's Hays gas plant. In southwest Saskatchewan, the Company began the second of three phases of its 115-well Crane Lake North shallow gas program. With use of new drilling and completion technologies, this 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.

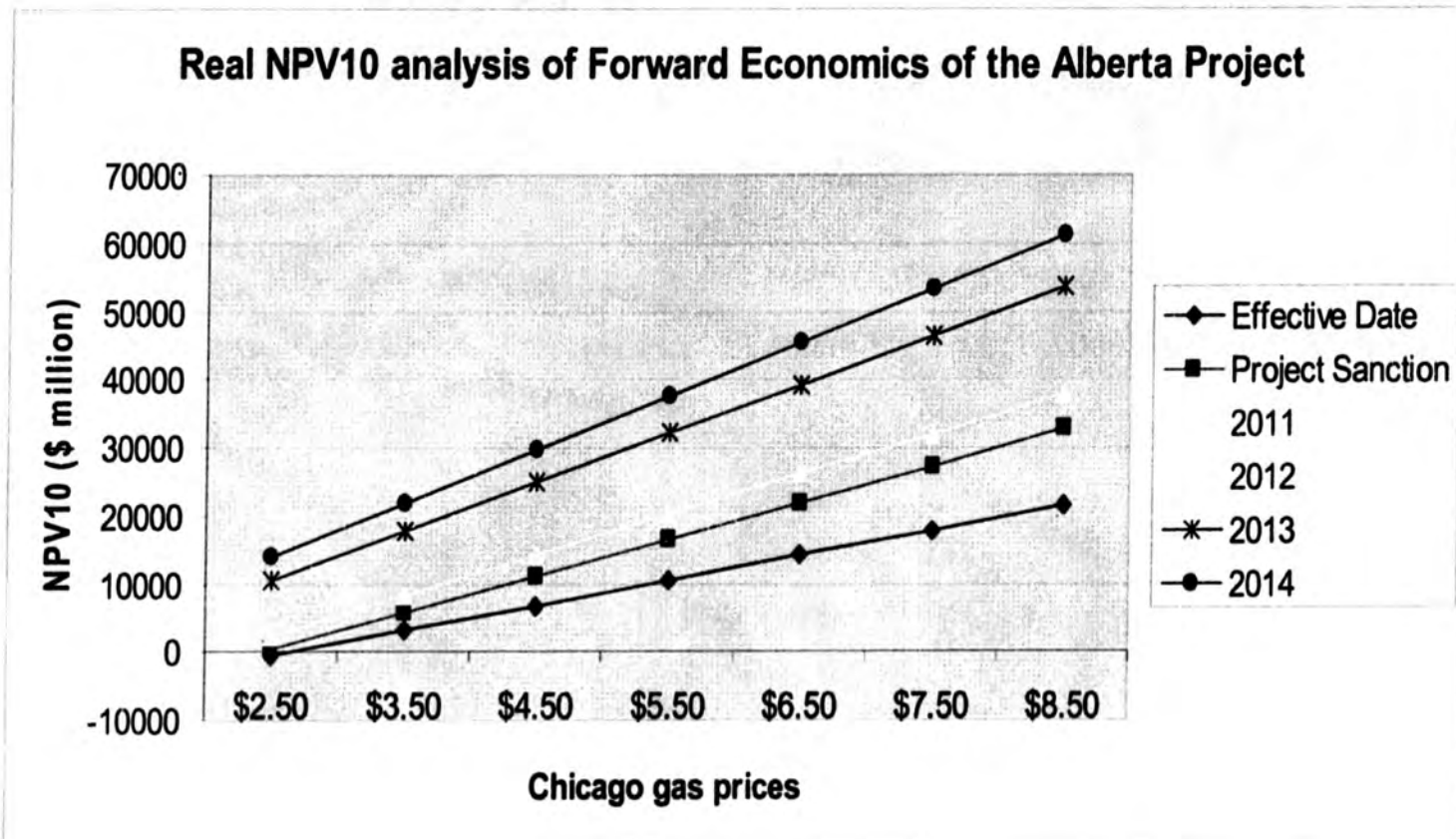
Fiscal certainty for Oil

