

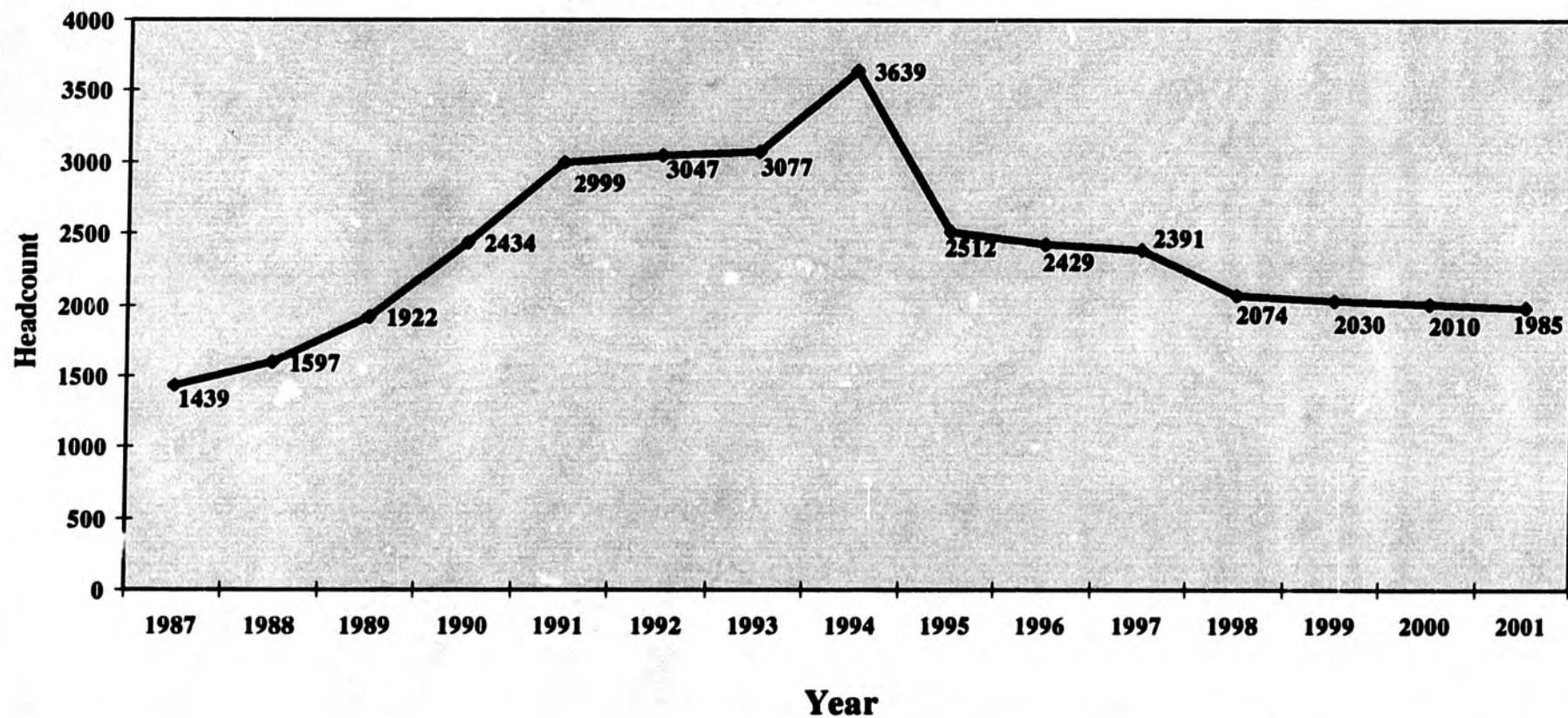
ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672

2642 SCOMM 118: HOUSE SPECIAL COMMITTEE OIL & GAS, 1999-2000



Total Employed by TAPS

Personnel Employed by TAPS





Expense Breakdown - 1998

(\$Millions)



Oil Spill Preparedness
14 Cents per Barrel

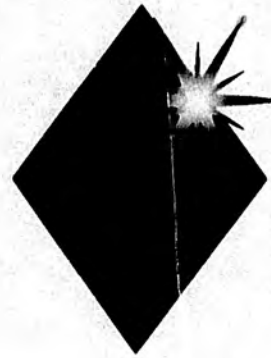
Taxes & Government Oversight
17 Cents per Barrel

Operations & Maintenance
88 Cents per Barrel



How the State of Alaska Shares TAPS' Costs

- ◆ TAPS' costs are paid by the tariff charged to transport oil in the system.
- ◆ State owns approximately 13% of North Slope production due to royalties.
- ◆ State levies a production tax based on value of North Slope oil. This averages approximately 10% for North Slope production.
- ◆ Value of North Slope crude is found by taking west coast value and subtracting transportation costs. Both TAPS and marine.
- ◆ Result: Due to royalty oil and production tax, the State pays approximately 23% of TAPS costs.



TAPS Impact to State of Alaska

- ◆ **TAPS Employees**
 - **2100 Alyeska Employees & Contractors**
 - **850 Alyeska employees**
 - **96% of Alyeska employees are Alaska residents**
 - **Alyeska payroll was \$96 million for 1998**
- ◆ **Contractors and Vendors**
 - **Approximately \$330 million spent in Alaska in 1998**
 - **To about 2,800 Alaska organizations**



Conclusion

As throughput declines to keep unit costs flat, the Trans Alaska Pipeline System must adapt to the number of barrels moving through the system by finding ways to be more efficient.

◆ This means:

- more Pump Stations in standby**
- continued consolidation of work and in the way we contract**
- less berths in operation as the number of tankers calling on Valdez decreases**
- invest in new technology to enhance safety and reduce costs**
- develop new methods for oil spill preparedness**

- ◆ The Trans Alaska Pipeline System must be as efficient as possible; we will not compromise the safety, reliability, or integrity of our system to do it.**

SCOMM

118:6

STATE OF ALASKA

TONY KNOWLES, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL AND GAS

550 WEST 7TH AVENUE, SUITE 800
ANCHORAGE, ALASKA 99501-3510
PHONE: (907) 269-8800
FAX: (907) 269-8938

March 16, 1999

Representative Jim Whitaker
Chair, House Special Committee on Oil and Gas
State Capitol, Room 13
Juneau, AK 99801-1182

Dear Representative Whitaker:

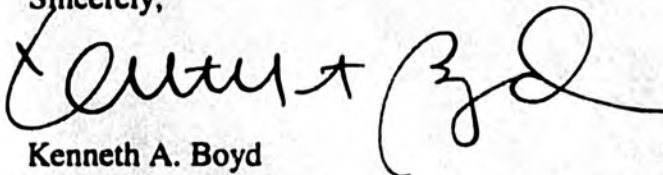
I am enclosing the following materials on the Pt. Thomson Unit for use at the Oil and Gas Committee meeting on Thursday March 18:

- A map of the North Slope showing the location of the Units and some recently drilled (and drilling) wells.
- A map of the Pt. Thomson Unit as it is currently configured.
- A (relatively) short history of the Pt. Thomson Unit from its formation in 1977 until present. There is also a two-page summary.
- A copy of the most recent Plan of Development (the 15th POD).
- A copy of a relevant Daily News article from 1997 that we can discuss at the meeting.

Obviously, there are many, many other documents regarding Pt. Thomson but I think this will be sufficient for our first meeting.

I look forward to addressing the committee by teleconference on Thursday.

Sincerely,



Kenneth A. Boyd
Director

KAB:gsr

Enclosures

Questions for Point Thomson:

If oil is produced at Point Thomson will the gas produced be reinjected and remain as a resource within the field?

How does the potential production rate and recoverable reserves for Point Thomson compare with other current North Slope projects such as Northstar, Liberty, Alpine, and Tam?

What options are being considered for the development of Point Thomson field by Exxon and its partners?

What is the current status of the Point Thomson lease.

If there was a export pipeline for gas at Prudhoe Bay how would the project economics change for Point Thomson?

Are there additional oil fields in the Point Thomson area which might benefit from the gas and potential MI available from the production of oil condensate from the Point Thomson field? *usable injectants*

What is the ownership of these satellite fields?

If all fields within the Point Thomson area were developed collectively, without regard to ownership, would the economics of oil development for the entire area improve?

Is there space available in the shutdown Badami Pipeline for transport of Point Thomson oil?

Given that there is space available in the shutdown Badami Pipeline how does the location of a pipeline entry point only 12 to 14 miles from the Point Thomson field impact project economics?

BP appears to have an incentive to develop additional production for the Badami Pipeline. Can the Point Thompson field be used to facilitate the development of satellite fields such as the BP Sourdough and Yukon Gold fields?

Is ownership of various transportation systems impacting the decision to develop Point Thomson?

How does the potential merger of Exxon and Mobil change the ownership of gas at point Thomson? On the North Slope as a whole?

Do you believe that Exxon has shown good faith due diligence in its development plans for the Point Thomson lease?

15
Development Plan 1
(1)
(2)
(3)
string of pearls
(14)

kt. of gas

(6)

(17)

(8)

might help

Trans F

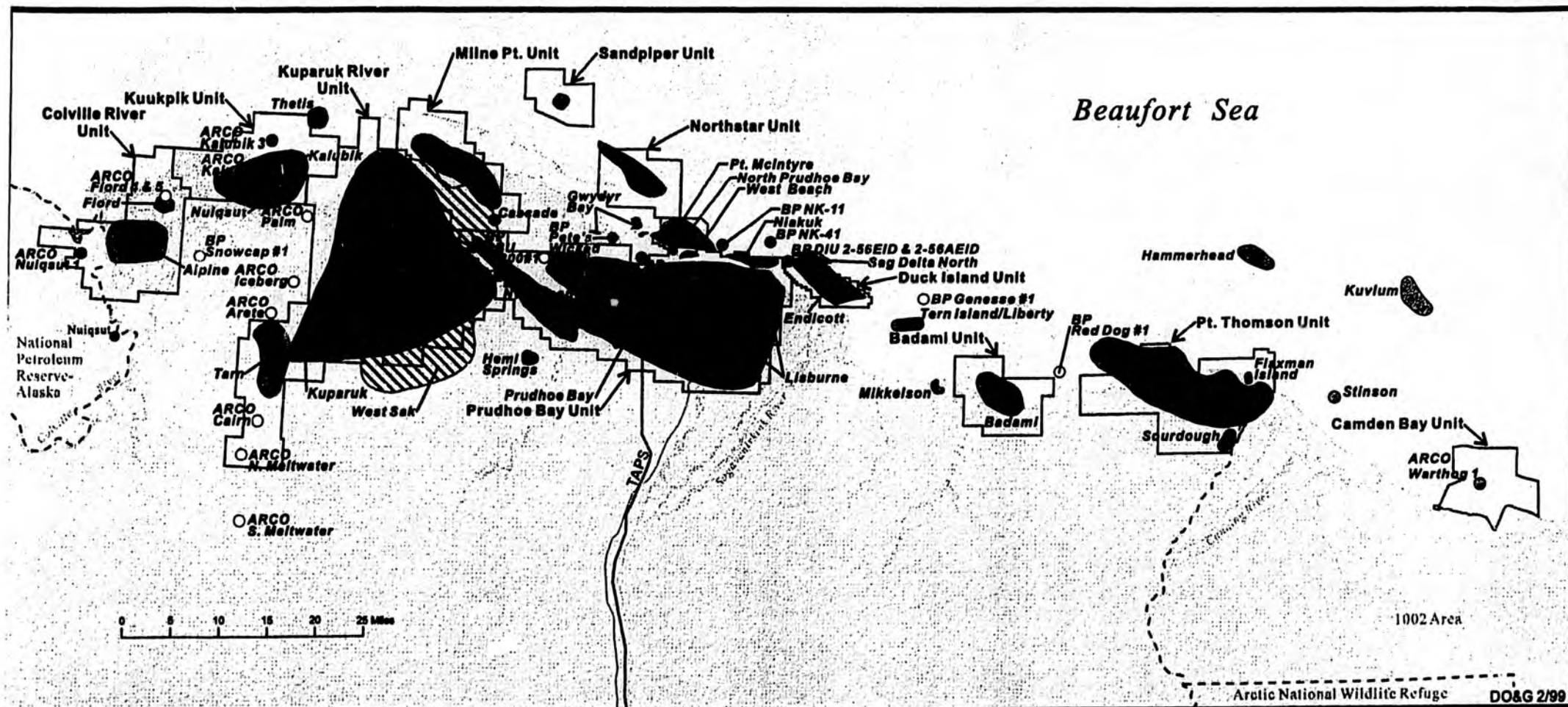
Does Exxon or any of its partners currently have any studies going on at this time concerning the development of the Point Thomson resource?

(9) ?

Northern Alaska Activity

Map Legend

-  **Units**
-  **Oil Field / Accumulation**
 -  **Selected Wells**
 -  **Proposed / Active Wells**



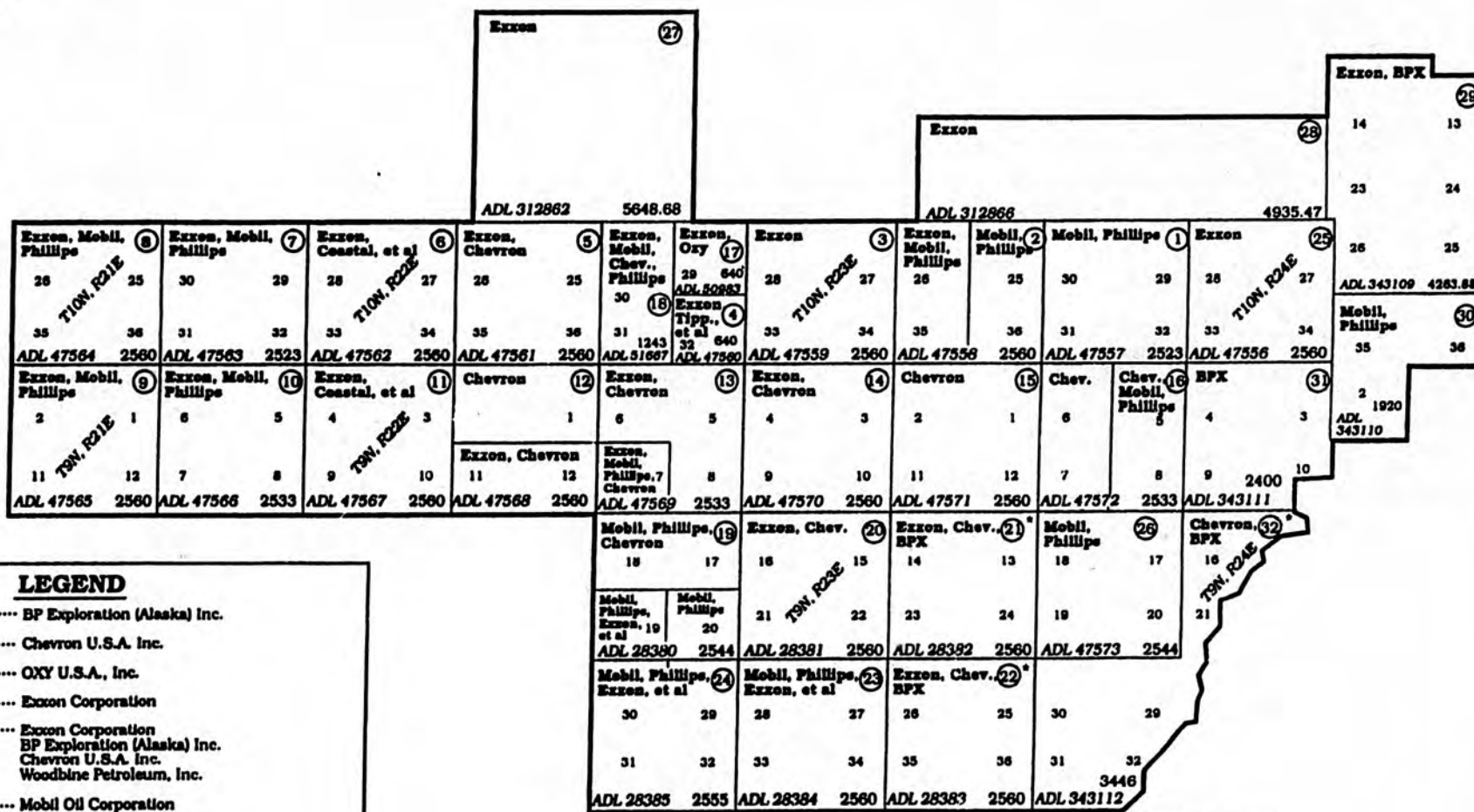
3/23/99

RECEIVED
JAN 27 1998
DIV. OF OIL & GAS

EXHIBIT "A"

