

SENATE RESOURCES 11945

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52.5779%¹, BP Exploration (Alaska) Inc. (BPXA) 29.1943%, Chevron U.S.A. Inc. (Chevron) 14.3125%, and ConocoPhillips Alaska, Inc. (CPAI) 2.821%. The Minor PTU Owners include twenty entities that hold the remaining 1.0944% interest in the PTU.

The Division approved the PTU Agreement effective August 1, 1977, with a five-year Initial Plan of Exploration. The original unit area included 18 state oil and gas leases comprising approximately 40,768 acres. The PTU Owners drilled 11 wells in and around the unit area between 1978 and 1983, and the Division certified six of those wells as capable of producing hydrocarbons in paying quantities under the regulations² and the PTU Agreement.³

On March 26, 1984, the Division approved an application to expand the unit area on condition that the PTU Owners drill a well on one of the two southern expansion leases by March 31, 1985, and a well on one of the ten northern expansion leases by February 1, 1990. The expansion added approximately 94,152 acres within 25 leases to the PTU. The PTU Owners failed to meet both drilling commitments; therefore, the two southern expansion leases and nine northern expansion leases contracted out of the PTU.⁴

In 1998, the Division denied a unit expansion application, which was submitted by Exxon as the owner of the proposed expansion lease, rather than as the PTU Operator, because it was not supported by the other PTU Owners. The Division found that adding a lease to a unit where the owners have demonstrated a lack of cooperation may discourage, rather than encourage, unit development. The Division's denial of Exxon's 1998 PTU expansion application instigated negotiations between the Division and the PTU Owners to redefine the unit boundary. Supporting technical data indicated that the Thomson Sand Reservoir extended beyond the existing unit boundary and that other portions of the unit were not underlain by known hydrocarbons.

On February 2, 2001, Exxon applied to simultaneously expand and contract the PTU boundary. On July 31, 2001, the Division and the PTU Owner entered into an agreement in which the

¹ Exxon Mobil Corporation holds 43.2361% working interest ownership in the PTU and ExxonMobil Oil Corporation holds 9.3418%, jointly referred to as Exxon.

² 11 AAC 83.361. Certification of Well Test Results. "For the purposes of 11 AAC 83.301 - 11 AAC 83.395, a well will be considered capable of producing hydrocarbons in paying quantities, as defined in 11 AAC 83.395, when so certified by the commissioner following application by the lessee or unit operator. The commissioner will require the submission of data necessary to make the certification, including all results of the flow test or tests, supporting geological data, and cost data reasonably necessary to show that the production capability of the well satisfies the economic requirements of the paying quantities definition." 11 AAC 83.395. Definitions. "Unless the context clearly requires a different meaning, in 11 AAC 83.301 - 11 AAC 83.395 and in the applicable unit agreements, ... (4) 'paying quantities' means quantities sufficient to yield a return in excess of operating costs, even if drilling and equipment costs may never be repaid and the undertaking considered as a whole may ultimately result in a loss; quantities are insufficient to yield a return in excess of operating costs unless those quantities, not considering the costs of transportation and marketing, will produce sufficient revenue to induce a prudent operator to produce those quantities;"

³ PTU Agreement, Article 9, Drilling to Discovery. "Within 6 months after the effective date hereof, the Unit Operator shall begin to drill an adequate test well at a location approved by the Director, ... and thereafter continue such drilling diligently until the top 100 feet of the Pre-Mississippian formation has been tested or until at a lesser depth unitized substances shall be discovered which can be produced in paying quantities (to wit: quantities sufficient to repay the costs of drilling, and producing operations, with a reasonable profit) ..."

⁴ One of the northern expansion leases remained committed to the PTU because a well drilled on that lease in 1982 was certified as capable of producing in paying quantities.

Division approved an expansion of the unit area in return for the PTU Owners' commitment to do certain items of work. This agreement also provided that the expansion leases would contract out of the unit and the PTU Owners would pay the State certain sums of money if the work was not done. This "Agreement Resolving All Pending Point Thomson Unit Expansion/Contraction Matters and Proceedings" (Expansion Agreement) identified seven Expansion Areas and one Work Commitment Area (WCA) outside of the preexisting PTU (All together referred to as "Expansion Acreage"). The Expansion Agreement included the following work commitments by the PTU Owners:

1. WCA Drilling Commitment: Drill a well through the Thomson Sand interval within the Work Commitment Area by June 15, 2003, or the WCA acreage would automatically contract out the PTU on that date. Drilling a new well or deepening the Red Dog #1 Well would have fulfilled the WCA Drilling Commitment.
2. 2006 Development Drilling Commitment: Commence development drilling in the PTU by June 15, 2006, or all of the Expansion Acreage would automatically contract out of the unit effective that date, and the PTU Owners would pay the State \$20,000,000 by July 1, 2006, to compensate for the unrealized bonus payments during the period that the Expansion Acreage was withheld from leasing.
3. 2008 Development Drilling Commitment: Complete drilling seven development wells in the PTU by June 15, 2008, or all of the Expansion Acreage would automatically contract out of the unit effective that date, and the PTU Owners would pay the State \$27,500,000 by July 1, 2008, to compensate for the unrealized bonus payments during the period that the Expansion Acreage was withheld from leasing.
4. Participating Area Commitment: Allocate production to the Expansion Acreage within a participating area approved by the Division by certain deadlines. The participating area commitment date is June 15, 2008, for Expansion Acreage primarily underlain by the Thomson Sand Reservoir; and June 15, 2010, for Expansion Acreage primarily underlain by a Brookian prospect.

In addition, the Expansion Agreement imposed contraction provisions and charges of up to \$27,500,000 if the PTU Owners failed to meet the drilling commitments. The Agreement also increased royalty rates on eight of the twelve expansion leases; from 12.5% to 16.66667% on one lease, and from 16.66667% to 20% on the other seven leases.

The May 24, 2002 Findings and Decision contains the Division's evaluation of the Expansion Agreement, which resulted in the Second Expansion and Third Contraction of the PTU. The Expansion Agreement added approximately 40,353 acres within 12 leases to the PTU, and excluded all or portions of 4 leases, containing approximately 7,572 acres; an overall increase in the unit area of 39 percent. The revised unit area encompassed approximately 116,607 acres within 46 leases.

The PTU Owners based the Expansion Agreement on their assumption that they could engineer and develop a commercially viable gas cycling project. In a gas cycling project natural gas is produced, gas condensates are removed, and the dry gas is re-inject back into the reservoir for later production. The PTU Owners would need to build a pipeline from the PTU to connect with the Badami Unit pipeline to ship the gas condensates through the existing Trans-Alaska oil pipeline for sale. The Expansion Agreement provided that if PTU Owners found, in their view, the project to be uneconomic by June 15, 2003 (the Contraction Election Deadline), the PTU Owners could elect to contract all of the Expansion Acreage out of the PTU, pay the State \$8,000,000 to compensate for the unrealized bonus payments during the period that the acreage was withheld from leasing, and be released from the remaining obligations in the Expansion Agreement.

The Division approved subsequent unit plans that described the PTU Owner's proposed plans for development of a gas cycling project including: facility design, preliminary engineering, updating the PTU geologic model, and initiating the permitting process. However, in the Nineteenth POD, approved effective October 1, 2002, Exxon stated that the PTU Owners could not justify drilling an exploration well in the WCA, the first drilling commitment in the Expansion Agreement, due to their findings that the costs would be higher and the potential accumulation smaller than they had previously anticipated.

On January 29, 2003, the Division found that the geological and geophysical data supported Exxon's proposal to transfer ADL 389728 from the WCA to Expansion Area #1. This amendment of the Expansion Agreement increased the applicable royalty rate for ADL 389728 from 16.66667% to 20% and the PA Extension Charge for Expansion Area #1 from \$17,031,000 to \$21,239,000.

Under the terms of the Expansion Agreement, the two remaining leases in the WCA contracted out of the PTU and the PTU Owners relinquished their interest in the leases effective January 21, 2003 and the PTU Owners paid the State \$940,000 because they failed to fulfill the first drilling commitment.

On April 24, 2003, Exxon requested a two-year extension of the next three deadlines in the Expansion Agreement: the Contraction Election Deadline, the 2006 Development Drilling Commitment, and the 2008 Development Drilling Commitment.

On May 15, 2003, the Division approved a one-month extension of the Contraction Election Deadline, but the Development Drilling Commitments were unchanged. On June 20, 2003, the PTU Owners requested an additional six-month extension of the Contraction Election Deadline. On July 14, 2003, the Division approved the Twentieth POD for the period October 1, 2003 through September 30, 2004, during which time, Exxon planned to acquire the necessary permits and approvals for the gas cycling project while evaluating the Thomson reservoir structure and reserve estimates to move the gas cycling project toward the next phase of funding approval. This decision also extended the Contraction Election Deadline until January 15, 2004 as follows:

- a) On or before July 15, 2003, the Working Interest Owners may elect to contract all of the Expansion Acreage out of the PTU, pay the State of Alaska \$8,000,000 to compensate for the unrealized bonus payments during the period that the acreage was withheld from leasing (Extension Charge).

and be released from the remaining obligations imposed in the Decision. The Extension Charge will be due on August 1, 2003.

- b) Notwithstanding the foregoing, the above described deadline for election is hereby extended for a period of six months, until January 15, 2004, in exchange for an increase of the Extension Charge by the sum of \$2,000,000, provided that, at any time during such six-month extended period, the PTU Owners may provide notification of their election hereunder, in which event the total Extension Charge of \$10,000,000 shall be reduced by an amount equal to 1/12 of \$4,000,000 for each full month of such six-month period remaining.

The Division agreed to extend the Contraction Election Deadline on May 15 and again on July 14, 2003, to allow additional time for the PTU Owners to further evaluate their proposed gas cycling project. The PTU Owners presented their current interpretation of the PTU geologic model and updated in-place and recoverable hydrocarbons estimates to the Division on October 16, 2003. Unfortunately, the PTU Owners' assessment of their proposed gas cycling project indicated higher costs and lower liquid recovery than they had previously estimated.

In a letter dated December 18, 2003, Exxon stated that engineering and resource evaluation work confirmed that, in their view, development of the resource at PTU is challenged. The resource evaluation work resulted in a significant reduction in condensate recovery under the PTU Owners' conceptual design for a gas cycling project. In addition, they found that their engineering design, along with permitting and environmental requirements added significant cost to the gas cycling project. After evaluating potential cost reduction measures and alternate development plans, Exxon concluded "that a standalone project prior to gas sales is not economically viable under the current fiscal system." Exxon's letter went on to request a further extension of the Contraction Election Deadline, until June 15, 2006. The Division's denial of Exxon's requested extensions provides in part:

"Over the past year, the Owners reviewed the geologic model, recalculated the recoverable liquid hydrocarbons, refined the engineering design to better estimate the cost of development, began evaluating the environmental impacts through the federal permitting process, and considered alternate development scenarios. Through these activities, the Owners determined that the gas cycling project is currently uneconomic and suspended the permitting process indefinitely. Representatives from ExxonMobil met with division staff on December 2, 2003, to discuss possible revisions to the State's current fiscal system that might make the gas cycling project commercially viable. However, the Owners have not made any specific proposals that would warrant a further extension of the Contraction Election Deadline.

Without a commercially viable project, the Owners may surrender the expansion acreage, pay the \$10 million Extension charge, and be released from the remaining obligations in the Decision. If the Owners do not exercise this option, they must begin development drilling in the PTU by June 15, 2006, or all of the Expansion Acreage will automatically contract out of the PTU and the Owners will pay \$20 million to the State of Alaska. We trust that the Owners will

continue to evaluate options to economically produce the known hydrocarbon resources underlying the PTU, and look forward to reviewing the proposed PTU Twenty-First Plan of Development in July 2004."

Although the PTU Owners found the gas cycling project to be uneconomic, they did not exercise their option to contract the Expansion Acreage out of the PTU prior to the January 15, 2004 Contractation Election Deadline.

The Twenty-first POD, dated August 31, 2004, stated that the PTU Owners were unable to identify a viable gas cycling project under the current fiscal terms and they planned to focus on gas sales rather than gas cycling. The Twenty-first POD included a proposal to share with the Division the results of the PTU studies including reserve estimates, distributions, and mapping for the Thomson Sand Reservoir as well as the Brookian and Pre-Mississippian reservoirs within the unit area and provide financial and technical information so the Division could conduct an independent economic evaluation of the PTU Owners' gas cycling project. But the WIOs would only provide this information if the Division executed an extraordinary confidentiality agreement.

North Slope producers Exxon, BPXA, and CPAI (Sponsor Group), three of the Major PTU Owners, submitted an application to the State under the Stranded Gas Development Act (SGDA), which proposed a fiscal contract that may or may not lead to construction of a major North Slope gas pipeline. The Sponsor Group does not officially represent the PTU, the PBU or any other unitized area on the North Slope. During the Twenty-first POD, the PTU Owners planned to evaluate the technical and commercial issues necessary for the PTU Owners to participate in a future open season for major gas sales from the North Slope.

On September 23, 2004, the Division approved the Twenty-first POD, on condition that Exxon provide the Division with existing technical information, costs, and other fiscal assumptions necessary for the Division to conduct an economic analysis of the PTU Owners' gas cycling project. The Division reminded Exxon of the statutory and regulatory confidentiality protections accorded sensitive information, and notified Exxon that the Division would not execute the proposed confidentiality agreement. The Division requested that Exxon provide copies of all of the requested data no later than November 15, 2004. In addition, the Division's approval of the Twenty-first POD required that the 22nd POD contain specific plans to fulfill the 2006 drilling commitment set forth in the Expansion Agreement.

Exxon appealed the Division's decision on the Twenty-first POD to the Commissioner of the Department of Natural Resources (the Commissioner). But on November 15, 2004, Exxon hand delivered a set of technical data to the Division. The Commissioner affirmed the Division's Twenty-first POD decision on November 24, 2004.

On June 21, 2005, Exxon proposed amending the Expansion Agreement such that the Expansion Acreage leases would remain within the PTU while the State and Sponsor Group continue negotiations over a fiscal contract and for the duration of any resulting fiscal contract. On July 1, 2005, the Division received Exxon's proposed 22nd POD, which included an update on activities during the term of the Twenty-first POD and planned activities during the one-year term of the 22nd POD. Exxon reported that the PTU Owners had incorporated the results of the prior geologic model, updated reservoir simulation, facility design, and cost estimates into a

conceptual depletion plan for the PTU gas sales project. Under that plan, the PTU Owners would produce PTU gas and send it to the PBU for further processing before shipping it via a North Slope gas pipeline for sale, but did not specify a time-frame for development.

The 22nd POD did not commit to timely development or production of utilized substances. Instead, it proposed further development of the gas sales conceptual depletion plan so the PTU Owners would be prepared to participate in some future open season for nominations to a North Slope gas pipeline. The 22nd POD provides that the exact timing of the open season will be dependent, in part, upon the successful completion of a fiscal contract under the SGDA. During the term of the 22nd POD, the PTU Owners planned to monitor the progress of the negotiations under the SGDA and adjust the PTU work schedule as necessary to participate in an open season. The 22nd POD included the items of work summarized as follows:

1. Incorporate geologic modeling of the Thomson Sand aquifer uncertainty and the Pre-Mississippian bedded facies in the reservoir simulation model to form the basis of a major gas sales depletion plan.
2. Initiate more detailed facility design or Conceptual Engineering.
3. Determine optimum drillsite and well locations and update drilling and completion plan costs to estimate total project costs and timing.
4. Share the results of the above tasks with the Division.
5. Begin planning the permitting process for the PTU gas sales project.
6. Continue working to obtain all PTU Owners' approval of a new PTU Operating Agreement.
7. Assist the Division with its independent assessment of the commercial viability of the gas cycling project.

The Division's July 27, 2005 response indicated that it would not accept Exxon's proposal to amend the Expansion Agreement by tying it to the SGDA negotiations or relieve the PTU Owners of the work commitments they made in return for including the Expansion Acreage in the PTU. However, the Division indicated that it would be willing to extend the 2006 and 2008 Development Drilling Commitments, if the PTU Owners agreed to drill an exploration/delineation well, in lieu of a development well, by June 15, 2006 that could provide pertinent information pertaining to appropriate development of the western portion of the Thomson Sand Reservoir. The Division gave Exxon ten days to submit an acceptable plan, which should include the following items:

1. ExxonMobil shall drill an exploration/delineation well within the PTU by June 15, 2006.
2. The well must be drilled to the Mississippian basement and located to
 - a. delineate the Thomson Reservoir west of the PTU #1 well,
 - b. evaluate connectivity and continuity within the Thomson Reservoir, and

- c. evaluate the extent of and the hydrocarbon properties within the oil rim.
3. ExxonMobil shall apply to the Alaska Oil and Gas Conservation Commission for Pool Rules and a depletion plan for the Thomson Reservoir.
4. ExxonMobil shall prepare a schedule of activities to obtain the necessary permits for construction of the PTU facilities and pipelines.
5. ExxonMobil shall compare core samples from the Badami wells with the appropriate PTU wells to evaluate the Brookian reservoirs within the PTU.

Division staff discussed the requested modifications to the 22nd POD with the PTU Owners on July 27, 2005, and on August 1, Exxon indicated that they would respond to the Division by the end of the month.

On August 31, 2005, Exxon submitted a revised 22nd POD and a letter requesting a one-year deferral of both the 2006 and 2008 Development Drilling Commitments, rather than an indefinite extension under the SGDA. The 22nd POD stated that the PTU Owners could not justify drilling an exploration well, but Exxon offered to hold a workshop with Division staff to evaluate whether drilling exploration/delineation wells could provide valuable information that would reduce the uncertainty associated with the western portion of the Thomson Sand Reservoir. Other than a commitment to drill an exploration/delineation well by June 15, 2006, the revised 22nd POD included the other modifications that the Division had requested. However, without a commitment to drill an exploration/delineation well within the PTU while requesting deferral of the Development Drilling Commitments and tying development activities in the 22nd POD to the SGDA, the PTU Owners' plans for development of the PTU are unacceptable.

III. STATE STATUTES, REGULATIONS, AND PTU AGREEMENT PROVISIONS RELEVANT TO EVALUATION OF THE PTU OWNERS' PLANS FOR DEVELOPMENT OF THE PTU

The standards and criteria for approval of unit plans are primarily set out in the State statute and regulations, and the applicable unit agreement.

