HB 3001
SB 3001
6/17/08
SPECIAL SESSION DOCUMENTS

Senator Huggins, Senator Stedman, Representative Samuels, members of the Alaska Legislature, citizens of the State of Alaska: Thank you for inviting me here to talk with you about the Point Thomson technical issues under the regulatory oversight of the Alaska Oil and Gas Conservation Commission, or AOGCC.

I will start with a brief description of the AOGCC's statutory responsibilities, just to put into perspective the small but important role we play in the State's quest to achieve North Slope gas sales. I'll then give you what I hope to be an easy-to-follow description of the issues concerning us at Pt Thomson. I'll end with a description of how we are working and will continue to work to ensure that Pt Thomson is developed and produced appropriately. After that I will be available for any questions you might have.

In understanding what the AOGCC does, it's important first to know how we are different from the DOG, from whom you've just heard. The DOG is responsible for maximizing the value to the State of Alaska of the oil and gas under State lands. The AOGCC regulates oil and gas operations throughout the State, not just on State lands, but also on Federal Native, and privately held lands. And the State, by law, has no greater standing in our adjudications than any other party.

The AOGCC has five primary responsibilities. We prevent waste of oil and gas, we encourage greater ultimate recovery of oil and gas, we protect sources of fresh ground water from harm by oil and gas operations, we protect human health and safety related to downhole oil and gas operations, and we protect correlative rights. And, as I said, we do this throughout the State, regardless of land ownership.

In our day-to-day regulatory oversight we are called upon to exercise all of these responsibilities in a variety of ways, but the two responsibilities I want to focus your attention on today are preventing waste of oil and gas and encouraging greater ultimate recovery of oil and gas. I ask you to keep these in mind as we proceed with the rest of this discussion. And I also ask you to keep in mind that nowhere in our list of responsibilities will you find mention of making the most money, balancing the budget, or making any particular set of constituents happy. You guys have the tough job – all we deal with is science and engineering.

So let's talk a little science and engineering.

Although most people think of and refer to Pt Thomson as a gas reservoir, the gas is so rich with condensate – liquid hydrocarbons associated with the gas – that we actually classify Point Thomson as an oil reservoir. That point is important because, as a general petroleum engineering rule, if you produce the gas from an oil reservoir before producing all of the oil first, you stand to lose some of the oil.

In engineering vernacular Point Thomson is what we call a gas condensate reservoir or a retrograde condensate reservoir. In such a reservoir, the hydrocarbons are in the gas phase until the pressure drops below a certain point – called the dew point. When the pressure drops below the dew point, some of the hydrocarbons, the condensates, switch to the liquid phase and drop out of the gas. When this happens, a substantial portion of those liquids can be trapped in the reservoir, and can never be recovered.

In many retrograde condensate reservoirs, cycling – that is reinjecting the produced gas over and over again to maintain high reservoir pressure until the liquid condensate has been recovered – is the way to prevent these losses. Looking simply at the reservoir mechanics issues – not getting into financial concerns or politics – cycling the gas until most of the liquids have been recovered is the way to achieve greater ultimate recovery and prevent waste from a gas condensate reservoir such as Pt Thomson.

Publicly available estimates of recoverable liquid hydrocarbons associated with the gas at Pt Thomson vary from 200 to 500 million barrels, depending on the source and the method of development. As I just said, if we produce Point Thomson as a gas reservoir without cycling first, a significant portion of those liquids are at risk. And don't let me underemphasize the value of this liquid resource; it's the size of another Alpine Field.

There is a second potential problem with not cycling first. If we don't recover those liquids first, then as the reservoir pressure drops they will drop out in the place where the pressure is lowest – adjacent to the wellbores. When liquids drop out there, they damage the producibility of the reservoir and, thus, decrease the ability of the wells to bring the gas up to the surface. The operator can undo some of this damage through well interventions, but these cost money, must be repeated as additional damage is done, and eventually may no longer be effective at fixing the problem.

This is important to the AOGCC because it will result not only in liquid losses, but also in gas losses. And it is important to the State for that reason AND because, under ACES, the State shares the cost of these interventions that will likely be done over and over to keep the gas wells producing. However, you should keep in mind that cycling will likely add significant capital costs, which the State would, again, share via ACES.

A third problem exists around producing the gas from Pt Thomson. Underlying this thick gas condensate reservoir is a relatively thin oil layer. If we produce the gas from Pt Thomson before producing the oil, much of that oil will be lost.

So what will the AOGCC do about our concerns?

Since we are charged with preventing waste of hydrocarbon resources in Alaska and since producing gas from an oil reservoir can cause waste, we determine when and how much gas can be produced from every oil reservoir throughout the State. And we do this with an eye to greater ultimate recovery of both the oil and the gas.

We do not typically dictate to an operator what he must do. Rather, the operator typically comes to us with a request for permission to do something and we allow it, disallow it, or allow some modification to the originally proposed plan. For instance, we do not tell an operator where or how deep to drill his wells. Rather, the operator requests to drill a particular well in a particular location to a particular depth using particular procedures. We approve the request, deny it, or approve it subject to some limitations or modifications.

The same will hold true for gas offtake from an oil field, such as Prudhoe Bay and Point Thomson. Before the operator can produce gas from Point Thomson, he must come to us and request a gas offtake allowable. As a very important part of that request, he must prove to us that waste will not occur. Without that proof we cannot grant the request.

Unfortunately not enough is currently known about the Thomson Sand, either the gas portion or the oil layer, to know what the right answer is – for the oil companies or the State. We don't know if there is adequate connectivity in the gas condensate part of the reservoir for cycling even to work. And if it doesn't work, then both the oil companies and the State will have wasted a lot of money. Also, we don't know enough about the characteristics of the oil in the oil layer to know whether it is technically recoverable. In other words, even if we all agreed to get that oil first, we don't even know if it can be done. The oil may or may not be too viscous to produce; the gas above and water below it may cone into the oil layer and drown out the oil production; the extremely expensive wells required to attempt to produce the oil may or may not be economical. We just don't know enough. And without a bit of drilling, producing, and cycling we never will.

This concludes my prepared testimony. I will be happy to answer any questions.

Cathy Foerster, AOGCC Commissioner
June 17, 2008

bp

Doug Suttles
President

BP Exploration (Alaska) Inc
PO. Box 196612
900 E. Benson Boulevard
Anchorage, Alaska 99519-6612

June 16, 2008

HAND DELIVERED

The Honorable John Coghill, Chair of House Rules Committee, Alaska Legislature
&
The Honorable Charles Huggins, Chair of the Senate Special Committee on Energy, Alaska Legislature

Re: Point Thomson Plan of Development, 2008

Direct 907 564 5422
Main 907 561 5111
Fax 907 564 5900
doug.suttles@bp.com

Mr. Chairman,

I would like to take this opportunity to confirm BP's position with regards to bringing Point Thomson into production.

BP is fully supportive of the proposed plan to delineate, develop and produce Point Thomson liquids (condensate and oil) and gas. BP has a significant stake in the leases holding a 32% working interest. BP demonstrated its commitment to the $1.3 billion Plan of Development by:

(i) providing a letter of commitment from our Chief Executive of Exploration and Production, Andy Inglis (attached),

(ii) agreeing to unit termination if the parties fail to meet specific milestones, and

(iii) changing the unit vote to a simple majority in order that no one party can block development decisions.

We believe that time is of the essence and that the delineation and development of Point Thomson as proposed, will provide vital information for finalizing the design of any gas pipeline project and the optimum development of Pt Thomson liquids.

We are very concerned that the study conducted by PetroTel Inc. for the Department of Natural Resources (DNR) only became public after the recent Point Thomson hearings before the DNR. The Pt Thomson owners have not been provided the opportunity to review the data on which the study is based or to respond to it on the record. The conclusions reached in the study have neither been audited nor critically examined by those who know the realities of the Point Thomson field best.

Point Thomson is very important to BP. We wish to move forward with delineation and full field development of both liquids and gas. The availability of Point Thomson gas is critical for the success of any major gas pipeline project.

BP stands ready to work with the State of Alaska to settle the current dispute over Pt Thomson. We are confident that we can find a solution that works for all parties.

Thank you for the opportunity to confirm BP's position regarding this important issue for BP, Alaska and the gas pipeline project.

Sincerely,

Doug Suttles

cc: Alaska Legislature

Andrew Inglis [illegible]
Group Managing Director and
Chief Executive of Exploration and Production

BP p.l.c.
1 St James's Square
London
SW1Y 4PD
United Kingdom

[illegible] March 2003

Our Ref: AG/DS/CL

Mr [illegible]
[illegible]
Department of Natural Resources
[illegible] W. [illegible] Avenue, Suite 1400
Anchorage
Alaska 99501-3650

[illegible]

Dear [illegible]

[illegible] Executive of Exploration & Production, I write to assure you of BP's [illegible] to the Plan of Development recently proposed by the owners of [illegible] Unit. BP is fully committed to carrying out the Plan of [illegible] and, on approval of the Plan of Development, will proceed to [illegible] of the commitments contained therein.

[illegible]

A [illegible]
Group Managing Director and
Chief Executive of Exploration and Production

Registered in England and Wales No. [illegible]
Registered Office: 1 St James's Square
London
SW1Y 4PD
United Kingdom

Chevron

Global Upstream and Gas

Chevron - Alaska Area
Point Thomson Testimony to the Alaska Legislature

John Zager
General Manager, Alaska

Vince LeMieux
Manager, Alaska New Ventures

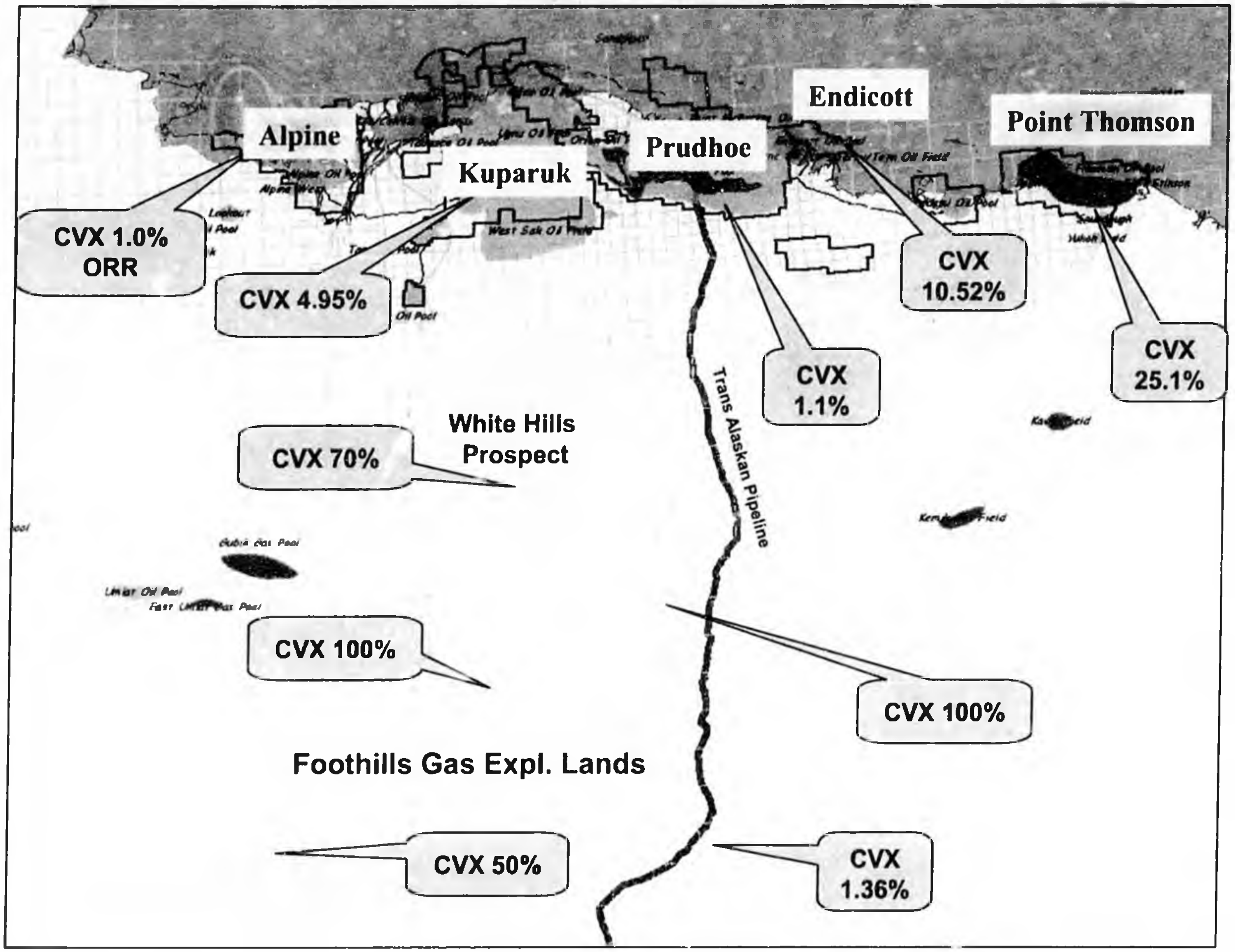
Anchorage, Alaska
June 17, 2008

Chevron has standing in the commercialization of North Slope gas

Working interests (WI) in established North Slope fields (PBU, KRU, DIU) and an overriding royalty interest in Alpine

- Active exploration, development and operation of oil and gas assets on the North Slope:
  - Completed the first season of our exploration program in our White Hills Prospect; and
  - Working on exploration of gas prospective leases in the Foothills area.
- Chevron is a 25% WI in the Point Thomson leases. Unique to Chevron, Point Thomson is its major source of North Slope gas.
- We have proposed an aggressive plan to begin production (POD), starting with gas cycling, condensate production and preparation of the field for major gas sales.
  - At a minimum the DNR decision will delay development through loss of 2008-09 drilling season.
  - It currently appears that the DNR is set on preventing development in favor of litigation by terminating the unit.

Chevron North Slope Assets



Point Thomson: Fact or Fiction?

#1: "Point Thomson is not needed for a g s pipeline."

#2: "The lessees are warehousing Point Thomson."

#3: "DNR rejected the plan of development on its merits."

#4: "The lessees are not doing any work on Point Thomson."

#5: "Point Thomson is 'wildly economic'."

Point Thomson: Fact or Fiction

#1: "Point Thomson is not needed for a gas pipeline."*

Fact:

- There are insufficient proven reserves available to back a commercially viable 4.5 BCFD gas pipeline without Point Thomson.
- Will anyone commit FT (ship-or-pay) for the 'yet to find' (YTF) resources? Without Point Thomson, this is a significantly bigger number.
- A Prudhoe Bay-only pipeline delivers less value to the State and Producers through higher tariff rates and the loss of oil resulting from blowing down Prudhoe Bay.

* This contradicts the previous administration position.

Point Thomson: Fact or Fiction

#2: "The lessees are warehousing Point Thomson."

Fact:

- At no time has there ever been a way to get the gas to market; it is disingenuous to say it has been warehoused.
- Until the recent ramp up in prices, the condensate resource was clearly uneconomic; it remains challenged.
- The oil resource is problematic due to its depth, range in quality, and potential range of recoverable volumes. It is currently viewed as economically challenged. The proposed POD is designed to resolve these uncertainties.

Point Thomson: Fact or Fiction

Chevron

#3: "DNR rejected the plan of development on its merits."

Fact:

- The prior plan and amended plan were rejected because they did not "commit to put the unit into production." The current plan commits to put the unit into production as well as delineate all reservoirs.
- In its April 2008 decision, the DNR stated that the current plan is "a technically reasonable first step for developing these lands."
- But instead of considering the plan on its merits, the Commissioner of the DNR has:
  - Taken the unprecedented step of decertifying wells for the purpose of terminating a unit through administrative action.
  - Has ruled that the proposed PODs do not coincide with his preferred development all the while refusing to specifically lay out his preferred development.
  - Moved to expropriate the asset despite acknowledging the plan's merits by claiming a lack of "trust" of the lessees.*
  - Refused to meet with the lessees to outline his expectations.

* For over 27 years, the Commissioners of DNR and the lessees agreed the PODs set out the appropriate course of action for the development of Point Thomson as evidenced by the ongoing DNR approval of the PODs up to August of 2005.

Point Thomson: Fact or Fiction

#4: "The owners are not developing Point Thomson."

Fact:

- Over the last 30 years, the owners have spent over $800 million on the exploration and development of Point Thomson.
- Despite the State's move to expropriate the leases, the lessees have dedicated significant resources to continue technical work:
  - Reservoir simulation and flow stream modeling;
  - Planning for development;
  - Initiating engineering design for facilities;
  - Making financial commitments for drilling rig and long-lead items; and
  - Progressing permitting applications.

Point Thomson: Fact or Fiction

#5: "Point Thomson is wildly economic."

Fact:

- The complexity and unique nature of this reservoir makes it a very challenging and expensive field to develop.
- While the upstream has been described as delivering a greater than 50% rate of return (ROR), specific to PTU it appears that the Black & Veatch base case depicts the value at a modest 13% ROR
    - Aggressive assumptions on gas price and cost trends
    - Base case of an initial gas blow down (i.e., no gas cycling)

The Future of Point Thomson

The Commissioner's **new view** of PTU ("validated" by the PetroTel report): PTU needs to cycle gas for as many as 20 years before major gas sales.

Chevron Comments on PetroTel report:

- PetroTel's work is theoretical; they clearly indicate they did not consider physical, environmental, safety, and economic factors; as a result of this and other optimistic assumptions, it significantly overstates resources in place and the amount that is recoverable.
- PetroTel claims that the field has "as much as 500MMSTB" of incremental recoverable liquids if cycled for 20 years. Even assuming cycling is possible and economic, the incremental liquid volumes are likely to be less than 150MMSTB and would likely result in an acceleration of PBU blow down **resulting in less oil produced on the North Slope not more.**

The Future of Point Thomson
Chevron's View

Chevron

- There is great uncertainty and therefore great risk in a gas cycling condensate project; it may or may not work.
  - Point Thomson has unique, challenging reservoir issues – it is like no other field, anywhere in the world.
  - Cutting edge technology is required for facilities and drilling.
  - Wide range of potential outcomes; most likely is failure
- Successful "oil rim" development is not certain.
  - Characteristics of the oil rim; oil quality, oil distribution across the field, oil reservoir quality, aquifer impact, etc. increase risk
  - Economics will be particularly challenged given potential recoveries and costs per well.
- One point of agreement by all: a phased approach is required (consistent, again, with the proposed POD).
  - In its April 2008 decision, the DNR stated that the plan is "a technically reasonable first step for developing these lands"

Developing Point Thomson Correctly

The right progression for PTU will be:

- Proceed with the proposed POD to bring PTU into production:
  - With timely approval, delineation drilling to begin this winter further testing extent and quality of reservoir
  - Gas cycling project progressed to test viability
  - Prepare for Major Gas sales in parallel with development work
  - Results from production in 2015 - 2018 timeframe
- If cycling doesn't work, adjust to PTU gas blowdown and preserve gas at Prudhoe Bay, and therefore, maximize overall oil production on the North Slope

Consequence of delay in proposal to produce PTU

- Under sizing of the initial pipeline 4 – 4.5 bcf/d to 3.5 bcf/d, thereby crippling economics and slashing over all revenues
- Premature termination of cycling at PBU and loss of oil ($120 wellhead/boe for oil vs $24 wellhead/boe for gas)
- Lower value of entire gas project to State and Producers

Chevron desires to market North Slope gas

- Chevron is currently not a participant in any of the proposed gas lines
- Chevron will participate in future North Slope gas sales:
  - We will commit FT for our known gas reserves to a pipeline that we are confident provides reasonable upstream economics and terms
- Our drivers are predictable economics and risk sharing:

Key Variable	Controllable?
Point Thomson resolution	Yes
Future Gas prices	No
Construction cost	Partially
Cost risk allocation	Yes
Certainty of state taxes	Yes

  - Many of these elements are aligned with the State
    - Encouraging the development of infrastructure to realize the value of gas assets on the North Slope
    - Doing projects in the most economic way; especially true given the nature of the ACES tax approach

Summary

- PTU is critical to any major gas pipeline.
- PTU development should begin as soon as possible; the proposed POD is the right plan.
- The DNR should have approved the proposed PTU plan on its merits. Why didn't it . . . ?
- The current lessees can and will (if allowed) develop Point Thomson better and faster than anyone else.
- Chevron is being forced to litigate to protect its rights.
- Chevron wants to sell its North Slope oil and gas.

So . . . Where are we?

- Protracted litigation; No settlement discussions
- Point Thomson is out of the gas pipeline
- Everyone agrees on the substance of the proposed POD
- Chevron stands ready to perform the proposed plan
- Owners remain ready to drill in 2008-09

And . . . What can be done?

- An independent, objective review of the pipeline analysis should be undertaken
- In an open and honest government, the parties to the Point Thomson litigation would sit down and talk through their differences

Role of the Alaska Oil and Gas Conservation Commission in Establishing Allowable Gas Offtake Rate for Prudhoe Bay

The State of Alaska and other interested parties are engaged in determining how best to bring North Slope gas to market. The Alaska Oil and gas Conservation Commission ("AOGCC") has a very important role in this process – to protect the public's interest by preventing waste and insuring greater ultimate recovery of both oil and gas. To fulfill this role, the AOGCC will decide what gas offtake rates should be allowed from Prudhoe Bay and other North Slope oilfields. Considering only the laws of science, these decisions are very simple; to prevent waste and insure a greater ultimate hydrocarbon recovery, produce all of the commercially recoverable oil in a reservoir first, and then "blow down" its gas cap. The AOGCC recognizes, however, that many other factors will – and should – be considered in exercising its regulatory powers.

Before considering other factors, it is essential first to understand the science. Extracting gas from an oilfield like Prudhoe Bay triggers a series of events. The pressure in the gas cap decreases and becomes lower than the pressure in the oil-bearing part of the reservoir. As driven by the laws of physics, the reservoir then works to get back to equilibrium, i.e., the same pressure throughout. To do this, some oil, which is at a higher pressure, moves up into the lower pressure gas cap and the pressure in the oil-bearing part of the reservoir drops. This process continues as the pressure throughout the reservoir equalizes at a lower pressure than before. And as more gas is withdrawn, the process repeats, causing more oil to move into the gas cap and also causing the reservoir pressure to decrease further.

Both the movement of oil into the gas cap and the decrease in reservoir pressure jeopardize oil reserves.

Let's look at the movement of oil into the gas cap first. Think about what happens when you drain the oil from your car or when you pour cooking oil into a measuring cup. When you empty the container, some of the oil sticks to it and will not come off. That is what happens to oil when it moves into the gas cap, a part of the reservoir that has never contained oil but has always only held gas. However, because that container is porous rock rather than glass or plastic, the amount of oil that sticks is much greater. The previously "dry" reservoir rock becomes coated with oil. Although some of this oil can be produced, a substantial portion (in some fields over 20 to 30 per cent) sticks to the rock and will never come out. In short, producing gas without replacing the gas cap fluids will cause some oil to stick to the reservoir rock and decrease the total recovery of oil.

Now let's look at decreasing reservoir pressure. Think about an aerosol container. It starts out with high pressure inside; if you puncture it, it will explode. As you use it, more and more of the fluids – both the active product and the carrier gas -- are released and the pressure decreases until, eventually, you push the button and nothing happens. When you shake it, you might be able to hear that there is still hair spray or some other product inside, but you can no longer get it out. At this point the pressure has decreased so that you could even puncture the container and nothing would happen. Similarly, in an oil reservoir, the reservoir pressure provides the energy that allows the oil to flow through the reservoir and up the well bore. As fluids are produced, the pressure decreases and the reservoir loses this energy. Eventually, as more and more gas is produced and the pressure continues to drop, there is insufficient energy to drive the oil from the reservoir. Typically, operators of oil reservoirs maintain reservoir pressure and energy by re-injecting produced gas and injecting water to replace produced oil. They continue this process until they have recovered all the oil. Then, when no commercially recoverable oil is at risk, they "blow down" the gas cap. They do this because producing gas from an oil reservoir and not replacing it will result in a decrease of reservoir energy and, therefore, a decrease in oil recovery.

Another bad thing happens when the reservoir pressure decreases; some oil changes from liquid to gas. The remaining oil becomes thicker. Think about soup cooking; as water evaporates, the remaining liquid becomes thicker. In an oilfield, this thickening makes it harder for the oil to flow and, thus, decreases oil recovery. We all know that it is much easier to draw water than molasses up a straw.

In summary, looking simply at the reservoir engineering science, producing gas from an oil reservoir while there is still commercially recoverable oil remaining WILL cause a portion of the oil resources to be lost, and thus, the gas cap in an oil reservoir should only be "blown down" when no commercially recoverable oil remains.

The explanation above assumes that all of the gas can be recovered after all of the oil has been produced, and for most Lower 48 scenarios this is a reasonable assumption. However, for the North Slope, there will be a trade-off between leaving oil in the ground and leaving gas stranded, and this trade-off will be influenced by several factors.

For example, the remaining useful life and increasing operating cost of the aging North Slope infrastructure will impact this balance between losing oil and stranding gas. Much of the North Slope infrastructure that was put in place thirty years ago for oil production will still be necessary for gas production. As this infrastructure ages, two things happen: 1) the cost to operate the equipment increases, and 2) components break and must be repaired or replaced. The later in time that the gas is produced, the higher the costs will be to operate, repair and replace equipment and, thus, the sooner the gas will become uneconomical to produce and the more gas that will be left stranded.

The minimum rate at which the Trans-Alaska Pipeline System ("TAPS") can operate will also impact the balance between losing oil and stranding gas. Although the gas will have its own line which will operate independently of TAPS, continued operation of the TAPS line will impact the economic life of the gas production because, as long as TAPS is operating, many of the operating, repair and replacement costs will be shared by both the oil and gas production, thus extending the time before either becomes uneconomical to operate.

These and other factors complicate making the gas offtake rate and timing decisions for North Slope fields. The AOGCC is charged with preventing waste and insuring the greater ultimate recovery by making sure that the operators act in accordance with good oilfield engineering practices. In executing this responsibility, the AOGCC must be cognizant of the balance between oil recovery optimization and gas recovery optimization. This will be no trivial task.

