

AK LEGISLATURE SPECIAL COMMITTEE FILES SCOMM 155 3300

4. Development Work Scope

Initial Phase Production and Gas Injection Development

This POD is a firm commitment to drill wells and begin commercial production from the Thomson Sand utilizing an IPS. Production start-up is anticipated by year-end 2014, provided POD approval is received and required permits are obtained in a timely manner. During the POD period, owners will drill delineation/development wells, complete Conceptual Engineering, Front End Engineering and Design (FEED) and execution planning, obtain permits and authorizations and construct facilities for the IPS project. The IPS development schedule reflects an estimate of the time required to secure the necessary permits through multiple agencies.

Initial Production System (IPS) Development

IPS development will achieve production of PTU hydrocarbons and assist with full development of both liquids and gas through a phased approach. The IPS development is not dependent on an off-lease road. Thomson Sand development wells, a central production facility (CPF), and infrastructure to support operations will be located at the existing PTU #3 exploratory well gravel pad. The small footprint required and utilization of an existing gravel pad will minimize new gravel requirements and environmental impacts.

Drilling for the IPS project will begin in the 2008/2009 winter season with the central injector and producer wells from the Point Thomson No. 3. The central gas injection well will develop an area located northwest of the PTU-3 site. The central producer will develop an area to the southeast of PTU-3.

Additionally, a disposal well will be drilled at the PTU-3 site to support drilling and production operations.

The IPS will be designed to produce at a gas offtake rate of 200 million cubic feet per day. This will yield condensate rates of about 10,000 barrels per day. Gas production rates at this level may be achieved from a single production well in the high pressure Thomson Sand reservoir. The processed gas will be compressed and re-injected into the Thomson Sand reservoir through a gas injection well. Liquid hydrocarbons will be separated and stabilized at the CPF, then shipped through a new pipeline from the PTU to a Badami pipeline tie-in for delivery to the TransAlaska Pipeline System (TAPS).

The CPF will consist of two trains capable of processing 100 million cubic feet per day and 5,000 barrels per day each. Each train will be equipped with reciprocating compressors capable of re-injecting gas at the required injection pressures (~10,000 psi). The liquids pipeline will be sized to handle full field development. Disposal of waste liquids will be handled using an on-site disposal well. Other infrastructure such as camps, utilities, warehouse, in-field road and airstrip will be included. No permanent off-lease roads are necessary during the term of this POD. These facilities will be designed to accommodate future development options. Attachment A shows a preliminary IPS development plot plan and description. Attachment B shows a preliminary IPS process flow diagram.

The IPS performance will provide information to address reservoir and technical uncertainties and help manage those risks. Expected production and pressure response associated with the IPS have been evaluated in recent technical studies. Data obtained

during the drilling program will be used to test model predictions. Production response from the IPS will further narrow the range of resource uncertainty. Low-side scenarios will be identified relatively quickly, likely within the first year of production. High-side scenarios will take a longer production period to establish or differentiate.

Development Support

Technical and environmental activities will be conducted, including updating and/or supplementing previous environmental baseline studies, preparing and submitting applications, and working with regulatory agencies to secure necessary drill well and facilities permits and minimize environmental impacts. To minimize environmental impact, opportunities for use of adjacent infrastructure for logistical support will be evaluated.

Expansion of Gas Injection Development

The IPS project will be designed to provide flexibility for expansion. In addition to facility and drilling considerations, the reservoir development and monitoring plan will include acquisition of information to reduce resource uncertainty for analysis of expansion options. Additional details are provided in Section 8.

Combined Gas Sales / Expanded Gas Injection Development

Owners will have the ability to expand gas injection in the context of other development work, which would include development plans worked in parallel with the status of a gas pipeline. This work will be addressed in more detail in subsequent plans of development.

POD progress reports will be provided to the DNR by October 1 of each year. Technical review sessions will be conducted at logical completion points.

8. Subsequent Delineation and Development

Subsequent phases of field delineation and development will be determined based upon reservoir and facilities performance with the IPS, the status of a gas pipeline project, expected hydrocarbon recovery, and commercial viability. Development scenarios include (1) expansion of gas injection (2) gas sales or (3) a combination of expanded gas injection and gas sales. Use of IPS facilities for delineation, long term production and development of other reservoirs after initial Thomas Sand development will also be determined. Figure 4-1 is a diagram that depicts conceptual development plan scenarios for the options described above. Attachment A also provides a conceptual expansion plan for the CIP.

5. Point Thomson Delineation and Development Schedule

The current schedule for the delineation drilling and IPS development project is provided below (note that certain field activities may be dependent upon Alaska seasonal constraints).

Year	2008	2009	2010	2011	2012	2013	2014
State POD Approval	☆						
DRILLING							
Drilling Permits							
Secure Rig	▲						
IPS Development Drilling							
Delineation Well Pads Construction							
Delineation Program Drilling							
Procure Materials							
CONSTRUCTION							
Conceptual Engineering							
Pre-FEED / FEED							
IPS Surface Facilities Permits							
Engineering / Permitting Support							
Procurement							
Module Fabrication							
Module Transport							
ANS Civil Work							
Pipeline Construction							
Module Installation / Commissioning							
Start-Up / First Production							☆

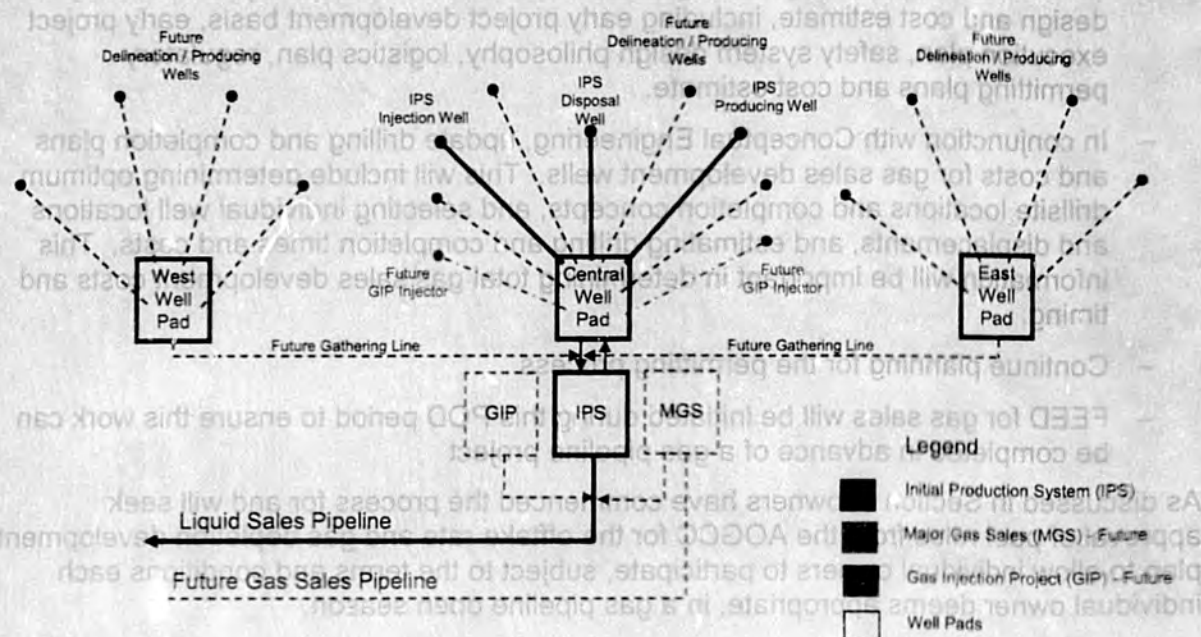
IPS project work will encompass the following activities:

- Perform Conceptual Engineering for the IPS project
- Perform FEED and execution planning to define the IPS project in sufficient detail to submit permit applications and update costs
- Initiate drilling in the 2008-09 winter season, upon receipt of permits
- Review and update environmental baseline studies, prepare permit applications, and support the permitting process to obtain the approvals
- Initiate construction, upon receipt of permits

6. Subsequent Delineation and Development

Subsequent phases of field delineation and development will be determined based upon reservoir and facilities performance with the IPS, the status of a gas pipeline project, expected hydrocarbon recovery, and commercial viability. Development scenarios include 1) expansion of gas injection, 2) gas sales or 3) a combination of expanded gas injection and gas sales. Use of IPS facilities for delineation, long term production and development of other reservoirs after initial Thomson Sand development will also be determined. Figure 4.1 is a diagram that depicts conceptual development plan scenarios for the options described above. Attachment A also provides a conceptual expansion plan for the CPF.

Figure 4.1 Conceptual Development Diagram



DEVELOPMENT PHASING:

- Initial Phase: Initial Production System or IPS (Solid Lines)
- Subsequent Phases (Dashed Lines) Could Include:
 - Gas Injection Project (GIP) Expansion
 - Major Gas Sales (MGS)
 - Combination of Both

7. Point Thomson Gas Sales Development

A significant step for a PTU gas sales development is to secure firm shipping capacity through a gas pipeline. To accomplish this, individual owners will need to make long-term commitments in an open season nomination process. This requires that the owners have confidence in the ability to produce the necessary volumes of gas from PTU and a good understanding of the cost of the facilities and wells required to implement a gas depletion development plan.

Owners will complete the work necessary to allow each individual owner to participate, subject to the terms and conditions each individual owner deems appropriate, in an open season for a gas pipeline after approval of pool rules by the AOGCC. PTU gas sales will require major facilities and pipeline additions / expansions and the drilling of additional wells. Gas sales Conceptual Engineering will be undertaken in parallel with engineering work for the IPS to ensure the IPS and potential gas sales development designs are integrated and compatible. Front End Engineering and Design (FEED) will be initiated during the POD period to ensure PTU gas sales development work can be accomplished in parallel with a gas pipeline. The following specific work tasks will be initiated and conducted during the POD period:

- Using geological modeling and reservoir simulation work completed in 2007, conduct Conceptual Engineering to develop the detail and quality of the facility design and cost estimate, including early project development basis, early project execution plan, safety system design philosophy, logistics plan, regulatory permitting plans and cost estimate.
- In conjunction with Conceptual Engineering, update drilling and completion plans and costs for gas sales development wells. This will include determining optimum drillsite locations and completion concepts, and selecting individual well locations and displacements, and estimating drilling and completion times and costs. This information will be important in determining total gas sales development costs and timing.
- Continue planning for the permitting process
- FEED for gas sales will be initiated during this POD period to ensure this work can be completed in advance of a gas pipeline project

As discussed in Section 9, owners have commenced the process for and will seek approval of pool rules from the AOGCC for the offtake rate and gas depletion development plan to allow individual owners to participate, subject to the terms and conditions each individual owner deems appropriate, in a gas pipeline open season.

8. Expanded Development

Gas Development

The IPS design will allow for expansion of gas injection development. Screening studies of expansion of gas injection development will be conducted after the IPS has commenced production and key performance information has been gathered. This work will be used to assess the potential for additional development through expansion at varying injection capacities. This work will be addressed in more detail in subsequent plans of development.

