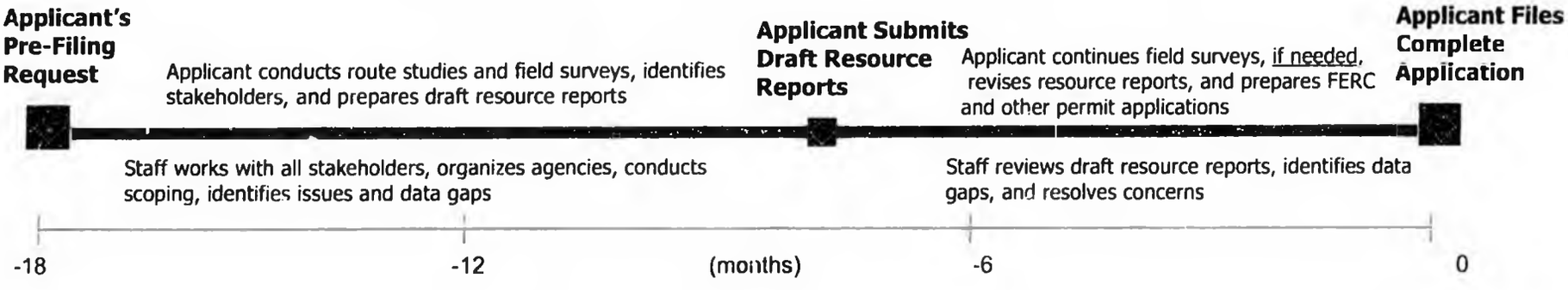
HB 3001
SB 3001
6/16/08
SPECIAL SESSION DOCUMENTS

FERC

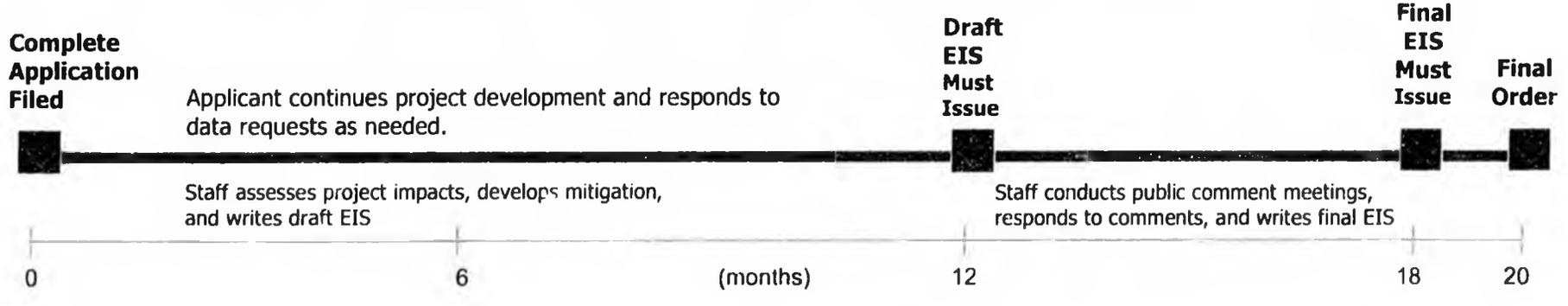
Alaska Natural Gas Pipeline Project
FERC's Environmental Review Process

Pre-Filing Review and Application Preparation

[Designed to assist applicant in its preparation of a complete application]