POINT THOMSON UNIT AGREEMENT

(Revised January 15, 1998)



LEGEND

BPX	BP Exploration (Alaska) Inc.
Chevron (Chev.)	Chevron U.S.A. Inc.
OXY	OXY U.S.A., Inc.
Exxon	Exxon Corporation
Exxon, et al	Exxon Corporation BP Exploration (Alaska) Inc. Chevron U.S.A. Inc. Woodbine Petroleum, Inc.
Mobil	Mobil Oil Corporation
Phillips	Phillips Petroleum Company
Coastal, et al	Coastal Oil and Gas Corporation Pennzoil Exploration and Production Co. Forest Oil Corporation Mobil Oil Corporation SNG Production Company Trans World Oil and Gas Ltd. Sunlite International Inc. Two-Four-Six Exploration Inc.
Tipp., et al	Tipperary Oil and Gas Corporation Chaparral Royalty Co. Richard Donnelly Kingdon R. Hughes Edward H. Leede Pacific Lighting Gas Development Company Bernice C. Peary, Trustee Robert Searis, Jr. Jeanne Searis

*Depth Severed Ownership -- See Exhibit "B" for Details

**Situated within T9N-10N, R21E-24E
Umiat Meridian, Alaska**

① Denotes T Numbers, as listed on Exhibit "B"



A History of the Point Thomson Unit

Prepared by Carol Lee, Unit Manager

March 15, 1999

Summary:

DNR approved the Point Thomson Unit Agreement effective August 1, 1977, with an initial term of five years. The original unit area included 18 State of Alaska oil and gas leases comprising approximately 40,768 acres.

On November 4, 1977, DNR certified the Point Thomson Well #1 as capable of producing in paying quantities.

The following is a listing of the Plans of Development that have been approved for the Point Thomson Unit:

POD	Term	Beginning Date	Ending Date
1 st POD	1 year	1/1/78	12/31/78
2 nd POD	1 year	1/1/79	12/31/79
3 rd POD	1 year	1/1/80	12/31/80
4 th POD	1 year	1/1/81	12/31/81
5 th POD	1 year	1/1/82	12/31/82
6 th POD	1 year	1/1/83	12/31/83
7 th POD	4 years	1/1/84	12/31/88
8 th POD	3 years	1/1/89	12/31/91
9 th POD	1 year	1/1/92	12/31/92
10 th POD	1 year	1/1/93	12/31/93
11 th POD	1 year	1/1/94	12/31/94
1 st Extension of 11 th POD	16 months	12/31/94	4/30/95
2 nd Extension of 11 th POD	3 months	4/30/95	7/15/95
3 rd Extension of 11 th POD	2 months	7/15/95	9/1/95
4 th Extension of 11 th POD	5 months	9/1/95	2/1/96
13 th POD	11 months	2/2/96	12/31/96
14 th POD	1 year	1/1/97	12/31/97
Interim POD	6 months	1/1/98	6/30/98
15 th POD	15 months	7/1/98	9/30/99

On April 16, 1982, DNR approved the First Amendment to the Point Thomson Unit Agreement. Article 11 of the Point Thomson Unit Agreement was amended so that the unit owners would not be required to form a Participating Area until 90 days before production begins.

On March 26, 1984, DNR approved the First Expansion of the Point Thomson Unit Area effective January 1, 1984. The expansion area included 25 additional leases comprising approximately 94,152 acres for a total unit area of approximately 134,920 acres. The expansion was conditioned upon a commitment to drill one well by March 31, 1985 and another well by February 1, 1990.

On January 17, 1985, DNR approves the Second Amendment to the Point Thomson Unit Agreement. Pertinent changes included amending Article 11 to accommodate the Net Profit Share Leases and a modification to Article 21, Rate of Prospecting, Development and Production.

On April 9, 1985 two leases contracted out of the Point Thomson Unit for failure to commence the required well by the March 31, 1985 deadline. On February 5, 1990, nine of the ten northern leases included in the First Expansion were contracted out of the unit area for failure to commence the required well by February 1, 1990. There are currently 32 leases within the Point Thomson Unit Area, comprising approximately 83,825 acres. Of these leases, six were issued in 1965, eighteen were issued in 1969, two were issued in 1970, two were issued in 1980, and four were issued in 1982. Commitment to the Point Thomson Unit extended all of the leases beyond their primary term.

On August 18, 1998, Exxon applied to expand the Point Thomson Unit to include one additional lease, ADL 372256. Kenneth A. Boyd, Director of the Division of Oil and Gas denied Exxon's expansion application on November 30, 1998. Exxon's appeal to Commissioner Shively is pending.

The Point Thomson Unit area contains 14 wells, seven of which DNR certified as capable of producing in paying quantities. Certification of the wells extends the primary term of seven leases. If the Point Thomson Unit expired, these seven leases would continue to be held by the certified wells.

The Major Point Thomson Unit Owners are as follows:	Exxon	44.95%
	Chevron	19.22%
	Mobil	14.35%
	Phillips	11.84%
	BP	<u>7.15%</u>
		97.51%

Each of the following companies or individuals holds less than 1% working interest in the Point Thomson Unit: Coastal Oil & Gas Corporation; Pennzoil Exploration and Production Company; Forest Oil Corporation; Oxy USA Inc.; Tipperary Oil & Gas Corporation; Transworld Oil & Gas Ltd; Two Four Six Exploration Inc; Edward H Leede; Pacific Lighting Gas Development Company; Samson Resources Company; Sunlite International Inc; Kingdon R Hughes; Chaparral Royalty Company; Leede and Pine; Peggy D McConnell; John W Perry (Estate); Robert Searls; Richard Donnelly; Mary Lou Holbrook; The George A Donnelly III 1991 Irrevocable Trust; The Robert R. Donnelly 1991 Irrevocable Trust; The Jan Donnelly O'Neill 1991 Irrevocable Trust; Woodbine Petroleum, Inc..

Point Thomson Unit

Detailed History:

- 10/29/76 Exxon submits application for designation of a unit area and for determination of location and depth of a test well.
- 1/7/77 DNR approves application for designation of area and approval of form.
- 5/3/77 Exxon submits application for final approval of Point Thomson Unit Agreement
- 6/6/77 DNR issues Preliminary Decision and Finding approving Point Thomson Unit for an initial term of five years. Original unit area included 18 State of Alaska oil and gas leases comprising approximately 40,768 acres. Working interest owners included Atlantic Richfield (ARCO), Cities Service (Oxy), Chevron, Conoco, Exxon, Mobil, Phillips, Pennzoil, Tipperary and several individuals.

Article 9 of the Pt Thomson Unit Agreement required the drilling of one exploratory well within six months of the date of the agreement and the unit operator to commence drilling additional wells by January 1 of each year.

- 6/7/77 Public Notice of Pt Thomson Unit Application
- 7/26/77 Final Decision and Findings approving the Pt Thomson Unit issued by J. P. Green, Director, Division of Land.
- 8/1/77 Commissioner LeResche approves Pt. Thomson Unit Agreement effective August 1, 1977.
- 11/2/77 Exxon requests Certification of the Pt Thomson #1 Well as capable of producing in paying quantities.
- 11/4/77 PT #1 Well Certified as capable of production in paying quantities.

Article 10 of the Pt Thomson Unit Agreement required the submission of a further Plan of Development after the completion of a well capable of producing unitized substances in paying quantities.

- 1/3/78 Exxon submit its 1st Plan of Development and proposes drilling the PT #2 Well.
- 5/28/78 DNR approves the 1st POD until 1/1/79.
- 9/6/78 Exxon requests Certification of PT #2 Well as capable of producing in paying quantities.

Point Thomson Unit
Detailed History
Page 4 of 15

9/26/78 Exxon proposed 2nd POD which includes drilling the Exxon #3 Well in Nov/Dec 1978.

10/9/78 DNR approves 2nd POD through 1/1/80.

1/5/79 DNR Certifies PT #2 Well as capable of producing in paying quantities.

10/18/79 Exxon submits 3rd POD and proposed drilling the PT #4 Well in February 1980.

2/22/80 DNR approves the 3rd POD for the period 1/1/80 – 1/1/81.

5/30/80 Letter to Exxon requiring the formation of a Participating Area within sixty days after completion of the Pt. Thomson Well #4.

6/13/80 Exxon proposes to amend the Point Thomson Unit Agreement, Article 11. The amendment provides that a participating area (PA) need only be established before production, not immediately after completion of a discovery well.

10/8/80 DNR sent a letter to Exxon withdrawing the May 30, 1980 request. A participating area will be required on/or before December 8, 1982 (5 years after completion of the Unit No. 1 certified discovery well). The effective date of the PA will be December 8, 1977, the completion date of the No. 1 well. The first automatic contraction of the unit area, if necessary, will occur in January of 1983.

12/1/80 Exxon submits the proposed 4th POD, which includes drilling four wells outside the unit area to test the extent of the reservoir.

12/19/80 DNR approves the 4th POD for the period 1/1/81 – 1/1/82 and requests a presentation of the C1 Well results.

7/22/81 DNR certifies the C1 Well as Capable of Producing in Paying Quantities.

8/24/81 Exxon provides C1 Well results presentation.

9/14/81 Exxon submits 5th POD and proposes drilling three wells, two in Nov. 1981 and one in the 81/82 winter drilling season.

9/25/81 DNR approves the 5th POD for the period 1/1/82 – 1/1/83.

1/5/82 Letter from Exxon referring to June 13, 1980 request to amend Article 11 of the PTU Agreement and proposing amending language in Article 20(c) to delete the requirement of a PA.

1/20/82 Memo from Kay Brown, Acting Director to Commissioner Katz recommending approval of the requested amendments to the PTU Agreement. "The effect of this

amendment could be to delay formation of a participating area for the Point Thomson Unit until production begins, probably in the late 1980's." She also recommends rescinding DNR's letter to Exxon of October 8, 1980, which required the establishment of a participating area by August 21, 1983. Memo addresses similar issues in Pt Thomson and Duck Island Units. October 8, 1980 letter on Duck Island Unit required the formation of a PA by August 21, 1983.

- 1/25/82 Commissioner Katz's letter to Exxon agreeing to amend Article 11 but not Article 20(c). Katz's decision requires all owners to ratify the amendment before DNR will approve it and rescinds DNR's letter of October 8, 1980. Katz's decision incorrectly provides August 21, 1983 as the required date to form a PA. The October 8, 1980 letter on Pt Thomson Unit required the formation of a PA by December 8, 1982.
- 4/16/82 Commissioner Katz approves and certifies amendment to the Point Thomson Unit Agreement.
- 6/18/82 DNR certifies the F1 Well as Capable of Producing in Paying Quantities.
- 7/27/82 Exxon notes that PTU Agreement is moving toward the end of the initial five-year term and they ask the commissioner for an interpretation of Article 20(c) of the PTU Agreement. Exxon argues that the PTU will be extended under Article 20(c) because there has been a valuable discovery of unitized substances and the PTU "shall remain in effect as long as unitized substances can be produced in quantities sufficient to pay for the cost of producing such substances." Exxon also says that if Article 20(c) does not extend the unit then Article 25 does. Article 25 is the PTU Agreement's force majeure provision and it specifically lists "uncontrollable delays in transportation" as a force majeure event. Exxon says that it has been prevented from developing and producing because of "uncontrollable delays in the availability of pipeline transportation necessary to market the unitized substance."
- 7/29/82 Brown notifies Exxon that she concurs with its interpretation of Article 20(c) and the PTU is automatically extended. Under the amendment approved in April 1982, to Article 11 of the agreement, a participating area must be formed prior to production from the unit.
- 11/19/82 Exxon submits the 6th POD. The plan does not include drilling any wells but proposes a drilling and sampling program, color aerial reconnaissance photography of the Pt Thomson area, a hydrology program, and geophysics, physical oceanography and coastal processes programs during 1982. 1983 projects include a geotechnical survey, hydrology study, and an onshore environmental survey.

Point Thomson Unit
Detailed History
Page 6 of 15

- 12/10/82 DNR approves the 6th POD for the period 1/1/83 – 1/1/84 and request a list of the studies and a meeting in Sept/Oct 1983 to discuss results of the studies.
- 10/28/83 Exxon submits 7th POD requesting a 5-year plan with no drilling until contracts are issued for a gas line.
- 11/29/83 DNR approves the 7th POD for the period 1/1/84 – 12/31/88. Annual progress reports are required.
- 12/7/83 Exxon gives notice of the proposed expansion of the PTU. The proposed expansion had been preliminarily approved by the director subject to a number of conditions including the condition that the state's royalty in kind share be free of cleaning and dehydration costs. Many of the companies objected to this requirement.
- 1/13/84 Exxon submits an application to expand the PTU. Not all owners had ratified the application.
- 1/20/84 Exxon submits a filing fee of \$20.00 per 11 AAC 88.105.
- 1/26/84 Public Notice of the expansion application published in the Anchorage Daily News. Thirty 30 public comment period.
- 2/15/84 Brown notifies Exxon that it is the continuing state policy that renegotiation of lease terms upon unitization constitutes a reasonable exchange of value for the benefits that the lessees obtain from the act of unitization and if the state concludes that renegotiations are necessary to protect the public interest, the state will seek to obtain those terms. She further notified them that the state could not take action on the application until they retracted their objection.
- 2/16/84 Exxon notifies Brown that they consent to the conditions imposed on expansion of the unit area. Within weeks, the rest of the lessees consented.
- 3/14/84 DNR questions whether the northern leases are justified for inclusion in the PTU. DNR requires a well be drilled on one of the northern twelve leases before February 1, 1990, as a condition for inclusion in the PTU. If the well is not drilled by that date the acreage will contract out of the unit. Two other leases are to be excluded from the expansion application.
- 3/26/84 DNR approves the First Expansion of the Point Thomson Unit effective retroactive to January 1, 1984. Expansion area includes 25 additional leases comprising approximately 94,152 acres for a total unit area of approximately 134,920 acres. The expansion was conditioned on the lessees acceptance of specific terms and conditions for the expansion leases as follows: (a) five leases had their rental, royalty, minimum royalty, drilling and producing terms amended

(State's RIV shall be free and clear of all lease expenses; (b) two leases a well drilling commitment by 3/31/85; (c) ten leases had a well drilling commitment by 2/1/90; and (d) within one year Exxon must submit an application to amend the PTU Agreement to accommodate the Net Profit Share leases.

8/31/84 Exxon requested amendments to Articles 2, 7, 11, 12, 18(f), 20(c), 21 and 30 of the Point Thomson Unit Agreement. Pertinent changes include amending Article 11 to accommodate the Net Profit Share Leases and a modification to Article 21, Rate of Prospecting, Development and Production. Article 21 is amended to read as follows: 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 [Fifteen (15)] thirty (3) 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, in any case, curtail rates of production to an unreasonable extent, considering unit productive capacity, transportation facilities available, and conservation objectives; or (iii) prevent this agreement from serving its purpose of adequately protecting all parties in interest hereunder, subject to applicable conservation laws and regulations. (Brackets deleted, Underline added)

12/21/84 Exxon submits 1st Annual Progress Report "[Due to the]... refusal of some Unit owners to release data from wells which are still held confidential, a Unit-wide owners' technical committee has not been feasible. Exxon is continuing efforts to enlarge the data base and conduct a joint study. Meanwhile, Exxon, working with the available data base, has continued its proprietary studies of the reservoir. This phase of Exxon reservoir studies will be completed next year."

