FILE COPY

IN THE SUPREME COURT FOR THE STATE OF ALASKA

STATE OF ALASKA, DEPARTMENT OF NATURAL RESOURCES,	)	
	)	**Supreme Court Case No. S-13730**
Appellant,	)	Trial Court Case No. 3AN-06-13751
vs.	)	(Consolidated Appeals)
	)	Case No. 3AN-06-13760 CI
EXXONMOBIL CORPORATION,	)	Case No. 3AN-06-13773 CI
OPERATOR OF THE POINT	)	Case No. 3AN-06-13799 CI
THOMSON UNIT; BP	)	Case No. 3AN-07-04634 CI
EXPLORATION (ALASKA) INC.;	)	Case No. 3AN-07-04620 CI
CHEVRON U.S.A. INC.;	)	Case No. 3AN-07-04621 CI
CONOCOPHILLIPS ALASKA, INC.,	)	
	)	
Appellees.	)	

REVIEW ON PETITION FROM THE SUPERIOR COURT FOR THE STATE OF ALASKA, THIRD JUDICIAL DISTRICT THE HONORABLE SHARON GLEASON, SUPERIOR COURT JUDGE

APPELLANT'S EXCERPT OF RECORD VOLUME 2 OF 2

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Filed in the Supreme Court of the State of Alaska, this 10th day of May, 2011.

Marilyn May, Clerk

By: [signature]
Deputy Clerk

Attorneys for Appellant State of Alaska, Department of Natural Resources

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

FRANK H. MURKOWSKI, GOVERNOR

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FAX: (907) 269-8918

Date: September 8, 2006

FACSIMILE-907-278-7001
CERTIFIED MAIL 7005 1820 0003 7399 2534
RETURN RECEIPT REQUESTED

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

RE: Point Thomson Unit
Extension of Appeal Period

Dear Mr. Walker:

Time is further extended for your clients' appeal consistent with the terms set out in the attached letter of September 8, 2006 to ExxonMobil.

Sincerely,

Michael L. Menge
Commissioner

cc: Bill VanDyke, Director, DNR, Division of Oil & Gas
Ken Griffin, Deputy Commissioner, DNR
Richard Todd, Senior Assistant Attorney General

"Develop, Conserve, and Enhance Natural Resources for Present and Future Alaskans."

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

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Date: September 8, 2006

FACSIMILE 907-564-3677
CERTIFIED MAIL 7005 1820 0003 7398 9558
RETURN RECEIPT REQUESTED

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

RE: Point Thomson Unit
Extension of Appeal Period

Dear Mr. Owen:

In order to assure that interested persons have an opportunity to comment on the proposed cure, if any, offered by Exxon, I am modifying the deadlines in my letter of August 31, 2006.

On August 31, 2006 I extended the time to appeal from the October 27, 2005 Amended Decision on the Proposed Plan of Development for the Point Thomson Unit (POD Decision) to October 20, 2006. The POD Decision put the Point Thomson unit in default. I also extended the time to cure the default to October 20, 2006.

The cure offered by Exxon must be in writing, and will be treated as a public document. It must be transmitted to my office in Anchorage in a manner such that it is received there no later than October 20, 2006, and Exxon may submit a cure at an earlier time if it so chooses.

I am now further extending the time to appeal from the POD Decision to November 3, 2006. On that date, Exxon and other interested persons, must deliver their appeal papers to my DNR office in Anchorage. The appeal papers must conform to the requirements of 11 AAC.02.010 *et. seq.* especially section 040 including, but not limited to, setting out a clear statement of all grounds for the appeal. Along with the appeal papers Exxon must submit to DNR all briefs, exhibits, evidence, argument and any other information and documents that it wants me to consider in connection with the appeal of the POD Decision and the proposed cure of the unit default. If Exxon prefers not to deliver its appeal materials to DNR, mailed or otherwise transmitted to my office so that they are received by November 3, 2006.

I will hold hearing on this matter beginning at 9:00 AM, November 13, 2006 at 550 West 7th, suite 1400, Anchorage, Alaska 99501. Persons wanting to participate at the hearing must pre-file testimony, exhibits, demonstrative aides, and any other item they plan on offering at the hearing such that it is received in my Anchorage office no later than November 3, 2006.

Sincerely,

Michael L. Menge
Commissioner

cc: Bill VanDyke, Director, DNR, Division of Oil & Gas
Ken Griffin, Deputy Commissioner, DNR
Richard Todd, Senior Assistant Attorney General

ExxonMobil Production Company
P.O. Box 196601
Anchorage, Alaska 99519-6601
907 561 5331 Telephone

Richard J. Owen
Alaska Production Manager
Joint Interest U.S.

ExxonMobil
Production

September 29, 2006

Commissioner Mike Menge
Alaska Department of Natural Resources
550 West 7th Avenue, Suite 1400
Anchorage, Alaska 99501-3650

Dear Commissioner Menge:

We have received your letter of September 8, 2006, extending the time to file an appeal of the October 27, 2005 Amended Decision on Denial of the Plan of Development for the Point Thomson Unit, and addressing submittal of a proposed cure in response to denial of the Point Thomson Unit (PTU) Twenty-second Plan of Further Development and Operation (POD 22). ExxonMobil intends to submit a modified POD on behalf of the PTU Working Interest Owners no later than October 20, 2006. Notwithstanding that submittal, it appears your schedule will necessitate our filing an appeal of the Amended Decision by November 3, 2006.

We understand from your September 8 letter that an appeal of the Amended Decision, as well as any material we wish DNR to consider in connection with that appeal or any proposed cure of the asserted default should be submitted by November 3, 2006. Thus, as we prepare a modified POD for submittal as noted in this letter, we also find it necessary (without waiver of any objection to the procedure set forth in your letter of September 8) to prepare to file an appeal and other papers that would need to be submitted by November 3, 2006. However, given that we will be submitting a modified POD by October 20, 2006, our understanding is that the hearing scheduled for November 13, 2006 would focus on the basis and supporting information for DNR approval of that submittal, rather than on the POD submitted on August 31, 2005.

In our November 9, 2005 letter requesting an extension of the time to appeal, and to cure, the denial of POD 22, we indicated that we would continue with activities set forth in POD 22 necessary to progress a gas sales development at PTU. While we requested approval of POD 22 for a one year time period through September 30, 2006, the work activity set forth in our plan extended beyond that date. We are continuing to progress work set forth in the POD we submitted on August 31, 2005. This work will carry through the date of action by DNR on the modified POD that we will submit by October 20, 2006. Submittal of a modified POD should meet any requirement for the Owners to have a POD and protect against any action being taken, until a final decision is made regarding the modified POD.

Please let us know if there are any questions or clarifications regarding this letter, or if any of our understandings are incorrect.

Sincerely,

RJO:jpc

A Division of **Exxon Mobil Corporation**

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

FRANK H. MURKOWSKI, GOVERNOR

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October 3, 2006

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

Dear Mr. Owen:

Thank you for your letter of September 29, 2006 suggesting that the hearing scheduled for November 13, 2006 will be limited to the submittal of information on any cure Exxon decides to offer. Be advised the hearing is not so limited. The hearing will cover both the appeal from the October 27, 2005 POD decision and the proposed cure. The written submittals due on November 3, 2006 should also address both the appeal from the default decision and the proposed cure. Any and all materials you want the Commissioner to consider in connection with the appeal need to be submitted on November 3, 2006.

Sincerely,

Michael L. Menge
Commissioner

cc: William Walker, Walker & Leveaque, LLC

"Develop, Conserve, and Enhance Natural Resources for Present and Future Alaskans."

ExxonMobil Production Company
P.O. Box 196601
Anchorage, Alaska 99519-6601
907 561 5331 Telephone

Richard J. Owen
Alaska Production Manager
Joint Interest U.S.

ExxonMobil
Production

October 18, 2006

DEPARTMENT OF
NATURAL RESOURCES
OCT 1 8 2006
COMMISSIONER'S OFFICE
ANCHORAGE

Mr. Michael L. Menge, Commissioner
Alaska Department of Natural Resources
550 West 7th Avenue, Suite 1400
Anchorage, Alaska 99501-3650

Dear Commissioner Menge:

Enclosed is the modified Plan of Further Development and Operation (Plan or POD) for the Point Thomson Unit (PTU). This Plan incorporates work activity performed from October 1, 2005, and for the period through September 30, 2010. On behalf of the PTU Working Interest Owners (PTU Owners), ExxonMobil, as PTU Operator, requests approval of this Plan for the period set forth in the POD.

The PTU Owners believe this POD is consistent with the terms of the Point Thomson Unit Agreement and provides for prudent development of the Unit Area. This Plan sets forth significant work activity to progress development plans for gas sales from PTU. The Plan also includes work plans to evaluate other development scenarios for the Thomson reservoir to facilitate other potential paths to development for PTU. The POD establishes milestones for completing specific activities, including drilling a well targeted to the Thomson Sand to acquire data and information to assist in the development planning for the Thomson Sand.

The PTU Owners believe that this POD addresses the concerns contained in the amended decision by the Division of Oil and Gas on POD 22 and should be approved by the Department of Natural Resources, thereby satisfying any requirement by the Department of Natural Resources for the PTU Owners to submit a POD that cures any asserted default under the Point Thomson Unit Agreement.

Thank you for your consideration of this Plan. We are available to clarify any aspect or answer any questions from the Department of Natural Resources.

Sincerely,

RJO:jpc
Attachment

xc: Bill Van Dyke, Acting Director, DNR, Division of Oil & Gas
Ken Griffin, Acting Deputy Commissioner, DNR
PTU Owners

PTU22P_000001

A Division of **Exxon Mobil Corporation**

POINT THOMSON UNIT

Plan of Further Development and Operation
For the period October 1, 2005 to September 30, 2010

In accordance with Article 10 of the Point Thomson Unit (PTU) Agreement and applicable regulations, and on behalf of the PTU Working Interest Owners (Owners), ExxonMobil submitted the Twenty-second Plan of Further Development and Operation (POD 22) to the Alaska Department of Natural Resources (DNR) in August 2005, for the period from October 1, 2005 through September 30, 2006. The DNR did not approve POD 22.

Throughout the past year, the Owners have continued to diligently conduct work necessary to develop the PTU hydrocarbon resources as part of an Alaska North Slope (ANS) gas pipeline project consistent with work set forth in the POD 22 submittal. Set forth herein is a modified Plan of Further Development and Operation (POD) which describes work performed to date since expiration (September 30, 2005) of the most recently approved Plan of Development (POD 21) and further development work from October 1, 2006 through September 30, 2010. The term of this POD is consistent with the time required to drill and evaluate the described Thomson Sand well.

Exxon Mobil Corporation (ExxonMobil), as Unit Operator and on behalf of the Owners, requests approval of this POD for the period October 1, 2005, through September 30, 2010.

1. Background Discussion – Point Thomson Unit Development

The Thomson Sand contained within the Point Thomson Unit is a large high pressure gas-condensate field. Since discovery in 1977, the Owners and DNR have recognized that PTU could best be developed through a North Slope gas pipeline project (Pipeline Project). They have also recognized that it might take a number of years for there to be a viable gas sales option, due to the complex nature and high cost of a project and the absence of a means of transportation.

Industry has pursued many different gas commercialization concepts for ANS gas, including gas-to-liquids, LNG and pipelines. Until recently, the outlook for an ANS gas pipeline has not been sufficiently promising. Consequently, the Owners have diligently worked to identify a viable development that could occur without construction of a Pipeline Project. Options like gas injection and gas storage would not provide as much value as a gas sales development, but were evaluated in order to ensure all potentially viable development scenarios were considered.

The current Owners are among the most technologically qualified oil companies in the world, have invested significant resources to gain an understanding of the Point Thomson reservoirs, and are the most capable to develop the technically challenging Point Thomson field.

PTU22P_000002

Exc. 000413

PTU REC_000666

2. Summary of POD Activities

During the term of this POD, the Owners plan to undertake development activities that relate to 1) support of gas sales development, 2) reevaluation of alternate development scenarios, and 3) technical/operational work in support of PTU development. In particular the POD includes the following work scope:

Gas Sales Development

- Continue technical work necessary for the Owners to participate in an open season
- Conduct Conceptual Engineering, based on the status of a Pipeline Project

Alternate Development Evaluation

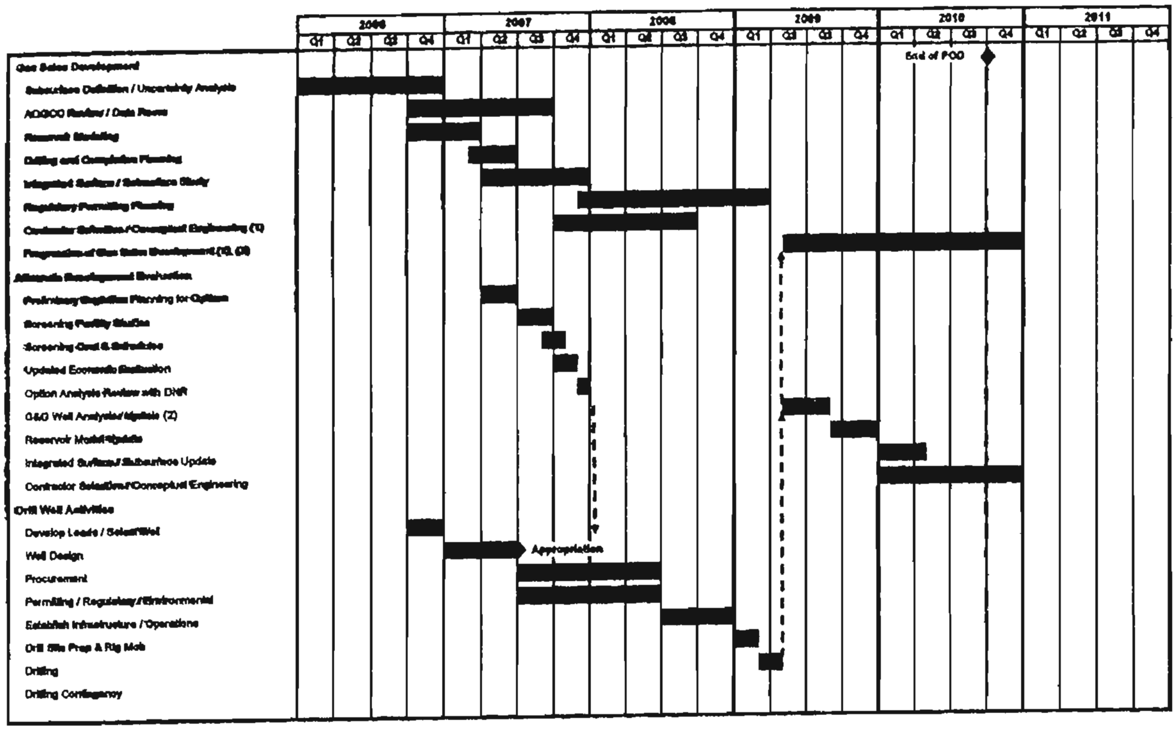
- Update technical work to conduct screening evaluation of alternate development scenarios, including gas injection and gas storage
- Assess development scenarios to determine commercial viability
- Progress technical definition and work activity as necessary to initiate Conceptual Engineering of a viable alternate development scenario.

Development Support

- Conduct technical and environmental activities to secure necessary drill well permits
- Drill a Thomson Sand well and evaluate results
- Continue environmental baseline studies and unit operating agreement negotiations

The following chart sets forth the anticipated timeline for these activities. Once a clear path to development emerges within the POD timeframe, a revised POD may be submitted to the DNR which may remove or add work activities to progress the identified development plan.