A. State Statute and Regulations

The Commissioner, or his designee, may approve a unit plan if he determines it is necessary or advisable in the public interest.³ The following statutes and regulations govern approval of unit plans:

AS 38.05.180(p) provides, in part:

To conserve the natural resources of all or part of an oil or gas pool, field, or like area, the lessees and their representatives may unite with each other, or jointly or separately with others, in collectively adopting or operating under a cooperative or unit plan of development or operation of the pool, field, or like area, or part of

³ By memorandum dated September 30, 1999, the Commissioner approved a revision of Department Order 003 that delegated this authority to the Director of the Division of Oil and Gas.

it, when determined and certified by the commissioner to be necessary or advisable in the public interest. . . . The commissioner may require oil and gas leases issued under this section to contain a provision requiring the lessee to operate under a reasonable cooperative or unit plan, and may prescribe a plan under which the lessee must operate. The plan must adequately protect all parties in interest, including the state."

[AS 38.05.180 (Q) PROVIDES, IN PART,

A PLAN AUTHORIZED BY (P) OF THIS SECTION, WHICH INCLUDES LAND OWNED BY THE STATE, MAY CONTAIN A PROVISION VESTING THE COMMISSIONER, OR A PERSON, COMMITTEE, OR STATE AGENCY, WITH AUTHORITY TO MODIFY FROM TIME TO TIME THE RATE OF PROSPECTING AND DEVELOPMENT AND THE QUANTITY AND RATE OF PRODUCTION UNDER THE PLAN.]

Under State regulation 11 AAC 83.303(a), the Director will approve a unit plan of development upon finding that it will: 1) promote the conservation of all natural resources; 2) promote the prevention of economic and physical waste; and 3) provide for the protection of all parties of interest, including the State. Subsection .303(b) sets out six factors that the Director will consider in evaluating a proposed unit plan.

11 AAC 83.343, Unit Plan of Development, provides as follows:

(a) A unit plan of development must be filed for approval as an exhibit to the unit agreement if a participating area is proposed for the unit area under 11 AAC 83.351, or when a reservoir has become sufficiently delineated so that a prudent operator would initiate development activities in that reservoir. All development operations must be conducted under an approved plan of development. A unit plan of development must contain sufficient information for the commissioner to determine whether the plan is consistent with the provisions of 11 AAC 83.303. The plan must include a description of the proposed development activities based on data reasonably available at the time the plan is submitted for approval as well as plans for the exploration or delineation of any land in the unit not included in a participating area. The plan must include, to the extent available information exists:

- (1) long-range proposed development activities for the unit, including plans to delineate all underlying oil or gas reservoirs, bring the reservoirs into production, and maintain and enhance production once established;
- (2) plans for the exploration or delineation of any land in the unit not included in a participating area;
- (3) details of the proposed operations for at least one year following submission of the plan; and

(4) the surface location of proposed facilities, drill pads, roads, docks, causeways, material sites, base camps, waste disposal sites, water supplies, airstrips, and any other operation or facility necessary for unit operations.

(b) The commissioner will approve the unit plan of development if it complies with the provision of 11 AAC 833.303. If the proposed unit plan of development is disapproved, the commissioner will, in his discretion, propose modifications which, if accepted by the unit operator, would qualify the plan for approval.

(c) The unit plan of development must be updated and submitted to the commissioner for approval at least 90 days before the expiration date of the previously approved plan, as set out in that plan. The update must describe the extent to which the requirements of the previously approved plan were achieved; if actual operations deviated from or did not comply with the previously approved plan, an explanation of the deviation or noncompliance must be included in the update. ... After the commissioner has determined that an updated unit plan of development is complete as submitted, or as modified by the unit operator following the commissioner's suggestions, the commissioner will have an additional 60 days in which to approve or disapprove the plan; if no action is taken by the commissioner, the update of the unit plan of development is approved.

(d) The unit operator shall submit an annual report to the commissioner describing the operations conducted under the unit plan of development during the preceding year.

(c) The unit operator may, with the approval of the commissioner, amend an approved plan of development.

B. The PTU Agreement Provisions

The following PTU Agreement provisions are relevant to the Division's evaluation of the PTU Owners' plans for development of the PTU.

Article 10, Plan of Further Development and Operation, provides as follows:

Within six months after completion of a well capable of producing unitized substances in paying quantities, the Unit Operator shall submit for the approval of the Director an acceptable plan of development and operation for the unitized land which, when approved by the Director, shall constitute the further drilling and operating obligations of the Unit Operator under this agreement for the period specified therein. Thereafter, from time to time before the expiration of any existing plan, the Unit Operator shall submit for the approval of the Director a plan for an additional specified period for the development and operation of the unitized land. The Unit Operator expressly covenants to develop the unit area as a reasonably prudent operator in a reasonably prudent manner.

Any plan submitted pursuant to this section shall provide for the exploration of the unitized area and for the diligent drilling necessary for determination of the area or areas thereof capable of producing unitized substances in paying quantities in each and every productive formation and shall be as complete and adequate as the Director may determine to be necessary for timely development and proper conservation of oil and gas resources of the unitized area, and shall:

- (a) specify the number and location of any wells to be drilled and the proposed order and time for such drilling; and,
- (b) to the extent practicable, specify the operating practices regarded as necessary and advisable for the proper conservation of natural resources.

Separate plans may be submitted for separate productive zones, subject to the approval of the Director.

Said plan or plans shall be modified or supplemented when necessary to meet changed conditions, or to protect the interests of all parties to this agreement. Reasonable diligence shall be exercised in complying with the obligations of the approved plan of development. ...

Article 16, Conservation, states:

Operations hereunder and production of unitized substances shall be conducted to provide for the most economical and efficient recovery of said substances without waste, as defined by or pursuant to state law or regulation.

Article 20, Effective Date and Term, provides in part:

This agreement shall become effective upon approval by the Commissioner or his duly authorized representative as of the date of approval by the Commissioner and shall terminate five (5) years from said effective date unless:

- (a) such date of expiration is extended by the Commissioner, or
- (b) it is reasonably determined ... that the unitized land is incapable of production of unitized substances in paying quantities ... or
- (c) a valuable discovery of unitized substances has been made or accepted on unitized land during the said initial term or any extension thereof, in which event the agreement shall remain in effect for such term and so long as unitized substances can be produced in quantities sufficient to pay for the cost of producing same from wells on unitized land and, should production cease, so long thereafter as diligent operations are in progress for the restoration of production or discovery of

new production and so long thereafter as the unitized substances so discovered can be produced as aforesaid, or

(d) it is terminated as heretofore provided in this agreement. ...

[ARTICLE 21, RATE OF PROSPECTING, DEVELOPMENT AND PRODUCTION, PROVIDES IN PART:

... THE DIRECTOR IS ALSO HEREBY VESTED WITH AUTHORITY TO ALTER OR MODIFY FROM TIME TO TIME AT HIS DISCRETION THE RATE OF PROSPECTING AND DEVELOPMENT AND THE QUANTITY AND RATE OF PRODUCTION UNDER THIS AGREEMENT WHEN SUCH ALTERATION OR MODIFICATION IS IN THE INTEREST OF ATTAINING THE CONSERVATION OBJECTIVES STATED IN THIS AGREEMENT AND IS NOT IN VIOLATION OF ANY APPLICABLE STATE LAW.

POWERS IN THIS SECTION VESTED IN THE DIRECTOR SHALL ONLY BE EXERCISED AFTER NOTICE TO UNIT OPERATOR AND OPPORTUNITY FOR HEARING TO BE HELD NOT LESS THAN THIRTY (30) DAYS FROM NOTICE, AND SHALL NOT BE EXERCISED IN A MANNER THAT WOULD (I) REQUIRE ANY INCREASE IN THE RATE OF PROSPECTING, DEVELOPMENT OR PRODUCTION IN EXCESS OF THAT REQUIRED UNDER GOOD AND DILIGENT OIL AND GAS ENGINEERING AND PRODUCTION PRACTICES; OR (II) ALTER OR MODIFY THE RATES OF PRODUCTION FROM THE RATES PROVIDED IN THE APPROVED PLAN OF DEVELOPMENT AND OPERATIONS THEN IN EFFECT ...; OR (III) PREVENT THIS AGREEMENT FROM SERVING ITS PURPOSE OF ADEQUATELY PROTECTING ALL PARTIES IN INTEREST HEREUNDER, SUBJECT TO APPLICABLE CONSERVATION LAWS AND REGULATIONS.]

IV. ANALYSIS OF THE PTU OWNERS' PLANS FOR DEVELOPMENT OF THE PTU

A discussion of the subsection 11 AAC 83.303(b) criteria, as they apply to the PTU Owners' plans for development of the PTU, is set out directly below, followed by the Director's findings relevant to the subsection .303(a) criteria, and the Director's decision.

1. Prior Exploration Activities and Geological and Engineering Characteristics of the PTU

The Thomson Sand Reservoir is the primary reservoir in the PTU, consisting of the Lower Cretaceous Thomson Sand interval trending generally west-northwest across the unit, and between approximately -12,780' and -13,128' tvdss⁶ in the Point Thomson Unit #1 discovery well (PTU1) drilled by Exxon in 1977. Exxon estimates that the Thomson Sand Reservoir contains approximately 8 trillion cubic feet (TCF) of gas and over 200 million barrels (MMB) of recoverable gas condensate with a discontinuous heavy-oil rim. The reservoir pressure is extremely high, around 13,000 pounds per square inch (psi). Other potentially productive

⁶ Total vertical depth subsurface (below sea level).

reservoirs present in the PTU include Brookian Lower Tertiary turbidite sands and what are informally referred to as the "Pre-Mississippian" carbonates. Although the Sourdough well data remain confidential, in 2001 BPXA disclosed that the wells encountered recoverable reserves of approximately 200 MMB in the Brookian section. All three reservoirs are, or may be, over-pressured throughout much of the PTU.

A subsurface ridge-like structural feature constrains the northern edge of the Thomson Sand accumulation. While Thomson Sand presence, hydrocarbon charge, and thickness are uncertain on the north flank of the feature, it is possible that the Thomson Sand Reservoir is present north of the feature within Expansion Area #6.

Eighteen exploration wells have been drilled within and around the PTU. At the request of the Unit Operator, the Division certified seven PTU wells as capable of producing hydrocarbons in paying quantities and granted five wells extended confidentiality⁷. The public PTU well data is summarized in Attachment I to this decision.

The available well data allows the Thomson Sand Reservoir to be described as very fine-grained sand along the southern margin of the unit coarsening northward to a conglomeratic facies and exhibiting an average porosity of about 16%. Permeability within the reservoir varies from 10 millidarcies (md) to more than 1,000 md.

The PTU Owners also acquired extensive seismic data over the unit. They merged and began prestack depth migration processing of four 3D seismic surveys, which cover essentially the entire unit area: the Point Thomson Unit, Flaxman Lagoon, Island Corridor West, and Challenge Island surveys. Merging the seismic data sets produced a more unified interpretation of the extent of the Thomson Sand Reservoir over the greater unit area. The well and geophysical data indicate that much of the PTU is underlain or is potentially underlain by oil, natural gas and gas condensate deposits in the Thomson Sand Reservoir, and by Brookian oil deposits. There also appears to be a thin and potentially discontinuous oil leg at the bottom of the Thomson Sand Reservoir. The PTU owners incorporated the well and seismic data into a common database, which is the basis for the PTU Owners' Thomson Sand Geologic and Reservoir Simulation Models.

The Sixteenth POD, submitted by Exxon on July 30, 1999, included a commitment to conform the unit boundary to consensus maps of the potential reservoirs. During the term of the Sixteenth POD, the PTU Owners developed consensus structure and isochore maps of the Thomson Sand Reservoir and five potential Brookian accumulations; and initiated unit expansion discussions with adjacent leaseholders. On July 31, 2001, the Division and the PTU

⁷ 20 AAC 25.537. Public and Confidential Well Information. "(d) Except as provided by (a) of this section, the reports and information required by this chapter to be filed by the operator will be kept confidential by the commission for 24 months following the 30-day filing period after well completion, suspension, or abandonment unless the operator gives written and unrestricted permission to release all of the reports and information at an earlier date. Upon notification that the commissioner of the Department of Natural Resources has made a finding that the required reports and information from a well contain significant information relating to the valuation of unleased land in the same vicinity, the commission will hold the reports and information confidential beyond the 24-month period and until notified by the commissioner of the Department of Natural Resources to release the reports and information."

Owners executed the Expansion Agreement, which restructured the unit boundary in exchange for the PTU Owners' exploration and development commitments.

The Eighteenth POD, approved effective October 1, 2001, included activities toward fulfilling the Expansion Agreement, including selecting a location and contracting for a rig to drill an exploration/delineation well in the WCA. During the term of the Eighteenth POD, the PTU Owners completed prestack depth migration of the combined PTU 3D data set (Point Thomson Unit, Challenge Island, Island Corridor West and Flaxman Lagoon) over the redefined unit area. Exxon continued to pursue facility design, engineering and geological studies, and environmental analysis toward development of the Thomson Sand Reservoir, and initiated the federal permitting process for a gas cycling project, which moved from conceptual engineering to front-end engineering and facility design during the Eighteenth POD.

In the Nineteenth POD, dated August 8, 2002, Exxon notified the Division that the PTU Owners would not drill an exploration well prior to the WCA Drilling Commitment deadline of June 15, 2003. The State and Exxon executed a Memorandum of Understanding to facilitate the State permitting process for the gas cycling project and Exxon proceeded with engineering design of the surface facilities during the term of the Nineteenth POD. On June 24, 2003, the PTU Owners presented their updated stratigraphic and structural interpretation of the Thomson Sand Reservoir, based on the merged PTU seismic data, to Division staff.

During the term of Twentieth POD, October 1, 2003 through September 30, 2004, the PTU Owners completed a number of technical studies to evaluate Thomson Reservoir quality, fault seal, and structural framework; which, to the PTU Owners, indicated a chance of greater compartmentalization and a higher risk of sand production. The PTU Owners also studied alternative facility designs and identified cost reduction measures for their proposed gas cycling project. The PTU Owners stated that, in their view, their proposed gas cycling project is not commercially viable. Exxon suspended all permitting activities for their proposed gas cycling project and deferred evaluation of the Pre-Mississippian formation that underlies the Thomson Sand Reservoir. The PTU Owners incorporated the results of the prior geologic model, updated reservoir simulation, facility design, and cost estimates into a depletion plan for a conceptual PTU gas sales project.

Despite rigorous analyses of seismic data, the depth of the subsurface geological structure of the Thomson Sand Reservoir west of the PTU1 well remains suspect and introduces substantial uncertainty about reservoir connectivity and continuity, fluid contacts, and the character of the underlying oil rim between the eastern and western areas of the PTU. An exploration/delineation well in this area would provide geologic and reservoir data that could confirm or reduce the structural uncertainty and aid the subsequent determination of recoverable reserves and development options for the PTU.

The PTU Owners' prior exploration activities identified several hydrocarbon accumulations within the unit area that are capable of production in paying quantities. The geological and engineering data indicate that the PTU is underlain by the Thomson Sand Reservoir, which contains significant oil, gas, and gas condensate reserves, and several Brookian oil reservoirs. However, there has been no further delineation of the known accumulations or exploration within the PTU since BPXA drilled the Sourdough #3 well in 1996. The PTU Owners have not yet begun development or production of the known hydrocarbon resources within the unit, and

the 22nd POD does not contain any commitments to do so. Therefore, the criteria in 11 AAC 83.303(b)(2) and .303(b)(3), do not support approval of the 22nd POD.

2. The PTU Owners' Plans for Development of the PTU

Although the Thomson Sand Reservoir was discovered in 1977 and the PTU contains several known hydrocarbon accumulations that are capable of producing in paying quantities, the PTU Owners have not committed to put the unit into commercial production. Instead, the PTU Owners propose that more studies are needed and a fiscal contract changing the State's royalty and tax share is required before they can begin development of the PTU.

According to Exxon, the focus of the 22nd POD is on preparing for a potential open season for major gas sales from the North Slope. The 22nd POD states

The timing of the open season process will be dependent upon successful completion of a fiscal contract between the Sponsor Group and the SoA under the Stranded Gas Development Act (SGDA). During the next year, the Owners will monitor progress of the contract negotiations under the SGDA and be prepared to adjust the work schedule to ensure the necessary work is conducted in sufficient time to allow the Owners to prepare for an open season for an Alaska gas pipeline while maximizing the efficiency of the work processes and sequence.

The Sponsor Group consists of only three of the Major PTU Owners: Exxon, BPXA, and CPAI, and does not officially represent the PTU lessees. The State is also negotiating with two other applicants that submitted proposals to build a North Slope gas pipeline. Depending on the progress of the negotiations, it is unlikely that a North Slope gas pipeline will be in operation before 2012, and the Sponsor Group has not yet made a public commitment to ever build a North Slope gas pipeline. However, regardless of the status of those negotiations, the PTU Owners have an obligation to diligently explore, delineate, and develop the hydrocarbon resources underlying the unit area.

The 22nd POD states that field activities associated with development drilling should begin three to three and one-half years before field startup, but it does not indicate when, if ever, an open season might occur or when, if ever, Exxon anticipates the commencement of development or production. At this point in time, the PTU Owners do not control if or when a North Slope gas pipeline will ever be operational. Reliance on third parties, beyond the control of the PTU Owners, is not grounds for the delay of PTU development and production.

While previous plans focused on developing unitized substances through a gas cycling project, the PTU Owners stated that project was not commercially viable and redirected their efforts to evaluate PTU development through gas sales. The 22nd POD describes several activities that the PTU Owners plan to execute during the next year to evaluate a conceptual PTU gas sales project, but those activities are all contingent on the Sponsor Group successfully negotiating a fiscal contract with the State under the SGDA.

The 22nd POD outlines the unit operator's plans for one year beginning October 1, 2005. Exxon plans to update the PTU geologic model and incorporate the results in the reservoir simulation to

identify potential upside gas production from the Pre-Mississippian section. The technical studies will be the basis for a gas sales depletion plan followed by conceptual engineering for detailed facility design. The 22nd POD anticipates completing the depletion plan in April 2006 and initiating conceptual engineering, a 9 to 12 month process that must be completed in time for the PTU Owners to be prepared to nominate gas in an open season, should one occur. During the conceptual engineering process, the PTU Owners plan to determine optimum drillsites and well locations, and update drilling and completion costs to estimate total project costs and timing. PTU conceptual engineering will also include provisions for Brookian development, which Exxon anticipates will occur after it develops the Thomson Sand Reservoir. However, the 22nd POD did not identify a firm date for the start of production.