Oil Rim Development

The Thomson Sand reservoir contains an oil column (oil rim) that underlies the gas and will be further appraised. Technical work that has been conducted to date indicates there are limited reservoir targets where high quality reservoir rock intersects the oil rim. To help address technical uncertainty regarding drilling cost, sand thickness, and producibility of the oil, delineation wells will be drilled to evaluate the Thomson oil rim, as discussed in Section 3.

Data collected during the drilling of each oil rim delineation well will be evaluated to determine the value of collecting additional information such as core, wireline logs, fluid samples and productivity. Depending upon the results from static data and other information gathered in drilling the wells, the next step would be to install temporary test equipment onsite and conduct a production test to improve understanding of the viability of developing and producing the oil rim.

During Conceptual Engineering and FEED for the IPS project, facilities will be designed to accommodate production from viable Thomson Sand oil rim wells. If oil rim testing results

are encouraging, production from viable wells will be processed at the IPS facilities. The pipeline, described in Section 4, for full scale liquid development of the PTU can accommodate production from the oil rim.

9. PTU Pool Rules

A key regulatory requirement for any PTU development is obtaining approval for pool rules from the AOGCC. As part of the process to obtain approval of pool rules, confidential PTU technical data has been shared with the AOGCC via a data room, beginning in August 2007. Following completion of the data room process, which is anticipated to be by year-end 2008, a request for approval of pool rules for the IPS development will be submitted to the AOGCC.

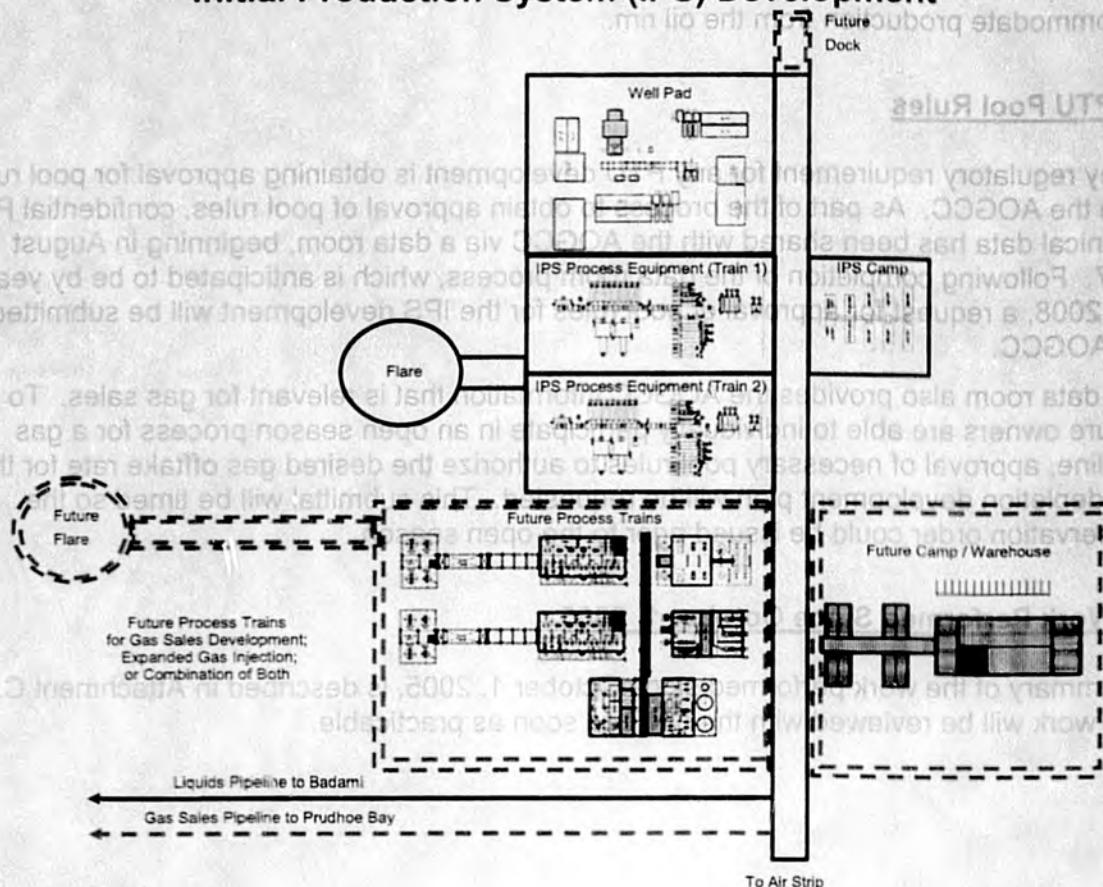
The data room also provides the AOGCC information that is relevant for gas sales. To ensure owners are able to individually participate in an open season process for a gas pipeline, approval of necessary pool rules to authorize the desired gas offtake rate for the gas depletion development plan will be requested. This submittal will be timed so the conservation order could be issued prior to the open season.

10. Work Performed Since October 1, 2005

A summary of the work performed since October 1, 2005, is described in Attachment C. This work will be reviewed with the DNR as soon as practicable.

<u>IPS Design Basis</u>	
• Single pad with 3 initial delineation/development wells (producer, injector and disposal)	
• Initial Production system for separation, compression and condensate stabilization	
• 2 train x 3 stage flash separation	
• 2 train x 2 stage gas injection compression (3,000 psi to 10,500 psi)	
• Power, water, sewage, diesel and methanol tanks, telecom	
• Liquid hydrocarbon export: 8" to 12" pipeline to Badami pipeline tie-in point	
• Construction camp, operations camp and warehousing siting	
<u>Summary</u>	
• Initial Gas Rate: 200 million cubic feet per day	
• Initial Condensate/Liquid Rate: 10,000 barrels per day	
• Initial oil rim liquids rate for processing at IPS facilities to be determined in conceptual engineering	

Attachment A Initial Production System (IPS) Development



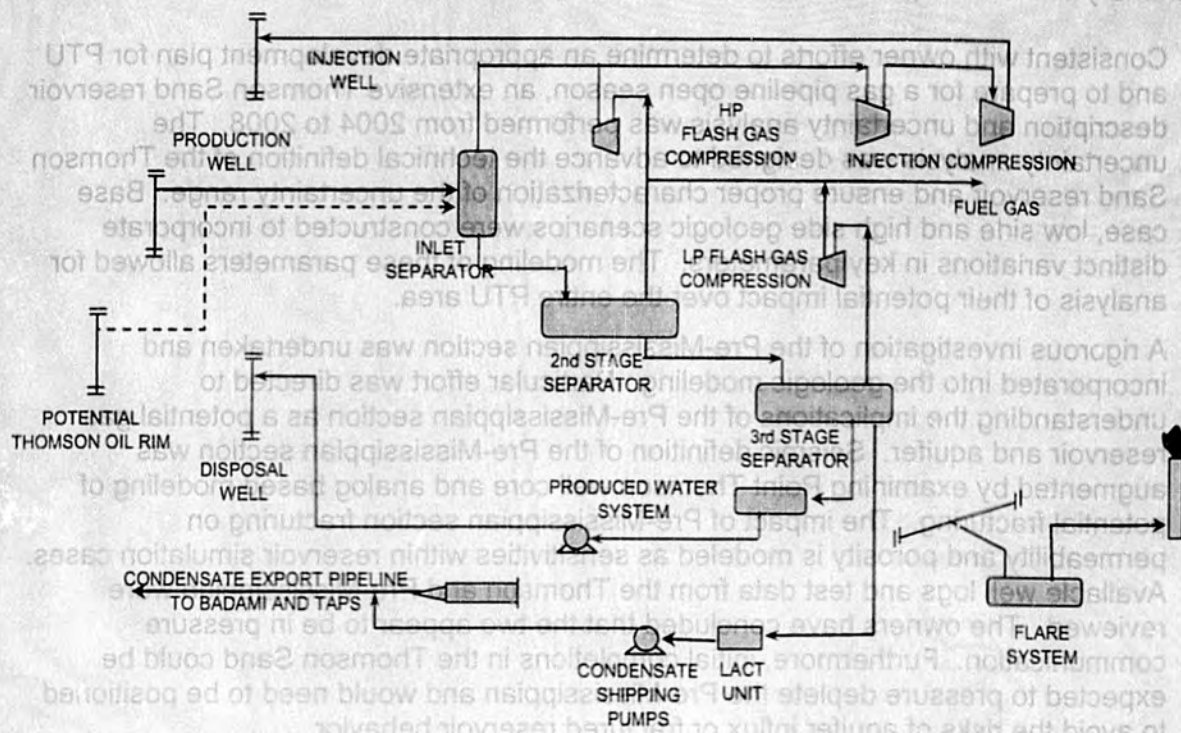
IPS Design Basis

- Single pad with 3 initial delineation/development wells (producer, injector and disposal)
- Initial Production system for separation, compression and condensate stabilization
 - 2 train x 3 stage flash separation
 - 2 train x 2 stage gas injection compression (3,000 psi to 10,500 psi)
- Power, water, sewage, diesel and methanol tanks, telecom
- Liquid hydrocarbon export: 8" to 12" pipeline to Badami pipeline tie-in point
- Construction camp, operations camp and warehousing; airstrip

Summary

- Initial Gas Rate: 200 million cubic feet per day
- Initial Condensate Liquids Rate: 10,000 barrels per day
- Initial oil rim liquids rate for processing at IPS facilities to be determined in conceptual engineering

Attachment B IPS Process Flow Diagram



Attachment C

Summary of Work Performed To Date

A summary of the work performed since October 1, 2005, is described below.

- C.1 Consistent with owner efforts to determine an appropriate development plan for PTU and to prepare for a gas pipeline open season, an extensive Thomson Sand reservoir description and uncertainty analysis was performed from 2004 to 2008. The uncertainty analysis was designed to advance the technical definition of the Thomson Sand reservoir and ensure proper characterization of the uncertainty range. Base case, low side and high side geologic scenarios were constructed to incorporate distinct variations in key parameters. The modeling of these parameters allowed for analysis of their potential impact over the entire PTU area.

A rigorous investigation of the Pre-Mississippian section was 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 was augmented by examining 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. Available well logs and test data from the Thomson and Pre-Mississippian were reviewed. The owners have concluded that the two appear to be in pressure communication. Furthermore, initial completions in the Thomson Sand could be expected to pressure deplete the Pre-Mississippian and would need to be positioned to avoid the risks of aquifer influx or fractured reservoir behavior.

An iterative preliminary reservoir model construction 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 were constructed and reviewed, they were used in full field compositional reservoir simulations. These simulations form the core of a statistical analysis that studied key subsurface factors impacting a PTU development.