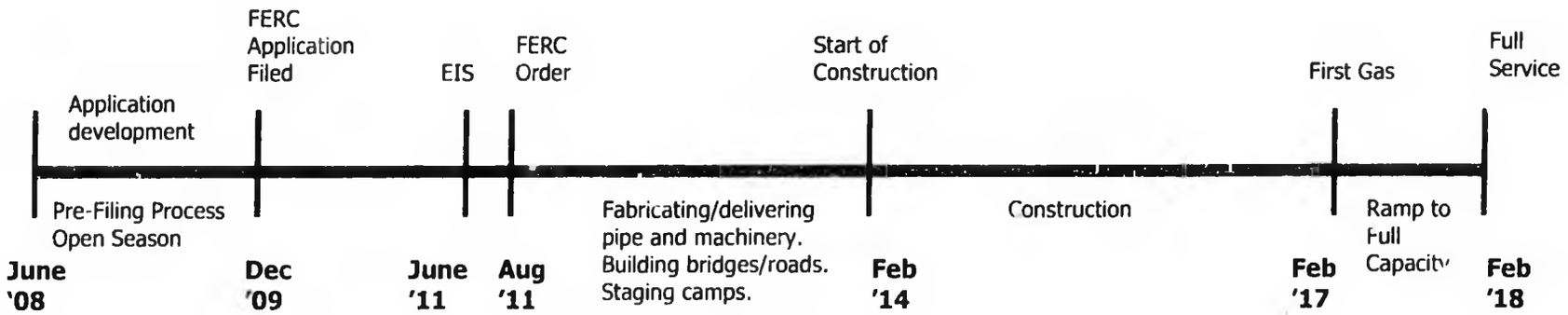
Statutory Time Limits for Environmental Review and FERC Action

