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**104:4**

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## **PETRO MARINE SERVICES**

Petroleum Marketing to the Marine Industry

**Petition for exemption from EPA limit on sulfur content in motor vehicle fuel  
Testimony before House Oil & Gas Committee  
12 August 1998**

We support the petition by the State of Alaska to EPA for a permanent exemption from the requirement to limit motor vehicle diesel fuel to no more than 0.05 % sulfur by weight.

Petro Marine Services is an Alaska owned and operated fuel marketing and distribution company. We serve 16 communities in Alaska many of which are isolated coastal communities not connected by roadways. The vast majority of the product is sold for use in vessels, for heating oil consumption and to other nonroad users. Highway diesel fuel sales amount to less than 2% of our total sales volume. If low sulfur diesel is mandated for highway use in the communities that we serve, it would have to be segregated from the moment it is purchased and throughout the transportation and distribution network. All of the fuel that we purchase for sale is moved via tank barge to our fuel plants. Providing segregation for small volumes of low sulfur diesel would greatly increase the cost per gallon and limit the flexibility and efficiency of our barging logistics. At our tank farms, we have nearly completed upgrading all facilities to meet the OPA '90 requirement for impermeable liners. It would be very costly to go back into these facilities now to add new tanks to provide segregated storage for low sulfur diesel. Ultimately, end-use consumers will bear the cost of meeting this requirement.

In addition to the added cost of segregation, all low sulfur diesel would have to be imported to Alaska, because no Alaska refiner currently produces this product. Normal supply routines would be disrupted in order to get low sulfur diesel fuel from the West Coast refiners. A great deal of the other fuel that we purchase in Alaska would also be purchased outside the state, because the tank barges could not travel to distant supply points simply to lift the small volumes of low sulfur diesel needed. As a consequence, a significant proportion of our annual fuel volume would be purchased off the West Coast thereby displacing Alaska fuel which could otherwise serve the local market. All this displaced fuel would be replaced with fuel carrying as much as 15 cents per gallon added freight charge due to the longer hauling distance. Alaska consumers should not be placed in a position whereby their energy costs will increase dramatically.



3111 "C" Street, Suite 500 • Anchorage, Alaska 99503

Phone (907) 562-5000 • Fax (907) 561-6500

A HARBOR ENTERPRISES COMPANY

All this seems an extraordinary disruption of the market and inflation of price to accommodate a product with relatively low sales volume statewide. The stated purpose of the Clean Air Act requirement for low sulfur diesel is to address health concerns associated with air-borne particulate. Alaskans rarely agree on any subject, but there appears to be a consensus that no general health problem exists here that could be corrected by this program. As stated in the state's petition to EPA, changing the motor vehicle diesel fuel requirement to low sulfur diesel will remove an insignificant amount of particulate matter from the air at an unacceptably high cost-to-benefit ratio. Compliance with the low sulfur diesel requirement is clearly unreasonable in consideration of the unique fuel supply economics in Alaska. We urge your continued support of a permanent exemption for all of Alaska.

\\VA NC\_SVR\VOLI\SHARED\Environmental\980812, Low sulfur testimony.doc

**PETRO MARINE SERVICES**

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Petroleum Marketing to the Marine Industry

# **MAPCO TESTIMONY ON HIGHWAY DIESEL**

**House Special Committee on Oil and Gas**

**August 12, 1998**

**MAPCO ALASKA PETROLEUM Inc. is here to clearly state our support for a full, final and permanent exemption for Alaska from the Sulfur requirements of the Clean Air Act that apply to diesel fuel used for transportation. The current exemption expires on October 1, 1998.**

**Nothing has changed since 1993 when the State first requested a waiver for sulfur in highway diesel that would indicate any other course of action. In fact, continued study and review during two temporary exemptions since that time have reinforced the desirability and need for the permanent exemption. And in April of 1998 EPA published its intent to issue a permanent exemption.**

**This committee has already heard the many reasons to support the permanent exemption. You have been told of the negative economic consequences that clearly outweigh any benefit from enforcing the sulfur requirements for highway diesel. Not granting the exemption would potentially require the importation of most if not all highway diesel. It would again require dyeing of non-highway diesel, which accounts for 95% of daily diesel use in Alaska. The separate tankage and other logistical requirements would pose an undue burden in rural areas of Alaska with the least competition. And these are the areas of Alaska that can least afford the economic burden of increased fuel costs.**

**MAPCO urges this committee to use all means possible to encourage EPA to promptly issue the full and final exemption. We also ask that you request DEC and the Governor write letters, make calls and take other appropriate measures to urge EPA to grant the full and final exemption.**

**Failure to receive this exemption as we near our fall and winter season could result in an emergency situation. Fuel would not be available to deliver foodstuffs, medical supplies, gasoline supplies and other commodities necessary for the health and safety of all Alaskans.**

**We appreciate your concern with this matter and request your prompt and comprehensive response in making sure EPA issues the full and final exemption in the next few days. We stand ready to offer our help and assistance to this end.**

**Thank you, and let me know if there are questions I can answer or others here with MAPCO can answer.**

**DEPARTMENT OF NATURAL RESOURCES**

*DIVISION OF OIL AND GAS*

3601 "C" STREET, SUITE 1380  
ANCHORAGE, ALASKA 99503-5948  
PHONE: (907) 269-8800

CERTIFIED MAIL  
RETURN RECEIPT REQUESTED

Fax (713) 656-1512

June 30, 1998

Exxon Company, U.S.A.  
Mark W. Albers, Manager Alaska Interests  
P.O. Box 2180  
Houston, TX 77252-2180

RE: Point Thomson Unit  
15th Plan of Development

Dear Mr. Albers:

Exxon Company, U.S.A. (Exxon) as unit operator originally submitted a 15<sup>th</sup> Plan of Development for the Point Thomson Unit (PTU) on October 1, 1997. By letter dated October 8, 1997, the Department of Natural Resources, Division of Oil and Gas (DO&G) notified Exxon that the plan was incomplete. DO&G recognized that the working interest owners had not shared the results of their respective exploratory efforts, and Exxon could not, therefore, write an integrated development plan. On December 24, 1997, DO&G approved an Interim Plan of Development (Interim POD) for the Point Thomson Unit. The Interim POD included the following requirements:

- 1) Exxon will submit current Exhibits A and B to the Unit Agreement by January 31, 1998.
- 2) By March 31, 1998, Exxon will:
  - (a) submit a list of the studies done to date with a synopsis of each one;
  - (b) submit a list of all agreements between the Point Thomson Unit owners with an explanation of each one; and
  - (c) provide a briefing on the results of the full field modeling and Parson's Study.
- 3) 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, or analyze and present the information themselves if ARCO does not.

- 4) 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.
- 5) Exxon will submit a preliminary draft of its 15th plan of development for DNR review and comment at the April meeting, and submit a draft POD by May 15, 1998.
- 6) Exxon will file a 15th Plan of Development by June 8, 1998.

During the six-month term of the Interim POD Exxon committed to submit the data listed above and coordinate with the other working interest owners to develop a plan to delineate all of the reservoirs in the Point Thomson Unit. Exxon had until June 30, 1998, to develop and submit a complete 15th Plan of Development (15<sup>th</sup> POD) to DO&G. Exxon as unit operator fulfilled all of the requirements itemized above with the exception of number 2) (c). Exxon did not schedule a briefing on the Parson's Study during the period of the Interim POD, however by mutual consent we intend to have the briefing some time this year.

On May 14, 1998, Exxon submitted a draft of the 15<sup>th</sup> POD. DO&G staff commented on the draft plan during a teleconference call held Thursday May 21, 1998. Exxon submitted a revised draft 15<sup>th</sup> POD on June 5, 1998. DO&G suggested changes to the revised draft by fax on June 9, 1998. On June 16, 1998, Exxon incorporated the requested changes and faxed another revised draft to DO&G. After some discussion and a few minor changes, Exxon submitted the 15<sup>th</sup> POD in final on June 19, 1998. This process of meeting and reviewing the draft documents was beneficial to produce a comprehensive Plan of Development that is acceptable to the Unit Operator, all of the working interest owners and DO&G.

The 15<sup>th</sup> POD includes an update on the work completed during the term of the 14<sup>th</sup> POD and the Interim POD. It also includes plans to establish a common database, delineation plans, and development planning studies to be completed during the term of the 15<sup>th</sup> POD. Exxon plans to explore potential synergies between development of the oil and gas reserves in the unit area.