During the 22nd POD, the PTU Owners plan to assess the permitting requirements for PTU gas sales. They will review the previous permitting activities undertaken for the gas injection project, evaluate the need for additional data and studies, and assess the interrelationship between permitting for PTU development and for the Alaska gas pipeline project. The PTU Operator will also apply to the AOGCC for a conservation order that addresses gas offtake and depletion plans for the Thomson Sand Reservoir and discuss other conservation orders needed for PTU development. Based on the permitting assessment, Exxon will update the project timeline and prepare a schedule of activities to obtain the permits and conservation orders needed to drill the PTU wells and to construct and operate the facilities and pipelines.

To address the Division's concern about reservoir uncertainty in the western unit area, the 22nd POD includes Exxon's offer to hold a workshop to evaluate whether drilling delineation wells could provide valuable information that would reduce the uncertainty associated with the western Thomson Sand Reservoir. The 22nd POD also includes plans to compare core samples from PTU and Badami wells to evaluate potential development of Brookian prospects within the PTU.

While there is some benefit to the proposals in the 22nd POD, it does not contain sufficient plans or commitments to timely develop and produce unitized substances. The PTU Owners are not entitled to condition development of the PTU on the construction of a pipeline by a third party or on modification of the state's royalty and tax rights. PTU Owners' plans for delineation and development of the unit area do not justify approval of the 22nd POD or the PTU Owners' request for extension of the 2006 and 2008 Development Drilling Commitments. The 22nd POD does not meet the criteria in section 11 AAC 83.303(b)(4).

3. Economic Costs and Benefits of the PTU Owners' Plans for Development of the PTU.

The cost to the state and the public of approving the 22nd POD is that the known underlying hydrocarbons will not be timely delineated and produced and the remainder of the unit area will not be timely explored. Moreover, the 22nd POD conditions PTU development on amending the State's existing tax and royalty structure in the Sponsor Group's fiscal contract and construction of a North Slope gas pipeline, which are an inappropriate basis upon which to condition PTU development.

In the short-term, development of the PTU could create additional jobs and in the long-term, development would create additional employment and income to State residents. The State and the public are primarily interested in timely oil and gas production from State leases. Every year

that production is delayed costs the State millions of dollars in unrealized interest on production revenue and delays the secondary benefits associated with PTU development. If the PTU Owners developed and began production from the PTU, the State would earn royalty and tax revenues over the long-term life of the field. Royalties, corporate income taxes, property taxes, and severance taxes would benefit the local and state economy, and provide revenue to the State's general, school, and permanent funds. The PTU Owners may reinvest revenues from PTU production in new exploration and development in the State.

Development of the PTU would also increase demand for goods and services supplied by local businesses, retailers, and service providers. An increased property tax base would benefit the residents and communities within the North Slope Borough and along the Trans-Alaska Pipeline corridor. Timely development and production from the PTU will lead to additional development and production from other reservoirs in the unit area and could provide an infrastructure base for exploration, development, and production outside of the unit area.

The Division's May 24, 2002 evaluation of the Expansion Agreement, found that the economic benefits of including the Expansion Acreage in the PTU outweighed the costs because the PTU owners made meaningful commitments to explore and develop the Thomson Sand Reservoir by drilling adequate exploration and development wells by dates certain, and agreed to increased royalty rates for some of the leases to compensate the state for lost opportunities to re-lease the acreage. If the Applicants fail to follow through with those commitments as scheduled, the Expansion Acreage will automatically contract out of the unit, and the PTU Owners must compensate the State for the lost opportunity to receive bonus payments in past lease sales. However, the PTU Owners have requested a one-year deferral of the Development Drilling Commitments. The 22nd POD, unlike the Eighteenth POD and subsequent plans, does not contain activities toward fulfilling the commitments in the Expansion Agreement.

In addition to the Development Drilling Commitments, the Expansion Agreement also contains the PTU Owners commitments to allocate production under an approved participating area by June 15, 2008, for Expansion Areas primarily underlain by the Thomson Sand Reservoir; and by June 15, 2010, for Expansion Areas underlain by Brookian prospects. If the PTU Owners ultimately fail to drill the required development wells, approval of a one-year deferral of the Development Drilling Commitments would delay receipt of any payments to compensate for withholding the Expansion Acreage from leasing, and if they do ultimately develop the PTU, deferral would delay receipt of facility and production related payments.

There are currently 45 state oil and gas leases committed to the PTU Agreement.⁸ Most of the PTU leases had a 1st-year primary term, except the four most recent leases, which were issued with 7-year primary terms. All but two of the PTU leases are beyond their primary term, but under Article 18 (d) of the PTU Agreement they are all extended for the duration of the unit term.⁹

⁸ Six of the PTU leases were effective in 1965, nineteen in 1969, three in 1970, two in 1979, four in 1982, one in 1988, eight in 1991, one in 1993, two in 1997, and one each in 2000 and 2002.

⁹ PTU Agreement, Article 18 (d) states "Each lease, sublease or contract relating to the exploration, drilling, development or operation for oil or gas of lands, committed to this agreement, which, by its terms might expire prior to the termination of this agreement, is hereby extended beyond any such term so provided therein so that it shall be continued in full force and effect for and during the term of this agreement."

In addition, the primary terms of seven PTU leases are extended because the Division certified wells located on those leases as capable of production in paying quantities. The PTU leases with certified wells are: ADL 28382, ADL 47556, ADL 47560, ADL 47567, and [ADL 47473] ADL 47573, which were issued on lease form DL-1 revised October 1963; ADL 312862 issued on DMEM-1-79B (Sliding Scale Royalty) revised November 5, 1979; and ADL 343112, issued on DMEM 1-82 (Net Profit Share) revised April 7, 1982. The primary term of these leases are extended under the individual lease agreements and State regulation 11 AAC 83.135, Shut-In Production. [PARAGRAPH 7 OF THE DL-1 LEASE FORM STATES:

EXTENSION BY SHUT-IN PRODUCTION. IF, UPON THE EXPIRATION OF THE PRIMARY TERM OR AT ANY TIME OR TIMES THEREAFTER, THERE IS ON SAID LAND A WELL CAPABLE OF PRODUCING OIL OR GAS IN PAYING QUANTITIES, THIS LEASE SHALL NOT EXPIRE BECAUSE LESSEE FAILS TO PRODUCE THE SAME UNLESS LESSOR GIVES NOTICE TO LESSEE ALLOWING A REASONABLE TIME, WHICH SHALL NOT BE LESS THAN SIXTY DAYS, AFTER SUCH NOTICE TO PLACE THE WELL ON A PRODUCING STATUS, AND LESSEE FAILS TO DO SO; PROVIDED, THAT AFTER SUCH STATUS IS ESTABLISHED SUCH PRODUCTION SHALL CONTINUE ON THE SAID LAND UNLESS AND UNTIL SUSPENSION OF PRODUCTION IS ALLOWED BY LESSOR.

LEASE FORMS DMEM-1-79B (SLIDING SCALE ROYALTY) AND DMEM 1-82 (NET PROFIT SHARE) CONTAIN SIMILAR EXTENSION PROVISION UNDER PARAGRAPH 5 (D) AND PARAGRAPH 4(D), RESPECTIVELY. HOWEVER, THESE TWO LEASE FORMS SPECIFY THAT THE LESSOR MUST GIVE THE LESSEE AT LEAST SIX MONTHS NOTICE TO PLACE THE WELL ON PRODUCTION. STATE REGULATION 11 AAC 83.135, SHUT-IN PRODUCTION CONTAINS SIMILAR LANGUAGE.]

The lessees have had twenty to thirty years to delineate, develop, and commence production from the hydrocarbon accumulations underlying these leases, which contain wells that are certified as capable of production in paying quantities. If the Division notifies the lessees that they must commence production, and they fail to do so within the time allowed, the leases will no longer be held by shut-in production, although the primary terms may continue to be extended by unitization or other extension provisions in the lease agreements.

If the PTU Agreement terminates and the leases expire, the Division could re-offer the acreage for lease in future lease sales and impose work commitments in the new leases.¹⁰ Re-offering the PTU acreage would also replace older lease forms with a more modern updated lease form. The Division received bonus bids totaling nearly \$146 million when the State originally issued the current PTU leases, and could attract significantly higher bid bonuses today.

Another benefit the state could realize by re-offering the unit acreage is the potential for increased royalty rates. Most of the leases in the core unit area have royalty rates of 12.5%. If the Division were to re-offer the acreage, it could impose higher royalty rates. The PTU Owners agreed to increased royalty rates for some leases in the Expansion Areas, ensuring that the State

¹⁰ "The Commissioner may include terms in any oil and gas lease imposing minimum work commitment on the lessee. These terms shall be made public before the sale, and may include appropriate penalty provisions to take effect in the event the lessee does not fulfill the minimum work commitment." AS 38.05.180 (h).

would receive the benefit of higher royalties on production from those leases without releasing the acreage. The royalty rate increased from 16.66667% to 20% for seven of the leases and from 12.5% to 16.66667% for one lease.

If the PTU is terminated and the Division re-offered the PTU acreage for bid, it might attract new lessees who may bring new ideas and energy as well as new geologic interpretations, engineering, development timelines, and marketing perspectives to develop the area. At this point, the current PTU Owners have had the leases for far beyond their primary term, and their conclusion today is simply that they cannot make enough money to justify development. It is time for the PTU Owners to develop and produce or give new lessees had a chance to develop the known hydrocarbon resources within the PTU.

In summary, the economic costs outweigh the benefits that might be gained by approving the 22nd POD. Therefore, the Division's evaluation of the section 303(b)(5) economic criteria does not support approval of the 22nd POD.

4. Environmental Costs and Benefits of the PTU Owners' Plans for Development of the PTU.

The PTU Owners do not propose any exploration, delineation, or development operations within the PTU. Therefore, the section 11 AAC 83.303(b)(1) environmental criteria neither supports nor condemns approval of the PTU Owners' plans for development of the PTU.

5. Other Relevant Factors to Protect the Public Interest

The PTU contains wells certified as capable of production in paying quantities. Considering the facts, it is now time to develop and produce the underlying hydrocarbons. If the PTU Owners have been unable to identify a commercial project in nearly 30 years, it is time to terminate the unit and re-offer the acreage to new lessees who will have the opportunity to develop the State's resources in a timely manner.

The Division has given the PTU Owners many opportunities over many years to develop the PTU. It is not in the public interest to grant a state lessee an indefinite extension on development merely because development in their view is not currently profitable enough or is too risky.

The intent of oil and gas leases is to give producers an opportunity to explore, develop, and produce within the primary term of the lease. That intent has been met and exceeded in this case. It is not in the public interest to change leasehold intent by allowing a lessee's parochial interests to supersede the State interest for orderly and reasonably prompt development.

The state's primary interest in oil and gas leases is development of hydrocarbons which yield oil and gas revenue. The state's interest is not met by allowing the producers to delay production until such time as the lessee determines that it is the lessee's optimum time to develop a known resource or the State agrees to compromise its tax and royalty system.

It is not fair to the public or other potential lessees to allow the current PTU Owners to continue to hold the leases, thereby precluding others from the opportunity to develop the resource.

V. FINDINGS

The PTU Owners' Plans for Development of the PTU fail to meet the criteria in 11 AAC 83.303(a) as follows.

A. Promote the Conservation of All Natural Resources.

If the Unit Operator proposed any operations under the 22nd POD, there would be environmental impacts associated with reservoir development. However, unitized development of the unit area would reduce the disruption of land and fish and wildlife habitat that would occur under individual lease development. This reduction in environmental impacts and preservation of subsistence access would, when taken in isolation, be in the public interest. While unitized operations conserve natural resources when compared to lease-by-lease development, development on a lease basis maybe preferable to no development at all. However, development of the Thomson Sand Reservoir is possible under a new unit agreement.

Additionally, before undertaking any specific operations, the unit operator must submit a unit plan of operations to the Division and other appropriate state and local agencies for review and approval, and the lessees may not commence exploration or development operations until all agencies have granted the required permits. The Division may condition its approval of a unit plan of operations and other permits on performance of mitigation measures in addition to those in the leases, if necessary or appropriate. Compliance with the mitigation measures would minimize, reduce or completely avoid adverse environmental impacts. Lease-by-lease operations would also require agency approvals, including mitigation measures.

B. Promote the Prevention of Economic and Physical Waste.

Exxon submitted geological, geophysical, and engineering data to support its interpretation of the hydrocarbon accumulations underlying the unit area. The available data indicates the PTU encompasses all or part of one or more hydrocarbon accumulations, but the PTU Owners' plans do not provide for delineation and timely development of those resources.

The PTU Owners stated that a gas cycling project was not commercially viable and the 22nd POD focuses on evaluating gas sales, but does not commit to produce and sell PTU gas. There is uncertainty regarding continuity of the reservoir in the western unit area, which could be addressed by drilling additional delineation wells. The Unit Operator has not adequately considered alternate development scenarios that incorporate both gas sales and gas cycling. Nor has Exxon evaluated the cumulative benefits of simultaneously developing the multiple hydrocarbon accumulations within the unit area. Timely development and production from the PTU does not preclude PTU gas sales at a later date. Focusing on gas sales at the exclusion of all other development options may result in waste of natural resources.

Gas cycling theoretically allows the recovery of significantly more liquids than would be recovered in a pure gas blow down project. In a gas blow down scenario, oil and gas condensates that remain in the field following gas sales may be largely unrecoverable. In addition, delaying timely production also constitutes waste. The Division and AOGCC must determine whether the proposed development will promote the conservation of oil and gas, but the Unit Operator has yet to apply to AOGCC for conservation orders and to the Division for

approval of a depletion plan. The Director has the authority to modify the rate of development to achieve the conservation objectives under the PTU Agreement, and I find that increasing the rate of development in the PTU is necessary and advisable.

C. Provide for the Protection of All Parties of Interest, Including the State

A majority of the State's general fund revenue is derived from North Slope oil and gas operations in the form of royalty, net profit shares, production tax, property tax, and corporate income tax. Failure to develop and produce known hydrocarbon accumulations deprives the State of incremental revenue, economic activity and jobs. Should the PTU terminate, the area could be re-leased and unitized again under an acceptable unit plan of development that includes commitments to develop and produce the underlying hydrocarbon accumulations.

Continuing this 30-year record of non-development and delay of an oil and gas lessee's obligations to develop and produce its oil and gas leases makes a mockery of the statutory, regulatory and contractual protections for the State as owner of the oil and gas estate. Therefore, the 22nd POD is unacceptable.

VI. DECISION

The 22nd POD fails to meet the requirements of 11 AAC 83.303 and .343 because it does not provide for the reasonable delineation and timely development of the hydrocarbon accumulations in the unit area. Nearly 30 years ago, lessees discovered the Thomson Sand Reservoir underlying the PTU, which to date has not been developed or put into commercial production. The PTU contains significant gas condensate and oil resources. Eighteen wells have been drilled within and around the PTU, but the most recent PTU well was drilled by BPXA nearly [20] 10 years ago. Although some of the leases are more than 40 years old, and several hydrocarbon accumulations within the unit area contain wells that are certified as capable of producing in paying quantities, the Unit Operator has not stated that production from the PTU is economic and has not committed to development and commercial production. To the contrary, the Unit Operator has stated the production from the unit is not economic.

1. The 22nd POD makes no commitment to timely develop and produce PTU oil, gas, or gas condensate. The 22nd POD is hereby denied.
2. Failure to obtain approval of the unit plan is grounds for default under the PTU Agreement and the State oil and gas regulations. The PTU Owners are hereby notified that effective October 1, 2005, the PTU Agreement is in default.
3. To cure the default, the Unit Operator shall submit an acceptable POD within 90 days, by Thursday, December 29, 2005.
 - a) An acceptable unit plan must contain specific commitments to timely delineate the hydrocarbon accumulations underlying the PTU and develop the unitized substances. The following commitments represent an example of an acceptable PTU plan of development:

- Development activities for the unit, including plans and deadlines to delineate the Thomson Sand Reservoir, bring the reservoir into commercial production, maximize oil, condensate, and gas recovery, and maintain and enhance production once established; and plans for the exploration or delineation and production of other hydrocarbon accumulations and lands that lie stratigraphically above or below the Thomson Sand Reservoir;
 - The PTU Owners shall sanction a commercial PTU development project by October 1, 2006, and provide the Division with evidence of corporate approval and commitment of project funding.
 - The PTU Operator shall begin commercial production of unitized substances from the PTU by October 1, 2009.
 - Details of the proposed operations to fulfill the 2006 Development Drilling Commitment, including the proposed surface location of the drill pad, bottom-hole location for the well, testing plan, and schedule of activities. The consequences of failure to fulfill the 2006 drilling commitment are specified in the Expansion Agreement.
4. Failure to submit an acceptable plan of development is grounds for termination of the PTU.
- [5. THE PTU OPERATOR SHALL COMMENCE DEVELOPMENT OPERATIONS WITHIN THE PTU BY OCTOBER 1, 2007. THE PTU OWNERS SHALL HAVE AN OPPORTUNITY FOR HEARING REGARDING THIS NOTICE TO MODIFY THE RATE OF PTU DEVELOPMENT.]
- [6. OIL AND GAS LEASES ADL 28382, ADL 47556, ADL 47560, ADL 47567, ADL 47573, ADL 312862, AND ADL 343112, MUST COMMENCE PRODUCTION IN PAYING QUANTITIES, AS DEFINED IN 11 AAC 83.105, FROM BY OCTOBER 1, 2009. THE DIVISION SHALL ALSO PROVIDE NOTICE TO THE NOTIFICATION LESSEES, EXXON MOBIL CORPORATION, EXXONMOBIL OIL CORPORATION, CHEVRON U.S.A., INC., AND DEVON ENERGY PRODUCTION COMPANY, LP UNDER SEPARATE COVER.]

A person affected by this decision may appeal it, in accordance with 11 AAC 02. Any appeal must be received within 20 calendar days after the date of "issuance" of this amended decision, as defined in 11 AAC 02.040 (c) and (d), and may be mailed or delivered to Thomas E. Irwin, Commissioner, Department of Natural Resources, 500 W. 7th Avenue, Suite 1400, Anchorage, Alaska 99501; faxed to 1-907-269-8918; or sent by electronic mail to dnr_appeals@dnr.state.ak.us. This decision takes effect immediately. If no appeal is filed by the appeal deadline, this decision becomes a final administrative order and decision of the department on the 31st day after issuance. An eligible person must first appeal this decision in accordance with 11 AAC 02 before appealing this decision to Superior Court. A copy of 11 AAC 02 may be obtained from any regional information office of the Department of Natural Resources.