In January 2006 the AOGCC, with the assistance of well qualified consultants, began a thorough review of the latest Prudhoe Bay reservoir simulation work made available by BP Exploration (Alaska) ("BPXA") and their partners to obtain a better understanding of the field that would enable the AOGCC to respond more promptly to a future gas offtake application. The information provided by BPXA and their partners was not in support of any application before the AOGCC and therefore is considered confidential information. This study was completed on February 28, 2007, and a non-confidential summary is available on the AOGCC website (http://www.aogcc.alaska.gov/Gas/gasindex.shtml). In general, the study concluded, that total energy recovery is substantially decreased with an earlier, higher rate gas sale. The study also concluded that increased oil capture prior to gas sales can increase hydrocarbon recovery and make the total hydrocarbon recovery less sensitive to gas offtake rates and gas sales startup dates.

Role of the Alaska Oil and Gas Conservation Commission in North Slope Gas Sales

The State of Alaska and other interested parties are engaged in determining how best to bring North Slope natural gas to market. The Alaska Oil and Gas Conservation Commission ("AOGCC") has an important responsibility in this process – to protect the public's interest by preventing waste and insuring greater ultimate recovery of oil and gas. To fulfill this role, the AOGCC must determine what gas offtake rates should be allowed from North Slope fields, most notably the Prudhoe Oil Pool and the Pt. Thomson gas condensate reservoir.

There are over 35 trillion cubic feet of gas reserves within these two fields. However, hundreds of millions of barrels of oil and condensate could be lost if gas offtake from these fields is not correctly managed.

In general, maintaining reservoir pressure enhances oil recovery, but producing gas depletes reservoir pressure. Therefore, gas reserves in most fields are usually sold only after the liquid hydrocarbon reserves have been depleted. Until then, the gas that is produced is used to promote liquid production in various ways (including being reinjected so that it can provide the energy needed to get the liquid hydrocarbons to the surface and providing a source of gas for miscible injectant used in enhanced oil recovery operations). And that is exactly what is happening right now at Prudhoe Bay and other North Slope fields.

The North Slope gas sales project will ultimately involve trade-offs between oil and gas recovery. The documents *Role of the Alaska Oil and Gas Conservation Commission in Establishing Allowable Gas Offtake Rate for Prudhoe Bay* and *Role of the Alaska Oil and Gas Conservation Commission in Approving Pool Rules for the Point Thomson Field* explain these trade-offs. This document explains the process the AOGCC is using to insure greater ultimate total hydrocarbon recovery, i.e., recovery of both oil and gas, as the North Slope gas project moves forward.

Normally, the operator of an oil or gas field applies to the AOGCC for "Pool Rules." These are specific rules that stipulate how to develop the reservoir in a way that maximizes oil and gas recovery. ExxonMobil and their partners at Point Thomson have not yet applied to the AOGCC for Pool Rules.

Nor have BP Exploration (Alaska) ("BPXA") and their partners at Prudhoe Bay applied for an amendment of the current pool rules to allow for a higher gas offtake rate. The existing Prudhoe Bay gas offtake rate was set in 1977 at 2.7 billion standard cubic feet (BCF) of gas per day. After deducting gas used as fuel and in enhanced recovery operations, this leaves about 2 BCF of gas per day available for sales. However, the gas sales scenarios that are being discussed publicly could require increasing the allowable Prudhoe gas offtake rate.

Normally the AOGCC would wait for an application from the operator and its partners before performing the reservoir studies necessary to establish or increase gas offtake rates. However, that would delay the AOGCC's decision-making such that it could disrupt the timetable for a potential gas pipeline project. The AOGCC needs to complete its evaluations and make its rulings for both Prudhoe Bay and Pt. Thomson so that the operators and their partners have approved allowable gas offtake rates that they can use in the "open season" process that is required under the Federal Energy Regulatory Commission ("FERC") regulations.

Therefore, the AOGCC has chosen a proactive approach. There are two ways the Commission might take a proactive role with respect to such studies. One would be to conduct or arrange for consultants to conduct independent reservoir studies. The other would be to participate with the operators and their partners in their reservoir simulation studies, so that questions can be answered and adjustments can be made up front. Assuming adequate cooperation on the part of the operators and their partners, the latter approach has significant advantages: lower cost to the State of Alaska, less time required to complete evaluation of the studies, more complete and accurate input data, and use of proven, probably more sophisticated reservoir evaluation tools.

In 2005, the AOGCC held hearings regarding whether the gas offtake rate from Prudhoe Bay should be updated. The AOGCC decided that, although the 1977 allowable gas offtake rate was based on the best available data at the time, the appropriate gas offtake rate must be redetermined using the reservoir description and performance information that has become available in the past 30 years. Further, BPXA, their partners and the AOGCC established principles by which to perform collaborative studies. The report of the 2005 hearings and the study principles were issued by the AOGCC on December 5, 2005.

The AOGCC contracted reservoir evaluation consultant to assist its technical staff in performing the Prudhoe Bay study. The BPXA and their partners agreed to provide the AOGCC staff and consultants access to their simulators including the underlying engineering, geologic, geophysical, and simulation information. A data room was set up in BPXA's Anchorage offices, equipped with computers and software allowing review of the simulator results. BPXA and their partners voluntarily offered to make the data room information available. The information meets the standards of AS 31.05.035(d) and 20 AAC 25.537(b), entitling it to be held confidential during and after the study period.

The AOGCC's Prudhoe Bay study process began in January 2006, and was completed on February 28, 2007. BPXA and their partners are not currently prepared to ask for a revised gas offtake rate from Prudhoe Bay, but the AOGCC has scheduled a hearing for June 19, 2007, to consider amendments to Rule 9 of Conservation Order 341D that set the 2.7 BCF of gas per day offtake rate for Prudhoe Bay. If and when BPXA and their partners apply for a revised gas offtake rate for Prudhoe Bay, they will be required to submit for the record reservoir studies that best reflect a reasonable range of offtake options and their effects. The AOGCC may request (including by subpoena) any other pertinent information that has been used in the study but was not included in the operator's submission of evidence in the hearings. Claims of confidentiality for evidence in the hearings will be determined by the AOGCC during the course of the hearings under governing law.

On April 26, 2006, the AOGCC and ExxonMobil and their partners at Pt. Thomson agreed upon a similar process for studying the allowable gas offtake rate from that field. The AOGCC has contracted reservoir evaluation consultants to assist its technical staff in performing the Pt. Thomson study. Under the agreement, AOGCC staff and consultants would have access to a data room in ExxonMobil's Houston offices. The data room would include reservoir engineering, geologic, geophysical, and simulation information and would be equipped with computers and software allowing review of the simulator results. The study was scheduled to begin before September 2006 and last up to six months, but has not yet begun. The AOGCC received conflicting information from various sources within ExxonMobil about when the study would begin. One source said the study would proceed, while another said the study would be shelved until resolution of legal issues regarding the status of the Point Thomson Unit and leases. On April 24, 2007, the AOGCC sent a letter to ExxonMobil asking them to clarify the status of this study. ExxonMobil informed the AOGCC that they do intend to proceed with the study and that it should begin in early July 2007.

Role of the Alaska Oil and Gas Conservation Commission in Approving Pool Rules for the Point Thomson Field

The State of Alaska and other interested parties are engaged in determining how best to bring North Slope gas to market. The Alaska Oil and Gas Conservation Commission ("AOGCC") has a very important role in this process – to protect the public's interest by preventing waste and insuring greater ultimate recovery of oil and gas. To fulfill this role, the AOGCC must determine what gas production rates should be allowed from North Slope oilfields. As part of this process, the AOGCC would evaluate a proposed plan to develop the Point Thomson Field as a gas field rather than as an oilfield. Generally, the greatest total hydrocarbon recovery from a retrograde condensate field would be achieved by conducting gas cycling operations to produce condensate (a liquid hydrocarbon that is considered "oil" under the Commission's governing law) until all of the economically recoverable liquid hydrocarbons have been produced. Only then should the gas be sold. The AOGCC recognizes, however, that many other factors will – and should – be considered in determining how the Pt Thomson Field should be developed.

Point Thomson is the largest proven yet still undeveloped field in Alaska. It is also one of the most difficult to develop and manage properly because the majority of the resources are contained in what is called a retrograde condensate reservoir. Retrograde condensate reservoirs around the world tend to be deeper and have higher pressures and temperatures than conventional reservoirs. These abnormally high temperatures and pressures cause the fluids in the reservoir to have unusual properties. Thus, a retrograde condensate reservoir acts differently than a typical oilfield such as Prudhoe Bay or a typical gas field such as the Kenai Gas Field. The differences in behavior are technically complex and difficult to describe, understand, and address; yet understanding and addressing these differences are essential to evaluating whether a plan of development satisfies the conservation requirements administered by the Commission.

A conventional oil reservoir is typically filled with a liquid hydrocarbon that has some solution gas in it. In such a reservoir all the fluid exists as a liquid, but as it is brought to the surface its pressure drops and some of its solution gas is released. The same thing happens underground. As the pressure decreases in the reservoir, gas in the oil comes out of solution. To understand how this works, think of a bottle of soda. Before the bottle is opened, its contents are under pressure and it appears that there is just liquid in the bottle. However when the cap is removed, the pressure in the bottle is reduced and bubbles will start to form and float to the surface of the soda.

Conversely, a conventional gas reservoir is typically filled with hydrocarbon gas. The gas may have a small amount of hydrocarbon liquid, called condensate, vaporized in it. This condensate will not drop out as a liquid in the reservoir because the temperature is too high. However it will separate from the gas when the gas is brought to the surface where the temperature is lower. This is similar to what happens when someone blows warm breath onto a cold window and watches it fog up. The water that exists as a vapor inside the warm lungs turns to condensation as it hits the cold window.

Retrograde condensate reservoirs do not behave in the same ways that conventional oil and gas reservoirs do. Dropping the pressure in the reservoir does not cause gas to form from oil, as is the case in a conventional oil reservoir. Nor does vaporized condensate remain a vapor, as is the case in a conventional gas reservoir. Rather, for a retrograde condensate reservoir, as the pressure decreases, liquids drop out of the gas in the reservoir.

When a retrograde condensate field is produced like a conventional gas field, the gas is produced and sold at high rates. Initially a large amount of condensate is produced with the gas. However the reservoir pressure drops quickly and condensate production drops dramatically because condensate is dropping out in the reservoir instead of at the surface. To further the problem, condensate that drops out in the reservoir is much more difficult to produce than that which remains entrained as a vapor in the gas. The liquid tends to build up and clog the pore spaces in the reservoir rock. Also, since this reservoir has never been exposed to liquid before, the rock acts as a sponge and some of the condensate will be immobilized and never come out. To make things worse, once the condensate comes out of the gas, very little of it will return to a gaseous state even if the reservoir pressure is later increased. In other words this is a problem that you can't fix after you cause it; it's like unringing a bell.

In addition to lost condensate recovery, if the reservoir pressure is reduced too quickly, the gas recovery will also decrease. The condensate that clogs up the reservoir and won't come out also blocks the gas from coming out. This is similar to an air filter on a car. When the filter is new, air will flow through it freely, but as it gets older the pores in the filter begin to clog with dirt (as the pores in the reservoir would clog with condensate) and the air will not flow through as well. Eventually no air at all will flow.

So what's the answer? To maximize condensate production from a retrograde condensate reservoir, it is necessary to keep the reservoir pressure high until the condensate has been recovered. Often this is accomplished through a process known as "gas cycling." In this process hydrocarbon gas is produced, the condensate is removed and sold, and the now-lean gas is injected back into the reservoir to maintain pressure and to sweep more condensate to the surface. As this process continues, the gas produced slowly becomes leaner and the yield of condensate decreases. Eventually the gas is stripped of most of the liquids and it is safe to sell the gas. This method delays gas sales, but it results in greater ultimate recovery of both liquid and gaseous hydrocarbons.

Another method used to develop retrograde condensate fields is to inject a substitute gas such as nitrogen or carbon dioxide either to replace or to supplement the produced gas for pressure maintenance. Unfortunately, there is currently no substitute gas available to Point Thomson.

These are just a few of the more common methods used for developing retrograde condensate fields and each has advantages and disadvantages that must be considered. Primary depletion as a gas field is the least efficient and results in the lowest hydrocarbon recovery. However, it is the simplest and cheapest method for the operator since it does not require an investment in equipment to recycle the gas. Gas cycling yields greater hydrocarbon recovery but may be less attractive to the operator because it has a higher up-front development cost for compression and it has low up-front cash flow due to the deferral of gas sales. Injection of outside substances has the possibility of maximizing both condensate recovery and cash flow, but it is the most expensive method because in addition to compression equipment it requires the purchase of a substitute gas.

Selection of an optimal method of development must consider all of the unique aspects of the reservoir in question, as well as the practicality and applicability of the various development methods.

ExxonMobil and their partners have indicated that the only development scenario that makes sense for the Point Thomson Field is to develop it as if it were a normal gas field, which would likely result in significant loss of liquid hydrocarbons. Because the AOGCC must determine whether this development option is consistent with good oilfield engineering practices and will result in greater ultimate recovery, the agency has contracted with an outside consultant who has extensive retrograde condensate reservoir expertise. The AOGCC and its consultant were to engage in a project to evaluate different development options and develop a sound technical basis for conservation orders related to the development plan that was to be proposed by ExxonMobil and their partners for the Point Thomson Field. This work was to have begun by September 2006, but has been delayed and will not start until early July 2007.

The AOGCC is cognizant that there is an ongoing dispute between ExxonMobil and their partners and the State of Alaska, Department of Natural Resources, about the status of the Point Thomson Unit and the leases that comprise the unit. Despite this dispute, the AOGCC has determined that continuing with the study of the Point Thomson reservoir is in the best interest of the State because, regardless of which party prevails, this type of study will need to be done to evaluate future development proposals.

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

May 16, 2008

Commissioned by

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

For the purpose of evaluating the hydrocarbon resource of the Thomson sand and potential depletion scenarios to maximize oil and gas recovery.

Study completed by

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

Summary of findings prepared by

Division of Oil and Gas, Resource Evaluation Staff
Jack Hartz
Julie Houle
Steve Moothart

Introduction

In 2007, the Resource Evaluation section of the Alaska Department of Natural Resources (DNR) Division of Oil and Gas (DO&G) initiated an independent technical assessment of the Thomson sand reservoir. The Division o f Oil & Gas contracted with PetroTel, Inc. to perform geologic and engineering evaluation of the Pt Thomson sands reservoir. PetroTel is recognized worldwide as industry leaders in enhanced oil recovery, reservoir characterization and simulation, coalbed methane, production, and exploration technologies. PetroTel provides professional consulting and advisory services utilizing a staff of 80 professionals with combined 1100 years of industry experience along with integrated project management support to domestic and international petroleum companies. Activities span the entire spectrum of technical, project, and commercial functions along with all facets of the hydrocarbon exploitation cycle.

With state-of-the-art software and sophisticated geostatistical and object modeling techniques, PetroTel reservoir engineers and geologists have successfully tackled a broad spectrum of difficult reservoir engineering problems by the intelligent application of reservoir simulation. Through the integration of reservoir geology, rock/fluid interactions, the dynamic pressure-volume-temperature relationships of oil gas and water (PVT properties), and process mechanisms, PetroTel engineers deliver reliable predictions of reservoir performance. Company expertise includes determination of in place hydrocarbons and reserves as well as providing a plan of development for discoveries that includes integrated economics.

PetroTel also has significant expertise in the development of gas condensate reservoirs with thin oil rims. They specialize in solutions and diagnostic tools that can advance the development of potential or undeveloped reserves. PetroTel has extensive experience that deals with pressure maintenance and improving recovery from gas condensate reservoirs.

The Pt Thomson sand accumulation is recognized as a high pressure retrograde condensate reservoir. which also contains a relatively thin oil column. The Petroleum Engineering Handbook[1] states "Development and operation of these (gas condensate) reservoirs for maximum recovery require engineering and operating methods significantly different from crude-oil or dry-gas reservoirs. The single most striking factor about gas-condensate systems (fluids) is that they exist either wholly or preponderantly as vapor phase in the reservoir at the time of discovery. This key fact nearly always governs the development and operating programs for recovery of hydrocarbons from such reservoirs; the properties of the fluids in place determine the best program in each case. A thorough understanding of fluid properties together with a good understanding of the special economics involved is therefore required for optimum engineering of gas condensate reservoirs. Other important aspects include geologic conditions, rock properties, well deliverability, well costs and spacing, well-pattern geometry, and plant costs."

The Resource Evaluation Group, DO&G undertook the evaluation of the Pt Thomson reservoir to better understand the resources contained in the reservoir and get an independent analysis of the development issues associated with gas condensate. The study had two main objectives: 1) to construct three-dimensional (3D) geologic models to evaluate the proven and potential hydrocarbon

[1] Bradley, H.B., 1987, Petroleum Engineers Handbook, 1987 Society of Petroleum Engineers, Chapter 39 Gas Condensate Reservoirs.

resource and 2) to import the geologic model into a dynamic reservoir simulator to test potential development and off-take scenarios to determine the impact on ultimate recovery of both gas and hydrocarbon liquids in the form of condensate and oil from an oil-rim in the reservoir. It should be noted that this study focuses on only the resource contained in the Thomson sand and does not Include the resource tested from the underlying Pre-Mississippian strata or the overlying Brookian accumulations

Results of PetroTel's work are summarized below.

1) The geologic and engineering analysis confirmed that gas cycling recovers more hydrocarbon than simple primary depletion based on known oil properties, gas properties, and reservoir characteristics.
2) Technical issues remain to be resolved; however, economic evaluation still needs to be done to validate conceptual conclusions and refine potential development scenarios.
3) Rigorous technical evaluation will be required as delineation of the reservoirs proceeds and additional physical information is acquired; more thorough and longer well tests are done; and as high quality reservoir oil, gas and condensate samples are acquired and analyzed.
4) Maximum recovery with gas cycling may require the import of gas in the form of waste CO_2, captured inert gases, methane or natural gas from reservoirs outside of the Pt Thomson reservoir to replace voidage caused by fuel usage and shrinkage. Technical literature also suggests water can be injected into gas condensate reservoirs to maintain pressure, however, that process has not been addressed with this study.[1]
5) **Gas cycling delays gas sales, but results in greater ultimate recovery of both liquid and gas hydrocarbons. In contrast, primary depletion as a gas reservoir results in the lowest hydrocarbon recovery of a retrograde condensate reservoir. Gas blowdown[2] for sale can be done at any time after gas cycling and recovery of the hydrocarbon liquids.**
6) From the eleven static geologic models created, the volume of original gas in place (OGIP) ranged from 8.5-10.4 trillion standard cubic feet (TSCF). The volume of associated condensate ranged from 490-600 million stock tank barrels (MMSTB)[3] of condensate in place.
7) The range of original oil in place in the oil-rim varied greatly depending on the depth used for the oil-water contact. Publicly available data indicate that the interval between lowest possible gas and highest known water could vary from 60 feet to 145 feet in true vertical thickness, representing a wide range of potential oil column thickness in the oil-rim. The various geologic models produced a range of volumes of original oil in place (OOIP) in the oil-rim from 580-950 MMSTB.
8) Recoverable hydrocarbon resources for the Thomson sand were determined from dynamic reservoir simulation and are primarily a function of the development method employed. Over 70 scenarios were run to model a variety of development methods and well configurations within the reservoir simulator.

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[2] Blow-down (also Blowdown) "A term applied to the commencement of production of gas for sale after the completion o a Cycling or Recycling operation. The term refers to the reduction of pressure in the formation as a result of the production of gas. ... ". Martin, Patrick H. and Kramer, Bruce M., 2000, Manual of Oil and Gas Terms, Eleventh Edition, Lexis Publishing, page 101.

[3] Million stock barrels - MMSTB, Million standard cubic feet – MMSCF or MMSCFG/D – Roman numeral designation for million. Stock tank barrel is equivalent of 42 US Gallons liquid at 60°F and 14.65 pounds per square inch absolute, psia (1 atmosphere). Standard cubic foot is measured at 14.65 psia and 60°F

9) Development of the Thomson reservoir by primary depletion (blowdown) has the potential to recover 210-305 MMSTB of liquid hydrocarbons in addition to 6-7 TSCF of gas.
10) Gas cycling for 20 years prior to gas sales has the potential to result in the ultimate recovery of 620-850 MMSTB of liquid hydrocarbons and still recover 4.8-5.9 TSCF of gas.
11) Gas cycling, has the potential to significantly increase recoverable oil and condensate as much as 500 MMSTB of condensate and oil beyond recovery from primary depletion blowdown. This incremental recovery of oil is larger than the expected ultimate recovery from the Alpine Oil Field.

The length of time required for gas cycling prior to gas sales will be determined by the resource available in the oil rim and how fast the gas volume can be cycled. The major determining factor in this decision is the number of wells that can be economically drilled and operated. More injection and production wells could accelerate cycling and recovery of the condensate liquids and oil. There are an optimal number of wells that will economically recover the maximum amount of oil and gas within a reasonable drilling budget; however, the scope of this study did not include optimization of development but rather was designed to estimate resource volumes and quantify the range of recoverable resource using conceptual development scenarios. Hydrocarbon liquids could be produced and sold using mostly existing oil pipelines prior to the construction of a North Slope gas pipeline. Once production of liquid hydrocarbons is established from the Thomson reservoir, the production facilities could be utilized to produce oil from the Brookian Flaxman and Sourdough accumulations.

Petroleum Potential and Exploration History of the Point Thomson Area

Well log and production or drill stem test data indicate that much of the Point Thomson area is underlain by the Cretaceous (Neocomian) Thomson sand that contains abundant natural gas and hydrocarbon liquids in the form of gas condensate, ranging from 35° to 45° API gravity[4,5]. In addition to gas and condensate, the Thomson sand also contains a thin and potentially discontinuous oil-rim at the bottom of the reservoir interval that has tested oil as high as 18° API gravity. The Point Thomson area contains the potential of hundreds of millions of barrels of oil in the shallower Tertiary Brookian reservoirs. Another potential productive reservoir is composed of carbonates and bedded metasedimentary strata in the "Pre-Mississippian" basement below the Thomson sand reservoir. The DO&G reported in their 2007 annual report that the Pt Thomson Area contained estimated undeveloped recoverable resources of 295 million stock tank barrels (MMSTB) of liquid hydrocarbons and 8 trillion standard cubic feet (TSCF) of gas.

Hydrocarbons were first discovered in the Point Thomson area in 1975 in the Alaska State A-1 well. This well tested a zone of the lower Tertiary Flaxman sand of the Canning Formation from 12,565 to 12,635 feet MD(measured depth) that flowed 23° API gravity oil at a rate of 2,507 BOPD (barrels of oil per day),

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[4] API Gravity – "Specific gravity measured in degrees on the American Petroleum Institute scale. The specific gravity of oil is normally specified … in terms of API degrees. On the API scale, oil with the least specific gravity has the highest API gravity. … the higher the API gravity the greater the value of the oil." ". Martin, Patrick H. and Kramer, Bruce M., 2000, Manual of Oil and Gas Terms, Eleventh Edition, Lexis Publishing, page 52.

[5] Condensate API gravity typically ranges from 40-60 degrees and are light color compared to oil. Black oils typically have API gravity that ranges from 25-35 degrees. Lake, Larry W., 2007, Petroleum Engineering Handbook, Volume V, Society of Petroleum Engineers, Chapter 10,

2.2 MMSCFG/D,GOR 864 SCF/STB (gas/oil ratio, standard cubic feet per stock tank barrel) (USGS, 1987).

In 1977, a second discovery well, the Point Thomson Unit No. 1 well was drilled and conducted two flow tests in the Lower Cretaceous (Neocomian) Thomson sand. From a zone between the depths of 12,963 to 13,050 feet MD, the well flowed 18° API gravity oil at a rate of 2,283 BOPD, 13.3 MMSCFG/D, GOR 5,830. Between the depths of 12,834 to 12,874 feet MD, the well tested at a rate of 3.86 MMSCFG/D, 170 BPD condensate, 45° API gravity (USGS, 1987).

Over the next seven years, six additional wells were drilled to delineate the two Pt Thomson discoveries. As a result of the additional delineation drilling, two other hydrocarbon reservoirs were encountered. In 1978, the Point Thomson Unit No. 2 well tested the "Staines River sand," a local sand in the Tertiary Canning formation at a depth of 11,580 to 11,678 feet MD that produced 21° API gravity oil at a rate of 248 BOPD, 124 MSCFG/D, GOR 500, after acid treatment (USGS, 1987).

In 1982, the Alaska State F-1 well tested the Thomson sand at a depth of 13,940 to 14,316 feet MD at a rate of 4.2 MMSCFG/D and 284 BOPD condensate of 35.3° API gravity. The well also tested the underlying "Pre-Mississippian" metasedimentary basement from 13,940 to 14,316 feet MD that flowed at a rate of 2.9 MMSCFG/D with 152 BPOD condensate of 34.8° API gravity. This test identified a third potentially productive zone in the Point Thomson area (USDOE, 1993).

State lands east of Prudhoe Bay saw renewed exploration activity during the 1990s after the discovery of the Badami oil field within turbidite sandstones of the Tertiary Canning Formation. First estimated to contain 100-150 MMSTB of recoverable oil, production began at Badami in August 1998. Since that time, production has been sporadic with the field periodically shut in due to connectivity issues within the reservoir. To date, over 5 MMSTB of cumulative oil production from Badami has been reported to the Alaska Oil and Gas Conservation Commission (AOGCC).

In 1994, BP Exploration Alaska (BPXA) and Chevron drilled the Sourdough #2 well targeting Brookian sands of the Canning formation in the southern portion of the former Point Thomson Unit; the Sourdough #3 well was drilled as a follow-up in 1996. Although the data from these wells are still held confidential, BP announced the discovery of hydrocarbons within turbidite sandstones of the Tertiary Canning Formation that could potentially contain 100 million barrels of recoverable oil in a 1997 press release. The Sourdough project would require up to 35 miles of pipeline to link up with the Badami field (Peninsula Clarion, 1997).

Additional discoveries have been announced in the offshore federal waters of the eastern Beaufort Sea within the Mississippian Kekiktuk Formation (Liberty) and Tertiary sandstones of the Sagavanirktok Formation (Hammerhead and Kuvlum). Once developed, production from Liberty is expected to peak at 40,000 BOPD, with a recovery target of 100 MMSTB (Petroleum News, 2007). While data from the U.S. Minerals Management Service (MMS) indicates that while neither Hammerhead nor Kuvlum have been fully delineated, the agency estimates 100-200 MMSTB of recoverable oil at Hammerhead, and 160-300 MMSTB at Kuvlum (MMS, 2006).