Summary Schedule for this POD



Notes:

(1) Based on the status of a Pipeline Project.
(2) Following analysis of Thomson Sand well results.

2.1 Significant POD Milestones

The Owners will provide annual progress reports of work conducted under this POD by October 1st of each year. The Owners will also conduct detailed technical review sessions on work activity as scheduled with the DNR. Key milestones contained in this POD are shown below:

Milestones	Date
• Commence Preliminary Depletion Planning for Alternate Developments	2Q 2007
• Initiate Screening Studies for Alternate Developments	3Q 2007
• Submit Drill Well Permit Applications	3Q 2007
• 2007 Status Review	4Q 2007
• Initiate Conceptual Engineering for Gas Sales Development	1Q 2008
• 2008 Status Review	4Q 2008
• Commence Drilling Operations	1Q 2009
• 2009 Status Review	4Q 2009
• POD submittal	3Q 2010
• 2010 Status Review	4Q 2010

3. Point Thomson Development

3.1 Point Thomson Gas Sales Development

Prior work indicates the most value for the Owners and the State will be derived if the Point Thomson gas field is developed as part of a Pipeline Project. Additionally, PTU gas sales development would provide necessary infrastructure to facilitate later development of other reservoirs within the Unit.

A significant step in enabling a gas sales development to move forward is to secure shipping capacity through a gas pipeline. To accomplish this, the Owners will need to make long-term commitments in an open season nomination process. Before making such commitments, the Owners must have confidence in the ability to produce the necessary volumes of gas from PTU and in the cost of the facilities required to do so.

The Owners have and are continuing to commit significant financial and human resources to develop PTU through a gas sales development. The current gas sales work will provide the necessary confidence in the capability of the reservoir to produce the required gas volumes and in field development costs to make these firm transportation commitments.

The overall objective of current PTU gas sales work is to provide necessary technical information so that the Owners will be prepared at the earliest possible date to participate in an open season process for a Pipeline Project. Because of the large number of Owners, it is important that the necessary information is provided in a timely manner.

A second, equally important, objective is to allow overall PTU development activity, including permitting, to progress concurrently with any viable gas development option. The work described in this POD is being planned to meet these objectives. To assure the timeliest advancement of PTU development, gas sales development plans will continue and will advance in parallel with evaluation of other development scenarios.

A PTU gas sales development would produce both gas and condensate from the Thomson Sand and Pre-Mississippian section. The gas would be delivered and sold to North American markets via a Pipeline Project. The condensate would be recovered in PTU processing facilities and delivered to the Trans Alaska Pipeline System (TAPS) for blending and sale with the crude oil currently being transported in TAPS.

The Thomson Sand is known to contain large quantities of gas. The Pre-Mississippian section, which is in direct communication with the Thomson Sand, could produce either gas or water during gas sales as the Thomson Sand reservoir pressure declines with gas withdrawals. A focus area of the geologic and reservoir engineering studies during the POD term is to enhance the understanding of the combined Thomson Sand / Pre-Mississippian section reservoir dynamics under gas sales and optimize the development plan.

Screening level designs and cost estimates of gas sales facilities and wells have been developed. During this POD the Owners plan to conduct the next stage of engineering, commonly referred to as Conceptual Engineering, to further advance the detail and quality of these designs and cost estimates. Conceptual Engineering represents a significant increase in activity and will require the commitment of increased financial resources and many staff-years of ExxonMobil and contract personnel.

To advance the gas sales development as outlined in this POD, the following specific work tasks are planned:

3.1.1 The Owners will complete the technical definition of the base case, low side and high side geologic modeling initiated during POD 21. The Owners will also complete a rigorous uncertainty analysis of the Thomson Sand and the Pre-Mississippian section. Reservoir simulation for low side, base case, and high side geologic models will be completed. This simulation work is expected to form the basis for an updated PTU gas sales depletion plan.

Results of the simulation work will also aid in selecting a PTU well location and support Conceptual Engineering activities.

3.1.2 Conceptual Engineering is planned to be initiated after the flowstreams are available from the reservoir simulation results and the development plan is confirmed. Conceptual Engineering requires approximately 9 to 12 months, and must be completed in time to allow all Owners to prepare to make nominations in the open season for a Pipeline Project. The Owners will be prepared to commence this activity based on the status of a Pipeline Project to ensure sufficient time is available prior to open season nominations.

3.1.3 In conjunction with Conceptual Engineering, drilling and completion plans and costs for development wells will be updated. This will include determining optimum drillsite locations and completion concepts, and estimating individual well locations, displacements, drilling/completion times, and costs. This information will be important in determining estimated total project costs and timing.

3.1.4 The Owners will continue planning for the permitting process for a PTU gas sales development. This work includes a review of the permitting experience and lessons learned from the former gas injection project activity, a review of future permitting related data and study needs, and an assessment of the interrelationship between permitting processes for PTU and that for a Pipeline Project. The Owners will identify key milestones for obtaining necessary permits for the drilling PTU wells and construction and operation of PTU facilities and pipelines. The project timeline will be updated with the results of this permitting assessment.

3.1.5 Gas sales development plans will incorporate key learnings gained from the drilling of the Thomson Sand well.

3.1.6 Modify the PTU economic model to include changes in market conditions, PPT, and any other issues which could impact the commercial viability of a PTU gas sales development.

3.2 Alternate Point Thomson Development Scenarios

The Owners continue to pursue options for commercially viable PTU development. Prior studies resulted in determinations that stand-alone gas injection development or Brookian development were not commercially viable. Results of these studies have been shared with the DNR. Other studies concluded that neither gas storage nor gas injection followed by gas sales was commercially viable.

However, the Petroleum Production Tax (PPT) passed by the Alaska Legislature in August 2006, and changes in market conditions and other potential issues could affect the commercial viability of alternate development scenarios either positively or negatively. It is currently uncertain whether the cumulative affects of these changes would improve or degrade the potential for other commercially viable developments.

The POD work plans include screening studies to evaluate the impact of the changes mentioned above and to determine whether more detailed work is warranted. This includes the following work activity:

3.2.1 Use the geologic model and reservoir engineering simulation work conducted during 2005-07 to prepare updated production flowstreams for a gas injection development, a gas storage development, and combinations of gas injection or gas storage development followed by gas sales.

3.2.2 Develop or update cost estimates for facilities and drilling costs for each of the identified development scenarios to allow meaningful evaluation.

3.2.3 Refine schedules for each development scenario including permitting timeframes.

3.2.4 Modify the PTU economic model to include changes in market conditions, PPT, and any other issues which could impact the commercial viability of these alternate development scenarios.

3.2.5 Use the modified PTU economic model to conduct updated economic analyses and assess commercial viability of gas injection and gas storage developments and combinations of gas injection or storage development, followed by gas sales.

3.2.6 Provide status report to DNR.

3.2.7 Update screening studies to incorporate key learnings gained from drilling of the Thomson Sand well.

3.2.8 Once one or more viable development scenarios are identified, then progress the technical definition necessary to initiate Conceptual Engineering.

Gas storage at Prudhoe Bay Unit (PBU) will require coordination with the PBU Operator in order to conduct reservoir depletion analyses that would identify the impacts of storing PTU gas at PBU.

3.3. Brookian Development Plans

The PTU contains several Brookian oil accumulations. These have been interpreted and mapped and past studies have found them to be not commercially viable as stand-alone developments. Because the Brookian and Thomson Sand will have different producing characteristics, commingled production is not practical during the early years of Thomson Sand production. Accordingly, design criteria for facilities to develop the Thomson reservoir will include considerations for expansion to accommodate later Brookian production. Having infrastructure for Thomson Sand development in place will facilitate opportunities for field testing to assess Brookian potential.

4. Thomson Sand Well

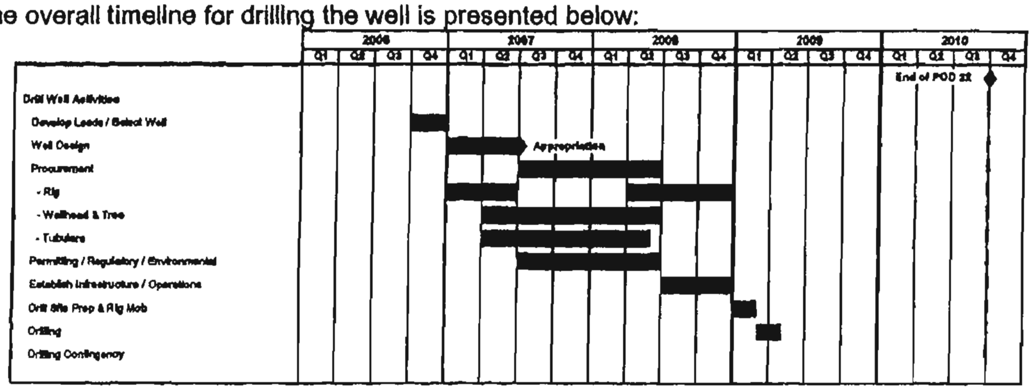
To further the definition and characterization of the Thomson Sand reservoir and the selection of **optimum development** plan, **the Owners** are proceeding with on-lease activity to drill a well into **the Thomson Sand** as described **below**:

4.1 The Owners will drill a well targeted to the Thomson Sand on the earliest prudent schedule. Selection of the well's surface and bottom hole locations and determination of the well objectives will occur first. After selecting the bottom hole location, work will focus on 1) completing a preliminary well design, 2) contracting for a drilling rig and making the necessary modifications to allow drilling a deep, high pressure Thomson Sand well, and 3) obtaining long lead time material, including casing, tubing and well head equipment.

4.2 It is anticipated that all aspects of well planning, approvals, permitting, rig contracts/modifications and long lead materials can be completed by 4Q 2008. Recognizing the physical constraints associated with preparation of the drilling rig and the delivery of specialized wellhead, casing and tubing equipment, the earliest initiation of the well is the 2008-09 winter season. To expedite drilling of the well, preliminary well design and procurement activities will occur in parallel with the alternate development screening process in section 3.2 of this POD beginning after approval of this POD. The screening process could result in modifications being made in the final well design. The Owners anticipate that well operations will be completed during the 2008-09 winter season, but it may be necessary to continue operations into the following summer season, or suspend the well and continue operations the following winter season.

4.3 Evaluation of the drilling results will occur following completion of the well.

The overall timeline for drilling the well is presented below:



4.4 The Owners are committed to drilling a well during the term of this POD, unless prevented from commencing the well by September 30, 2010 for reasons of force majeure or permitting delays on timely submitted permit applications. However, if drilling of the well does not occur as provided for in this POD, the Owners will pay the State of Alaska $40 million for not having drilled the well, unless prevented from drilling the well for reasons of force majeure or permitting delays on timely submitted permit applications.

5. Additional Work Plans

5.1 The Owners will progress sharing of confidential PTU technical data with the Alaska Oil and Gas Conservation Commission (AOGCC) via a data room process. After this process is completed, a request for approval of a conservation order to authorize the desired gas offtake rate from the Thomson Sand reservoir will be submitted. This submittal, which will include the PTU depletion plan, will be timed to allow the conservation order to be issued prior to the open season for a Pipeline Project. The Owners will also work with the AOGCC to define the appropriate time to apply for other Pool Rules that may be needed to develop PTU and will include the results in the schedule of activities for permitting of the PTU wells and facilities.

5.2 The Owners will continue to progress a new Unit Operating Agreement.

5.3 The Owners will contribute funding to Polar Bear environmental baseline studies that will be conducted by the USGS, Alaska office.

5.4 The Owners will review other environmental baseline studies that have been completed in the past few years and evaluate the need to update and continue these studies. Studies will be conducted as required to maintain the ability to file necessary permits without impacting potential development timing.

5.5 Regulatory and permitting activities will be conducted in parallel with other activities undertaken in this POD as follows:

- 5.5.1 Assessment of the general permitting approach envisioned for each development scenario
- 5.5.2 Develop a comprehensive permitting strategy for development plans progressed to Conceptual Engineering. This will typically include development of a memorandum of understanding with the lead permitting agency.
- 5.5.3 In preparation for the environmental review process undertaken during Front End Engineering Design (FEED), the Owners will begin to collect necessary data needed to develop terms of reference and support environmental review.

5.6 At the conclusion of Conceptual Engineering, the Owners plan to be in a position to proceed with FEED, subject to Owners approval. FEED represents a substantial increase in the effort, detail and costs related to the development design, and is typically done by an engineering, procurement, and construction contractor with extensive ANS experience with similar projects. FEED will become the design basis for purchase orders issued for major production equipment and for environmental assessment and permitting.

The detailed cost estimate derived from FEED typically becomes the basis for an Owner's funding decision for a project. FEED typically takes 12 to 18 months to complete and is not scheduled for completion within the timeframe of this POD.

6. Work Performed Since October 1, 2005, Under POD 22

A summary of the work performed since October 1, 2005, is described below. The Owners are available to review this work with the DNR.

6.1 Extensive geologic modeling has been completed as part of a broad uncertainty analysis effort to advance the technical definition of the Thomson Sand reservoir and ensure proper characterization of the range of uncertainty. Multiple base case, low side and high side geologic scenarios have been constructed that incorporate distinct variations in facies distribution, reservoir thickness, porosity, structural interpretation and depth conversion. These scenarios facilitate the modeling of a wide range of parameter variations and subsequent analysis of their potential impact over the entire PTU area.

A rigorous investigation of the Pre-Mississippian section has been undertaken and incorporated into the geologic modeling. Particular effort was directed to understanding the implications of the Pre-Mississippian section as a potential gas reservoir and aquifer. Seismic definition of the Pre-Mississippian section has been augmented by examination of Point Thomson well core and analog based modeling of potential fracturing. The impact of Pre-Mississippian section fracturing on permeability and porosity is modeled as sensitivities within reservoir simulation cases.

An iterative preliminary reservoir model building and simulation effort was completed in support of the overall uncertainty analysis. This work was used to evaluate changes in the geologic models and identify major factors impacting dynamic performance and recovery. A rigorous analysis of these major factors was implemented and formed the basis for input to the geologic models. After the geologic models are constructed and reviewed, they are used in full field compositional reservoir simulations. These simulations form the core of a statistical analysis which will study key subsurface factors impacting a PTU gas sales development.

The results of the uncertainty analysis serve as a guide in the selection of representative low, high and base case models. The base case model will serve as the basis for depletion planning and flowstreams for the gas sales development.

Other significant technical efforts that are being conducted include a laboratory study to measure and analyze rock compressibility data from Point Thomson core samples and a surface subsidence study.

6.2 Facilities and pipeline work was focused on preparing execution plans for Conceptual Engineering. The execution plan includes a detailed scope of work listing each of the deliverables to be prepared, the degree of completion (initial, update, final) and responsible party (Owner, Engineering Contractor). The plan also includes determination of organization and staffing level requirements. This will allow for a rapid initiation and ramp-up of Conceptual Engineering upon completion of the reservoir simulation work.

6.3 A Completion Concept Workshop was conducted to examine drilling and completion designs and to define the optimum completion concept for gas sales development wells. The outcome of the workshop was a ranking of the applicability of completion concepts to meet the gas sales development well objectives of high producing rates, long life, minimal sand production and low life cycle cost. The results of the workshop will be used during the Conceptual Engineering phase to study, refine and optimize the concept selected.