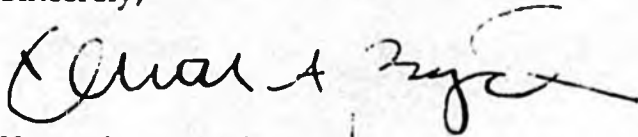
There has been considerable interaction between Exxon, the Working Interest Owners and DO&G over the past nine months to formulate a comprehensive plan to develop all potential reservoirs within the Point Thomson Unit Area. Finalizing Agreements between the Owners to share well and seismic data is the first step toward achieving an integrated plan of development. Only after those

Exxon Company, U.S. A.  
Point Thomson Unit  
15th Plan of Development  
June 30, 1998  
Page 3

Agreements are in place can the Owners incorporate their information into a shared database. A shared database is essential to produce consensus maps of the reservoirs within the PTU. The Owners shall demonstrate the exchange of sufficient data by September 30, 1998, to map the work contemplated by the 15<sup>th</sup> POD or the unit will be in default. The Owners shall provide a status report to the DO&G on or before September 30, 1998, to demonstrate the progress toward completing the first step. The Owners shall create a common technical PTU database and consensus maps for all prospective reservoirs within the PTU by September 30, 1999. The Owners shall present the consensus maps to DO&G before the end of the 15<sup>th</sup> POD. A review of the oil rim study results will also be presented to DO&G by September 30, 1998. A review of the Parson's Study may be scheduled along with the other review meetings.

DO&G considered the criteria in 11 AAC 83.303 and finds that the 15<sup>th</sup> POD protects the public interest. The 15<sup>th</sup> POD is approved for the period July 1, 1998 through September 30, 1999. The 16<sup>th</sup> Plan of Development is due on July 2, 1999, 90 days before the 15<sup>th</sup> POD expires.

Sincerely,



Kenneth A. Boyd  
Director

cc: BP Exploration (Alaska) Inc.  
Chevron U.S.A. Inc.  
Mobil Oil Corporation  
Oxy U.S.A. Inc.  
Phillips Petroleum Company  
Arco Alaska Inc.  
Thompson, Dept. of Law

**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

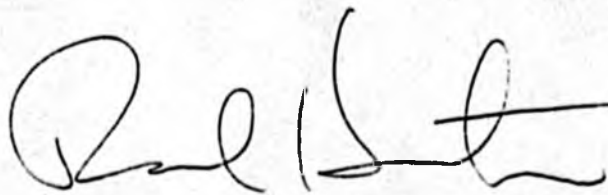
Dear Mr. Boyd:

Exxon, as Unit Operator and on behalf of the Working Interest Owners, hereby submits the enclosed Fifteenth Plan of Further Development and 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

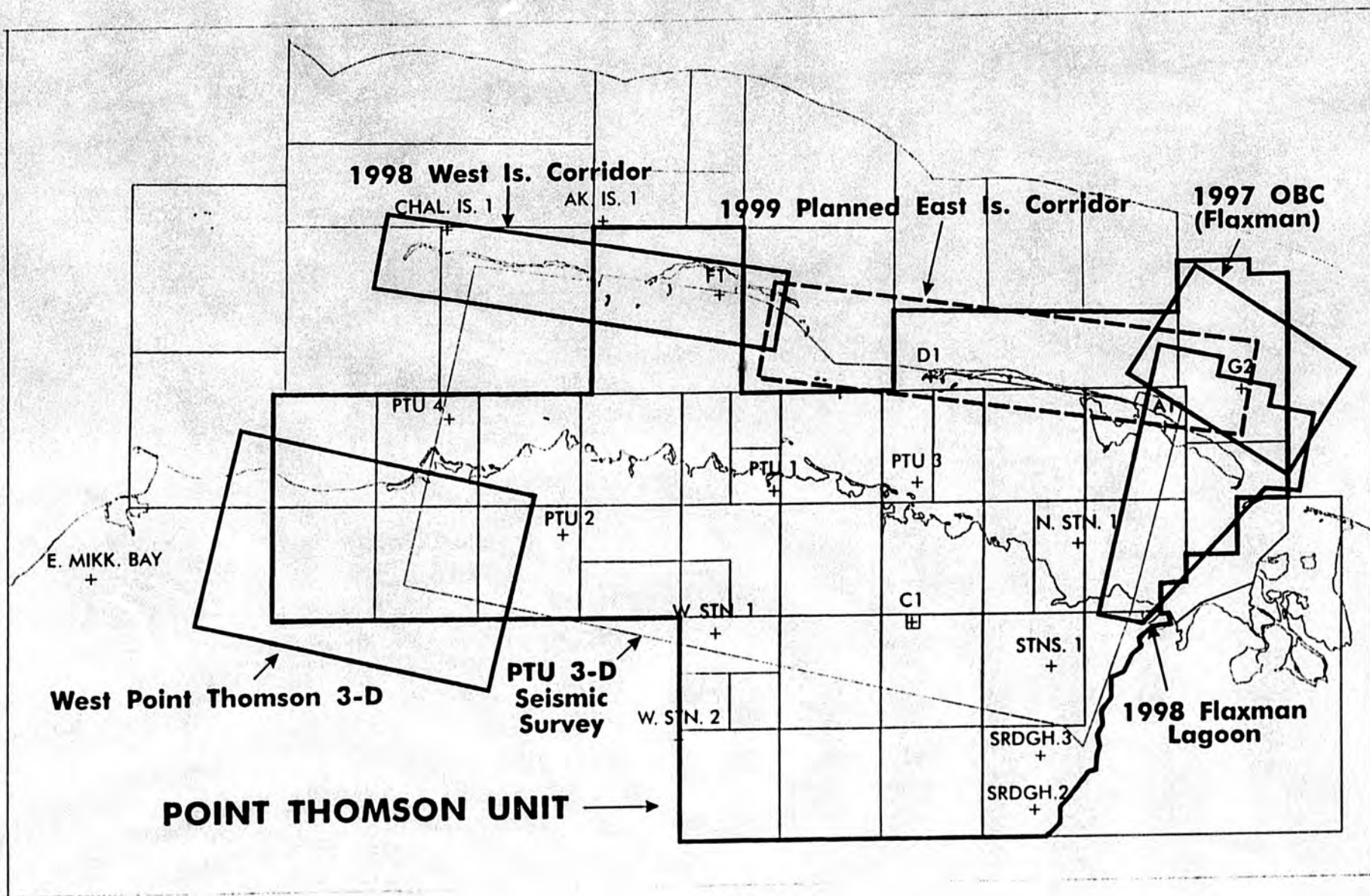
ACTIVITIES	1Q98	2Q98	3Q98	4Q98	1Q99	2Q99	3Q99	4Q99	1Q00	2Q00	3Q00	4Q00
<b>DEVELOPMENT PLANNING</b>												
1. PTU Other Resource Evaluation Oil Rim Geochemistry/Simulation, Flaxman Scoping Model and Basement Studies	■	■										
2. PTU Gas Resource Evaluation Scenario Upgrades (FFM), Evaluation 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
<b>POD SCHEDULE</b>												
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



**EXXON** COMPANY, U.S.A.  
POST OFFICE BOX 2180 • HOUSTON, TEXAS 77252-2180

PRODUCTION DEPARTMENT  
ALASKA INTEREST

L. R. HOWARD  
MANAGER

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OCT 02 1997

DIVISION OF OIL & GAS

MIKE -  
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FAX FILES

October 1, 1997

**Fifteenth Plan of Further Development  
and Operation**  
Point Thomson Unit

VIA FAX (907-562-3852) &  
AIRBORNE EXPRESS

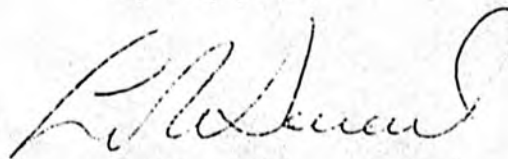
Mr. Kenneth A. Boyd, Director  
Alaska Department of Natural Resources  
Division of Oil and Gas  
3601 "C" Street, Suite 1380  
Anchorage, Alaska 99503-5948

Dear Mr. Boyd:

Exxon, as Unit Operator and on behalf of the Working Interest Owners (Owners), hereby submits the enclosed Fifteenth Plan of Further Development and Operation (15th POD) for the Point Thomson Unit for your review and approval. The 15th POD contains an update on the work activities commenced/completed under the 14th POD and a summary of the Owners' work plans for the ensuing calendar year. The work activities associated with Phase II of the Unit's development screening study will be completed during the 15th POD term.

Should you have any questions regarding the 15th POD, please do not hesitate to call me at (713) 656-7000 or Mr. Raul Huerta at (713) 656-7111.

Very truly yours,



LRH:MMM  
h:\data\ptu\15podevr.doc

Enclosure  
cc: PTU Working Interest Owners



**Point Thomson Unit**  
**Fifteenth Plan of Further Development and Operation**  
(And an Update on the Fourteenth Plan of Further Development and Operation)

This Fifteenth Plan of Development is submitted to the Commissioner of the Alaska Department of Natural Resources (DNR) pursuant to Article 10 of the Point Thomson Unit (PTU) Agreement and 11 AAC 83.343.