The timing of development of these and other Brookian oil accumulations in the area will likely follow the commercialization of the gas and liquids reserves within the Point Thomson sand.

Geologic Setting of the Thomson Sand

The Thomson sand is an informal name that describes a sequence that is stratigraphically correlated with the Kemik Sandstone of Early Cretaceous (Neocomian) age (Figure 1). Both intervals commonly consist of preserved isolated accumulations of locally derived sediment overlying the regional Lower Cretaceous unconformity (LCU), whose composition is controlled by the local provenance eroded by the unconformity.

The Thomson sands contain significant detrital dolomite and quartz sand that are interpreted as Neocomian age fan-delta complexes that were sourced from a northern provenance composed of northerly-dipping pre-Mississippian metasedimentary units. The Thomson interval includes a broad range of rock types ranging from conglomeratic dolomite breccia to fine-grained sandstone and siltstone. In general, the coarser conglomerate facies of the Thomson sand are present to the north, proximal to the interpreted source area, while the finer-grained distal facies are more prevalent to the south. A block diagram (Figure 2) depicts a highly interpretive, schematic representation of the depositional setting of the Thomson sand during an advanced stage of transgression of the Neocomian Barrow Arch rift margin uplift and development of the Lower Cretaceous Unconformity (LCU).

Other sand occurrences are irregularly distributed along the LCU surface to the south of the Point Thomson area, depending on local thickening into accommodation space attributed to paleotopography created by the differential erosion of Ellesmerian and pre-Mississippian units below the LCU. North of the rift shoulder uplift, syn-rift sands may have been deposited as sediment gravity flows down fault relay ramps to accumulate in relatively deep water. Similar sands form major reservoirs in the Point McIntyre and Niakuk fields north of Prudhoe Bay, but the concept has not yet been tested with a drill bit north of the Point Thomson area.

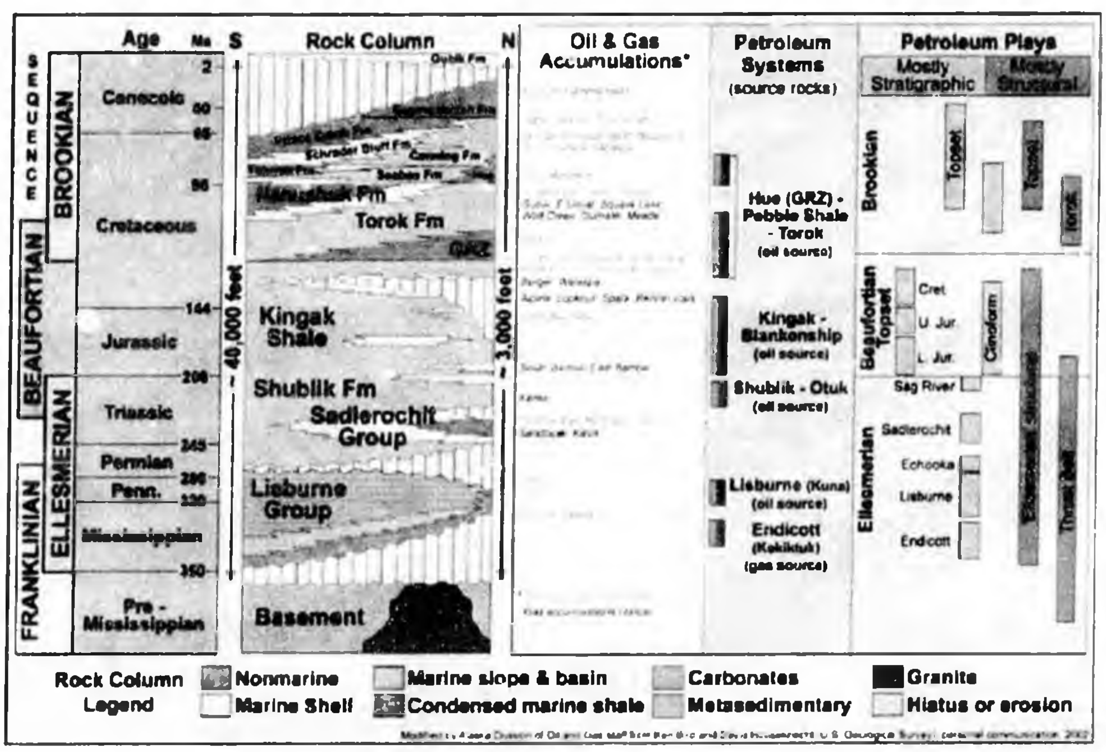

Figure 1, Alaska North Slope Stratigraphic Column

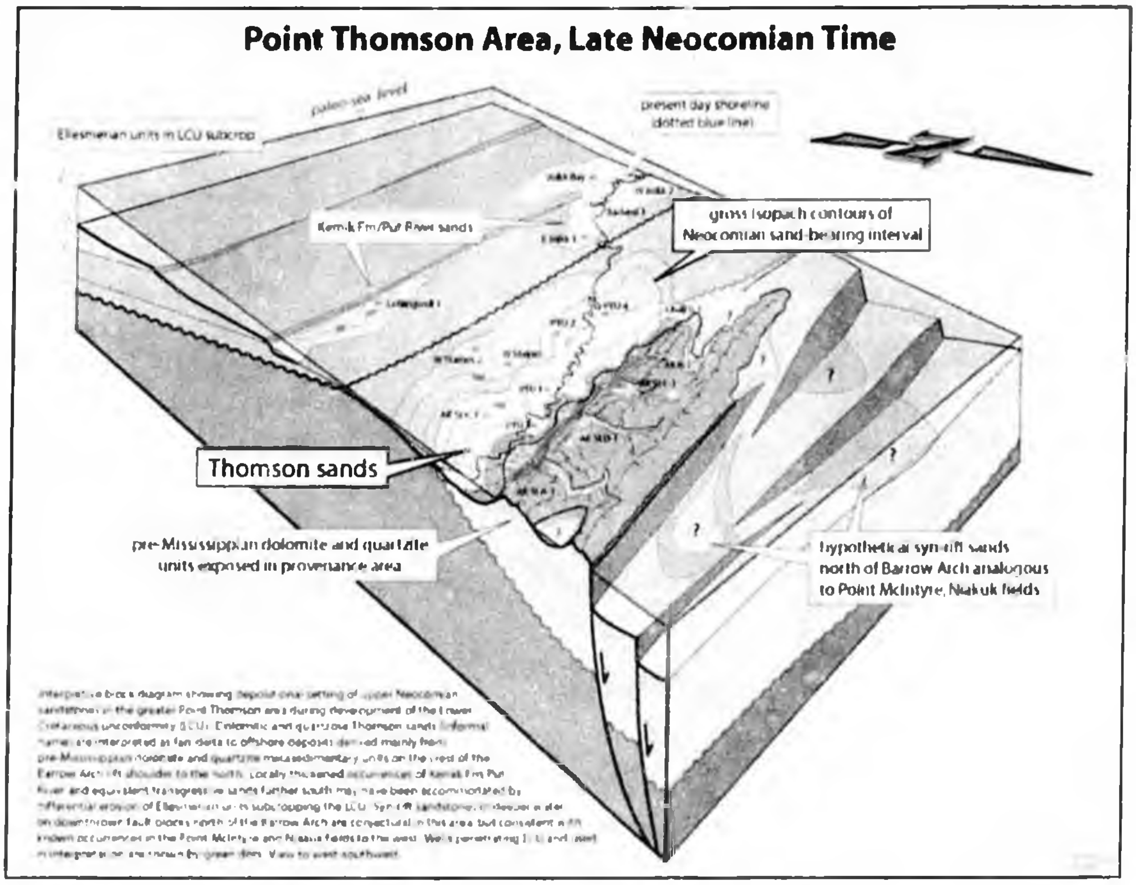

Figure 2, Block diagram of Point Thomson area in Late Neocomian time

First discovered in 1977, the oil, gas, and gas condensate contained within the Thomson sand is the largest proven, yet still undeveloped, field in Alaska. Between 1975 and 1996, a total of 17 wells have been drilled within the boundaries of the former Point Thomson unit. 1982 was the last time that a well was drilled into the Point Thomson reservoir. Although attempts were made to test most of the wells, tests were of short duration and were hampered by the high mud weights that were required to contain high reservoir pressure. Some of the tests were further complicated because they straddled both the gas and oil legs of the reservoir. No definitive, isolated test exists in the oil-rim of the Thomson reservoir. Additional wells are still needed to specifically delineate and test the productivity of Thomson oil-rim. Delineation wells in the oil-rim should include vertical pilot holes with horizontal laterals for production tests and include rigorous sampling for oil quality and PVT studies.

A number of the Point Thomson wells were drilled on the flanks of the accumulation and delineate the aerial extent of the core area of the Thomson reservoir. Along the western margin of the area though, no well has been drilled to demonstrate the western limit or trap of the reservoir or define the structural or stratigraphic continuity of the core reservoir from southeast to northwest. Additional wells are still required to adequately delineate the western limits of the hydrocarbon accumulation.

Thomson Sand Retrograde Condensate

The majority of the proven hydrocarbon resource in the Thomson sand is contained in the form of gas with entrained liquids known as a retrograde condensate. The Alaska Oil and Gas Conservation Commission (AOGCC) has released a paper entitled "Role of the Alaska Oil and Gas Commission in approving Pool Rules for the Point Thomson Field"[6] which gives an informative overview of the differences between a retrograde condensate reservoir and conventional gas and oil reservoirs. Retrograde condensate reservoirs tend to be deeper and have higher pressures and temperatures than conventional reservoirs. Due to the abnormally high pressures and temperatures, the fluid in a retrograde condensate reservoir does not behave like those in conventional oil and gas reservoirs. Pressure reduction in a conventional oil reservoir, causes the gas to expand and evolve out of solution from the oil. As gas evolves the oil becomes thicker (more viscous) and flows more slowly.

Technical literature (Society of Petroleum Engineers) has abundant examples of how condensate reservoirs perform under primary depletion and gas cycling. As pressure drops in a retrograde condensate reservoir, vaporized hydrocarbon liquids will condense when the reservoir pressure decreases below a certain point (dew point). If this happens in the reservoir, the condensate will remain trapped in place and clog the pore space, causing reduction of relative permeability; reducing well productivity and ultimate recovery. During primary depletion, the reservoir pressure will steadily decrease below dew point and hundreds of millions of barrels of condensate will become trapped in the reservoir and never be produced. Once the condensate comes out of the gas in the reservoir, very little of it will return to a gaseous state even if the reservoir pressure is later increased. Ideally, reservoir pressure should be maintained above dew point to keep vaporized liquid entrained to condense in surface facilities, thereby maximizing recovery. Results of the Pt Thomson sand reservoir modeling confirm the losses of condensate recovery during blow down. The blow down cases at best recovered about one-half the condensate that cycling cases recovered. The difference is directly attributable to trapped condensate.

Prudent development practices require keeping the reservoir pressure high (near or above dew point) until all of the economically recoverable liquid hydrocarbons have been produced in order to maximize the recovery of both oil and gas in a retrograde condensate field. "Gas cycling" is considered the best method of producing a retrograde condensate reservoir. This process involves producing hydrocarbon gas; removing the condensate for commercial sales; and then re-injecting the "lean gas" back into the reservoir to maintain pressure and sweep more condensate to the production wells. Once most of the condensate has been recovered, all the wells can be converted to gas production wells and the gas sold to market.

In addition to the dry gas and entrained condensate, the Thomson sand contains hundreds of millions of barrels of oil in the oil-rim. The gas cycling process can be applied simultaneously to the Thomson oil-rim after delineation and development. These hydrocarbon liquids could be produced and sold using mostly existing oil pipelines before a North Slope gas pipeline is operational. Once production of condensate and oil begins from the Thomson reservoir, it is anticipated that this would facilitate the delineation, development and production of some of the outlying Brookian oil discoveries in the Thomson area.

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6 URL: http://www.state.ak.us/local/akpages/ADMIN/ogc/Gas/PtThompson_Pool_Rules.pdf. Retrieved April, 2008.

Studies of gas cycling in both the gas cap and oil rim were conducted using static geologic models and dynamic reservoir simulations to estimate recoveries under different development schemes. Results of those studies are documented later in the Reservoir Simulation section of this report.

DNR Evaluation of the Thomson Sand

Geologic Model Results

A total of eleven 3D geologic models were constructed of the Thomson sand. The distribution of facies and reservoir properties were varied in the different cases to account for the uncertainty between the well control points. A range of depths for the fluid contacts was also used to capture the uncertainty in identifying those contacts in the well logs or from available test data. The volume of original gas in place (OGIP) from the eleven static geologic models ranged from 8.5 – 10.4 trillion standard cubic feet (TSCF).

The volume of associated condensate ranged from 490 – 600 million stock tank barrels (MMSTB) condensate in place. Publically available well test data from the Thomson sand indicate condensate yields of 44-75 barrels condensate/MMSCF gas produced. The average yield was 64 STB/MMSCF.

The potential for a significant volume of oil in place below the gas cap in the oil-rim was also identified. The range of original oil in place in the oil-rim varied greatly depending on the depth used for the oil-water contact. Publicly available data indicate that the interval between lowest known gas and highest known water could range from 60 feet to 145 feet in true vertical thickness. This is the range of thickness available to be occupied by oil in the oil-rim. The range of volumes of original oil in place (OOIP) in the oil-rim varied in the models from 580 – 950 MMSTB.

All the volumes reported out of the geologic model are original hydrocarbons in place for the Thomson sand reservoir and do not include the hydrocarbons tested from the bedded carbonates of the Pre-Mississippian basement or those hydrocarbons tested from the overlying Brookian intervals. Reservoir properties within the Pre-Mississippian strata are not as well constrained by the available data as in the Thomson sand.

Because the Thomson sand directly overlies bedded carbonate strata of the Pre-Mississippian, it is likely in communication with the Pre-Mississippian. Recoverable volumes for the Thomson sand were determined from the dynamic reservoir simulation and were demonstrated to be a function of the development method employed. Neither the Pre-Mississippian nor Brookian reservoirs were included in the reservoir simulation. Both should be considered as considerable upside since they have been successfully tested in multiple wells. Further delineation drilling is required to fully access the resources in-place and production impacts of these reservoirs on future development.

Reservoir Simulation Results

Upon initialization of the reservoir simulation model, over 70 scenarios were run to model a variety of development methods and well configurations. The development methods included primary depletion (gas blowdown), gas cycling followed by gas blowdown, and development of the oil-rim. Numerous cases were run for each type of development to test different well configurations such as horizontal wells, well constraints such as rate limits and operating pressures, and the number of development wells. In this way, we were able to judge the relative impact the different variables had on the ultimate recovery of the resource within each type of development. All model cases were run out to thirty years of production. It should be noted that no physical constraints to the development wells such as location of surface drill sites and facilities or drilling departure from surface location have been applied during the modeling. At this stage of the analysis scenarios were designed and run to discover and evaluate the key sensitivities to recovery, rather than to derive optimal production economics.

Primary Depletion (Gas Blowdown)

Gas blowdown can be done at any time after cycling and recovery of the hydrocarbon liquids. In the following cases, gas blow down is done first without pressure maintenance or gas injection. Six primary depletion cases were run in the reservoir model. Three cases contained a fixed number of wells at startup and three cases included additional wells that were added later. Gas producers were constrained to a maximum rate of 150 MMSCF/D and a minimum bottom-hole pressure (BHP) of 3000 psi. Cases were run with 8, 16 and 22 wells. Initial gas production rates for these three cases varied from 0.4 – 1.2 BSCF/D[7]. Additional cases included: 12 initial producers with 4 new producers drilled after 4 years, 16 initial producers with 3 additional wells drilled after 8 years and 16 producers with 6 additional wells drilled after 4 years. Initial gas production rates for these three cases ranged from 0.8 to 1.2 BSCF/D. Three more primary depletion cases were run in both gas cap and oil rim. Cases were run with 22, 13 and 13 gas producers in the gas cap and 4, 30 and 20 oil producers in the oil rim. Oil producers were constrained to a maximum rate of 7000 STB/D and a minimum bottom-hole pressure (BHP) of 3000 psi. Initial gas production rates for these three cases ranged from 1.0 to 1.2 BSCF/D

With a BHP limit of 3000 psi, gas recovery can approach 60% for the 16- producer and 22-producer cases. The recovery can reach 70% at lower BHP of 2000 psi. The 8-producer case can recover 45% of the gas in 30 years. The number of wells and timing of drilling could be optimized to meet gas demand or gas sales contracts. Twenty-two wells could drain the gas in the reservoir in 12-15 years.

Condensate recovery during primary depletion of the gas cap is only about 25% of the in place volume after 30 years. The majority of the condensate is lost in the reservoir because the reservoir pressure drops below dew point. Pressure maintenance and gas recycling is needed to recover more condensate. Primary depletion is also detrimental to any future recovery from the oil-rim due to loss of energy within the oil by the reduction of reservoir pressure. Oil rim recovery ranged from 3-16% in the cases of primary depletion in both gas cap and oil rim if primary depletion is the only recovery method.

Gas Cycling Followed by Gas Blowdown

The model cases run demonstrate that full scale gas cycling should be initiated early in order to achieve maximum recovery of the condensate and any other potential hydrocarbon liquids in the gas cap. Cycling also maintains reservoir pressure for development of the oil-rim. In a gas cycling project, the ultimate recovery of condensate and timing of subsequent gas blowdown is a function of the rate at which the in place volume of gas can be produced and recycled. This can be optimized by the number of development wells in place.

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[7] BSCF/D – Billion standard cubic feet per day.

Four base cases of cycling the produced gas for 30 years with a different numbers of wells were run to test the impact of well count on the potential ultimate recovery of condensate. Additional cases with gas blowdown commencing after 10 and 20 years of cycling were run to test how much condensate could be produced prior to blowdown for gas sales.

The four base cases consisted of: a minimum development case of 4 producers and 2 injectors; a case with 8 producers and 4 injectors; a 16-producer with 5-injector case; and a case with 22-producers and 8 injectors which resulted in the highest hydrocarbon recovery of the four cases. Producers were constrained to a maximum rate of 150 MMSCF/D and a minimum BHP of 3000 psi. The injectors were limited to a maximum rate of 300 MMSCF/D and a maximum injection pressure of 15000 psi. In all cases 90% of the produced gas was cycled back into the reservoir.

Condensate recovery after 30 years for the four cases ranged from only 24% of the in place volume for the 4-producer case, to 86% recovery for the 22-producer case. At the end of cycling the injectors can be converted to gas producers. Gas blowdown with the 30 wells producing subsequent to gas cycling can recover up to 70% of the remaining recycled gas within 12 years.

Additional cases were then run with gas cycling for both 10 years and 20 years before blowdown. For the 22-producer and 8-injector development, after 10 years of cycling 62% of the condensate is recovered and then 57% of the original gas in place (OGIP) is recovered during the ensuing blowdown. Cycling for 20 years recovers 76% of the condensate and then 56% of the gas (OGIP).

Oil-rim Development

One of the key results of the study was that it became obvious that oil rim development had to be done during a gas cycling phase. Because there is uncertainty about the quality of the oil and reservoir rock in the oil-rim, to preserve reservoir energy and sustain maximum oil producibility oil rim reservoir pressure must be maintained. The oil-rim is a relatively thin zone of the reservoir that lies between the gas cap and underlying aquifer. For this reason the use of dedicated horizontal wells will be required to avoid coning of the adjacent gas or water. Injection of the recycled gas into the oil-rim will help reduce the viscosity, improve swelling, mobilize and displace the oil.

Model cases were run that included production wells in the oil-rim as part of both a primary depletion and gas cycling developments. Individual cases in both development strategies varied the number of oil-rim producers from 4 to 20 and ultimately 30 oil wells. Sensitivities were also run on gas- oil ratio (GOR) cutoffs for the producers, minimum BHP, and the use of offsite gas for supplemental gas injection.

In a primary depletion scenario, adding four wells into the oil-rim recovered 3% of the original oil in place. Increasing the number of oil-rim wells to twenty or thirty upped the recovery to almost 16% of OOIP. In a gas cycling scenario, the addition of four wells in the oil-rim achieved 11% recovery after 30 years of cycling, going to gas blowdown after 10 or 20 years of cycling recovered 7% and 9 % of the oil-rim OOIP respectively.

Increasing the number of oil-rim wells during gas cycling development in the model increased the recovery of oil significantly. In a case with 13 gas producers, 18 gas injectors and 20 oil-rim producers, recovery of oil from the oil-rim approaches 50% of the in-place volume after 30 years of cycling. This is 3-15 times better recovery than during primary blowdown. By varying the length of time of cycling before gas blowdown from 5 to 10 and then 20 years in the same development scenario the recoveries from the oil-rim drop to 31%, 39% and 43% respectively.

Mode...g of development scenarios for the oil-rim demonstrates that to achieve maximum recovery of the oil resources located below the gas cap in the oil-rim reservoir pressure maintenance by gas cycling is cr :ial. The difference in recovery from the oil-rim between primary depletion and a cycling project that maintains reservoir pressure can be as much as **35% more** of the total in-place volume.

Use of Offsite Gas

Production from the oil rim increases the voidage within the reservoir. The results from model cases involving large scale development of the oil-rim (30 horizontal producers) indicated that due to the increased off-take, reinjection of 90% of the produced gas will not be sufficient to maintain reservoir pressure. A decrease in reservoir pressure below dew point results in lower condensate recoveries and the reduction also decreases oil-rim recovery.

Gas from outside sources (offsite) could be imported and injected into the Thomson reservoir to help maintain reservoir pr sure. Offsite gas can be in the form of carbon dioxide (CO2), inert gas such as nitrogen, methane or natural gas.

The use of CO2 for pressure maintenance may have multiple benefits depending on the source and availability.

- CO2 is commonly removed as a byproduct from produced gas in a gas treatment plant prior to sale.
- If enough CO2 is available for pressure maintenance, it could allow sale of some Point Thomson gas before gas blowdown.
- CO2 should be fully miscible with the Thomson oil and thus reduce the viscosity and further increase recovery.

CO2 is considered a "green house gas" and re-injection into a reservoir is a method of sequestering carbon and as such government tax incentives may be available in the form of carbon credits to offset and/or mitigate CO2 re-injection costs.
Although the importation of offsite gas would require the construction of a gas line to Point Thomson, once gas cycling is completed, the line would be available for gas sales.

The large scale oil-rim development cases that needed supplemental pressure support indicated a volume of 200-500 MMSCF/D would be required in addition to the Thomson gas during the cycling process. A comparison of cases with and without offsite gas showed an increase in condensate recoveries from 33% to 60% of the original condensate in place. This is a potential increase of 130-160 MMSTB.

Conclusions from Geologic and Reservoir Modeling

1. In addition to gas, the area contains hundreds of millions of barrels of hydrocarbon liquids. These hydrocarbon liquids exist in the form of condensate liquids; a thin and potentially discontinuous oil leg at the bottom of the Thomson sand reservoir; and oil in the overlying Brookian sediments. Exploration wells drilled prior to 1982 have tested oil from each of these reservoirs. Adequate infrastructure to transport these liquids to market exists within thi.. miles of this reservoir.

Therefore, the potential development of the Point Thomson area should not be limited to production of the dry gas.

2. Evaluation of the potential hydrocarbons in place in the Thomson sand reservoir by DNR and PetroTel's 3D geologic models results indicate the following volumetrics:
    - Original gas in place of 8.5-10.4 TSCF.
    - retrograde condensate - 490-600 MMSTB in place
    - Oil rim - 580 to 950 MMSTB original oil-in-places.

3. Reservoir simulation of the Thomson sand reservoir evaluated various development scenarios for the reservoir. These scenarios included primary depletion of the reservoir (gas blowdown), production and re-injection of the gas after recovering the condensate (gas cycling), and the addition of dedicated horizontal production wells into the oil-rim in both gas blowdown and cycling cases. Over 70 individual cases where run in the reservoir simulator varying the number of development wells and operating constraints in an attempt to determine the optimum recovery for each development scenario.

4. The producible liquids contained in the Thomson reservoir could technically be developed before a gas pipeline is built.

5. In order to maximize the recovery of the hydrocarbon liquids in the reservoir it is necessary to keep the reservoir pressure high until all of the economically recoverable liquid hydrocarbons are produced. This is most often accomplished through gas cycling. In the reservoir simulator cases run, gas cycling was applied in the gas cap for 30 years in conjunction with development and gas cycling of the oil-rim.

    - Gas cycling recovered 86% or 420-516 MMSTB of condensate.
    - Recovery from the oil-rim was close to 50%, 290-475 MMSTB.

6. Shorter duration Gas Cycling:
    - Cycling gas for 10 years prior to blowdown results in recoveries of:
        - Condensate - 62% or 300-370 MMSTB
        - Oil Rim - 39% or 225-370 MMSTB of the oil-rim

    - Cycling the gas for 20 years increases the recoveries:
        - Condensate - 76% or 370-450 MMSTB
        - Oil Rim - 43% or 250-400 MMSTB.

    - Subsequent blowdown of the gas cap after 10 and 20 years cycling recovers 57% and 56% or 4.8-5.9 TSCF of gas reserves.

7. Primary depletion is the fastest method to produce the gas from the reservoir but recovers the least hydrocarbons. Simulation results showed: 70% of gas recovered or 6-7 TSCF with 22 wells in 12-15 years.
    - Condensate recovery is approximately 26% of the in place volume, or 127-156 MMSTB
    - Oil-rim recovery during primary depletion is only 3-16% 30-150 MMSTB of oil.
    - The majority of the condensate is left in the reservoir by condensation below dew point.
    - Pressure maintenance and gas recycling is needed to maximize condensate recovery.

- Primary depletion reduces recovery from the oil-rim due to loss of energy by the depletion of reservoir pressure.
- Gas blowdown and sale of the gas can be done at any time after cycling and recovery of the hydrocarbon liquids.

8. A gas blowdown scenario could recover over 500 million barrels less than a gas cycling scenario. This difference is larger than the expected ultimate recovery from the Alpine Oil Field.

9. There is uncertainty in the original oil-rim volume in place and the ultimate recovery of that oil, even though it has flowed during testing of the PTU-1 exploration well.
   - Even if the oil rim was discounted entirely, the difference in condensate recovery between primary depletion (blowdown) and gas cycling for 20 years is potentially over 300 million barrels.
   - This represents three times the targeted recovery from the proposed off shore development of the Liberty Field.
   - During the period of gas cycling, further delineation of the oil-rim will determine the scale of development needed to maximize recovery from that portion of the resource.