The factors having the greatest impact on resource size and performance were facies, porosity distribution, and structural uncertainty related to velocity-depth conversion. The facies distribution was varied to represent a reasonable range of possible depositional environments for the Thomson Sand, ranging from laterally amalgamated fan deltas to more discrete fan delta lobes with intervening lower quality siltstone facies. Correspondingly, the porosity ranges were varied to be consistent with the facies distributions. Three facies types are present in the Thomson Sand; conglomerates, sandstones and siltstones. Conglomerates exhibit high as well as low porosity due to the deleterious effects of cementation, sandstones exhibit the best porosity, and the siltstones generally exhibit the lowest porosity. The facies and porosity impacted both the resource size and recovery. The impact of structural uncertainty was analyzed and varied as a function of distance from well control by flexing the structure up and down. Structure primarily impacts the resource

size. Although these three factors had the most significant impact, other factors that could impact the resource and recovery were investigated as part of the uncertainty analysis such as reservoir thickness and water saturation, as well as Pre-Mississippian volume, connectivity, and faulting.

The results of the uncertainty analysis served as a guide in the selection of input parameters for the construction of representative low, high and base case models. Based on the geologic models completed in 2007, the in-place resource range for the Thomson Sand in the Point Thomson field was updated. The resultant simulation models formed the basis for the PTU development planning studies conducted in 2007.

- C.2 Development planning studies were completed to evaluate alternate development options. This included developing screening cost estimates for facilities and drilling. The alternate development options included gas injection and gas storage options. This work resulted in the selection of the IPS described in this POD as the appropriate way to bring the PTU into commercial production.
- C.3 Facilities and pipeline work was focused on preparing execution plans for Conceptual Engineering for both hydrocarbon liquids production via the IPS and gas sales. 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.
- C.4 Significant completion related technical studies were conducted including a laboratory study to measure and analyze rock compressibility data from Point Thomson core samples, a surface subsidence study, a well operability limit (WOL) study and a completion design study. The results of these studies will be used during the Conceptual Engineering phase to study, refine and optimize the completion concept selected.
- C.5 Previous permitting support documents were reviewed in preparation for permitting activities. A significant amount of work for the previous gas injection development has been identified as applicable for other development options.
- C.6 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 in May 2006. The review included discussion of the previous gas injection development efforts and introduced the owners' work to assemble a proprietary worldwide database of potential Point Thomson analogue reservoirs. The results of the analogue study and worldwide database were presented to the AOGCC in December 2006. The data room process was initiated in August 2007 with the first in a series of steps to share confidential subsurface description and development plans for the

Thomson Sand reservoir. Steps 1 and 2, comprising Reservoir Data & Interpretation and Structure & Seismic Interpretation, have been completed. Step 3 on Fluid Data & Analysis is ongoing.

- C.7 In preparation for commencing drilling in the 2008/2009 winter season, detailed well construction work has been performed to establish the functional and technical specifications for hardware (i.e., casing, tubing, wellhead, trees and subsurface drilling and completion equipment), drill rig requirements, fluid design (i.e. mud and cement), and well operability limits. A drill rig has been secured and purchase orders for long-lead materials placed to commence development drilling for the IPS.

C.2 Development planning studies were completed to evaluate alternate development options. This included developing screening cost estimates for facilities and drilling. The alternate development options included gas injection and gas storage options. This work resulted in the selection of the IPS described in this POD as the appropriate way to bring the PTU into commercial production.

C.3 Facilities and pipeline work was focused on preparing execution plans for Conceptual Engineering for both hydrocarbon liquids production via the IPS and gas sales. 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.

C.4 Significant completion related technical studies were conducted including a laboratory study to measure and analyze rock compressibility data from Point Thomson core samples, a surface subsidence study, a well operability limit (WOL) study and a completion design study. The results of these studies will be used during the Conceptual Engineering phase to study, refine and optimize the completion concept selected.

C.5 Previous permitting support documents were reviewed in preparation for permitting activities. A significant amount of work for the previous gas injection development has been identified as applicable for other development options.

C.6 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 in May 2006. The review included discussion of the previous gas injection development efforts and introduced the owners' work to assemble a proprietary worldwide database of potential Point Thomson analogue reservoirs. The results of the analogue study and worldwide database were presented to the AOGCC in December 2006. The data room process was initiated in August 2007 with the first in a series of steps to share confidential subsurface description and development plans for the

**TESTIMONY OF CRAIG HAYMES
ON POINT THOMSON'S 2008 PLAN OF DEVELOPMENT**

TO THE ALASKA COMMITTEES ON AGA / ENERGY

JUNE 17, 2008

INTRODUCTION

Chairmen, members of the committee, legislators:

Good afternoon. For the record, my name is Craig Haymes. I am the Alaska Production Manager for ExxonMobil, based in Anchorage. I want to thank the committee and the legislators for the opportunity for ExxonMobil, as operator, and on behalf of the 27 lease holders to update you on Point Thomson and particularly to present a brief outline of the Point Thomson Unit (PTU) Plan of Development (POD) that was submitted to the Department of Natural Resources (DNR) on February 19, 2008. You should have received a handout package which contains a PTU brochure, my prepared testimony and associated slides, along with a copy of the February 19, 2008 PTU POD.

I intend to discuss three key areas today.

- The PTU POD and the benefits we see for the State and the 27 lease holders from this plan
- The criticality of Point Thomson gas to the success of the Alaska gas pipeline project

- Significant concerns we have with the recent representation of Point Thomson resources through DNR's summary of PetroTel's report

Before I move into the details of the POD, I would like to make a few introductory comments. ExxonMobil and the other 26 lease holders were very surprised and disappointed with the DNR's decision last week to not reconsider the POD that was submitted on February 19, 2008. The POD contains a project that is already underway that will bring the PTU resources into production by year end 2014. There is no faster path to bring the PTU into production, there is no other way to ensure that the PTU gas will be available for a gas pipeline, gas which is critical to the success of a gas pipeline. Until 3 weeks ago, everyone agreed that Point Thomson was critical for a gas pipeline. We don't understand how this can change so rapidly, when Point Thomson contains 25% of the known gas resources on the North Slope. I will discuss the criticality of Point Thomson gas in more detail later in the presentation.

As I mentioned, this POD is a project that will bring PTU into production by 2014. We have Alaskan companies working on the project right now. We are ramping up to over 200 jobs by February 2009 alone. Significant spending is already happening and activities are underway in the State today. We are moving forward with critical activities in preparation to commence a multi-year drilling program this winter. The first well will be commenced in less than 8 months! Since the decision last week, we have had quite a few phone calls from concerned contractors, Alaskans, and employees on their future. We are awarding more contracts to Alaskan companies this week and next. We have

told everyone to keep going, because we are optimistic that the DNR will want to resolve this issue in a way that will put Alaskans to work now.

We have consistently stated that we, and the other 26 lease holders, want to resolve the Point Thomson dispute rather than litigate. We believe the current POD provides a way forward. The DNR recognized in their decision on April 22, 2008, that the POD "...may present a technically reasonable first step for developing these lands from a conservation perspective." We are happy to have further discussions with the DNR on our POD. The 27 lease holders do not want to litigate, but if we have to we will. We would like to find a way to resolve this issue with the DNR. We are looking to the future.

As I mentioned the fastest path to move Point Thomson to production is through the current lease holders and through the current POD. The drilling program that commences this winter will provide us with important information about the reservoir, the initial production data we obtain will be critical to assess the resource size at Point Thomson. The drilling, reservoir and dynamic production data will be essential for future expansion, leading to a gas sales development.

With those opening remarks, I would now like to provide you with a brief overview of the PTU POD.

The PTU POD is an unconditional commitment to production by year end 2014 through a project estimated to cost \$1.3 Billion. The PTU POD is supported by all of the lease holders. The PTU POD will not only establish production and further delineate the Point

Thomson resources, but will also set-up Point Thomson for future phases of development, including additional gas cycling, oil production, gas sales or some combination. With this initial phase of development, Point Thomson will be the highest pressure gas cycling project in the world, and gas cycling will be through world class drill wells. While the owners are excited with the current POD, there are significant unique challenges and risks with the Point Thomson reservoirs, which I will highlight today.

POINT THOMSON – ISOLATED FROM THE REST OF THE NORTH SLOPE

The PTU is located 60 miles east of Prudhoe Bay and the Trans-Alaska Pipeline and 22 miles east of Badami. The PTU is in a remote and environmentally sensitive area, close to ANWR. There is no road to the PTU. It is an area of approximately 80,000 acres.

The Point Thomson reservoir straddles the coastline and is over 12,000 feet deep. The pressure of this reservoir is 10,200 psi, which is over twice the pressure of Prudhoe Bay. The Point Thomson reservoir is abnormally pressured, which means that the pressure is extremely high for the depth. As such, higher cost drilling and well completion operations are required due to the stringent safety measures necessary to maintain well control. In addition, high pressure injection and fluid handling facilities are required to safely manage these high pressures. I will talk more about those challenges later.

Under this POD, the condensate, which is a liquid hydrocarbon recovered from the gas at the surface (like diesel or kerosene) would be exported through the Trans Alaska

Pipeline System (TAPS) by tying into the existing oil pipeline network as shown in red. I will talk more about the way a condensate is recovered later.

POINT THOMSON – OBTAINING INFORMATION

Nineteen exploration wells have been drilled at Point Thomson, represented by each of these red dots. Fourteen of these wells penetrated the Point Thomson reservoir. We have collected over 3600 feet of core from these wells and completed 20 well tests.

In addition to the 19 wells that have already been drilled, we have also integrated the data from eight 3D seismic surveys. Seismic interpretation at Point Thomson is complicated due to variances in perma-frost thickness. The permafrost thickness at Point Thomson is as much as 2000 feet onshore and thins offshore beneath the shallow coastal waters. This variance creates challenges in determining the complex structural picture of the deep Thomson reservoir.

POINT THOMSON – POD COMMITMENTS

There has been quite a bit of discussion about whether the lease holders at the PTU have fulfilled the commitments they made.

I would like to define a plan of development or POD. A POD contains work plans that are necessary to ultimately develop and produce a reservoir for optimum hydrocarbon recovery. The process for a POD is the same for any reservoir in Alaska. Work undertaken in a POD usually consists of activities such as studies, engineering or drilling of wells. These work activities are agreed with the DNR up front when the POD

is approved, and then the lease holders move forward with those work plans. As the lease holders move forward with the work plans, new information is obtained and changes in the planned work activities may result. These changes to work plans are reviewed with the DNR and factored into the future work plans and the next POD. The DNR approves the next POD, perhaps with conditions or changes, which are discussed and agreed, and then the lease holders continue with their work plans. This cycle continues for the life of the reservoir. Typically, PODs have a term of one to two years. This is the same process that is used at Prudhoe Bay, Kuparuk, Endicott, and most, if not all of the reservoirs in the State, including Point Thomson.

There have been 21 PODs at PTU between 1978 and 2005 and all were approved by the DNR. Historically, the work performed by the lease holders pursuant to these POD's was reviewed by the DNR and served as a basis on which subsequent POD's were approved.