Director Mark D. Myers signed the original Amended Decision on October 27, 2005

Mark D. Myers, Director
Division of Oil and Gas

Date

cc: Thomas E. Irwin, Commissioner DNR
John Norman, Chair AOGCC
Richard Todd, Senior Assistant Attorney General

Attachment I

Point Thomson Unit Leases

Well ID	Well Name	Well Type	Well Status	Well Date	Well Location	Well Depth	Well Completion	Well Production	Well Notes
28360	019	Core	2,544.00	8/1/1985	West Steines Sl. No.1 1970			GCM with trace OIL	DSTR3,4&5: negligible GCM
28364	023	Core	1,760.00	9/1/1985					
28365	024	Core	637.00	9/1/1985					
28361	020	Core	2,560.00	10/1/1985					
28362	021	Core	2,560.00	10/1/1985	Alaska State C-1 1981	Y	DSTR4: 90 bbls O&GCM		DSTR2: 1.75 MMCFGD, 455 BCPD (37.3 API)
28363	022	Core	2,560.00	10/1/1985					
47566	012	Core	2,560.00	10/1/1989					
47569	013	Core	2,533.00	10/1/1989					
47570	014	Core	2,560.00	10/1/1989					
47571	015	Core	2,560.00	10/1/1989					
47572	016	Core	2,533.00	10/1/1989	N Steines River 1 1982		CONFIDENTIAL		CONFIDENTIAL
47562	006	Core	2,980.00	10/1/1989					
47567	011	Core	2,560.00	10/1/1989	PTU Well No.2 1978	Y	DSTR5&6: 248 BOPD and 124 MCFGD		NONE
47556	025	Core	2,560.00	10/1/1989	Alaska State A-1 1975	Y	DSTR2&3: 2,567 BOPD (23.1 API) and 2.17 MMCFGD		NONE
47559	003	Core	2,560.00	10/1/1989					
47561	005	Core	2,560.00	10/1/1989					
47557	001	Core	2,523.00	10/1/1989					
47558	002	Core	2,560.00	10/1/1989	PTU Well No.3 1979		NONE		DSTR2: 6,348 MMCFGD and 476 BCPD (36 API)
47563	007	Core	2,523.00	10/1/1989	PTU Well No.4 1980		DSTR3: 20 bbls O&GCM		DSTR1: 306 BYPD
47564	006	Core	2,560.00	10/1/1989					
47566	010	Core	2,533.00	10/1/1989					
47573	026	Core	2,544.00	10/1/1989	Steines R. Sl. No.1 1979	Y	CONFIDENTIAL		CONFIDENTIAL
47560	004	Core	640.00	4/1/1970	PTU Well No.1 1977	Y	DSTR3: 2.25 MMCFGD and 132 bbls (44.4 API)		DSTR1: 2,283 BOPD (18.4 API) and 13,307 MMCFGD DSTR2: 3.88 MMCFGD and 170 bbls (46.4 API)
50983	017	Core	640.00	4/1/1970					
51667	018	Core	1,243.00	4/1/1970					
312682	027	Core	5,648.86	2/1/1980	Alaska State F-1 1982	Y	DSTR3: 73 MCFGD and 41 BCPD (35-50 API) DSTR5C: 141 MCFGD and 145 BOPD (22.1 API)		DSTR1: 3.02 MMCFGD and 152 BCPD (35.3 API) DSTR2: 4.8 MMCFGD and 266 BCPD
312696	028	Core	4,836.47	2/1/1980	Alaska State D-1 2/16/1982		NONE		NONE
343110	030	Core	1,920.00	8/1/1982					
343111	031	Core	2,400.00	8/1/1982					
343112	032	Core	3,446.00	8/1/1982	Sourdough No. 2 1984 Sourdough No.3 1986	Y	CONFIDENTIAL		CONFIDENTIAL
343109	029	Core	1,970.16	8/1/1982	Alaska State G-2 1983		CONFIDENTIAL		CONFIDENTIAL
372256	038	3	1,412.00	12/1/1988					
375084	043	4	1,062.00	4/1/1991					
377015	033	1	3,554.30	8/1/1991	Challenge Is. No.1 1981		NONE		BLOWOUT ... OIL below 12,963'
389727	045	6	2,143.39	8/1/1991					
377019	034	1	2,779.16	8/1/1991					
389728	046	1	2,952.62	8/1/1991					
377017	035	1	5,696.18	8/1/1991					
377020	037	2	1,909.74	8/1/1991					
389730	047	6	3,684.31	8/1/1991					
382101	042	5	1,280.00	7/1/1993					
388425	039	6	1,162.06	1/1/1996	Alaska Island No.1 1982		NONE		2.9 MMCFGD and 165 BCPD (36 API)
388426	040	6	821.74	1/1/1996					
389716	036	7	1,473.92	6/1/2001					
390310	048	Core	15.80	4/1/2003					
45			106,200.55						



ALASKA

DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL & GAS

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CERTIFIED MAIL
RETURN RECEIPT REQUESTED

October 20, 2005

Mr. Richard J. Owen, Alaska Production Manager, Joint Interests U.S.
ExxonMobil Production Company
3301 C Street, Suite 400, P.O. Box 196601
Anchorage, AK 99519-6601

RE: Point Thomson Unit
Extension of Appeal Period

Dear Mr. Owen,

On September 30, 2005, the Division issued a decision entitled *Denial of the Proposed Plans for Development of the Point Thomson Unit* (the Decision), which included an appeal provision that stated, in part.

"A person affected by this decision may appeal it, in accordance with 11 AAC 02. Any appeal must be received within 20 calendar days after the date of "issuance" of this decision, as defined in 11 AAC 02.040 (c) and (d), ..."

Exxon Mobil Corporation, the Point Thomson Unit Operator, received the Decision by certified mail on October 5, 2005 therefore; the 20-day appeal deadline is October 25, 2005. The Division grants a 10-day extension of the appeal period. Any appeal of the Decision must be received by November 4, 2005.

Sincerely,

Original signed by William Van Dyke, Petroleum Manager

Mark D. Myers
Director

cc: Thomas E. Irwin, Commissioner DNR
Richard Todd, Senior Assistant Attorney General

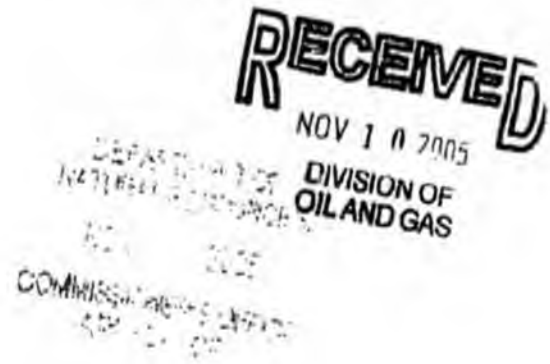
ExxonMobil Production Comp.
P.O. Box 188601
Anchorage, Alaska 99518-6601
907 561 5331 Telephone

Richard Owen
Alaska Production Manager
Joint Interest U.S.

ExxonMobil
Production

November 9, 2005

Michael Menge, Commissioner
Department of Natural Resources
550 W. 7th Avenue, Suite 1400
Anchorage, Alaska 99501



Dear Commissioner Menge:

On October 27, 2005, the Director of the Division of Oil and Gas issued the Amended Decision Denial of the Proposed Plans for Development of the Point Thomson Unit ("Amended Decision"). It is our understanding that the Amended Decision superseded the September 30, 2005 decision entitled Denial of the Proposed Plans for Development of the Point Thomson Unit.

ExxonMobil, as Point Thomson Unit Operator and on behalf of the Point Thomson Unit Working Interest Owners, hereby requests an extension of the time to appeal the Amended Decision, and of the time to cure set out in that decision, to May 31, 2006. During this time period, the PTU Owners will continue with activities set forth in our plan of development necessary to progress a gas sales development at PTU. In addition, we respectfully request that you extend the deadlines and obligations set forth in the May 24, 2002 Decision of the Director on the PTU Application for the Second Expansion and Third Contraction of the Unit Area by six months.

We request the DNR advise us if our understandings are not correct or if you disagree with any matter addressed in this letter, and that you grant our requests for extensions.

Sincerely,

A handwritten signature in black ink, appearing to be "Richard Owen", written over a horizontal line.

RJO:ddm
FD022 Appeal Riv_11-9-05.doc

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

FRANK H. MURKOWSKI, GOVERNOR

550 WEST 7TH AVENUE, SUITE 1400
ANCHORAGE, ALASKA 99501-3650

PHONE: (907) 269-8431
FAX: (907) 269-8918

November 10, 2005

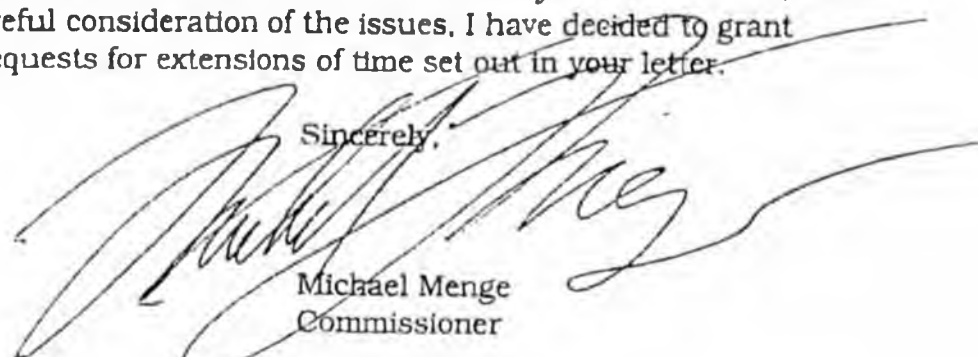
Richard J. Owen
Alaska Production Manager
ExxonMobil Production Company
PO Box 196601
Anchorage, AK 99519-6601

Re: ExxonMobil Production Company's Request for an Extension of Time

Dear Mr. Owen:

The Department of Natural Resources office received your November 9, 2005 letter. After careful consideration of the issues, I have decided to grant ExxonMobil's requests for extensions of time set out in your letter.

Sincerely,



Michael Menge
Commissioner

cc: Bill Van Dyke, Director, Division of Oil and Gas
Richard Todd, Department of Law

WALKER & LEVESQUE, LLC

ATTORNEYS AT LAW
731 N Street
Anchorage, AK 99501
(907) 278-7000 | Fax (907) 278-7001

Email: bill@wlews@ak.net

VIA FACSIMILE: 269 8918

November 16, 2005

Michael Mengo, Commissioner
Alaska Department of Natural Resources
550 West Seventh Avenue
Suite 1400
Anchorage AK 99501

DEPARTMENT OF
NATURAL RESOURCES

NOV 16 2005

COMMUNICATIONS SECTION
ANCHORAGE

RE: Extension of Point Thomson Unit appeal deadline

Dear Commissioner:


Upon inquiry, we obtained documents today showing that ExxonMobil requested, and you granted by letter on November 10, 2005, an extension until May 31, 2008, of the deadline to appeal the Director's October 27, 2005 Amended Decision-Denial of the 22nd Plan of Development for the Point Thomson Unit. We inquired whether that extension applies to all parties, and Mr. Havelock of the Division of Oil & Gas advised that he is consulting your office on that question. This letter follows up on the same question.

The Alaska Gasline Port Authority (AGPA) and its chairman, Jim Whitaker, whom this firm represents, are parties affected by the original Denial of September 30, 2005 and the Amended Decision of October 27, 2005, as fully described in our Agency Demand of September 16, 2005.

Please advise by 12 noon Wednesday, November 18, 2005, that the extension to May 31, 2008 granted to ExxonMobil also applies to my clients. If you deny an extension in parity with that granted to ExxonMobil, please advise me of your basis for different treatment between the parties. This letter should not be construed as an affirmation of your November 10, 2005 extension granted to ExxonMobil; my clients reserve their right to appeal that extension, for, *inter alia*, undue delay, at a later date.

Very truly yours,

WALKER & LEVESQUE, LLC

for 

William M. Walker

STATE OF ALASKA

DEPARTMENT OF LAW
OFFICE OF THE ATTORNEY GENERAL

FRANK H. MURKOWSKI, GOVERNOR

1031 WEST 4TH AVENUE, SUITE 200
ANCHORAGE, ALASKA 99511-1994
PHONE: (907) 269-3255
FAX: (907) 279-6644

November 15, 2005

VIA FACSIMILE (907) 278-7001
& U.S. MAIL

William M. Walker
Walker & Levesque, LLC
731 N Street
Anchorage, Alaska 99501

RE: Extension of Point Thomson Unit appeal deadline

Dear Mr. Walker:

I have reviewed your letter of November 15, 2005. DNR will not reject an appeal from the Amended 22nd PTU POD decision on the ground of timeliness if it is received on or before May 31, 2006.

Sincerely,

DAVID W. MARQUEZ
ATTORNEY GENERAL



By:

Richard Todd
Assistant Attorney General

RT/sak

cc: Michael Menges, Commissioner, DNR
Kenneth Griffin, Deputy Commissioner, DNR
Kevin Banks, Director, DNR
Brian Havelock, DNR
Craig Richards, Walker & Lavesque, LLC

**PRESENT-
ATION:
COOK INLET
OIL & GAS
INDUSTRY,
2/1 1/05**



KENAI PENINSULA BOROUGH

Oil and Gas Office
 43335 Kalifornsky Beach Road, Suite 16
 Soldotna, Alaska 99669-8250
 BUSINESS (907) 714-2335 FAX (907) 262-6762
 CELL (907) 398-8245
 bpoppp@borough kenai ak us www.cookinletoilandgas.org

DALE BAGLEY
 MAYOR

Senate and House Resources Committee Kenai Peninsula Hearing February 10th & 11th Schedule of Events & Tours

February 10th

5:30pm to 7:30pm: Reception at the Challenger Learning Center of Alaska
 Next to Kenai Central High School on Kenai Spur Hwy/ Facility #283-2000
 Sponsored by Kenai Peninsula Borough & Peak Oilfield Service Company
 Hors d'oeuvres & hosted beer & wine service

February 11th

7:15am: Legislators & staff meet at Challenger Learning Center for facility tours
 Dress warmly! Wears shoes you don't mind getting dirty. Travel light!

7:30am: Tour groups depart Challenger Center

Group #1		Group #2	
9 members		4 members	
Rep. Chenault, Rep. Ramras, Sen. Stedman Sen. Stevens, Rep. Olson, Sen. Elton, Rep. Elkins, Charisse Millett, House Oil & Gas staff Dan Dickinson, Dept. Revenue		Sen. Wagoner Rep. Seaton AOGCC Commissioner Dan Seamount Peninsula Clarion Reporter Mark Quiner	
7:30am	Unocal picks up group @ CLCA	7:30am	XTO picks up group @ CLCA
8:00am	Arrive @ Unocal Heliport	7:50am	Arrive @ XTO Heliport
8:05am	Safety briefing & Mustang suits	7:55am	Safety briefing & Mustang suits
8:30am	Depart Unocal Heliport for Steelhead platform	8:25am	Depart XTO heliport for "A" or "C" platform
8:50am	Arrive @ Steelhead platform/ tour	8:40am	Arrive @ platform/ tour
10:20am	Depart Steelhead for heliport	10:20am	Depart platform for heliport
10:40am	Arrive @ heliport	10:35am	Arrive @ heliport
10:50am	Depart heliport for LNG plant/ Unocal drives group to plant	10:45am	Depart heliport for Agrium/XTO drives group to plant
11:00am	Arrive @ ConocoPhillips LNG Plant	10:55am	Arrive @ Agrium Nitrogen Plant
12:10pm	Depart LNG Plant/ ConocoPhillips drives group to CLCA	12:10pm	Depart Agrium/ Agrium drives group to CLCA
12:30pm	Arrive @ Challenger Learning Center for lunch	12:30pm	Arrive @ Challenger Learning Center for lunch

February 11th (cont.)

12:30pm: Soup & sandwich lunch at Challenger Learning Center
Lunch provided by ConocoPhillips Alaska

1:30pm: Joint Senate & House Resources Committee meeting
Presenters:
Kate Giard, Chairman, Regulatory Commission of Alaska
Dan Seamount, Board Member, AOGCC
Agrium
ASRC
Aurora Gas
ConocoPhillips Alaska
Forest Oil Company
Marathon Oil Company
Pioneer Oil Company
Tesoro Alaska
Udelhoven Oilfield System
Unocal Alaska

Attending, but not testifying:
Dan Dickinson, Director of Tax Division, DOR
Mark Myers, Director of Oil & Gas Division, DNR

5:30pm: Tentative end of Committee meeting

Attendees

Senators

1. Senator Tom Wagoner, Chair Senate Resources Committee
2. Senator Bert Stedman
3. Senator Gary Stevens
4. Senator Kim Elton

Representatives

1. Rep. Jay Ramras
2. Rep. Mike Chenault
3. Rep. Kurt Olson
4. Rep. Carl Gatto
5. Rep. Paul Seaton
6. Rep. Jim Elkins

Administration

1. Dan Dickenson, Director Tax Division, Department of Revenue
2. Mark Myers, Director Oil & Gas, Department of Natural Resources (at noon)
3. Steve Porter, Deputy Commissioner, Department of Revenue

Staff

1. Mary Jackson
2. Konrad Jackson
3. Charisse Millette
4. x

MJ pick up Gatto 10:15am Friday.