6.4 Previous permitting support documents were reviewed in preparation for restarting permitting activities. A significant amount of work for the previous gas injection development has been identified as being applicable to the gas sales development.

6.5 The process of applying for pool rules from the AOGCC was initiated. The AOGCC and the Owners agreed to a protocol for the sharing of confidential data with the agency and the protocol was adopted by the AOGCC at a public meeting on April 26, 2006.

A comprehensive PTU review was held for the AOGCC and their consultants on May 11, 2006. The review included discussion of the previous gas injection development study efforts and introduced the Owners' work to assemble a worldwide database of potential Point Thomson analogue reservoirs.

Attachment 1

Work Performed Under POD 21

Under POD 21, the primary focus of the Owners was to progress the technical definition and commercial evaluations necessary for a PTU gas sales development. The near term objective was to ensure the Owners would be in a position to participate in a future open season for a Pipeline Project. The facilities technical definition for gas injection development was well into FEED and the subsurface technical definition was approaching funding quality when work was suspended. The corresponding technical definition for gas sales development, however, was only at a pre-screening level.

The facilities component of the POD 21 work was to conduct screening designs and prepare cost estimates for the facilities needed to produce the Point Thomson reservoir to a Pipeline Project. This is a prerequisite to conducting Conceptual Engineering, which is a significant effort planned to begin during the POD 22 period. Conceptual Engineering is the level of technical definition necessary for the Owners to participate in the open season process.

Geological and reservoir studies begun under POD 21 are aimed at improving the subsurface technical definition of the Thomson and Pre-Mississippian intervals to understand the reservoir dynamics under gas sales and to evaluate production flowstreams and economics of the new higher definition gas sales cases.

A significant effort was also expended during POD 21 to provide the DNR with data on the gas injection development, the gas sales development and potential combinations of gas injection and gas sales development. A major data submittal was made on November 15, 2004, which provided data as required in Sections 1 and 3 of the previous POD, on studies related to the Brookian reservoirs and the gas injection development. A second submission was made on April 8, 2005 in response to Governor Murkowski's and Dr. Myers' letters requesting data on gas sales developments and developments in which gas sales would be combined with gas injection development.

Several workshops were held with the DNR to review the data, methodologies and results. A comprehensive technical review was held with DNR staff on June 29, 2005 to review work done during the past year.

Under POD 21, the Owners spent in excess of four million dollars, which represented approximately ten staff-years of technical work, to advance efforts toward commercializing the PTU hydrocarbon resource. The Owners continued to participate in environmental baseline surveys and development of technical data from the PTU area, completed numerous technical studies and reports, and continued to identify and evaluate project risk reduction opportunities.

Seven specific work areas were enumerated in POD 21 to be pursued by the Owners during the period from October 1, 2004 through September 30, 2005. Comments on each are provided below.

1. *The Point Thomson Owners will share with the ADNR results of evaluations and other work associated with potential hydrocarbon resources within the unit area, including the Brookian and Pre-Mississippian reservoirs to include reserve estimates, distributions and mapping.*

   Existing data on the Brookian reservoir was included in the November 15, 2004 data package, Exhibit 5, and was further addressed in the April 8, 2005 data submission, Exhibit 8. The Brookian was also reviewed extensively at the June 13-15, 2005 subsurface workshops that are discussed under Item 3. As discussed in these data packages and at the workshop, there are significant hurdles to overcome in achieving commercially viable development of the Brookian reservoirs in the PTU area, most notable among these is the reservoir connectivity/recovery uncertainty.

   The Pre-Mississippian section has been the subject of extensive new work during the past year. Specific activities included reassessment of all well tests; review of all cores and core studies; review of the drilling history; seismic interpretation focused on definition of the bedded Pre-Mississippian section; and geological interpretation including fracture characterization. Results of the Pre-Mississippian 3-D studies were incorporated into the 2005-06 combined Thomson/Pre-Mississippian 3-D geologic models. Screening simulation studies were performed in parallel using information from the Pre-Mississippian studies. The results of the Pre-Mississippian work, including interim reserves estimation and distribution, were reviewed with the staff of the DNR on June 29, 2005.

2. *Consult with the DNR and review the Economic Spreadsheet Model of PTU Gas Injection Project, including assumptions on rates of oil (condensate) and gas production, costs (finding, development, and production) with related spreadsheet equations, economic parameters that drive the model, and results of the model. ExxonMobil will hold economic workshops with ADNR staff to review the spreadsheet calculations and results.*

   Gas injection development economic model input data was provided to the DNR in the November 15, 2004 submission, including all production flow rates and costs for what was referred to as the Rev. B" case. In the April 8, 2005 submission, similar data was provided for the FEED, Rev. B case. ExxonMobil reviewed the spreadsheet equations, parameters and results at a workshop on May 24, 2005 and is available along with the other Owners to conduct additional workshops at the DNR's request.

3. *Provide the DNR with existing technical information, costs, and other fiscal assumptions (including government take ramifications) necessary to assist the DNR in completion of their economic analysis of the Gas Injection Project. To that end, the Owners will provide DNR with the following:*

   a) *The pre-stack depth migrated seismic data set in SEGY format (8 millimeter, DLT or DVD) with deconvolution and without deconvolution; full stacks plus velocities. XY's are provided in a digital file of bin centers with a 3D-inline map in a .cgm file.*

b) Digital files (ASCII) of the xyz grids that represent the results of the seismic interpretation, geologic model, and the reservoir simulation, and the centerline faults for these interpretations, including all information used in the in-place volumetrics and recoverable reserve estimates for all reservoirs or potential reservoirs evaluated to this point.

c) Access to the results of the seismic interpretation, the geologic model, and the reservoir simulation at ExxonMobil offices in Houston, Texas.

d) Data and interpretations of recent core studies that address potential sanding of the Thomson sand.

e) Well, facility, and infrastructure construction cost estimates (including sequence and timing) and operating cost estimates.

All requested data was provided in the November 15, 2004 data submission to the DNR as provided in the approval of POD 21 in the decision of the Director. The seismic information requested in paragraph a) was included in Exhibit 1 of the submission, the geologic model requested in paragraph b) including faults was included in Exhibit 2, and the Thomson Sand core studies pertaining to the potential for sanding requested in paragraph d) were included in Exhibit 3. Exhibit 4 of the package included the technical and economic input assumptions, facility design information including capital and expense costs, and tables itemizing all flowstreams, capital and expense costs, and price netback forecasts including pipeline costs as requested in paragraph e).

A workshop (teleconference) was held on May 26, 2005 to discuss the depth conversion that was made during the 2001 to 2003 timeframe and that was the basis for the GIP's geologic model. Prior to this review a paper entitled "A History of Top Thomson Depth Mapping (2001 to 2003) for the ADNR" was provided to the DNR staff. A copy of the material presented on May 26 was subsequently provided to the DNR.

A workshop was held for the DNR in ExxonMobil's offices in Houston during June 13-15, 2005 as provided for in paragraph c. The purposes of this workshop were to provide the DNR a comprehensive technical understanding of geoscience interpretations, geologic model and reservoir simulation used for the PTU GIP and to share information used for in-place volumetrics and recoverable reserve estimate for the Thomson reservoir. During this workshop access to the results of the geophysical, geologic and reservoir interpretations was made available. Additionally, at the DNR's request, a half day core workshop was conducted where Thomson Sand and Pre-Mississippian section cores from key wells were reviewed. ExxonMobil remains available to conduct additional technical workshops at the DNR's request.

4. *Activity during POD 21 will include work on progressing technical and commercial evaluations necessary to assure the Owners will be in a position to participate in a future open season for major gas sales from the North Slope of*

Alaska. ExxonMobil, BP, and ConocoPhillips are major working interest owners in Point Thomson, and comprise the Sponsor Group that has submitted an application under the Stranded Gas Development Act (SGDA) addressing a major gas pipeline. The Sponsor Group, as well as Chevron Texaco, depends on PTU resources to underpin firm supply commitments for major gas sales. The Point Thomson Owners possess both the capability and North Slope experience necessary to develop and reliably operate the Point Thomson Unit and to overcome its associated technical challenges.

a) Develop a conceptual gas sales depletion plan. Work will include reservoir simulation to enhance production and recovery predictions under various gas sales scenarios; initial identification of sales rates and well placement along with associated optimizations; assessment of the impact of the Pre-Mississippian on gas sales performance; and uncertainty analysis to assess the impact of reservoir connectivity and sand control issues.

b) Conduct screening evaluations of Point Thomson gas sales production facilities. Planned activities include evaluation of PTU gas separation, compression and conditioning alternatives, export pipeline design concepts, and identification of infrastructure and alternatives requirements. The Owners plan to work with the Prudhoe Bay Unit (PBU) Owners to conduct a screening evaluation of gas receiving facility options at PBU.

c) Identify and implement additional PTU gas sales planning and technical work necessary to support SGDA negotiations and consistent with the schedule outlined by the gas pipeline Sponsor Group.

d) Share results from a through c above with the DNR as available, but no later than July 1, 2005.

A conceptual depletion plan was developed. This depletion plan incorporated the results of the prior geologic model with updated reservoir simulation and updated facilities designs and cost estimates. As is normal with major projects, this represents one step or phase in the project development process. The depletion plan will be further refined during the next year as well as in subsequent phases of work.

The work performed under this item 4 was reviewed with the DNR on June 29, 2005. This included a review of the screening level gas sales depletion plan and the gas and condensate flowstreams that were used in the screening evaluation of PTU gas sales production facilities. The overall production scheme is to produce gas from PTU and deliver the gas to the Prudhoe Bay area where it can be further processed in a gas treatment plant and prepared for sale. Receiving facility design has been coordinated with the PBU Operator to ensure compatibility with PBU operations and plans for gas sales from PBU.

Reservoir simulation studies to further refine the effect of the Pre-Mississippian section on PTU gas sales as well as work on an uncertainty analysis are continuing. The Owners provided a final submittal to the DNR on this work on September 30, 2005. The simulation work during the past year included a screening assessment of the impact of the Pre-Mississippian section and

Thomson aquifer influx on Thomson production and possible enhancements to the 2003 gas sales screening study depletion plan. Due to schedule requirements and the need to progress this screening work within the past year, this work was based on the 2003 geologic model.

The 2003 geologic model was updated to include the Pre-Mississippian section that is in communication with the Thomson Sand reservoir. The updated model will provide the basis for the reservoir simulation that is to be performed in the second half of 2005 and in 2006. In addition to the base case model, technical work towards construction of low and high side models is ongoing. Work during 2006 will address the low and high side geologic model as well as simulation of the base, low and high side models.

Several studies needed to generate this new object based geologic model have already been completed, including a seismic lineament study to construct a more detailed representation of faulting in both the Thomson Sand and the Pre-Mississippian section, along with other Pre-Mississippian work as detailed under item 1 above. Additional depositional and structural scenarios will be incorporated to model a full range of high and low side scenarios. These additional realizations will help in understanding questions of reservoir continuity, development planning, and number of wells needed. Uncertainty analysis will proceed concurrently with the geologic modeling efforts and will help define the risks and range of uncertainty inherent to the PTU reservoirs while providing input to the geologic modeling as well as forming the basis for updated resource estimates.

Studies have been done to support the Fiscal Contract negotiations for a Pipeline Project and provide data to both the Owners and the State. Work included evaluation of PTU gas sales development costs, evaluation of production allocation to tracts for royalty purposes, and provision of information to evaluate commercial viability of development alternatives.

5. *In addition to sharing with DNR the Economic Spreadsheet Model for the gas injection only scenario (item #2 above), the Owners will carry out an economic evaluation of a gas sales only scenario based on the information developed under item #4 above.*

   a) *The Owners will also carry out a preliminary economic evaluation of a gas injection followed by gas sales scenario.*

   b) *The Owners will present the results of their evaluation of all three scenarios, and their sensitivities with respect to gas and liquids screening analysis, to ADNR during the term of POD 21. ExxonMobil will hold additional workshops with ADNR staff to review the economic spreadsheet calculations and other related model results.*

A review of the gas injection, gas sales, and combination cases and results of the preliminary screening analyses was held with the State Gas Cabinet, which included the DNR, on March 4, 2005. Input data for the preliminary economic evaluation of a gas sales only and a gas injection followed by gas sales scenario were provided to the DNR in the April 8, 2005 data submission and the results were qualitatively discussed in that submission. The gas injection case was reviewed in more detail in the May 24, 2005 workshop. The updated facilities screening study results for a gas sales development based on work during the past year was shared with the DNR in the June 29, 2005 presentation. ExxonMobil is available at the DNR's convenience to further discuss the model and results.

6. *Continue participation in baseline environmental surveys in the Point Thomson area. Activities include cooperative funding of Polar Bear denning surveys and report preparation, a Beaufort Sea waterfowl breeding report, a report on large animal (Caribou) use of riparian zones, and a report on experimental gravel re-vegetation plots.*

   The 2005 Polar Bear denning survey is currently underway and a report will be prepared at the conclusion of the survey. Reports have been finalized for the Beaufort Sea waterfowl breeding, large animal (Caribou) use of riparian zones and experimental gravel re-vegetation.

7. *Advance final negotiations toward a new Unit Operating Agreement with the objective of securing approval by the aligned Owners and the smaller interest Owners.*

   Negotiations are ongoing to finalize the new Unit Operating Agreement. In the last year significant progress has been made on two major issues, gas balancing and accounting. The Owners continue to move forward on an agreement that can be presented to management for approval.

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Richard J. Owen
Alaska Production Manager
Joint Interest U.S.

ExxonMobil
Production

October 18, 2006

DEPARTMENT OF
NATURAL RESOURCES
OCT 1 8 2006
COMMISSIONER'S OFFICE
ANCHORAGE

Mr. Michael L. Menge, Commissioner
Alaska Department of Natural Resources
550 West 7th Avenue, Suite 1400
Anchorage, Alaska 99501-3650

Dear Commissioner Menge:

On November 10, 2005, the Department of Natural Resources approved an extension to the obligations, including drilling commitments, in the May 24, 2002 Decision of the Director on the PTU Application for the Second Expansion and Third Contraction of the Unit Area (Expansion Decision). This extension was based on the expectation that the Fiscal Contract being negotiated for an Alaska Gas Pipeline Project would be approved and would resolve the Expansion Decision obligations. It now appears unlikely that the Legislature will act on the Fiscal Contract prior to the deadline in the current extension, so we propose resolving all matters associated with the Expansion Decision as outlined below.

The obligations in the Expansion Decision were based on a gas injection development for the Point Thomson Unit (PTU). In 2004, a gas injection development was determined to not be commercially viable. As a result and given progress made toward an Alaska Gas Pipeline Project, the PTU Working Interest Owners (PTU Owners) have been actively pursuing a gas sales development for PTU.

ExxonMobil, on behalf of the PTU Owners, proposes to resolve all outstanding obligations under the Expansion Decision by paying the Department of Natural Resources $20,000,000 and surrendering 20,000 acres from the PTU, as shown in the attached acreage map and lease description. All acreage remaining within the Unit will be subject to the significant commitments made by the PTU Owners as part of the Plan of Development submitted on October 18, 2006.

We believe this approach is in the best interest of the State and the PTU Owners. If acceptable, we would suggest that this settlement be documented, and that the associated payment and acreage release be completed by November 15, 2006.