Overview

The 14th POD was submitted to the DNR on October 1, 1996. Under the 14th POD, the Working Interest Owners (Owners) committed to complete the activities associated with Phase I of the Point Thomson Development Screening Study (the "Study") and, if warranted by the results of Phase I, begin the Study's Phase II activities. By letter dated November 29, 1996, the DNR approved the 14th POD for a one (1) year term from January 1, 1997 to December 31, 1997, subject to the following conditions:

- A June 1997 meeting wherein the Owners would present to the DNR a progress report on the Study's Phase I activities, and
- At the earliest opportunity, a report on the results of the farmout initiative on Unit Tracts 8, 9, and 10, including the outcome of negotiations with ARCO on a 3-D Seismic Farmout Agreement affecting those tracts.

The Owners satisfied the conditions for the approval of the 14th POD as follows:

- By letter dated March 7, 1997, Exxon advised the DNR that Exxon, Mobil, and Phillips each had consummated a farmout agreement with ARCO covering their respective working interests in Unit Tracts 7, 8, 9, and 10.
- On June 18, 1997, representatives of the Owners met with the DNR and presented a progress report on the Study's Phase I activities.

During the term of the 14th POD, the Owners have continued their efforts to develop the PTU, with the focus on a screening evaluation of potential Thomson Sand reservoir development scenarios. The proposed 15th POD builds upon the 14th POD by refining certain of those development scenarios. The Owners, through their technical studies, have improved their understanding of the complex issues associated with producing a high pressure gas reservoir in a remote location. For example, the drilling and completion technologies necessary to drill and produce high throw, large-bore wells at high

production rates have been examined. Additionally, high quality geologic and reservoir simulation models have been built to enable estimation of reserves and flowstreams for various development scenarios. Well cost estimates, facility screening cost estimates, and proprietary economic models have also been updated.

While the work accomplished pursuant to 14th POD has led to an increased understanding of the Thomson Sand reservoir by the Owners, hurdles to development remain; particularly, high development costs, lack of a gas market and transportation system, and the unique challenges associated with high pressure gas cycling. Consequently, development of the Thomson Sand reservoir is not economically justified at the present time.

Three of the Owners (Exxon, BP and Phillips) have joined the State of Alaska's North Slope Gas Commercialization Team which will research and recommend changes to the State's tax and royalty structure to improve the economic feasibility of a North Slope gas project. This study may have applicability to PTU gas.

### **Update on the Fourteenth Plan of Development (14th POD)**

#### **Development Steering Committee (DSC) Formation**

The Owners approved the formation of the DSC by an affirmative vote of 99.37% of the PTU voting interest. The DSC was charged with the coordination and completion 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 3-D geologic model of the Thomson Sand was constructed. The model encompasses approximately 330 square miles and contains approximately 2,000,000 cells (each cell 2ft. x 600ft. x 600ft.). Each cell has been assigned a facies type (3 possible) and porosity, permeability and hydrocarbon saturation all of which are keyed to the specific facies type. Areal trend maps were generated by the Geologic and Reservoir Modeling Committee (GRMC) to control the distribution of the facies and porosity within the model, whereas the permeability values were developed using geostatistical methodologies. Hydrocarbon saturation values are capillary pressure based and linked to the porosity and facies type. The fine scale geologic model provides the foundation for the reservoir simulation models built for the Thomson Sand reservoir.

#### **Reservoir Simulation**

The reservoir simulation work was conducted by Exxon Production Research under the direction of the GRMC. Three reservoir simulation models were built: a uniform cross-

section, a finely-gridded mechanistic cross-section, and a 3-D full-field model. The uniform cross-section model was used to test the relationships between phase behavior, capillary pressure, and relative permeability. The mechanistic model was utilized to test various depletion mechanisms such as gas cycling, blowdown, and water injection. The full-field model was utilized to provide estimated flowstreams and recoveries for various development scenarios.

#### **Well Designs and Cost Estimates**

Well design work was conducted by Exxon Production Research under the direction of the DSC. Studies were performed in the following areas: wellbore stability; hole cleaning; drilling torque and drag; casing design; completion installation; workover access; and drilling days vs. depth. Screening level well cost ranges were developed by Exxon and reviewed by DSC participants.

#### **Facilities Designs 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 several different Thomson Sand development scenarios. Scenarios included gas cycling and blowdown cases, with sensitivities for alternatives including condensate pipeline tie-in to the Badami project, gas injection at PBU, gas dehydration and chilling to improve condensate recovery, and water injection for pressure maintenance. The final results of this study were provided to the DSC participants on September 2, 1997.

#### **Farmout Initiative**

The farmout agreements from Exxon, Mobil and Phillips required ARCO to commence the acquisition of a 3-D seismic survey ("Survey"), covering Unit Tracts 7, 8, 9, and 10, on or before March 31, 1997. According to ARCO, Northern Geophysical completed acquisition of the Survey on March 30. The Survey was acquired as part of a larger, 3-D seismic program conducted jointly by BP and ARCO. The Survey data is currently being processed; data delivery is expected by year-end.

#### **Exploration 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. BP and Chevron believe the Sourdough prospect could contain upwards of 100 million barrels of recoverable oil. Further exploration and appraisal of the Sourdough prospect are under consideration by BP and Chevron.

## Fifteenth Plan of Development (15th POD)

### Work Plans

During the term of the 15th POD, the Owners plan to complete the remaining activities associated with Phase II of the Study. The tools and information developed from the 14th POD work efforts will be used to refine the gas cycling and blowdown development scenarios evaluated during Phase I of the Study. Areas of study will include: location and number of drill sites, location and number of producer and injector wells, and analysis of gas off-take vs. facility size to improve capital efficiency. Depending upon the results of this work, the Owners may undertake additional work to refine the current screening level design and cost estimates to match the upgraded scenarios.

A current work schedule for the Study is attached as Exhibit 1.

The Owners continue to monitor activity at Badami. As Badami drilling, development and pipeline construction progresses, the Owners will look for additional development and cost synergies with that project, if available.

Various owners are currently discussing possible exploration drilling in or around the PTU. At this time, no firm locations have been established. The Owners may supplement the 15th POD to address any exploration activity within the Unit that may occur during its term. Depending on the nature and extent of any such exploration activity, the Owners may request an extension to the term of the 15th POD as part of such supplement.

### Requested Term

The Owners hereby request a one (1) year term for the 15th POD, January 1, 1998 through December 31, 1998.

### Exhibit 1 - Point Thomson Development Screening Study Schedule

ACTIVITIES	1Q96	2Q96	3Q96	4Q96	1Q97	2Q97	3Q97	4Q97	1Q98	2Q98	3Q98	4Q98
<b>Phase I</b>												
1. Brainstorm development scenarios to be evaluated	■											
2. Build Thomson Sand 3-D geologic model		◆	■	■								
3. Develop well designs and cost estimates		■	■	■	■	■						
4. Build Thomson Sand reservoir simulation models & evaluate devel. scenarios				■	■	◆	■					
5. Develop cost estimates and economic models; screen development scenarios				■	■	■	■					
<b>Phase II</b>												
6. Upgrade cycling and blowdown development scenarios and economics								■	■	■	■	
7. Upgrade facility and pipeline screening cost estimates, if warranted										■	■	■