In summary, gas cycling delays gas sales, but it is through this process that the maximum recovery of the condensate in the gas cap and any other liquid hydrocarbons can be achieved. Cycling also maintains reservoir pressure for development of the oil-rim and is a viable recovery mechanism. The length of time required for gas cycling prior to gas sales will be a combination of the resource available from the oil rim and the rate at which the in place volume of gas can be produced and recycled. A large factor in this will be the number of development wells that can be economically drilled and operated. More wells equals faster cycling and faster recovery of the condensate liquids. These liquids could be produced and sold before the construction of a North Slope gas pipeline. Production of liquid hydrocarbons from the Thomson reservoir could facilitate oil production from the other discovered reservoirs such as the Brookian Flaxman and Sourdough accumulations.

Acronyms and Abbreviations

AEO	Annual energy outlook
AGIA	*Alaska Gasline Inducement Act, AS 43.90 et. seq.*
AMEC	AMEC-Paragon Engineering Company
ANCSA	*Alaska Native Claims Settlement Act, 43 U.S.C. § 1601*
ANGPA	*Alaska Natural Gas Pipeline Act, 15 U.S.C. §§ 720 et. seq.*
ANGTA	*Alaska Natural Gas Transportation Act, 15 U.S.C. §§ 719 et. seq.*
ANGTS	Alaska Natural Gas Transportation System
ANNGTC	Alaska Northwest Natural Gas Transportation Company
AS	Alaska Statute
BC	British Columbia
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
BMP	Best Management Practices
Btu	British thermal unit
BV	Black and Veatch
cf	cubic foot
CO_2	carbon dioxide
CPCN	Certificate of Public Convenience and Necessity
C.F.R.	Code of Federal Regulations
DNR	Alaska Department of Natural Resources
DO	designated officer
DOE	U.S. Department of Energy
DOG	Alaska Division of Oil & Gas
DOT	Department of Transportation
DOT-PHMSA	Department of Transportation, Pipeline and Hazardous Materials Safety Administration
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EOR	enhanced oil recovery
EPA	Environmental Protection Agency
EPC	engineering, procurement and construction
EPCM	engineering, procurement and construction management
ERR	Economically recoverable reserves
°F	degrees Fahrenheit
FEED	front end engineering design
FERC	Federal Energy Regulatory Commission
FID	Final Investment Decision
FPC	Federal Power Commission
GAAP	generally accepted accounting principles
GHV	gross heating value
GTP	gas treatment plant
H_2S	hydrogen sulfide
H_2O	Water
HSE	health, safety and environment
IRR	Internal Rate of Return
IOS	International Organization for Standardization

LNG	liquefied natural gas
LOS	Likelihood of Success
LSCC	Little Susitna Construction Company
MAGTC	MidAmerican Energy Holdings Company and MEHC Alaska Gas Transmission Company, LLC
MAOP	maximum allowable operating pressure
m^3	cubic meters
Mbpd	Million barrels per day
mcf	thousand cubic feet
mmBtu	million British thermal unit
mmcf	million cubic feet
MMS	US Department of Interior Minerals Management Service
NARG	North America Regional Gas Model
NBP	Northern Border Pipeline
NEB	National Energy Board (Canada)
NEB Act	*National Energy Board Act*
NEPA	*National Environmental Policy Act*
NETL	National Energy Technology Laboratory
NGA	*Natural Gas Act, 15 U.S.C. § 717 et. seq.*
NGL	natural gas liquid
NPA	*Northern Pipeline Act, 1977-78, c. 20, R.S., 1985, c. N-26*
NPRA	National Petroleum Reserve - Alaska
NPV	Net Present Value
NYMEX	New York Mercantile Exchange
OCS	Outer Continental Shelf
OFI	Office of the Federal Inspector
OGIP	Original gas in place
O&M	operations and maintenance
OSHA	Occupational Safety and Health Administration
PA	Precedent Agreement
PDF	Portable Document Format
PFC	Petroleum Finance Company
psi	pounds per square inch
psig	pounds per square inch gauge
QP	Qatar Petroleum
RCA	Regulatory Commission of Alaska
RFA	Request for Applications
RIK	Royalty-in-Kind
RIV	Royalty-in-Value
ROW	right-of-way
SCF	standard cubic feet
SGDA	Stranded Gas Development Act AS 43.82
SME	Subject matter expert
TAGS	Trans-Alaska Gas System
TAPS	Trans-Alaska Pipeline System
TCAlaska	TransCanada Alaska Company, LLC and Foothills Pipe Lines, Ltd.
tcf	trillion cubic feet
TransCanada	TransCanada Corporation
TRR	Technically recoverable reserves

TSM	TAPS Settlement Methodology
U.S.C.	United States Code
USGS	United States Geological Survey
WCSB	Western Canada Sedimentary Basin
YESEAA	*Yukon Environmental and Socio-Economic Assessment Act*
YPC	Yukon-Pacific Corporation
YTF	Yet to Find
YTG	Yukon Territorial Government

Glossary

TERM	DEFINITION
Acceptable Credit Rating	A Credit Rating not lower than any of the following: "BBB-" from Standard & Poor's, a division of the McGraw-Hill Companies, Inc. and its successors and assigns (S&P), "Baa3" from Moody's Investors Service, Inc. and its successors and assigns (Moody's), "BBB-" from Fitch Ratings Ltd. and its successors and assigns (Fitch), or "BBB (low)" from Dominion Bond Rating Service Limited and its successors and assigns (DBRS). In the event an entity is rated by two or more of S&P, Moody's, Fitch and DBRS, the lowest rating shall prevail.
Actual Capital Cost	The capital cost that is approved by FERC in the U.S. and the Northern Pipeline Agency and National Energy Board in Canada as the final capital cost of the Project following the In-Service Date and which TransCanada is authorized to include in the Project rate base for the recovery and return calculation pursuant to such approvals.
AECO	The Alberta Energy Company (AECO) hub was originally a storage facility in Alberta where natural gas was bought and sold. As suppliers and customers increasingly used this storage facility to buy and sell natural gas, the location was quickly established as the point at which the benchmark Alberta price was established in the marketplace. While this storage facility still exists, AECO today generally refers to the Alberta gas price and Alberta pricing point. When gas is said to be traded at the AECO hub, it is actually being traded on a notional (non-physical) point on the Nova Inventory Transfer pipeline system.
AGIA Commissioners	Commissioner of Revenue and Commissioner of Natural Resources
Agreement on Principles	Agreement Between the United States and Canada on Principles Applicable to a Northern Natural Gas Pipeline, September 20, 1977, U.S. – Can., 29 U.S.T. 3581.
Alaska Open Season	The process that complies with 18 C.F.R. Part 157, Subpart B (Open Seasons for Alaska Natural Gas Transportation Projects) pursuant to which TransCanada shall solicit initial binding commitments from potential Shippers for capacity on the Alaska Section, and the GTP in the event TransCanada is the sponsor for the GTP, which shall take place concurrently with the Yukon-BC Open Season and the Alberta Open Season.
Alaska Section	The section of the Pipeline System located in Alaska which runs from the outlet of the GTP near Prudhoe Bay, Alaska to the Alaska/Yukon border near Beaver Creek, and which would include related pipeline, compression, measurement and other permanent and temporary facilities located in Alaska.
Alaska Shippers	Those Shippers that commence service at a receipt point on the Pipeline System in Alaska.
Alberta Hub	The natural gas trading hub on TransCanada's Alberta System, where natural gas and natural gas liquids are traded and which trading activities are facilitated by the NOVA Inventory Transfer (NIT).
Alberta Open Season	The process pursuant to which TransCanada shall solicit initi[al] binding commitments from potential shippers for capacity on the

TERM	DEFINITION
	Alberta Section and TransCanada's Alberta System from the British Columbia/Alberta border near Boundary Lake to the Alberta Hub and further downstream for deliveries to the Alberta border, which shall take place concurrently with the Alaska Open Season and the Yukon-BC Open Season.
Alberta Section	The existing Foothills Pre-Build System located in Alberta and any new pipeline required to be built and owned by Foothills in Alberta in order to provide access to the Alberta Hub from the Yukon-BC Section, including related pipeline, compression, measurement and other permanent and temporary facilities owned by Foothills and located in Alberta.
Alberta System	TransCanada Corporation's wholly-owned, 15,000 mile natural gas transmission system in Alberta which gathers natural gas for delivery to end users and to liquids extraction facilities within the province and for delivery through provincial export locations to major natural gas market areas across North America. The Alberta System is a significant component of the Alberta Hub.
Anchor Shipper	A shipper who has reached an agreement with the pipeline sponsor, generally through one-on-one negotiation to support the project, by making a large early commitment to capacity on the proposed pipeline.
Antitrust	Opposing or intended to regulate business monopolies, such as trusts or cartels, especially in the interest of promoting competition.
ANS	The Alaska North Slope, which is the portion of Alaska north of sixty-eight degrees North latitude.
ANS Explorers	Those companies that have been or will be exploring for natural gas on the North Slope of Alaska.
ANS Producers	BP Exploration (Alaska) Inc., ConocoPhillips Alaska, Inc. and ExxonMobil Alaska Production Inc.
Base Capital Cost	The capital cost of the Pipeline System that is approved by FERC in the CPCN in Alaska and by the Northern Pipeline Agency and National Energy Board in the Leave to Construct in Canada.
Basin Control	The ability of the Major North Slope Producers to control the North Slope basin and discourage competitor producers from initiating and/or increasing their exploration and production activities in the area due to potentially high tariffs and uncertain access to essential pipeline capacity to move new production to markets.
Basis Point	One hundredth of a percentage point, or 0.01%. This term is usually used to discuss small fluctuations in equity indexes, interest rates, and yields on fixed annuities.
Blow Down	The rapid production of either oil or natural gas from a hydrocarbon reservoir. In terms of the Prudhoe Bay Unit and other mature reservoirs on the North Slope, blow down will signal a shift from a production approach that is designed to maximize the production of oil to an approach that is focused on the production of natural gas.
Bridge Shipper	An entity, usually governmental, that temporarily covers some of the unused capacity or commitments in the event that the new pipeline fails to attract enough paying customers to fill it.

TERM	DEFINITION
Canada Open Season	The combined Yukon-BC Open Season and the Alberta Open Season.
Canada Section	The Yukon-BC Section and the Alberta Section.
Capital Cost Overrun	That amount, if any, by which the Actual Capital Cost of the Pipeline System exceeds the Base Capital Cost or other agreed to amount.
Capital Cost Overrun Loan	The project loan which credit is proposed to be enhanced by the U.S. Loan Guarantee, and pursuant to which a Capital Cost Overrun would be financed.
Capital Cost Overrun Surcharge	The provisional toll which Surcharge Shippers are required to pay, when the market gas prices at the Alberta Hub are above a pre-determined threshold, for servicing the Capital Cost Overrun Loan.
Central Gas Facility	Existing facility at Prudhoe Bay that provides initial processing of the wet natural gas that has been separated from the ANS crude oil stream. Some natural gas liquids are extracted and the remaining gas stream is, for the most part, discharged for re-injection.
Collateral	(i) an irrevocable standby letter of credit from a financial institution acceptable to TransCanada with a Credit Rating of at least A by S&P and A2 by Moody's; or (ii) unencumbered cash collateral in a form satisfactory to TransCanada; or (iii) other collateral which may be mutually acceptable to the shipper and TransCanada.
Commission or FERC	Federal Energy Regulatory Commission
Contingent Liability	Liabilities that may or may not be incurred by an entity depending on the outcome of a future event such as a court case.
Credit Rating	The respective rating assigned to the long-term senior unsecured debt (not supported by third party credit enhancement) of an entity by S&P, Moody's, Fitch or Dominion Bond Rating Service and their respective successors and assigns. If an entity does not have a long-term senior unsecured debt rating, the corporate Credit Rating (or deemed equivalent) shall be used as a substitute.
Cure Period	A provision in a contract allowing a defaulting party to fix the cause of a default, for example a repayment grace period.
Decision to Proceed	The transition point between the Development Phase and the Execution Phase of the Project; the major Project milestone at which the final decision is made with respect to whether to proceed to execution of the Project or not.
Definition Sub-Phase	That portion of the Development Phase that begins with the conclusion of the Open Season and ends when all major Project approvals are in place and the final Decision to Proceed has been made.
Delivery Point	Any point on the Pipeline System where gas may be taken off the Pipeline System.
Discount Rate	AGIA specifies various discount rates to be analyzed in considering the NPV of future cash flows to the state. The discount rates specified are zero, five, six, and eight percent.
Divisible Income	The net cash flow from the proposed project.
Dry Gas	Natural gas that does not contain significant condensates or liquid hydrocarbons.
End User	The ultimate consumer of a product, especially the one for whom the

TERM	DEFINITION
	product has been designed.
FERC Open Season Regulations	The FERC regulations as set forth in 18 C.F.R. § 157, Subpart B (Open Seasons for Alaska Natural Gas Transportation Projects).
Firm Transportation Service	The transportation service provided to a Shipper on a pipeline system pursuant to a Transportation Services Agreement (TSA) between the Shipper and a pipeline whereby the pipeline agrees to make available to the Shipper on a firm basis the capacity on the pipeline system subscribed for in the TSA and the Shipper agrees to pay for such capacity as per the TSA whether the Shipper uses such capacity or not.
First Nations peoples	The Indian peoples of Canada, both Status and non-Status, as defined in the Indian Act, R.S., 1985, c. I-5.
Foothills System or Foothills Pre-Build or Pre-Build	The existing natural gas pipeline system built under certificates issued pursuant to Canada's Northern Pipeline Act that starts at Caroline, Alberta that branches into two legs, with one leg running south-east to Monchy, Saskatchewan and the other leg running south-west to Kingsgate, British Columbia, which is owned by Foothills Pipe Lines Ltd., a wholly-owned subsidiary of TransCanada Corporation.
Gas Cap	An oilfield term indicating the condition which occurs as oil is removed; the gas becomes mobilized and accumulates as a "gas cap" on the oil formation. Also, the portion of a reservoir occupied by free gas (gas not in solution).
Gas Treatment Plant (GTP)	In the TransCanada application, the GTP is necessary for treating some natural gas that is to be shipped via pipeline from the Alaska North Slope (ANS). The GTP will process over 5 billion cubic feet per day (bcf/d) of residue gas from the existing Central Gas Treatment Facility located at Prudhoe Bay. This residue gas would be treated by removing the undesirable constituents (e.g., CO_2) by dehydration and filtration processes. The 4.5 bcf/d of sales gas would be chilled to 28°F and compressed to 2500 pounds per square inch gauge (psig) prior to shipping. The CO_2 would be returned to the residue gas stream and re-injected into the Prudhoe Bay reservoir.
Guarantee	A financial guarantee in the form acceptable to TransCanada from a party with an Acceptable Credit Rating.
Henry Hub	The Henry Hub is a pipeline interchange located near Erath, Louisiana. The Henry Hub is the designated delivery point for the NYMEX Natural Gas futures contract. The Henry Hub is also a highly liquid trading point, with numerous buyers and sellers of both physical natural gas and financial derivatives. The Hub provides access to more than a dozen interstate and intrastate pipeline interconnects
Hub	A major natural gas receipt and delivery and/or trading point.
Hurdle Rate	The minimum rate of return producers must achieve to pursue a project.
In-Service Date	The date for Commencement of Commercial Operations of the Pipeline System.
In-State Shippers	Those Shippers that subscribe for transportation services with the Alaska Section for natural gas delivery to a delivery point within the

TERM	DEFINITION
	State of Alaska.
Internal Rate of Return	The internal rate of return (IRR) is a metric used to determine the efficiency of an investment, as opposed to the net present value (NPV), which indicates value or magnitude. The IRR is the annualized effective compounded return rate which can be earned on the invested capital, i.e., the yield on the investment.
Investment Grade	Applies to an assessment of a shipper's creditworthiness and means a long term senior unsecured debt rating of at least BBB- by Standard & Poor's (S&P); Baa3 by Moody's Investor Services (Moody's); BBB- by Fitch Ratings (Fitch); or BBB (Low) by Dominion Bond Rating Service (DBRS).
Leave to Proceed	Has the meaning ascribed to it in Section 2.2.4.2(2) "Canadian Regulatory Approvals".
Levelized cost	The present value of the total cost of building a pipeline over its economic life, converted to equal annual payments. Costs are levelized in real dollars (i.e., adjusted to remove the impact of inflation).
License	The license to be granted under the Alaska Gasline Inducement Act, AS 43.90 et. seq.
Line Pack	A quantity of gas purchased for operational (non-commercial) use by the pipeline entity to fill and pressurize the pipeline prior to the commencement of commercial operations. The line pack quantity is generally considered a permanent part of the pipeline's asset base (and its cost is included in the tariff), allowing the pipeline to deliver gas for a shipper at a pipeline delivery point at the same time the shipper delivers that quantity of gas to a pipeline receipt point.
Lower 48	The contiguous states of the United States, i.e. not including Alaska or Hawaii.
Mainline	The large diameter pipeline that is routed generally along the TAPS pipeline and the Alaska Canada Highway, compressor stations and related facilities, including any additions, improvements, expansions, extensions or renewals or replacements to the pipeline, compressor stations, or related facilities, designed to transport gas from the ANS to off-take points and to connect with other pipelines.
Major NS Producers	Phrase used to describe major North Slope producers including Exxon, British Petroleum, and ConocoPhillips
Management Committee	A committee of senior representatives of TransCanada who direct the organization and who will provide executive guidance to senior management of the Project and will consider approvals for significant Project scope and budget changes.
Midstream Capital Costs	The capital costs of the pipeline, GTP, compressor stations, and (as applicable) LNG liquefaction facilities are a key input into the Midstream Model, and significantly affect Midstream tariffs.
Midstream Divisible Income	Consists of profits for the pipeline owner as well as property and corporate income taxes.
Midstream Element	Means a gas transmission pipeline, a gas treatment plant, the main pipeline (mainline), compressor stations, or a NGL plant.

TERM	DEFINITION
Natural Gas Liquids	Natural gas liquids include propane, butane, pentane, hexane and heptane, but not methane and ethane, since these hydrocarbons need refrigeration to be liquefied.
Net Present Value (NPV)	Net Present Value is an economic calculation used to appraise the financial value of long-term projects. An NPV calculation figures the present value of an investment that may generate returns for many years; in short, the AGIA NPV calculation allows us to understand, in terms of today's money, the profits (or losses) that an Offeror's AGIA Application offers the State.
Negotiated Rate Shippers	Those Shippers that have elected to pay the transportation tariff/toll in accordance with the Negotiated Rate has the meaning ascribed to it in Section 2.2.3.7 "Negotiated Rates"
Net Back value	The net back value is defined as the unit price or value of a product such as natural gas at a particular point on the pipeline (or upstream of the pipeline such as at the point of production.) The net back value is calculated by subtracting from the downstream sales price of that product all the costs incurred to deliver the product to the point of sale.
Net Cash Flow	The net cash flow from gas, or "Upstream Divisible Income", is: (1) the final destination price of the gas, times (2) the volume of gas transported, minus (3) total tariff payments and (4) out of pocket production costs.
NOVA Inventory Transfer or NIT	A notional point on TransCanada's Alberta System that acts as a market hub, where the transfer of title to gas transported on such system occurs, and which transfer can only occur following payment by the shipper of the receipt toll. NIT functions as both a market and supply hub by providing direct access to over 300 bcf of connected storage, a large (3 bcf/d) intra-Alberta market and multiple pipelines which transport approximately 17 bcf/d to major markets across North America.
Off-take Point	A delivery connection location, consisting of necessary valves, flanges and fitting, where gas flows out of a mainstream pipeline to other pipelines for distribution.
On Spec	On speculation, or speculatively.
Open Season	An open season is the process during which a pipeline company seeks customers to make firm transportation commitments (usually long-term) to a project, e.g., the concurrent initial binding Alaska Open Season, Yukon-BC Open Season and Alberta Open Season. An open season is the process during which a pipeline company seeks customers to make long-term firm transportation commitments to a project.
P_x	Indicates that an outcome or proposed action has a X% likelihood of occurring. For example and outcome of proposed action of P_{50}, has a 50% likelihood of occurring.
Precedent Agreement	An agreement between a Shipper and TransCanada entered into following the completion of the Alaska Open Season, the Yukon-BC Open Season or the Alberta Open Season, as applicable, pursuant to which such Shipper agrees to commit a certain amount of gas to the Alaska Section, the Yukon-BC Section or the Alberta Section and

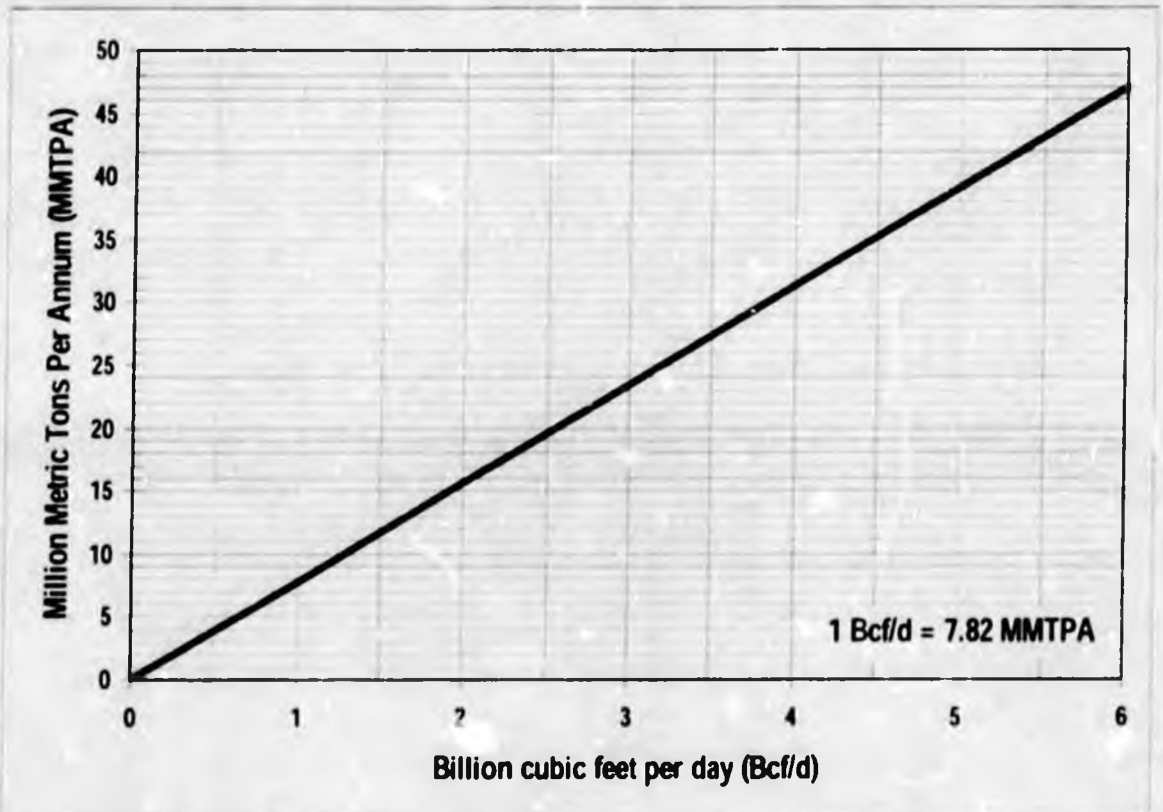
TERM	DEFINITION
	TransCanada's Alberta System, as applicable, which shall be superseded and replaced by the Transportation Services Agreement prior to the In-Service Date.
Proposal Sub-Phase	That portion of the Development Phase that begins with the award of the AGIA license and ends with the conclusion of the Open Season
Proved Reserves	Reserves of natural gas that are claimed with reasonable certainty (80% to 90% confidence) to be recoverable in future years by specified techniques.
Ratemaking	The practice of establishing rates of payment for services, as for public transportation or utilities.
Rebuttable Presumption	An assumption made by a court, one that is taken to be true unless someone comes forward to contest it and prove otherwise.
Receipt Point	Any point on the Pipeline System where gas may be put into the Pipeline System.
Receipt Shippers	Those Shippers that enter into a Transportation Services Agreement with TransCanada's Alberta System pursuant to which the Shippers agree to deliver gas into the Alberta System and pay the receipt toll.
Recourse Rate	Recourse rates are cost-based rates set by FERC under conventional public utility rate-making methods. In Section 2.2.3.5(1) of TransCanada's application Recourse Rate is used to describe that the 100% load factor for the Alaska section would be $1.06/mmBtu in constant 2007 dollars.
Recourse Rate Shippers	Those Shippers that have elected to pay the transportation tariff/toll for the Alaska Section in accordance with the Recourse Rate as described in Section 2.2.3.5 "Rate Structure and Supporting Information".
Regasification	The practice of converting liquefied natural gas back into gaseous form to send to market, often after moving it into cold storage tanks.
Rolled-in rates	Is a term used by FERC to differentiate between rolling-in the construction costs of new pipeline expansion with the existing facilities or developing costs on an incremental basis (establishing separate cost-of-services and separate rates for the existing and expansion facilities).
Royalty In-Kind	Royalty is a share of production. When taken "in-kind" the State of Alaska physically takes custody of the oil or gas produced.
Royalty In-Value	When taken "in-value" the royalty share is left with the producer, who must sell 100 percent of the oil or gas, and pay the State of Alaska its royalty share of the net proceeds from the sale of 100 percent of the oil or gas, or the market value of the oil or gas, whichever is higher.
Sealift	The barging of large oil and gas field equipment from where it is built to where they are installed.
Shippers	Those entities that contract for gas processing and transportation services on the GTP and the Pipeline System.
Sovereignty	Supremacy of authority or rule as exercised by the State.
Spend-Curve	A component of calculating cost and schedule range data that shows when in the process the dollars will be spent to develop and construct the project
State	State of Alaska
Surcharge Shippers	Those Negotiated Rate Shippers that elect the Capital Cost Overrun

TERM	DEFINITION
	Surcharge option.
Take or Pay Contracts	Agreements between a buyer and a seller that obligate the buyer to pay a minimum amount of money for a product or service, even if the product or service is not utilized or purchased.
Tangible Net Worth	Total assets (exclusive of goodwill and other intangible assets) minus total liabilities, as reported in the provider's unqualified audited annual financial statements and unaudited quarterly financial statements in accordance with generally accepted accounting principles in the country in which the provider is organized, consistently applied.
Tariff	The rate and terms of service materials associated with operations of the pipeline. Frequently, this term only refers to the rates to be charged for particular services.
Term-differentiated Rates	Rates that that vary by the length of the contract term. These rates allow the pipeline to recover its capital costs from shippers over a longer period, thus lowering the rates paid by shippers that sign longer-term contracts.
Transportation by Others or TBO	Commercial arrangements whereby one pipeline system contracts for capacity on another pipeline system. The pipeline system taking the capacity uses it to provide integrated service to parties on its system.
Transportation Services Agreement	The agreement between a Shipper and TransCanada pursuant to which TransCanada agrees to provide natural gas transportation services on the Alaska Section, the Yukon-BC Section, the Alberta Section or TransCanada's Alberta System, as applicable, to the Shipper and the Shipper agrees to abide by the terms and conditions of the agreement and pay the applicable tariff/toll for subscribing for capacity on the Alaska Section, the Yukon-BC Section, the Alberta Section or TransCanada's Alberta System, as applicable.
Twenty (20) Must Haves	The twenty statutory requirements of the Alaska Gasline Inducement Act as specified in AS 43.90.130
Upstream Divisible Income	The net cash flow from gas, or "Upstream Divisible Income", is: (1) the final destination price of the gas, times (2) the volume of gas transported, minus (3) total tariff payments and (4) out of pocket production costs. Upstream Divisible Income is shared between the Producers, the State of Alaska, and the federal government through royalty, and state production taxes.
Wet Gas	Natural gas that contains methane and natural gas liquids such as butane, propane and ethane.
Work Commitments	A promise on the part of the participants to the fiscal contract to take the steps necessary to implement the gas pipeline project. With regard to the SGDA contract, work commitments refer to a promise on the part of the participants to the fiscal contract to take the steps necessary to implement the gas pipeline project
Yet-to-find (YTF) area	Production areas which, according to the NETL Alaska Gas Study and other sources, have a significant amount of economically recoverable reserves, but which have not yet been discovered.