Sincerely,

RJO:jpc
Attachments

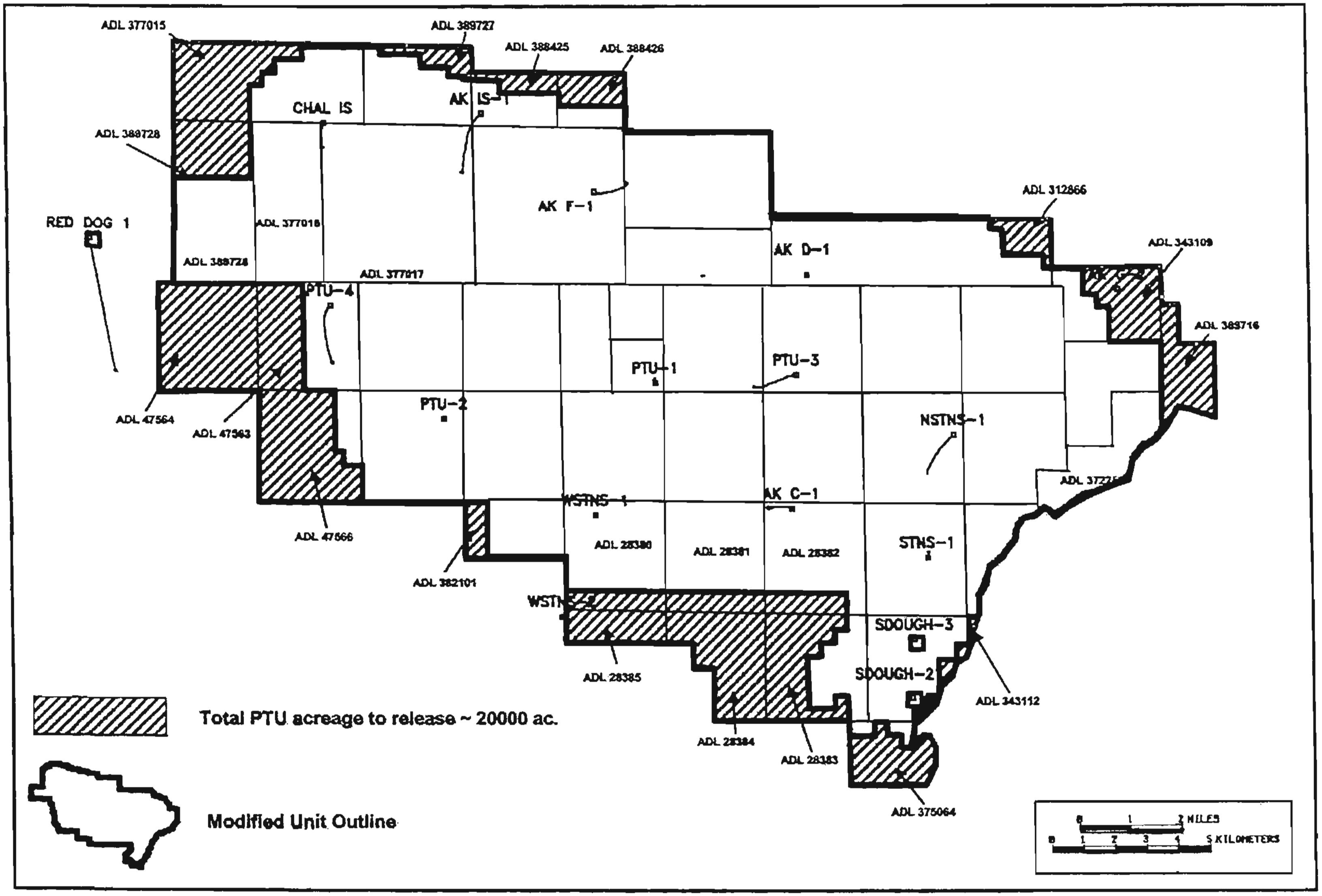
xc: Bill Van Dyke, Acting Director, DNR, Division of Oil & Gas
Ken Griffin, Acting Deputy Commissioner, DNR
PTU Owners

PTU22P_000018

Exc. 000429

PTU REC_000682

Point Thomson Unit



Exc. 000430

PTU Confidential Information Pursuant to PTUCA

PTU22P_000019

PTU REC_000683

POINT THOMSON UNIT LEASE DESCRIPTION
Acreage to be Retained/Released

Unit Tract	ADL Number	Original Lease Acres	Retained Acres	Surrendered Acres
19	28380	2544.00	2225.70	318.30
20	28381	2560.00	2240.00	320.00
21	28382	2560.00	2320.00	240.00
22	28383	2560.00	1200.00	1360.00
23	28384	1760.00	0.00	1760.00
24	28385	637.00	0.00	637.00
7	47563	2523.00	1280.00	1243.00
8	47564	2560.00	0.00	2560.00
10	47566	2533.00	390.00	2143.00
28	312866	4935.70	4555.70	380.00
29	343109	1970.16	700.16	1270.00
32	343112	3446.00	3180.00	266.00
43	375064	1062.00	246.60	815.40
33	377015	3554.30	1455.00	2099.30
42	382101	1280.00	960.00	320.00
39	388425	1162.08	717.00	445.08
40	388426	821.74	233.07	588.67
36	389716	1473.92	0.00	1473.92
45	389727	2143.39	1520.00	623.39
46	389726	2952.62	1968.42	984.20

DEPARTMENT OF NATURAL RESOURCES

NOV 0 3 2006

COMMISSIONER'S OFFICE ANCHORAGE

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

ADDITIONAL MATERIAL REGARDING PLAN OF DEVELOPMENT

FOR THE POINT THOMSON UNIT

BRIEF OF BPXA IN SUPPORT OF APPROVING THE MODIFIED PLAN OF FURTHER DEVELOPMENT AND OPERATION AND REVERSING THE DECISION THAT DISAPPROVED THE TWENTY-SECOND PLAN OF DEVELOPMENT

November 3, 2006

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Exc. 000434

PTU REC_000860

INTRODUCTION

ExxonMobil, as operator of the Point Thomson Unit ("PTU" or "Unit"), has submitted a modified Plan of Further Development and Operation ("Modified POD") for the Unit. BPXA is a 32% working interest owner ("Owner") in the PTU. ExxonMobil is submitting materials in support of approving the Modified POD. BPXA submits this brief as a complement to and in support of ExxonMobil's submissions. BPXA supports the Modified POD because it advances development of the PTU in accordance with the standards of a reasonable, prudent operator, and is in the mutual interests of the Owners and the State of Alaska.

The Modified POD commits to specific work that will further delineate the hydrocarbons within the PTU and advance production of all those resources. The Modified POD focuses on preparations for a gas sale, because the Owners believe that committing the PTU resources to gas sales will offer the greatest financial benefit to the State, as well as the Owners. The Commissioner of Revenue has issued preliminary findings and a determination regarding a proposed Fiscal Contract for a gas pipeline project, which corroborate that emphasizing preparations for gas sales from the PTU serves the State's best interest. The Modified POD also describes steps that will be taken simultaneously to support development of the PTU's resources if construction of a gas pipeline is delayed.

Submission of the Modified, multi-year POD that covers the period beginning on October 1, 2005, when the Twenty-First POD expired, mooted the Owners' appeal from the decision by the former Director of the Division of Oil and Gas disapproving the Twenty-Second POD submitted on August 31, 2005. Submission of the Modified POD renders it legally irrelevant whether the former Director erred in disapproving the prior submission. However, the Commissioner directed the parties to present their appeal arguments simultaneously with their arguments for approving the Modified POD. Thus, Part II.C of this brief presents legal analysis that demonstrates that the former Director erred in rejecting the Twenty-Second POD.

STATEMENT OF FACTS

DNR approved the PODs that governed the studies and development at the PTU through 2005

Ever since the PTU was formed in 1977, the Owners have spent substantial resources in search of a reasonable and prudent means of developing this Unit.[1] As the State has recognized, for many reasons the PTU is a particularly difficult field to develop.[2] Virtually all of the successful commercial development on Alaska's North Slope to date has been of oil resources, rather than gas.

The Owners' activities in support of developing the PTU have been governed by the series of PODs approved by the Department of Natural Resources ("DNR"). DNR's approval of each successive POD required the determination that the plan was a "reasonable" plan that protected all parties in interest, including the State.[3] As Department of Revenue ("DOR") Commissioner William Corbus recently wrote:

> Historically, continuance of the PTU unit and leases has, until the latter half of 2005, been with the concurrence of Commissioners of Natural Resources of several administrations of varied political perspectives. The PTU leaseholders have invested significant amounts of money over several decades in exploring this acreage and in addressing major

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1 *See generally* ExxonMobil Brief.

2 Prefiled Testimony of Gary Christman (hereafter "Christman PT") at 2; Prefiled Testimony of Donald Dunham (hereafter "Dunham PT") at 2; BPXA Ex. 58 at 23 (letter dated Oct. 18, 2006, from Commissioner Corbus to legislators referring to the "highly challenging technical demand and uncertainties associated with developing the Thomson Sand Reservoir in a safe and environmentally sound manner").

3 AS 38.05.180(p) (employing the same language as in former AS 38.05.180(m), which was in effect when the PTU was first formed); *see also* 11 AAC 83.343 (referring to the standards in 11 AAC 83.303).

technical issues. In recognition of those facts, each of these administrations has been a party to extending these leasehold interests.[4]

From the earliest history of the Unit, the Owners and DNR understood that the best way to develop the gas in the PTU would be in conjunction with commercial development and marketing of the gas in the Prudhoe Bay Unit ("PBU").[5] However, the Owners and operator did not just wait for someone to build a gas pipeline; they made substantial efforts to identify a prudent alternative that would enable development in the absence of a gas pipeline from Alaska's North Slope to markets.[6] In approving the PODs in effect through September 2005, DNR acknowledged each time that the Owners' efforts were reasonable and prudent and conformed with the requirements of the Unit Agreement and the law.

The PTU gas cycling project

With the concurrence of DNR, the Owners completed extensive studies of development options, focused particularly on a possible gas cycling project that would produce condensate that could be shipped to market through the Trans Alaska Pipeline System ("TAPS").[7] Early indications showed that the project was on the margin of being commercially viable, but BPXA as well as ExxonMobil and the other Owners devoted substantial resources to attempting to manage the risks and to design a reasonably prudent gas cycling project.[8]

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[4] BPXA Ex. 57 at 13 (letter dated Oct. 18, 2006, from Commissioner Corbus to Tom Irwin).

[5] The ExxonMobil Brief quotes from the POD approved for 1978: "If commercial quantities of gas are discovered, development of a gas market outlet will be related to studies to market gas from the Prudhoe area.".

[6] BPXA Ex. 58 at 24 (letter dated Oct. 18, 2006, from Commissioner Corbus to legislators, noting that the PTU Owners have "already spent an enormous amount of money attempting to monetize Point Thomson").

[7] BPXA Exs. 13, 14, 20, 21, 23, 24, 27, 28 (submission and approval of Seventeenth through Twentieth PODs); Dunham PT at 1-3.

[8] Dunham PT at 2-3; Prefiled Testimony of Steven Dunn (hereafter "Dunn PT") at 4-5.

As the gas cycling project was advanced into the Front End Engineering Design (FEED) phase, newly available data forced re-evaluation of the project. The newest, most reliable models of the subsurface characteristics of the PTU's Thomson Sand reservoir increased the likelihood that the reservoir is more disconnected than was previously believed.[9] Connectivity is one of the essential elements of a successful cycling project, since injector and producer wells must connect in order for cycling to be possible. The newest studies decreased the reliable estimates of the amount of condensates that could be produced by about 35%.[10] Around the same time, the detailed FEED work being done demonstrated that the estimated costs for constructing a gas cycling project had increased by approximately 30%. Between the decreasing estimates of production and the increasing estimates of costs, the per unit cost of development doubled.[11]

The PTU Owners kept DNR well-informed of their re-appraisals of the economic viability of the cycling project.[12] In the Twentieth POD, applicable from October 1, 2003, through September 30, 2004, DNR approved the operator's plans to re-examine the cycling project to try to cut costs -- but it was clear then that the gas cycling project could be problematic.[13] After additional briefings by the operator to DNR during the first half of 2004,[14] DNR approved the Twenty-First POD for the year from October 1, 2004, through September 30, 2005, and in so doing approved a plan that involved no further work on FEED, and instead

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9 BPXA Exs. 61, 63, 64; Dunham PT at 3.

10 Dunham PT at 3.

11 Dunham PT at 3.

12 BPXA Exs. 25, 27 at 3-4; Dunn PT at 2.

13 In approving the Twentieth POD in July 2003, DNR specifically noted that the Owners were still analyzing whether the gas cycling project could be made commercially viable. [BPXA Ex. 28 at 2].

14 BPXA Exs. 33, 61, 63, 64, 65.

emphasized developing the PTU for gas sales.[15] In a subsequent letter, DNR expressly acknowledged the Owners' assessment that "the gas cycling project indicates higher costs and lower liquid recovery than previously estimated" and that the Owners "determined that the gas cycling project is currently uneconomic."[16] DNR stated that it "appreciates the considerable expertise and resources that the Owners dedicated to evaluating the PTU gas cycling project." [BPXA Ex. 30 at 2]. At no time did DNR cite anything to contradict the Owners' determination that in 2004 and 2005 the gas cycling project was not commercially viable and not a project that a reasonable, prudent operator then would pursue.[17]

Planning for PTU gas sales

By October 2004, when the Twenty-First POD took effect, major events were occurring, both in Alaska and at the national level, that supported the focus on gas sales from the PTU. In 2003, the Alaska legislature amended the Stranded Gas Development Act to cover construction of a natural gas pipeline to transport gas from Alaska North Slope fields.[18] In 2004, the United States Congress passed the Alaska Natural Gas Pipeline Act, calling for federal action

[15] BPXA Ex. 34. The Twenty-First POD reported that significant cost reduction potential had been identified, but the reductions were not sufficient to yield a commercially viable gas injection project. [*Id.*]. DNR approved that POD conditionally on September 23, contingent on the operator supplying additional documentation; the operator appealed that requirement but then supplied the data. [BPXA Exs. 35, 36 at 8]. In criticizing the Twenty-First POD for not committing to supply data, DNR expressed no criticism of the conclusion that FEED should be suspended. [BPXA Exs. 35, 36].

[16] BPXA Ex. 30 at 1, 2. BPXA independently evaluated the data the operator provided and concurred with the conclusion that cycling was not commercially viable. [Dunn PT at 1]. Notably, gas cycling is not a common mode of development in retrograde condensate fields worldwide.

[17] Dunn PT at 3; *see also* BPXA Ex. 57 at 13 (including statement by Commissioner Corbus in October 2006 that the assertion that the PTU could be profitably developed without a pipeline project is "unsupported").

[18] Ch 4, SLA 2003 (adding AS 43.82.100(1) and related provisions).

to expedite the construction of a gas pipeline from Alaska's North Slope to the Lower 48 States.[19]

In January 2004, BPXA, ConocoPhillips, and ExxonMobil, all Owners in the PTU, applied to be considered a qualified Sponsor Group proposing a qualified project under a contract ("Fiscal Contract") pursuant to the Stranded Gas Development Act.[20] The Sponsor Group described a proposed project to build a gas pipeline to carry natural gas from the North Slope that could make gas available to markets in Alaska and elsewhere in North America. To be commercially viable, the pipeline would require commitments based on the known resources of gas from both the PTU and the PBU.[21] The Commissioners of both the DOR and DNR approved the Sponsor Group application in January 2004 [BPXA Ex. 32], and soon thereafter the State and the Sponsor Group began regular, intensive negotiations for a Fiscal Contract that would govern the terms under which a major pipeline project would be constructed.