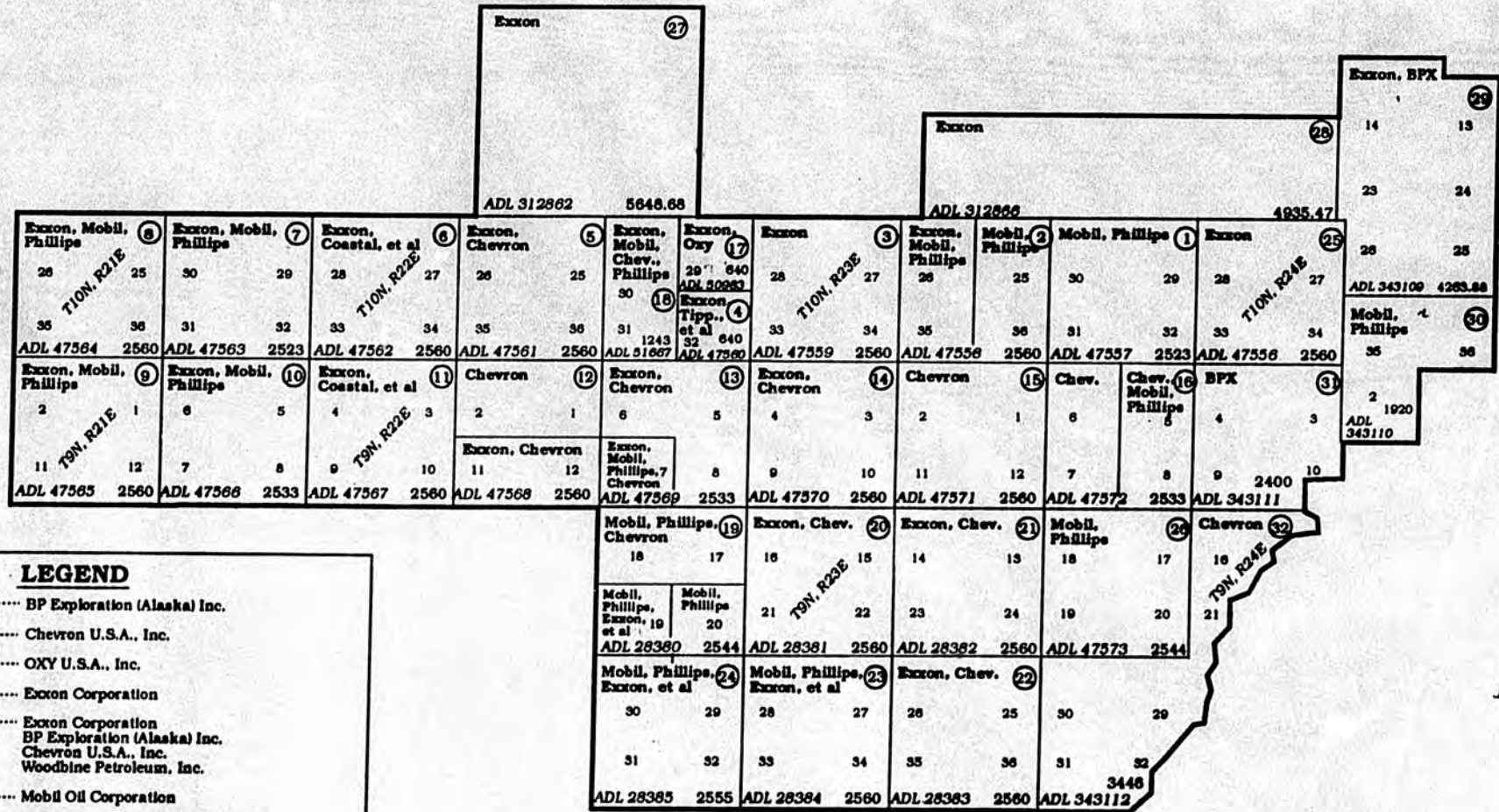
- ◆ Progress update meeting with Alaska DNR on June 27, 1996
- ◆ Progress update meeting with Alaska DNR on June 18, 1997

38 TRAKTS  
83, 82 (Acres)

# EXHIBIT "A"

## POINT THOMSON UNIT AGREEMENT

(Revised September 1, 1993)



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. Peery, Trustee Robert Searls, Jr. Jeanne Searls

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

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



## A History of the Point Thomson Unit

Prepared by Carol Lee, Unit Manager

July 23, 1998

### 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 <sup>st</sup> POD	1 year	1/1/78	12/31/78
2 <sup>nd</sup> POD	1 year	1/1/79	12/31/79
3 <sup>rd</sup> POD	1 year	1/1/80	12/31/80
4 <sup>th</sup> POD	1 year	1/1/81	12/31/81
5 <sup>th</sup> POD	1 year	1/1/82	12/31/82
6 <sup>th</sup> POD	1 year	1/1/83	12/31/83
7 <sup>th</sup> POD	4 years	1/1/84	12/31/88
8 <sup>th</sup> POD	3 years	1/1/89	12/31/91
9 <sup>th</sup> POD	1 year	1/1/92	12/31/92
10 <sup>th</sup> POD	1 year	1/1/93	12/31/93
11 <sup>th</sup> POD	1 year	1/1/94	12/31/94
1 <sup>st</sup> Extension of 11 <sup>th</sup> POD	16 months	12/31/94	4/30/95
2 <sup>nd</sup> Extension of 11 <sup>th</sup> POD	3 months	4/30/95	7/15/95
3 <sup>rd</sup> Extension of 11 <sup>th</sup> POD	2 months	7/15/95	9/1/95
4 <sup>th</sup> Extension of 11 <sup>th</sup> POD	5 months	9/1/95	2/1/96
13 <sup>th</sup> POD	11 months	2/2/96	12/31/96
14 <sup>th</sup> POD	1 year	1/1/97	12/31/97
Interim POD	6 months	1/1/98	6/30/98
15 <sup>th</sup> 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 14, 1984, DNR approved the First Expansion of the Point Thomson Unit Area. 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 well drilling commitment 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.

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 following is the approximate ownership of the Point Thompson Sand Formation:

Exxon	41.0%
Chevron	23.1%
Mobil	16.3%
Phillips	13.5%
BP	6.1%

In three leases, with a total of 8,566 acres, the ownership is divided at depth. The ownership in those three leases above the Point Thomson Sand Formation is as follows:

Chevron	26.16%
Exxon	21.50%
BP	52.33%

The ownership in the three leases below the Point Thomson Sand Formation is as follows:

BP	46.75%
Exxon	29.89%
Chevron	23.37%

Each of the following companies or individuals holds less than 1% working interest in the Point Thomson Unit: Pennzoil, Coastal, Forest, Oxy, Grace, Sunlight, Transworld, Woodbine, Tipperary, Leede, Leede & Pine, Donnelly, Chapparal, Searls, Perry, Hughes, Pacific Lighting, Two Four Six Corp. [All percentage figures are approximated.]

## **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 1<sup>st</sup> Plan of Development and proposes drilling the PT #2 Well.

Point Thomson Uint  
Detailed History  
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- 5/28/78 DNR approves the 1<sup>st</sup> POD until 1/1/79.
- 9/6/78 Exxon requests Certification of PT #2 Well as capable of producing in paying quantities.
- 9/26/78 Exxon proposed 2<sup>nd</sup> POD which includes drilling the Exxon #3 Well in Nov/Dec 1978.
- 10/9/78 DNR approves 2<sup>nd</sup> 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 3<sup>rd</sup> POD and proposed drilling the PT #4 Well in February 1980.
- 2/22/80 DNR approves the 3<sup>rd</sup> 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 4<sup>th</sup> POD, which includes drilling four wells outside the unit area to test the extent of the reservoir.
- 12/19/80 DNR approves the 4<sup>th</sup> 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.

Point Thomson Uint  
Detailed History  
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- 9/14/81 Exxon submits 5<sup>th</sup> 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 5<sup>th</sup> 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 6<sup>th</sup> 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.
- 12/10/82 DNR approves the 6<sup>th</sup> 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 7<sup>th</sup> POD requesting a 5-year plan with no drilling until contracts are issued for a gas line.
- 11/29/83 DNR approves the 7<sup>th</sup> 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 1<sup>st</sup> 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 1<sup>st</sup> Annual Progress Report.
- 1/21/85 DRN approves amendments to the PTU Agreement as proposed.
- 4 /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 2<sup>nd</sup> 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 3<sup>rd</sup> 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 4<sup>th</sup> 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 8<sup>th</sup> 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 7<sup>th</sup> 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 8<sup>th</sup> 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.
- 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 9<sup>th</sup> POD for 4-year term. The proposed 9<sup>th</sup> 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 9<sup>th</sup> 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 10<sup>th</sup> POD. The owners propose to undertake a multi-year Reservoir Characterization Study on the Thomson Sand.
- 11/27/92 DNR approves 10<sup>th</sup> 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 11<sup>th</sup> 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 11<sup>th</sup> 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 12<sup>th</sup> 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 12<sup>th</sup> 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 12<sup>th</sup> POD.
- 12/22/94 DNR agrees to extend the 11<sup>th</sup> 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 11<sup>th</sup> 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 11<sup>th</sup> 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 11<sup>th</sup> 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 11<sup>th</sup> POD and discuss possible work initiatives for the 12<sup>th</sup> and future PODs.
- 10/31/95 Exxon submits 13<sup>th</sup> 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 13<sup>th</sup> 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 13<sup>th</sup> POD farmout initiative.
- 6/27/96 Meeting to review progress under the 13<sup>th</sup> 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 14<sup>th</sup> POD, a continuation of the phased development study and farmout initiative begun under the 13<sup>th</sup> POD.

- 11/29/96 DNR approves the 14<sup>th</sup> POD for the period 1/1/97 – 12/31/97. Request a meeting no later than June 1997 for a Phase 1 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 15<sup>th</sup> POD. The work activities associated with Phase II of the Unit's development screening study will be completed during the 15<sup>th</sup> POD.
- 10/8/97 DNR determines the 15<sup>th</sup> 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 15<sup>th</sup> 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 15<sup>th</sup> 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.

Point Thomson Uint  
Detailed History  
Page 13 of 15

- 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 15<sup>th</sup> POD.
- 5/21/98 Teleconference call with Exxon and WIOs to discuss draft 15<sup>th</sup> POD.
- 5/29/98 Teleconference call with Exxon and WIOs to discuss draft 15<sup>th</sup> POD.
- 6/5/98 Exxon submits revised draft of 15<sup>th</sup> POD.
- 6/9/98 DNR faxed comments of revised draft POD to Exxon.
- 6/16/98 Exxon submits 15<sup>th</sup> POD
- 6/19/98 Exxon submits final 15<sup>th</sup> POD.
- 6/30/98 DNR approved 15<sup>th</sup> 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 15<sup>th</sup> 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 15<sup>th</sup> POD. The owners shall create a common technical PTU database and consensus maps for all prospective reservoirs within the PTU by September 30, 1999.