1/17/85 DNR accepts 1st Annual Progress Report.

1/21/85 DRN approves amendments to the PTU Agreement as proposed.

4/9/85 Two leases, ADLs 28386 and 28387, were contracted out of the PTU for failure to commence the required well by the 3/31/85 deadline.

9/11/85 Pt Thomson Development Review Meeting held. Exxon provided confidential information to the Division of Oil and Gas regarding a gas cycling development schedule for the PTU. Start-up of the project was planned for 1991-1992.

12/6/85 Pt Thomson Development Review Meeting and submittal of 2nd Annual Progress Report. "Efforts during the past year have focused on two areas: 1) continued evaluation and analysis of available well and seismic data to refine knowledge of the reservoir and develop additional drilling plans, and 2) continued engineering

and field studies to ascertain the viability of a potential gas cycling/condensate recovery project. To date no agreement has been reached, but the WIOs are continuing to pursue mechanisms which would yield access to the well data for purposes of common data base analyses."

- 9/29/86 Exxon submits 3rd Annual Progress Report. "In spite of the economic downturn experienced by the oil industry this past year, Exxon devoted approximately 6 man-years of technical support activity to Point Thomson development. These efforts continued to focus on improved reservoir description, well deliverability analysis, and engineering studies to more accurately assess the technical feasibility and reservoir performance of a potential gas cycling condensate recovery project."
- 9/29/87 Exxon submits 4th annual Progress Report. "Due to continued lack of a transportation system for Point Thomson gas, efforts in 1987 focused on assessing the reservoir risk associated with a potential gas cycling development and evaluating areas to enhance its economic viability. In spite of the poor economic climate in the oil industry this past year, several man years of work were devoted toward improving the technical understanding to the reservoir and gas cycling feasibility."
- 12/16/87 Pt Thomson Development Review Meeting.
- 6/15/88 Meeting to discuss proposed well location.
- 8/9/88 DNR Letter to Exxon: PTU #5 Well location acceptable to satisfy 2/1/90 contraction date.
- 8/15/88 Letter from Exxon informing DNR that a confidential well data trade has been finalized.
- 9/27/88 Exxon submits 8th POD for 3-year term. The plan includes a 3D seismic program over 2/3 of the unit area and drilling the PT #5 Well in February 1990. In the annual progress report to the 7th POD, Exxon acknowledged that gas cycling to extract liquids was identified as the only other potential development alternative prior to major gas sales. The option is considered high risk and viewed as uneconomic by a majority of working interest owners.
- 10/6/88 DNR approves the 8th POD for the period 1/1/89 - 12/31/91.
- 6/7/89 Meeting to discuss 1989 3D Seismic program and plans for drilling the PT #5 Well.
- 8/10/89 Exxon requests later date for drilling obligation.

Point Thomson Unit
Detailed History
Page 9 of 15

- 8/15/89 DNR approves revised drilling schedule. Well to be drilled during 90/91 drilling season. If well is not drilled all 10 leases contract out of the unit on 2/1/90 and penalty payment of \$9.5 million.
- 8/27/89 Exxon submits Annual Progress Report. "During the past year, PTU owners have made excellent progress toward accomplishing the goals of the Eighth POD, both in acquisition and processing of the 3-D seismic survey and in planning the PTU Well #5. ;...The survey operations were concluded on May 15, 1989, as a result of deteriorating ice conditions. A total of 83 square miles of data were collected. The completed survey covers the main portion of the Unit, including the possible gas cycling area."
- 10/10/89 DNR accepts Annual Progress Report
- 1/8/90 Exxon notifies DNR that the PT #5 well will not be drilled.
- 2/5/90 Nine of the ten northern leases included in the First PTU expansion were contracted out of the unit area for failure to commence the required well by 2/1/90. After this contraction, the PTU contains 32 leases comprising approximately 83,825 acres.
- 9/28/90 Exxon submits Annual Progress Report. "During the past year the PTU owners made substantial progress toward accomplishing the goals set out for the Eighth POD as submitted for approval on September 26, 1988. While attempts to initiate the drilling of the PTU No. 5 were unsuccessful, the owners succeeded in acquiring and processing the planned 3-D seismic survey data.
- 8/19/91 Exxon submits 9th POD for 4-year term. The proposed 9th POD includes continued efforts to more accurately assess field development potential through completion of geologic structure maps of currently known reservoirs. Exxon's preliminary work suggests reserves may be up to one-third less than the nominal 5tcf assigned to the field.
- 8/29/91 Meeting to discuss proposed Plan of Development.
- 1/3/92 DNR approves 9th POD for only one year from 1/1/92 - 12/31/92. DNR requested Exxon to expedite consensus mapping efforts in order to evaluate all PTU development opportunities.
- 8/27/92 PTU working interest owners presented consensus structure map of Thomson Sands to DNR.
- 10/1/92 Exxon submits 10th POD. The owners propose to undertake a multi-year Reservoir Characterization Study on the Thomson Sand.

- 11/27/92 DNR approves 10th POD for the period 1/1/93 – 12/31/93.
- 6/23/93 Pt Thomson Unit owners met with DNR to discuss PTU development options. The owners said that a liquid recovery program was uneconomic at this time. They had no plans to use the gas for other North Slope uses. A major gas sale from the North Slope fields was highly unlikely in the near future. They explained their plans for further geology and reservoir studies of the Point Thomson reservoir(s). They did not propose any new exploration work.
- 9/29/93 Exxon submits the 11th POD proposing to continue the Reservoir Characterization Study. At the end of this one year term, the environmental facies analysis, petrographic analysis, petrophysics, geologic model construction, and the review of existing engineering data will be complete, and work will be well underway on the drill stem test interpretations, fluid property studies, and deliverability calculations.
- 12/17/93 DNR approves the 11th POD for the period 1/1/94 – 12/31/94 and gives notice to Exxon of intent to contract the unit boundary effective January 1, 1995. "Little exploration work has been conducted on tracts within the unit boundary in the past few years. No exploration work was conducted under the tenth plan nor is any contemplated under the eleventh plan. The tracts identified in Attachment #1 to this letter have not been shown to overlay any hydrocarbon reservoir. Absent significant and actual on-the-ground exploratory activity on the tracts identified in Attachment #1 on or before December 31, 1994, pursuant to 11 AAC 83.356(e) and 11 AAC 83.343(b), I plan at this time to contract the unit boundary effective January 1, 1995."
- 1/12/94 DNR and Dept. of Law representatives met with BP Exploration. BPX stated that it was completely surprised by the notice of intent to contract the unit area. In response to the notice letter, Exxon encouraged all other owners to make a case to the state regarding the contraction matter and the activity in the unit. BPX mentioned that they proposed farm-in agreements to Exxon to drill prospects in the south and center of the unit. Exxon rejected these proposals. BPX also noted continued problems with the sharing of information among the owners. As part of its agreement with BPX, Chevron refuses to share information with Exxon about its farmout with BPX. BPX discussed their Sourdough prospect. They noted that it may communicate with the Flaxman prospect to the north on PTU leases.
- 2/3/94 Chevron, BPX and Exxon met with DNR staff. The companies stated there would be a working interest owners meeting on February 10, 1994. Exxon read a prepared statement and asked that five tracts be deleted from the proposed contraction area because they were part of the Sourdough prospect. Director Eason responded that he was not willing to discuss the unit piecemeal and he wants a response to the State's contraction notice. Exxon had concerns about the rationale for the proposed contraction and the meaning of significant activities.

Eason requested that Exxon put their questions in writing. BPX stated that they planned two wells for the Sourdough prospect, #1 outside the unit and #2 inside the unit. The #1 well would be subject to an Exploration Incentive Credit (EIC). By drilling the #2 well inside the unit, they would be giving up any right to an EIC estimated to be worth \$2.5 MM.

- 2/16/94 Letter from Exxon questioning decision to contract the unit boundary.
- 2/25/94 DNR responded to Exxon on contraction and drilling commitments.
- 4/15/94 BPX applied for a paying quantities determination for the Sourdough #2 well.
- 4/26/94 DNR certified the Sourdough #2 well as capable of production in paying quantities. The southern half of this lease was identified as a lease subject to the division's PTU contraction notice.
- 5/11/94 Meeting for DNR to have a better understanding of known and potential reservoirs in the Pt Thomson Unit and surrounding areas.
- 9/29/94 Exxon submits 12th POD including a discussion of marketing issues.
In April 1994, BPXA completed drilling the Sourdough #2 well located within the PTU. In June 1994 DNR certified the well as capable of production in paying quantities.
- BPXA conducted the Yukon Gold 3D seismic program during the 1994 winter season. This program covered all or a portion of 10 PTU leases.
- During the 12th POD the owners propose to complete the Reservoir Characterization Study including drill stem test interpretations, fluid property studies, and deliverability calculations. Engineering screening studies will be initiated during the 12th POD.
- 12/22/94 DNR agrees to extend the 11th POD until April 30, 1995 "to review the discussions and the documents exchanged to date regarding our respective views on contraction of the unit area and on diligent further exploration and development of the PTU acreage."
- 4/20/95 DNR agrees to further extend the 11th POD until July 15, 1995, to provide an opportunity for both parties to review the issues regarding our respective views on contraction of the unit area and on further diligent exploration and development of the PTU acreage.
- 7/14/95 DNR agrees to further extend the 11th POD until September 1, 1995, to provide an opportunity for Exxon, Commissioner Shively and appropriate staff to review the

issues regarding our respective views on contraction of the unit area and on further diligent exploration and development of the PTU acreage.

- 8/31/95 DNR agrees to further extend the 11th POD until February 1, 1996. "The Twelfth Plan of Development will be resubmitted on or before November 1, 1995. Prior to resubmitting the Twelfth POD staff from Exxon and this division will meet to assess progress on the Eleventh POD and to consider additions to the Twelfth and subsequent Plans. I expect this meeting can take place in late September."
- 10/4/95 Meeting to review progress under the 11th POD and discuss possible work initiatives for the 12th and future PODs.
- 10/31/95 Exxon submits 13th POD for 23-month term. Owners will undertake a study aimed at evaluating potential development scenarios for the PTU. Exxon, Mobil and Phillips each plan to initiate a farmout effort targeting flank PTU acreage.
- 11/15/95 BP submits request for Lease Operations approval for Sourdough #3 Exploration Well to be drilled during the winter of 1995/96 on ADL 343112 within the PTU.
- 12/28/95 DNR approves the 13th POD for the period February 2, 1996 through December 31, 1996. Request a June meeting to evaluate the potential development scenarios.
- 1/25/96 Meeting to discuss the 13th POD farmout initiative.
- 6/27/96 Meeting to review progress under the 13th POD. Exxon has completed preliminary work on several potential development scenarios using aggressive cost and wellbore deliverability assumptions. Owners concluded that a full 3D geologic model and reservoir simulation model needed to be constructed early in the life of the study, i.e. in Phase I. A farmout proposal from ARCO was received on July 2. BP is also interested. Revised schedule: Phase II to commence late 1996 and carry into 1997.
- 10/2/96 Exxon submits the 14th POD, a continuation of the phased development study and farmout initiative begun under the 13th POD.
- 11/29/96 DNR approves the 14th POD for the period 1/1/97 – 12/31/97. Request a meeting no later than June 1997 for a Phase I progress report of the PTU development screening study and a report of the farmout efforts.
- 3/7/97 Exxon, Mobil and Phillips had granted farmouts to ARCO.
- 10/2/97 Exxon submits the 15th POD. The work activities associated with Phase II of the Unit's development screening study will be completed during the 15th POD.

- 10/8/97 DNR determines the 15th POD is incomplete. The plan does not include delineation of all reservoirs in the unit area. 30 days to submit a revised POD.
- 11/6/97 Exxon submits a letter stating that the Unit's working interest owners believe the submitted 15th POD is complete.
- 11/24/97 DNR responds to Exxon as to requirements for a complete POD.
- 12/16/97 Meeting with PTU owners. DNR will entertain an interim POD for six months to allow time to develop a fully integrated unit plan of development.
- 12/19/97 Exxon submits a revised 15th POD.
- 12/24/97 DNR approves an Interim POD for the period 1/1/98 – 6/30/98. Request a meeting no later than April 15, 1998. Exxon must submit current Exhibits A and B to the Unit Agreement by January 31, 1998. By March 31, 1998, Exxon will submit: (1) a list of the studies done to date with a synopsis of each one; (2) a list of all agreements between the Point Thomson Unit owners with an explanation of each one; and (3) provide a briefing on the results of the full field modeling and Parson's Study. Exxon will also coordinate with ARCO to arrange a presentation of the 3D seismic data collected by ARCO under a farmout agreement with Exxon by March 31, 1998. The division also requested a briefing by BP and Chevron during the first quarter of 1998, on the Plan of Exploration for the Sourdough prospect.
- 1/27/98 Exxon submits new unit Exhibits A and B.
- 2/11/98 DNR meeting with Exxon on the milestones in the Interim POD.
- 3/2/98 Chevron and BP provide a technical presentation on the Sourdough #3 well extended confidentiality.
- 3/30/98 Exxon submitted a list of the studies done to date with a synopsis of each one and a list of agreements between the PTU owners with an explanation of each one.
- 4/2/98 Pt Thomson Review attended by representatives from Exxon, BP, Chevron, Mobil, Phillips and DNR. Exxon provided a briefing on the results of the full field modeling and Parson's study.
- 4/7/98 Chevron and BP provide a technical presentation on the Sourdough prospect.
- 4/7/98 Arco presents 3D seismic data over farmout area.
- 5/14/98 Exxon submits a draft of the 15th POD.

5/21/98 Teleconference call with Exxon and WIOs to discuss draft 15th POD.

5/29/98 Teleconference call with Exxon and WIOs to discuss draft 15th POD.

6/5/98 Exxon submits revised draft of 15th POD.

6/9/98 DNR faxed comments of revised draft POD to Exxon.

6/16/98 Exxon submits 15th POD

6/19/98 Exxon submits final 15th POD.

6/30/98 DNR approved 15th POD for the period 7/1/98 through 9/30/99. Exxon will establish a common database, develop delineation plans, and complete development planning studies during the term of the 15th POD. Exxon also plans to explore potential synergies between development of the oil and gas reserves in the unit area. A status report is due by September 30, 1998, to demonstrate the exchange of sufficient data to map the work contemplated by the 15th POD. The owners shall create a common technical PTU database and consensus maps for all prospective reservoirs within the PTU by September 30, 1999.

8/18/98 Exxon submits an application for expansion of the PTU to include ADL 372256.

8/24/98 DNR letter, Exxon's expansion application is incomplete.

9/3/98 Exxon and DNR staff meet to discuss PTU expansion application.

9/11/98 Exxon submits additional information to supplement PTU expansion application.

9/24/98 DNR publishes public notice of PTU expansion application.

9/30/98 PTU owners present status report on 15th POD to DNR.

10/20/98 BP submits comments on PTU expansion application.

10/22/98 Letter from DNR to Exxon requesting clarification of September 30, 1998 status report and requiring bimonthly updates on efforts to share information among the PTU owners.

10/23/98 Mobil Exploration & Producing U.S. Inc. submits comments on PTU expansion application.

10/23/98 Phillips Petroleum Company submits comments on PTU expansion application.