In light of the determination that gas cycling was not commercially viable, and in light of the ongoing negotiations for a gas pipeline project that to be successful would require a commitment of PTU gas, the Twenty-First POD contained work commitments focused on

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19 15 U.S.C. §§ 720 - 720m (2006).

20 AS 43.82.100 - .130; BPXA Ex. 31.

21 BPXA Ex. 31 at 13 ("The project plan assumes the Alaska Gas Pipeline Project will be underpinned by gas supplied from leases within the Prudhoe Bay Unit (PBU) and Point Thomson Unit (PTU). Both of these resources would be necessary to support the pipelinc project.").

preparing the PTU Owners to participate in the earliest Open Season[22] for the pipeline. [BPXA Ex. 34 at 4-5]. As noted above, DNR approved this POD. [BPXA Ex. 35].[23]

During the term of the Twenty-First POD, the PTU Owners concentrated on completing a state-of-the-art model of the PTU's Thomson Sand reservoir, so they then could run simulations to establish the optimal means of developing the PTU reservoir for gas sales.[24] Using the available geologic models, the Owners developed a conceptual depletion plan for gas sales. [BPXA Ex. 55 at 14].

The PTU Owners also provided support to both the Sponsor Group and the State during their negotiations of a Fiscal Contract.[25] Throughout the negotiations, the plan remained that the PTU would be developed so that PTU gas could be committed to the pipeline project. DNR representatives were members of the State's negotiating team and understood the importance of including PTU gas in any pipeline project plan.[26]

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22 "Open Season" means a Federal Energy Regulatory Commission pre-subscription or open season, or a corresponding process on a Canadian regulated pipeline that is conducted in accordance with the rules and regulations in effect. In lay terms, during an Open Season, owners of gas offer commitments to ship defined quantities through the pipeline.

23 BPXA's representative to these meetings specifically recalls then-Commissioner Irwin stating that he expected the next POD would focus on developing the PTU in light of the pipeline negotiations. Dunn PT at 2.

24 BPXA Ex. 55 at 12-15. Dynamic modeling in now underway. BPXA Ex. 55 at 9.

25 BPXA Exs. 37, 38, 39, 70 (data requests); BPXA Exs. 69, 71, 72, 74, 76 (data provided).

26 Dunn PT at 3; BPXA 49 at 5 (Recital 11 of the Fiscal Contract agreed-to by the parties states specifically that "PTU Gas resources are essential to anchor the Project and achieve the economies of scale consistent with delivering ANS [Alaska North Slope] Gas to Canadian or United States markets at a competitive cost of supply. The terms of this Contract are necessary for PTU Owners to commit their Gas resources in future Open Seasons." (italics for defined terms omitted)).

The Twenty-Second POD as a logical extension of the Twenty-First POD

On behalf of all the Owners, ExxonMobil prepared to submit the Twenty-Second Plan of Development to DNR during the summer of 2005. The conversations between DNR and the PTU Owners prior to submission of the POD appeared generally supportive of the Owners' activities.[27] The Twenty-Second Plan of Development was drafted to be a logical extension of the prior year's plan.[28]

Like the Twenty-First POD, the Twenty-Second POD emphasized the work essential to prepare the PTU Owners to participate in the earliest Open Season. At the time the Twenty-Second POD was submitted, the State planned to have a mutually agreed-on form of the Fiscal Contract to submit to the public and the legislature before the end of the 2006 legislative session (a goal that in fact was achieved[29]). Compared to September 2004, when the Twenty-First POD was approved, nothing had changed with respect to the geological data to suggest that a reasonably prudent operator would pursue a PTU gas cycling project. Similarly, because DNR had accepted suspending FEED for the cycling project, nothing had changed with respect to advancing a cycling project closer to construction.

The former Director's disapproval of the Twenty-Second POD surprised BPXA.[31] BPXA's representative was particularly taken aback by the suggestions for what should be

27 Dunn PT at 3.

28 Dunn PT at 2; BPXA Exs. 44, 75.

29 BPXA Ex. 49.

31 Dunn PT at 3. The only clear area where the former Director and the Owners appeared to disagree before the Twenty-Second POD was submitted concerned whether the POD should contain a commitment to drill a well. Otherwise, the final version of the Twenty-Second POD incorporated the major changes that DNR requested to the draft version. [BPXA Exs. 42. 44]. The Twenty-Second POD did not contain the drilling commitment, but it would have been impossible to commit to complete a well into PTU's Thomson Sand within a one-year POD. [BPXA Ex. 44 at 1 (statement by the operator that a well "cannot be justified at this time, and the

contained in an "acceptable" POD.[32] DNR had no evidence that any reasonable, prudent operator would drill a well in less than a year, sanction a project within a year, and commit to completing all the steps that precede production (design, permitting, procurement, and construction) in just four years.

Developments following October 2005

The current DNR Commissioner extended the Owners' time to file an appeal from the former Director's decision denying the Twenty-Second POD [BPXA Exs. 48, 52, 53], and the Owners continued work to advance the PTU toward a plan of development predicated upon production of gas for delivery to a gas pipeline project. The Owners

- conducted extensive geologic modeling;
- examined facilities and pipeline design at a preliminary level, so they would be prepared to move into the more detailed Conceptual Engineering ("CE") phase;
- reviewed permit applications from the gas cycling project to identify what aspects remained relevant to a gas production project; and
- initiated the process of applying for pool rules with the AOGCC -- a prerequisite to any form of development. [BPXA Ex. 55 at 8-10].

The State and Sponsor Group agreed on a proposed Fiscal Contract [BPXA Ex. 49], and the DOR Commissioner issued Preliminary Findings and Determination, as required by the Stranded Gas Development Act,[33] detailing why the proposed Fiscal Contract is in the State's best interest. [BPXA Ex. 51]. Those Findings discuss the importance of having PTU gas available to commit to the pipeline. [*Id.* at FIF-ES-12 ("The Point Thomson Unit (PTU) . . . is an

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necessary well planning to safely and successfully drill an exploration/delineation well into the high pressure PTU formation has not been performed")]; *see also* Dunn PT at 3; Prefiled Testimony of Gary Christman (hereafter "Christman PT") at 4-5].

32 Dunn PT at 3.

33 AS 43.82.400.

important factor in the economic viability of the gas pipeline project.")]. However, the legislature did not act on the proposed Fiscal Contract, so the expectation that a Fiscal Contract would be in place by October 2006 was not realized.

In October 2006, the Owners submitted the Modified POD that is now before the Commissioner for approval. [BPXA Ex. 55]. This Modified POD contains commitments in excess of those set forth in the Twenty-Second POD, and for that reason the Modified POD extends beyond a single year.

The commitments of the Modified POD

Instead of imprudently trying to instantly develop the PTU resources, the Modified POD sets forth commitments to proceed through the systematic, comprehensive planning processes that are recognized to be, not just reasonable and prudent, but essential to the success of any major development project.[34] The Owners' recent experiences with the gas cycling project underscore the prudence and importance of this approach. There, they saw how advancing a project too rapidly could be imprudent, as would have been the case if facilities for the cycling project had been constructed before sufficient studies were completed.[35] During the term of the Modified POD, the Owners will:

- complete the process of planning for Conceptual Engineering for a gas sales project;
- conduct Conceptual Engineering[36]; and

34 BPXA Ex. 4 (1981 Rand study on successful projects stresses importance of planning); Ex. 77 (materials from the IPA Institute, the expert retained by the State during Fiscal Contract negotiations to teach a course on successful development of mega-projects, stress the importance of systematic, upfront planning); Prefiled Testimony of Corey Herod (hereafter "Herod PT") at 1-6 & Exs. CH-1, 2, 3 (attached to Herod Testimony).

35 Herod PT at 5. Pressure from DNR contributed to the decision to accelerate the engineering and permitting before all the subsurface analysis was completed. [BPXA Ex. 17].

36 The Owners have already approved funding for CE.

- complete the planning for permitting and the application for pool rules. [BPXA Ex. 55 at 4-5].

Although these planning concepts may sound simple, they are not. Each represents a significant investment of both manpower and financial resources -- and it would be unreasonable and imprudent to attempt to progress a major project to the development stage without laying this groundwork.[37]

The Modified POD also commits to further delineation of the PTU's resources through the drilling of an appraisal well. Any well drilled into PTU's Thomson Sand will be a technically difficult and expensive well, for a number of reasons, including that the well

- must be deeper than most North Slope wells;
- must contend with higher underground pressures than most North Slope wells; and
- must be designed for drilling into gas-bearing sands rather than oil-bearing sands.[38]

Available drilling rigs must be modified, and the well itself and other essential equipment must be designed specifically to respond to the unusual characteristics of the PTU reservoir.[39] Providing time for proper planning and procurement of proper equipment is essential to ensure that the well can be drilled safely and will obtain key information for planning production from the reservoir.[40] Drilling is planned for winter 2008-09. Because of the needs to plan and to

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37 Herod PT at 2-4; Prefiled Testimony of Peter Hanley (hereafter "Hanley PT") at 1-3 & Exs. PH-1, 2, 3 (attached to Hanley Testimony); *see generally* BPXA Ex. 4 (Rand report), Ex. 77 (IPA materials).

38 Christman PT at 2; Dunham PT at 2; BPXA Ex. 58 at 23 (quoted *supra* n.2).

39 Christman PT at 1-4.

40 *Id.* at 1-5

procure an appropriate rig and other equipment, no reasonable, prudent operator would plan to drill a well of this kind sooner than that.[41]

Finally, in recognition that the future of the proposed Fiscal Contract is uncertain, the Modified POD contains the Owners' commitment to continue the process of appraising alternatives to development other than for gas sales. Some of these alternatives have been studied and rejected before, but economic conditions change,[42] technology advances, and projects that once were determined to be not commercially viable might be evaluated differently in light of changing conditions.[43] Under the Modified POD, the Owners will update computer simulations that will allow comparisons of different development options, including combination projects such as gas cycling followed by gas sales, or gas storage at Prudhoe Bay followed by gas sales. They will also gather the information to compare the costs of different development strategies. [BPXA Ex. 55 at 5-6].

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41 *Id.* at 5.

42 Bill Van Dyke, Acting Director of the Division of Oil and Gas recently observed that the Petroleum Production Tax (PPT) enacted by the legislature in August 2006 was specifically designed to encourage new projects by lowering the cost of exploration and development. *Oil leasing generates $3.2 million,* ANCHORAGE DAILY NEWS, Oct. 28, 2006, at D1.

43 *Cf.* Dunn PT at 4-5 (describing how a project to develop the PTU through Badami once appeared economically viable, but the evaluation changed when economic conditions changed); Dunham PT at 1-4 (describing how the gas cycling project appeared economically viable at one time, but ceased to be when economic conditions changed).

ARGUMENTS

I. THE COMMISSIONER SHOULD APPROVE THE MODIFIED POD, BECAUSE IT COMPLIES WITH THE PTU AGREEMENT AND APPLICABLE REGULATIONS AND APPROVAL IS IN THE BEST INTEREST OF THE STATE.

A. LEGAL STANDARDS

1. The Unit Agreement

The Unit Agreement for the Development and Operation of the Point Thomson Unit ("PTU Agreement") is the contract between the State and the lessees,[44] and governs the operator's obligations to develop the Unit. Under Section 10, the operator expressly covenants "to develop the unit area as a reasonably prudent operator in a reasonably prudent manner" ("RPO Standard"). [BPXA Ex. 2 at 8 § 10]. The operator must periodically submit to DNR a POD providing for the timely development of the unit area under the RPO Standard. [*Id.*]. Once approved, the POD sets forth the operator's development obligations for the period of the POD.

The RPO Standard contained in the Unit Agreement is aligned with generally accepted oil and gas principles that dictate that virtually every claim of improper operation should be analyzed under the RPO Standard:

> Every claim of improper operation by a lessor should be tested against the general duty of the lessee to conduct operations as a reasonably prudent operator in order to carry out the purposes of the oil and gas lease.[45]

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[44] *See Exxon Corp. v. State,* 40 P.3d 786, 788 (Alaska 2001) ("A unit agreement is a contract between the department and lessees[.]"). The original Point Thomson Unit Agreement took effect on August 1, 1977, and was amended in 1982 and 1985. BPXA Ex. 1 is the original PTU Agreement; BPXA Exs. 3, 5, 7, 8, and 11 relate to amendments. BPXA Ex. 12 is a version compiled by DNR, which is intended to reflect all the amendments.

[45] *Young v. Amoco Production Co.*, 610 F. Supp. 1479, 1485 (D.C. Tex. 1985) (quoting *Amoco Production Co. v. Alexander*, 662 S.W.2d 563, 568 (Tex. 1981)).

The RPO Standard generally requires the operator to act (1) in good faith; (2) with the expertise and competence of one engaged in the oil industry; and (3) with due regard to the mutual interests of both the lessee and the lessor.[46]

The RPO Standard is not just an obligation on a lessee or operator; it is also a limitation on what a lessor, including a government lessor, may demand from a lessee. This is so because the RPO Standard is based upon principles of good faith and fair dealing, which applies to both parties to a contract, and upon the duty of a lessee and lessor to cooperate.[47] The Owners and operator would not act in accordance with the Unit Agreement if they submitted a POD that did not contain a commitment to act in a reasonable, prudent manner. Concomitantly, DNR would not act in accordance with the Unit Agreement if it disapproved a POD on the ground that it did not contain certain commitments that DNR would like to see included, if DNR lacks a basis for concluding that a reasonable, prudent operator would make those commitments.

The Owners' interests must be considered in any diligence-determination conducted under the RPO Standard.[48] The statute under which the PTU Agreement was

[46] *See Saudner v. Mid-Continent Petroleum Corp.*, 292 U.S. 272, 280 (1934) (stating that RPO Standard requires lessee to do "[w]hatever, in the circumstances, would be reasonably expected of operators of ordinary prudence, having regard to the interests *of both lessor and lessee*" (emphasis added)); *Mendota Coal & Coke Co. v. Eastern Ry. & Lumber Co.*, 53 F.2d 77, 81 (9th Cir. 1931) (stating lessee must "proceed with due regard to his own interests, as well as those of the lessor"); *Burlington Resources Oil & Gas Co.*, 146 IBLA 335 (1998) (stating that an operator is not obligated to pursue uneconomic projects even if there is some benefit to the lessor, but must act only as a reasonably prudent operator under the circumstances, with regard to the interests of both the lessor and lessee); *see generally* JOHN LOWE, OIL AND GAS LAW 308 (1988) ("reasonably prudent operator must consider his lessor's interests while pursuing his own").

[47] *See* HOWARD R. WILLIAMS & CHARLES I. MEYERS, OIL AND GAS LAW (hereafter "WILLIAMS") § 802.1 (2005); *Casey v. Semco Energy, Inc.*, 92 P.3d 379, 384 (Alaska 2004) (reiterating the well-established point that the covenant of good faith and fair dealing is implied in every contract in Alaska).