MJ pick up Mark Myers at 12:15pm

MJ drop off for 5:20 flight out : Mark Myers & Carl Gatto

ALASKA STATE LEGISLATURE



Official Business

SENATE RESOURCES COMMITTEE

Senator Tom Wagoner, Chair

State Capitol, Room 427

Juneau, AK 99801-1182

Phone: (907) 465-4907 Fax: (907) 465-4779

WAGONER'S

Senator Ralph Seekins, Vice-Chair

Senator Ben Stevens

Senator Kim Elton

Senator Fred Dyson

Senator Bert Stedman

Senator Gretchen Guess

Joint Senate & House Resources Committee

Feb. 11, 2005

1:30pm: Challenger Learning Center – Kenai, Alaska

1. Call to order

2. Opening Remarks by Chairman Wagoner

3. Regulatory Presenters:

- a. Kate Giard, Chair: Regulatory Commission of Alaska
- b. Dan Seamount, Commissioner: Alaska Oil & Gas Conservation Commission

4. Industry Presenters:

- a. Agrium (Bill Boycott)
- b. ASRC Energy Services (Dan Wuthrich)
- c. Aurora (Dave Bollins)
- d. ConocoPhillips Alaska () *Scott Jepsen*
- e. Marathon Oil Company (John Barnes)
- f. Pioneer Oil Company (Gary Carlson)
- g. Tesoro Alaska (Steve Hanson)
- h. Udelhoven Oilfield System (James Udelhoven)
- i. Unocal Alaska (John Zager)

5. Closing remarks by Committee Members (subject to time).

6. Adjournment.

JOINT SENATE & HOUSE RESOURCE COMMITTEE

FEBRUARY 11, 2005

KENAI

JOHN A BARNES

MARATHON OIL COMPANY

I'd like to thank you for the opportunity this afternoon to present Marathon's views regarding opportunities to enhance Cook Inlet Exploration and Development. First, despite the word oil being the second word in Marathon's corporate name, for nearly a decade our activities in the Cook Inlet have been focused on natural gas. As such, my comments will be focused accordingly.

Clearly, the topic of the day is the decline in Cook Inlet natural gas reserves and the associated impacts. At this time, based on an annual burn of around 200 bcf per year, and around 2,000 bcf (or 2 tcf) of remaining proven reserves, there is about a ten year supply of natural gas left in the Cook Inlet. In and of itself, this situation does not seem overly problematic – after all, this reserve situation is not much different from that in the Lower 48. However, the Cook Inlet market differs from other investment opportunities available to Marathon and other operators in several important ways:

1. The gas supply is isolated from the rest of North America – what we have here is all we can rely upon for our local needs.
2. The mild summer-harsh winter climate means that the large utility component of local demand has huge swings between summer and winter utility demands. This reality requires one of three solutions:
 - a. very large prolific gas reservoirs,
 - b. significant gas storage capabilities, or
 - c. pipeline connections to other sources.

Unfortunately, the large prolific reservoirs are being depleted and replaced by smaller less prolific reservoirs, no significant storage capacity currently exists and as I have already noted, there is no pipeline to other gas sources.

3. **Operating and capital costs are generally much higher in Alaska.**
4. **Permitting and regulatory hurdles can be significant in Alaska, which affects both how quickly something can be done, as well as how much it costs and the effort required.**

The net effect of these issues is that there has been a decline in Cook Inlet natural gas reserves and deliverability, and a not unexpected increase in natural gas prices as Cook Inlet proven gas reserves continue to decline.

The decline of proven reserves in the Cook Inlet was not a surprise. In 1996 one major gas producer testified before the Alaska legislature that they expected to see insufficient gas supply in the Cook Inlet to meet all needs by the mid 2000's. During the decades of oversupply, the price for Cook Inlet natural gas was extremely low by US standards, creating the opportunity for a significant industrial base using the cheap energy and feedstock. During the recent years, the supply of gas has first approached and now fallen below overall demand. As should be expected, this resulted in increased natural gas prices. On the positive side, this situation has stimulated recent exploration efforts in the Cook Inlet, which for the first time ever are focused solely on finding natural gas. This is a good start, but there is more to do.

The Cook Inlet needs a step change in natural gas exploration and development activity and I believe the State of Alaska, as well as industry, has been responding to this need for several years. I'll mention first some positive steps which have been taken, and then talk a bit about where there is clearly need for more activities by both the state and industry.

Several years ago, the State of Alaska enacted the Areawide Lease program. This has been demonstrated to be a very effective program which annually makes available lands open for leasing.

In 2003 the Legislature passed, and the Governor signed several bills directed at providing incentives for new exploration and development activities. Marathon was particularly interested in House Bill 61, an Investment Tax Credit for exploration and development of Cook Inlet

Gas Reserves. This was kicked around for several years in Juneau until the time was ripe for passage. One possible action the State could take would be to look at strengthening this incentive. It could be extended to include revitalizing old fields, returning shut-in fields to market, or perhaps even including a greater fiscal incentive.

In 2000 Enstar signed a gas sales agreement with Unocal, which was approved by the RCA, which reflected the need to pay higher prices for natural gas as an incentive for new exploration and development.

All of these actions, as well as others, have led to a recent increase in exploration and new gas discoveries in the Cook Inlet.

And recently the US DOE completed a report which identified significant potential in the Cook Inlet for additional gas through infield reserves growth, new discoveries and from coal bed methane. This same report identifies the need for significant capital expenditures to bring this gas to market and provides a high level discussion of the viability and costs associated with a spur line running to southcentral Alaska from a north slope gas line.

A few specifics from the report indicate that:

- An expenditure of \$500 million is associated with finding infield reserve growth of 1.4 tcf.
- An expenditure of \$5-6 billion is associated exploration and development of 6-8.5 tcf of potential resource.
- An expenditure of \$500 million is associated with a spur line.

These are all huge expenditures for which investors will want to closely control as many areas of risk as possible. We need to remember that one way or another, most producing companies are publicly owned. These companies are essentially stewards of value for their owners. All of us in this room make investments and desire a reasonable return – if we don't like the risk or the potential reward, we take our business elsewhere. We need to see the Cook Inlet producers in the same light, and understand their desire to generate a reasonable return for their shareholders.

What can State and local legislators and regulatory bodies do to encourage investment, which is what exploration and development

really is? They need to understand and help manage (or at least not increase) investment risk.

Oil and gas producers cannot control subsurface risk, but companies understand this and manage it.

They cannot control the risk associated with the price they get for their product, but will be willing to spend money where and when they expect to get a fair return on their investments. What this means is that Cook Inlet natural gas prices must be competitive with prices in other areas where companies can drill for and produce gas. Unless new world class natural gas discoveries are made, the era of low price natural gas in the Cook Inlet would appear to be over.

Companies work hard to control project execution risk in the areas of cost and timetables. This is a critical competency for companies which are successful. It is hoped that additional activity in the Cook Inlet will be sufficient to support an effective contract and supply base. (MOVE THIS)

The most notable risk companies now face in Alaska is regulatory and tax uncertainty. No oil and gas development speech is ever given by industry which does not identify the need for stability in these areas. I'm certain you all recognize that a good reputation takes a long time to develop, but unfortunately can be easily lost by one event.

In the Cook Inlet, Marathon is most frustrated by the delays and burdens associated with obtaining permits & regulatory approvals, which we believe greatly exceeds that which is required to best serve the public interest. At best it slows down drilling and development and increases costs, which negatively affects every Alaskan business and consumer. At worst, it kills investment and drives investment capital elsewhere, depriving Alaskans the opportunity to benefit from the State's considerable natural resources and attracting new individuals and businesses (or even retaining those we already have).

To drill a gas well onshore in the Cook Inlet can require up to 50 permits, plans, permissions and reports often involving several state, federal, and local jurisdictions. Each of these takes time. Each one costs the operator and regulatory body money to prepare, review and

approve. And each one is a potential target for litigation directed at delaying or stopping development. This is an extremely complicated problem. The permits have some basis in legislation, law and regulation. To truly impact this problem will require coordination, rationalization and trust between jurisdictions and their regulatory bodies. I'd also like to mention that Marathon respects and works well with numerous individuals and agencies. They work hard and I know so many of them are committed to doing what is right and prudent. Many agencies have also shown a great interest, an open door to discussing the issues I've raised here and we appreciate these efforts and are eager to do our part to keep lines of effective communication and cooperation open.

In addition to the permit requirements for wells and facilities, Marathon has found the permitting and regulatory time and costs associated with pipelines to be particularly burdensome. Most, if not all, new gas discoveries in the Cook Inlet will require new pipelines tied into the existing network. Marathon believes efforts to streamline the overall permitting and regulatory process for these lines will benefit not only the producers but also the end users; which includes utility customers like you and I. Recently Chairperson Giard and her fellow RCA Commissioners have begun an effort to address many of these issues. Marathon welcomes her interest and supports this effort.

GUY-ARD

Responses to several specific questions were included in the invitation and I'll offer Marathon's views.

1. As to bringing in a jackup rig to the Cook Inlet, Marathon is concerned with the permitting and expected legal challenges associated with bringing any discovery to market. Remember, a well drilled from a jackup is just the start. Mitigating the risks associated with setting a new platform in the Cook Inlet is a formidable task.
2. Marathon has been active exploring for new gas opportunities on the Kenai National Wildlife Refuge. Although challenging, it is possible and I believe we have done a good job balancing the needs to care for the environment and develop resources.

In summary, Cook Inlet has some great attributes:

First, it is a basin with proven gas productivity and significant upside in gas resources.

Second, there is good access to lands.

Third, there is a market which needs more natural gas for both utility and industrial customers.

However, it also has considerable challenges. I strongly feel that there are two great needs:

First, the overall success of Cook Inlet gas exploration and development will be tied to the permitting and regulatory burden, including pipelines. This is the area where efforts by the State of Alaska to streamline and create more consistency in the process can have the greatest impact.

Second, the potential need to incentivize gas exploration, development and production investment activities should be considered.

Thank you.

**Regulatory Commission of Alaska
2005 Improvement Initiative**

- Goal: Identify Regulations Projects to Address in 2005**
- Goal: Increase Public Involvement in the Development of RCA Workplan**
- Goal: Address Weaknesses in RCA Regulations**

Approved by the RCA on January 26, 2005

**Regulatory Commission of Alaska
Public Meeting - January 26, 2005
Regulations Projects Approved**

Item	Proposal Number	Description	Administrative Impact			Proposed Method
			Complexity	Duration	Starting Month	
<u>TELECOMMUNICATIONS</u>						
A.	1	Intercarrier Compensation	Very	2 Years	Jan-05	NOI
B.	2	New Federal IXC Provisions	Moderate	1.5 Years	Jan-05	NOI
C.	4	ETC Rules	Moderate	1.5 Years	Apr-05	NOI
D.	9	Depreciation Table	Moderate	1 Year	May-05	Advisory Group
E.	28	Affordability	Very	2 Years	Jun-05	Advisory Group
<u>ADMINISTRATIVE</u>						
F.	15	Electronic Filings	Routine	1 Year	May-05	Advisory Group
G.	30	Timeliness Standards	Routine	1 Year	Nov-05	Advisory Group
<u>PIPELINES OR GENERALLY APPLICABLE</u>						
H.	18	Alternate Dispute Resolutions	Very	1.5 Years	Mar-05	Staff Develop Regs with FERC++
I.	21	Tariff Filings	Moderate	1.5 Years	Oct-05	Staff Develop Regs++
J.	24	Discovery	Very	2 Years	Oct-05	NOI
K.	19	Stipulations	Very	1 5 Years	Mar-05	Staff Develop Regs++

++

It was pointed out subsequent to the public meeting that the original plan discussed with the pipeline interests was to have these regulations prepared in a working group or other alternative method which involved stakeholders. The Chairman agrees this was the intention of the group and will bring a correction back to a public meeting in the future for a vote of the Commission

Regulatory Commission of Alaska
Public Meeting - January 26, 2005
Regulations Projects and Statutory Revisions
Public Comments
Comments - Proposed Regulations

Proposal Number	Description	Utility & Pipeline Comments	
		Supporting Comments	Opposing Comments
TELECOMMUNICATIONS			
1	Intercarrier Compensation	ACS - extremely important GCI - Already Open. AT&T Alascom - useful proceeding	
2	New Federal IXC Provisions	ACS - extremely important GCI - Already Open. AT&T Alascom - rated as its most important R-docket.	
3	Customer Weighting	ACS - open, but with low priority. Not an immediate issue.	ACS - Maybe can do in R-03-03 GCI - Resolve in R-03-03
4	ETC Rules	Summit RC - High priority, need rules on designation of ETC status and on ETC standards	ACS - FCC actions pending, no docket needed GCI - Resolve on a Case By Case Basis, rules could be preempted.
5	Triennial Review Issues		ACS - more prudent to wait for FCC GCI - No regs are needed.
6	Quality of Service	RC, Summit	ACS - don't open due to limited resources GCI - Reality is regs will do little if costly to implement. AT&T Alascom - No quality of service problems, let competition address quality of service
7	Telecommunications Act - Rewrite		ACS - Don't know yet where headed, too early, suggests maybe a workshop. GCI - R Docket is too cumbersome a process to develop responses to legislative inquiries.

Regulatory Commission of Alaska
Public Meeting - January 26, 2005
Regulations Projects and Statutory Revisions
Public Comments
Comments - Proposed Regulations

Proposal Number	Description	Utility & Pipeline Comments	
		Supporting Comments	Opposing Comments
TELECOMMUNICATIONS			
8	Bundling - Outstanding issues		ACS - Bundling only recently implemented, issues for consideration are not an immediate concern AT&T Alascom - would give bundling issues a low priority GCI - These rules are not critical.
9	Depreciation Table	ACS (mid priority), RC, Summit, GCI (with suggestion)	GCI - Adopt the FCC table in R-03-03
10	Carrier of Last Resort	ACS - should consider shared COLR issues, use separate LEC and IXC proceedings, assigns a mid priority	AT&T Alascom - no need in IXC market; issue was adequately addressed in R-03-03. GCI - Case by case basis. Regs will be easier to adopt after real-world experience.
11	Housekeeping Changes to IXC Registration	GCI - Address after Staff produces proposed rules.	
12	Registration of Payphones; Annual Report Requirements for Private and Public Interest Payphones	GCI - If the Commission is receiving many applications, address after Staff produce proposed rules.	
13	Update/ standardizing of filing forms	GCI - Address after Staff produces proposed rules.	ACS
14	800 Query Policies	AT&T Alascom - 800 Query policies are an area of confusion and difficulty	ACS - better to resolve pricing issues through the tariff process, R Docket may not be necessary GCI - Resolve in adjudicatory dockets.

Regulatory Commission of Alaska
Public Meeting - January 26, 2005
Regulations Projects and Statutory Revisions
Public Comments
Comments - Proposed Regulations

Proposal

Number Description

Utility & Pipeline Comments

Supporting Comments

Opposing Comments

TELECOMMUNICATIONS

ADMINISTRATIVE

15	Electronic Filings	<p>ACS (mid priority), AT&T Alascom Chugach - Supports but need to better define cost. Appears low. Tesoro/Agrium support Conoco (North Slope) Lower priority Enstar supports GCI - Necessary when Commission is able to accept electronic filings.</p>
----	--------------------	--

16	Practices and Procedures	<p>GCI - Address after Staff produces proposed rules.</p> <p>Tesoro/Agrium support, limited scope Chugach discovery comments also focused on practice and procedure. Enstar supports, limited scope</p>	ACS
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17	Housekeeping - PAS	<p>GCI - Address after Staff produces proposed rules.</p>	ACS - not critical project
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PIPELINES OR GENERALLY APPLICABLE

18	Tariff Filings	<p>Tesoro/Agrium support, prefiled testimony</p>	<p>ACS - of little value to ACS, but maybe to others BP - Believes statutory changes are nec. GCI- Requiring prefiled testimony will be highly contentious.</p>
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19	Stipulations	<p>BP - Believes statutory changes are nec. Chugach - Supports proposal to identify standards.</p>	<p>ACS - not critical project GCI - Case by case basis. Tesoro/Agrium - Best left to adjudication Enstar - agrees with Tesoro/Agrium</p>
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20	DR&R	<p>BP - Believes statutory changes are nec.</p>	<p>Tesoro/Agrium - Best left to adjudication</p>
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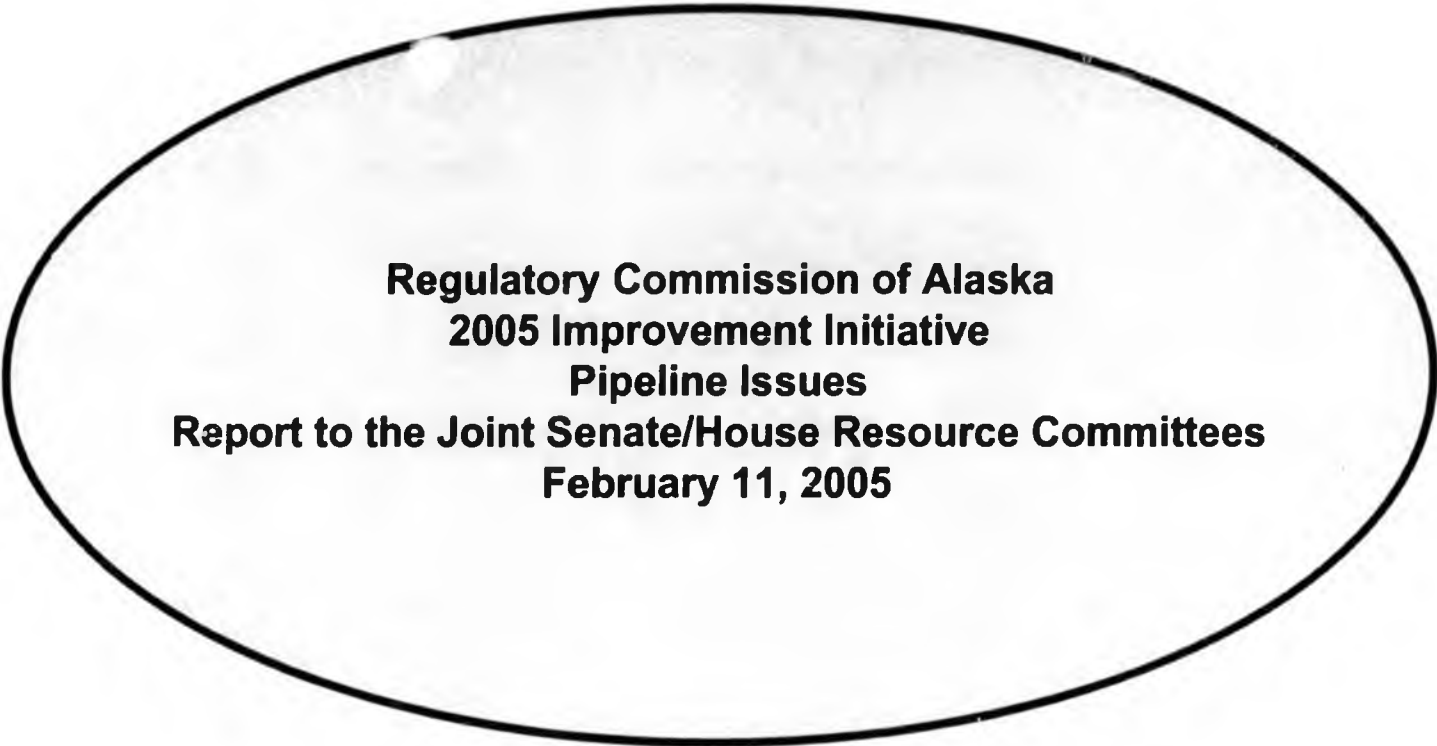
Regulatory Commission of Alaska
Public Meeting - January 26, 2005
Regulations Projects and Statutory Revisions
Public Comments
Comments - Proposed Regulations

Proposal Number	Description	Utility & Pipeline Comments	
		Supporting Comments	Opposing Comments
TELECOMMUNICATIONS			
21	Discovery	ACS - historical difficulties with discovery, mid priority project BP - Highest Priority (one of three) Tesoro/Agrium support Conoco (North Slope) Chugach Supports and has specific recommendations for commission consideration	GCI - Case by Case Basis.
22	Pipeline Certification		Tesoro/Agrium - no clear need
23	Transfers	GCI - Appropriate but not critical. Conoco (North Slope) - Lower priority Enstar supports	ACS - not critical project Tesoro/Agrium - no clear need
24	Alternate Dispute Resolutions	BP - Highest Priority (one of two) Tesoro/Agrium supports, but hesitant, must be done properly Conoco (North Slope) support Enstar agrees with Tesoro/Agrium	ACS - not critical project
25	Open Season	Conoco (Cook inlet) supports Chugach supports and encourages Commission to work with Utilities to understand natural gas needs.	Tesoro/Agrium - Best left to adjudication Enstar - agrees with Tesoro/Agrium
26	Instate Gas use		Tesoro/Agrium - No need for R-docket Enstar - high priority issue, but not for R docket
ITEMS ADDED DURING PUBLIC MEETING			
27	Access Charge Reform 2	AT&T Alascom - First phase of access charge reform was beneficial, encouraging investment and reducing arbitrage. Given time for review, would be good to consider phase 2 reforms. In R-01-01 all agreed to move to phase 2. RC - Supports review	ACS - recent reform was only just completed, learn from implementation before attempting new reform, Intercarrier Compensation reform is occurring, further considering access charge reform now is not a good use of resources.