- 11/30/98 Director Boyd issues Commissioner's Decision and Finding denying PTU expansion application.
- 11/30/98 Exxon submits bimonthly update/progress report on 15th POD.
- 1/4/99 Exxon appeals Director Boyd's November 30, 1998 decision to Commissioner Shively with request for extension of time to submit additional written material and requests special procedures for hearing process.
- 1/4/99 DNR response to November 30, 1998 bimonthly update/progress report on 15th POD.
- 1/15/99 Commissioner Shively grants Exxon's request that the deadline for filing additional material on the appeal be extended until March 1, 1999, and asks why Exxon requires special hearing procedures.
- 2/26/99 Exxon submits additional written material to supplement appeal, and concludes that there are no facts in dispute and therefore a hearing is not necessary.
- 1/29/99 Exxon submits bimonthly update/progress report on 15th POD.

EXXON COMPANY, U.S.A.

POST OFFICE BOX 2180 • HOUSTON, TEXAS 77252-2180

PRODUCTION DEPARTMENT
ALASKA INTEREST

PAUL HUERTA
EXPLOITATION MANAGER

June 19, 1998

VIA FAX (907 562-3852)
AND AIRBORNE EXPRESS

Fifteenth Plan of Further Development
and Operation
Point Thomson Unit
North Slope, Alaska

Mr. Kenneth A. Boyd, Director
Division of Oil and Gas
Alaska Department of Natural Resources
3601 "C" Street, Suite 1380
Anchorage, Alaska 99503-5948

Dear Mr. Boyd:

Exxon, as Unit Operator and on behalf of the Working Interest Owners, hereby submits the enclosed Fifteenth Plan of Further Development an Operation (15th POD) for the Point Thomson Unit for your review and approval.

The 15th POD contains an update on the 14th and interim PODs, as well as the Owners work plans for the next 15 months.

Should you have any questions, please feel free to call me at 713 656-7111.

Sincerely,



JRG:rij
Enclosure

RECEIVED

JUN 22 1998

DIV. OF OIL & GAS
DIRECTOR'S OFFICE

POINT THOMSON UNIT

Fifteenth Plan of Further Development and Operation and Update on the Fourteenth and Interim Plans of Further Development and Operation

In accordance with all applicable regulations, attached below is the updated Fifteenth Plan of Further Development and Operation (POD) for the Point Thomson Unit (PTU) which is submitted by Exxon as Unit Operator and on behalf of the Working Interest Owners ("Owners").

Overview

During the term of the 14th and Interim PODs, the Owners continued their efforts to commercialize the PTU, with the focus on evaluating the potential of various Thomson Sand reservoir gas development scenarios. The Owners, through their technical efforts, improved their collective understanding of many of the complex technical challenges associated with developing a high pressure gas reservoir in a remote location. The drilling and completion technologies necessary to drill and produce expensive, high throw, large-bore wells at high production rates have been examined. Additionally, detailed geologic and reservoir simulation models have been completed to: (a) assist in the estimation of reserves and flowstreams for numerous development scenarios, and (b) prompt the orderly development of facility design concepts and cost estimates.

While the work accomplished pursuant to the 14th and Interim PODs has led to an increased understanding of the Thomson Sand reservoir by the Owners, hurdles to economic development remain; particularly, high well and facilities costs, lack of a gas market and transportation system, and the unique technical challenges associated with high pressure gas cycling. Consequently, development of the Thomson Sand gas is not economically justified at the present time. However, the Owners remain committed to finding ways to overcome the technical and commercial challenges associated with the resource in order to eventually commercialize all hydrocarbon accumulations in the PTU area.

Additionally, three of the PTU Owners (Exxon, BP and Phillips) have worked with the State of Alaska's North Slope Gas Commercialization Team which has recommended that changes be made to the State's tax and royalty structure to improve the economic feasibility of a North Slope gas project. This work culminated in the Governor's introduction of Stranded Gas legislation (HB 393) earlier this year. Several of the Owners testified at many legislative hearings, which culminated in the Legislature approving HB 393. Future fiscal legislation will continue to be monitored for applicability to PTU resource commercialization.

Update on the Fourteenth and Interim Plans of Development

DNR Update

On April 2, 1998, the Owners presented a PTU progress update to the staff of the Alaska DNR. The update included a report on the Thomson reservoir full-field model, an overview on Drilling Technology, a PTU Facility Screening Study which included screening level cost estimates, the Thomson Oil Rim and pre-Mississippian/Basement, as well as the PTU Common Database and future PTU Work Plans.

Development Steering Committee (DSC) Formation

On June 11, 1997, the Owners approved the formation of the DSC. The DSC was charged with the coordination and development of a unit screening "tool kit" consisting of well design and cost estimates, facilities design and cost estimates, and selection and evaluation of development scenarios.

Fine Scale Geologic Model

A fine scale state-of-the-art 3D geologic model of the Thomson Sand encompassing approximately 330 square miles was constructed. Consensus trend maps, generated by the Unit's Geologic and Reservoir Modeling Committee (GRMC), were used to outline the distribution of facies and porosity within the model. This fine scale geologic model provides the foundation for the Thomson Sand reservoir simulation models and for the evaluation of development scenarios.

Reservoir Simulation

The reservoir simulation work was conducted by Exxon Production Research Company under the direction of the DSC. Initially, three reservoir simulation models were built to evaluate exploitation of the gas resource. The final results of this study were provided to the DSC participants on February 5, 1998. A fourth reservoir simulation model was built to evaluate possible oil rim depletion scenarios.

Well Design and Cost Estimates

Well design evaluation was conducted by Exxon Production Research Company under the direction of the DSC. Screening level well cost ranges were developed and reviewed by DSC participants in March 1998.

Facilities Design and Cost Estimates

Parsons Process Group Inc. was commissioned by the DSC to conduct a study to define "screening level" design and cost estimates for the facilities that would be required for various Thomson Sand development scenarios. The final results of this study were provided to the DSC participants on September 2, 1997.

Basement Studies

A pre-Mississippian/Basement interpretation was presented to the Unit Owners, and an overview has been presented to the staff of the Alaska DNR.

Thomson Oil Rim Studies

Geochemical analysis of the PTU-1 and C-1 cores was completed. These results have been presented to the Unit Owners, and an overview has been presented to the staff of the Alaska DNR. Further work may include an evaluation of the Mobil Staines River State #1 core, and if feasible, modeling of the producibility of the oil rim.

Flaxman Fan Studies

A scoping study has been initiated to evaluate the Flaxman Sand (Brookian) accumulation. The Owners plan to refine this model with newly acquired 3D seismic data and the results will be incorporated into the overall Brookian studies.

Farmout Initiative

The farmout agreements from Exxon, Mobil and Phillips required Arco to commence the acquisition of a western PTU 3D seismic survey, covering Unit Tracts 7, 8, 9, and 10, on or before March 31, 1997. According to Arco, Northern Geophysical commenced acquisition of the land portion of the required survey on or before March 30, and has now completed the acquisition of this data. The survey data has been processed and a copy of the land portion has been delivered to the Farmers. Arco conducted a proprietary presentation of the western PTU 3D seismic data with the staff of the Alaska DNR on April 7, 1998.

Appraisal Activity

On March 13, 1997, BP and Chevron publicly announced that the Sourdough #3 Well had confirmed the prior oil discovery made by the Sourdough #2 Well. Both of the wells are located within the PTU. A proprietary review of Sourdough was conducted for the staff of the Alaska DNR by BP and Chevron on April 7, 1998. Further appraisal of the Brookian play, including a possible drillwell, is under consideration by BP and Chevron.

Fifteenth Plan of Development (15th POD)

Common Database Plans

The Owners request that the term of the 15th POD extend from July 1, 1998 through September 30, 1999. During the term of the 15th POD, the Owners will finalize trade agreements, which will grant them access to well and seismic data. The Owners will create a common technical PTU database and consensus maps for all prospective reservoirs within the PTU by September 30, 1999. The Owners will present the consensus maps to DNR before the end of the 15th POD. Consensus mapping means an effort by all major Owners to use the shared technical data and various individual Owner interpretations to produce unified (agreed upon), comprehensive interpretations of each reservoir. Consensus mapping is necessary to evaluate prospectivity within the Unit, and to ultimately support refinements in development planning studies and development modeling. Measurable progress has been made to date in this regard, and plans are in place to further this effort as indicated below:

- All major Owners in the PTU have signed a ballot agreeing to participate in a current geo-technical boring program (Ballot 98-1).

- The DSC will soon be considering an environmental studies ballot (Ballot 98-2) to assess potential impacts of future development plans in the PTU area.
- The DSC has agreed to conduct a pressure-volume-temperature (PVT) forum on or about June 11, 1998 to reach consensus on PVT analysis and characterization which will be shared among all the DSC members.
- The Owners will conduct a PTU well core party during mid to late July 1998 during which all cores will be analyzed to help with Brookian reservoir description and modeling. All Owners are securing necessary management approvals and are verifying the availability of all PTU well cores.
- The Owners met on May 26 and 27, 1998, and have scheduled two additional meetings to further discuss the common database and progress negotiations on the agreements to share this data. The Owners are targeting to have most agreements in place by September 1, 1998. The Owners meetings are tentatively scheduled for the week of June 22 in Houston, and during the week of July 27 in Alaska. The Owners will update the Alaska DNR on the status of the common database on or before September 30, 1998.

The draft Licensing Agreement for the northern PTU 3D surveys has been provided to all PTU Owners by BP and Chevron. The surveys are shown on the attached plat. With the acquisition of these surveys, as well as the reprocessed PTU 3D and the western PTU (Arco) 3D, geophysical and geologic mapping of the Brookian reservoirs will begin during the proposed term of the 15th POD. However, Owners' access to this data and total participation in all Brookian mapping efforts remain a challenge, due to varied ownership in the Brookian accumulations.

BP and Chevron have offered to include their Sourdough proprietary data into the common database discussed above, with adequate protection and value provided for the data. This will be discussed in more detail at the Owner meetings discussed above.

Delineation Plans

POD 15 delineation activities will be primarily focused on acquiring 3D seismic data over the Brookian reservoirs as part of the development of the common technical database.

In the northern PTU/Flaxman area new 3D data has been acquired by BP and Chevron and is in the process of being evaluated for licensing by the Owners. The data that has been acquired is shown on the attached plat as 1997 OBC (Flaxman), 1998 West Island Corridor, and 1998 Flaxman Lagoon. This data, when processed, will be evaluated and integrated into the geologic model discussed above. BP intends to complete its 3D coverage along the northern and eastern portion of the PTU by year-end 1999 (conditions permitting). Owners have the option to acquire a license on this data and participate in Unit studies and mapping efforts for the Brookian reservoirs. Of course, one of the Owners' challenges is that Brookian accumulations are isolated and discrete and may not have similar ownership as that which exists within the Thomson reservoir. Each Owner will evaluate their particular need to acquire this data. The long-range plan is to merge all 3D data into one updated PTU 3D survey, as directed by the consortium of Owners.

In the western PTU area, Arco continues to evaluate its options pursuant to the recent trade agreements with Exxon, Mobil and Phillips.

In the southern PTU area, BP and Chevron continue to study further Brookian development, including possible plans for a drillwell in 1999. As plans develop for any drillwell, the Alaska DNR will be kept advised. At this time, no PTU Owner (including Arco) has a firm commitment for a drillable well location to submit to the DNR.

Development Planning Studies

Thomson Gas Reservoir

The Owners plan to complete the remaining scoping activities associated with Phase II of the Thomson reservoir study. The Unit "tool kit" developed during the 14th and Interim PODs will be used to refine gas cycling and blowdown development scenarios evaluated during Phase I of the study. Phase II of the Thomson Reservoir study includes optimization and high grading of locations and the number of drill sites, varying the location and number of producers and injectors, high grading gas offtake rate vs. facility costs and cost reduction. A PTU forum on PVT properties will be held on or about June 11, 1998, and will be based on a foundation of expanded PVT data sharing among the Owners. In addition, laboratory capillary pressure measurements are planned for additional facies representation. Depending upon the results of this effort, the Owners will undertake any additional work necessary to refine the current screening level design and cost estimates to match the upgraded scenarios. Once this effort is completed, Phase III operations, if warranted, will be progressed and could include conceptual engineering and appraisal delineation planning.

Thomson Oil Reservoir

The Owners will perform additional geochemical analysis on core data from the Mobil Staines River State #1 well. Planned analysis of simulation results may result in additional investigation of oil rim depletion scenarios. A review of the oil rim study results will be held with the DNR by September 30, 1998, as requested.

Brookian Accumulations

The Unit Owners will work together to build or update geophysical, geological, and reservoir models within the PTU area. Exxon as Unit Operator will coordinate the building or updating of as many specific Brookian development models as needed, after the common technical database is established. Consensus hydrocarbon flowrates and cost estimates will be developed to evaluate stand-alone Brookian developments and possible Brookian/Thomson co-developments. Assuming that the planned 3D activities occur as scheduled, the Brookian development models could be completed as soon as the 4th Quarter of 1999.

In addition, BP and Chevron have recently conducted a geotechnical program (soil borings) to help surface facilities and pipeline planning in the PTU area. The major Owners in the PTU have all signed ballots agreeing to share this data and pay their share of the costs for this work. BP and Chevron are also considering various engineering and environmental studies as well.

The DSC will soon be considering an environmental studies ballot (Ballot 98-2) to assess potential impacts of future development plans in the PTU area.

Integrated Development Model

After the Owners create the common technical database, develop a unit Brookian model(s), and scoping cost estimates, a generic integrated development model will be built to test development sensitivities for the Thomson and Brookian Sands. The development model can then be used to evaluate synergies and allow Unit Owners to share conclusions and enhance the understanding of development possibilities within the Unit. As noted above, completion of an integrated development model is targeted by year-end 1999.

Summary

In summary, the Owners' major emphasis for PTU development during the term of the 15th POD will be to: (a) create a common shared technical database for the PTU area, and (b) complete an evaluation of the common database in accordance with the attached PTU schedule/timeline, in an effort to look for synergies between potential oil and gas developments in the PTU area.

The Owners recognize that challenges remain in creating the shared technical database, but are committed to exploring all avenues for making this a reality. We expect to have most of the common database in place by September 1, 1998. The Owners further recognize that this shared database for the PTU area will allow all Owners to participate in the building/updating of geophysical, geological, reservoir and facility models for all reservoirs within the PTU area. A unified effort by the Owners in this regard should result in a common understanding of conclusions by year-end 1999.