[48] The current regulations require that the State ensure that a plan "provide for the protection of all parties of interest," not just the State. *See* 11 AAC 83.303(a).

approved makes that point. It provides that a unit agreement may be approved only if it protects the interests of all parties.[49] Many cases have made the same point and further announced the rule that the obligation to produce with diligence does not obligate an operator to drill at a loss.[50]

A decision by the Interior Board of Land Appeals (IBLA) in a case called *Nola Grace Ptasynski* shows how the RPO Standard serves to limit a government lessor, even where express lease obligations governing the general subject matter might appear to authorize the government to demand unprofitable drilling.[51] In the *Nola Grace Ptasynski* case, the government's regulation and the standard lease terms both provided that a lessee must drill any wells necessary to protect the leased lands from drainage or else pay compensatory royalties. When the government lessor thought the leased acreage was being drained, it notified the lessees that they must drill a well or pay compensatory royalties. The lessees responded, among other things, that the well could not be drilled profitably and that they had diligently developed the acreage. The government lessor asserted that it did not matter whether the lessee could provide evidence that a paying well could not be drilled on a legal location; the government claimed that, under the lease and the regulation, the duty to drill a well to protect against drainage was absolute.

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49 AS 38.05.180(p) (formerly AS 38.05.180(m)).

50 *See, e.g., Brewster v. Lanyon Zinc Co.*, 140 F. 801, 814 (8th Cir. 1905) ("[L]essee must . . . proceed with due regard to his own interests, as well as those of the lessor. No obligation rests on him to carry the operations beyond the point where they will be profitable to him, even if some benefit to the lessor will result from them." (quoted in WILLIAMS § 806.3)); *see also Young,* 610 F. Supp. at 1485-86 ("the lessee's obligation as to development is measured by this same reasonably prudent operator standard in that he is not required to begin or continue in the performance of such operations unless there is a reasonable expectancy of profit not only to the lessor, but also to the lessee").

51 *Nola Grace Ptasynski*, 63 IBLA 240 (1982).

The IBLA rejected the government lessor's claim that it was authorized to demand that the lessee drill an unprofitable well. The IBLA reasoned that the RPO Standard applied, and was not abrogated by any language in the lease or regulation. The IBLA noted that the "*prudent operator rule is, in essence, a limitation* on the generally recognized implied duties of a [lessee . . . and] courts have long noted that: 'Under the usual statement of the standard for prudent operation there is no obligation upon the lessee to drill offset wells unless there is a sufficient quantity of oil or gas to a pay a reasonable profit to the lessee.'"[52] The IBLA further observed that no rational lessee would drill an offset well if it would not be profitable.[53]

The IBLA gave three main reasons for rejecting the government lessor's claim that, because the lease and regulation contained an express requirement that a lessee must drill, the lessor could demand such drilling, even when a reasonably prudent operator would not drill. First, the IBLA held that the language of the regulation did not clearly nullify the prudent operator rule. Second, the regulation, like the lease, could be read as implicitly embracing the prudent operator rule. The final reason is quoted below:

> Finally, the Associate Solicitor's conclusion is suspect precisely because it results in the imposition of economic obligations on the lessee which clearly do not involve rational economic considerations. If the recoverable oil underlying the land where drainage is occurring is insufficient to support the cost of recovery, no intelligent landowner would make out-of-pocket expenditures to drill a well. The oil lost through drainage is not an economic loss to the landowner, because its attempted recovery would actually cost the landowner money. Thus, while in some conceptual sense the landowner has lost the oil drained, there has been no economic loss occasioned by the drainage. The landowner is no worse off than he was before the offending well commenced to drain his meager reserves, and considerably better off than he would be if he tried to recover them by drilling an offset well. ***A lessee should not be obligated to pursue a course of economic folly which a prudent owner would forego.***

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52 *Id.* at 247 (*quoting Olsen v. Sinclair Oil & Gas Co.*, 212 F. Supp. 332, 333 (D. Wyo. 1963) (emphasis added)).

53 *Id.*

> It is difficult to understand why the Government would contend that, while no prudent operator would drill in such a situation, it is nevertheless required that the Government's lessee drill or pay compensatory royalty. For one thing, it is hard to quantify proper "compensation" when there is, in point of fact, no real economic loss to the Government through drainage. The Government is not seeking to be made whole, but, on the contrary, is attempting to obtain an actual benefit beyond any economic loss actually suffered. It may be that the United States might desire to enforce such a requirement. But, in the absence of a regulation specifically countenancing this result, thereby giving notice to all prospective lessees, we cannot agree with the Associate Solicitor's analysis. Accordingly, we expressly hold that ***where the evidence establishes that a prudent operator would not drill an offset well to protect against drainage there is no requirement that the lessee nevertheless either drill the offset well or tender compensatory royalty.***[54]

Although the duty to develop, which is at issue in the current case, is different in some respects from the duty to drill an offset well, both are based on the same rationale of a duty to cooperate and are subject to the same RPO Standard. As discussed below, the Modified POD meets the RPO Standard. Where, as here, the State has made no showing that the gas cycling project would be commercially viable, then it cannot demand that the Owners go forward with such development. That demand would violate the contractually agreed-to RPO Standard in Section 10 of the PTU Agreement, and it would be inconsistent with the statutory duty of DNR to protect all parties, not just the State.

2. Significant amendments to the Unit Agreement

ExxonMobil's submission to the Commissioner provides a detailed history of the amendments of the PTU Agreement.[55] One portion of the history deserves some emphasis.

The PTU Agreement originally provided that the operator would apply for approval of a Participating Area almost immediately (within one month if practicable) after

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54 *Id.* at 251-52 (footnotes and citations omitted) (emphases added).

55 *See also*, BPXA Exs 3, 5, 7, 8, and 11 (documenting the history of certain lease amendments).

completion of a well capable of producing in paying quantities. [BPXA Ex. 2 at 7 § 11]. In 1982, after discussions between DNR and the lessees, that provision was amended.[56] The amendments led to the version of the PTU Agreement now in effect, which states that no application for a Participating Area needs to be submitted until "At least ninety (90) days prior to commencement of production of unitized substances into a pipeline or other means of transportation to market." [BPXA Exs. 8, 11, 12 at 11 § 11]. The amendments reflected the parties' recognition that the PTU lessees could not be compelled to take on themselves the burden of constructing a pipeline or otherwise creating a market, and therefore it would be unfair and unreasonable to expect the lessees to begin production right after a discovery, potentially years before the produced gas or oil reasonably could reach a market.

The amendment of Section 11 of the PTU Agreement, given final approval in 1985, brought that section into line with a provision that has been in Section 25 from the beginning. Section 25 of the PTU Agreement addresses unavoidable delay, sometimes referred to as "*force majeure*." Section 25 of the PTU Agreement, like Section 27 of the DL-1 lease form that applies to many of the leases in the PTU, explicitly treats lack of transportation as a type of "*force majeure,*" which excuses any obligation under the Unit Agreement.[57]

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56 In explaining the rationale for the amendment, ExxonMobil noted that the form lease was developed for use in the Lower 48 States, and conditions on Alaska's North Slope were quite different. [BPXA Ex. 3].

57 BPXA Ex. 2 at 17 § 25 ("All obligations under this agreement requiring the Unit Operator to commence or continue drilling . . . shall be suspended while . . . the Unit Operator despite the exercise of due care and diligence is prevented from complying with such obligations, in whole or part, by . . . uncontrollable delays in transportation . . . ."); BPXA Ex. 1 at 4 (State of Alaska Competitive Oil and Gas Lease Form No. DL-1 (revised October 1963), Section 27 states: "Should Lessee be prevented from complying with any expressed or implied covenant of this lease, from conducting drilling operations thereon, or from producing or marketing oil or gas from said land after efforts made in good faith, by reason of . . . failure or lack of adequate transportation facilities . . . then while so prevented and for a reasonable time

The concern of all parties about problems resulting from lack of transportation to market is understandable. At the time the DL-1 leases were issued, TAPS did not exist, so the ability to market either oil or gas from Alaska's North Slope was a huge question. The PTU Agreement was signed in 1977, the year oil first flowed through TAPS, but the reliability of that mode of transportation remained untested; then, as now, there was no means to transport oil from PTU to TAPS and no means to transport any produced gas to a market.

The fact that years have passed and there is no natural gas pipeline is not the fault of the PTU lessees. No principle of oil and gas law could be read to require a lessee to construct a multi-billion dollar pipeline.[58] The lack of a pipeline or other means of transportation is highly relevant to the type of POD a reasonable, prudent operator at PTU will submit. Simply put, no reasonable, prudent operator would produce gas from the PTU without a means to transport it to market. DNR accordingly approved a succession of PODs that did not include producing gas without a means for transporting it to market.

3. Leases, Statutes, and Regulations

The PTU Agreement was properly approved and is consistent with the statutes and regulations that existed in 1977. The development obligations in the PTU Agreement control over any inconsistent obligations that might be imposed

after within to resume operations, Lessee's obligation to comply with such covenant shall be suspended and Lessee shall not be liable for damages for failure to comply therewith.").

[58] *See infra* n. 67 (citing cases).

- under the leases, as expressly provided in the PTU Agreement[59] or
- under current regulations, as expressly provided in both the PTU Agreement and in the regulations themselves.[60]

When the PTU Agreement was adopted, the only statute or regulation that mentioned Plans of Development was former AS 38.05.180(m), which was essentially identical to the current AS 38.05.180(p). The pertinent language in this statute provides that DNR may require the operator of an oil or gas unit to operate in accordance with a "reasonable" unit plan of operation, and that the plan must "adequately protect all parties in interest, including the state." The State's regulatory scheme first mentioned Plans of Development in the version of 11 AAC 83.343 adopted in 1981, but that version contained no criteria by which a POD should be evaluated.

The current versions of 11 AAC 83.303 and .343 were promulgated in 1983, six years after the effective date of the PTU Agreement. Section 303 sets forth the criteria that should be considered when DNR evaluates a Plan of Development.[61] Section 303(a) provides that, when the Commissioner evaluates a POD, the Commissioner must consider whether the

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59 Section 18 of the PTU Agreement provides that the "terms . . . of all leases . . . are hereby expressly modified and amended to the extent necessary to make the same conform to the provisions" of the PTU Agreement. [BPXA Ex. 2 at 13]. The DL-1 lease form that is the form of most of the PTU leases is generally consistent with the Unit Agreement's development obligations. [BPXA Ex. 1 § 20].

60 The Unit Agreement states explicitly that it incorporates and is controlled by the pertinent oil and gas statutes and regulations in effect at the time the Agreement took effect, and that later-enacted statutes and regulations apply only to the extent not inconsistent with the terms of the Agreement. [BPXA Ex. 2 at 1-2 § 1]. The current regulations contain comparable provisions. *See* 11 AAC 83.301(b) ("11 AAC 83.301 - 11 AAC 83.395 apply to an existing oil and gas lease or approved unit agreement where not inconsistent with the lease or unit agreement or regulations in effect on the effective date of the lease or unit agreement.").

61 11 AAC 83.303(c)(3) and .343(b) (both establishing that the criteria of .303(a) and (b) govern approval of a POD).

POD is "necessary or advisable to protect the public interest."[62] That section states that a POD protects the public interest and should be approved if it

- promotes conservation of all natural resources;
- promotes prevention of economic and physical waste; and
- protects all parties of interest, including the State.[63]

Six secondary factors should be considered when evaluating the first three criteria.[64]

These later-enacted regulations may apply to evaluation of a POD for PTU only if they are consistent with the RPO Standard and other provisions explicitly stated in the Unit Agreement. The concepts conveyed in the regulations are not dissimilar from the broad concepts stated explicitly in the Unit Agreement and from the concept of a "reasonable" plan that protects the interests of all parties that is stated explicitly in the governing statute. However, DNR may not interpret or apply the regulations in a way that

- furthers the State's interests while ignoring the Owners' interests, or
- reads out of existence provisions of the PTU Agreement.

For example, the PTU Agreement contains the *force majeure* provision discussed in the preceding section, which relieves the Owners of their duty to produce in the event of "uncontrollable delays in transportation." [BPXA Ex. 2 at 17 § 25]. Similarly the DL-1 lease form relieves a lessee from that duty in the event of a "failure or lack of adequate transportation facilities." [BPXA Ex. 1 at 4 § 27]. These provisions are not found in the current oil and gas

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62 11 AAC 83.303(a).

63 *Id.*

64 11 AAC 83.303(b). Those factors were written specifically to guide the decision whether to approve a proposed new unit, but they can be adapted to apply to the decision whether to approve a proposed POD. The final factor is all-embracing, and, like AS 38.05.180(p), makes clear that the ultimate question is whether the plan is in the public interest.

model unit agreement.[65] To the extent that the former Director's decision can be read as obligating the Owners to begin production from the Unit within four years even though there is no pipeline,[66] this reading would be inconsistent with the PTU Agreement, with the DL-1 Lease Form, and with the established principle of oil and gas law that the implied duty to market does not include the duty to build a pipeline.[67]

The current regulations can be interpreted readily in a way that is consistent with the PTU Agreement. The appropriate analysis should focus on whether the Modified POD describes the operations of a reasonable, prudent operator and whether it serves the interests of all parties, including the State. The analysis should consider whether the Modified POD promotes conservation of the resource and prevention of economic and physical waste, which, of course, are just parts of the RPO Standard. The analysis would not, however, consider whether the Owners should be required to build a pipeline or to create a market where none exists.

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65 It is neither good nor bad that there are differences among unit agreements. What may have been in the parties' best interests at one point in time may not be what would have been in the parties' best interests at another point in time. The State, however, may not recast an agreement after it has made one, as explicitly acknowledged in both the PTU Agreement and the State's own regulations.

66 Inconsistent with his seeming imposition of a duty to build a pipeline, the former Director also stated that the Owners have no control over the construction of a natural gas pipeline. [BPXA Ex. 46 at 16].

67 *See, e.g.*, RICHARD W. HEMINGWAY, THE LAW OF OIL AND GAS § 8.9(c) (3d ed. 1991); *Craig v. Champlin Petroleum Co.*, 435 F.2d 933, 938 (10th Cir. 1971) (no duty to build gathering lines and a processing plant to connect to a field nine miles away, where gas prices were higher); *Kretni Development Co. v. Consoliated Oil Corp.*, 74 F.2d 497, 500 (10th Cir. 1934) ("a lessee [may be] obligated to put forward a reasonable effort to market gas produced on the leased premises, but certainly that duty does not extend to the point of providing pipe line facilities ninety miles in length at a large outlay of money with an extending financial hazard die to possible exhaustion of the supply and other frequently encountered factors, in order to reach a market at which the product may be sold"); *Ashland Oil & Refining Co. v. Staats, Inc.*, 271 F. Supp. 571, 575 (D. Kan. 1967) ("We will not so enlarge the lessee's duty to market production so as to require it to devote a long and costly gathering system to transport gs to the nearest commercial market.").

B. The Modified POD Describes The Actions Of A Reasonable, Prudent Operator.

1. The Modified POD Contains Significant Work Commitments To Develop PTU For Gas Sales.

The Modified POD describes detailed work commitments designed to allow the Owners to participate in the initial Open Season for a North Slope gas pipeline. Participation in an Open Season requires confidence about the amount of natural gas that can be produced. Accordingly, the Modified POD calls for completing the dynamic models (also referred to as simulations) that show how fluids would flow underground if wells were drilled at certain locations. These studies will assist in developing an optimal depletion plan. This work has begun, and is scheduled for completion in early 2007. [BPXA Ex. 55 at 3].

A reasonable, prudent operator would not plan for development without first completing this type of dynamic modeling, based on the best, most comprehensive static models to describe the subsurface characteristics.[69] The PTU Owners' experience with the gas cycling project illustrates this point well. There, the Owners spent substantial sums toward design and planning simultaneously with the dynamic reservoir modeling for a gas cycling process. When newly available geologic interpretations forced the Owners to downgrade the estimates of the amount of condensate that could be produced through cycling, they were able to suspend the engineering work on the cycling project without incurring the unnecessary expense that would have resulted if they had rushed into construction without waiting for the geologic data.