On a number of occasions during this 27 year period, the lease holders sat down with the DNR and reviewed the work completed and why it was not prudent or economic to begin producing Point Thomson resources at that time. These work activities have advanced the DNR's and lease holders' current understanding of the resource potential at the PTU and the significant risks that exist. These reviews never would have occurred if the lease holders had not been devoting their significant efforts, including spending over \$800 million, to find ways to begin production at Point Thomson. It was the information gathered from this past work that has allowed the lease holders to arrive at the current POD.

The recently submitted POD is unique and I want to focus on this. This POD specifies both work activities and a firm commitment to develop Point Thomson and to bring it on production. The State wants production at the PTU, as does ExxonMobil and the other 26 lease holders who are committed to production of hydrocarbons from the PTU through this POD. I will talk more about this commitment and assurances offered shortly.

PTU – EFFORTS TO DEVELOP

There has been a lot of discussion recently about timely development at PTU. As I mentioned earlier, the 27 lease holders have spent over \$800 million to date in an effort to develop PTU resources. The PTU has significant risks, many of which I will talk about later.

Prior to 2002, oil averaged less than \$20 per barrel and gas averaged less than \$4 per million cubic feet, and the outlook for prices reflected that reality. Historically the lease holders looked at many different ways to commercialize the PTU resources, whether it was gas cycling, oil production or gas sales, but no development was found to be commercially viable. All of these results were reviewed with the DNR on a regular basis, and the work completed was taken into account for the subsequent POD.

It is only recently that commodity prices have increased significantly; however, given historical volatility of prices, there is still a risk that higher oil and gas prices will not be sustained. It is important to recognize that significant investments are required to

develop PTU resources - an estimated \$1.3 billion for 10,000 barrels per day of condensate is an example. The lease holders are taking on the price commodity risk any time they make an investment over decades.

POINT THOMSON – PLAN OF DEVELOPMENT

This PTU POD is based on a foundation of objective technical work. We have used all of the data from the 19 exploration wells and the eight 3D seismic programs. We have taken that data and using state-of-the art modeling techniques, analyzed the very challenging reservoirs in the Point Thomson field.

We have looked beyond Point Thomson and assessed over 230 analogous fields worldwide to assist us in developing this POD. I will talk more about these results shortly. We have also utilized the collective expertise of four of the largest private oil and gas companies in the world.

To date the lease holders have spent over \$800M at Point Thomson. This POD commits the lease holders to an estimated \$1.3 Billion project, and includes an initial phase of production designed to accommodate future expansion capability.

PTU POD – PLAN TO PRODUCE CONDENSATE

Through this POD, the Point Thomson facilities will produce 10,000 barrels per day of condensate by year end 2014, by cycling 200 million cubic feet per day through production facilities. The facilities include an export liquids pipeline sized for the

expected full development (up to 70,000 barrels per day), an airstrip, camp and facilities.

The drilling and production facilities will be designed and installed to minimize the impact on the environment. We will be using ice roads and existing gravel pads as much as practicable, and no off-lease roads are planned.

The PTU POD includes a commitment to drill a minimum of five wells, not only to cycle gas and produce condensate, but also to delineate all of the PTU reservoirs. In addition to the gas cycling, oil production can be accommodated in these facilities if the oil rim is found to be productive through well testing. These oil wells will be drilled so that they can also be potential gas production wells in the future. This POD provides for the delineation of all PTU reservoirs. The production facilities are being designed and built so that they can be expanded, either for cycling, oil production, gas sales or combinations of these options. The lease holders have significant incentive to fully develop the resource. The initial estimated cost of \$1.3 billion produces 10,000 barrels of condensate per day, but we need to build on that to realize the full value of the PTU resources.

PTU – PROJECT ACTIVITY UNDERWAY

The lease holders are committed to the PTU POD. Key project activities to achieve production by 2014 are underway right now. We have significant resources working on this project.

We have already contracted the Nabors Rig 27E and commenced \$20 million of rig upgrades to ensure it is ready to commence drilling at the PTU this winter. Significant rig upgrades are required, including new drilling mud and electrical systems, to ensure that the rig can drill safely into the very high pressure Point Thomson reservoir. This upgrade work is happening now.

We have also ordered long lead materials for the first well. These long lead materials include casing strings and wellhead equipment which are made of high strength steel using special corrosion resistant alloys. These materials require at least nine months to manufacture and are scheduled to arrive in Alaska in November 2008.

Next week we will award a contract to an Alaskan company worth tens of millions of dollars to construct and maintain a 50 mile ice road and airstrip at the PTU. The ice road will run from Endicott along the coastline to the PTU and require over 30 to 40 workers to build and maintain. Another activity that will commence next week is a PTU site survey to ensure that we scope and plan all necessary equipment and materials for preparing the site for the drill rig.

We had initiated discussions with the DNR to progress permitting applications for the site activity and drilling operations this winter. Approval of these permits will be critical to ensure we can continue to progress the project activities as we ramp up to over 200 jobs by Feb 2009.

With permit approvals, we will be in a position to undertake significant activities, including:

- During July and August, the barging of ice road construction facilities and pad equipment to the PTU, including camp set-up, gravel hauling, mobilization of earthwork equipment and pad preparation. This will require two deck barges (200' by 60'), accompanying tugs and significant other support services including aviation. Approximately 23 round trips from Prudhoe Bay will be required given the significant materials and equipment required. Over 20 people will be required for this activity, contracted with Alaskan companies.
- During December and January, the construction of the 50 mile ice road and subsequent mobilization of the drilling rig to the PTU site. Over 30 to 40 people will be required for this activity through an Alaskan company to be announced next week.
- By February 2009, we will spud the first well of a multi year drilling program, with over 200 jobs required for the drilling operation through Nabors drilling contractor.

PTU POD - ADDRESSING DNR'S CONCERNS ON TIMELY DEVELOPMENT

The lease holders are excited with the PTU POD Project and look forward to working with the State to progress this initial phase to production by 2014.

POINT THOMSON - PRODUCE CONDENSATE BY CYCLING GAS

What do we mean by cycling gas to produce condensate? The cycling of gas requires two wells; a production well and an injection well. These wells will be placed four miles apart in the heart of the reservoir to provide a true test on the effectiveness of cycling gas at Point Thomson. There are some significant risks, which I will discuss later.

The gas reservoir is at a temperature of 230 degrees F and a pressure of 10,200 psi. The gas production well is expected to produce 200 million cubic feet per day. We then take that produced or "wet" gas, which is gas saturated with condensate, through a central processing facility where the pressure and temperature will be reduced through multiple separators. As the temperature and pressure drop, some of the wet gas condenses into a liquid called gas condensate. The condensate, which is somewhat like diesel or kerosene, will then be sent to market via TAPS. After condensate is extracted, the dry gas remaining (excluding fuel) is pressured to 10,200 psi and then injected back into the reservoir. Over time, more and more of the injected dry gas moves through the reservoir towards the production well and helps to produce more wet gas. That is why this recovery mechanism is called a "cycling" project, as the gas is cycled through the reservoir. By injecting the gas, reservoir energy is conserved for future production and gas sales.

PTU POD – ADDRESSING DNR'S CONCERNS ON TIMELY DEVELOPMENT

The lease holders have prepared this POD based on significant technical analysis of all available data and through prudent management of the risks and good reservoir management practices. The lease holders have leveraged the expertise of four of the largest oil and gas companies in the world, ExxonMobil, BP, Chevron and ConocoPhillips.

As the lease holders developed the POD we listened very carefully to the DNR's concerns. Earlier this year the DNR advised the lease holders that they would like to

to see a POD that contained timely development, reservoir delineation and a firm commitment to complete the work plans. We believe the current POD addresses these concerns.

However, to ensure we were taking into account DNR's concerns, we requested specific feedback and guidance on what DNR wanted to see in the next POD. It has been very frustrating to the 27 lease holders that in the year leading up to last weeks rejection of the POD we received no additional guidance on what the POD should contain, despite our repeated requests to the DNR. In fact, the DNR actually advised us to disregard their prior guidance. This lack of communication has been disappointing, but we continue to believe that dialogue between the DNR and lease holders provides the best path for resolution of the POD and the PTU in a way that will maximize benefits of this resource to the people of Alaska and the lease holders.

As I mentioned, the DNR requested the lease holders address three general areas as part of the POD. The first area was around timely development.

The lease holders believe the PTU POD addresses DNR's concerns about timely development through a detailed schedule of milestones leading to production by 2014. We already have Alaskan contractors in place to commence the five-well drilling program this winter and will employ over 200 workers.

As I mentioned earlier, Point Thomson will be producing 10,000 barrels per day of condensate by 2014 through this initial development phase, with future expansion capabilities.

PTU POD – CLEAR AND COMMITTED TIMELINE

As part of the PTU POD, the lease holders submitted a detailed schedule that would allow the DNR to monitor progress and milestones on an ongoing basis. There are three main components to this schedule. Blue represents drilling activities, grey engineering and permitting activities and green procurement, construction and installation activities.

As shown on the schedule we are commencing the five-well drilling program this winter and it will continue through to 2012. We are planning to start the drilling program now to provide us with early information for the project design, but also to ensure that if there are any delays with drilling these world class wells, that the delay does not impact production by 2014.

We have allowed four years in the schedule to complete engineering and permitting activities which are critical for the success of the project. Finally, we have allowed two years to order the high pressure long lead materials required, and two winter seasons to install the facilities, leading to production by year end 2014.

In our POD we committed to this timeline of milestones and stated that we would look for ways to accelerate the schedule.

PTU POD – PLAN TO DEVELOP AND DELINEATE

In addition to these activities, we also included in the POD a commitment to complete the AOGCC Pool Rules Data Room process, which we commenced voluntarily in August 2007. We are prepared to complete this process by the end of this year. We also committed to complete conceptual engineering and to submit a Pool Rules application to the AOGCC by mid 2009 for a gas sales development. These are essential activities that will underpin a gas sales development at PTU, critical for an Alaska gas pipeline project.

PTU POD – ADDRESSING DNR's CONCERNS OF RESERVOIR DELINEATION

As I mentioned earlier, the lease holders listened very carefully to what the DNR were looking for in this POD. I have already discussed the first area, and would now like to discuss the second area – reservoir delineation.

The lease holders believe the PTU POD meets DNR's concerns on reservoir delineation through a minimum of a five-well drilling program for this initial phase. The POD not only commits to cycling gas and producing condensate, but also commits to drill three additional delineation wells. In fact, the POD states that the lease holders will drill additional wells as necessary to achieve the objectives of cycling gas and delineation of all reservoirs.

What do the wells look like?

PTU POD – PLAN TO DEVELOP AND DELINEATE

The PTU POD has a clear production commitment and a delineation commitment that will set up PTU for future development.