**Regulatory Commission of Alaska
Public Meeting - January 26, 2005
Regulations Projects and Statutory Revisions
Public Comments
Comments - Proposed Regulations**

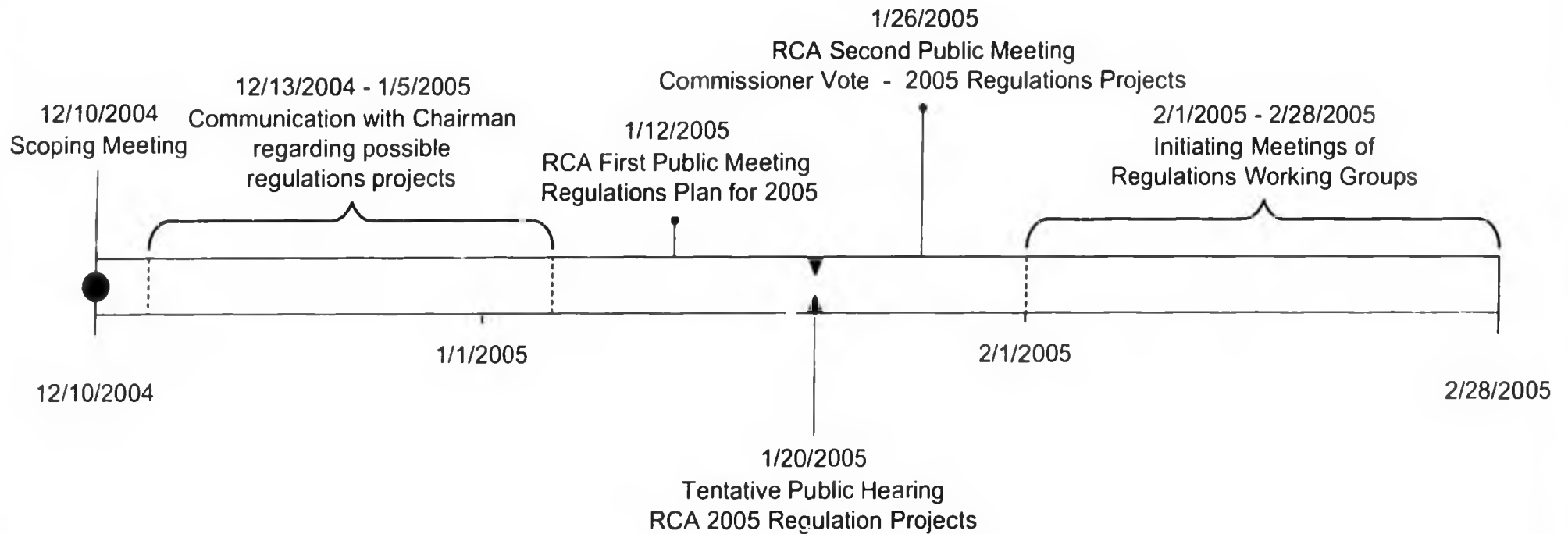
Proposal Number	Description	Utility & Pipeline Comments	
		Supporting Comments	Opposing Comments
TELECOMMUNICATIONS			
28	Affordability	ACS (mid priority), RC (high priority). RC would limit to telco issue.	
29	Exparte/ Pre application discussions	ACS - suggests the Commission review its exparte rules; specifically mentions meetings on adjudicatory matters before a docket is opened, pre application discussions, and discussions during rulemakings, sees as mid priority	
30	Timeliness Standards	ACS - believes notice of inquiry is needed, refers to interpretation of timeliness standards in the case involving Carr Gottstein. Sees as high priority.	
31	Rural Regulatory Parity	RC - High priority, need to address due to pending competition in rural areas without adequate rules	
Harbour	Pipeline Connection Forms		
Harbour	Affiliate relationships		
Harbour	Power/gas supply agreements		
Harbour	F-W-A standards - financial info		
Read in	Utilize JPO	Conoco Phillips - Written Comments	
Read in	Preapplication meetings	Conoco Phillips - Written Comments	
Read in	Flow lines	Joint Pipeline Office Written Comments	

Note: ATA indicated its rural interests were represented by the Rural Coalition



**Regulatory Commission of Alaska
2005 Improvement Initiative
Pipeline Issues
Report to the Joint Senate/House Resource Committees
February 11, 2005**

▶ RCA 2005 Improvement Initiative 2005 Regulations Projects Planning and Preparation



Dave Walters
Unocal Alaska

Meg Yaege
Colleen Mukavitz
ConocoPhillips
Transportation

Tony Izzo, Enstar
Natural Gas

Jane Petry,
ExxonMobil
Pipeline

Steve Haagenson,
Golden Valley (via
teleconference)

Kent Hampton,
Kenai Kachemak
Pipeline, LLC

Jim Senn, Agrium
US, Inc.

Rodney Cason
Tesoro Alaska
Pipeline Company

Leonard Gurule,
Forest Oil
Corporation

Jerry Brossia
Joint Pipeline Office

Regulatory Commission of Alaska
2005 Improvement Initiative
Scoping Meeting
Pipeline Issues
December 10, 2004

Bill Corbus &
Scott Porter
Department of
Revenue

John Norman,
Alaska Oil & Gas
Conservation
Commission

Phil Reeves, Alaska
Attorney General's
Office

Judy Brady, Alaska
Oil & Gas
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Dawn Bishop, RCA

Jim Strandberg,
RCA

Kate Giard, RCA

Shawn Brown
Kenai Pipeline
Company

Al Bolea, BP
Pipelines Alaska,
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John Barnes,
Marathon Oil
Company

Mark Hanley,
Anadarko
Petroleum

Chuck Coulson, BP
Exploration Alaska,
Inc.

Rob Knapp, Koch
Alaska Pipeline
Company

Doug Chapaodos,
Petro Star, Inc.

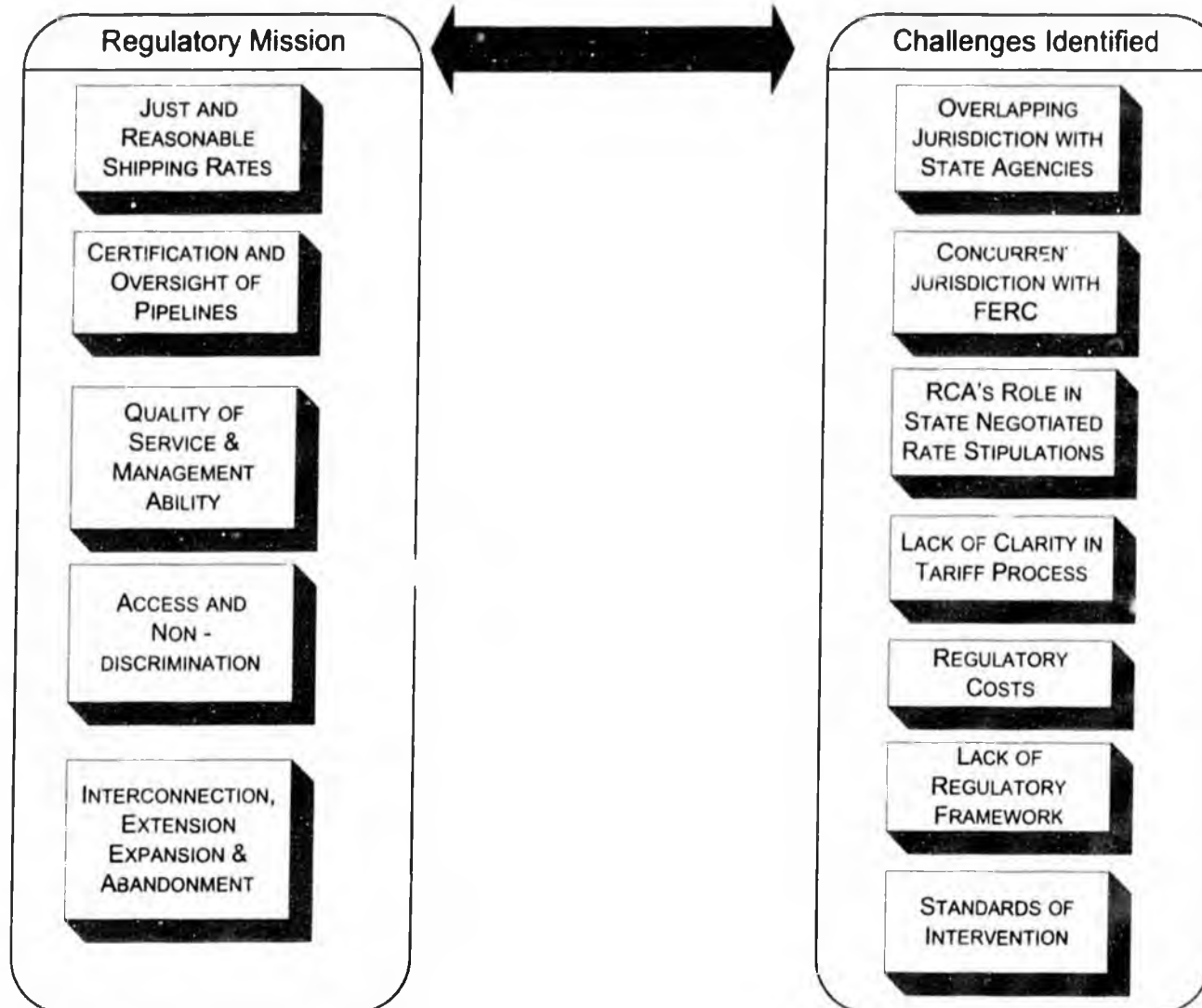
David Boelens,
Aurora Gas, LLC.

Lanston Chinn,
Kuukpik
Transportation
Company, LLC

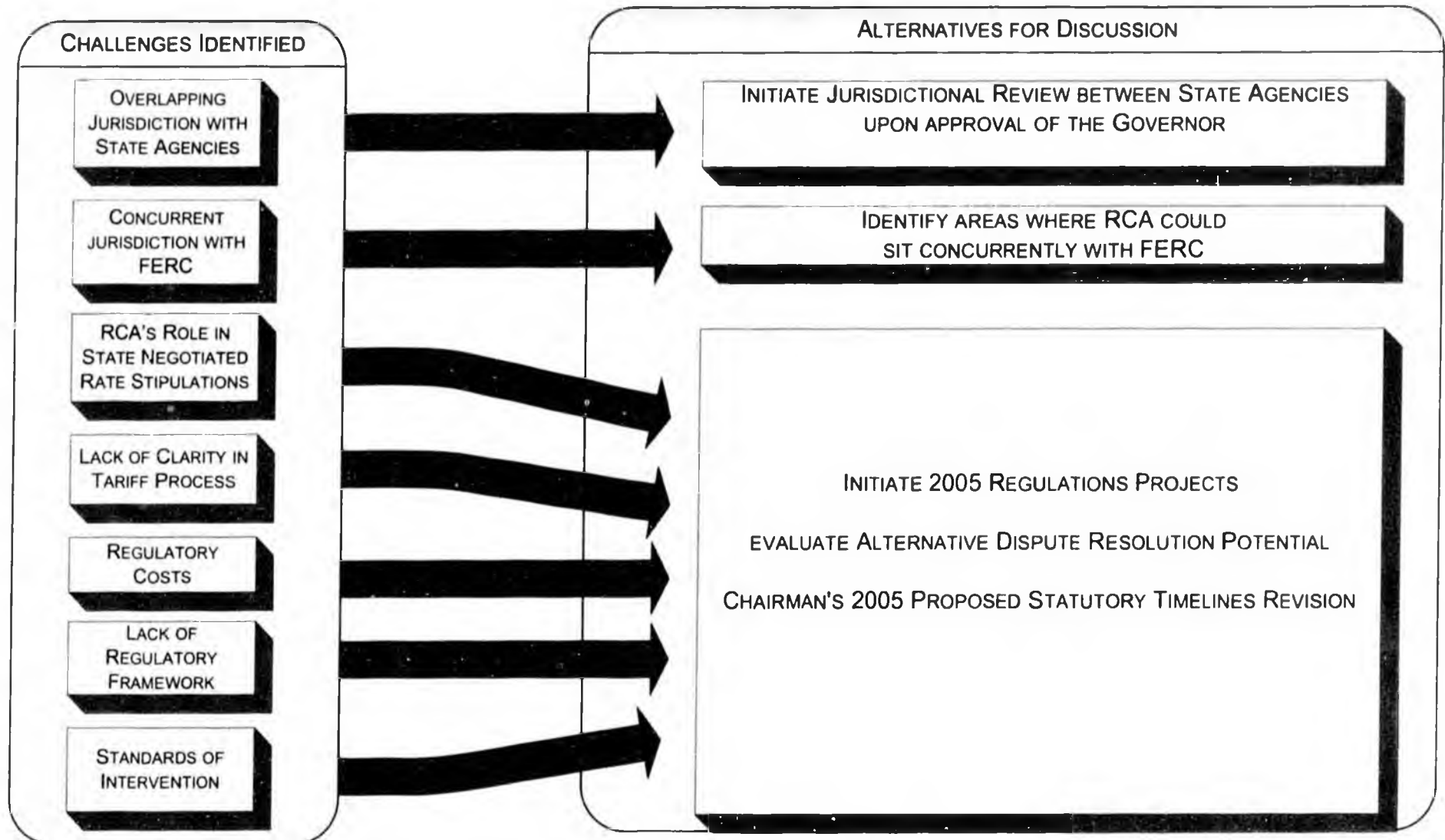
Marty Rutherford,
Department of
Natural Resources

RCA 2005 Improvement Initiative

Mission versus Challenges



RCA 2005 Improvement Initiative Challenges & Alternatives



RCA 2005 Improvement Initiative

Next Steps

Jurisdictional Overlap

INITIATE JURISDICTIONAL REVIEW BETWEEN STATE AGENCIES
UPON APPROVAL OF THE GOVERNOR

OBTAIN APPROVAL FROM GOVERNOR'S OFFICE FOR
STATE AGENCY PARTICIPATION

POSSIBLE AGENCY PARTICIPANTS
RCA
DNR
REVENUE
JOINT PIPELINE OFFICE
ATTORNEY GENERAL

INDUSTRY PARTNERS TO PROVIDE WHITE PAPER ON
SPECIFIC AREAS OF OVERLAP FOR ANALYSIS

AGENCIES CONTRIBUTE RESOURCES TO EVALUATE
OVERLAP



**RCA 2005 Improvement Initiative
Next Steps
Concurrent Jurisdiction with FERC**

RCA STAFF TO IDENTIFY OPPORTUNITIES

RCA MEETING WITH FERC IN JANUARY/FEBRUARY IN DC
TO SCOPE VARIOUS PROJECTS

JOINT FERC/RCA LETTER TO GOVERNOR

CHAIRMAN'S REPORT TO OVERSIGHT COMMITTEE IN
MARCH

→ **RCA 2005 Improvement Initiative**
Next Steps
2005 Regulations Projects

TARIFF RULES FOR PIPELINES

ALTERNATIVE DISPUTE RESOLUTION

DISCOVERY RULES GOVERNING PIPELINE CASES

STIPULATIONS

DR&R (CURRENTLY OPEN DOCKET)