Units

Bcf/d	billion cubic feet per day
Btu	British thermal unit (Btu). The term "Btu" is used to describe the heat value (energy content) of fuels.
Calorific Content	The heating value or calorific value of a fuel is the amount of heat released during combustion.
Decatherms	A decatherm is a measure of heat energy equal to 1,000,000 British thermal units (Btu). It is approximately the energy equivalent of burning 1000 cubic feet (often referred to as 10 Ccf) of natural gas
Ft	feet
In	Inches
M	Meter
MMBTU	**MMBTU** represents one million BTU, which can also be expressed as 1 decatherm (10 therms)
MMTPA	Million Metric Tons Per Annum. 1Bcf/d = 7.82 MMTPA
psig	pounds per square inch gauge
Tcf	trillion cubic feet

Billion cubic feet per day (Bcf/d) – Million Metric Tons per Annum (MMTPA) Conversion Chart



ExxonMobil

Point Thomson Unit Development

ALASKA COMMITTEES ON AGIA / ENERGY

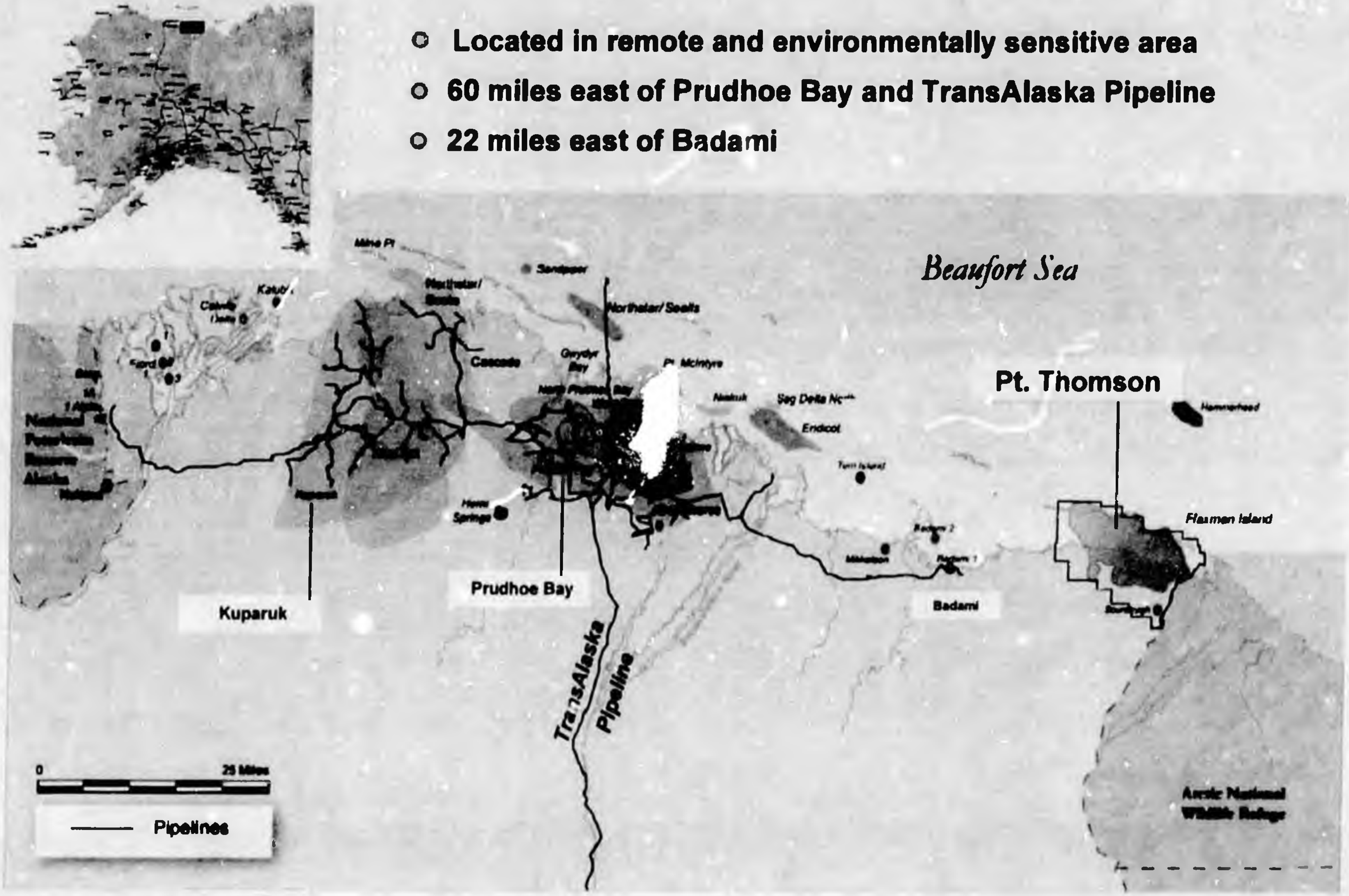
June 17, 2008

Craig A. Haymes
ExxonMobil Alaska Production Manager

Point Thomson – Isolated from Rest of North Slope

ExxonMobil

- Located in remote and environmentally sensitive area
- 60 miles east of Prudhoe Bay and TransAlaska Pipeline
- 22 miles east of Badami

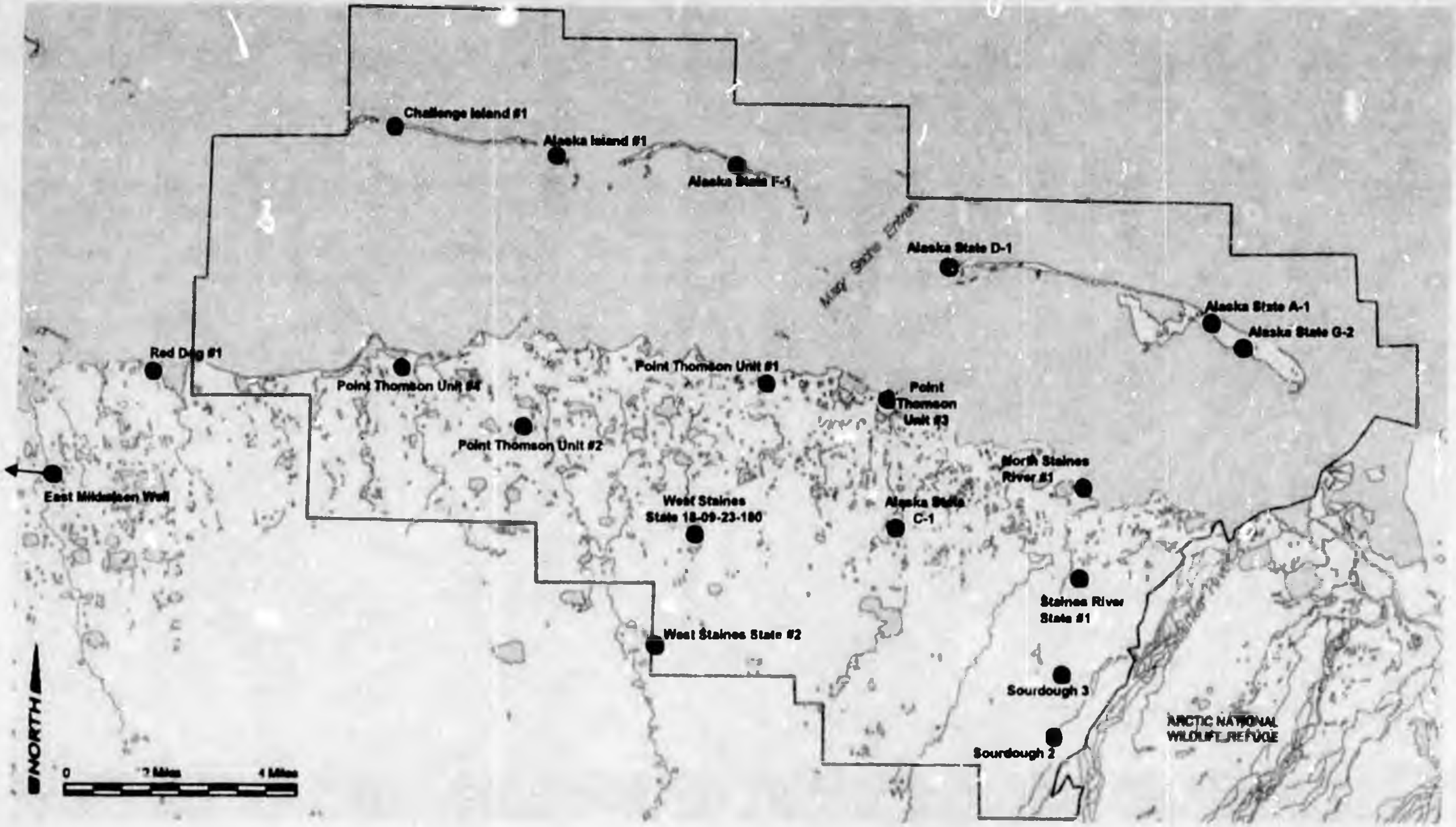


June 17, 2008

Point Thomson – Obtaining Information

ExxonMobil

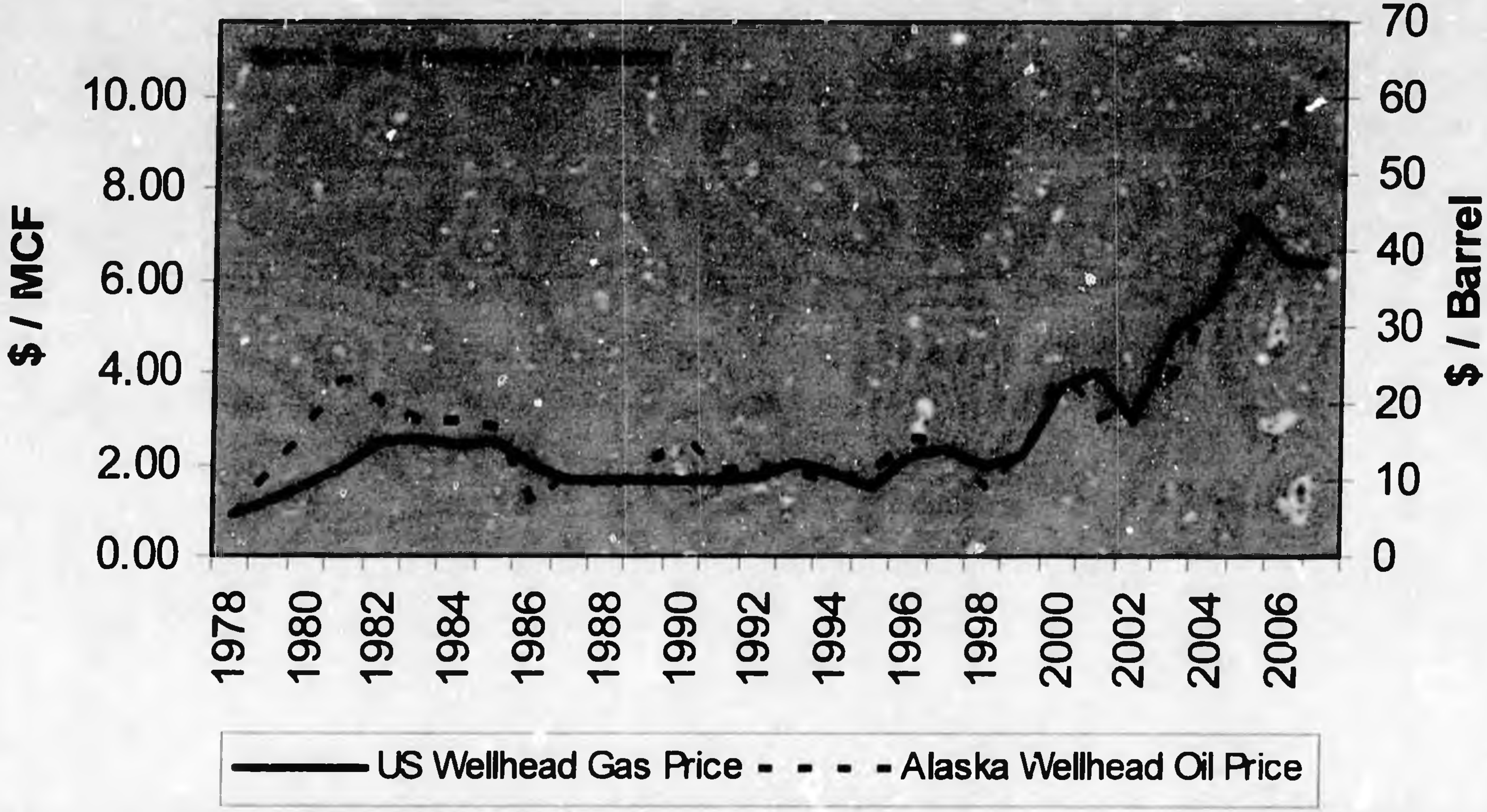
- 19 Exploratory Wells Drilled
- Eight 3D Seismic Acquisitions



Point Thomson – POD Commitments

ExxonMobil

Historical Oil and Gas Prices



Point Thomson Plan of Development (POD)

ExxonMobil

$1.3 Billion Project

- Future Expansion Capability

Plan of Development (POD)

Cooperative Owner Efforts

Development Planning

Learning from Worldwide Operations

Geological and Reservoir Modeling

Data Interpretation

3D Seismic Surveys

Drilled 19 Exploration Wells

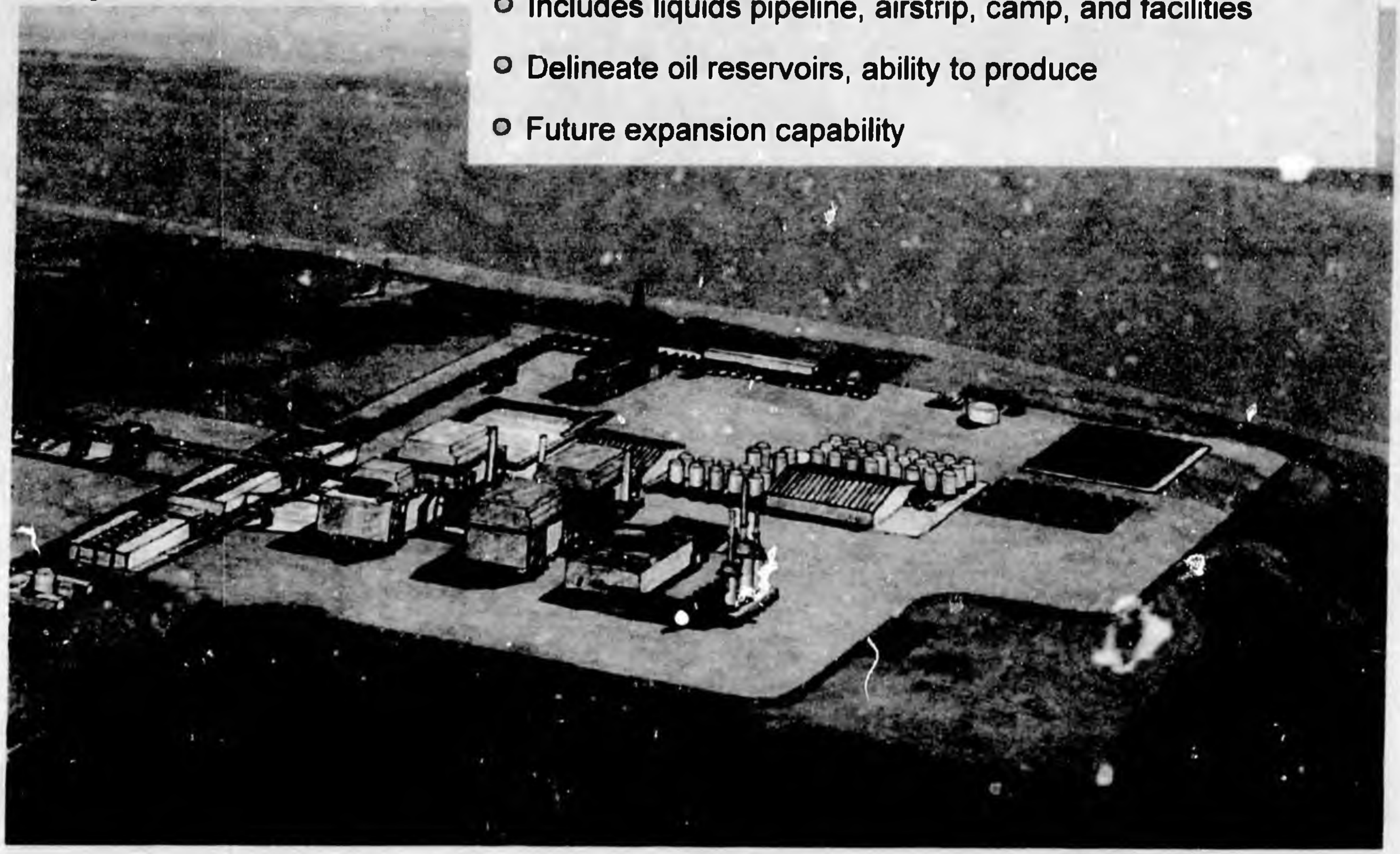
> $800 Million spent to date

PTU POD - Plan to Produce Condensate

ExxonMobil

Project Illustration

- Production by YE 2014: 10,000 BPD, inject remaining gas
- Includes liquids pipeline, airstrip, camp, and facilities
- Delineate oil reservoirs, ability to produce
- Future expansion capability



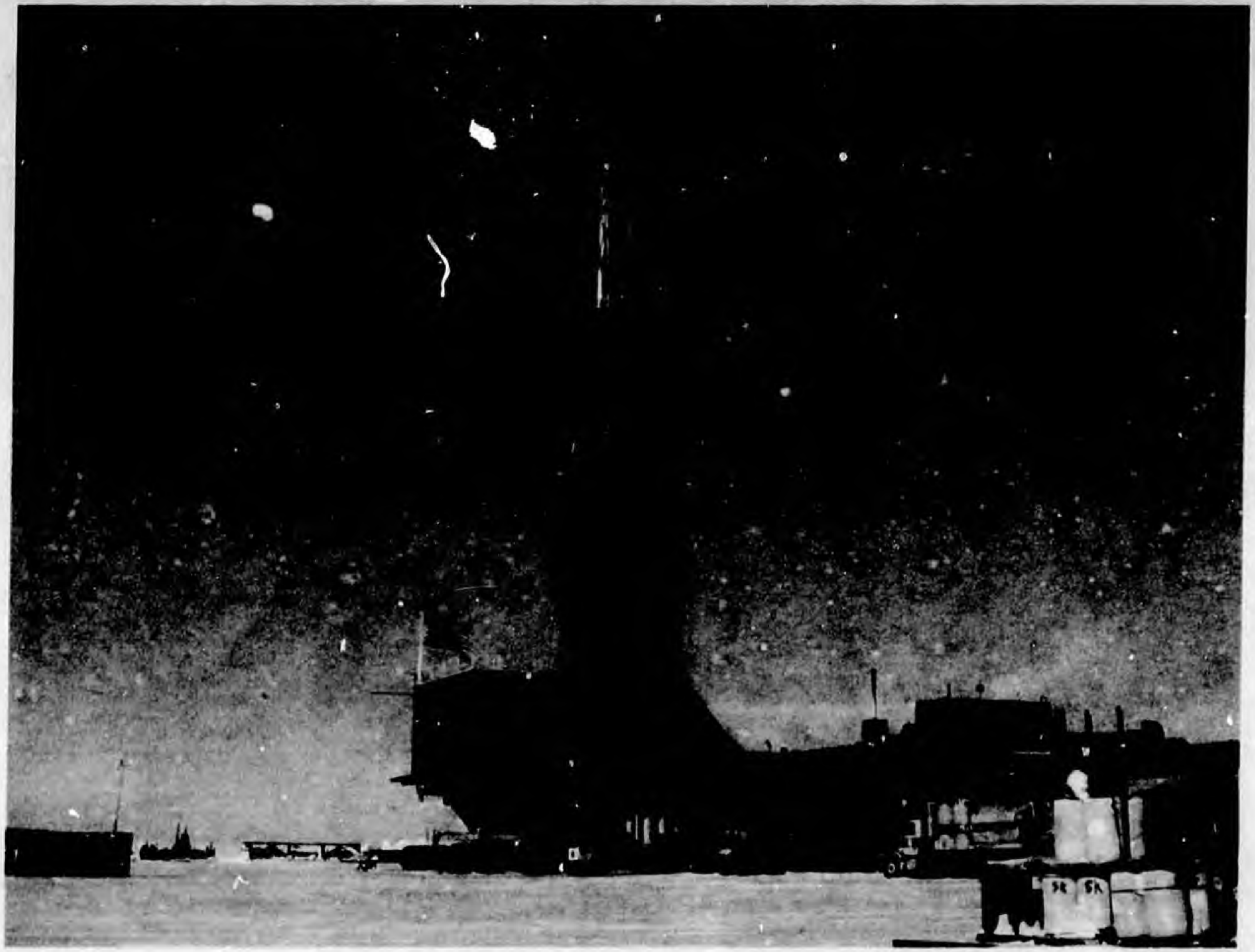
PTU – Project Activity Underway

ExxonMobil

- Nabors Rig 27E contracted
- Rig upgrades ($20M) commenced – Anchorage, North Slope
- Long lead drilling materials ordered

PTU - Drilling Rig with Upgrades Underway

ExxonMobil



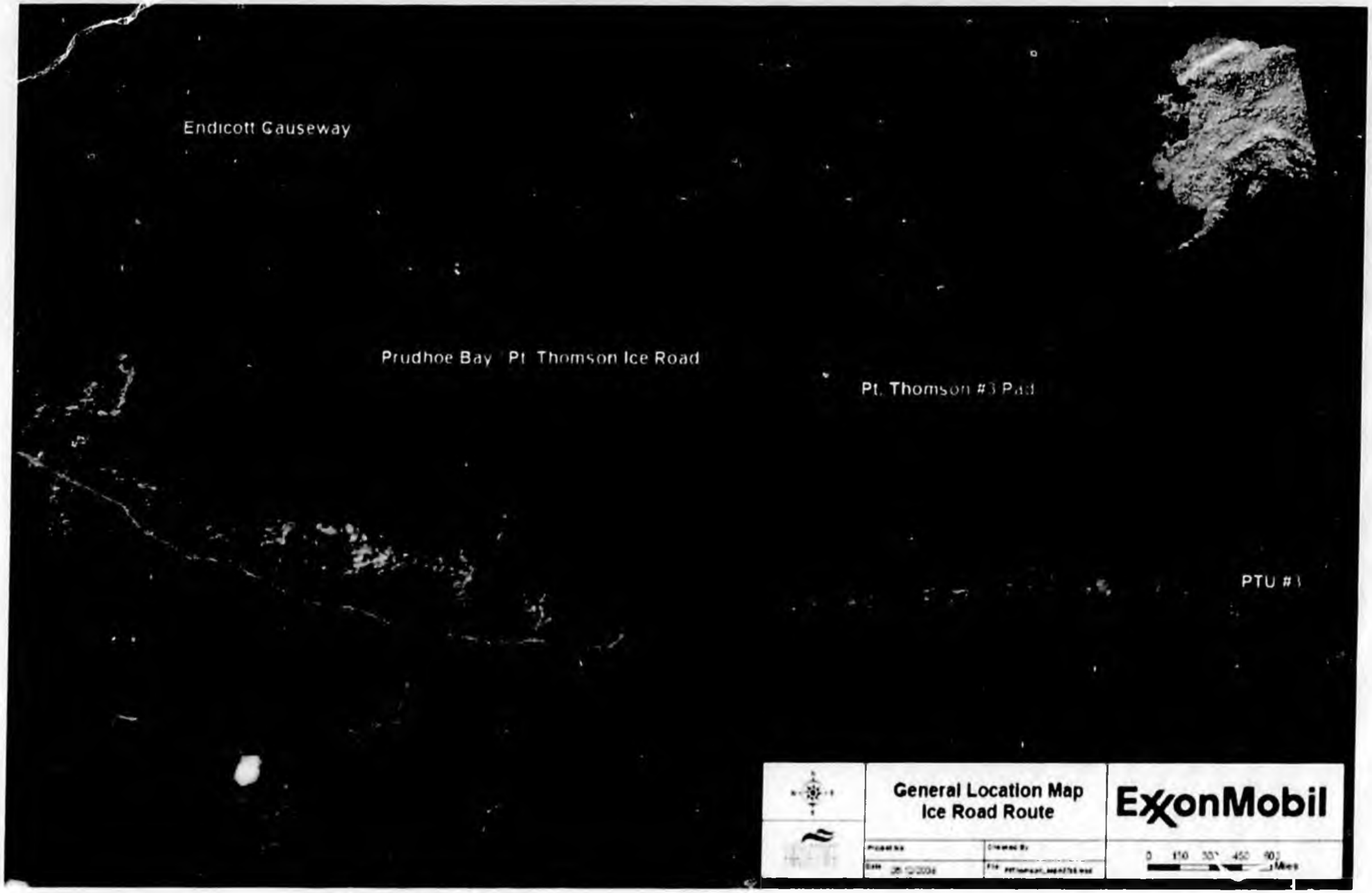
PTU – Project Activity Underway

ExxonMobil

- Nabors Rig 27E contracted
- Rig upgrades ($20M) commenced – Anchorage, North Slope
- Long lead drilling materials ordered
- **50 mile ice road and airstrip contracted to Alaskan company**