In addition to the cycling project wells, there will be three additional delineation wells targeting gas and oil reservoirs, as shown in the East, West and an unspecified location (5th well). These delineation wells will target a thin heavy oil rim at the edge of the gas reservoir, and through logging and well testing, we will determine if these wells can commercially produce oil. If productive, the oil wells can be tied back to the central processing facility and the oil produced and exported along with the condensate through TAPS.

However, there is great risk with these oil rim wells. The oil is very viscous or heavy and therefore does not flow easily. The heavy oil accumulation is relatively thin and discontinuous and sandwiched between gas and water. Since the gas and water are much more mobile in the reservoir, there is a high risk that the gas and water will flow preferentially rather than the more viscous heavy oil. We certainly hope that these wells are commercially viable, as each one will cost approximately \$80 to \$100 million dollars. To put that in perspective, a typical Prudhoe Bay well currently costs \$6 to 8 million dollars – a PTU well is 10 to 15 times more than a Prudhoe Bay well.

The delineation wells will also target the shallower Brookian oil prospects and test their potential. It should be noted that the Brookian oil prospects are not connected to the

main Thomson reservoir and appear to be very similar to the Badami accumulations that BP is developing at the Badami Unit 22 miles to the west of PTU.

If the oil delineation plan indicates that the oil rim cannot be produced in commercial quantities, we will keep the wells and could use them as future gas production wells. We can do this, as the wells will also penetrate the gas reservoir. This is important as we can also use these wells to monitor the pressure on the flank of the reservoir, as we cycle gas in the center and produce condensate. By monitoring the pressure of these wells on the flank we can determine if the production and injection wells are communicating with each other. That information will help us determine the size and dynamic characteristics of the reservoir. If we get favorable results, we will have the ability to expand gas cycling with the next phase of development.

For example, we could expand the central production facility to accommodate additional cycling using the wells that were drilled to help delineate the Thomson resource. The beauty of this POD is that it provides the flexibility to accommodate different outcomes and to pursue future expansions in a timely manner.

The lease holders have significant incentive to expand the facilities and produce more liquids and gas. Spending \$1.3 billion for 10,000 barrels per day of condensate has significant technical and operational challenges, but we view it as a necessary and prudent step for the lease holders to take.

PTU POD – ADDRESSING DNR's CONCERNS ON FIRM COMMITMENT

As I mentioned earlier, the lease holders listened very carefully to what the DNR were looking for in this POD. I have already discussed the first and second area, and would now like to discuss the third area – firm commitment.

During the March hearing, where the lease holders unanimously supported and presented this PTU POD to the DNR, we discussed numerous assurances to demonstrate our firm commitment to bring PTU onto production by 2014. Specifically we provided:

- A timeline that provided a clear path to production. This is a unique POD for PTU. This means that the lease holders have agreed to carry all of the development risks, all of the reservoir risks, all of the technical risks to bring Point Thomson into production.
- Confirmation that we had secured a drill rig and ordered long lead materials to ensure we can commence drilling the five-well program this winter.
- A detailed schedule, as I showed you earlier, which would allow the DNR to monitor progress on an ongoing basis.

After the hearing in March, the lease holders provided the DNR with two additional assurances. Senior management from BP, Chevron and ExxonMobil sent letters to Commissioner Irwin confirming that our respective corporations were fully aware of the PTU POD, and were fully committed to the POD.

Finally, the lease holders provided a draft proposed Superior Court order that would provide the DNR the ability, through the Superior Court, to terminate the PTU if any one of seven interim milestones, as outlined in the PTU POD schedule, were not met.

The lease holders believe they have clearly demonstrated a clear commitment to production for the PTU. Some may ask, how can we trust the lease holders to keep their commitments? As I mentioned, this POD contains unique commitments; commitments that have not been made before with clear mechanisms for the DNR to ensure performance.

PTU POD – PRUDENTLY MANAGES RISK

The PTU POD is a phased development that will prudently manage many risks. I have grouped the main risks into five key areas.

It will be important for the lease holders to effectively manage the health, safety and environmental risks of this project given the high pressure operation will be in an arctic environmentally sensitive location.

It is also critically important that the reservoir risks are managed appropriately, for both the state and the lease holders. The Point Thomson reservoir is a retrograde condensate field that behaves differently compared to traditional oil and gas reservoirs. There are uncertainties in reservoir quality, connectivity and size that are particularly significant to gas injection and cannot be resolved with seismic interpretation or delineation drilling alone. Delineation of the gas and oil sections of the reservoir and

initially cycling gas in the 'heart' of the reservoir will allow us to prudently manage these risks. I will discuss the cycling risks in more detail shortly. Cycling the gas will conserve the resource and set-up Point Thomson for the next phase of development.

Managing the high pressure operations and facilities will also be important. We will require separation facilities rated for 3,000 psi and compression facilities rated in excess of 10,000 psi. The inlet separator alone will require a steel wall thickness of six inches. The wells that we will drill will be extended reach and in an over-pressured environment. Prudently managing the facilities and leveraging technology will be critical for the success of the project.

PTU POD - PRUDENTLY MANAGES RISK

As we drill and operate the high pressure operations we will learn from facility and well performance, which will allow us to successfully manage operations in future developments.

Finally, the Point Thomson world class wells and facilities will require world class project management skills. Management of costs and schedule will be critical for this initial phase and subsequent phases of development. Over the last five years, the average facilities cost and schedule of 44 ExxonMobil operated major projects came within five percent of the cost projected at funding.

ExxonMobil and the lease holders are fully committed to bring Point Thomson into production by year end 2014, which will set up Point Thomson for subsequent expansions for gas cycling, oil production, gas sales or combinations.

PTU – RESERVOIR QUALITY AND PERFORMANCE

I would now like to discuss reservoir quality and performance associated with the cycling operation.

When we drill the production and injection wells we are hoping to find high quality reservoir. We are also hoping that when we commence cycling gas between these wells that the gas will flow freely as represented by the red arrows from the injection well on the left to the production well on the right. It is this sweeping effect that will push wet gas with condensate to the producer and allow the production of condensate to the TAPS pipeline.

However, as we all know, no reservoir is homogenous; they are in practice of variable quality and accurately quantifying the degree of quality is paramount to selecting the appropriated development concept for the reservoir. For example, we could drill the two wells and find the quality is good in the vicinity of the well, but then when we cycle the gas find that the two wells do not communicate or communicate poorly. In such a case, this would directly translate into significantly less condensate produced than would be expected in a good quality reservoir.

The PTU POD prudently manages this risk by targeting the initial cycling wells in the heart of the field. This will allow us to learn more about the reservoir dynamics and performance and re-calibrate our geological and reservoir models with dynamic

production data. We can then move forward with the next phase of development, with a strategy that maximizes value for all stakeholders, the State and the lease holders.

CYCLING AT HIGH-INJECTION PRESSURE

The lease holders have completed an assessment of over 230 analogous gas fields around the world. These are gas fields operated by many different companies. I have shown a selection of these fields on this chart, represented by individual bars. Due to the proprietary nature of the study; we have removed field names from the graph.

Point Thomson is shown as the red bar, with a pressure of 10,200 psi. Blue bars represent gas fields that were developed by gas blowdown or gas sales. Yellow bars are fields that were initially developed by gas cycling. As you can see on this graph, the highest pressured known gas cycling project in the world is close to a wellhead gas injection pressure of 7000 psi. Point Thomson will be the world's highest pressure gas cycling project when operational. This means that the technical challenges and cost implications are unprecedented.

WELLS REQUIRED FOR HIGH PRESSURE OPERATIONS

In addition to the high pressure facilities, we also have high pressure drilling operations. A typical Point Thomson gas injection wellhead is shown in the picture on the left hand side of this slide. This injection wellhead is rated at 15,000 psi and is over twice the height of a typical wellhead at Prudhoe Bay or Kuparuk.

As I mentioned earlier, the reservoir pressure is abnormal at Point Thomson, at over 10,200 psi. The reservoir straddles the coastline and as such will require extended reach wells. As a result we will require amongst the heaviest drilling mud in the world to drill these wells, and when completed will have world class wells. The mud density will be 16 pounds per gallon, which is over twice the density of water.

The combination of high pressure, extended reach drilling and heavy mud requirements results in drillwell costs at Point Thomson that are very high, ranging from 10-15 times the typical cost for a Prudhoe Bay well and requiring almost five times longer to drill.

PTU POD – PHASED APPROACH MITIGATES RISK

When you look at the collective risks at Point Thomson they are significant. The combination of reservoir management risks, drilling risks and facilities risks are unique. This PTU POD prudently manages these risks through the application of good oil and gas field practices, by utilizing proven technology and by leveraging the collective owner's worldwide experience.

The lease holders will be able to apply critical learnings from this initial development and set-up Point Thomson for future development expansions leading to a gas sales development.

PROPOSED PLAN OF DEVELOPMENT FOR POINT THOMSON

In summary, this PTU POD provides

- Clear commitment to production by 2014

- Over 200 jobs this winter
- Further delineates all reservoirs through a minimum of a five-well drilling program
- Provides dynamic information about the reservoirs, critical information to help determine the full potential of the resource
- Conserves the gas resources through cycling
- Minimizes environmental impacts through utilization of ice roads and existing gravel pads
- Provides flexibility and expandability for cycling, oil production, major gas sales, or combinations thereof
- Ensures that Point Thomson gas is available for a Gas Pipeline Project

PTU POD - PHASED APPROACH MITIGATES RISK

ExxonMobil, and the 26 other lease holders of the PTU are excited and committed to bringing Point Thomson into production by 2014 through this POD. The dynamic information we learn from this early production will be critical to set Point Thomson up for future expansions.

IMPORTANCE OF POINT THOMSON GAS TO GAS PIPELINE PROJECT

I would now like to address the importance of Point Thomson gas to the success of a future gas pipeline. In considering all future development scenarios for Point Thomson, one key consideration is the timing of a gas pipeline project and the availability of Point Thomson gas on the success of that project

PROPOSED PLAN OF DEVELOPMENT FOR POINT THOMSON

Point Thomson gas represents 25% of the discovered North Slope gas resources. It is estimated that Point Thomson can provide daily gas production of approximately 1 BCF

per day. This production will provide the economies of scale needed on a mega-project such as the Alaska gas pipeline. I would like to note that the actual field offtake is a matter that will be addressed with the AOGCC at the appropriate time.

Inclusion of Point Thomson gas is critical to the success of the Alaska gas pipeline project for a number of reasons:

- Provides support for the critical firm transportation commitments (or "FT") which are necessary to secure project financing and making the project a reality. The market is looking for long term commitments.
- Provides security of supply for downstream consumers by ensuring supply in the event of a temporary shutdown in the Prudhoe Bay Field or should "Yet to Find" gas not materialize or not be adequate to meet gas marketing commitments.
- Mitigates liquids production impacts at Prudhoe Bay. With the production of PTU for gas sales, more Prudhoe Bay gas can remain in the field and continue to enhance oil recovery. [We recognize the field offtake for PBU is a matter that will be addressed with the AOGCC]

Inclusion of PTU gas in a Alaska gas pipeline project provides economies of scale for the project design resulting in reduced tariffs on shippers of gas, which results in increased value to all stakeholders, including the State of Alaska, PTU lease holders, other field owners and even explorers. The importance of low tariffs was recognized last Friday by Governor Palin. She wrote in an ADN Compass piece that "Transportation fees must be kept as low as possible." Including Point Thomson gas in a Alaska gas pipeline does just that.