A second focus of the Modified POD is on Conceptual Engineering ("CE") for a gas sales project. CE is the second major step in the systematic planning process that all major

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[69] BPXA Ex. 77 (Module 4 on the importance of completing basic data gathering).

companies use when approaching a major project.[70] It would only be reasonable and prudent to adhere to this industry standard. For a project the size of any PTU development, a reasonable prudent operator expects to spend approximately one year and $5 to $10 million on CE.[71] The Modified POD fits this pattern by planning a year in the CE stage. [BPXA Ex. 55 at 3]. The detailed planning process shown in the Modified POD comports with the industry standard, and it would not be reasonable or prudent to rush into development without systematically working through the key stages of the planning process. This type of advance planning permits thoughtful decisions to be made before materials are ordered and construction workers are hired. The frontloading of design and planning may appear to an outsider as a way to delay development, but the opposite is true. Experience by prudent oil and gas operators over many decades has shown that CE results in having the project completed faster, safer, and in a more cost-effective manner. Failure to provide for this type of systematic planning would sharply reduce the likelihood that the project will succeed at all.[72]

A third aspect of the Modified POD includes work that will prepare the operator to submit applications for essential permits. Though "prepare to permit" may sound like a non-event, fully understanding the complex permitting process establishes without question that preparing to permit requires substantial time and expertise, and that devoting the time to prepare for permitting will materially advance the ultimate development of the project. Testimony from Peter Hanley, one of the foremost experts on permitting for oil and gas development projects on Alaska's North Slope, describes the work that a permit applicant must do in advance of

70 Herod PT at 3-4 & Exs. CH-1, 2, 3.

71 Herod PT at 3.

72 BPXA Ex. 4 at 87 ("It is virtually a platitude that time spent in planning and preparation pays off"), Ex. 77 at Module 6; Herod PT at 1.

submitting any permit applications, and how extensive upfront, advance work prevents delays as the project proceeds. Based on his experience, the approximately 16 months allocated by the Modified POD to regulatory permitting planning is a reasonable time frame.[73]

A fourth significant aspect of the work under the Modified POD is establishment of a data room for the AOGCC, so the AOGCC and its consultants may make independent determinations on pool rules to provide for conservation of the resource. Because the AOGCC may rely on the modeling described above, it is imperative that the models be as accurate as possible. Following study, the AOGCC would be prepared to review the operator's application for pool rules. Early establishment of the data room (as provided for by the Modified POD) will allow the AOGCC to issue timely pool rules.

The Modified POD also commits to drill a well into the Thomson Sand on the earliest prudent schedule.[74] The dynamic modeling now being done will assist in deciding the optimal location for the bottomhole of the well. The drilling results, in turn, will provide information to be incorporated into future, more refined models that can be used in designing and executing the gas sales project. [BPXA Ex. 55 at 5].

In sum, the Modified POD contains commitments to important steps that will advance development and production of the PTU through gas sales. The systematic planning reflects the actions of a reasonable, prudent operator. The Modified POD will meaningfully and deliberately advance the gas sales project that will serve the best interests of the State and the Owners.

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73 Hanley PT at 1-3 & Exs. PH-1, 2, 3.

74 Christman PT at 1-5.

2. The Modified POD Contains Significant Work Commitments To Address Alternative Paths To Development In The Event The Alaska Gas Pipeline Project Is Delayed.

Although the PTU Owners agree with the DOR Commissioner that the development of a gas pipeline project is in the State's best interest and that committing PTU gas to the pipeline project is essential for the pipeline to succeed,[75] the Owners also understand the possibility that the pipeline project may be delayed. Consequently, the Modified POD includes commitments to devote substantial resources to continuing to attempt to identify a commercially viable alternative development that a reasonable, prudent operator would pursue if the major pipeline project were deferred.

As with the commitments regarding the gas sales project, the commitments regarding study and screening of alternative development projects comport with the planning processes of all major companies considering major projects.[76] The Owners have identified a number of alternative possible projects, either as stand-alone projects or combination projects. These include the gas cycling option (previously advanced to FEED but now suspended), gas cycling followed by gas sales, and gas production for storage at PBU, followed by gas sales.[77] During the term of the Modified POD, the Owners will study both the geologic and technological components of these alternative development possibilities. They will complete and review simulations of flowstreams, and they will retain the contractors with expertise to provide

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75 BPXA Ex. 51 at FIF-ES-12, FIF-55, Ex. 57 at 13 (Commissioner Corbus recently reiterated that the decision to address the PTU in the Fiscal Contract was "a reasonable and necessary step given the importance of PTU resources and deliverability to the fiscal contract"), Ex. 58 at 23 (Commissioner Corbus wrote that PTU reserves and gas deliveries "will play an integral part in the proposed gas pipeline project").

76 Herod PT at 5-6; *see* BPXA Ex. 35 at 2 (DNR wrote in September 2004 that "A prudent unit operator should evaluate all alternatives to develop unitized substances.").

77 BPXA Ex. 59; Dunn PT at 6.

preliminary designs and cost estimates.[78] With comparable data on the different options, they will be able to make an informed choice on which, if any, project appears most economic to pursue. Past study of these alternatives has indicated that these projects were not commercially viable at the time they were studied -- but technology advances, relative costs change, and the newly enacted Petroleum Production Tax represents a major modification of the State's economic environment.[79] Additionally, information learned through the drilling may affect the reappraisals of these development possibilities. [BPXA Ex. 55 at 6].

The commitment to appraise and re-appraise a variety of alternative options, while concentrating on the project that currently appears most viable and most in the State's interest, represents the action of a reasonable, prudent operator.

3. The Modified POD Promotes Conservation Of The Resources.

It has long been recognized that unitized development reduces disruption of the environment and preserves subsistence access in ways that isolated, lease-by-lease development would not.[80] Moreover, as DNR has recognized, unitized development promotes conservation of the resources.[81] The Modified POD provides for unitized development.

The Modified POD commits the Owners to work closely with the AOGCC. The Owners' efforts to develop the most up-to-date, comprehensive, reliable static and dynamic models of the PTU's main reservoir should assist the AOGCC's analyses. Approval by the

78 BPXA Ex. 55 at 5-6; Dunn PT at 5.

79 *See* BPXA Ex. 57 at 18 (Commissioner Corbus recently observed that a gas cycling project at the PTU might be more economic after passage of the PPT); *see also supra* n.42.

80 This is one point on which the Owners and the former Director agree. *See* BPXA Ex. 46 at 20.

81 *See, e.g.*, BPXA Ex. 22 at 24.

AOGCC of pool rules plan will signify that agency's determination that the oil and gas resources are being appropriately conserved.

4. The Modified POD Promotes Prevention Of Economic And Physical Waste.

The systematic planning processes embraced by the Modified POD reflect the industry standard. As discussed above, those processes have been developed over decades to provide the best way to advance a major project efficiently and without waste. All reasonable, prudent operators engage in staged planning, because devoting time to gathering information, analyzing risk, and making informed decisions early in the process prevents spending money imprudently later on.[82] It would be irresponsible and inconsistent with the RPO Standard to skip the planning stages and to sanction a major development project within the time period of the Modified POD. Because of a worldwide development boom, construction costs are increasing rapidly, so sound planning that avoids risks and waste is more important than ever.[83] The commitments to planning outlined in the Modified POD serve the goal of advancing development efficiently while promoting prevention of economic and physical waste.

5. The Modified POD Covers The Period Of Time That Is Reasonable To Accomplish The Activities Described.

The Modified POD covers a five-year period, including the one year that has elapsed since the Twenty-First POD expired and four years forward from October 1, 2006. This time is necessary to allow a reasonable, prudent operator to complete the activities in the Modified POD.

Major time constraints surround the commitment to drill a well into the PTU's Thomson Sand. The Modified POD anticipates commencement of drilling early in 2009. As

82 BPXA Exs. 4, 77; Herod PT at 1-5.

83 Herod PT at 6.

detailed in the testimony of Gary Christman, all the suitable drill rigs on the North Slope are already contracted for the 2007 and 2008 drilling seasons. From this fact alone, it would be extremely difficult to plan for drilling in the PTU before 2009.[84] Substantial preparation for drilling -- including well design, rig modification design, procurement of materials, and planning for and obtaining essential permits -- will go on while waiting for a suitable drill rig to become available.[85]

Because the well is complex, and because successful and safe drilling will require procuring specialty materials for the well and associated drilling equipment, circumstances beyond the Owners' control may require that the drilling be continued into a second season.[86] Summer drilling could complicate the permitting process, so any additional drilling might be scheduled for winter 2010 rather than summer 2009.[87] For this reason, the Modified POD shows a drilling contingency period extending through early 2010.

After the well is drilled, experts need time to analyze what was learned through the drilling. The preliminary design and cost estimations that are developed in the CE stage can be completed in parallel with planning for and drilling the well. However, any further effort to progress a project should take account of what is learned from the drilling. In FEED, engineers determine the number and location of wells, plan facilities in greater detail, and obtain price quotes from particular vendors for major project components.[88] The experience with the gas cycling project, where the Owners withdrew from FEED because of new analyses concerning the

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84 Christman PT at 1-2.

85 *Id.* at 2-4; Hanley PT at 3-5.

86 Christman PT at 2-4.

87 Hanley PT at 4.

88 Herod PT at 3.

subsurface characteristics of the reservoir, shows the wisdom of generally scheduling FEED for any future project at the PTU to begin after this well is drilled.[89]

Understanding the work commitments of the Modified POD makes plain that any reasonable and prudent operator would allot five years for the work that has been completed and the work that is planned.

C. THE POD PROTECTS THE INTERESTS OF ALL PARTIES, INCLUDING THE STATE.

One of the Owners' goals in the Modified POD is to conduct the work necessary to position the Owners to participate in the initial Open Season for a North Slope gas pipeline. Under the Stranded Gas Development Act, the DOR Commissioner determined that the Fiscal Contract negotiated between the Sponsor Group and the State is "in the long-term fiscal interests of the state."[90] As described by the State, the inclusion of the PTU gas is essential to a successful pipeline project; without a commitment of the PTU's gas, the pipeline project would not be commercially viable.[91] The DOR Commissioner recently reiterated the State's view that inclusion of the PTU in the Fiscal Contract "was a reasonable and necessary step, given the critical importance of PTU reserves and deliverability to the fiscal contract." [BPXA Ex. 57 at 13]. He also observed that "[w]ithout a gas pipeline much of the vast amount of value to the state represented by PTU will never be realized." [BPXA Ex. 58 at 23]. The DOR Commissioner's determinations are founded on more than two years of negotiation and the exchange of thousands of documents and detailed data concerning statewide economics and

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89 BPXA Ex. 77 at Module 4 (stressing the importance of completing basic data gathering early in the process); Herod PT at 5.

90 AS 43.82.400(a)(1); *see* BPXA Ex. 51.

91 BPXA Ex. 49 at 5, Ex. 51 at FIF-ES-12, FIF-55.

Alaska North Slope gas resources. In light of these findings, the commitments in the Modified POD that move the PTU toward development of gas sales clearly serve the State's best interests.

Moreover, the State's interests are protected by the multi-faceted nature of the Modified POD. The Modified POD does not focus exclusively on preparations for gas sales. As discussed above, the Owners also have committed to continue their studies of other development possibilities in an effort to identify another mode of development, less profitable to the State than development for gas sales but still commercially viable. These studies protect the State by putting the Owners in a position to move forward if the North Slope pipeline project stalls and another viable development option for the PTU is identified.

Some have suggested that the State's interests could be better served by taking the leases away and re-leasing them to other companies, who might develop them more quickly.[92] The conclusion that others could or would develop the leases more quickly, with greater financial benefit to the State, is highly speculative. Inevitably, the first consequence of this approach would be delay, since the Owners vigorously dispute that DNR has any basis for terminating the PTU and taking back the leases, so litigation would ensue. Litigation about the PTU leases would delay not just development of the PTU; it would delay progress of the entire pipeline project, because of the importance of knowing that PTU gas will be available.[93]

More important, no one else has ever prepared a viable economic plan for development of the PTU. As Commissioner Corbus observed, the current Owners understand the technical and economic challenges of the PTU better than anyone else and are some of the world's most technically competent companies. [BPXA Ex. 58 at 24]. The $800 million that the

92 BPXA Ex. 46 at 21-22.

93 The State's expert economist, Pedro Van Meurs, described the risk of delay to the pipeline project that would result from litigation about the PTU Owners' obligations to develop. *See* Testimony to the Alaska State Legislature Special Session, May 11, 2006, at 158-59.

Owners have invested in exploring and attempting to find a viable means to develop PTU demonstrates that the absence of development to date has not been from lack of trying. Until October 2005, every DNR Commissioner recognized that continuing the leasehold interests served the State's interests. [BPXA Exhibit 57 at 13]. Nothing has changed, except that the prospects for construction of a gas pipeline and for development of the PTU in conjunction with the pipeline project are better than ever. It would not be in the State's best interest to terminate the PTU at this time.[94] It is in the State's best interest to approve the Modified POD so that work to develop the PTU resources will continue.

II. IF THE COMMISSIONER REACHES THE ISSUES RAISED IN THE APPEAL FROM THE DENIAL OF THE TWENTY-SECOND POD, THE COMMISSIONER SHOULD DETERMINE THAT THE DIRECTOR ERRED IN DISAPPROVING THE TWENTY-SECOND POD.

A. IF THE COMMISSIONER APPROVES THE MODIFIED POD SUBMITTED IN 2006, THEN THE APPEAL FROM THE 2005 DENIAL IS MOOT AND NEED NOT BE ADDRESSED BY THE COMMISSIONER.

A claim is moot if it "has lost its character as a present, live controversy."[95] If a challenged law or rule has been repealed or expired, any challenge is moot, because the party bringing the challenge would not be entitled to any relief, even if it prevails.[96]

That situation applies here if the DNR Commissioner approves the Modified POD. -The Modified POD covers the period of time originally addressed in the Twenty-Second POD, which would have expired by now even if it had been approved. Whether or not the

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94 Issues regarding whether the PTU could be terminated are, of course, not before the Commissioner. Only the superior court may terminate a unit agreement. *See* 11 AAC 83.374(d).

95 *Akpik v. State, Office of Mgmt. & Budget,* 115 P.3d 532, 535 (Alaska 2005), *quoted in State, Board of Fisheries v. Grunert,* 139 P.3d 1226, 1232 n.25 (Alaska 2006).

96 *Alaska Railroad Corp. v. Native Village of Eklutna,* 142 P.3d 1192, 1198 (Alaska 2006); *Grunert,* 139 P.3d at 1232-33 (holding that a challenge to an expired emergency regulation was moot, though agreeing to review it under the public interest exception to the mootness doctrine).

former Director erred when he disapproved the Twenty-Second POD no longer has any consequence. If the Owners persuade the Commissioner that the former Director erred, they would be entitled to no relief.

Therefore, the Owners' appeal from the former Director's decision disapproving the Twenty-Second POD is moot, if the Commissioner approves the Modified POD.

B. EVEN IF THE COMMISSIONER DISAPPROVES THE MODIFIED POD SUBMITTED IN 2006, THE APPEAL FROM THE 2005 DENIAL IS STILL MOOT AND NEED NOT BE ADDRESSED BY THE COMMISSIONER.