EXHIBIT 1 - POINT THOMSON DEVELOPMENT WORK SCHEDULE

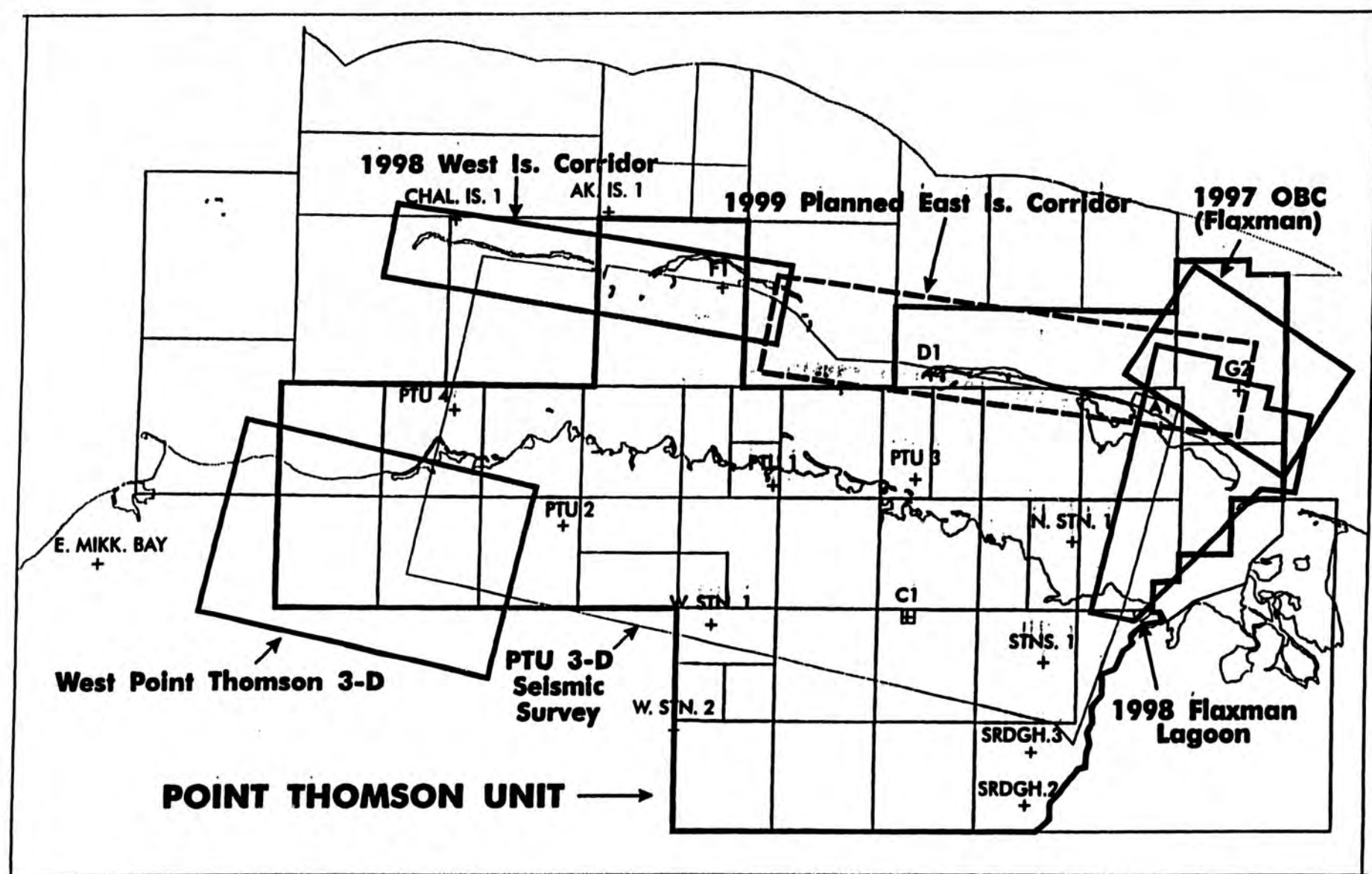
ACTIVITIES	1Q98	2Q98	3Q98	4Q98	1Q99	2Q99	3Q99	4Q99	1Q00	2Q00	3Q00	4Q00
DEVELOPMENT PLANNING												
1. PTU Other Resource Evaluation Oil Rim Geochemistry/Simulation, Flaxman Scoping Model and Basement Studies												
2. PTU Gas Resource Evaluation Scenario Upgrades (FFM), Evaluation and Economics Update, Cost Reduction (Phase II)												
3. Common Database Upgrades/Data Sharing Agreements												
4. PTU Brookian Oil Evaluation Data Trades, Seismic Process./ Interpret., Geol. Interpret. and Modeling, Simulation, Devel. Scoping												
5. Integrated Development Model												
6. Conceptual Engineering/Appraisal Planning (Phase III), if Warranted												

ACTIVITIES	1Q98	2Q98	3Q98	4Q98	1Q99	2Q99	3Q99	4Q99	1Q00	2Q00	3Q00	4Q00
POD SCHEDULE												
1. Interim POD												
2. POD 15 (Proposed)												
3. POD 16												

● Alaska DNR Reviews

Point Thomson Unit/Plan of Development 15

PTU 3D SEISMIC ACQUISITION PROGRAM



ONE LEAGUE!

State teams
talk it over

Sports, E-1



DRY DUNE
Panel OKs
extra money

Metro, D-1



From black
to white

Saturday, H-1

Anchorage Daily News

50 CENTS
VOL. LI, NO. 347 •

ANCHORAGE, ALASKA, SATURDAY, DECEMBER 13, 1997

FINAL
EDITION



Ken Boyd, director of the state Division of Oil and Gas, says Exxon's Point Thomson plan doesn't include enough work in 1998 and pays too little attention to a known oil deposit.

State presses oil partners

Exxon, others get message to try harder at Point Thomson patch

By STAN JONES
Daily News reporter

State officials are pressuring Exxon Corp. and several oil-industry partners to try harder to get oil out of a big patch of North Slope tundra and Beaufort seabed around Point Thomson.

Ken Boyd, director of the state Division of Oil and Gas, has sent prodding letters to Exxon since early October, when the company filed its Point Thomson development plan for the coming year.

That four-paragraph plan calls for, among

other things, studying where to put wells should development occur. But it does not involve drilling any new wells.

Boyd contends Exxon's plan doesn't call for enough work in 1998 and pays too little attention to at least one known oil deposit in the area.

He is scheduled to meet with the Point Thomson owners Tuesday to try to settle the argument.

"I want to know why they can't put this thing together," Boyd said.

Exxon has so far declined to modify its plan, insisting it complies with state law and regulations as is.

Exxon is the lead company among the Point Thomson owners, meaning it represents the other companies in dealings with the state. Oil and gas units such as the one at Point Thomson are formed out of separate leases so the co-owners will cooperate to ensure all deposits in the unit are developed for maximum yield and minimum cost.

Bob Davis, an Exxon spokesman in Houston, Friday would say only that the owners are working together to meet Boyd's con-

Please see Back Page, POINT THOMSON

So none goes without



Judge orders wolves out of Yellowstone

Recovery program ruled illegal; removal delayed to allow appeal

By LOUIS SAHAGUN
Los Angeles Times

DENVER — In a move that may end one of the most successful conservation experiments in recent history, a Wyoming federal judge Friday

Regional federal wildlife authorities in Denver said they have no firm contingency plan in place if their anticipated appeal fails beyond trying to recapture the estimated 165 animals in the area and releasing them

POINT THOMSON: State wants to see some serious exploration

Continued from Page A-1

cerns and expect to get the development plan approved.

The pace and timing of oil development are key concerns to the state. Oil revenue finances about 80 percent of the state's general fund, the money under the most immediate and direct control of the Legislature. Oil money also finances the Alaska Permanent Fund, which pays the annual dividend that reached a record \$1,297 per resident this year.

The Point Thomson unit, an 84,000-acre collection of leases on state land just outside the Arctic National Wildlife Refuge, is known to hold at least two sizable oil deposits.

One, near the middle of the unit, is called the Point Thomson sandstone. It is believed to con-

tain about 200 million barrels of very light crude called "condensate," according to state geologists.

The other deposit, at the southeast corner of the unit, is the Sourdough reservoir, announced in March by BP Exploration (Alaska) Inc. It is believed to hold at least 100 million barrels of ordinary crude, according to state geologists.

So far, Exxon has maintained the Point Thomson sandstone would not be profitable to develop. BP, meantime, has not said if it considers Sourdough worth developing.

Boyd said in an interview the two companies should share information on the deposits and consider developing them simultaneously.

Boyd said that splitting the cost of facilities needed by both developments — such as an airfield and a pipeline to carry Point Thomson oil west to Prudhoe and the start of the trans-

Alaska pipeline — might improve the economics enough to make both pay off, even if neither would be profitable by itself.

"How can you say something is not economic if you don't have all the information?" Boyd said. "If they're not going to cooperate, what's the point in having a unit?"

Point Thomson is about 50 miles east of Prudhoe Bay, raising the cost of getting its oil to the trans-Alaska pipeline for shipment south. But, said Boyd, BP's development of the Badami field, about midway between Prudhoe and Point Thomson, will cut in half the distance to the nearest pipeline.

BP spokesman Paul Laird said his company is deferring to Exxon on the development plan, and hasn't had time to consider joint development of Sourdough oil and the Point Thomson condensate.

The ownership breakdown at Point Thomson is as follows, according to Phillips Petroleum Co.: Exxon, 46 percent; Chevron, 22 percent; Mobil, 15 percent; Phillips, 12 percent; and BP, 5 percent.

A Phillips spokesman said the company is leaving the development plan up to Exxon, but likes the idea of developing the two deposits simultaneously.

"This is definitely something we think would be a smart thing to do," said Arne Holhjem, a Phillips official in Houston.

Boyd said it's remotely possible the state will try to take back and re-auction the Point Thomson leases if Exxon and its partners don't come up with a suitable development plan. But that's not likely, he said.

"That's just not a goal," Boyd said. "I would rather have the area explored."

WOLVES: Judge orders Canadian transplants out of U.S. wilderness

Continued from Page A-1

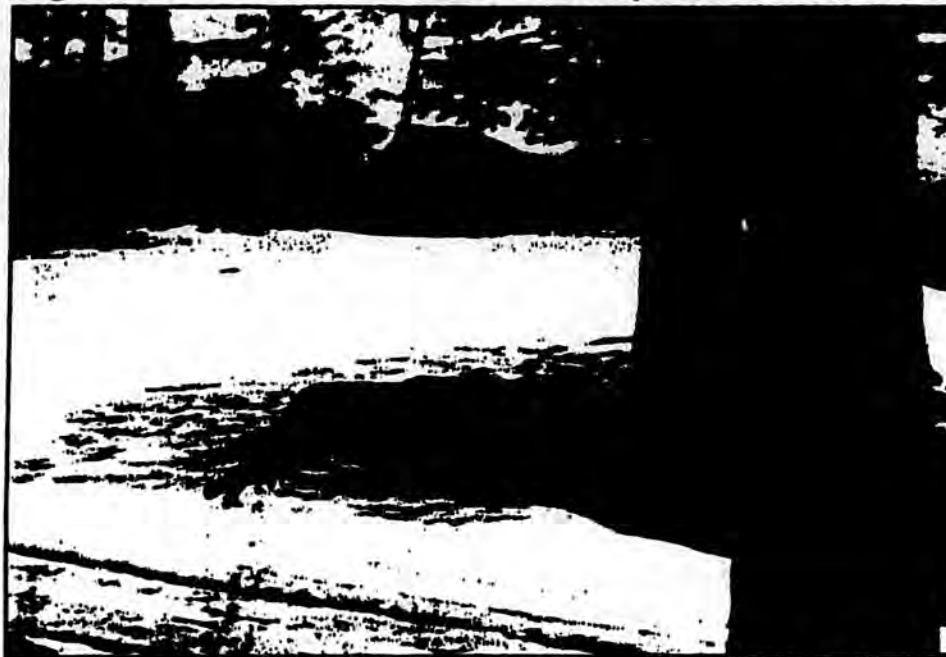
not go that far. "We will appeal," he said. "But we will obey the law of the land."

Ranchers hailed the ruling as a major victory and vindication of their efforts to halt the \$7 million federal project that they always have feared could deplete livestock.

"It's an early Christmas present for the ranchers of Montana, Wyoming and Idaho," said Steve Lechner of the Mountain States Legal Foundation, a multiple use advocacy group that represented the Wyoming Farm Bureau in the lawsuit.

Dean Kleckner, American Farm Bureau Federation president, agreed, saying the ruling could help stem what he called "overzealous regulation by the government."

At stake is a successful project designed to bring wolves back to the top of the food chain in the nation's oldest national park. With 85 wolves in several packs now loping through the forests, significant repercussions already are being recorded through-



DOUGLAS PEAC / Associated Press No photo

A wolf leaps across a road and into the wilds of central Idaho in this 1995 photo.

out the 2.2-million-acre park's wildlife hierarchy.

Before they were vanquished by government-backed poison and trapping

campaigns in the 19th and 20th centuries, wolves thrived in nearly every region of North America.

Once numbering in the

millions, only a few thousand wolves are left in the Lower 48 and about 7,000 in Alaska, according to game officials. Their absence disrupted the

natural predator and prey relationships throughout the Rocky Mountain region and resulted in a population explosion of deer and elk.

Biologists believe that the Fish and Wildlife Service's wolf recovery project, which is based on years of consultation with scientists and 160,000 public comments, succeeded because of the abundance of game and Yellowstone's status as a remnant of America's wild frontier.

The goal has been to create a breeding population of 100 wolves in Yellowstone and in Idaho within five years, and then remove wolves from the endangered species list.

However, under the project the reintroduced wolves were considered "experimental populations," meaning they lacked federal endangered species protections and could be shot if discovered feeding on livestock.

Native wolves migrating south from Montana and Canada occasionally mix with the experimental populations, thereby losing their federal protections.

JACKAL: No apologies

Continued from Page A-1

He carried out the 1975 seizure of OPEC oil ministers and was involved in the 1976 Palestinian hijacking of a French jetliner to Entebbe, Uganda, that ended with an Israeli commando raid.

Very early in his career, he was also linked to the 1972 massacre of 11 Israeli athletes at the Munich Olympics, but Israel later said he was not involved.

After eluding capture for decades, Ramirez now is being tried for the Paris killings of two French investigators and a man in the Popular Front for the Liberation of Palestine whom Ramirez suspected as an informer.

With thinning hair and mustache, the native Venezuelan once known as a ladies' man beamed at the six women in the nine-member jury as they took their places, drawing muffled laughter from the public.

But the ruddy-faced Ramirez then grew serious, taking his defense into his own hands to argue that the

3/23/99

CURRICULUM VITA

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PERSONAL INFORMATION

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EDUCATION

B.S. [1972] Dept. of Economics, University of Illinois.

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PROFESSIONAL EXPERIENCE

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Board of Directors, International Assoc. for Energy Econ., Houston Chapter, 1989-95.

Director, Bureau of Business and Economic Research, and Professor of Economics,
University of Maryland, 1991.

Director, Center for Public Policy, University of Houston, 1987-90.

Associate Professor, Department of Economics, University of Houston, 1983-89.

Associate Professor, Department of Economics, University of Illinois, Champaign-Urbana,
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Research Affiliate, Energy Laboratory, Massachusetts Institute of Technology, 1981-83.

Research Collaborator, Dept. of Applied Mathematics, Brookhaven Natl. Lab., 1980-81.

Visiting Scientist, Center for Energy Policy Research, Massachusetts Institute of
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Assistant Professor, Dept. of Economics, Univ. of Illinois, Champaign-Urbana, 1977-81.

Research Analyst, Energy Laboratory, Massachusetts Inst. of Technology, 1976-77.

Technical Assistant, National Bureau of Economic Research, Cambridge, Mass., 1975-76.

Prepared Testimony of James L. Smith

Introduction

My name is James L. Smith and I reside at 10537 Beinhorn Road, Houston, Texas. The Alaska Oil and Gas Commission has asked me to provide this testimony, which represents my independent judgment and professional opinion regarding certain economic aspects of unitized operations at the Prudhoe Oil Pool.

I am trained as an economist and I specialize in the field of energy economics. I received the B.S. degree (1972) in Economics from the University of Illinois, and the M.A. (1976) and Ph.D. (1977) degrees in Economics from Harvard University. I currently serve on the faculty at the Business School of Southern Methodist University in Dallas, where I hold the Cary M. Maguire Chair in Oil and Gas Management. The views I express here are my own and do not necessarily reflect the views of Southern Methodist University. Previously, I have served on the faculty at the University of Illinois (Champaign-Urbana), the University of Houston, and the University of Maryland (College Park). Most of my teaching, writing, and research deals with the subject of energy economics. In addition to my academic duties, I have served as a consultant to various oil and gas companies and government agencies. I have also served from time to time as an expert witness in regulatory and legal proceedings that involve energy matters, including the Alaska North Slope Gas Royalty case. My resume is included as Attachment 1 to this testimony.