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

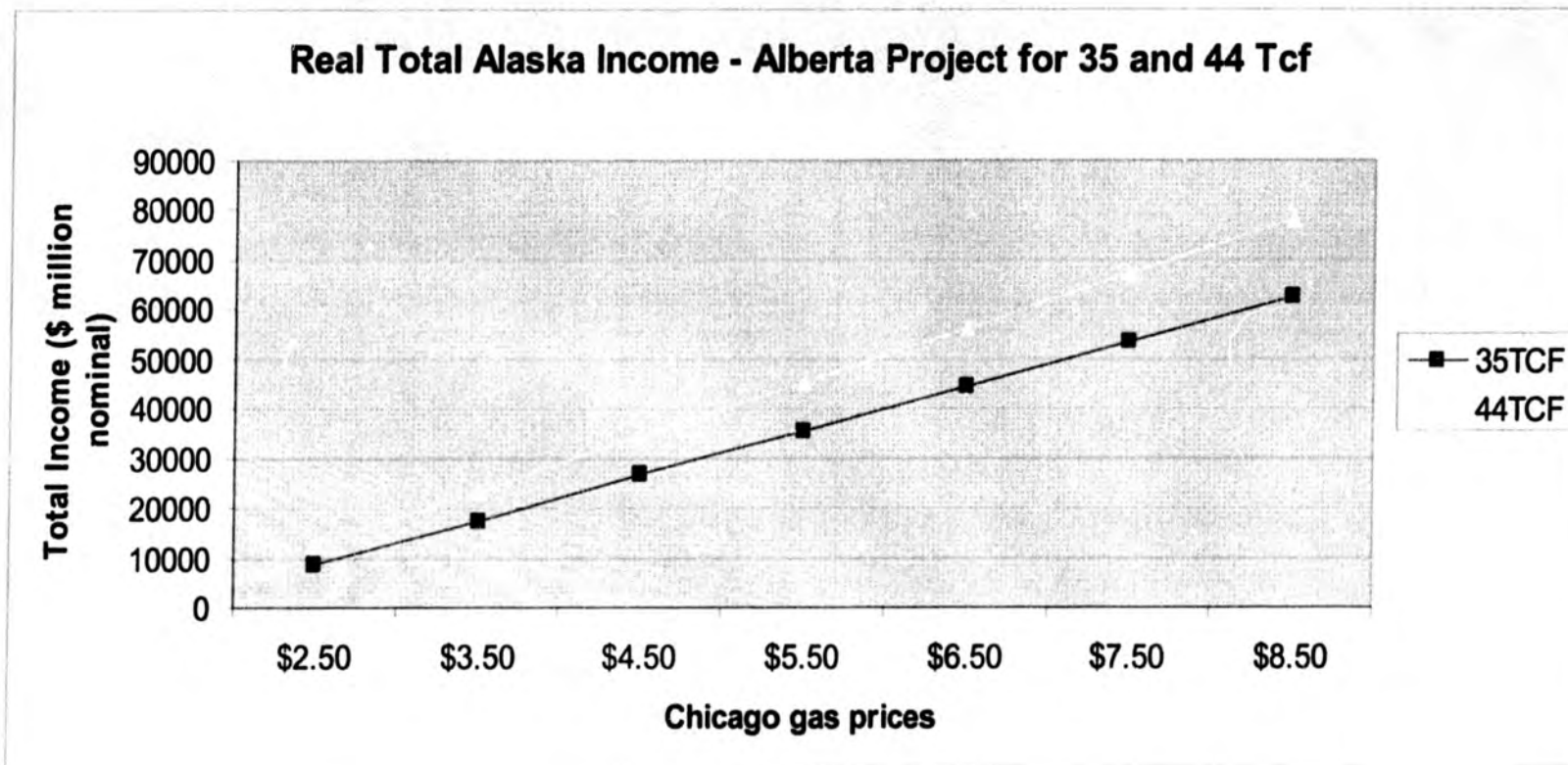
30 year full line - 44 Tcf

35 year full line - 51 Tcf

35 year full expanded line - 70-77 Tcf

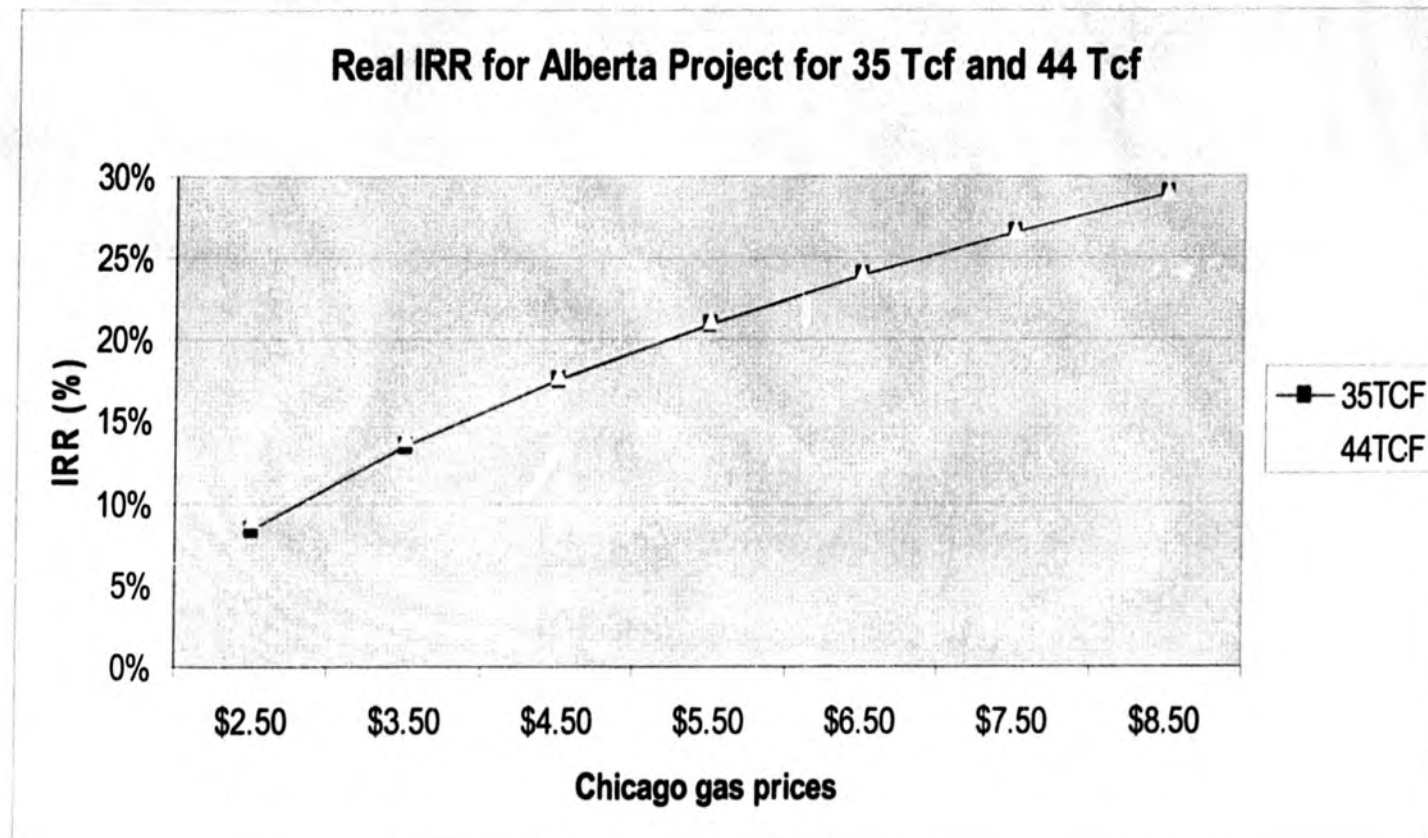
In order to study the economic impact an analysis was done of a 35 Tcf and 44 Tcf case.