The question whether the former Director was incorrect in 2005 is moot even if the Commissioner disapproves the Modified POD. In disapproving the Twenty-Second POD, the former Director gave the Owners an opportunity to submit a Modified POD, and they have done so. Obviously, the point of inviting a Modified POD was to allow the owners the chance to address the Division's concerns, and the Owners did so by committing to more activities in support of developing the PTU.

If the Commissioner disapproves the Modified POD, the Owners have the right (among other steps) to appeal that decision to the superior court.[97] There would be little value to having the superior court evaluate whether the Twenty-Second POD described the activities of a reasonable, prudent operator, when, as a result of the initial disapproval, the Owners responded to the agency's request to submit a Modified POD that commits to do more. Any review by a court should examine the agency's rulings on the most extensive plan the Owners submitted, disregarding the plan that was superseded. Consequently, there is no reason to issue a decision on whether the Twenty-Second POD should have been approved.

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97 *See* 11 AAC 02.020(b) ("The commissioner's decision on appeal is the final administrative order and decision of the department for purposes of appeal to the superior court.").

C. THE DIRECTOR ERRED IN DISAPPROVING THE TWENTY-SECOND POD SUBMITTED IN AUGUST 2005.

For the reasons set forth above, the Commissioner should declare that the appeal from the former Director's denial of the Twenty-Second POD is moot, and therefore not reach the merits of the appeal. The following arguments in support of the appeal need be considered only if the Commissioner rejects the preceding analysis.

1. The Twenty-Second POD Described The Activities Of A Reasonable, Prudent Operator Acting In The Best Interest Of The State.

Because the Twenty-Second POD covered only a one-year period, rather than the five-year period of the Modified POD, it did not contain the same breadth of commitments. Nonetheless, for the period it covered, it contained the commitments of a reasonable, prudent operator acting in the mutual interests of the State and the lessees.

The primary focus of the Twenty-Second POD was on preparing the Owners to participate in a future Open Season for a North Slope gas pipeline. When the Twenty-Second POD was submitted, the State and the Sponsor Group were actively negotiating a Fiscal Contract for a pipeline project. Given the timing, it was reasonable and prudent for the Twenty-Second POD to concentrate on commitments to prepare to participate in an Open Season.

The work commitments to advance this goal were significant. They included commitments to (a) continue the reservoir simulation studies necessary to develop a depletion plan; (b) conduct screening stage evaluation of production facilities necessary to advance the project planning to the CE stage; (c) fund continued baseline environmental studies necessary for preparation of an Environmental Impact Statement; and (d) review the permit preparation work completed during the efforts to advance a gas cycling project to identify the required additions and changes to support a permitting plan for a gas sales project. [BPXA Ex. 44]. The Twenty-

Second POD, like the Modified POD, reflected the careful, staged planning that is absolutely essential for the success of a major project.

The PTU Owners had determined that the gas cycling project was not viable, and they had suspended FEED for that project.[98] DNR was aware of that decision, and in 2004 approved the Twenty-First POD, which contained no commitments to continue active progress on the cycling project. [BPXA Ex. 34]. The Twenty-Second POD was a logical extension of the Twenty-First. Because the Twenty-Second POD contained the commitments of a reasonable, prudent operator, it should have been approved.

2. The Former Director's Disapproval Of The Twenty-Second POD Was Arbitrary, Unreasonable, And Unsupported By Any Evidence.

Absolutely no evidence before the former Director supported his determination that a reasonable, prudent operator would commit to the activities that he believed should be included in an acceptable POD for that year. In fact, the evidence establishes that no reasonable operator could or would have done what the former Director wanted.

The former Director suggested that a well should be drilled into the Thomson Sand before June 2006.[99] However, the evidence establishes that planning for such a technologically complex well will require more than a year; procuring and modifying an appropriate drilling rig and associated drilling equipment will take approximately two years. Attempting to proceed faster would risk a well and drilling equipment that are not properly designed and could jeopardize human safety and the environment.[100]

98 BPXA Ex. 29 at 1, Ex. 30 at 1, 2.

99 BPXA Ex. 46 at 23.

100 Christman PT at 1, 5.

The former Director suggested that a commercial PTU development should be sanctioned by October 1, 2006, less than a year after his decision.[101] The systematic procedures most likely to result in a successful project do not provide for sanction until after FEED is completed.[102] For a large project, FEED typically takes 18 months.[103] The former Director knew that, under the Twenty-Second POD, which DNR had approved, the Owners had suspended FEED for the gas cycling project, and no other project was ready to begin FEED. To sanction a major project means to commit the financial resources to complete the project. No reasonable, prudent operator would have planned to do that by 2006.

The former Director stated that the Owners should be prepared to begin production of a unitized substance by October 2009, less than four years from his decision.[104] Again, that timing is neither reasonable nor prudent. It fails to take account of the planning, design, procurement, and permitting that must occur before production can begin. The Modified POD represents a reasonable package of accomplishments for four years going forward from October 2006. As shown earlier, that timing is reasonable to allow for the planning and drilling of <u>one</u> well, and the evaluation of the results of that drilling. By no stretch of the imagination could a reasonable, prudent operator of the PTU in 2005 commit to be in production in four years.

The former Director criticized the Twenty-Second POD for including too much that depended on third-party efforts to construct a pipeline. But, as discussed above, lessees of a remote unit cannot be compelled to build an extensive transportation network from the unit to

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101 BPXA Ex. 46 at 22.

102 Herod PT at 3 & Ex. PH-1.

103 Herod PT at 3.

104 BPXA Ex. 46 at 22.

markets. On the other hand, a reasonable, prudent operator certainly should be attentive to surrounding circumstances. When it appears that transportation to market may become available, a reasonable, prudent operator should prepare to take advantage. Criticizing the operator for not being blind to the prospect of a pipeline was irrational and unreasonable.

Part of the former Director's criticism of plans to emphasize gas sales rested on the fact that the pipeline project would require changes in the State's existing tax and royalty structure in order to succeed. [BPXA Ex. 46 at 17]. But it was not unreasonable or imprudent to anticipate such changes. In enacting the Stranded Gas Development Act, the Alaska Legislature specifically recognized that such changes likely would be necessary to foster construction of a multi-billion dollar pipeline.[105] In 2006, the legislature did in fact change part of the tax structure, in a move expressly designed to promote oil and gas exploration and development.[106] The former Director was arbitrary and irrational in condemning the operator for making a realistic assessment of the economic conditions, and in proposing plans that would be viable and further the interests of the State and the Owners, though contingent upon foreseeable changes to the financial structure being implemented.

The former Director could not reasonably order production based on a gas cycling project that in fact was not a viable project. He could not reasonably conclude that the gas cycling project should be advanced, when all the major Owners had determined that the project was not viable. In his decision, the former Director cited no evidence to support a conclusion that gas cycling was a commercially viable project in 2005.[107] Additionally, the Owners could

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105 *See* AS 43.82.200, .210, .220.

106 AS 43.55.011 and Third Special Session ch 2, SLA 2006.

107 Commissioner Corbus has called the claim that it is profitable to develop the oil in the PTU "unsupported." [BPXA Ex. 57 at 12].

BPXA EXHIBITS
IN SUPPORT OF APPROVING THE MODIFIED
PLAN OF FURTHER DEVELOPMENT AND OPERATION
AND REVERSING THE DECISION THAT DISAPPROVED
THE TWENTY-SECOND PLAN OF DEVELOPMENT

BPXA Ex #	Description	Date
1	Form DL-1, State of Alaska Competitive Oil And Gas Lease	9/16/1969
2	Unit Agreement for the Development and Operation of the Point Thomson Unit	3/1/1977
3	Letter from Exxon (C. Jones) to DNR proposing amendment to Point Thomson Unit Agreement	6/13/1980
4	UNDERSTANDING COST GROWTH AND PERFORMANCE SHORTFALLS IN PIONEER PROCESS PLANTS, by Edward Merrow et al. © 1981 The Rand Corporation	9/1/1981
5	Letter from Exxon (H. Bushnell) to DNR, requesting approval of amendment to Section 11 of Point Thomson Unit Agreement	1/5/1982
6	Exhibit number not used	
7	Letter from DNR to Exxon, approving amendment to Point Thomson Unit Agreement Section 11	1/25/1982
8	Approval - Certification - Determination by DNR regarding amendment to Point Thomson Unit Agreement	4/16/1982
9	Letter from Exxon (D. Jones) to DNR, proposing amendment to Point Thomson Unit Agreement Section 20	7/27/1982
10	Letter from DNR to Exxon, acknowledging extension of Point Thomson Unit Agreement	7/29/1982
11	Letter from DNR to Exxon, with Determination and Approval of amendment to Point Thomson Unit Agreement	1/21/1985
12	Unit Agreement for the Development and Operation of the Point Thomson Unit (as compiled by DNR to reflect changes to date)	2/8/1994
13	Cover letter and Submission of Seventeenth Plan of Development	6/28/2000

BPXA Ex #	Description	Date
14	DNR approval of Seventeeth Plan of Development	8/18/2000
15	Cover letter and Application for Expansion/Contraction, Point Thomson Unit	1/31/2001
16	DNR response to Application for Expansion/Contraction	5/1/2001
17	Letter from Exxon (J. Justice) to DNR regarding Application for Expansion/Contraction	6/19/2001
18	Exhibit number not used	
19	Exhibit number not used	
20	Cover letter and Submission of Eighteenth Plan of Development	8/31/2001
21	DNR Approval of Eighteenth Plan of Development	9/14/2001
22	Cover letter and DNR Findings and Decision conditionally approving the Application for the Second Expansion and Third Contraction of the Point Thomson Unit Area	5/24/2002
23	Cover letter and submission of Nineteenth Plan of Development	8/5/2002
24	Cover letter and DNR approval of Nineteenth Plan of Development	9/13/2002
25	DNR letter concerning conditions for extending deadlines established in Expansion/Contraction Agreement	5/7/2003
26	Letter from Exxon (R. Buckley) to DNR responding to May 7, 2003, letter regarding extending deadlines in Expansion/ Contraction Agreement	6/20/2003
27	Cover letter and submission of Twentieth Plan of Development	7/2/2003
28	DNR letter approving Twentieth Plan of Development and extending Unit Contraction Election Deadline	7/14/2003
29	Letter from Exxon (R. Buckley) to DNR proposing modifications to Expansion/Contraction Agreement	12/18/2003

BPXA Ex #	Description	Date
30	DNR letter responding to proposal to modify Expansion/Contraction Agreement	1/8/2004
31	Amended Application for Development of a Contract Under AS 43.82, submitted by BPXA, ConocoPhillips, and ExxonMobil	1/20/2004
32	Approval of Application under the Alaska Stranded Gas Act, signed by DOR Commissioner Corbus and DNR Commissioner Irwin	1/23/2004
33	Email transmitting DNR's suggestions to modify draft Twenty-First Plan of Development	6/23/2004
34	Cover letter and submission of Twenty-first Plan of Development	8/31/2004
35	DNR conditional approval of Twenty-First Plan of Development	9/23/2004
36	Final Order and Decision of DNR Commissioner, affirming Director's decision regarding Twenty-First Plan of Development	11/24/2004
37	Letter from the Office of the Governor, requesting data	2/24/2005
38	Letter from DNR requesting data	3/7/2005
39	Letter from DNR requesting data	6/29/2005
40	Cover letter and submission of draft Twenty-Second Plan of Development	7/1/2005
41	Letter from Exxon to DNR, regarding request for certain data	7/14/2005
42	Letter from DNR requesting modifications to draft Twenty-Second Plan of Development	7/27/2005
43	Letter from ExxonMobil, requesting time to respond to DNR request for modifications of draft Twenty-Second Plan of Development	8/1/2005
44	Cover letter and submission of Twenty-Second Plan of Development	8/31/2005

BPXA Ex #	Description	Date
45	Resignation letters from DNR staff	10/27/2005
46	Amended Decision Denial of the Proposed Plans for Development of the Point Thomson Unit	10/27/2005
47	Letter requesting extension of time to appeal the Amended Decision, Denial of the Proposed Plans for Development of the Point Thomson Unit	11/9/2005
48	Letter from Commissioner Menge granting extension of time to appeal	11/10/2005
49	Proposed Alaska Stranded Gas Fiscal Contract agreed to between the State of Alaska and BPXA, ConocoPhillips Alaska, Inc., and ExxonMobil Alaska Production, Inc.	5/24/2006
50	Letter from Commissioner Menge extending deadline for appeal	5/26/2006
51	Preliminary Findings and Determination by Commissioner of Revenue regarding the proposed Fiscal Contract, as required by the Stranded Gas Development Act	5/10/2006
52	Letter from Commissioner Menge extending deadline for appeal and establishing procedures	8/31/2006
53	Letter from Commissioner Menge extending deadline for appeal and establishing procedures	9/8/2006
54	Letter from Commissioner Menge clarifying procedures	10/3/2006
55	Cover letter and submission of Modified Plan of Development for the period from 10/1/05 through 9/30/2010	10/18/2006
56	Letter from ExxonMobil proposing resolution of outstanding issues under Expansion/Contraction Agreement	10/18/2006
57	Letter from Commissioner Corbus to Tom Irwin, responding to criticisms of proposed Fiscal Contract	10/18/2006

BPXA Ex #	Description	Date
58	Letter from Commissioner Corbus to legislators, responding to criticisms of proposed Fiscal Contract	10/20/2006
59	Letter from BPXA to DNR, expressing support for Modified Plan of Development	10/20/2006
60	Exhibit number not used	

CONFIDENTIAL EXHIBITS
Pursuant to AS 38.05.035(a)(9), and common law

BPXA Ex #	Description	Date
61	Point Thomson Gas Injection Project Overview, presented by ExxonMobil to DNR	4/8/2004
62	Exhibit number not used	
63	Point Thomson Gas Injection Project, Cost Reduction and Optimization Effort Overview, presented by ExxonMobil to DNR	5/20/2004
64	Point Thomson Gas Injection Project, Economic Input Assumptions, Technical and Financial Data, presented by ExxonMobil to DNR	5/20/2004
65	Planning for Twenty-First Plan of Development, presented by ExxonMobil to DNR	6/23/2004
66	Letter from Badami Delivery Unit Manager to ExxonMobil as operator of Point Thomson Unit, re Indicative FSA Terms at Badami	8/10/2004
67	Cover letter and data submitted in response to DNR requirements in order conditionally approving Twenty-First Plan of Development	11/15/2004
68	Exhibit number not used	
69	Cover letter and data submitted in response to data requests from Governor's Office and DNR	4/8/2005
70	DNR request for additional data (containing description of documentation and data previously provided)	5/4/2005
71	Cover letter and data submitted in response to data requests from DNR	6/2/2005
72	Cover letter and data submitted in response to request from DNR	6/2/2005
73	Letter from ExxonMobil to DNR proposing modification of Expansion/Contraction agreement deadlines	6/21/2005
74	Planning for Twenty-Second Plan of Development, POD 21 Interim Deliverables, presented by ExxonMobil to DNR	6/28/2005

CONFIDENTIAL EXHIBITS
Pursuant to AS 38.05.035(a)(9), and common law

BPXA Ex #	Description	Date
75	Planning for Twenty-Second Plan of Development, POD 21 Update and POD 22 Plan, presented by ExxonMobil to DNR	6/30/2005
76	Letter from ExxonMobil responding to DNR requests for data	7/11/2005
77	Successful Megaprojects, A Seminar for Those Involved in Large and Complex Projects (contains handwritten notes of seminar participant), materials prepared by Independent Project Analysis, Inc.	11/29/2005