The Scope of My Testimony

The Commission has asked me to comment on the Oil Rim-Gas Cap structure of the Prudhoe Bay Unit and its likely impact on field development, resource recovery, and waste. In addition, I have been asked to consider whether it would be appropriate to seek more complete

integration of interests in the Puhoe Oil Pool via compulsory unitization proceedings or other means. I have also been asked to evaluate and comment on pertinent elements of the working interest owners' testimony and contentions in this regard.

My report is organized around nine specific questions which the Commission has raised. I will attempt to address each question separately and in turn, but I recognize that several of the questions are closely related and therefore discussion of certain key issues may spill over into several parts of my testimony. The series of nine questions and my responses follow.

(1) *Explain the concepts and purposes of unitization and unit as they apply to oil and gas properties or reservoirs.*

The purpose of unitization is to eliminate incentives for wasteful and competitive practices in the development of a single pool by multiple owners. This goal is achieved by treating the pool as if it were a single asset in which each owner holds an individual interest.

Once this unitized structure has been created, the owners then share a common interest in finding and implementing the development program that maximizes the value of their jointly-held asset. This is the principal objective of unitized operations. All owners gain from actions that increase the value of the pool. All owners lose from actions that diminish the value of the pool. None profits at the expense of another. The permanent alignment of interests created by unitization produces incentives for each owner to enter into durable and robust commitments to pursue the common good.

The economics literature is quite clear regarding the objectives of unitized operations. Professor Stephen McDonald, in his classic exposition on the subject, summarizes the nature of unitization and unit operations as follows:

In sum, unitization converts a multiplicity of interests in a common reservoir to a single interest for purposes of extractive operations, and at the same time fixes the shares of participants in common net benefits. What then profits the unit as a whole profits each participant proportionately.¹

In terms of specific benefits, Professor McDonald lists four main advantages that can be expected to follow from unitized operations:² First, unitization tends to lead to the voluntary adoption of the optimum rate of production. Second, unitization allows the affected operators to adjust the rate of production so as to search continuously for maximum present value as events unfold and prices and costs change. Third, unitization leads to a more rational calculation regarding the disposition of gas produced with oil. And fourth, unitization makes possible a more rational use of cap gas in an oil reservoir. Each of these four separate objectives of unitized operations appears relevant, perhaps critical, to achieving efficient management of the Prudhoe Oil Pool.

(2) *Does the existence of separate participating areas for the Oil Rim and Gas Cap with different equity participations, or do other features of the existing contractual and property arrangements, mean that the Prudhoe Oil Pool is not unitized, or is not completely or not perfectly unitized?*

A pool is completely unitized when all commercial substances (e.g., oil and gas) contained within it are combined to form a single asset, as described above. The contractual arrangements that govern the Prudhoe Oil Pool have not achieved this. Instead, they have divided the reservoir substances into what are effectively two assets: the Oil Rim asset and the Gas Cap asset.

¹ Stephen L. McDonald, *Petroleum Conservation in the United States*, The Johns Hopkins Press, 1971, page 201.

² Stephen L. McDonald, *The Leasing of Federal Lands for Fossil Fuels Production*, Resources for the Future, 1979, pages 135-136.

Because development and production of one asset significantly impacts recovery of the other, potential conflicts can arise among the owners, despite the appearance of integrated operations. Because certain working interest owners hold a larger share of the Gas Cap asset than of the Oil Rim asset (and vice versa), the interests of individual owners in alternative field development projects and investments are misaligned. There is no natural consensus on a common course of action in developing the field. For example, plans to promote oil recovery at the expense of gas would affect separate owners differently, depending on their relative holdings of the two assets. Lacking a natural consensus on a common course of development and extraction, the owners have to rely on trading, bargaining, and compromise to forge a plan of action that is jointly acceptable. The ultimate impact of this compromise on field operations would depend on the relative bargaining strengths of the various parties and the scope of the disagreements they have to resolve.

Unitization of an oil field is distinct from a simple pooling of interests. The fact that certain interests have been pooled to create the Oil Rim and Gas Cap participating areas does not mean that the field has been unitized and does not ensure that the objectives of unitized operations will be achieved. This fundamental distinction is sometimes overlooked, even within the industry, as Burke and Starcher have noted:

The terms *pooling* and *unitization* are sometimes used interchangeably. However, unitization is normally more than a mere accumulation of acreage to create a drilling unit. Generally, unitization combines the economic interests in a reservoir to permit the joint exploration, development and operation in a more efficient manner.³

³ Frank M. Burke, Jr., and Mark L. Starcher, *Oil and Gas Taxation in Nontechnical Language*, PennWell Publishing Co., 1993, page 72.

Because of the coexistence of Oil Rim and Gas Cap participating areas, the natural alignment of interests that is produced by unitizing all reservoir substances into a single asset does not exist within the Prudhoe Oil Pool. In that sense, the Pool has not been completely unitized.

(2) *To what degree do the existing property and contractual arrangements for the Prudhoe Oil Pool fulfill the purposes of unitization?*

Although there is no objective scale upon which this question can be answered, I think it is fair to say that the existing contractual arrangements fall far short of achieving the purposes of unitization. Later in this testimony, I will cite specific conflicts between Oil Rim and Gas Cap interests that have jeopardized the optimum recovery of oil, raised questions concerning the rational disposition of gas, and demonstrated the lack of resilience of field development plans to changes in operating conditions. These are the very problem areas that unitization is specifically intended to avoid.

Given the existing contractual arrangements that have created dual assets under joint management (Gas Cap and Oil Rim), it is doubtful that the full benefits of unitization can be achieved. The dual participating-area structure of the Prudhoe Oil Pool would be expected to not jeopardize efficient management of the field only if at least one of the following three special requirements were met: (1) no physical communication or interaction between the reservoir substances contained within the Oil Rim and Gas Cap; (2) matching equity shares in the Oil Rim and Gas Cap held by each individual owner of the field, or (3) effective and costless bargaining procedures in place to resolve disputes and achieve compromise on issues where individual interests are not aligned. None of these conditions is met in the case of the Prudhoe Oil Pool. Consider each factor in turn.

(1) Physical Communication. If the reservoir substances were not in physical communication, then there would be less need to worry about the effect of the dual-participating area structure in the first place. Actions that benefit the Oil Rim could proceed without adverse consequences for the Gas Cap, and vice versa. However, the situation within the Prudhoe Oil Pool appears to be the opposite. From the outset, the owners have recognized that reservoir pressure provided by the Gas Cap would assist in the production of oil. I believe that the extent of physical interaction between Oil Rim and Gas Cap remains a significant issue as alternative depletion projects and development plans are being debated today. For example, BP's witness before the Commission reports that initiation of a major gas sale around the year 2005 would be expected to reduce ultimate recovery of oil reserves by 400 million barrels.⁴ Thus, depending on the strength of the next factor (i.e., differences in the extent of each owner's relative holdings in the Gas Cap versus Oil Rim), the potential exists for significant conflict regarding the management and ultimate disposition of the two jointly-held assets.

(2) Disparate Holdings. If each owner's equity interest in the Gas Cap matched that same owner's equity interest in the Oil Rim, potential conflicts that stem from the dual participating-area structure would be much diminished. This is because each owner would then give as much weight to Oil Rim values as to Gas Cap values. Any plan that would enhance the value of the Gas Cap by, say, \$2 billion at the expense of reducing the value of the Oil Rim by \$2 billion would be rejected by each and every owner. Major conflicts would be less likely if each owner's participation in the Oil Rim was the same as that owner's interest in the Gas Cap.

⁴ See the testimony of Mr. Stevens at page 353.

In fact, the differences between Oil Rim and Gas Cap holdings of each owner are quite significant, and therefore potentially divisive. BP holds roughly 51% of the Oil Rim, but only 14% of the Gas Cap. Arco and Exxon each hold roughly 22% of the Oil rim, but 43% of the Gas Cap. The smaller owners hold roughly 5% of the Oil Rim and 1% of the Gas Cap.⁵ These disparities are large enough to create substantial economic conflicts among the owners regarding how the two assets should be jointly managed.

(3) Conflict Resolution. The ultimate impact of conflicts that stem from the dual participating-area structure depends on the owners' ability to bargain, compromise, and set aside individual interests for the good of the entire unit. If conflicts can be quickly resolved in accordance with the greatest good, at reasonably low cost, and without delaying field development activities, then the conflicts that occasionally arise between Oil Rim and Gas Cap owners would be of little concern to the Commission. However, past experience shows that the process of resolving disputes among these owners is expensive, time-consuming, and disruptive to the planning and execution of field development activities. I will elaborate later on the potential for unresolved Gas Cap-Oil Rim conflicts to impair efficient operation and development of the Prudhoe Oil Pool.

It may be helpful to review the parties' own concerns about the extent to which the dual participating-area structure would engender conflict and impede development. There is no doubt that this was initially a concern to Arco and Exxon. [REDACTED]

[REDACTED].⁶ I believe that the Arco and [REDACTED]

⁵ The percentages may not add up to 100% due to rounding.

Exxon traders still acknowledge having been concerned back then about the potential for Oil Rim-Gas Cap conflicts--even before any such disputes had arisen. [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

Despite repeated efforts to consolidate the Oil Rim and Gas Cap interests, however, the parties failed in their negotiations to form a single participating-area. In lieu of that, and to avoid subsequent conflicts between Oil Rim and Gas Cap interests, the traders carefully crafted provisions of the Prudhoe Bay Unit Operating Agreement (PBUOA) in a manner that was intended to achieve a balance of interests and to commit all parties to what appeared to be an effective plan of development. Close attention was paid to the matter of how costs and production would be allocated between the two participating areas and the responsibilities of each participating area in meeting Unit plans and objectives. There were also special provisions included in the agreement to maintain balance between the interests of the two participating areas as the field proceeded through different stages of development, and provisions to restore balance if development scenarios deviated from expectations.

This approach appears to have worked reasonably well for several years during the first phase of field development. However, by the mid-1980s the system of trades designed to balance

See, for example, [REDACTED] and Mr. Harrison's AOGCC testimony at page 931.

[REDACTED]

[REDACTED]

the competing interests and produce consensus on major development issues appears to have broken down. Serious disputes arose between Oil Rim and Gas Cap interests and these conflicts threatened to impair Unit operations.¹⁰ Only through a series of protracted legal proceedings and private negotiations, leading in some cases to revisions of the PBUOA, were the owners able to resolve these disputes and move on to implement planned development activities.¹¹

The [redacted] distinction between "company economics" versus "unit economics" that ran through these disputes confirms the extent to which the dual participating-area structure has failed to fulfill the basic purpose of unitized development.¹² Within a properly functioning unit, the distinction between company-based and unit-based economics would be transparent and innocuous. By looking at the unit, each owner would see an image of himself. The same tradeoffs, opportunities, and costs facing one would be shared by all. This is not how things appear to work within the Prudhoe Oil Pool.

Although the original PBUOA may have achieved a certain *balance* among interests of the competing owners (at least as those interests were perceived at the time), it did not *align* their interests. This is a key distinction that has not been emphasized much in the testimony of previous witnesses before this Commission. Any balance that is effected through a series of fixed trades among owners is precarious since the value of the constituent trades will very likely change with the passage of time as prices, costs, and reservoir performance evolve. Once certain trades grow less favorable, the owners who are adversely affected will experience individual incentives

¹⁰ The basic disputes centered on the allocation of costs and produced substances between the Oil Rim and Gas Cap participating areas [redacted]

¹¹ The resolution of disputed issues has taken place in a piecemeal fashion, with a series of individual agreements being reached (or imposed) on separate issues as they have arisen. Consider, for example, the San Diego FGSO arbitration, the GHX Agreement, the Issues Resolution Agreement, and Conservation Order No. 360.

¹² See, for example, [redacted] and the AOGCC testimony of Mr. Meggs at page 735.

to reinterpret or renegotiate the burdensome contract provisions, perhaps even to the extent of withholding performance.

Unitization is intended to mitigate such problems not by balancing the interests of all owners at a certain point in time, but by aligning their interests permanently. By effectively consolidating all interests into one asset which is jointly owned, (i.e., one participating area), the interests of all owners tend to remain aligned in support of a common plan--that which maximizes the value of the unit--even as market conditions, investment timing, and field development opportunities evolve.

To summarize my thoughts on this issue, the existing contractual arrangements that treat the Oil Rim and Gas Cap as separate assets are likely to engender conflicts that are difficult to resolve and which have the potential to impair development and operation of the field. This situation is not consistent with the purposes of unitized operations.

(3) *How significant would be the costs, uncertainty, "malincentives," and other problems that working interest owners claim would result from compulsory unitization proceedings?*

I believe that the costs of a compulsory unitization procedure would be significant. I am in general agreement with other witnesses who have described the inherent difficulty of combining the two participating areas into a single equity structure. We know that the owners have already attempted to achieve a single equity structure on several occasions, and failed at each juncture. I believe that the owners' efforts in this direction have been in earnest, and that their repeated failure reflects, at least partially, the difficulty of their task.

I do not necessarily agree, however, that the Commission should conclude from these prior failures that the task of compulsory unitization must be viewed as prohibitively difficult. Nor do I agree that the process of compulsory unitization would be chaotic or unfair. The

principal difficulty that the Commission would face in a compulsory unitization proceeding would be to arrive at appropriate estimates of the net economic values of the Gas Cap and Oil Rim assets. There are three major uncertainties associated with that estimation: (1) future netback values of the oil and gas resources at wellhead; (2) timing of a major gas sale; and (3) expected volumes of oil and gas to be sold from the field. Compulsory unitization would require probabilistic judgments to be made, either explicitly or implicitly, regarding each of these factors, and for the associated development scenarios to be weighted accordingly in arriving at the expected net economic value of future sales from each participating area.

Although difficult, these uncertainties are not unlike what the owners must deal with anyway. Evaluation of alternative development plans requires certain assumptions or judgments to be made regarding these three factors whether equities are organized into one or two participating areas. In other words, I do not believe that the owners or the Commission would have to start from scratch in pondering these factors. Further, part of the cost and effort that would be required of the owners and of the Commission in preparing for a compulsory unitization proceeding would probably be incurred anyway somewhere along the line in the normal course of reservoir study, development planning, performance review, and regulatory oversight that is required for diligent and proper management of the Prudhoe Oil Pool.

The most notable cost of a compulsory unitization proceeding, and one that would constitute a large burden borne by the owners, is the cost of uncertainty--each owner having to accept an outcome that would have an unpredictable impact on the value of their holdings. The risk of an adverse outcome is a true economic cost that the owners cannot afford to ignore. I believe that the owners' reluctance to put their whole equity at risk in any single proceeding has played a dominant role in the failure of the previous voluntary efforts to achieve a single

participating area. Rather than putting the whole pie up for grabs at once, the owners prefer to continue working within a framework that deals with a series of somewhat smaller and more compartmentalized issues. That approach requires negotiations over each slice of the pie as it is placed on the table, and it may seem less risky for the owners than compulsory unitization. Any one who feels shortchanged at one stage can hope to make it up at the next. And by continuing with voluntary efforts to resolve their conflicts, the owners are able to retain control of the process, including veto power over any outcomes that they strongly oppose. This further reduces the risk they face.

Although the fear of losing equity to others would be a burden placed on each owner in the process of compulsory unitization, the Commission would not directly bear any part of that burden or share in the cost of uncertainty. That does not necessarily mean, however, that the Commission should ignore the burden of risk in deciding how to proceed. I believe that a key issue in deciding whether to move to compulsory unitization is the question of how much weight (if any) to place on the owners' discomfort with the risk that such a proceeding would entail. If the Commission's responsibility encompasses a role in assisting owners to minimize costs (including the cost of bearing commercial risk), then more emphasis should be placed on this aspect. If the Commission's responsibility is limited to protecting the State of Alaska's interest in the Field as a whole, then more weight should be placed on the question of whether compulsory unitization would increase the size of the pie and reduce economic waste--letting the chips fall where they may.