FRANK H. MURKOWSKI, Alaska, *Chairman*

PETE V. DOMENICI, New Mexico  
DON NICKLES, Oklahoma  
LARRY E. CRAIG, Idaho  
BEN NIGHTHORSE CAMPBELL, Colorado  
CRAIG THOMAS, Wyoming  
JON KYL, Arizona  
ROD GRAMS, Minnesota  
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SAM E. FOWLER, CHIEF COUNSEL FOR THE MINORITY

# United States Senate

COMMITTEE ON  
ENERGY AND NATURAL RESOURCES

WASHINGTON, DC 20510-6150

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July 15, 1998

RECEIVED

JUL 21 1998

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

Dear Mr. Boyd:

This is to advise you that the Senate Energy and Natural Resources Committee has scheduled a hearing to conduct oversight on the results of the Arctic National Wildlife Refuge, 1002 Area, Petroleum Assessment, 1998, conducted by the United States Geological Survey. The hearing will take place on Thursday, July 23, 1998 at 9:30 a.m. in room SD-366 of the Dirksen Senate Office Building, Washington, D.C.

The Committee respectfully requests you or your designee to present testimony. Specifically, the Committee would be interested in hearing your view of the results of this Assessment especially as it relates to state and private lands; how these estimates compare with previous estimates; what has been the state of Alaska's experience with use of advanced seismic technology compared with that used more than a decade ago in delineating potential fields; what has been the state's experience with economic field size; how has the advancement of technology helped in discovering new reserves and developing them while minimizing the environmental impacts, and how useful these new results may be in determining if the subsurface resources of the Arctic National Wildlife Refuge are being threatened from development on non-federal lands adjacent to ANWR.

We ask that you submit 100 copies of your testimony to the Committee by close of business on July 21, 1998. In addition, a copy of your written testimony on a computer disk in any format would be greatly appreciated. Because of time limitations, we ask that you limit your oral testimony to five to seven minutes. Your written testimony can be comprehensive, and it will be included in the official hearing record.

On behalf of the Committee, I would like to thank you in advance for your cooperation and participation in the Congressional hearing process. Your insights will considerably help the Committee and the Senate formulate sound policy. Should you have any questions, please contact Brian Malnak or Jo Meuse at (202) 224-6730.

Sincerely,

A handwritten signature in black ink, appearing to read "Frank H. Murkowski". The signature is written in a cursive style with a large initial "F".

Frank H. Murkowski  
Chairman

**Testimony of Kenneth A. Boyd  
Before the United States  
Senate Energy and Natural Resources Committee**

**Arctic National Wildlife Refuge 1002 Area  
July 23, 1998**

**Introduction**

Mr. Chairman and members of the Committee, for the record my name is Ken Boyd and I am the Director of the Alaska Division of Oil and Gas. I have B.S. and M.S. degrees in geology from the Rensselaer Polytechnic Institute. I have worked in the oil and gas business, in a variety of capacities, since 1973. Much of this time has been spent working on Alaska exploration.

I have been asked to comment on the latest U.S. Geological Survey estimates of undiscovered petroleum resources beneath the ANWR coastal plain. Because the 1998 ANWR 1002 Petroleum Assessment (conducted by the United States Geological Survey) has not been released, I cannot comment in detail on it at this time. I will be pleased to provide a review once the report is finalized.

I have seen the USGS fact sheet that summarizes some of the findings of this assessment. In very simple terms the assessment shows more oil in ANWR than in many previous assessments. However, as the USGS points out in its fact sheet, "One cannot make a meaningful comparison with previous assessments without knowledge of differences in assessment methodology, assumptions and data". Until the final report is released, I will withhold any detailed comments.

I can, however, make some general observations, and have provided a table and bar chart to show some earlier resource estimates alongside the new USGS numbers. The table shows three categories of undiscovered resources: in-place oil, technically recoverable oil and economically recoverable oil. Please note that only the 1987 USGS/BLM assessment of in-place oil is directly comparable to the new study. The new study shows an overall increase in the mean estimated in-place oil from 13.8 BBO (billion barrels of oil) in the 1987 study to 20.7 BBO today. The other categories of undiscovered oil are not directly comparable due to differences in methodology and play selection. However, gross comparisons of estimates derived from the 1995 USGS Regional Assessment indicate that the new study is generally more optimistic in its assessment of both technically recoverable and economically recoverable oil. For example, in 1995 the USGS mean estimate of risked economically recoverable oil was 0.898 BBO for the entire 1002 area. The new mean estimate is 0.6 BBO in the deformed region (eastern 1002 area) and 2.6 BBO in the undeformed (western 1002 area). Again, I must stress that the technically recoverable and economically recoverable estimates are not directly comparable.

In my opinion, the most important facts revealed so far from the USGS fact sheet are:

1) the estimates for finding recoverable oil are quite high, and in fact, have been increased from previous assessments;

- 2) these scientists believe the bulk of the undiscovered oil resides in the northwest part of the 1002 area rather than to the east as was assessed in previous studies;
- 3) more oil has been allocated to the younger (Brookian) reservoirs in stratigraphic traps; less oil has been allocated to the deeper Ellesmerian reservoirs in structural traps;
- 4) the assumed 512 million barrel commercially developable field size for ANWR is probably too conservative for the undeformed, western part; smaller accumulations are likely to be economic, especially if infrastructure is established in the Point Thomson, Sourdough and Flaxman areas.

As you know, a number of public estimates of the oil and gas potential of the 1002 area have been made over the last 18 years. The latest USGS estimates confirm what geoscientists have been saying for years. The 1002 area holds extremely high promise for finding commercial petroleum deposits. This is great news for Alaska and great news for the Nation.

I think it is also important to offer you some of my own observations based upon the exploration and development activity on state-owned North Slope lands west of the 1002 area.

The acquisition and interpretation of 3D seismic data has revolutionized exploration and step-out development efforts. Modern 3D data provides enhanced and incredibly accurate imaging of potential subsurface reservoirs. This reduces exploration and development risk, reduces the number of drilled wells and in turn, reduces both overall costs and environmental impacts. No 3D seismic data are yet available in the 1002 area, therefore the benefits of 3D have yet to be realized.

The Minimum Economic Field Size (MEFS)—the volume of oil required for a prospect to be economically successful—has decreased over time for the North Slope. In years past, fields of 500 million to 1 billion barrels of recoverable oil were believed to be necessary for economic success. Today, due to better technology, and lower finding and development costs, fields in the 120 to 150 million barrel range are being developed. Much smaller accumulations closer to existing infrastructure are also being developed.

Environmental impacts from development activities are being reduced. Advances in production technology continue to shrink the "footprint" of development. Computer mapping of critical habitats and wildlife use patterns has led to site-specific stipulations and regulations that can mitigate potential conflicts. The developments at Badami, Alpine and Northstar are good examples of modern, minimal impact oil fields in environmentally sensitive areas.

The last several years have been exciting times in the Alaska oil patch. The current high level of oil and gas activity in Alaska can be attributed to a favorable business climate and the use of new technology to reduce costs. This favorable climate exists, in large part, due to an ongoing series of new legislation that has improved the state's stature in the world oil marketplace. Areawide leasing is one example. On the technology side, 3D seismic and extended reach drilling have enabled the industry to drill "smarter" wells that allow substantial reductions in costs.

The industry commitment to Alaska's oil and gas future has been amply demonstrated in recent lease sales. Our Beaufort Sea Sale held last November brought in \$28 million and the state collected \$55 million from our first areawide sale held last month on the North Slope. I expect to see a further jump in exploration activity as a result of these sales. Naturally, I hope this exploration will lead to further development such as is occurring at the Badami, Tarn and Alpine fields, to name a few. Exploration and development of so-called "satellite" fields—fields in and near existing fields—is moving ahead at a rapid pace. The Tarn field, at the southwest edge of the Kuparuk field, is the latest satellite to start production. Much of this activity is made possible by new technology.

Not too far off is the construction of the first arctic, subsea oil pipeline in the world at the Northstar field. North American records for extended reach drilling have been set at Niakuk, and they continue to reach farther and farther as the technology improves. Enhanced oil recovery projects are underway in several fields. Last session, the Alaska legislature began serious debate on bringing Alaska's vast natural gas resources to market. In early August the final Environmental Impact Statement for the National Petroleum Reserve-Alaska (NPR-A) should be released. I hope to see a sale there later this year or in early 1999. And then there is ANWR.

#### Minimum Economic Field Size

You have also asked for my view on economic field size. For North Slope lands leased by the state, minimum economic field size has decreased dramatically over time. I believe that several factors have contributed to the decrease.