PTU – 50 Mile Sea Ice Road

ExxonMobil



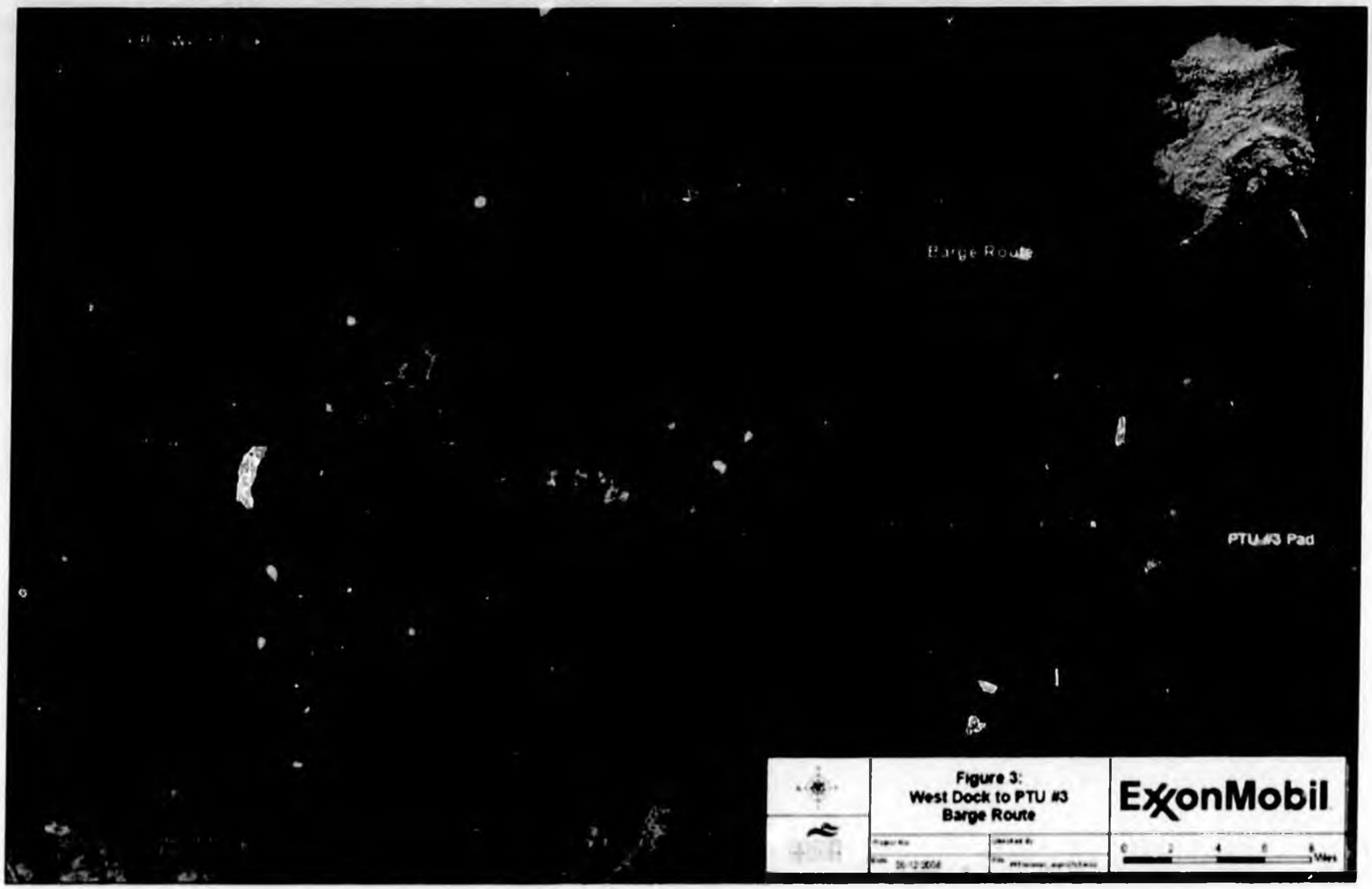
PTU – Project Activity Underway

ExxonMobil

- Nabors Rig 27E contracted
- Rig upgrades ($20M) commenced – Anchorage, North Slope
- Long lead drilling materials ordered
- 50 mile ice road and airstrip contracted to Alaskan company
- **Drilling/Project site survey week of 6/23**
- **Permitting applications in June**
- **Barging of ice facilities and pad equipment in July/August**

PTU – Route for Summer Barge Activity

ExxonMobil



PTU – Summer Site Preparation Plan

ExxonMobil

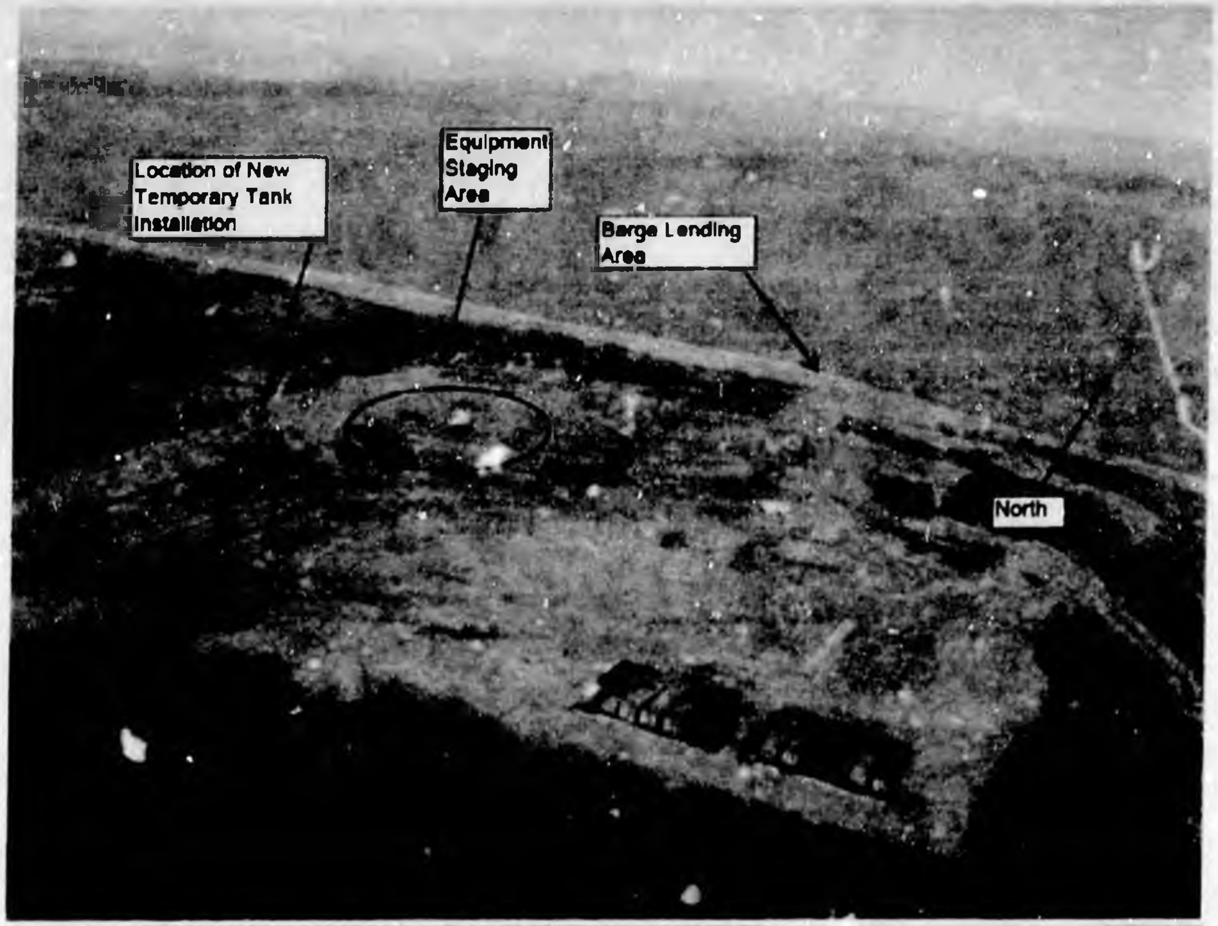


Figure 2
ExxonMobil
Point Thomson
Equipment Staging and Pad Preparation Project Schedule

ID	Task Name	Start	Finish
1	Barging of Equipment and Materials	7/15/08	8/30/08
2	Camp Setup	7/15/08	7/20/08
3	Gravel Hauling	7/21/08	7/30/08
4	Pad Preparation	8/1/08	8/15/08
5	Onsite Equipment Backhaul	8/16/08	8/17/08
6	Final Equipment Staging	8/16/08	8/30/08
7	Security Crew Standby	9/2/08	1/31/09

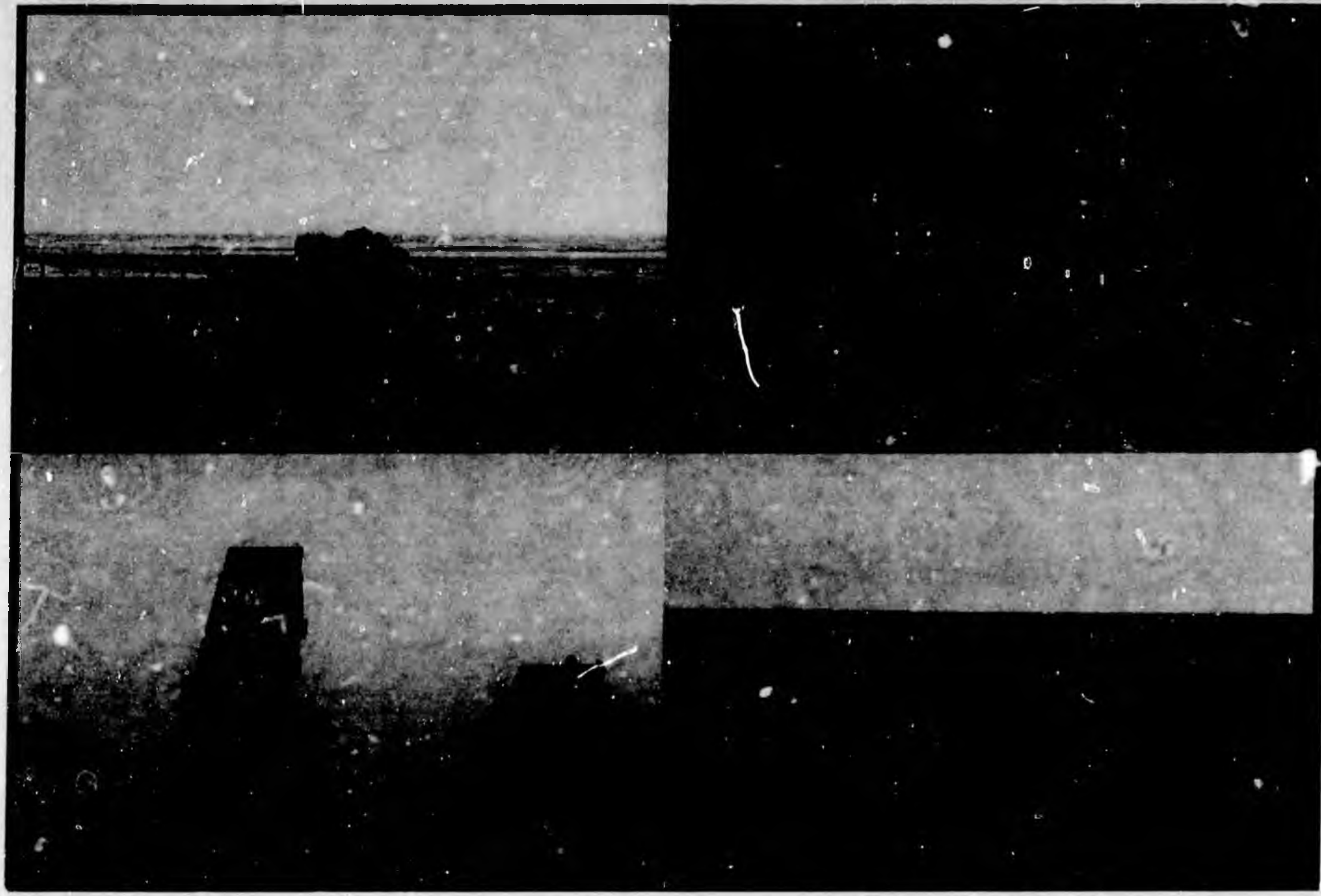
PTU – Project Activity Underway

ExxonMobil

- Nabors Rig 27E contracted
- Rig upgrades ($20M) commenced – Anchorage, North Slope
- Long lead drilling materials ordered
- 50 mile ice road and airstrip contracted to Alaskan company
- Drilling/Project site survey week of 6/23
- Permitting applications in June
- Barging of ice facilities and pad equipment in July/August
- **Construct ice road and mobilize rig to PTU in December/January**

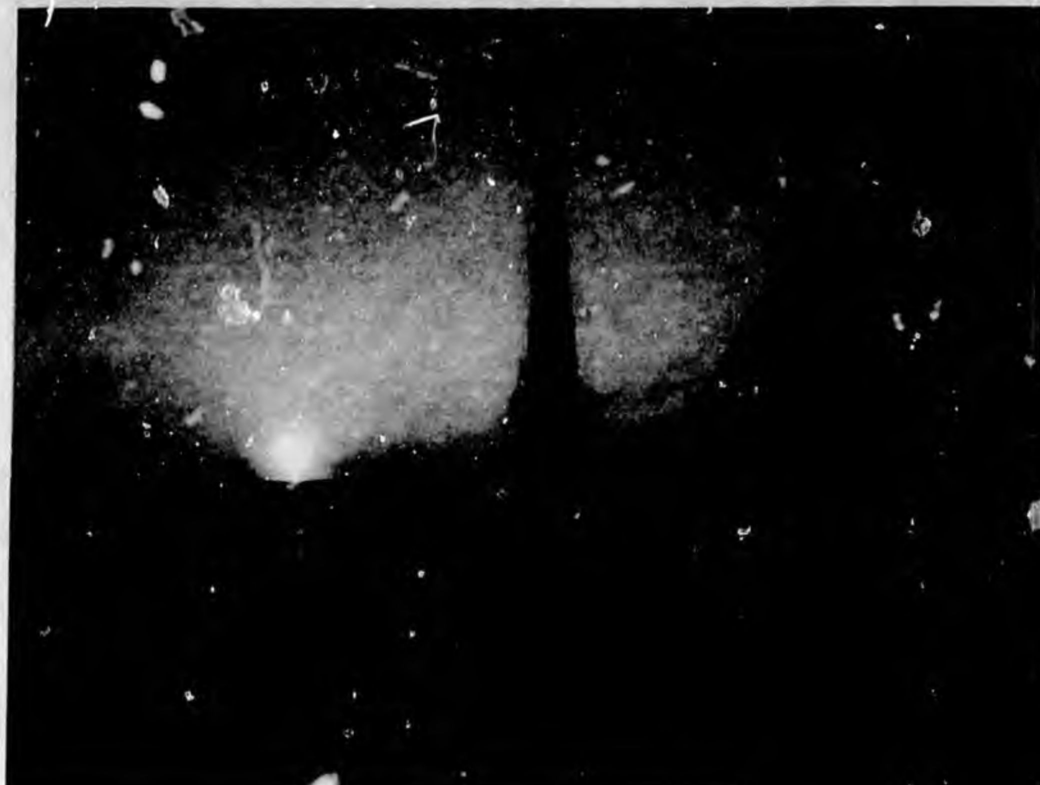
PTU – Ice Road Construction & Maintenance

ExxonMobil



PTU – Rig Move Over Ice Road

ExxonMobil



PTU – Project Activity Underway

ExxonMobil

- Nabors Rig 27E contracted
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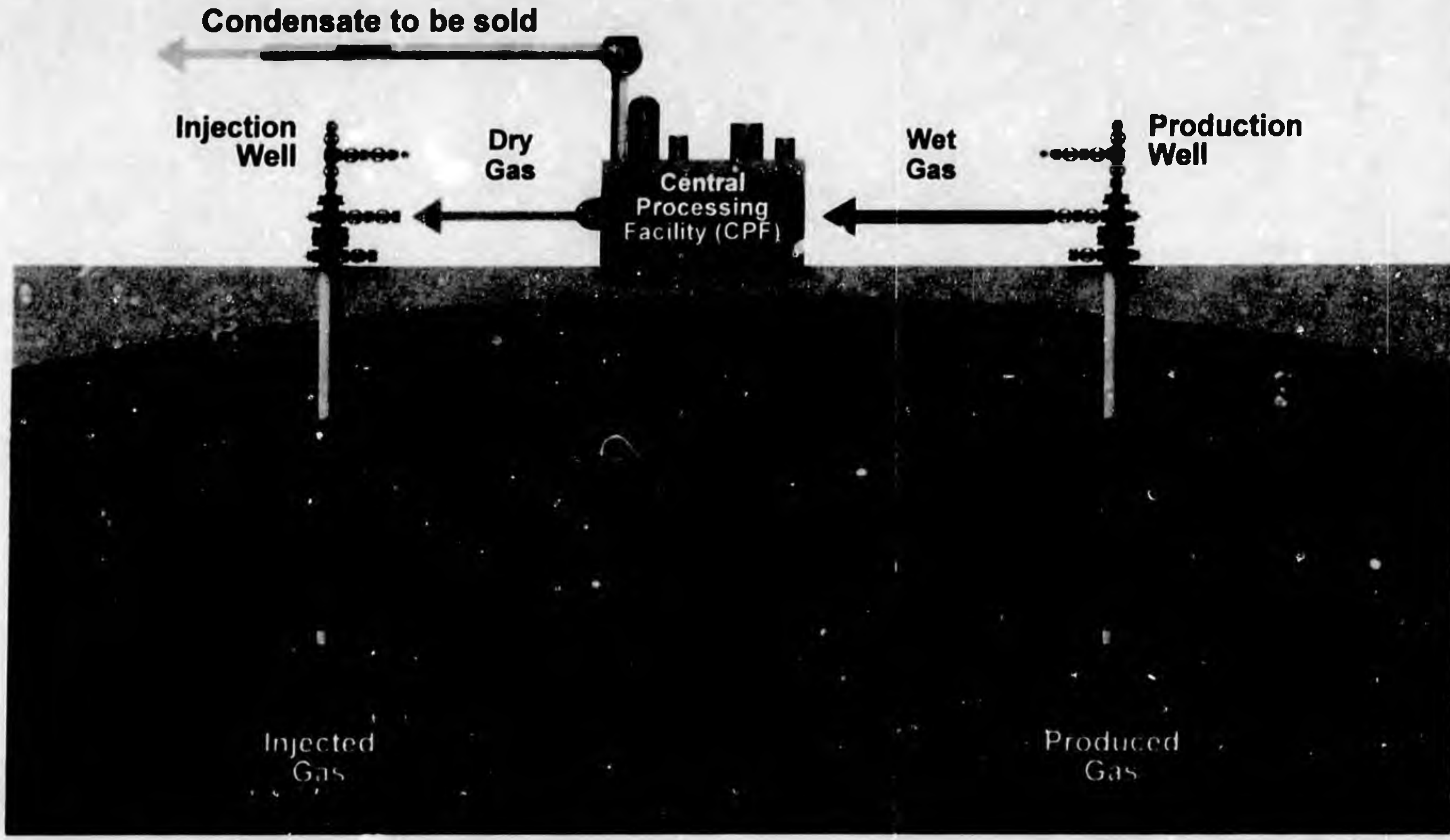
- Drilling/Project site survey week of 6/23
- Permitting applications in June
- Barging of ice facilities and pad equipment in July/August
- Construct ice road and mobilize rig to PTU in December/January
- **Spud 1st well February 2009**

Point Thomson - Produce Condensate by Cycling Gas ExxonMobil



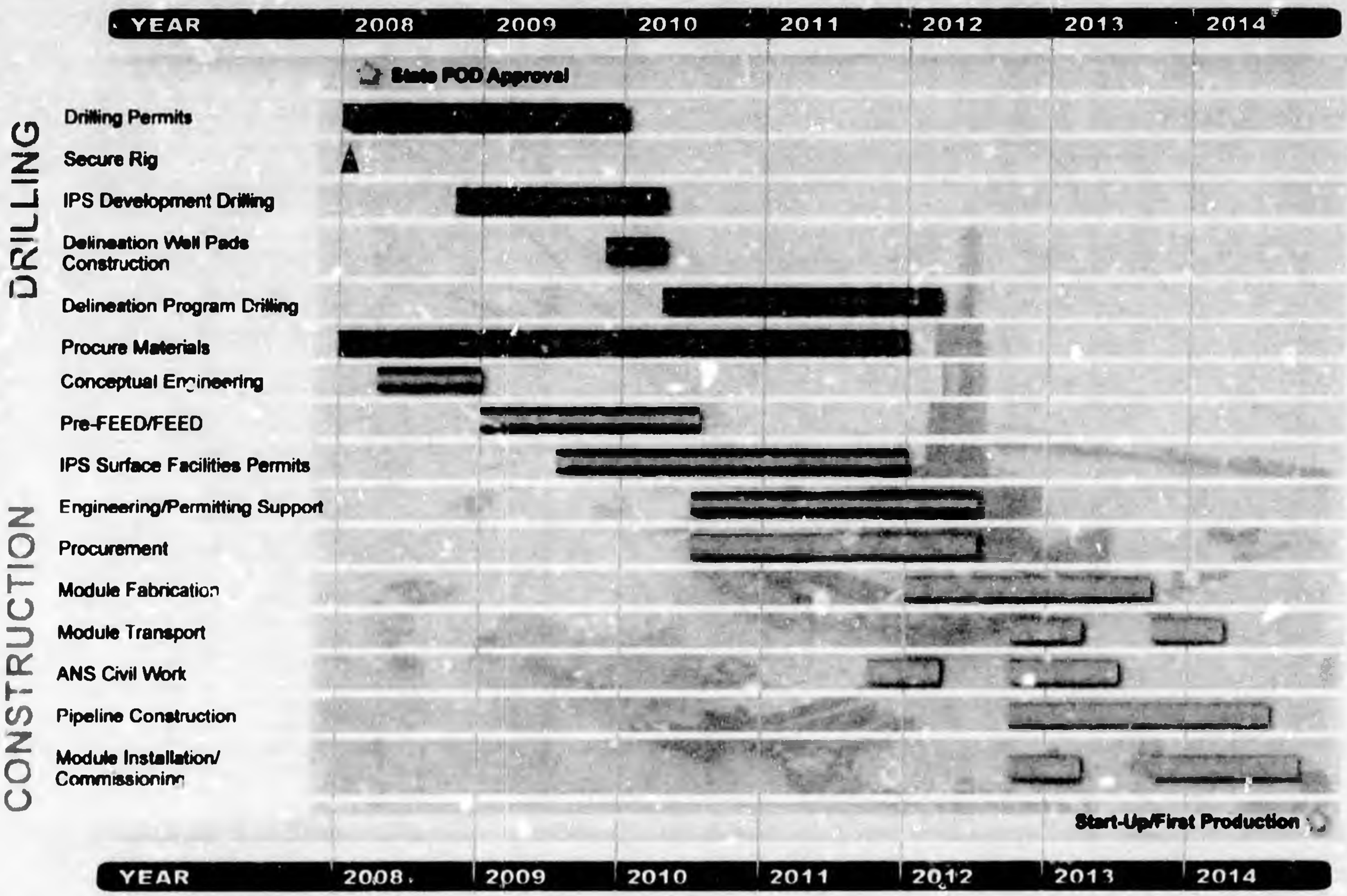
PTU POD - Addressing DNR's Concerns

ExxonMobil

- Engineering & Drilling Starts 2008
  - > 200 jobs by next winter
- Production begins 2014
- 10,000 Barrels per Day
- Future Expansion Capability