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.

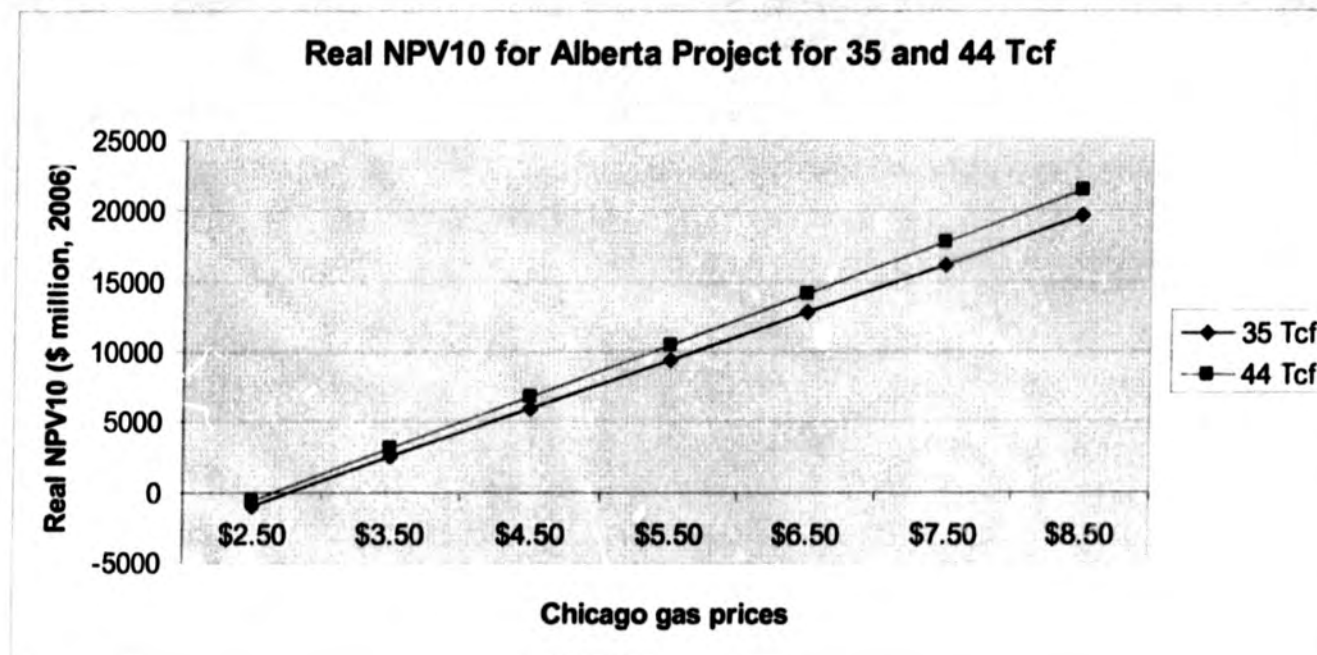
Fiscal certainty for Oil

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;

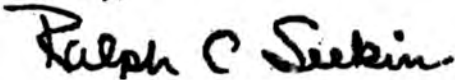
4) The Commission's review of competition issues as part of its processing of a certificate application;

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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 - ANGTA and the Attorney General's report. Page 7
 - The 1981 waiver. Page 8
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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.