The first factor is 3D seismic technology. 3D seismic is rapidly replacing 2D as the "conventional" approach to development and exploration as costs decrease and as computer aided interpretation increases the amount of information that can be extracted from the data. All new fields currently being developed and parts of many existing fields on the North Slope have been resurveyed with 3D seismic in order to place and guide development wells. The coverage and sheer volume of data that the 3D seismic method generates leaves no blank spaces on the map to guess about and very small prospects can be delineated that could be missed or misinterpreted with 2D data. The 3D data cube is uniform and consistent so that changes in the data can more reliably be attributed to changes in the subsurface. Also, 3D seismic produces much better structure maps of the subsurface, especially in areas that are highly faulted. For these reasons, more 3D seismic will be acquired, both offshore and onshore, in the future.

In imaging the small, stratigraphic prospects currently of interest on the North Slope 3D seismic technology is definitely an improvement over 2D. Advancements in acquisition, processing and interpretation have enabled geophysicists to produce 3D visualizations of sand bodies only a few hundred feet wide at great depths. That being said, there is no guarantee that the sand will be saturated with oil in commercial quantities or that it will have good reservoir characteristics (such as sufficient permeability). These risk factors remain, even with the most sophisticated interpretation. However, the industry is working hard to get the most out of the seismic data and it would not surprise me to see these problems substantially solved in the future.

3D seismic yields such convincing results and confidence in the interpretation that companies are more willing to commit to drilling expensive, long reach wells thus minimizing surface impacts. With the advent of 3D seismic data, the State has noted an increase in drilling activity from existing pads in the Prudhoe Bay and Kuparuk River Units utilizing long offset drilling technology. 3D seismic has contributed to the industry's increased drilling success rate. For example, BP recently announced that the success rate for its North Slope exploration wells has been 1 in 2 over the past five years. About three years ago, the A.D. Little consulting firm reported the North Slope exploration success rate as 1 in 12. 3D seismic not only gives the explorationist a clearer view of the subsurface, it gives the production manager a tool to drill more efficient development wells. It allows industry to drill "smarter" wells to produce new and existing fields, substantially reducing production costs. "Smarter" means fewer wells drilled with a greater precision than could have been achieved even five years ago. 3D, in combination with computerized drill bits equipped with sensors and communication gear and other new technology, allow industry to "steer" wells to reservoir targets with previously unimagined precision. 3D seismic also assists in designing water floods and other cost-effective production enhancing techniques. In short, 3D seismic produces an interpretation that is more reliable and comprehensive than the old 2D data could generate and this results in maximizing reservoir recovery while minimizing surface disturbance.

Technology has assisted in reducing the well costs in other ways. Extended reach drilling (ERD) has pushed past 20,000 feet. Besides improving the economics, ERD helps environmentally by shrinking the "footprint" of development. Other new well technologies include through-tubing rotary drilling, coiled tubing drilling and multilateral wells. Combining these technologies allows the companies to drill so-called "designer wells". These wells, which twist and turn in some very exotic shapes, allow the drillers to target very small and difficult to reach oil deposits. Simply working smarter has let industry shorten the time to complete wells, reduce overall costs, and reduce environmental impacts.

The statistics show that with this new technology and other cost cutting measures, industry has reduced its operating costs thereby decreasing the minimum economic field size. Between 1991 and 1996, ARCO reported that its operating expenses on the North Slope were reduced from \$2.29 per barrel to \$1.54 per barrel (a 33% reduction); development well costs were reduced from \$3.0 million per well to \$2.0 million per well (a 33% reduction); and well hook-up costs were reduced from \$1.5 million per well to \$0.6 million per well (a 60% reduction). Between 1996 and 1997, development well costs were reduced another 15%. ARCO reported these cost reductions in "dollars of the day", and considering inflation over this period, these reductions are, to quote ARCO, "even more dramatic".

ARCO is not the only company that has reported a dramatic reduction in operating costs on the North Slope. In June BP reported that operating costs at the Prudhoe Bay field have been cut by 50% since 1991. Also BP reported that the well costing \$3 million in 1991, now costs \$1 million (a 67% reduction).

BP's Northstar development illustrates the effect of this dramatic reduction in production costs on minimum economic field size. In June of 1994, Amerada Hess concluded the Northstar field was uneconomic because development costs would exceed \$1.2 billion and eventually sold the

field to BP. Today, BP expects to begin production of the field's 145 million barrels of reserves in 2000. Its estimated development costs: \$350 million (a 70% reduction).

The state is also witnessing the development of very small fields near existing infrastructure as well development of fields miles away from infrastructure that several years ago would have been considered uneconomic. Fields that either have been recently developed or are moving forward with development using existing infrastructure include: Niakuk, Tarn, Sambucca, Midnight Sun, Pete's Wicked, Cascade, Eider, Sag River, and Tabasco. In addition to Northstar, other small stand-alone fields are coming on line. Those fields (with their reported reserves and estimated development costs) include: Alpine (365 million barrels of reserves with \$650 million development cost), Badami (120 million barrels with \$300 million development cost), and Liberty (120 million barrels with \$250 million development cost). The development of these smaller accumulations demonstrates that the minimum economic field size on the North Slope has been substantially reduced.

I cannot comment with specificity on what the USGS characterizes as its "rather conservatively" assumed 512 million barrel minimum commercially developable field size for ANWR reported in the USGS fact sheet because the analysis supporting that figure has not been released. I can say, however, if the known accumulations in the Point Thomson Unit area are developed, a field much smaller than 512 million barrels of reserves near the east side of the Canning River would likely be economic.

#### Drainage Issue

You have also asked whether new technological results are useful in determining if the subsurface resources of ANWR are being threatened by development of adjacent non-federal lands. Obviously, if better seismic data for ANWR were available, I would be in a better position to answer your question. And most of the geological and geophysical data the state possesses for adjacent state acreage is confidential. So I cannot tell you about the state's view on whether the Sourdough accumulation extends into ANWR.

What I can say is, if any of the known accumulations in the area around the Point Thomson Unit extend into ANWR, the chairman of Alaska's Oil and Gas Conservation Commission has stated that the so-called "rule of capture" controls. Our attorney general's office has told us the same thing. That means that the state believes that a state lessee could drain federal acreage. The federal government would have so-called "correlative rights", that is the right of an adjacent owner of an oil pool to produce his equitable share of the oil.

#### 3D Seismic in ANWR

I was on the team of companies that designed the ANWR seismic program in the early 1980's. The discussions were long and complicated (helped somewhat by the fact that these meetings were held in Hawaii). My personal experience interpreting ANWR seismic data is fairly extensive. I worked as an ANWR consultant doing contract seismic interpretations. I consulted for a number of companies and my experience was always the same. I would be assigned someone from the company to work with, often someone with considerable seismic

interpretation background, but no experience in ANWR. The company interpreters always started in the undeformed area near Kavik and began moving east. It all seems so easy to start. Then you reach the deformed section near the center of ANWR and the evaluation suddenly becomes much more difficult. Using an analogy I would describe the action this way:

At first you are walking along a well-lighted hallway in an unfamiliar building. Everything is as it should be with doors leading into offices here and there. The hallway makes a turn occasionally, but you always have your bearings.

Then you come to a door marked "Central ANWR." You open the door and step into a room full of mirrors. You struggle along, making some progress until the room starts to spin. Now you are uncertain where you are, or where you came from.

Then the lights go out.