PTU POD - Clear and Committed Timeline

ExxonMobil



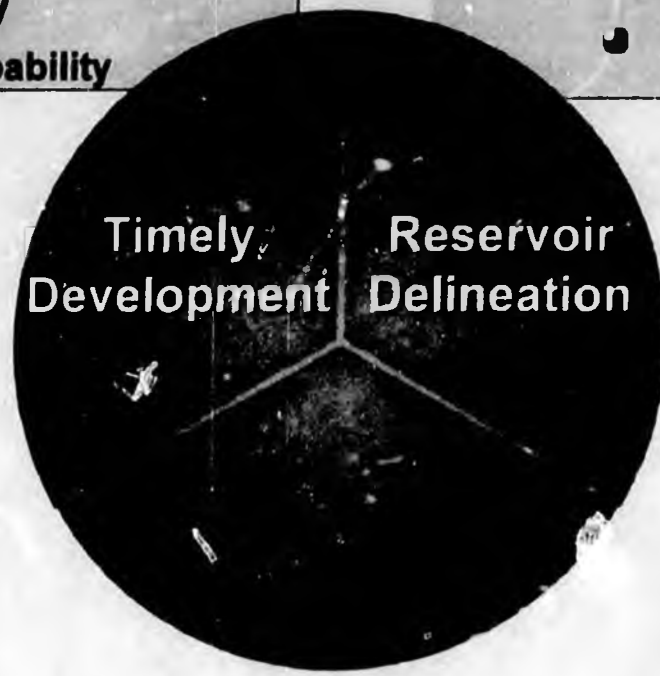
June 17, 2008

PTU POD - Addressing DNR's Concerns

ExxonMobil

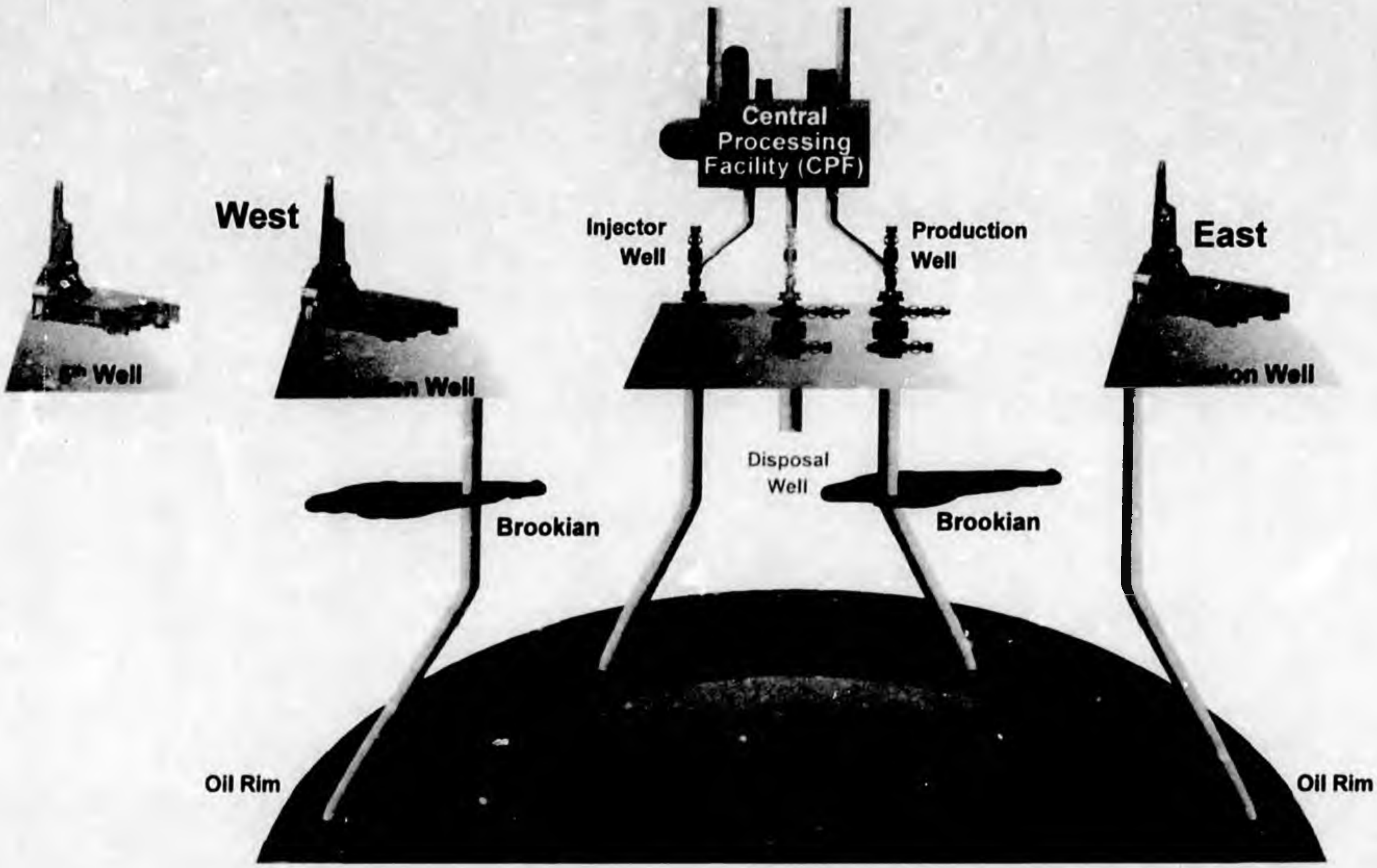
- Engineering & Drilling Starts 2008
  - > 200 jobs by next winter
- Production begins 2014
- 10,000 Barrels per Day
- Future Expansion Capability

- Drilling Program – Gas, Oil, Condensate
  - 2 gas cycling wells
  - 3 oil / gas delineation wells
  - Additional Wells if required



PTU POD - Plan to Develop and Delineate

ExxonMobil



June 17, 2008

PTU POD - Addressing DNR's Concerns

ExxonMobil

- Engineering & Drilling Starts 2008
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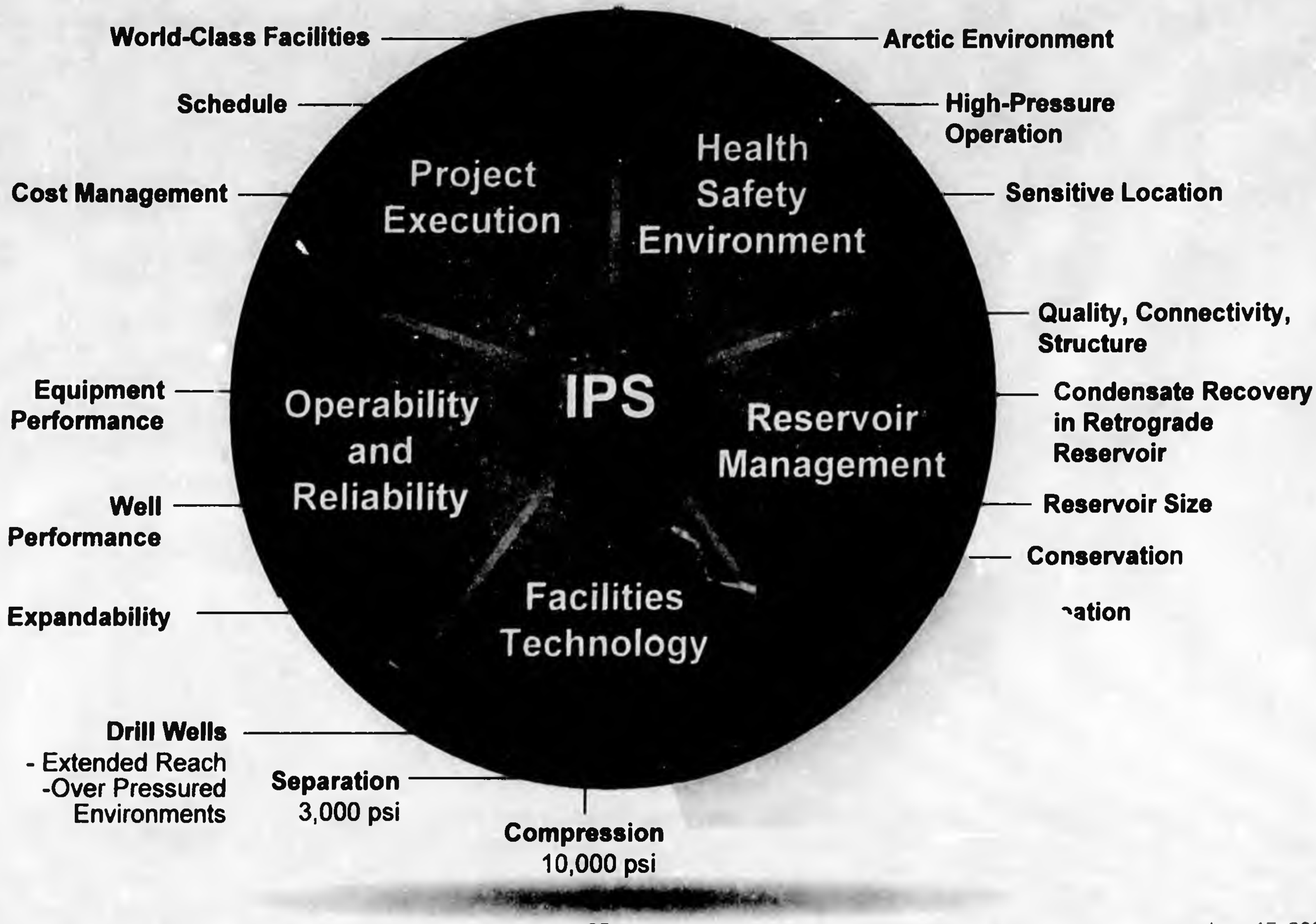
- Drilling Program – Gas, Oil, Condensate
  - 2 gas cycling wells
  - 3 oil / gas delineation wells
  - Additional Wells if required

- Term of POD through to Production
- Owners support $1.3 Billion Project
- Already Secured Rig; Long Lead Materials
- Scheduled Milestones for State to Monitor Progress
- Owners Support Assured by Corporate Executives
- Agreed to Unit Termination if Milestones Not Met

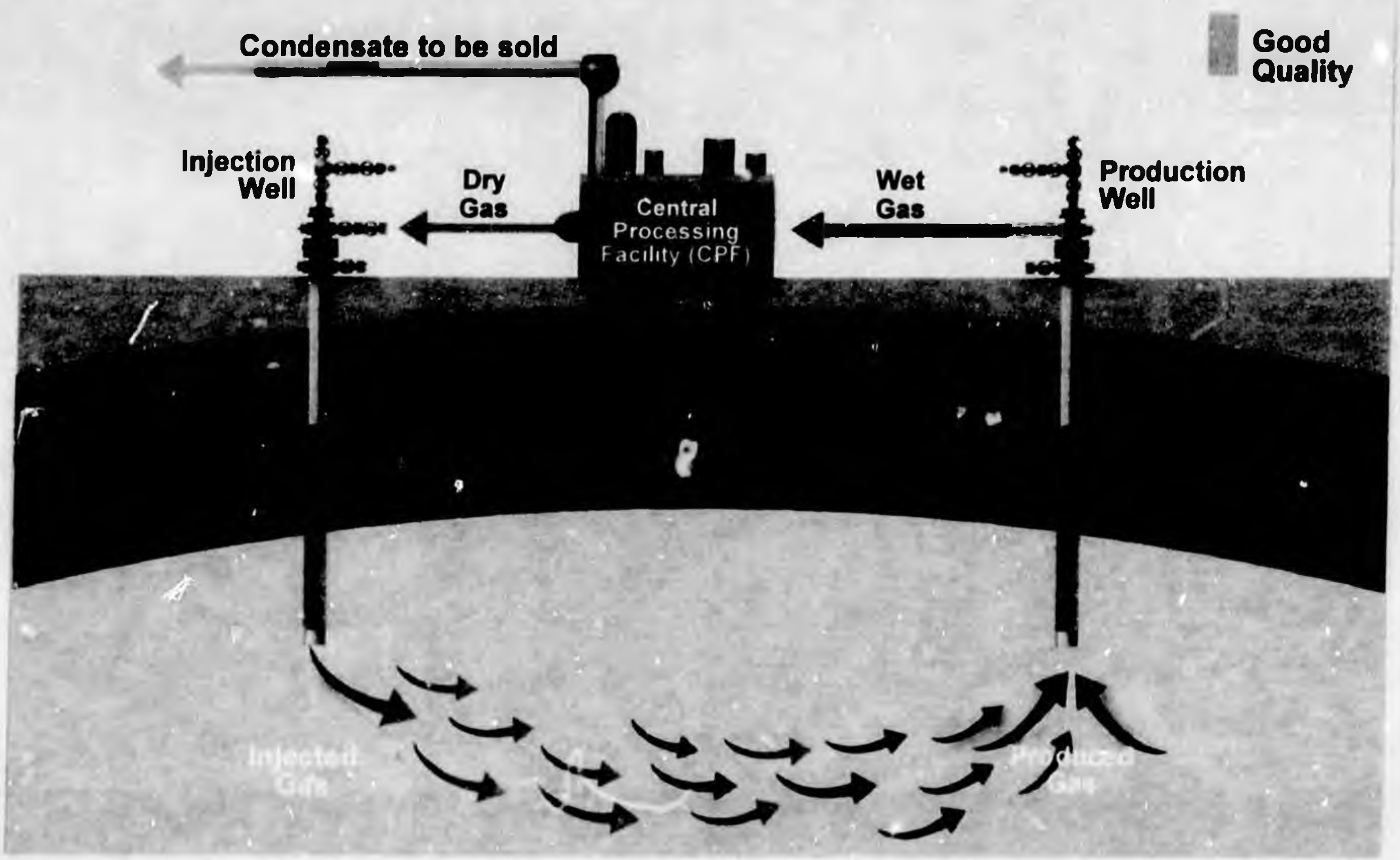
PTU POD - Prudently Manages Risk

ExxonMobil



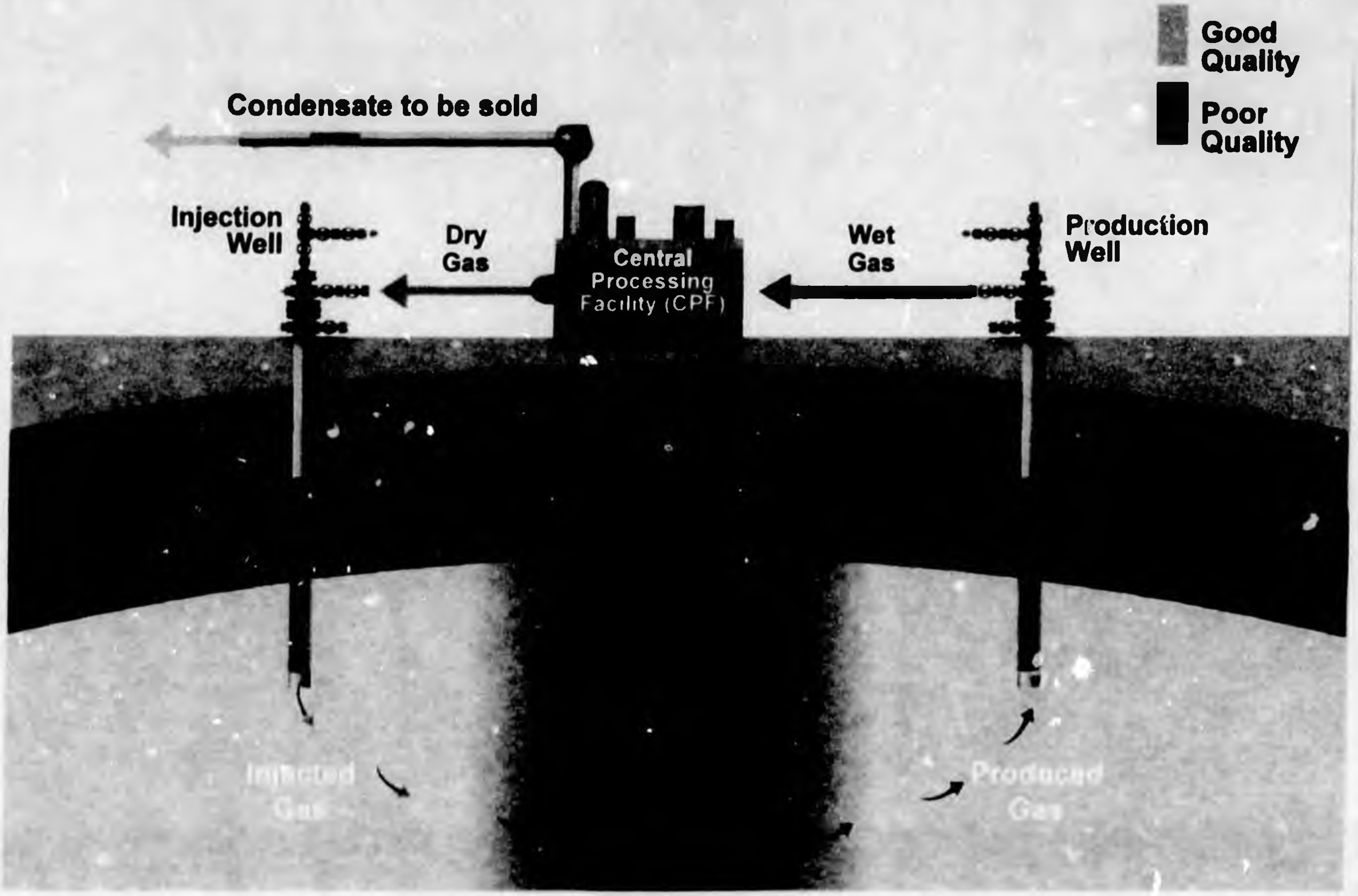
PTU - Reservoir Quality and Performance

ExxonMobil



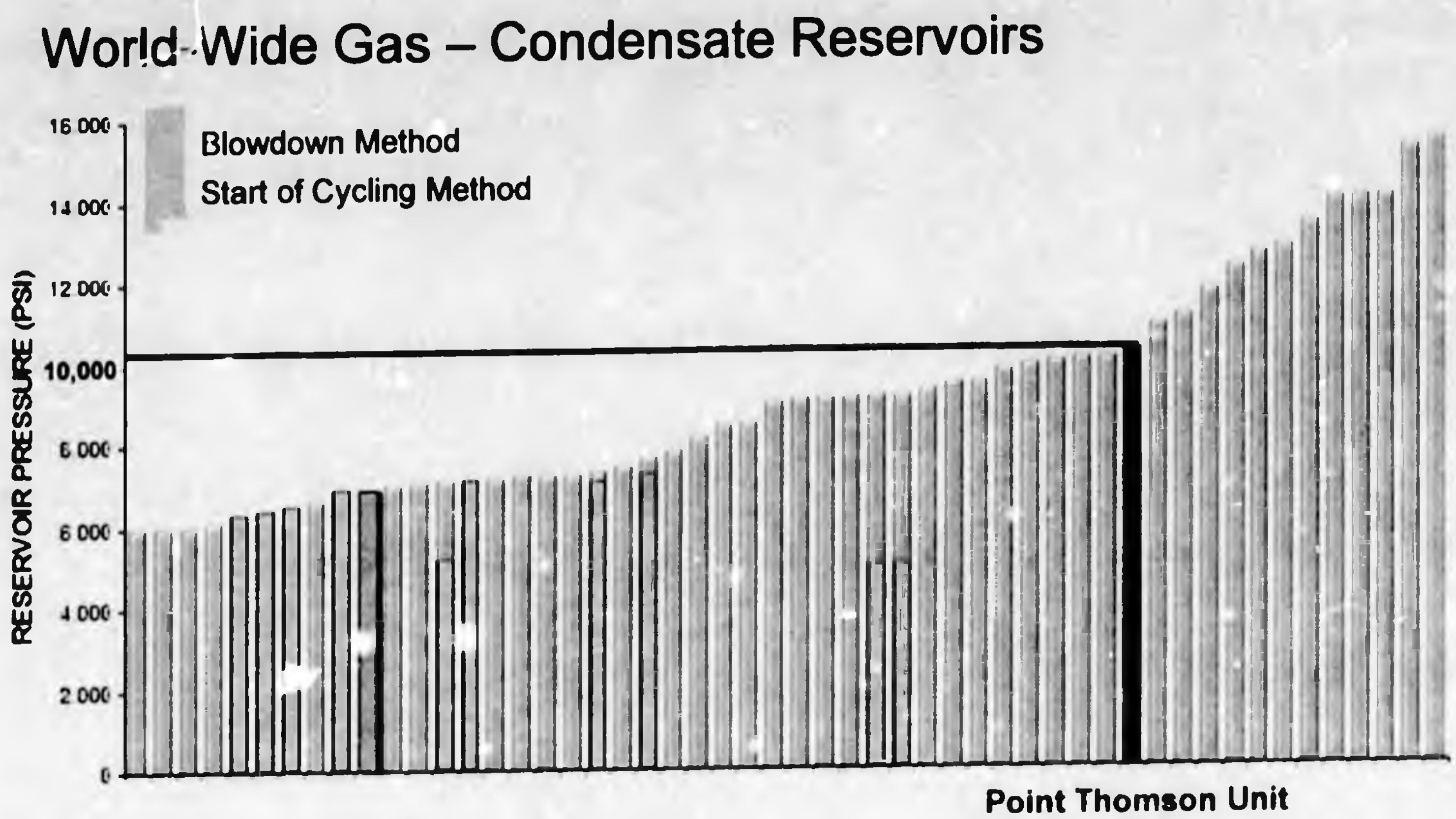
PTU - Reservoir Quality and Performance

ExxonMobil



Cycling at High-Injection Pressure

ExxonMobil



- No cycling projects similar to Point Thomson
  - >10,000 psi injection pressure
- World's highest pressure gas cycling project

June 17, 2008

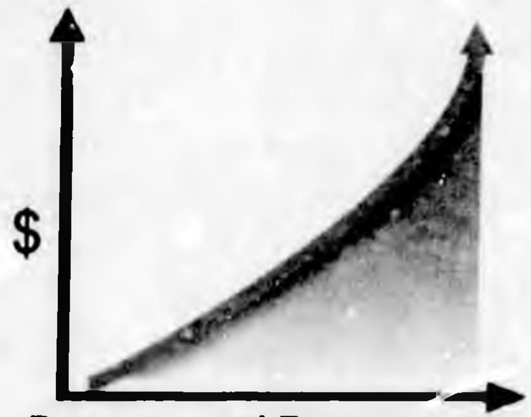
Wells Required for High-Pressure Operations

ExxonMobil

Point Thomson Well

Point Thomson Drilling

- Abnormal pressure
- Extended reach
- Heavy mud
- World class wells



PTU POD - Phased Approach Mitigates Risk

ExxonMobil

Operations

- Over Pressured
- Long Reach

Apply Critical Learnings

- Well Data
- Dynamic Information from Cycling
- Operability Learnings for Expansions

POD

Facilities

- Utilize Proven Technology
  - Compressors and Separators

Drilling

- Fewer Wells
- Limit Reach to Proven Capability
- Apply Proprietary Technology

Management

- Targets Reservoir "Heart"

Proposed Plan of Development for Point Thomson

ExxonMobil

- **Provides for Production**
  - Commence Engineering 2008
  - Commence Drilling Program Winter '08–'09
  - Provides Jobs – Over 200 People Employed Next Winter
  - 10,000 Barrels Condensate Per Day - 2014

- **Further Delineates Reservoirs**
  - Producer and Injector Wells
  - 3 oil/gas Delineation Wells
  - Additional wells if required
- **Provides Information About Reservoirs**
  - Reservoir Quality, Performance, and Size
  - Prudently Manages Risk – Reservoir & Technology
- **Conservation**
  - Cycling Enhances Resource Recovery
- **Minimizes Environmental Impacts**
  - IPS Utilizes Existing Gravel Pad
  - Offshore Drilling from Onshore Pad
  - Utilization of Ice Roads
- **Expandability**
  - Cycling, Oil Production, and Major Gas Sales

Importance of PTU Gas to Gas Pipeline

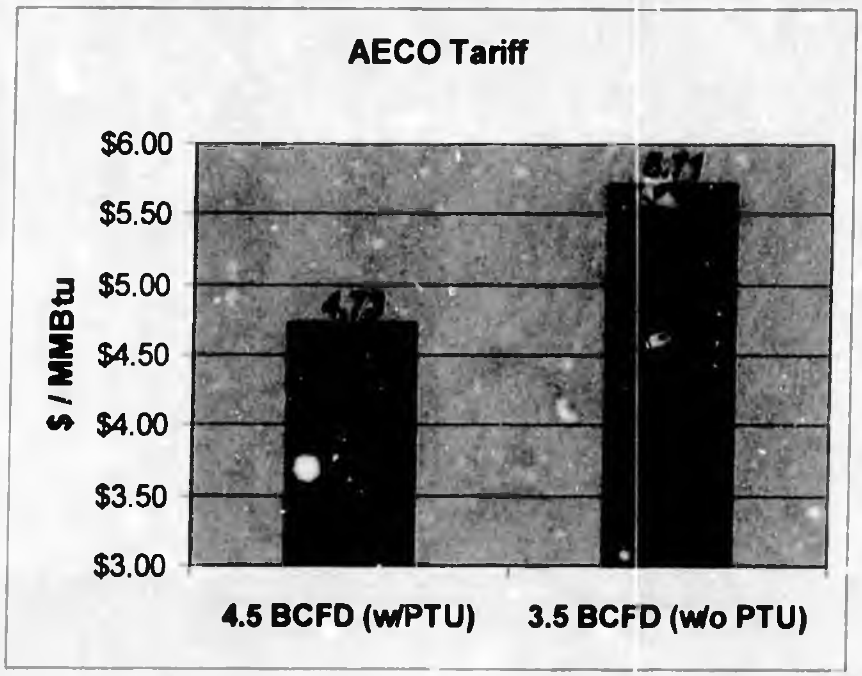
ExxonMobil

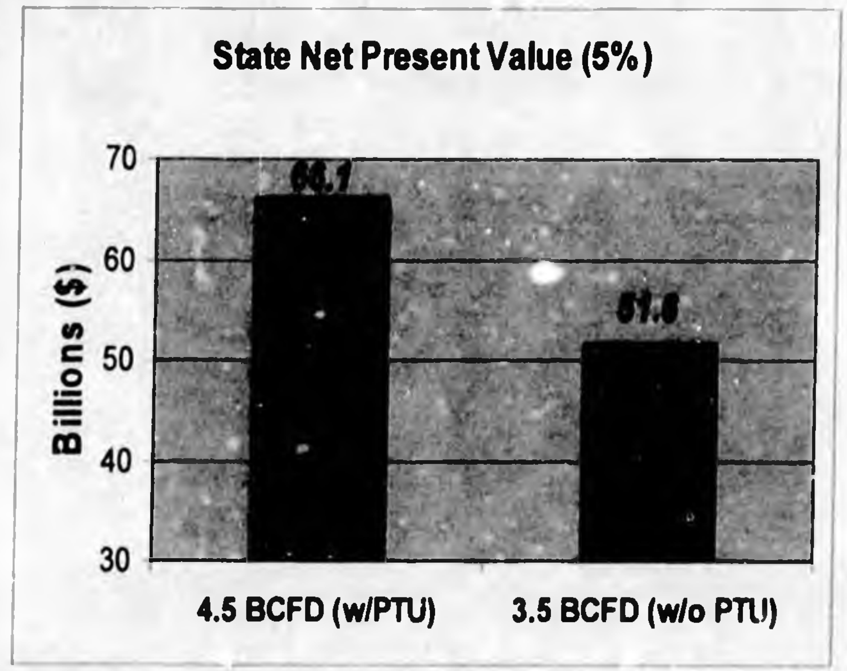
- **PTU Gas represents ~25% of the discovered North Slope gas resource**
- **Supports critical firm transportation commitments ("FT") necessary to secure project financing**
- **Provides security of supply for downstream consumers**
  - Not relying solely on Prudhoe Bay Unit gas or "yet to find" gas to meet commitments
- **Improves liquid recoveries at Prudhoe Bay**
  - Not required to produce Prudhoe Bay Unit at higher gas rates to meet FT / marketing requirements
- **Provides economies of scale for a gas pipeline project**
  - Allows optimization of initial project design
  - Reduces tariff, increases value to all stakeholders

Importance of PTU Gas to Gas Pipeline

ExxonMobil

- **Without PTU gas, pipeline tariff increases by ~$1.00 / MMBtu**
  - Less value for State *($14.5 billion dollars)* and Producers
  - Essentially requires a PBU gas discovery within the next few years
- **Significant impacts on shippers, including explorers**
  - Annual Impact: ***$1.3 billion dollars***
    - 3.5 BCF / Day * 365 Days * $1.00 / MCF
  - Impact over 25 years: ***$32 billion dollars***





Source: Black and Veatch – Alaska Gasline Determination Forum

PTU – DNR Summary of PetroTel's Assessment

ExxonMobil

- **PTU lease holders have not been provided the recent PetroTel study, but based on DNR's summary of the analysis;**
  - ➢ Report appears to be based on selective and limited data
  - ➢ Report indicates significant critical work yet to be done
  - ➢ Report does not address key development planning, reservoir planning, economics, environmental considerations, costs, feasibility of drilling wells . . .
- **No sound technical conclusions can be drawn from this report; significant work remains.**
- **The DNR's summary of the PetroTel report clearly overstates the developable liquid hydrocarbons (condensate and oil)**
  - ➢ Oil recovery at PTU is unlikely to exceed 5% (PetroTel - "close to 50%")
- **Our technical work shows that over 90% of developable hydrocarbons (gas, condensate, oil) can be produced today through a gas sales development**
- **Our POD provides the opportunity to recover even more liquids prior to the start of gas pipeline operations**
- **PTU lease holders remain willing to share their technical work and expertise on these issues**

Point Thomson Project

ExxonMobil

ExxonMobil

Taking on the world's toughest energy challenges.