Using data provided to the public by the Administration and their consultants, the gas pipeline tariff would increase by ~\$1.00/MMBtu if PTU gas is not available to participate. That is a 20% increase in tariffs for the 3.5 BCFD pipeline versus the 4.5 BCFD pipeline. In fact the consultant's report shows a reduction in NPV to the State of almost \$15 Billion dollars without PTU gas. Importantly, this increase in costs could also discourage exploration.

If PTU gas is excluded from a 3.5 BCFD pipeline, approximately 18 TCF of additional discovered gas is required to fulfill a 25 year shipping commitment. This additional gas would have to come from exploration activity within the next few years in time for the first open season. The amount of discovered gas required would be almost equivalent to discovering another Prudhoe Bay, with minimal dependency on the gas to recover hydrocarbon liquids. This level of discovered gas would be required to offset the natural decline that occurs in gas reservoirs while meeting the 25 year commitment at 3.5 BCFD. If PTU gas was included, the additional gas required would be reduced significantly, substantially reducing the dependence on successful near term exploration activities. [Appendix J of Alaska Gasline Determination Document]

If the tariff is \$1.00/MMBtu higher, the costs of gas transportation would increase by \$1.3 billion dollars a year! Over 25 years, the potential term of the FT shipping commitments, shippers would have to pay increased costs of over \$32 billion dollars!

It is very clear that PTU gas is critical to a gas pipeline project. For this reason, we believe the PTU POD should be approved so that we are all in the best position to determine how best to produce PTU and be ready for a gas pipeline.

PTU – PETROTEL ASSESSMENT

I would now like to discuss PetroTel's recent assessment work on Point Thomson, as summarized by the DNR in Appendix O of the Alaska gas pipeline determination documents. I would like to note that the PTU lease holders have not been provided with a copy of the recent PetroTel detailed study, but based on DNR's summary of their analysis we have a number of significant concerns.

The summary report appears to be based on a selective and limited data set and indicates that significant critical work is yet to be done in quite a number of major areas. The report provides an estimate of recoverable liquid and gas hydrocarbons, but does not address fundamental necessary technical work such as development planning, well and reservoir optimization, environmental considerations, risk assessment, costs and economics. This level of technical work is essential to gain a proper understanding of the resource recovery at Point Thomson or for any reservoir in the world.

Based on the significant lack of fundamental technical work no sound conclusions on producible hydrocarbon resources can be drawn from this report. In fact the DNR's summary of the PetroTel report clearly overstates the developable liquid hydrocarbons.

Let me be clear that ExxonMobil and the other 26 lease holders have as much incentive as the State of Alaska to maximize resource recovery at Point Thomson. We have completed extensive reservoir and development planning work leveraging years of objective technical work. We have utilized the expertise of four of the largest private oil and gas companies in the world. Our assessment of Point Thomson is based on all of the data and information available and we have used state-of-the-art geological and reservoir modeling techniques. We have also benchmarked Point Thomson with over 230 analogous gas fields from around the world.

As an example, we have undertaken significant technical work assessing the potential of the oil rim in the Thomson reservoir. We have concluded that the oil rim is thin, discontinuous and heavy. Even DNR's summary of PetroTel's report recognizes that the PTU oil rim is heavy oil, thin and discontinuous; yet it estimates a recovery factor of "close to 50%". The report also assumes you can drill up to 3000 feet horizontal wells to develop the heavy oil. It is highly unlikely that such long reach horizontal wells can be drilled at Point Thomson due to the extended reach and high pressure.

The lease holders have done extensive modeling and benchmarking on the oil rim and cannot achieve an economic recovery factor that exceeds five percent. We believe that once we have the opportunity to share our technical work with the DNR we will jointly conclude that a low economic recovery factor is prudent for the heavy oil rim in the Thomson reservoir.

As I mentioned earlier, the lease holders have completed extensive technical work on all of the PTU reservoirs. This technical work shows that over 90% of the developable hydrocarbons (gas, condensate and oil) can be produced today through a gas sales development. However, we also recognize a gas pipeline project is still many years away. As such, ExxonMobil and the 26 other lease holders developed the current POD which provides the opportunity to recover even more liquids prior to the start of gas pipeline operations.

Through a confidentiality agreement, we are currently sharing all of our most recent technical work with the AOGCC through the Pool Rules Data Room process, which commenced in August 2007. We are doing this on our own initiative as we believe it is a critical step towards assessing the future development of Point Thomson, whether it be gas cycling, oil production, gas sales or a combination.

The PTU lease holders remain willing to share the same technical work and expertise with the DNR.

POINT THOMSON - SUMMARY

I would like to wrap up my testimony. In summary,

- ExxonMobil and the other 26 lease holders were very surprised and disappointed with the DNR's decision last week to not reconsider the POD that was submitted on February 19, 2008.

- The PTU project is already underway and will bring the PTU resources into production by year end 2014, with future expansions leading to a gas sales development.
- We have Alaskan companies working on the project right now. We are ramping up to over 200 jobs by Feb 2009 alone.
- There is no faster path to bring the PTU into production, there is no other way to ensure that the PTU gas will be available for a gas pipeline.
- The drilling data and production data we will obtain through this POD will be critical to assess the resource size at Point Thomson.
- We are already progressing a Pool Rules process through a data room with the AOGCC, a critical step to assessing the optimum development plan for PTU resources.
- There is no better way to ensure the success of the gas pipeline than to continue to progress current PTU development. The PTU gas is critical to the success of a gas pipeline, with 25% of the known gas resources on the North Slope.
- We have consistently stated that we, and the other 26 lease holders, would like to resolve the Point Thomson dispute rather than litigate.
- We would like to find a way to resolve this issue with the DNR, we are looking to the future.

ExxonMobil has been in Alaska for over 50 years and we look forward to working with the Administration, the legislators, industry and the people of Alaska to develop Alaska's resources into the future.

Thank you again for the opportunity to testify today.

POINT
THOMSON
PROJECT

Commitment to Produce

POINT THOMSON PROJECT

ExxonMobil

Taking on the world's toughest energy challenges.™



Plan of Development

Provides for Production

- ▶ Commence Engineering 2008
- ▶ Commence Drilling Program Winter '08-'09
- ▶ Provides Jobs to Over 200 People Next Winter
- ▶ 10,000 Barrels Condensate Per Day - 2014

Further Delineates Reservoirs

- ▶ Producer and Injector Wells
- ▶ Western Delineation Well
- ▶ Eastern Delineation Well
- ▶ 5th Delineation Well (East or West)

Prudently Manages Risks

- ▶ Phased Approach
- ▶ Reservoir Quality and Performance
- ▶ Drilling, Facilities, and Technology

Minimizes Environmental Impacts

- ▶ IPS Utilizes Existing Gravel Pad
- ▶ Offshore Drilling from Onshore Pad
- ▶ Utilization of Ice Roads

Conservation

- ▶ Cycling Enhances Resource Recovery

Expandability

- ▶ Cycling, Oil Production, and Major Gas Sales

\$800 Million Spent to Date

- ▶ 19 Wells Drilled
- ▶ Eight 3-D Seismic Surveys

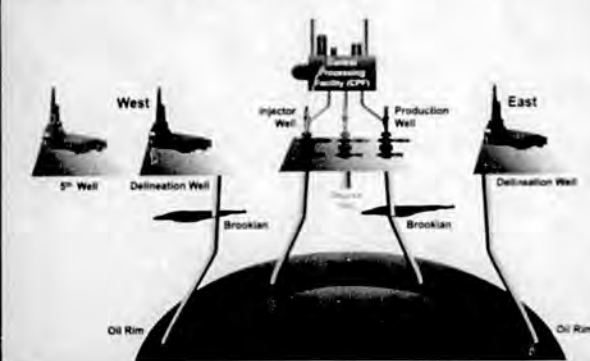
Development

Plan to Develop and Delineate



Production

Plan to Produce Condensate



Commitment

Clear and Committed Timeline



High Pressure Wells



Produce Condensate by Cycling Gas



Point Thomson Unit



Remote High Cost Environment

Challenges and Risks

World's highest pressure gas cycling project

- ▶ 10,000 psi injection pressures
- ▶ Over twice as high as Prudhoe Bay

3,000 psi separator pressure

Extended reach, abnormal pressure drilling

- ▶ World class combination of mud weight and departure

Variable reservoir rock quality

Variable Permafrost thickness

World class project in a remote environment

Solution: Phased Approach

Key Goals

- ▶ Bring PTU into Production
- ▶ Prudently Manages Risk-Reservoir and Technology
- ▶ Future Expandability
- ▶ Positions PTU for Gas Sales
- ▶ Greater Ultimate Recovery



\$1.3 Billion Projected Investment by Owners

- ▶ Owners Support Assured by Senior Corporate Executives
- ▶ Already Secured Drilling Rig and Long Lead Materials
- ▶ Scheduled Milestones for State to Monitor Progress
- ▶ Agreed to Unit Termination if Milestones Not Met

SENIR: presented Tuesday 6-17-2008
morning 1

- AGIA License Hrrgs
Anch. AK

Background on the Point Thomson Unit and Litigation History and Status

Testimony of DNR before Special Session of Alaska Legislature

✓ June 17, 2008

Nan Thompson, Units Manager, Division of Oil and Gas

- 1) Background on Point Thomson Unit-The efforts to encourage development have been ongoing for years.
 - a) The essence of an oil and gas lease is timely production. The state agrees to lease its land to a developer in exchange for a share of the production; which is paid as royalties. Oil and gas leases contain a commitment that the lessee will diligently explore and develop the property. When a lessee fails to fulfill this duty, the lease is forfeited. Article 8, Section 8 of the Alaska Constitution mandates that a lessee's breach of his duty to develop results in forfeiture.
 - b) An oil and gas lease is a temporary (commonly 5 to 10 years) right to explore for and develop hydrocarbon resources. The purpose of the primary term of a lease is to allow the Lessee sufficient time to explore, delineate, and produce the hydrocarbon resources. Leases expire at the end of their primary term unless the lease is producing oil or gas or the lease has become part of a unit.
 - c) Units are formed when a group of lessees apply to the state to form a unit because their leases overlay a common geologic formation that holds recoverable oil or gas. There are about 48 units in Alaska, 14 on the North Slope and 34 in Cook Inlet. Unitization extends the term of lease so that the discovered resources can be produced in an efficient and coordinated manner that will maximize recovery and minimize waste.