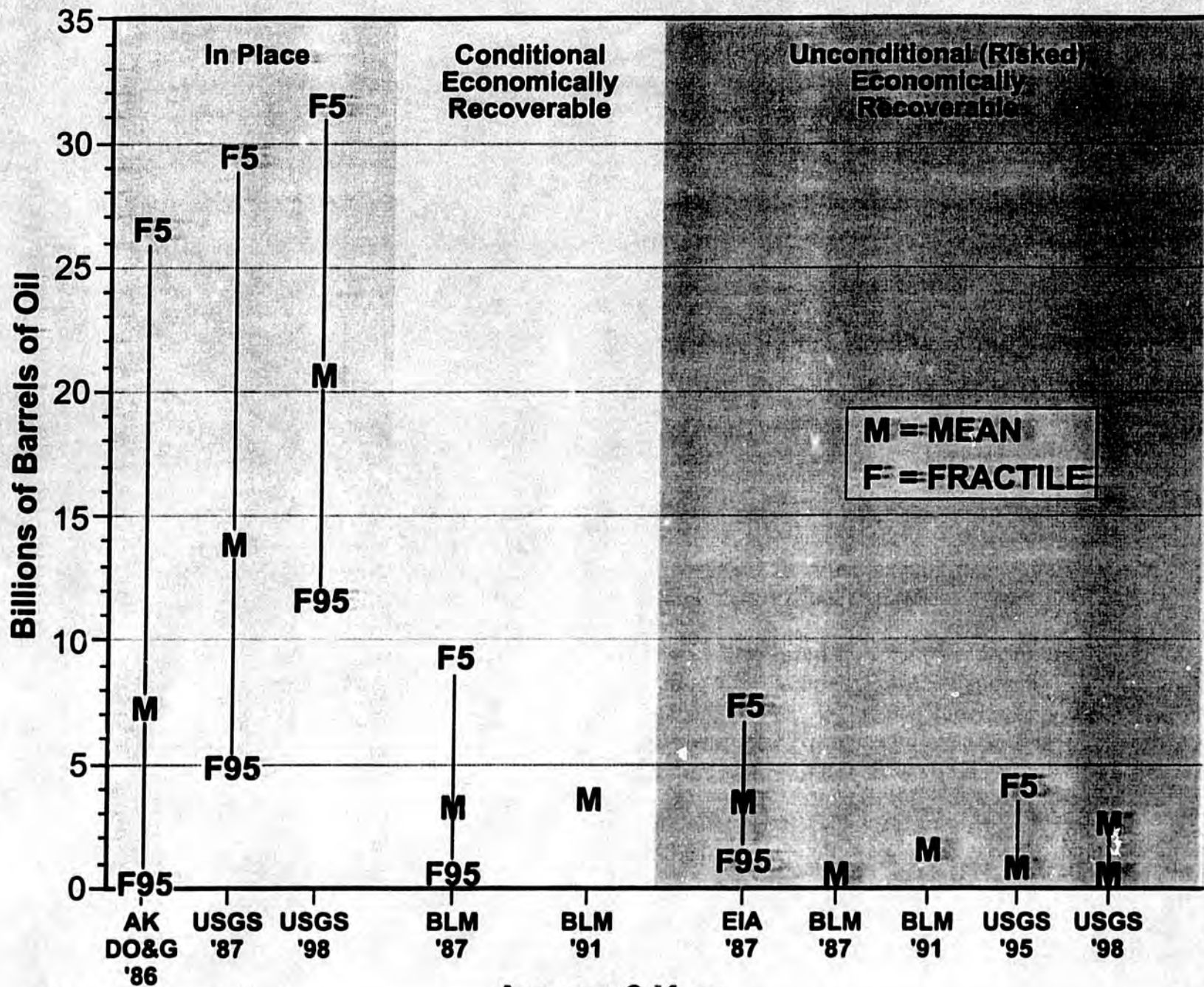
ANWR seismic data has served us well to this point, but after 15 years it is time to face the reality that we have wrung all the information out of this data that we can. 3D seismic has proved its value repeatedly. 3D seismic in ANWR would go a long way in unraveling a number of secrets that this incredibly complicated piece of real estate holds. 3D seismic coverage in the northwest quadrant of the 1002 area, especially adjacent to Sourdough and the Point Thomson Unit, would help delineate and extend known geologic trends and prospects. On the Canning River delta the old 2D seismic data set is very thin, consisting of only three seismic lines. That data is not extensive enough to adequately map and evaluate potential prospects. A comprehensive 3D seismic program east of the Canning River would go a long way toward answering the questions about the extent of known accumulations and the presence of other prospects.

#### Conclusion

I would like to thank the Chairman and this committee for their time and attention. The new estimates of undiscovered oil in ANWR are encouraging and should be viewed in a very positive light. It is not often that one of the Nation's premier assets—the petroleum potential beneath the ANWR coastal plain—gets upgraded so dramatically. In combination with this is other good news for every one of us that is concerned with preserving the surface values of the coastal plain. There is a heightened awareness in the petroleum industry operating in arctic Alaska to extract hydrocarbons in an environmentally safe and acceptable way. A revolution in drilling and development technology, and computer mapping applications has and will continue to dramatically reduce the footprint of development. The life of an oil field is temporary, with large fields lasting 30 to 50 years and smaller deposits depleted in 10 to 15 years. Our job is to make sure that our temporary occupation in these remote areas for petroleum extraction does not produce any long-term detrimental impacts.

Fields can be developed in sensitive areas by using the new technologies in combination with site specific stipulations and mitigation measures. I firmly believe that sound science is the necessary foundation for implementing successful development in the Arctic, both in the profitable extraction of our domestic petroleum resources and the protection of our sensitive

surface values. The Alpine oil field is being developed without gravel road access in a remote and sensitive part of the Colville River delta. The stand-alone development of this 365 million barrels of reserves will consist of two small development pads connected by a three mile long road/airstrip, and occupy only about 115 total surface acres. I believe this can be a model for remote oil field operations—what the Governor calls “Doing It Right”—and I believe we will continue to develop new techniques to minimize and mitigate environmental impact.



			Agency & Year
F95	Mean	F5	
0.08	7.22	26.52	AK DO&G in place 1986
4.8	13.8	29.4	USGS in place 1987
11.6	20.7	31.5	USGS in place 1998
0.61	3.23	9.24	BLM Undiscovered conditional economically recoverable oil in 1987
	3.57		BLM Undiscovered conditional economically recoverable oil in 1991
1.2	3.45	7.35	EIA Unconditional (risky) economically recoverable oil 1987
	0.6137		BLM Unconditional (risky) economically recoverable oil 1987
	1.642		BLM Unconditional (risky) economically recoverable oil 1991*
0.01	0.898	4.129	USGS Unconditional (risky) economically recoverable oil in 1995
	0.6		USGS Unconditional (risky) economically recoverable oil in 1998 (Deformed)
	2.6		USGS Unconditional (risky) economically recoverable oil in 1998 (Undeformed)

SOURCE: Alaska Division of Oil & Gas, July 1998

\*Reflects a change in original probability from 19% to 46%.

Estimates of Undiscovered Oil Resources in the Coastal Plain of the Arctic National Wildlife Refuge 1986 - 1998.

## ANWR Undiscovered Oil Estimates Comparison of USGS 1998 Estimates

Total In-Place Unconditional Estimates (1) (billions of bbls)		
	1987 BLM	1998 USGS
Fractile	OIL Estimate	OIL Estimate
F95	4.8	11.6
F75	8.2	
F50, median	11.9	
F25	17.2	
F05	29.4	31.5
Mean	13.8	20.7
Mode	8.8	

(1) The in-place estimates are directly comparable.

Undiscovered, Unconditional Technically Recoverable Oil in ANWR 1002 Area (2) (billions of bbls for oil)					
1995 USGS Nat'l Assessment Northern Alaska Province		1998 USGS Assessment 1002 Area			
		1002 Area Fed Excluding State & Native	1002 Area All lands Entire asses area	Undeformed Area	Deformed Area
Fractile	OIL Estimate	OIL Estimate	OIL Estimate	OIL Estimate	OIL Estimate
F95	2.34	4.254	5.724	3.403	0.0
F5	15.43	11.799	15.955	10.224	3.185
Mean	7.41	7.668	10.322	6.420	1.248

(2) The technically recoverable estimates are NOT directly comparable; different methodology, different plays.

Undiscovered Economically Recoverable Oil Estimates (3) (billions of bbls)						
	Conditional 1987 BLM Most Likely	Conditional 1987 BLM Optimistic	Conditional 1991 BLM Update	Unconditional 1995 USGS Derived from Reg'l Assesmnt	1998 USGS Deformed	1998 USGS Undeformed
Fractile	Economic Case	Economic Case	Mean Est Only			
F99	0.49	0.18		na		
F95	0.59	0.23		0 *		
F75	1.12	0.67		na		
F50, median	2.21	1.49		0.00		
F25	4.24	3.67		na		
F5	9.24	7.65		4.129 *		
F1	17.19	15.73		na		
Mean	3.23	2.66	3.57	0.898 *	0.6	2.6
Marginal Prob	19%	26%	46%	na		
MEFS	0.44	0.15		0.40		
Risked Mean *	0.6137 *	0.6916 *	1.6422 *	0.898 *		

(3) The economically recoverable estimates are NOT directly comparable due to differences in methodology.

Economically Recoverable (billions of bbls)	
	Mean Oil Estimate
<\$15.00	0.0
\$18.00	2.4
\$20.00	3.2

(3 fields) (1 field)  
(512 MM bbls MEFS)

FRANK H. MURKOWSKI, Alaska, Chairman

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# United States Senate

COMMITTEE ON  
ENERGY AND NATURAL RESOURCES

WASHINGTON, DC 20510-6150

[WWW.SENATE.GOV/~ENERGY](http://WWW.SENATE.GOV/~ENERGY)

July 23, 1998

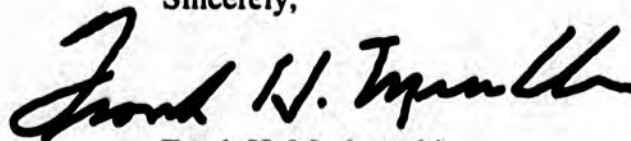
Mr. Kenneth A. Boyd  
Director, Division of Oil and Gas  
Department of Natural Resources  
State of Alaska  
3601 C Street, Suite 1380  
Anchorage, Alaska 99503-5948

Dear Mr. Boyd:

I want to thank you for your recent participation in the Senate Energy and Natural Resources Committee's oversight hearing on the results of the Arctic National Wildlife Refuge, 1002 Area, Petroleum Assessment, 1998. Your testimony provided valuable insight into the work performed by the USGS and the results it produced. I especially want to thank you for your very descriptive explanations of the benefits of 3-D seismic data. Your presentation was both technically precise and easily understood, a rare combination. I am forwarding some additional questions to you and would appreciate it if you could respond to them prior to the hearing record closing on August 6.