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 be n 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 mand tes 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 though 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 "unambigous' 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 Directo 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.

Alaska Department of NATURAL RESOURCES Division of Oil and Gas

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

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

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 18º 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 – 10.4 trillion standard cubic feet (TSCF)
  - Associated condensate = 490 – 600 million stock tank barrels (MMSTB)
  - Potential oil (oil-rim) = 580 – 950 MMSTB

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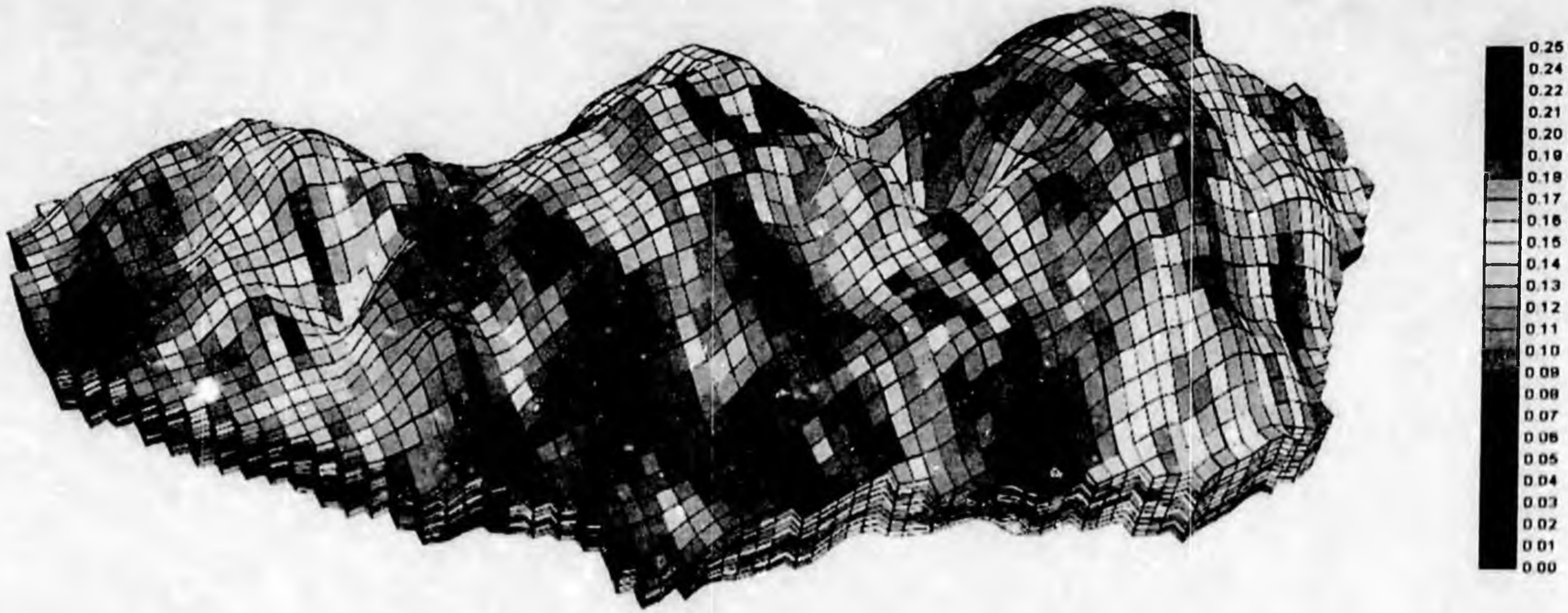
Simulation Model Porosity



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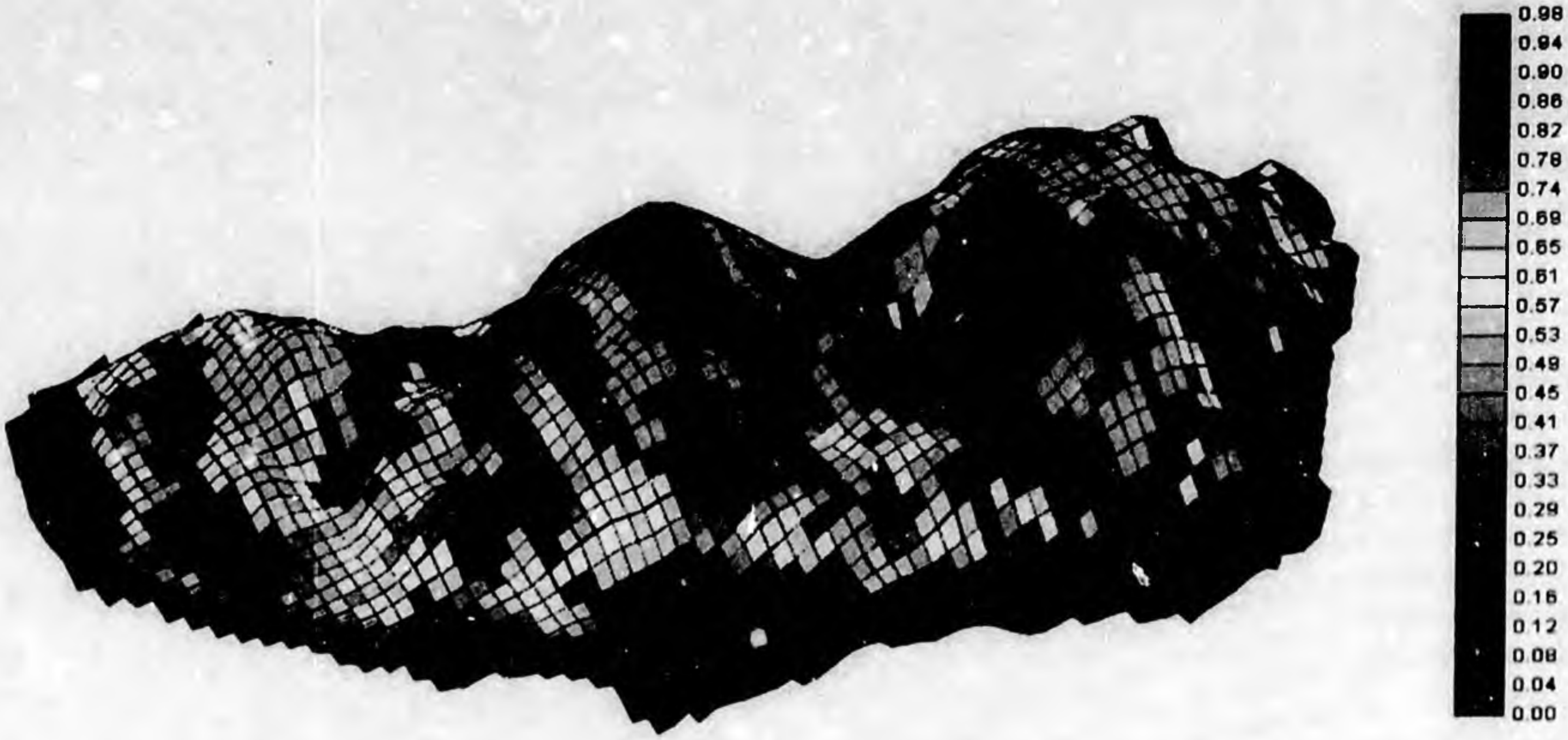
Simulation Model - Sg



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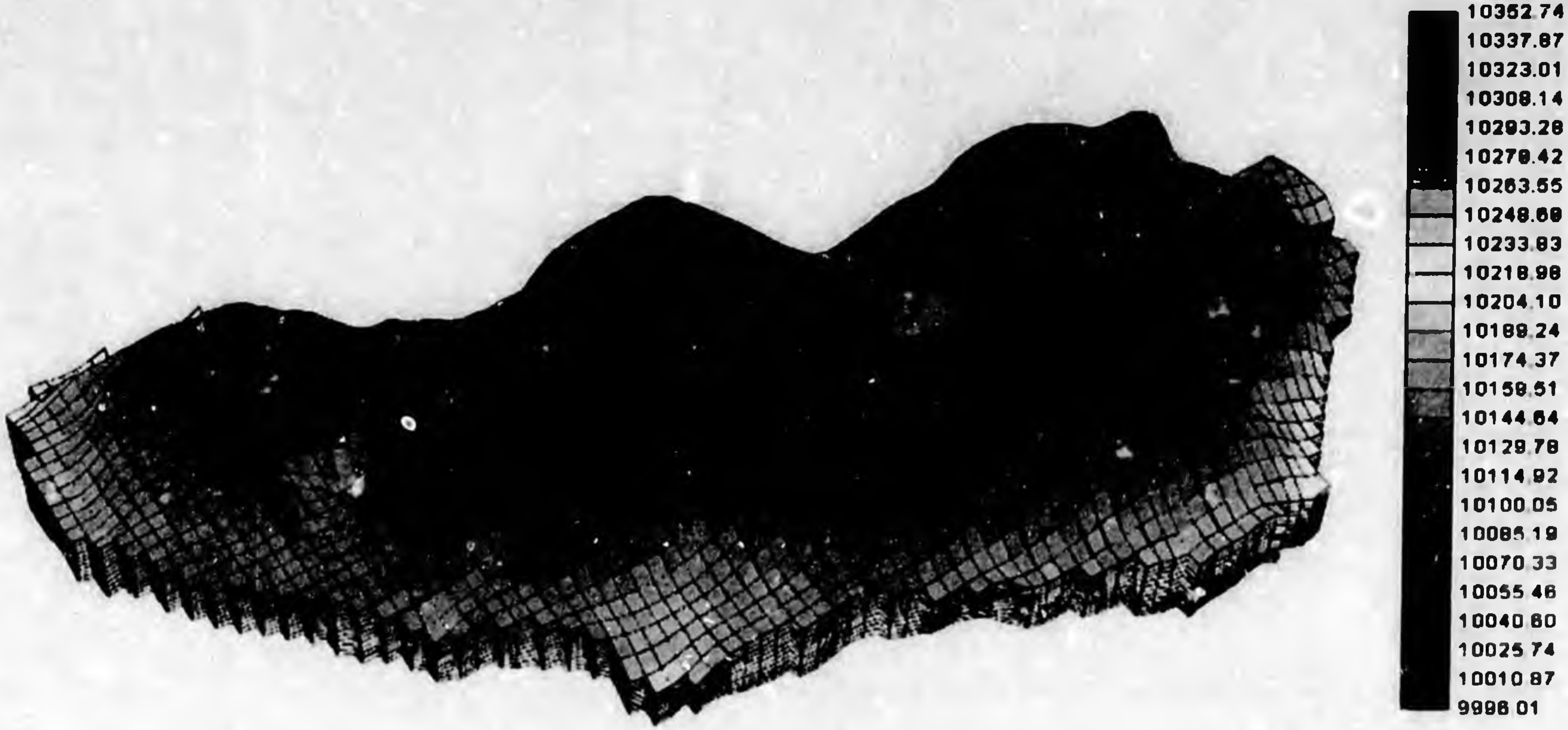
Simulation Model - Pressure



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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

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Point Thomson Reservoir Study
Reservoir Simulation - Primary Depletion

- 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

Point Thomson Reservoir Study
Reservoir Simulation - Gas Cycling

- Maintain reservoir pressure until all economically recoverable condensate and oil are produced

- Gas cycling applied in the gas cap in conjunction with development and gas injection in the oil-rim

- Gas cycling for 20 years increases the oil recoveries:
    - Condensate - 76% (370-450 MMSTB)
    - Oil Rim - 43% (250-400 MMSTB)

- Gas cycling for 10 years results in oil recoveries of:
    - Condensate - 62% (300-370 MMSTB)
    - Oil Rim - 39% (225-370 MMSTB)

- Subsequent blowdown of the gas cap after 10 and 20 years cycling recovers 57% and 56% (4.8-5.9 TSCF) of original gas in place

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Point Thomson Reservoir Study

Reservoir Simulation - Oil Rim Development

- Oil-rim not adequately delineated or tested
  - Additional wells are needed

- Oil Rim Production:
  - Would likely require of horizontal wells
  - Requires pressure maintenance to sustain maximum oil producibility
    - Gas cycling, direct lean gas injection, miscible gas injection (CO_2), water injection or aquifer encroachment
  - Gas injection helps reduce the viscosity, improve swelling, and mobilize oil
  - Use of offsite gas, such as dry gas or waste CO_2 from Prudhoe, may maximize recovery

- In primary depletion potential oil-rim recoveries varied from 3-16% (30-150 MMSTB) of original oil in place depending on number of wells drilled
    - Gas cycling for 20 years could potentially recover close to 45% (250-400 MMSTB) of the in-place volume of the oil-rim

- Uncertainty in the original oil-rim volume and potential ultimate recovery
- Delineation of the oil-rim during gas cycling will determine the scale of development

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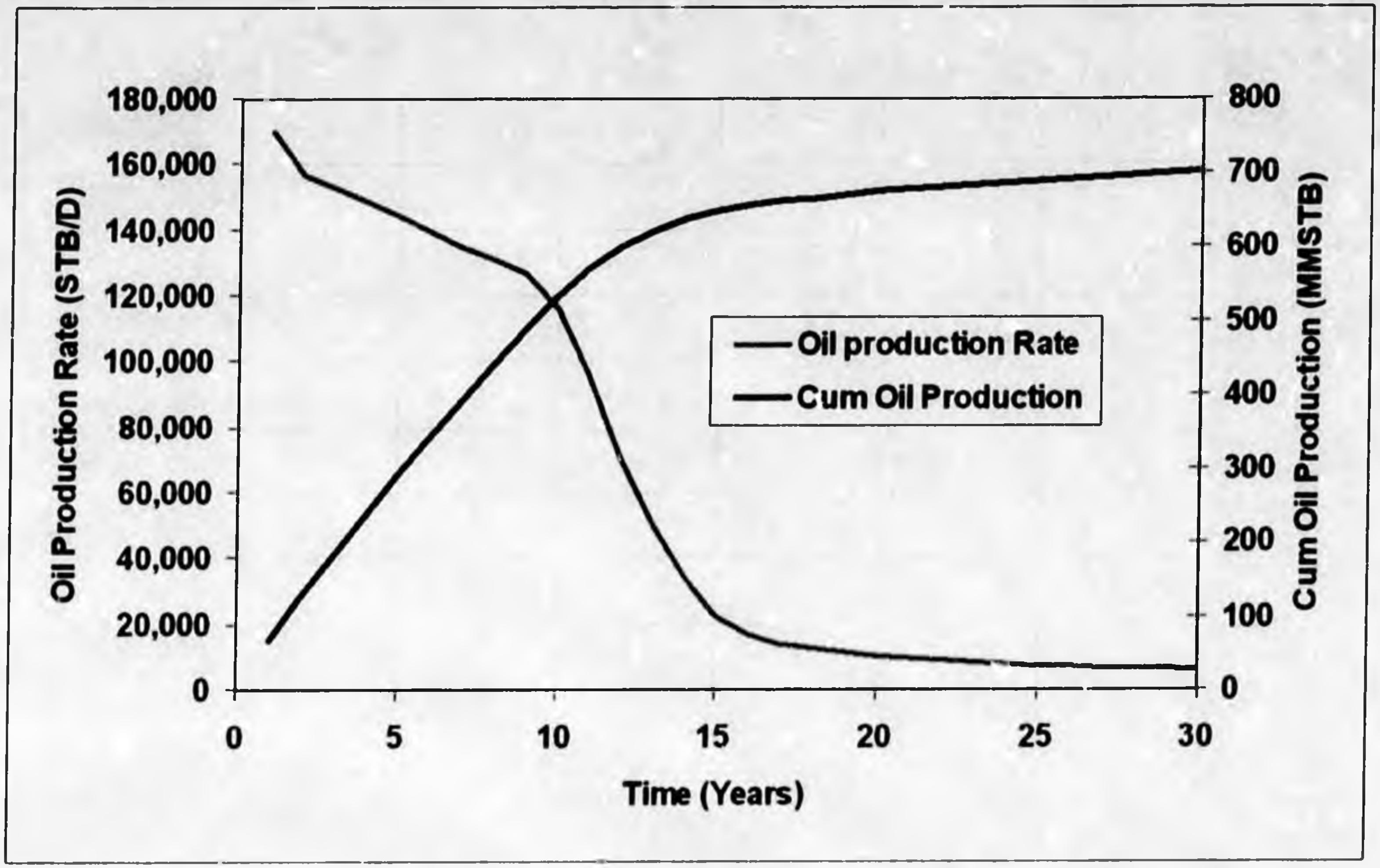
Oil Production Rate and Cumulative Oil Production

BHP=3000 psi



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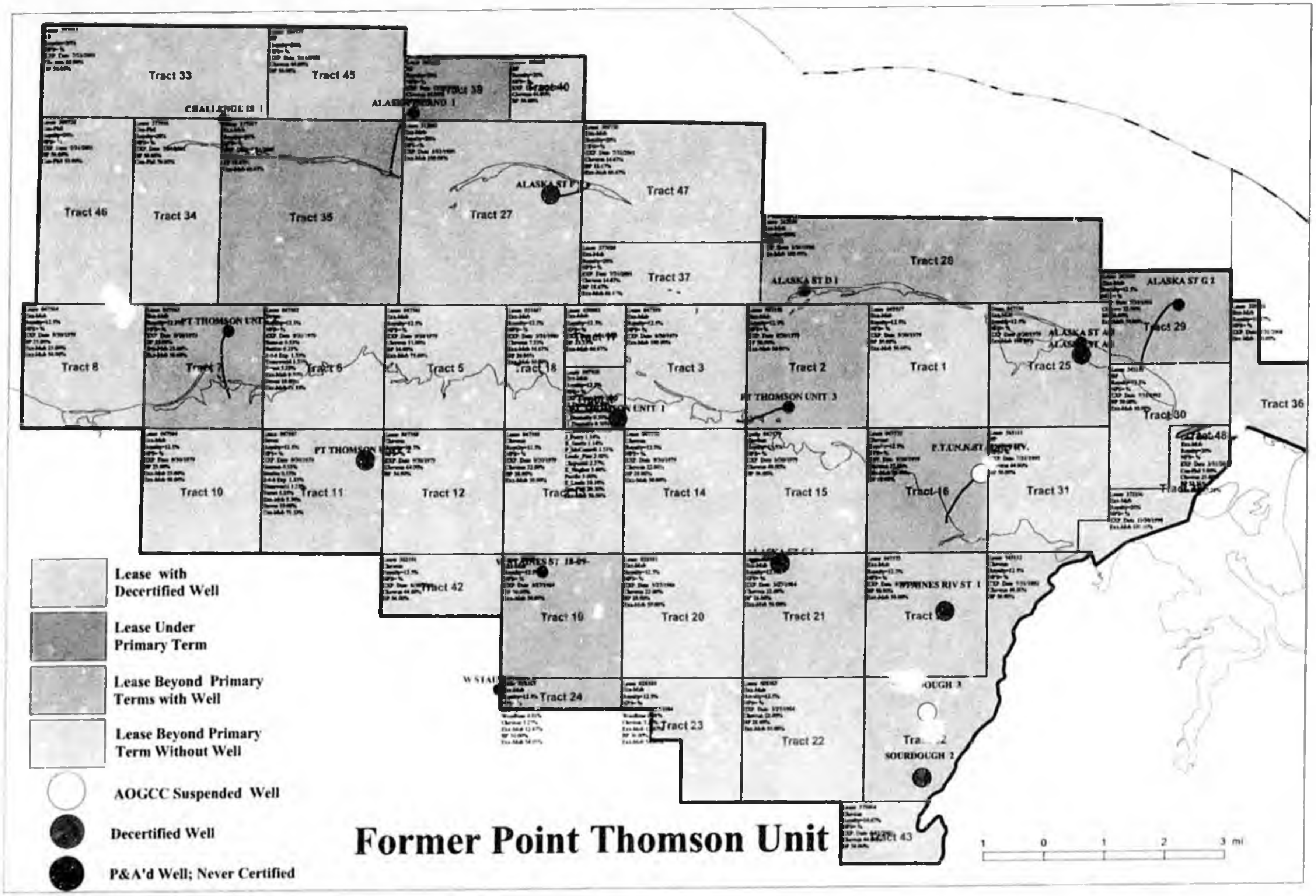
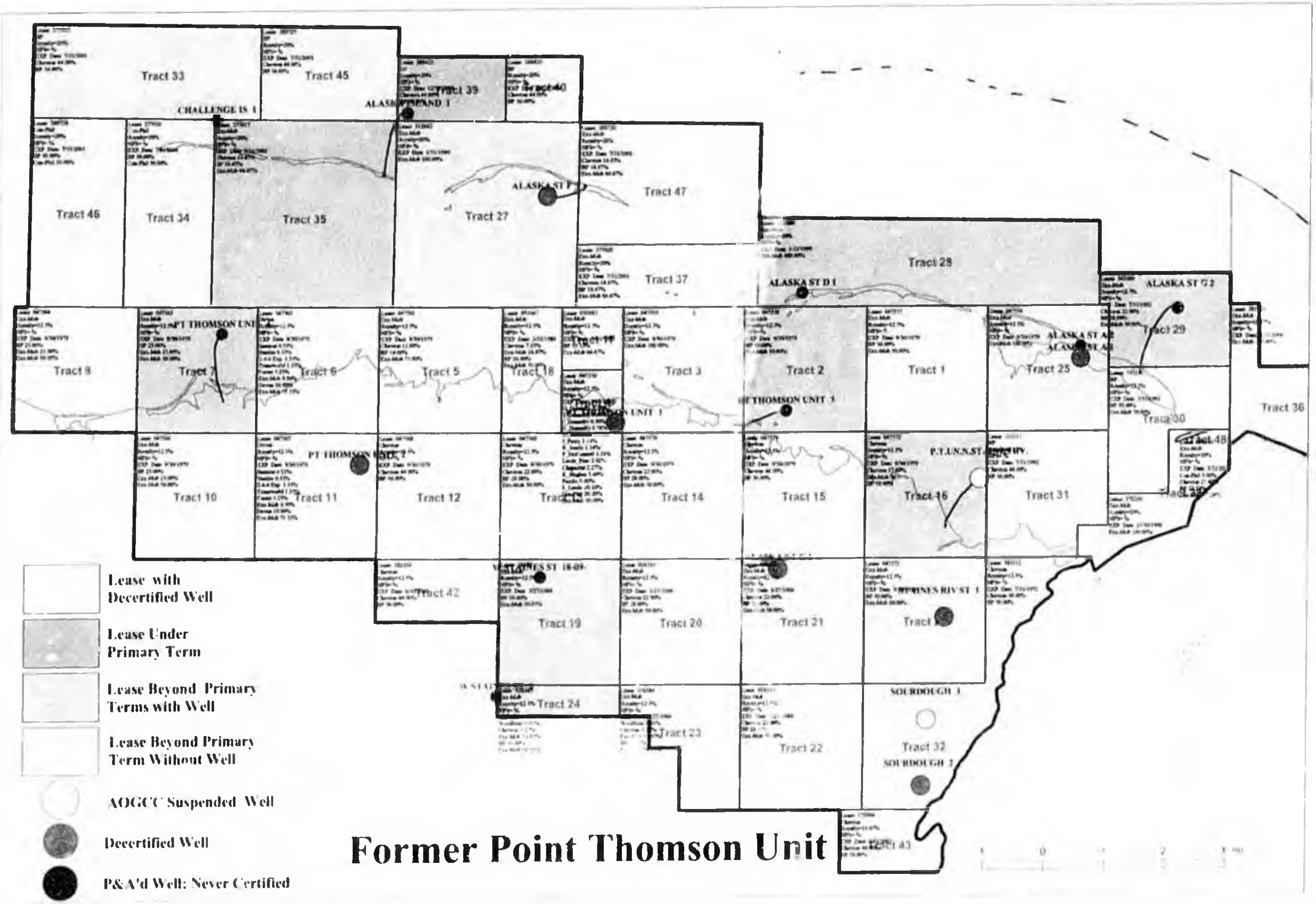
Point Thomson Reservoir Study
Conclusions

- Primary depletion may recover 6-7 TSCF of gas and 210-305 MMSTB of condensate and oil
  - Results in the lowest hydrocarbon recovery of a retrograde condensate reservoir
  - Gas blowdown can be done after gas cycling and recovery of the condensate and oil
- Gas cycling for 15-20 years and subsequent blowdown may recover about 6 TSCF of gas and 620-850 MMSTB of condensate and oil
  - Gas cycling may delay gas sales, but can potentially increase recovery of condensate and oil by over 500 MMSTB
- Additional wells needed to delineate and test the Thomson oil-rim
  - Delineation of the oil-rim during gas cycling will determine scale of development
  - Pressure maintenance required to sustain maximum producibility and recovery of oil and condensate



Former Point Thomson Unit



Former Point Thomson Unit