Several witnesses have described the process of compulsory unitization as almost certainly being chaotic, inherently unfair, and virtually impossible to complete. I disagree. The process of compulsory unitization of the Prudhoe Oil Pool would benefit significantly from the fact that the

resource has already been fairly divided into two assets. The remaining task that would be the subject of compulsory unitization proceedings would be to consolidate these two participating areas, not to revisit or revise the basis on which initial equity allocations were determined.

The only deliberations that should play any role in the proceedings would be focused on the single question of what is the economic value of the Gas Cap asset *relative* to that of the Oil Rim asset. That ratio is a single number, one parameter. I call that parameter the "e-factor" for "equity." I have already commented on the difficulty in arriving at that number, and I am not discounting those remarks here. What I am saying is that the proceedings could be narrowly focused and specifically organized around this one question: what is an appropriate value for the e-factor?

Other witnesses have emphasized the extent to which the owners have relied on trades that were made when the Unit was formed, as reflected in provisions of the PBUOA. They also suggest that it would be unfair (and perhaps violate the owners' correlative rights) to abandon or circumvent those provisions now. I agree. But I do not see that issue as being one of the dangers of a compulsory unitization proceeding. In arriving at an appropriate value for the e-factor, I would imagine that the provisions of the PBUOA would be taken into account exactly as the owners have agreed to them. Each owner of the Gas Cap holds a determinate share of that asset and certain responsibilities as a Gas Cap owner for financing shared unit operations. Likewise for the Oil Rim. In determining the net economic value of the Gas Cap asset under any particular development scenario, the net present value of Gas Cap revenues less costs would be estimated, in accordance with all relevant provisions of the PBUOA. As I understand that agreement, it translates the various trades between Gas Cap and Oil Rim owners into specific formulae and rules for allocating produced substances and costs. I do not see anything unfair or in violation of

the owners correlative rights in applying those rules to estimate the net value of the Gas Cap asset or the Oil Rim asset.

Once an appropriate value for the e-factor has been determined, the process of compulsory unitization would be straightforward. Each owner's share in the consolidated participating area would consist of the weighted average of that owner's existing equity shares in the Gas Cap and Oil Rim, respectively. The e-factor would be the appropriate weighting factor for this calculation and it would be applied uniformly to all owners.

Since calculation of the e-factor would incorporate and conform with all agreements that have been mutually agreed by the owners, it would then embody the various trades upon which the existing agreement rests and it would circumvent none of the deals upon which the various owners have been relying. For that reason, I do not see the process of consolidating the two participating areas into a single equity as being unfair to the interests of any owner, or in violation of correlative rights.

(5) *Are there significant development or operational decisions still to occur in the future that could be adversely affected by features of the existing contractual and property arrangements for the Prudhoe Oil Pool?*

There are several major issues remaining where the Gas Cap and Oil Rim interests might conflict. I would start by recalling Mr. John Morgan's testimony to the effect that 50% of the production from the Prudhoe Oil Pool that BP deems possible by the year 2005 depends on investments that have yet to be made.¹³ The owners' mutual agreement to fund those investments

¹³ See the AOGCC testimony of Mr. Morgan at page 797.

will therefore play a significant role in the remaining life of the field, as it is currently expected to play out.

Additionally, we should consider the ability of the owners to respond to various unexpected developments that might affect future operations. What would be the impact on production incentives and development planning at Prudhoe Bay if world oil prices were to double within the next few years. For example, suppose that civil unrest within Saudi Arabia and elsewhere in the Mideast permanently slows oil production from those areas. What types of enhanced oil recovery at Prudhoe Bay would make sense under that higher-price scenario, and what portions of the field would be involved in heightened efforts to enhance oil recovery? What types of risk would be associated with relatively high-cost enhanced oil recovery facilities? And is it possible that some of those risks might fall disproportionately on owners of the Gas Cap while the rewards would be concentrated on owners of the Oil Rim?

Rising oil prices usually carry gas prices in the same direction. Therefore, we might pursue further the scenario of high oil prices sketched above. Suppose that due to the rising price trend, the Prudhoe Bay gas reserve becomes "commercial" at roughly the same time that oil prices are rapidly appreciating. By "commercial" I mean that the gas could be transported to market leaving a positive, but small, netback value at the wellhead. Should the gas then be sold, or should it be used for enhanced oil recovery? Would all of the owners agree on this type of issue? According to all previous testimony presented to this Commission, the decision to proceed with a major gas sale is a "no-brainer" on which all sides would obviously agree. If the netback value per mcf were large enough, that might be true. But I have strong doubts. If the netback value were relatively small, especially when compared to the value of 400 million barrels of oil

production which the major gas sale would be expected to displace, then I see the potential for serious disputes to emerge between the Oil Rim and Gas Cap interests.

Exxon's position, as I understand it, is that no such dispute would matter. The owners are already committed by contract to support a major gas sale of 2 TCF per day. The contract is apparently interpreted by Exxon to mean that it and Arco could unilaterally proceed to sell their gas. I find this testimony to be less than convincing. Speaking of plans to unilaterally undertake any type of depletion policy, over the protest of other owners, is far removed from the ideal of unitized operations undertaken to promote the common good. Moreover, I am surprised if it is Exxon's position that a major gas sale of 2 TCF per day has already been determined to promote the common good and therefore must proceed against whatever opposition BP would mount. Prior to knowing the netback value of gas at the wellhead, it would be impossible to know whether its sale does in fact promote the common good. Of course, the eventual netback value has not yet been determined, and that is why the owners have testified that uncertainty in gas values has stymied voluntary efforts to consolidate the two participating areas.

Nonetheless, if for the sake of argument we temporarily accept Exxon's claim that it has already been determined that it would be in the interest of the Unit for the gas to be sold, there is still a problem: how can we be sure that BP would also agree to produce and sell its gas? If it is appropriate Unit policy for Exxon's gas to be produced and sold, would it not also be appropriate Unit policy for BP's gas to be produced and sold? Whereas Exxon's unilateral action to sell its gas might solve all of Exxon's problem, it may solve only one-half or one-third of the Unit's problem. Thus, I see management concurrence in the size and timing of a major gas sale as a possible source of future Gas Cap-Oil Rim conflicts.

Another type of potential conflict between the Gas Cap and Oil Rim interests, and one of major importance, could arise as the field approaches the end of its productive life. Eventually, it will come time for the owners to reach a decision to terminate production and abandon the field. At that point, would the Gas Cap interests gain by prolonging oil production past the economic limit of the oil reserve if the payoff to them was that continued operations would keep alive the option for an eventual major gas sale? Would the incentive for them to do so be reinforced by the differential allocation of produced liquids (gas condensate and NGL) to the Gas Cap owners? I am not sure of the answers, but I think these questions should be addressed.¹⁴

(6) *Has the two participating-area structure resulted in benefits for developing the Prudhoe Oil Pool that would not have occurred otherwise?*

The principal benefit of the two participating-area structure is that it helped to facilitate the negotiations that ultimately lead to formation of the Prudhoe Bay Unit. If it is presumed that voluntary negotiations would have failed without the two participating areas, and that development of the field would not have proceeded, then we must count the creation of the dual participating-area structure as an enormous benefit to all parties concerned. However, if it is presumed that the State of Alaska would or could have used its powers to intervene and "revive" the failed negotiations in some manner, as seems likely, then the strategic importance of the two participating areas is diminished.

The owners have testified that the structure of competing interests which stems from their Gas Cap-Oil Rim rivalry has also been of significant value in stimulating greater scrutiny of development decisions and promoting more extensive research and better understanding of

¹⁴ [REDACTED]

development opportunities than would otherwise have occurred. What I do not understand about this argument is why, if extra effort and scrutiny are beneficial to the unit in cases where the owners are in conflict, such effort and scrutiny would not also be provided or undertaken in instances where the interests of the owners are more closely aligned. Whether interests are aligned or in contention, all owners share the incentive to research and debate matters that are vital to the value of their investment.

Further, I would expect the exchange of ideas and information among multiple owners to actually work better and carry greater weight in units where the interests and goals of respective owners are aligned--as in a single participating area. At least in that case there would be less incentive for any owner to shade or distort information to reflect favorably on projects that might enhance that owner's individual position at the expense of others. If owners have competing incentives within the unit, I would expect each owner to discount to some degree the information, analyses, and interpretations that are provided by the others.

(7) *To what degree would changes in the contractual and property arrangements for the Prudhoe Oil Pool such as combining the two participating areas reduce or eliminate the incentives for competitive, as distinguished from cooperative, behavior on the part of the working interest owners or otherwise reduce or eliminate disputes among them?*

While certain technical differences and commercial conflicts might remain, I believe that representatives of all the major owners agree that consolidation of the two participating areas into a single equity structure, *once achieved*, would go very far towards eliminating the conflicts that have accompanied development of the Prudhoe Oil Pool.

Of course, not all potential conflicts can be avoided no matter how the Unit is structured. If there are multiple owners who face significantly different costs of capital or who realize

different netbacks on produced oil, conflicts may emerge in taking one course of action over another. Such conflicts are based on circumstances that originate outside the Unit.

Unfortunately, there is no way to structure the Unit to anticipate the ebb and flow of those external differences or to neutralize them. This contrasts with the type of conflicts that stem from the existence of dual participating areas, which are not inherent in the nature of unitized operations, and which could be eliminated by consolidation of equity within a single participating area.

It is my opinion that few, if any, of the conflicts that have divided the owners of the Prudhoe Oil Pool stem from external circumstances. The cost-sharing disputes that caused the parties to adopt the so-called GEX-1 agreement did not arise because Exxon faced a higher cost of capital than Arco. BP did not initiate the Energy Conservation Task Force to save fuel gas in 1984 because it had a contract to sell petrol in Europe that Arco could not duplicate. The recent standoff on NI-NGL did not arise because Arco pays more federal income tax than BP. The fundamental conflict that drives all of these disputes is the fact that the owners have varying stakes in oil versus gas-related projects. Consolidating the two participating areas would go a long way towards resolving the disputes that have impaired development of the field.

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

(8) *Are there alternatives to compulsory unitization that could be employed to reduce or eliminate incentives for competitive behavior on the part of the working interest owners or otherwise reduce or eliminate disputes among them?*

I am not aware of any other approach, besides consolidating the holdings into a single participating area, that would ensure that the interests of the respective owners are in alignment and remain so as events unfold over the remaining life of the field. I have already commented on the limitations of attempting to balance the interests of multiple owners at one point in time in order to win agreement on a particular issue. The problem with this approach is that it is not robust--the balance is likely to be lost as circumstances and opportunities change. The environment is not static, and even with a binding and well-executed contract in hand, disputes may arise among owners whose interests fall out of alignment. At that point, each owner will find reasons to interpret the provisions of the contract in favor of its own position and to resist interpretations that threaten its interests.

[REDACTED]

Several witnesses have discussed the "case-by-case" approach to resolving Unit conflicts, which is an alternative to compulsory unitization that the Commission must consider. Rather than aligning the owners' interests once and for all via unitization, the case-by-case approach would rely on the Commission's oversight to deal with any future disputes if and when they arise. The idea would not be to eliminate future conflicts, but to get the Commission's help in resolving them.

There are some risks associated with the case-by-case approach. If intervention by the Commission in field operations is not something that the owners generally welcome, certain disputes and conflicts may simmer beneath the surface for an indefinite period of time before any owner would come forward. If the underlying issues are time-sensitive, with physical or economic waste hanging in the balance, such delay could be an important drawback.

In addition, the positions and analyses that respective owners might put to the Commission during such proceedings would be subject to the problem of malincentives. If the issues in dispute are not purely technical in nature, but based on conflicting equity interests within the pool, some owner may have an incentive to shade its presentation toward the outcome that is most favorable to its vested interest. In adjudicating these disputes, the Commission would very likely have to consider, at least implicitly, many of the same factors that would enter into a compulsory unitization proceeding.

Another danger in waiting for disputes to emerge is that the delay in responding to some potential problem could jeopardize major opportunities to enhance recovery. Consider the prospect of a major gas sale, for example. Any sale of gas from Alaska will require a major investment in transportation infrastructure, whether the gas is to be moved by pipeline or tanker. That investment will depend, in part, on the willingness of outside financiers to provide funds. If

a major conflict between the Gas Cap and Oil Rim owners regarding the size or timing of gas sales remains unresolved at that stage, the resulting project uncertainty would probably impact the financing, and perhaps preclude the project from going forward. There are lots of major gas projects on the drawing boards of producers all over the globe, each poised to proceed under the right market conditions. Anything that delays the ability of Alaskan producers to seize a window of commercial opportunity for a major gas sale also diminishes the likelihood that a major gas sale will ever occur. Other things being equal, there is a clear advantage in having put the affairs of the Unit in good working order well in advance, not at the last minute.

(9) *Has the two participating-area structure or other features of the contractual and property arrangements for the Prudhoe Oil Pool resulted in any delay of or failure to pursue any development project or impaired any operation?*

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

Conflicts stemming from the two participating-area structure have also impaired the implementation of major field development initiatives. Apart from the MI-NGL dispute, about

20 [REDACTED]
21 [REDACTED]
22 [REDACTED]
23 [REDACTED]
24 [REDACTED]
25 [REDACTED]
26 [REDACTED]

which the Commission has heard from others, [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

28 [REDACTED]
29 [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

Weighing the Arguments Against Compulsory Unitization

Many of the witnesses who have already appeared before the Commission have offered a wide range of reasons why a compulsory unitization proceeding should not be initiated. I will close my remarks by commenting on some of the most prominent reasons given, and in the process attempt to summarize some of my own views.

Reason #1: *"The Unit is not broken; there is no problem, and therefore no need to fix it."*

Proponents of this view claim that the interests of the owners are already integrated to the extent possible, and that the conflicts that do emerge from time to time stem from external differences between the owners, not from the two participating-area structure of the Prudhoe Oil Pool. I

disagree. The two participating-area structure appears to generate major conflicts among owners that put the intended benefits of unitization in jeopardy.

Reason #2: *"The Unit may be broken; but the Commission should not attempt to fix it via compulsory unitization because that cure may be worse than the disease."* I have mixed feelings about this argument. The "cure" admittedly involves putting each owner's equity interest at some risk, and this represents a heavy burden--large enough to have prevented the owners from voluntarily consolidating the two participating areas into one. If this burden is a matter that properly falls under the Commission's purview, then it would have to be weighed very carefully against the benefits of achieving a greater alignment of interests among the owners. However, I do not agree that the "cure" is bad for the other reasons often given: I do not think that the process of compulsory unitization would be chaotic, unmanageable, or inherently unfair or in violation of the correlative rights of the owners.

Reason #3: *"Compulsory unitization should not be imposed by the State because it would not be a panacea for all that ails the Unit."* In my opinion, this argument is a red herring that deflects attention from the issues at hand. It is akin to arguing that we should not vaccinate children against disease because that would not solve the problem of world hunger. Most of the major conflicts that have been associated with Unit developments do stem from the two participating-area structure, and these problems would be resolved if the dual equities were consolidated. If other problems would remain unresolved, then the owners and the Commission might want to consider additional measures to further enhance operations within the Unit.

Reason #4: *"Compulsory unitization would be viewed by many as the State reneging on an agreement and would therefore establish a damaging precedent that could discourage future investment from coming to Alaska."* On legal grounds I cannot say whether initiating a

compulsory unitization procedure at this stage in the life of the field would constitute reneging on a contract. I do believe that the Commission operates under a charter that requires it continuously to guard the State's oil and gas resources against preventable waste. In that sense, any owner who enters into an agreement with the State to operate subject to the Commission's authority must know that its operations will be constrained by and subject to such considerations at all times. Moreover, from an economic perspective, I believe that consolidation of the separate equities into a single participating area can be accomplished without destroying any of the agreements, trades, or deals upon which the owners have been relying.