FORM WORKING COMMITTEES, TIMELINES AND
GOVERNANCE

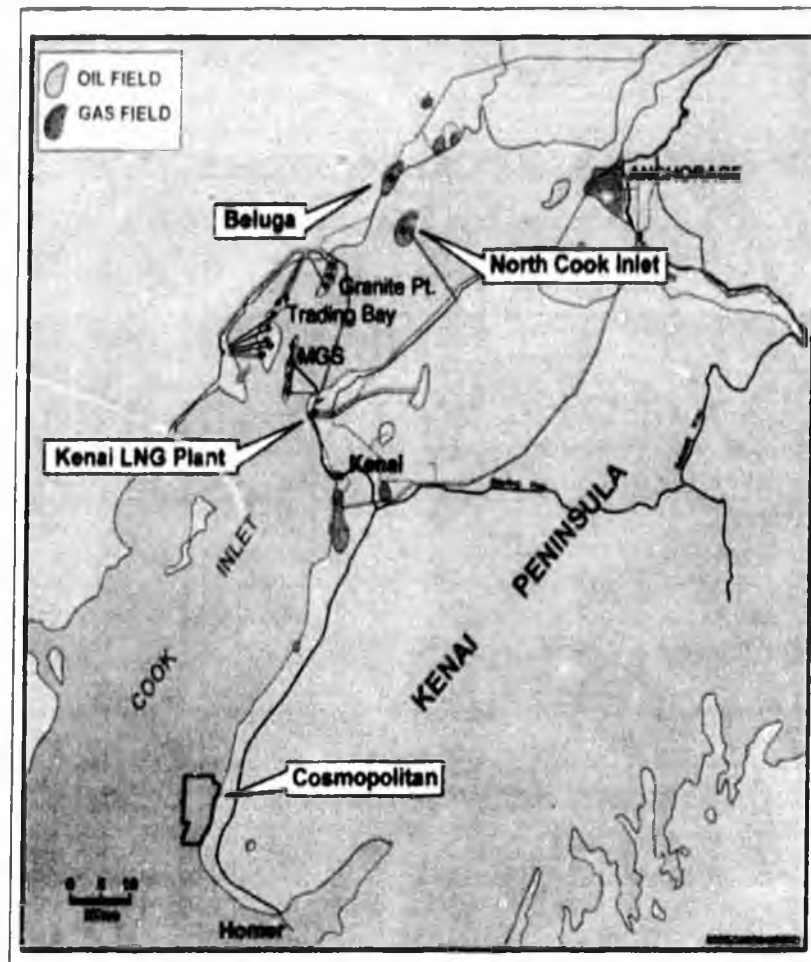
ConocoPhillips Testimony Joint Senate/House Resource Committee

February 11, 2005

Overview



- ConocoPhillips has been a part of the Cook Inlet community since the early '60's
- Cook Inlet Assets
 - Beluga River Field - 1968
 - Operator
 - 33% Working Interest
 - North Cook Inlet Unit - 1969
 - Operator
 - 100% Working Interest
 - Kenai LNG Plant - 1969
 - Operator
 - 70% Working Interest
 - Cosmopolitan (Exploration play)
 - Operator
 - 70% WI
- ConocoPhillips Alaska Focus
 - ANS gas
 - NS exploration
 - Development potential in existing assets

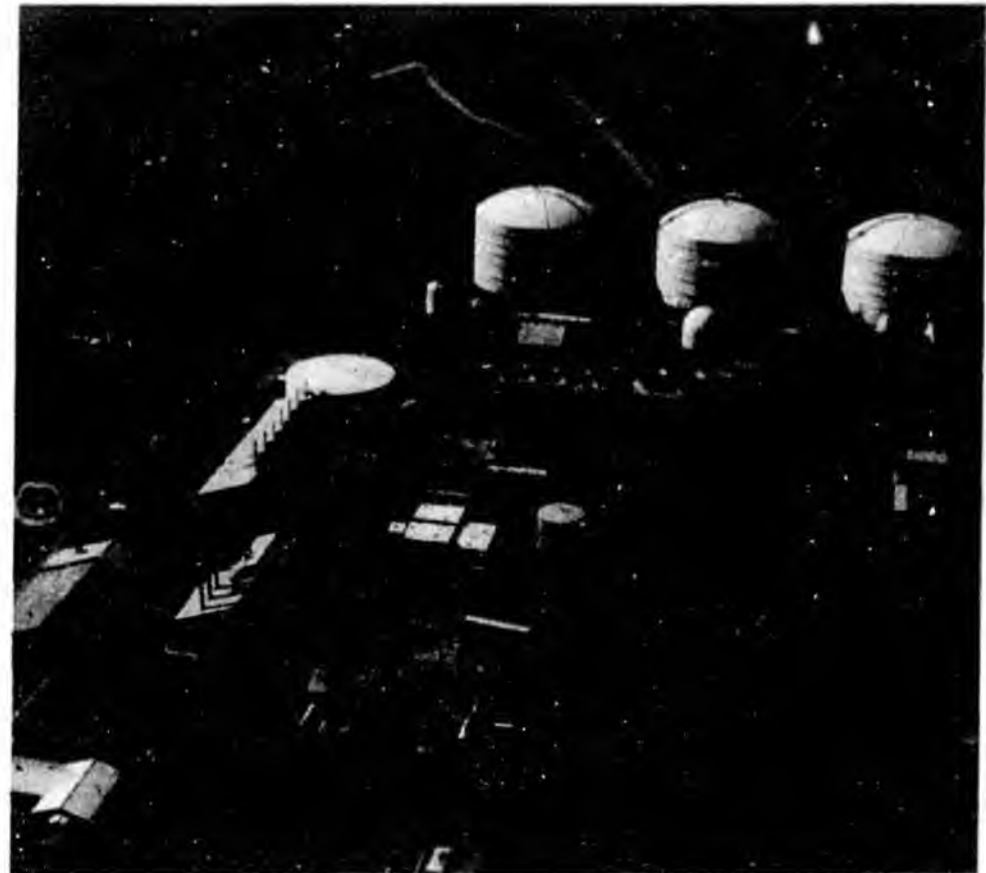


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- **\$54MM in Financial Contributions**
 - \$16MM royalties
 - \$11MM severance taxes
 - \$2MM property taxes (Kenai Borough)
 - \$8MM in wages
 - \$17MM Cook Inlet area supplier spend
 - \$220,000 in direct contributions to Kenai Peninsula non-profits

- **Cook Inlet operations employs ~90 local residents**



Cook Inlet Business Environment



- Advantages
 - Stable, talented workforce
 - Supportive government and local population
 - Significant infrastructure
 - Resource rich

- Recommendations
 - Stable state-wide tax environment
 - Non-discretionary tax credits for exploration and new investments (including existing fields)
 - Increased access to lands and efficient permitting processes



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ASRC Energy Services

a subsidiary of Arctic Slope Regional Corporation

Alaska State Legislature Senate Resources Committee

Cook Inlet Basin Oil & Gas Forum

February 11, 2005

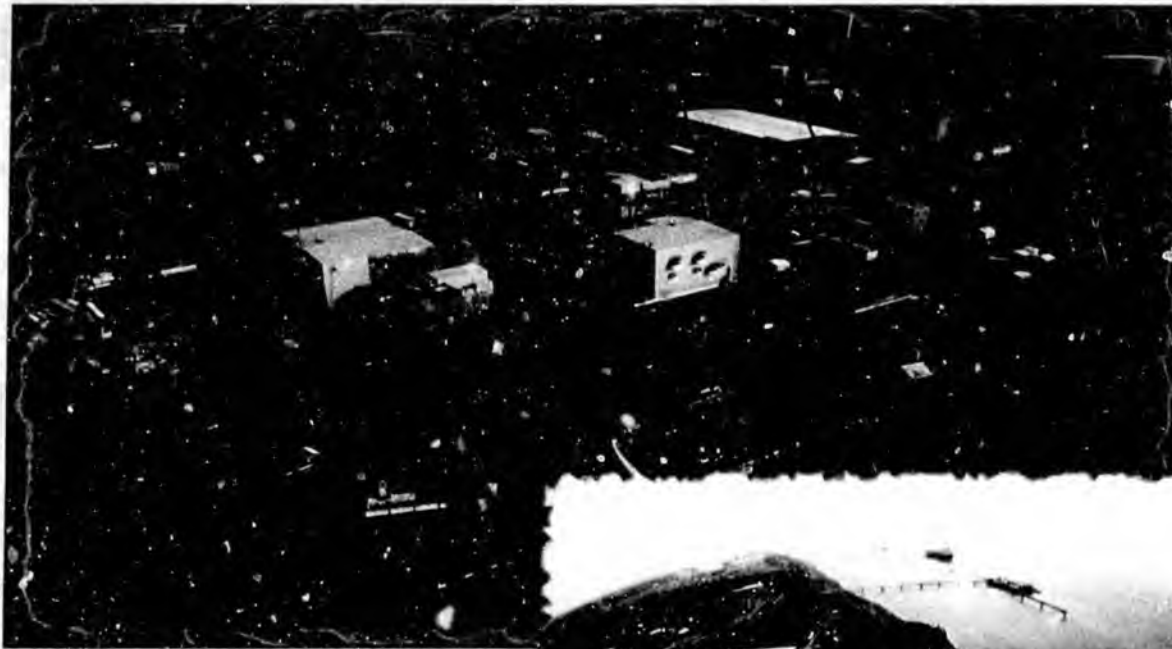
Nikiski, AK Fabrication Facility



CAPACITIES:

- Largest deep-water fab dock face in Alaska
- 10,000 ton dock face capacity + beaching
- Live-load + Dead-load capabilities
- 25,000 tons/yr module capacity
- 26,000 sq. ft. shop (environmentally controlled)
- 31 acres; 8 acres lighted dock/lay-down
- pipe, steel fabrication
- 2100 LF Dock-face

Alpine Module Assembly Project

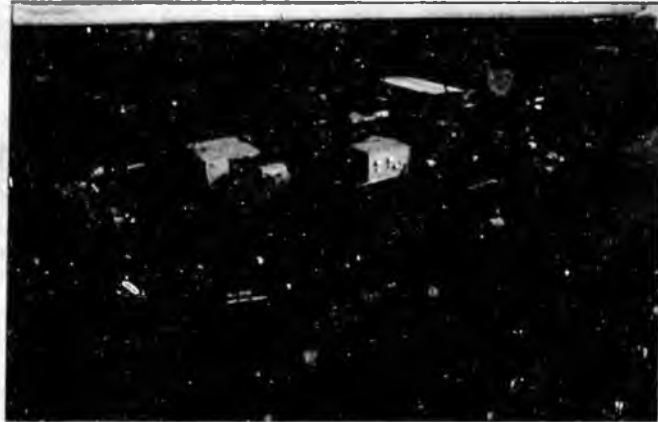


- 18 Modules
- 5,000 tons total
- 9 sealift modules at Nikiski
- 1,100 tons largest
- 14 month duration



PHOTO BY: ROB STAPLETON

Assembly Site Schedule



Alpine Project:

- 3/98 Site preparation began - \$1.4mm upgrades
- 6/98 Module construction and assembly began
- 7/99 Modules shipped to North Slope
- 11/00 Oil flowing at Alpine

Local Community Impact



- 759,000 man-hours expended by local labor and staff
- \$23.2mm+ wages paid to local craft
- 340 craft personnel
- 46 staff personnel
- \$1.2 mm spent on subcontracts to:
 - Atigun, Inc.
 - R & K Industrial
 - Metal Magic
 - Guardian Security
 - Laidlaw Transit
 - Dunkin & Bush
 - Others

Community Impact (cont.)



- \$7.5mm spent with local vendors on:
 - Consumables
 - Commodities
 - Tools
 - Equipment rentals
 - Services
 - Materials
- Community college worked to train craft for the project (21 welders)

Existing Fields Are Showing Their Age

Opportunities to attract new projects by:

- Streamlining permitting process
- Providing tax and other incentives to attract new exploration and development
- Supporting an exploration rig for offshore development
- Support the 2006 Alaska Cook Inlet OCS lease sale.

Thank You



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bpoppp@borough.kenai.ak.us www.cookinletoilandgas.org

DALE BAGLEY
MAYOR

Cook Inlet Oil & Gas 2004 Annual Report

Bill Popp, Oil and Gas Liaison

January 21st, 2005

The Kenai Peninsula Borough and the Cook Inlet Basin, as Alaska's first oil and gas province, continues to play a vital role in the economy of Alaska. This report will address a number of important issues related to oil and gas reserves, future production and related issues of interest to the Kenai Peninsula Borough.

Highlights of this report include:

- Net proven natural gas reserves within the Cook Inlet Basin have increased for the first time since 1997. (Page 4)
- Forecasted Cook Inlet natural gas annual production levels will not drop below 200 billion cubic feet until 2007. (Page 5)
- U.S. Department of Energy study estimates significant undiscovered reserves of conventional natural gas in excess of 13 trillion cubic feet yet to be discovered in the Cook Inlet Basin. (Page 6)
- The Prevailing Value of Cook Inlet natural gas continues to trend upwards and is approaching an annual average in excess of \$3.00+ per thousand cubic feet of natural gas. (Page 6)
- Cook Inlet natural gas pricing will continue to trend upwards in 2005. (Page 7)
- Natural gas exploration will continue at strong levels in the onshore regions of Cook Inlet in 2005. (Page 8)
- The deliverability of natural gas within the Cook Inlet Basin may become an even more significant issue for both industrial and utility users in the next winter season unless storage capacity is established within the Cook Inlet Basin. (Page 10)
- Several North Slope natural gas pipeline projects, none of which have yet achieved clear economic viability, will continue to develop in 2005. (Page 11)

- Federal Outer Continental Shelf (OCS) lease sale 199 is on schedule for May, 2006 and offers significant potential oil and natural gas reserves opportunities. (Page 14)
- Proposed Bristol Bay oil & gas leasing could offer opportunities to the support industry companies of the Kenai Peninsula Borough. (Page 15)
- Net proven oil reserves within the Cook Inlet Basin were significantly downgraded in 2004 and are forecasted to be depleted by the end of 2016. (Page 16)
- New State and Federal incentives will be needed to stimulate new oil exploration efforts within the Cook Inlet Basin if new proven oil reserves are to be discovered. (Page 18)
- Crude oil related exploration efforts will be at modest to minimal levels in 2005. (Page 19)
- Dismantling, Removal & Restoration (DR&R) standards for Cook Inlet platforms will become a major topic in the next few years related to taxable property values within the Kenai Peninsula Borough. (Page 20)
- The Cook Inlet National Pollutant Discharge Elimination System (NPDES) oil and gas general permit renewal process could impact the economics of Cook Inlet offshore platforms. (Page 21)
- The Pebble Gold-Copper project in Iliamna, if developed, will offer opportunities to the Kenai Peninsula Borough for several hundred jobs and general infrastructure and economic development. (Page 21)
- Workforce demands exceeding several thousand skilled workers in the oil and gas related industries could develop in Alaska during the next 4 to 8 years. (Page 23)

Natural Gas

Cook Inlet natural gas reserves have been an issue in recent years due to declines in net proven reserves and problems related to the deliverability of natural gas to utility and industrial end users. This section will examine these two topics and the future outlook for solutions.

Natural Gas Reserves

The following chart describes Cook Inlet natural gas proven reserves since the most recent peak proven reserves year of 1997. Reserves replacement data are calculated inclusive of annual natural gas consumption and net proven reserves.

Estimated Cook Inlet Basin Reserves, Consumption and Reserves Replacement 1997 to 2004				
Year	Proven Reserves ¹ (Billion Cubic Feet)	Total Annual Production ² (Billion Cubic Feet)	Net Proven Reserve Increase/Decrease (Billion Cubic Feet)	Reserves Replacement (Billion Cubic Feet)
1997	3,281	215	+439	+653
1998	3,066	215	-215	0
1999	2,843	213	-223	-10
2000	2,564	216	-279	-63
2001	2,460	222	-104	+118
2002	2,240	210	-220	-10
2003	2,031	208	-209	-1
2004	2,088	219 ³	+57	+276

Based on this data, Cook Inlet natural gas proven reserves have grown for the first time in seven years by 57 billion cubic feet (bcf). Of more significance is the increase in reserves replacement in 2004 that generated 276 bcf of natural gas that offset 2004 total annual consumption while contributing to a net gain of proven reserves in the Cook Inlet Basin.

Significant declines in proven reserve estimates in the offshore McArthur River and North Cook Inlet units and the onshore Swanson River Unit totaled 124.3 bcf in lower reserves were offset by new exploration efforts in the Ninilchik, Deep Creek & Beluga Units and in-field rework efforts in the Kenai Unit that generated 219.6 bcf of new proven reserves. The balance of increased natural gas reserves replacement totaling 180.7 bcf in 2004 was the result of exploration and in-field rework in several smaller units located throughout the Cook Inlet Basin.

These new proven natural gas reserves estimates have generated a revised production forecast¹ that is represented in the following graph.