- d) ExxonMobil acquired several leases in the Point Thomson area in 1965. ExxonMobil and Chevron acquired 14 more leases in 1969 and 1970. The majority of the remaining leases were acquired in the 1980s and early 1990s.
- e) The Point Thomson Unit was formed in 1977 with 18 leases comprising approximately 41,000 acres of state land. The boundaries have been expanded and contracted several times in the last 30 years. Unit boundaries can be expanded to include lands proven to overlay a producible resource. Unit boundaries are periodically contracted to exclude leases the unit operator fails to develop. The state's form unit agreement requires that all lands not included in a participating area (a process used to allocate production for royalty accounting purposes) within five years of formation of the unit contract out of the unit.
- f) The Point Thomson Unit included 45 leases with approximately 106,000 acres of state land when Commissioner Menge issued his decision to terminate it in November 2006. The leasehold interests were held by ExxonMobil-52%, BP-29%, Chevron-14%, Conoco 2.8% and other minor interest holders.¹
- g) The working interest owners elect a unit operator to manage the unit's business; ExxonMobil has been the unit operator throughout this unit's history. Under the Unit Agreement, ExxonMobil was primarily responsible

¹ The working interest owners agreed amongst themselves several years ago to cross-assign leasehold interests, but did not file the assignments with the state until the day before the leases were to expire. Under DNR's regulations, the cross-assignments are not valid until filed with DNR and approved. Because of the impending lease terminations, DNR did not process the assignments. The impact of the assignments would be to decrease EM's interest in the unit and increase Chevron's.

for exploring and developing the unitized lands. In the recent remand hearing, the working interest owners submitted amendments to the unit operating agreement to change the voting percentages with the stated purpose of preventing one of the major owners from blocking an action the other two agreed upon. Those amendments were contingent on DNR's acceptance of the 23rd POD and not agreed to by ConocoPhillips, thus their current status is not clear.

- h) During the first five year of the unit's existence, ExxonMobil submitted five one-year PODs and drilled several exploration wells. The first POD promised "[i]f oil is discovered in sufficient quantities to warrant future development, the Prudhoe Bay to Valdez oil pipeline will be the probable marketing outlet for the area." Since the early 1980s, ExxonMobil has known about the existence of significant quantities of oil and gas condensate, but has not produced anything.
- i) Despite significant uncertainty about the unit's resources, the unit operator drilled no more wells after 1982. New wells would yield geophysical data that would resolve the remaining uncertainties about the reservoir. Two wells were drilled by BP and Chevron in the 1990s and several other wells were drilled by other producers on lands outside of the unit boundary.
- j) The unit agreement originally provided that it would expire after five years if Lessees failed to form a participating area. Participating areas are formed before production begins to allocate the production to the appropriate lease. Thus, when the parties signed the unit agreement, they expected that the unit would begin production by 1983. Because ExxonMobil was unable to commit to production by then, DNR agreed to remove the PA formation requirement to prevent the unit from terminating. The amendment extended rather than removed the obligation to produce. When DNR agreed to amend the unit agreement it expected that production would begin by the late 1980s.

- k) The years since 1983 can be characterized as a struggle between the state and the unit operator, with DNR demanding development activity and ExxonMobil either insisting that it was not economic or promising to drill wells that were never drilled. The remand decision and decision on reconsideration detail the history.
- l) In 1985 and 1990, DNR contracted leases from the unit because Lessees failed to drill promised wells. In 1995 DNR rejected the 12th POD because it did not include a development commitment.
- m) Significant quantities of oil were discovered by ExxonMobil in 1975, and by BP and Chevron in 1994. The unit plans have never included development of this oil.
- n) By the time the 13th POD was due, the Division of Oil and Gas had a new director who accepted ExxonMobil's promise to develop the unit lands with "farm-out" agreements. Then Director Boyd clearly stated the Division's objective: "Most importantly the division wants a fair and honest attempt to get this acreage explored and be appraised of efforts to develop and produce the Pt. Thomson sands accumulation itself."
- o) When the negotiations over the Stranded Gas Development Act became active in 1997, ExxonMobil linked Point Thomson development with construction of a gas pipeline. ExxonMobil suggested that before the construction of a gas line, it would produce the hundreds of millions of barrels gas condensates through a gas cycling program. In 2001, Exxon also promised that the PTU's considerable oil reserves would be produced starting in 2010. From the late 1990s until 2005, DNR approved PODs with the expectation that wells would be drilled to further delineate the unit's resources and that ExxonMobil was progressing towards production with

development drilling to begin by 2006. During this period, ExxonMobil drilled no wells.

- 2) Unit Litigation-DNR has been successful so far and the litigation will probably continue to the Alaska Supreme Court.
 - a) The basis for the litigation was the 2001 2nd Expansion agreement and the 18th through 22nd PODs that were designed to implement the commitments made in that agreement.
 - b) In 2001 ExxonMobil asked DNR to expand the unit and filed the 18th POD. They repeated their commitment to develop the land by saying "The Owners have endeavored in the attached response to unambiguously demonstrate our commitment to the development of the Point Thomson Unit. We are committing to an aggressive work program and the expenditure of substantial funds that will put us in a position to initiate project execution activities as early as possible." That "unambiguous" commitment was to expedite permitting and engineering studies, drill an exploration well by 2003, a production well by 2006 and seven more production wells by 2007. DNR agreed to expand the unit based on these commitments, but none of the proposed development activity occurred. ExxonMobil eventually paid a penalty of \$20 Million, plus interest, for failure to perform the promised work.
 - c) Since the 21st POD expired in September of 2005, this unit has not been operated under an approved plan of development. The first proposed 22nd POD was submitted and rejected because it did not contain adequate work commitments. Intense negotiations ensued, but the revised POD submitted months later was also rejected. The unit was put in default. The working interest owners asked for reconsideration and appealed to the Commissioner. At the end of the Murkowski administration, Commissioner Menge terminated the unit because ExxonMobil submitted a POD that did

not comply with Director Myers' criteria for what an acceptable POD must contain. Acting Commissioner Rutherford affirmed Commissioner Menge's decision when the lessees asked for reconsideration after the new Governor was sworn in.

- d) The litigation began with lawsuits filed in Superior Court that were eventually consolidated before Judge Gleason. ExxonMobil also separately filed an action for damages and injunctive relief that was dismissed by Judge Michalski. ExxonMobil appealed the dismissal, but never filed their brief with the Alaska Supreme Court.
 - e) Judge Gleason ruled in December 2007 that DNR properly rejected the 22nd POD and that it had the legal authority to terminate the unit, but remanded the case to the agency because she found that DNR had not given the parties enough notice that the unit might terminate and the opportunity to argue about other alternative remedies.
 - f) DNR had a hearing earlier this year on the 23rd POD, the remedy proposed by ExxonMobil. Commissioner Irwin found that the proposal did not meet the statutory criteria for approval and did not protect the state or public interests. Commissioner Irwin also found that the Lessees' failed to explain why termination was not an appropriate remedy given the unit's history. When asked to reconsider, he came to the same conclusion. The remand record will soon be sent back to Judge Gleason.
 - g) Judge Gleason has not set a hearing or told the parties whether she would like briefs and/or oral arguments on DNR's decision. It is likely that her final decision will be appealed to the Alaska Supreme Court.
- 3) Lease Actions-The timing and process for reclaiming the 45 leases varies according to the historical level of activity on those lands.

- a) Almost all of the leases are beyond their primary terms, and thus held because they were a part of the unit. After the initial unit termination decision, DNR began the process of terminating the leases in February 2007 and the leaseholders appealed. Further action on the lease appeals was delayed until the status of the unit was resolved. Thus, agency action on the status of all 45 leases is pending.
- b) 18 of the leases have no wells and are beyond their primary terms and therefore expire when they are no longer part of a unit.
- c) On the leases with wells that were once "certified" there is a factual dispute about whether the wells are still capable of production that is likely to be litigated.



presented 6-17-2008 Tuesday morning
Anch. AK
Howard Johnson Plaza

AGIA License Hearings

PetroTel
Leaders in Oil and Gas Technology

Resource Assessment and Field Development Study of the Thomson Sand, in the Point Thomson Area, North Slope Alaska

Commissioned by
State of Alaska, Department of Natural Resources, Division of Oil and Gas

PetroTel Inc.

5240 Tennyson Pkwy, #207
Plano, TX 75025

Investigators:

- ✓ Anil Chopra - Distinguished Reservoir Engineering Advisor
- Fred Stalkup - Distinguished Reservoir Engineering Advisor
- Qichong Li - Senior Reservoir Engineer
- Ravi Sharma - Project Director
- Thomas Phillips - Distinguished Geological Advisor
- Thomas O'Brien - Distinguished Geological Advisor

Alaska Division of Oil and Gas

- Jack Hartz - Reservoir Engineer
- ✓ Julie Houle - Petroleum Geologist
- ✓ Steve Moothart - Petroleum Geologist

6/16/2008

Commissioned: Spring 2007

Point Thomson Reservoir Study

Purpose / Scope

- PetroTel Inc. conducted an independent evaluation of the Point Thomson reservoir to determine the resources contained in the reservoir and analyze possible recovery methods
- Two main objectives:
 - Construct three-dimensional (3D) geologic models to evaluate the proven and potential hydrocarbon resource
 - Dynamic reservoir simulation to test potential development and off-take scenarios
 - Determine the impact on ultimate recovery of both gas, associated condensate and oil
- Focused on the Thomson sand and does not include resources tested from the underlying Pre-Mississippian strata or overlying Brookian accumulations