I could not agree with you more when you stated, "ANWR seismic data has served us well to this point, but after 15 years it is time to face the reality that we have wrung all the information out of the data we can." I strongly believe that if Congress is ever to make an educated decision about the 1002 Area that this decision must be based on the best available science. I plan on moving forward with giving the USGS the authority to use their expertise to obtain this data and I would like to be able to count on you to provide the technical expertise. We simply cannot, as an oil dependent nation, ignore an area that demonstrably has the highest oil potential of any region in North America which can be produced with less environmental impact than anywhere in the world.

Sincerely,



Frank H. Murkowski  
Chairman

Enclosure

## QUESTIONS

1. In your testimony you referred to many dramatic examples of cost reductions in drilling and production in the past six years. For example, you quote a reduction in development costs at Northstar of 70%. Do you see these trends continuing? Are there other opportunities for cost reductions in the next 10 years?

What is your overall take on the USGS economic assumptions?

2. Your testimony presents a very clear picture of the accuracy and benefits of 3-D seismic. Any technology that reduces risk from a 1 in 12 to a 1 in 2 rate must be utilized. My question is, when is the best time to get 3-D seismic? Should it be obtained prior to leasing or should it be the responsibility of the lessee after leasing?

What Does the State do in this regard?

If we were to support 3-D seismic prior to leasing, who should pay for it, industry, the federal government?

3. What is your feeling on the 3 x 6 mile seismic grid in the light of a statement by a previous Director of the Alaska Division of Oil and Gas who testified, "Such a large grid size, when combined with the lack of well data control and the extremely complex geology, virtually guarantees that many potential oil and gas traps of significant size may not be recognized".

How has 3-D helped in understanding the Pt. Thompson unit?

Would you expect an oil company which had leases in the 1002 area to drill exploration wells on the basis of the present seismic grid?

# STATE OF ALASKA

TONY KNOWLES, GOVERNOR

## DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

3601 "C" STREET, SUITE 1380  
ANCHORAGE, ALASKA 99503-5948  
PHONE: (907) 269-8800

August 5, 1998

The Honorable Frank H. Murkowski, Chairman  
United States Senate  
Committee on Energy and Natural Resources  
Washington, D.C. 20510-0150

Dear Senator Murkowski:

Thanks for your letter of July 23. Despite the long trip (not to mention the heat), I enjoyed participating in the ANWR hearing. I expect trying to get some kind of 3-D seismic legislation will, in certain quarters, cause a seismic event of its own. Your letter contained several questions that I will try to answer here.

1. **Question:** In your testimony, you referred to many dramatic examples of cost reductions in drilling and production in the past six years. For example, you quote a reduction in development costs at Northstar of 70%. Do you see these trends continuing? Are there other opportunities for cost reductions in the next 10 years?

**What is your overall take on the USGS economic assumptions?**

**Answer:** I cannot be sure that the companies will be able to continue the dramatic reductions in drilling and production costs that they have achieved over the past few years. I am sure that they will continue to focus on ways to reduce those costs. There is some information suggesting the companies are continuing cost reductions. The companies reduced the average cost for new and sidetracked wells in the Prudhoe Bay Unit between 1996 and 1997 (the most recent numbers). Moreover, I do see other opportunities for cost reductions on the horizon because Alaska has become a laboratory for applying new technology. The State certainly hopes this trend of cost reductions continues because it allows optimism despite low oil prices.

The division has not had an opportunity to review the USGS final economic report. The division's economists did review a draft, but were asked not to share its contents until the report was final. They offered several comments and suggestions to the USGS on the report, and we will withhold judgment until we have seen the final report.

2. **Question:** Your testimony presents a very clear picture of the accuracy and benefits of 3-D seismic. Any technology that reduces risk from a 1 in 12 to a 1 in 2 rate must be utilized. My question is, when is the best time to get 3-D seismic? Should it be obtained prior to leasing or should it be the responsibility of the lessee after leasing?

Senator Frank H. Murkowski  
August 5, 1998  
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**What does the State do in this regard?**

**If we were to support 3-D seismic prior to leasing, who should pay for it-- industry, the federal government?**

Answer: There is no hard-and-fast rule regarding the timing of acquisition of 3-D seismic. For example, several companies were shooting massive 3-D programs in NPR-A last winter in anticipation of an upcoming sale. But the shooting was concentrated in an area presumed to need that type of data. The best time to get 3-D seismic is when you think you need it. In the case of areas that have good 2-D coverage, 3-D is often used after the sale to evaluate specific plays or prospects. However, because of the complexity of the geology in ANWR, in my opinion, the government and industry could use 3-D seismic now. It is needed in both the "undeformed" western portion and in the structurally complex eastern portion of the coastal plain. "Undeformed" does not mean "uncomplicated" or "easy"; to the contrary, these types of reservoirs have an internally complex geometry that cannot be unraveled with 2-D data. Unlike the previous ANWR 2-D surveys, which were shot in what is called a "regional" program (i.e., it covered the whole region), 3-D would be targeted to specific plays or prospects. The State does not shoot its own seismic data but does have the right to obtain all seismic data shot on State lands.

There is no simple answer to "who pays" if 3-D seismic is shot prior to leasing. The original ANWR 2-D survey (actually there were two years of acquisition) was a "group shoot" whereby a group of companies share the cost of acquisition and initial processing. Then the data is shared by only that group (although there is almost always a provision for companies that did not participate to "back-in" and get the data later by paying a premium for the data. This premium is then split among the original participants). The disadvantage of late participation (besides having to pay the premium) is that the company has no input in parameter selection for the survey. I expect you will get a number of opinions on the "best" way to obtain (and pay for) the data.

**3. Question: What is your feeling on the 3 x 6 mile seismic grid in the light of a statement by a previous Director of the Alaska Division of Oil and Gas who testified, "Such a large grid size, when combined with the lack of well data control and the extremely complex geology, virtually guarantees that many potential oil and gas traps of significant size may not be recognized".**

**How has 3-D helped in understanding the Pt. Thomson unit?**

**Would you expect an oil company which had leases in the 1002 area to drill exploration wells on the basis of the present seismic grid?**

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Answer: The grid size in ANWR is fairly typical of older, regional 2-D surveys shot all over the world. Simply stated, the grid size is so coarse that some plays and prospects will be missed, overlooked or misidentified. The existing seismic data set—actually two sets, one dynamite, one Vibroseis—is technologically obsolete as well as incomplete. While useful for determining gross structural and stratigraphic patterns, it simply cannot compete with modern 3-D seismic technology. 3-D data has helped Pt. Thomson in the same way it has helped every other area to which it has been applied. It has helped the Unit owners better understand the complex geology present in this area. Some of the Pt. Thomson Unit Working Interest Owners have been, and will continue to, acquire 3-D data in the area. 3-D seismic certainly played a very large role in the Sourdough discovery, as well as the discoveries at Alpine, Badami, Tarn and a number of the new "satellite" discoveries around the Prudhoe and Kuparuk fields. 3-D seismic is clearly the exploration tool of choice for the present and the foreseeable future.

It is important to realize that 3-D seismic does not make the rocks "better" (in the same way that having a CAT scan won't necessarily make you healthier). 3-D is simply a tool to help geoscientists make better informed decisions about the subsurface of the earth, just as CAT scans help doctors make better informed decisions about the interior of the human body. Not every field that has been shot with 3-D has increased in size or gone on to be produced. Arco's Sunfish field in Cook Inlet is an example of this. After shooting 3-D over Sunfish, Arco dramatically downgraded the field and ultimately sold it to Phillips Petroleum. Phillips is trying to make a go of the field (now called Tyonek Deep) this year.

I doubt very much that companies would want to risk a lot of money in ANWR without having 3-D data in hand. I do believe companies would bid at a sale without 3-D if this were the only alternative. Given the geological complexity, I suspect these bids would be conservative and the revenues from the sale would be reduced for both the state and federal governments. Successful bidders would move quickly to shoot 3-D over their leases prior to drilling. I sincerely doubt that many wells will be committed in ANWR prior to acquiring 3-D seismic over the prospect to be drilled.

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I hope I have answered most of your questions. The "who pays" question will take a lot of discussion to resolve. I hope the debate can start soon.

Sincerely,



Kenneth A. Boyd  
Director