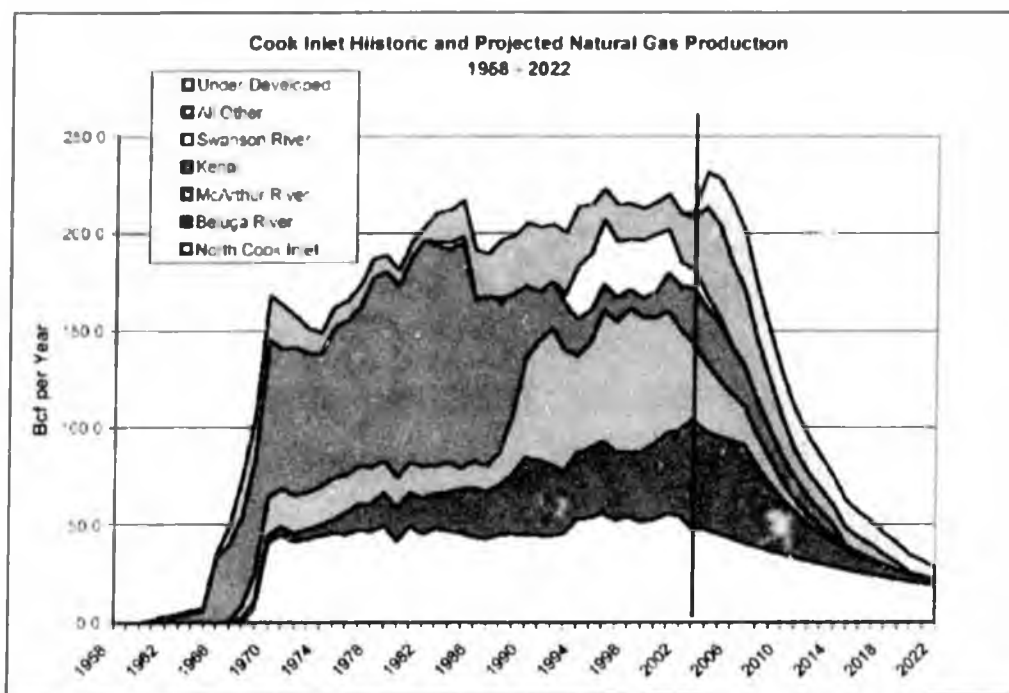
¹ State of AK, Department of Natural Resources, Division of Oil & Gas Annual Reports 1996 through 2004

² State of AK, Department of Natural Resources, Division of Oil & Gas Annual Reports 1996 through 2004

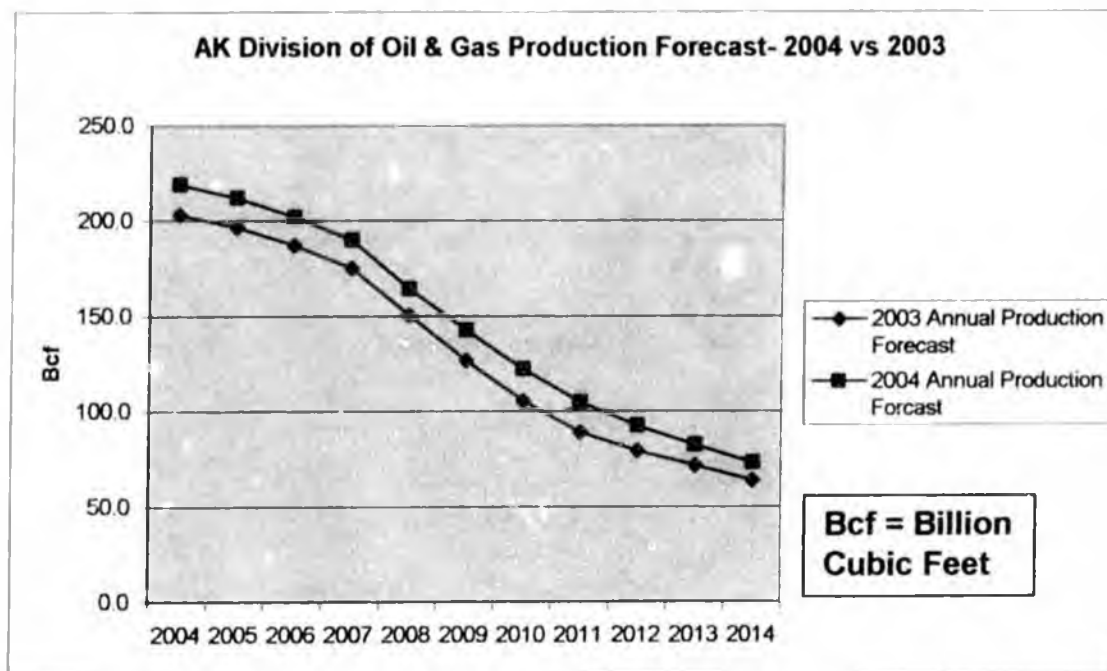
³ State of AK, Department of Natural Resources, Division of Oil & Gas 2004 Annual Report, Page 4-25 Forecast of Natural Gas Production in 2004

⁴ State of AK, Department of Natural Resources, Division of Oil & Gas 2004 Annual Report, Figure IV.6

Cook Inlet (Billion Cubic Feet per Year)



The significance of this updated production projection is that the previously forecasted annual production decline below the 200 bcf threshold, last projected for 2005, has now been pushed back to the year 2007. Additionally, the ten-year forecast now projects an additional total production of 157 bcf of natural gas over the previous ten year forecast in the 2003 Annual Report.⁵ This revised ten-year forecast is represented in the following graph.



⁵ State of AK, Department of Natural Resources, Division of Oil & Gas 2004 Annual Report, page 4-25

This new reserves replacement effort by industry has been driven by increased Cook Inlet market prices for natural gas that have been on the rise in recent years. This upward pricing pressure is discussed later in this report.

Proven natural gas reserves replacement was a subject of intense public and industry discussion in 2004. Of most significance to this dialog was the release of the U.S. Department of Energy (DOE) study⁶ of potential reserves within the Cook Inlet Basin. This study, based on a statistical analysis of publicly available geological and industry data, estimates that there are potentially 13 to 17 trillion cubic feet (tcf) of natural gas reserves yet to be discovered within the Cook Inlet Basin.

However, costs to discover and develop these potential reserves are substantial. The DOE study estimates that efforts to find and develop 50%, or 8 tcf of these potential reserves would cost a minimum of \$5.0 billion if the reserves were mainly located onshore. In simplistic terms, at the FY2004 Cook Inlet average annual Prevailing Value of \$2.82 per thousand cubic feet (mcf) of natural gas, this 8.0 tcf of natural gas would have a gross value of \$22.56 billion.

In evaluating the likelihood of whether reserves of this size could still exist within the Cook Inlet Basin, the study noted that 95% of all Cook Inlet's current proven natural gas reserves were discovered before 1970. The study also noted that there was no natural gas focused exploration in the Cook Inlet Basin until the late 1990's. All previous discoveries were, in effect, accidental and coincidental to exploration for structurally trapped oil. And finally, there is a significant absence of medium to large gas fields when viewed from geologic expectations, based on similar geological structures elsewhere. With significant new exploration, which would require substantial financial investments, there is a high likelihood of discovering significant new natural gas reserves within the Cook Inlet Basin.

Natural Gas Pricing

Delivered natural gas prices to all consumers in Alaska continued to rise during the most recently completed reporting period ending in 2003. According to the U.S. Department of Energy,⁷ the cost of delivered natural gas to Alaska consumers were as follows:

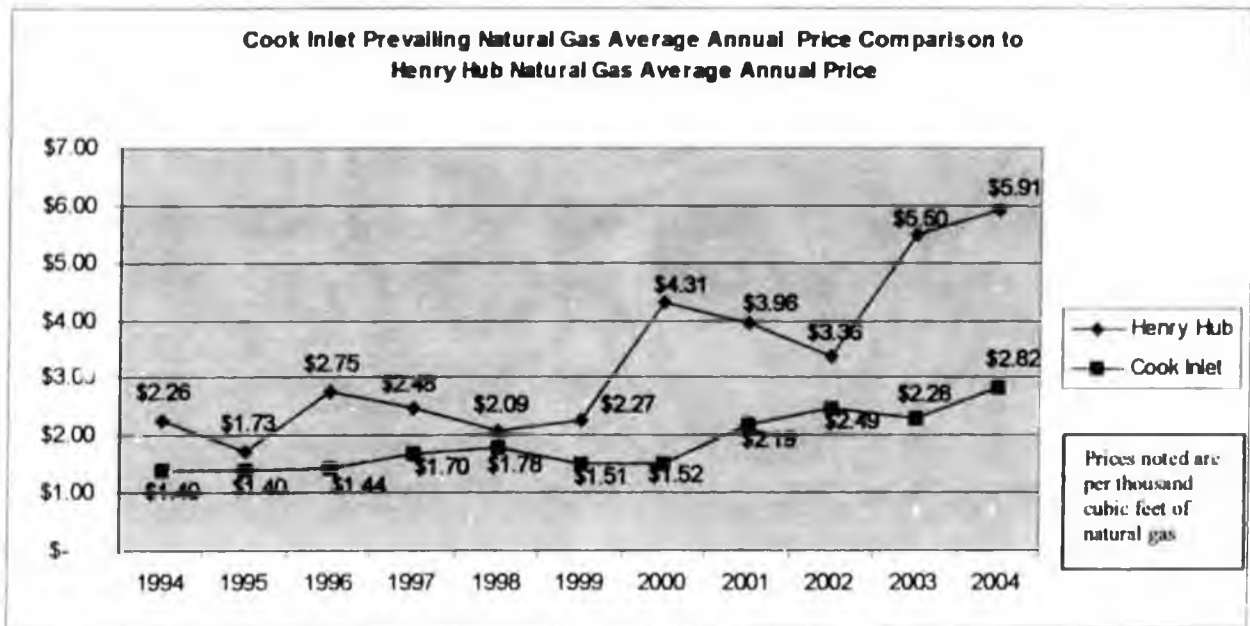
U.S. Department of Energy Costs of Delivered Natural Gas to Consumers		
Alaska Consumer	Price per mcf	% increase since 1999
Residential	\$4.39/mcf	21%
Commercial	\$3.58/mcf	64%
Industrial	\$1.75/mcf	40%
Electric Power	\$2.33/mcf	47%

This delivered cost analysis is an average of delivered natural gas prices from across Alaska, including the North Slope, and are not necessarily specific to any one company or region. However, these statewide cost trends are indicative of recent pricing trends within the Cook Inlet Basin. Based on the following information, this upward pricing trend will continue in 2005.

⁶ U.S. Department of Energy, "South-Central Alaska Natural Gas Study," June, 2004

⁷ U.S. Department of Energy, Energy Information Administration, "Natural Gas Annual 2003," December, 2004

Since 1999, the annual average prevailing value of Cook Inlet natural gas⁸ increased by 87%, from \$1.52 to \$2.83 per mcf. Similarly, natural gas prices in the broader U.S. markets have also seen dramatic increases. Using the Henry Hub commodity price⁹ as a comparative indicator, Lower 48 natural gas prices have increased 160%, from \$2.27 to \$5.91. These two price indicators are represented in the following ten-year history graph:



The comparison of Cook Inlet natural gas prices to Henry Hub natural gas prices is particularly germane to the topic of Cook Inlet natural gas prices.

In late 2001, the Regulatory Commission of Alaska (RCA) approved a Gas Sales Agreement¹⁰ (GSA) between Unocal & Enstar that is tied to a trailing three year average of daily Henry Hub natural gas Futures prices, with a floor price of \$2.75 per mcf of natural gas. The RCA, reasoning that Cook Inlet natural gas reserves were in decline and that current prices for Cook Inlet natural gas were not competitive in the context of the larger global exploration markets, approved this agreement with the intent to spur new natural gas exploration and development within the Cook Inlet Basin. This premise seems to be initially justified, based on the latest Cook Inlet natural gas reserves estimates described earlier in this report.

Based on the new pricing structure, it is likely that the average annual Prevailing Value of Cook Inlet natural gas will exceed \$3.00 per mcf in 2005. This upward pricing trend will likely continue through the end of 2005 and is directly affected by lower 48 natural gas

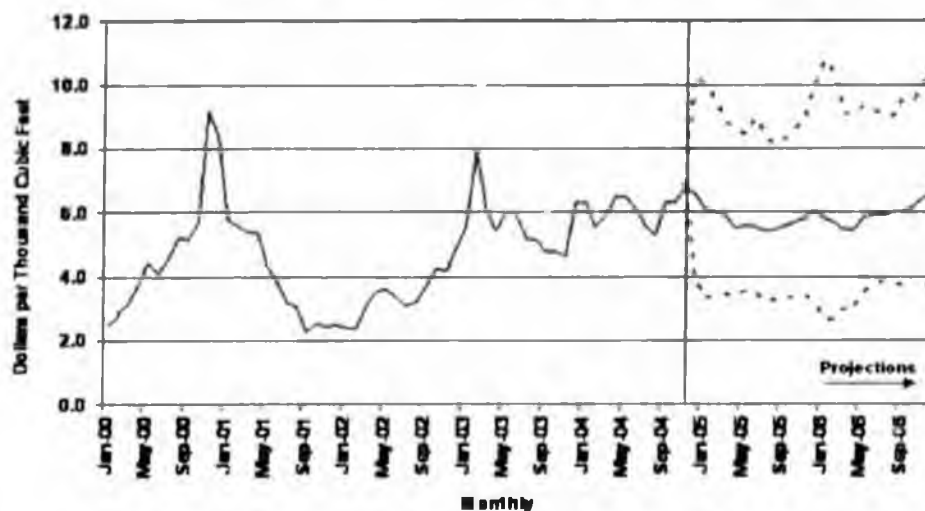
⁸ State of Alaska, Department of Revenue, Cook Inlet Natural Gas Prevailing Value, www.tax.state.ak.us. "As provided under 15 AAC 55.173(b) for gas delivered in the Cook Inlet area, the Department will publish on the 15th of each calendar quarter, the prevailing value for that quarter. This prevailing value is the weighted average price of significant sales of gas to publicly regulated utilities in Cook Inlet."

⁹ U.S. Federal Reserve Bank of St. Louis, Economic Research Division: Wall Street Journal/Haver Analytics

¹⁰ Regulatory Commission of Alaska, Order #U-01-7(8) approving GSA between Unocal & Enstar/Semco Energy

prices¹¹ described in the following chart¹² that provides an 18-month projection for national trends in natural gas pricing:

**Figure 9. U.S. Natural Gas Spot Prices
(Base Case and 95% Confidence Interval*)**



*The confidence intervals show ± 2 standard errors based on the properties of the model. The ranges do not include the effects of major supply disruptions.

Source: History: Natural Gas Week; Projections: Short-Term Energy Outlook, January 2005



Natural Gas Exploration Outlook for 2005

Several companies have planned exploration efforts in the Cook Inlet Basin, while several are still on the sidelines awaiting specific announcements, if any, for new exploration efforts in the Cook Inlet Basin. Here is a recap of those companies:

- **Unocal** continues to focus on the lower Kenai Peninsula in the Ninilchik and Anchor Point areas. Several exploration and development wells are planned for the third quarter of 2005 in addition to a comprehensive seismic study scheduled to cover all lease tracts in and near the Deep Creek, Ninilchik and Nikolaevsk Units. Unocal has completed the multi-million dollar extension of the KKPL pipeline in 2004 through Ninilchik and out to the Happy Valley Gas Field and will examine needs for collector lines to connect new producing wells in the area to the KKPL. Offshore efforts are focused on maintenance for 2005.
- **Marathon Oil Company** continues an aggressive schedule of exploration and development work in 2005 after an equally strong year of effort in 2004. Work continues in the Ninilchik Unit to fully explore and develop this significant coastal field. Ongoing infield rework efforts will continue at many of Marathon's existing fields such as the Kenai Unit. Seismic work in Marathon's newly acquired acreage along the Kenai River corridor between Soldotna and the eastern boundaries of the Sterling area will likely begin this year. In addition, it appears work will finally begin

¹¹ U.S. Department of Energy, Energy Information Administration "Annual Energy Outlook 2005 Overview"

¹² U.S. Department of Energy, Energy Information Administration "Short-Term Energy Outlook 2005," January, 2005

this year on the East Swanson prospect in the Kenai National Wildlife Refuge. Marathon is the lead on this joint venture with Unocal and Cook Inlet Region, Inc. Preliminary results from the Kasilof Unit directional drilling project may also be released in 2005. Finally, Marathon reactivated the Spark platform in late 2004 for natural gas production.

- **Aurora Gas LLC** is the most active new player in Cook Inlet in recent years with very aggressive and successful history of re-entry projects that develop previously abandoned exploration wells looking for natural gas. Aurora is continuing that effort in 2005, mainly on the Westside of Cook Inlet. However, Aurora is expanding its operations in 2005 to venture into exploration drilling for oil which will be discussed later in this report. Aurora estimates that new Westside prospects could contain 400 bcf to 1.0 trillion cubic feet of gas.¹³
- **ConocoPhillips** has no announced plans for new exploration or development activities in 2005. Operations at the North Cook Inlet Unit will continue on a status quo basis. Natural gas produced at the Tyonek platform will continue to serve the LNG plant in Nikiski.
- **Forest Oil Company**, which has previously exclusively targeted oil in Cook Inlet, has announced several efforts to explore for and develop onshore natural gas in 2005. These efforts will be focused on the Westside of Cook Inlet and on two exploration licenses in the Susitna Basin that encompass over 850,000 acres.
- **Cook Inlet Region Incorporate (CIRI)** has substantial sub-surface oil & gas rights in the Cook Inlet Basin and continues to develop those resources in partnership with Marathon Oil Company and Unocal. In particular, in-holdings within the Kenai National Wildlife Refuge at the East Swanson Prospect will be a significant project in 2005.
- **Gas Pro/Northstar Energy/Alliance Energy** are three companies owned by the same general group of investors that have made several moves in 2004 on the lower Kenai Peninsula in preparation for 2005. All of this activity will be focused on the North Fork Unit, where an initial reserve of approximately 15 bcf was identified in the late 1960's. Northstar Energy successfully completed the approval process for a gas supply agreement with Enstar to deliver natural gas to the Homer and Anchor Point areas for utility uses. The next step that Northstar must now complete is the drilling of a second, and if needed third, development well at the North Fork Unit to prove up a 20 year uninterrupted supply of natural gas. To date, Northstar Energy has not announced firm plans for this next step. In the mean time, Alliance Energy has taken a stronger leaseholder position around the North Fork Unit. No firm plans for exploration have been announced for these new lease tracks.
- **Pelican Hill Oil & Gas** is another new independent explorer in the Cook Inlet Basin. Focused on the Westside of Cook Inlet, Pelican drilled an exploration well in 2004 which was not successful. Four more exploration wells are planned to be completed by spring 2005.
- **Other Companies** with lease positions but no active natural gas exploration efforts planned or announced for 2005 include:
 - **Escopeta Oil & Gas/BBI**, the largest offshore leaseholder in Cook Inlet, estimates its leases contain 6.3 trillion cubic feet of natural gas¹⁴ and is seeking investors.

¹³ Petroleum News Publication "The Explorers," Aurora Gas LLC profile, page 30

¹⁴ Petroleum News Publication "The Explorers," Escopeta Oil & Gas/BBI profile, page 81

- **Pioneer Natural Resources**, with significant leases in the Mat-Su region, has no plans announced.
- **Pioneer Oil Company**, with leases on the Westside and in Mat-Su region, has no plans announced.
- **Storm Cat Energy Corp.**, with leases in the Mat-Su region, has no plans announced.

Natural Gas Deliverability

The ability to deliver sufficient quantities of natural gas to meet peak demand days has become a growing problem for several years and could become more pronounced in 2005 and 2006. Simply put, if deliverable volumes of natural gas are insufficient to meet peak demand, then usage by industry and utilities is curtailed on a prioritized basis. This problem becomes most pronounced on the coldest, darkest days of winter when utility demand for natural gas is at its highest, and is compounded by the normal demand patterns of industrial users of natural gas.

First to be curtailed are the industrial users such as Agrium and ConocoPhillips LNG plants, followed by the utilities if necessary. Industry estimates vary, but the current range for peak demand day requirements for all industrial and utility users in the Cook Inlet Basin is between 850 to 900 million cubic feet per day.

The problem of deliverability of natural gas has become more pronounced in recent years due to the aging nature and physical location of natural gas fields within the Cook Inlet natural gas system. It is not so much a lack of natural gas in the ground, but rather the growing lack of ability to flow sufficient amounts of natural gas to meet peak demand requirements. As natural gas wells and fields age, flow rates that previously might have been, as an example, 4 to 6 million cubic feet (mmcf) or more per day drop significantly. Additionally, as older fields are depleted, existing pipeline systems may not be able to transmit sufficient volumes of natural gas from new fields that are being brought on line to replace aging and depleted natural gas fields.

The following graph provided by Marathon Oil Company in early 2004, though somewhat dated, gives a clear example of the significance of this issue.