*presented
Steve Mothart*

Point Thomson Reservoir Study Geology / In-Place Volumetrics

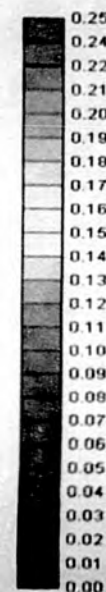
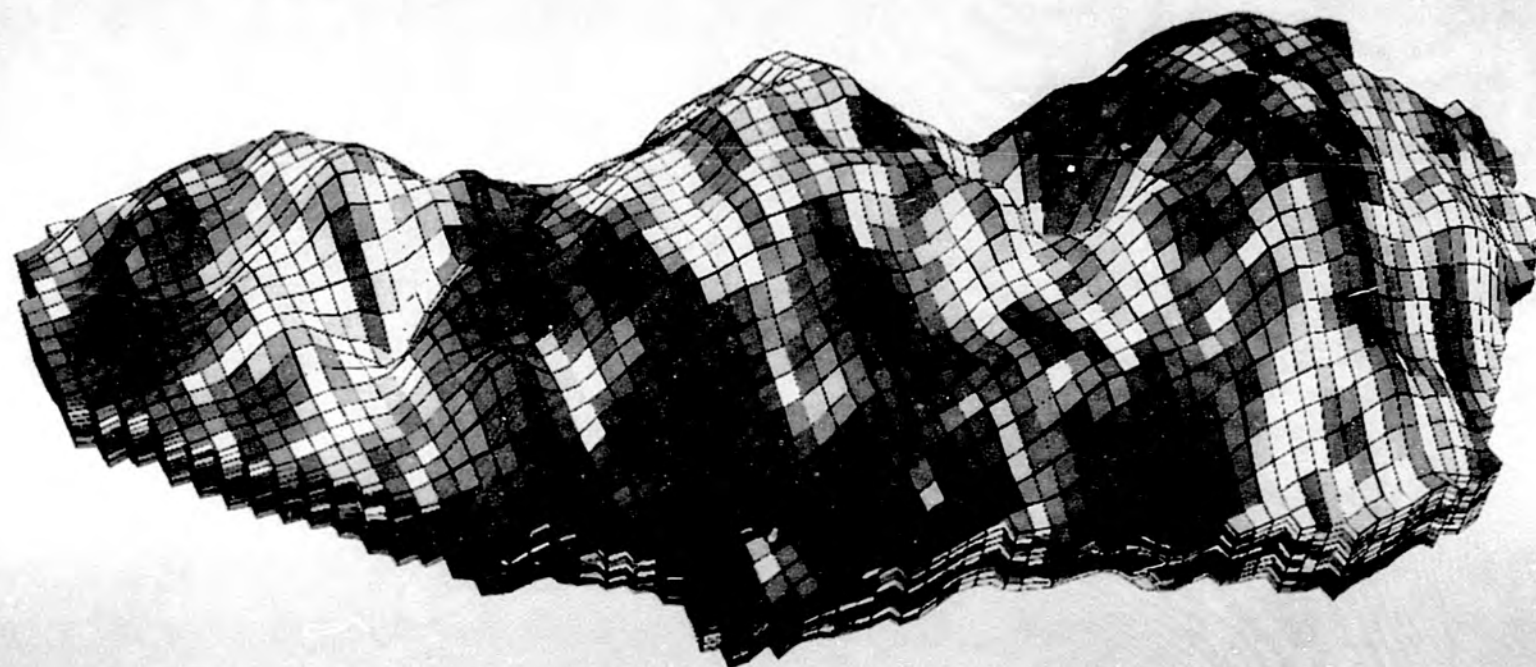
- Eleven 3D geologic models were constructed
- In addition to gas and condensate, Thomson sand also contains a thin and potentially discontinuous oil-rim that tested over 18° API gravity oil
- No definitive, production test exists in the oil-rim of the Thomson reservoir
- Range of volume in the oil-rim varied in the models due to uncertainty of the depth of fluid contacts
- Original in-place hydrocarbon volumes from geologic models:
 - Gas = 8.5 ^{to} 10.4 trillion standard cubic feet (TSCF)
 - Associated condensate = 490 – 600 million stock tank barrels (MMSTB)
 - Potential oil (oil-rim) = 580 – 950 MMSTB

liquid
hydrocarbons
entrained in
gas

42 gal
@ surface
conditions

presented by
Steve Moothart
3

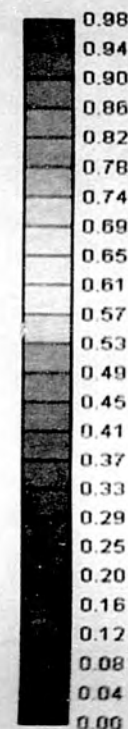
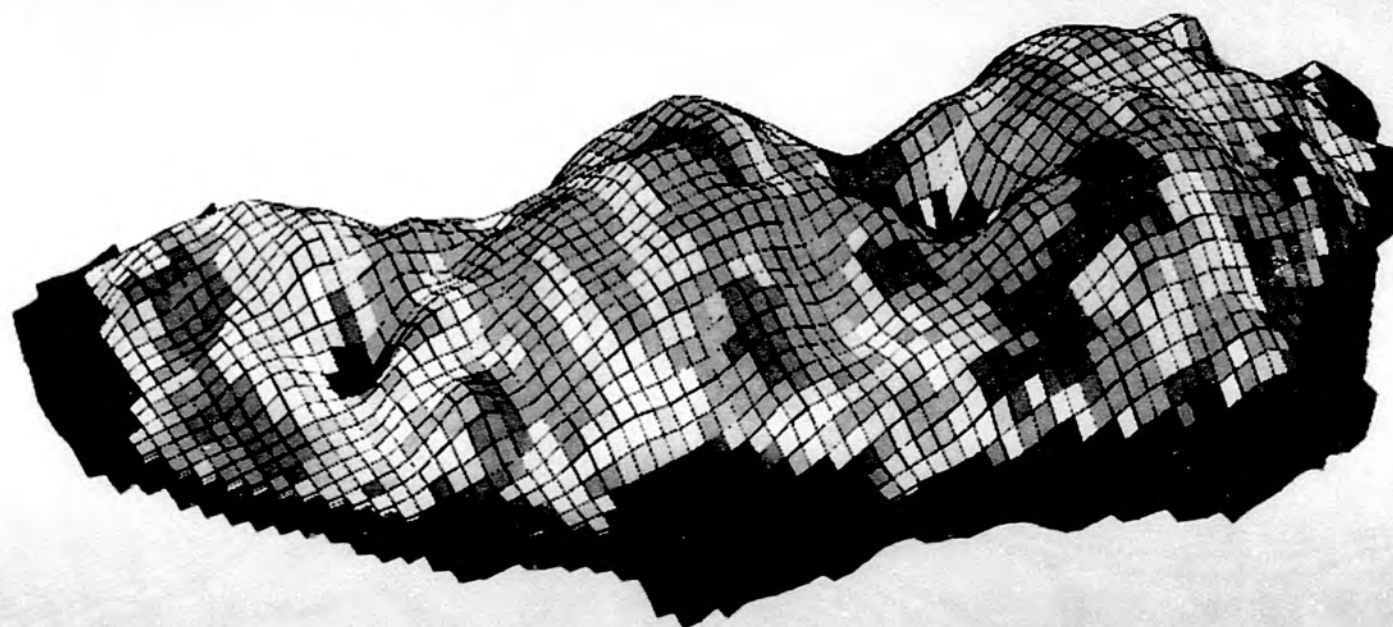
Simulation Model Porosity



presented by: Dr. Chopra

Simulation Model - Sg

*(Gas Saturation)
gas in the gas cap*

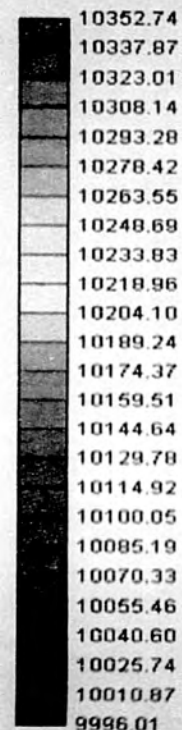
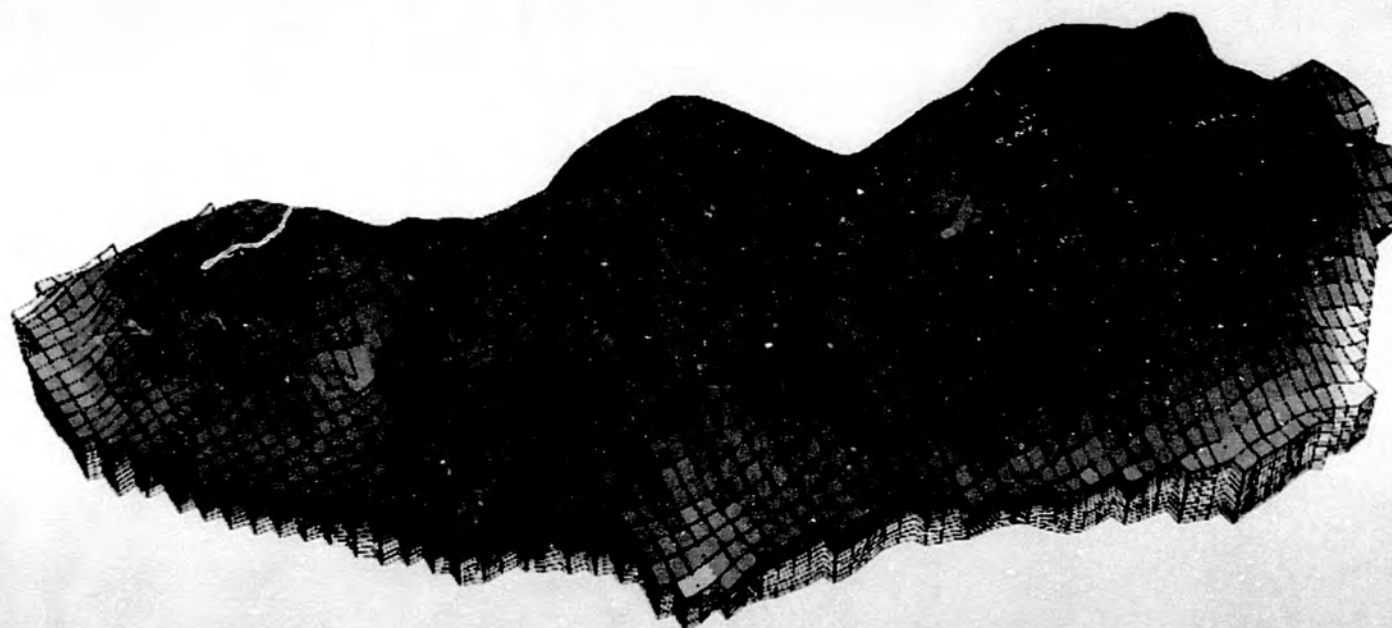


presented: Dr Chopra

very high pressure

Simulation Model - Pressure

@ 12,500' depth



presented by: Dr Chopra

Point Thomson Reservoir Study

Reservoir Modeling- Over 70 simulations

- Cases were run to model different recovery methods including primary depletion, gas cycling, and oil rim production
- Scenarios were designed to test and evaluate key sensitivities to recovery method
 - Well configurations
 - Operating constraints
 - Number of development wells
- Evaluated impact of variables on ultimate recovery with development method
- No physical constraints such as location of surface drill sites and facilities or drilling departures were modeled

Point Thomson Reservoir Study

Reservoir Simulation - Primary Depletion

1st
Scenario

- Primary depletion (gas blowdown) fastest - but recovers the least total hydrocarbons
 - Up to 70% of gas recovered (6-7 TSCF) with 22 wells in 12-15 years
 - Condensate recovery is approximately 26% of the in place volume (127-156 MMSTB)
 - The majority of the condensate is left in the reservoir by condensation below dew point
- Pressure maintenance required to increase condensate recovery
- Reduction of reservoir pressure during primary depletion significantly reduces potential recovery from the oil-rim
- Gas blowdown and sale of the gas can be done at any time after cycling and recovery of the condensate and oil

loss of
74% of
condensate