Reason #5: *"Compulsory unitization should not be imposed because the Commission has no statutory or legal authority to do so."* I have no knowledge or opinion regarding the validity of this claim or the weight that should be attached to it.

Reason #6: *"Compulsory unitization should not be attempted because the problem of malincentives would undermine the process and interfere with field operations."* The malincentives that threaten to interfere with operations at the Prudhoe Oil Pool stem from the dual participating-area structure, not from the attempts to consolidate the separate equities. Whether or not compulsory unitization is pursued, the same malincentives will exist. It is misleading to argue that by circumventing the process of compulsory unitization we can also circumvent the effects of whatever malincentives are thought to exist within the Unit. Proponents of the "case-by-case" approach to conflict resolution apparently believe that the malincentives of the owners would be less damaging if played out over a long series of disputes than if confronted once and for all during the process of consolidating the two participating areas. My own view is that malincentives that are allowed to linger and persist beneath the surface would probably be

more damaging in the long run, and less predictable, than the rather obvious preference of each owner to emerge from compulsory unitization with the largest possible equity share.

I want to thank the Commission for allowing me to present these views. This completes my prepared testimony.

SCOMM

118:7

Alaska State Legislature

House Special Committee on Oil & Gas

State Capitol
Room 13
Juneau, AK. 99801-1182



Phone (907) 465-3004
Fax (907) 465-2070

MEMORANDUM

TO: Legislators and Legislative Staff
FROM: Representative Jim Whitaker 
DATE: January 11, 2000
RE: House Oil and Gas Committee Procedures

The Oil and Gas Committee will meet Tuesday and Thursday at 10:00 a.m. in room 17 unless otherwise noticed. All hearing requests must be submitted in writing along with a sponsor statement by noon Wednesday in order for the bill to be scheduled the following week.

Upon notification that the legislation has been scheduled for a hearing, please submit the following documents no later than 9:00 a.m. on the day before the committee meeting:

- sectional analysis (if available)
- position papers
- suggested amendments or committee substitutes
- list of potential witnesses
- any additional background information
- teleconference sites

Packets will be delivered to the committee members by noon the day before the committee hearing. Should you have any question, please contact Lori Backes, Committee Aide (x2283).

Chairman: Representative Jim Whitaker
Committee Members:

Representatives Fred Dyson • Gail Phillips • Brian Porter • Joe Green • John Harris
• Allen Kemplen • Tom Brice • Hal Smalley

Alaska State Legislature

House Special Committee on Oil & Gas

State Capitol
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Phone (907) 465-3004
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House Special Committee on Oil and Gas January 11, 2000

Synopsis

In opening the meeting of the House Special Committee on Oil and Gas, Chairman Whitaker described the order of business for the committee and outlined issues which the committee will take up during this second session of the 21st Alaska Legislature.

The first order of business will be the hearing of bills and resolutions assigned to the committee, followed by the charge to "discern and understand issues relating to the oil and gas sector in Alaska", including:

- the commercialization of Alaska North Slope gas
- examination of the North Slope crude market dynamic
- ascertain the status and application of Section 38.05.177 of the Alaska Land Act regarding "Shallow Natural Gas Leases"
- examine the status of oil and gas lease sales in Alaska
- review the regulatory regime of the Alaska oil and gas industry, including a definitive charting of the authority and roles of the various entities; AOGCC, Dept. of Natural Resources, Dept. of Revenue, Dept. of Law and the Legislature, and
- in the event the acquisition of Arco by BP goes forward with the approval of the FTC, the committee will conduct an examination of the implications the merger holds for Alaska.

Representative Whitaker clarified that the issue of the acquisition will be discussed within the purview of the Oil and Gas Committee only in terms of understanding the effects associated with it, and the positive non-political steps which the legislature can take or recommend regarding increased production rates, commercialization of North Slope natural gas, continuation of an equitable and stable taxing regime, and furthering a "straight-forward, non-nonsense dialogue between BP and this committee."

The Chairman then opened up the discussion to the members of the committee who offered their own concerns and suggested issues they were interested in having the committee address.

Chair: Representative Jim Whitaker
Members: Representatives Fred Dyson • Gail Phillips • Brian Porter • Joe Green
• John Harris • Allen Kemplen • Tom Brice • Hal Smalley

Representative Phillips stated that she would be interested in hearing more about the "Peninsula Group", and that perhaps a joint meeting with members of the Canadian Parliament would be appropriate to discuss the Canadian connection with regard to gas.

Representative Green mentioned that the Renaissance Oil Company had expressed an interest in Alaska, and he suggested that the committee look into ways of encouraging "independents" to come to the state.

Representative Kemplen would like the committee to receive a presentation by Anadarko regarding how they would fit into the oil and gas production scenario in Alaska if the merger is approved. He also added that he would be interested in a presentation on alternative fuels, such as "fuel cells" and how the market demand for oil and gas may be affected by the invention of more fuel efficient vehicles. Rep. Kemplen also would like the committee to receive an update on the status of South Central Alaska energy reserves.

Representative Smalley stated that he would like the committee to learn more about "value added projects" in the oil and gas industry around Alaska.

Representative Dyson offered that he had attended a meeting with PNWER, (Pacific North West Economic Region) and would like information regarding a McKenzie Delta project, and a summary of production of heavy oil by BP. In expressing concern over national security issues, he requested the committee receive information regarding unknown oil reserves in Alaskan basins. Rep. Dyson also questioned whether the committee's purview may allow a look at the problems associated with the Alaska railroad transporting fuel.

Representative Harris would like the committee to do what it can to encourage the oil companies to provide more jobs for Alaskans, and is interested in having the committee examine the economic effects the City of Valdez's "vessel tax" may have on oil production in Alaska.

If you would like any information regarding meetings of the House Special Committee on Oil and Gas, contact committee aide, Lori Backes at 465-2283.

Chair: Representative Jim Whitaker

Members: Representatives Fred Dyson • Gail Phillips • Brian Porter • Joe Green
• John Harris • Allen Kemplen • Tom Brice • Hal Smalley

SCOMM

118:8

**Alaska North Slope LNG Project
Testimony for the House Special Committee on Oil and Gas
(January 13, 2000)**

Mr. Chairman, for the record, my name is Steve Alleman. My current assignment is as the Commercial Manager for the Alaska North Slope LNG Project, I reside in Anchorage, and I am employed by Phillips Petroleum Company. Thank you for the opportunity to testify today on behalf of the Sponsor Group.

Today, I will provide an overview of the status of the project and then will be happy to address questions. The Sponsors presented testimony to this committee on two occasions last year, and to avoid repetition, I will use those statements as foundation and discuss new developments, activities and plans since we last visited with the committee.

I am very pleased to be here today to say that the Alaska North Slope LNG Project has made considerable progress this year. As you will hear, we have a solid forward plan for commercializing North Slope gas via LNG and to our knowledge, no one is applying more resources and money than us to do so.

Most recently, the membership in our group has changed. BP is now a 12 percent member. This is a very welcome addition, considering BP's extensive North Slope lease position and operations, its world wide project experience, and its interest in pursuing all options to commercialize Alaska gas. In addition to BP, the other members, of course, are ARCO Alaska, Foothills Pipe Lines, Marubeni Corporation and Phillips Petroleum. As we have often stated, and it is even more true today, this is a very experienced and strong group that we believe provides the best chance for commercialization of North Slope gas via the LNG option.

The object of this group is the same as when we formed in 1998: to develop a competitive LNG export project at the earliest possible time as market conditions warrant. To be competitive, we need to exploit our advantages and overcome our challenges. An Alaska project has several positives including a developed resource, proximity to the market, and political stability. But it has two significant challenges:

the cost of an 800-mile pipeline and the fact that the project needs to be appropriately sized to afford it the best chance to enter the market.

Previous State studies and our own internal studies point to a potential answer to the cost issue. To be competitive, an Alaskan LNG project needs cost reductions unique to Alaska, it needs federal and state fiscal modifications and certainty. Our studies suggest that the combined level of federal and state fiscal relief that is needed may be politically feasible. This is because relief that occurs early in the project can help improve the project economics while still providing federal and state revenues later in the project.

The issue of project size requires creative thinking and effort. We believe that the marketability and timing of an LNG project improve if it is smaller. History shows that the successful mega-LNG projects serving East Asia started with a small size then built up in steps. Our analysis convinced us that previously studied projects of 14-15 million tons per year were just too large to be competitive with other market entry projects.

Accordingly, over the past year, we have worked to improve our chances with the marketplace by reducing the size of our project while at the same time evaluating our opportunities for further cost reductions. We completed an updated and detailed assessment of market conditions. This helped us determine the largest volume project that could enter the market in a reasonable timeframe. We are also systematically engineering the project to ensure that the optimum size can be achieved. We are now optimizing our Market Viable Project, or as we call it, our MVP.

This past fall, we announced this MVP as a 7-million ton per year LNG export project, which has been established, as our working basis for further refinement and optimization. This is about half of the project size that has been assumed for over a decade. Again, our motivation is to develop a project that is appropriately sized to gain a toehold in the market while at the same time having the ability to expand that project as market conditions warrant. Thus, with a projected pre-shipping cost of \$5-6 billion, we have significantly reduced our project risk in the areas of market, capital cost, and financing.

As for the market and what it is telling us about timing and the overall prospects for an Alaska project, there are encouraging signs. While the economic turmoil of the past few years in our target Asian markets has negatively impacted near term demand for LNG, there seems to be good prospects for substantial, sustained growth in the long term. However, we must face the reality that the competition for market share will be fierce. While the LNG marketplace will favorably view the positive aspects of an Alaskan project that I mentioned earlier, these savvy buyers will ultimately commit to an Alaskan project only when it becomes economically competitive with their best alternatives.

Therefore, we think it is important to clarify our thinking on two points. As a result of our in depth analysis and LNG market experience, the Sponsor Group does not subscribe to the idea of a "market window" for an Alaskan project. We do believe, however that once an Alaskan project is economically competitive, then it can legitimately vie for a share of what we project to be a long term, more sustained demand growth. Second, we recognize that the affirmative decision that will cause an Alaskan project to happen will come from the market, not from the investors or from government. LNG projects are not like oil development; you can not afford to "build it and they will come". The market will drive this project and the LNG buyers will need to be enticed to an Alaskan project by making it economically competitive.

To maintain a continuous market presence; to be available to respond to market questions; as well as to provide information on our project to these LNG markets, the Alaska North Slope LNG Project announced in September of 1999, its opening of a market liaison office in Tokyo, Japan. This office is located in Marubeni's Tokyo complex and is maintained by Marubeni personnel. As a Sponsor group member, Marubeni provides its own project and market expertise complimented by the experience and expertise of the other sponsors including that of Phillips Petroleum Company who, as you know, has been marketing LNG to Japan from Alaska for over 30 years.

Often we get the question: "What is the schedule for starting up the project?" In light of my earlier statement, the more relevant question

is: "What are the activities and schedule for making the project economically competitive and enticing to the LNG buyers"? In just a moment, I will address that question. But first, I want to discuss the matter of pipeline route and LNG plant site that is sometimes associated with the question of project timing.

As we announced this past fall, the project sponsors have narrowed the route and site to two alternatives: first to Anderson Bay in Prince William Sound and second to Nikiski in Cook Inlet.

When we narrowed our site selections to two alternatives, we found that neither was clearly better than the other. The Cook Inlet route may offer some cost advantages and more naturally fits with Cook Inlet's role as the center for gas usage in Alaska. While the Prince William Sound route has some existing permitting, which may give it a nominal time advantage.

But the real question is not where does permitting stand today, but what is required to fully permit either alternative to the point where construction of a project can occur. Based upon our sponsors' expertise of actually permitting and then building multi-billion dollar projects as well as from the benefit of external analysis, we determined that both locations require substantial additional permitting and refinement before a project is ready to fund. Therefore, this perceived time advantage could be mitigated with cooperation from the federal and state government.

Further, we found that permitting for either alternative was not the pacing item for a market driven startup. We believe that it is better to identify an economically competitive project first, and then optimize the project for location. Neither site works if the overall project isn't doable.

And now, let me answer the question I posed earlier about our ongoing activities to make the project competitive. As I do so, please keep in mind my earlier comments that an Alaskan project needs cost reductions and fiscal modifications before it can be competitive.

The sponsor agreement calls for the completion of the first stage of the Alaska North Slope LNG Project work about mid-year. At that time, we will have completed the pre-conceptual engineering, the various optimization studies and the revised cost estimate for the MVP. At that time, we will have a revised understanding of the economics of the project and the information necessary to begin discussions with the LNG markets.

We are planning for success. We are developing our specific Stage 2 plan for key work products necessary to move this project beyond Stage 1. We will spend the balance of Stage 1 refining our economics, optimizing our systems and pipeline designs and preparing to move into Stage 2, if the Sponsors so decide. One major factor in this decision is whether the Stage 1 findings in June sufficiently suggest that we have the potential for an economically viable project. Another major factor in the decision will be the level of federal and state government support expected as the project proceeds. On this point, I would quickly point to what an important, positive signal the 1998 Stranded Gas Development Act, HB-393 gave to the sponsor group, when it was organizing for Stage 1.

By this summer, we will also have completed a variety of commercial initiatives necessary to advance the project. Federal fiscal modifications will be leveraging to the economic viability of the project. The completion of key elements of our first stage of work allows us to provide better definition of the MVP for discussions in Washington. In the near future, we will finalize an internal draft of a "white paper" on federal issues which will layout various ways forward and which will serve as the initial foundation for federal discussions in the coming months.

Also, before the end of Stage 1, we plan to submit an application for state fiscal relief under the Stranded Gas Development Act (HB 393). This will begin what we expect will be a multi-year process of negotiating and developing a proposed state fiscal contract. We would not expect that proposed contract to be submitted to the legislature earlier than the 2002 session.

I would like to use my last topic as the springboard for Sponsor Group's legislative interests in 2000. For this session, we hope that

the Alaska Legislature will favorably consider legislation in the area of commercial regulation of instate gas. We have developed a legislative concept that will provide that the instate gas volumes be regulated on a non-discriminatory basis that does not jeopardize the security of long term, contracted export volumes. The intent of this concept is first, to be applicable to all stranded gas pipelines; second, to be complementary to a non-discriminatory federal process; third to clarify state and federal jurisdictions; fourth to provide the rules for instate gas transportation and sales; and finally, to provide needed exemption from public utility designation. This concept would need amendments to the Pipeline Act, Public Utilities Act and Right-of-Way Leasing Act. Legislation in this area would resolve a key uncertainty in the area of commercial regulation and we respectfully recommend it to the Legislature.

In summary, Mr. Chairman, I would like to quickly highlight some, but not all, of the key activities that have been keeping us busy since we last met, those include:

- Development and refinement of an economic model specific to this project
- Description and definition of our 7 MTA, projected pre-shipping \$5-6 billion - Market Viable Project
- LNG Plant site selection analysis and reduction to two preferred locations
- Pipeline route analysis and reduction to two preferred alternatives
- Cooling medium analysis and selection for the LNG Plant
- Development of key cost estimating assumptions
- Development of a contract and technology selection strategy
- Numerous internal and external pipeline, plants and system design evaluations and optimizations
- Opening of our market liaison office in Tokyo
- Development and drafting of needed pipeline regulatory legislation
- HB393 application development for filing this spring
- Initial discussions and project updates to the Alaska delegation, DOE, and DOC in Washington, DC.
- Numerous contacts, meetings and project updates to the administration and legislators
- Project updates to the Port Authority Mayors as well as to the Anchorage, Kenai and the Matanuska-Susitna boroughs

... as well as many other previous and ongoing activities.

I hope that this brief overview of our plans and basic thinking will show the committee that the sponsors are actively trying to commercialize Alaska North Slope gas. At this point, I would like to thank the Chairman for the opportunity to testify and would be happy to address the committee's questions.