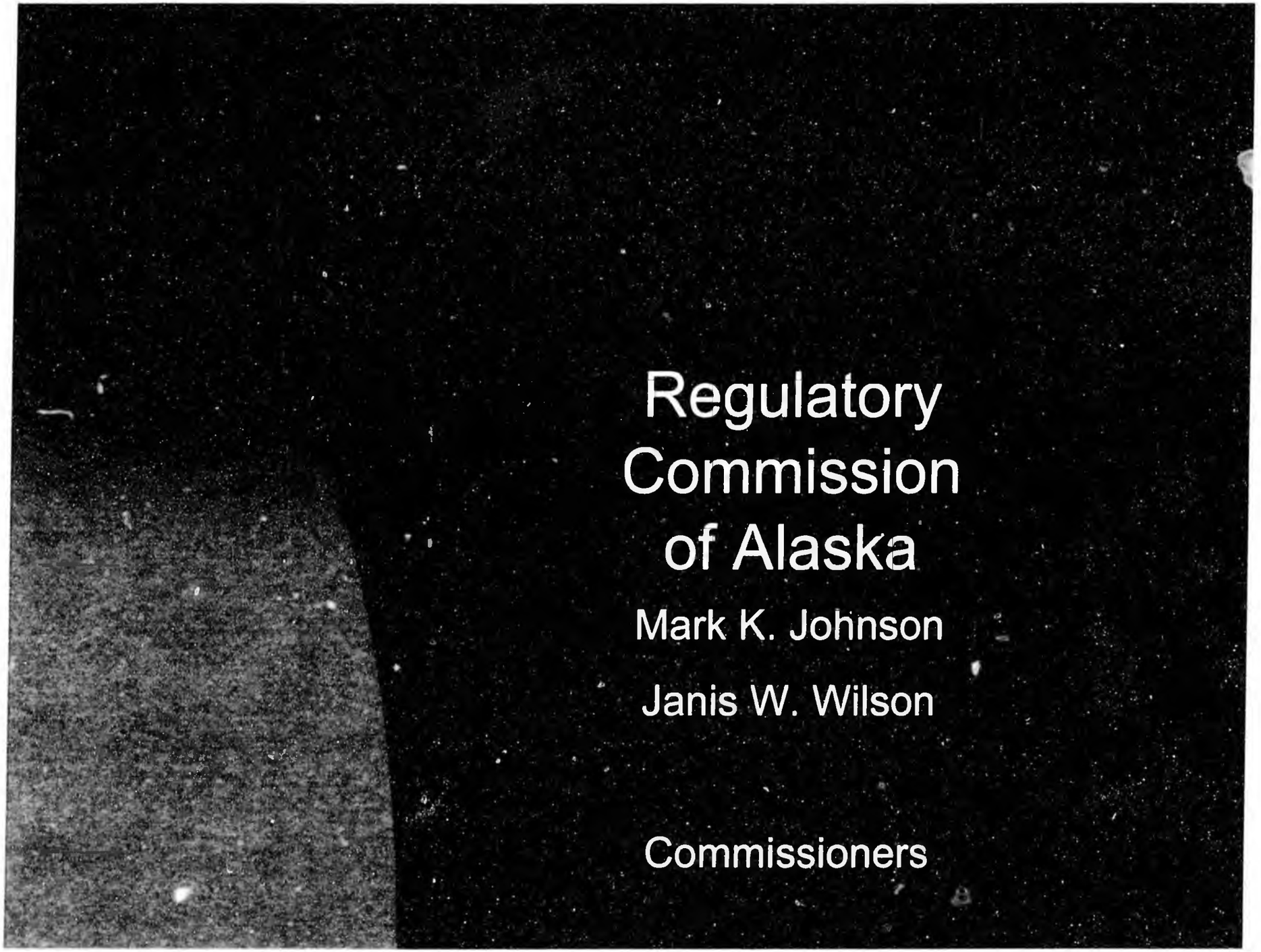


Office of Energy Projects

Alaska Pipeline Timeline

Example Case




Regulatory
Commission
of Alaska
Mark K. Johnson
Janis W. Wilson
Commissioners

RCA Regulates:

Utilities

- Natural gas distribution
- Natural gas pipelines
- Electric power generation, transmission, and distribution
- Water and sewer
- Telephone
- Solid waste

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- Petroleum product pipelines
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- Alaska Natural Gas Pipeline Act, Section 108(a)

- (a) Local Distribution – Any facility receiving natural gas from an Alaska natural gas transportation project for delivery to consumers within the State –

  (1) shall be deemed to be a local distribution facility within the meaning of section 1(b) of the Natural Gas Act (15 U.S.C. 717(b) [a facility regulated by a state commission as to rates and services];

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RCA Pipeline Authority

- Issue and oversee "certificates of public convenience and necessity"
- Ensure safe and adequate service and facilities
- Approve shipping rules and rates
- Conduct audits and oversee finances and management

DENALI
the alaska gas pipeline

June 15, 2008

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E., PJ-11
Washington, DC 20426

Re: Docket No. PF08 - ___ - 000
Pre-filing Process
Denali – The Alaska Gas Pipeline Project

Dear Ms. Bose:

Denali – The Alaska Gas Pipeline LLC ("Denali") has been formed to pursue a project (the "Denali Project") to construct and operate an Alaska natural gas transportation system as defined by Section 103 of the Alaska Natural Gas Pipeline Act ("ANGPA"). This letter requests approval to use the pre-filing procedures pursuant to 18 CFR 157.21(b) and consistent with 157.21(d) and (f) as otherwise specified by Commission staff during our initial consultation on the Denali Project.

This request is being submitted much earlier in the process than is normally the case with major pipeline projects. Because of the scope of the Denali Project, project design and application development will require a much longer time period (approximately 36 months) than is typically the case. Taking into account the extended pre-application period, and because Denali was only recently formed and is still being staffed, we have not initiated a number of the activities that are normally required in Section 157.21(d), nor will we meet the timelines contemplated by Section 157.21(f). However, as was suggested by Commission staff during our initial consultation on the Denali Project, initiating the pre-filing process now will be beneficial by enabling Denali and the Commission to exchange information and coordinate planning and activities to insure a timely and efficient application development and review process.

As required by Section 157.21(b)(1), Denali provides the following information in support of this request.

1. ***A description of the schedule desired for the project including the expected application filing date and the desired date for Commission approval, including at least six months of pre-filing review (Section 157.21(d)(1)).***

The current estimated schedule for the Denali Project is attached as Exhibit A. Assuming a successful open season within that schedule, Denali would expect to submit its complete application to the Commission in August 2011. Consistent with the expedited process contained in Section 104(d) of ANGPA, Denali would desire Commission approval no later than August 2013.

2. ***An explanation of why the prospective applicant is requesting to use the pre-filing process under this section (Section 157.21(d)(3)).***

Denali submits this request to use the Commission's pre-filing process under Section 157.21 in order to engage the Commission early in the process and facilitate staff involvement in the environmental data collection and in the development of and participation in Denali's Public Participation Plan.

The Denali Project will be one of the largest construction projects in North American history, making early engagement between Denali and Office of Energy Projects particularly valuable, even before development of all of the information normally available at the time of a pre-filing request.

It is important to note that at this early point, Denali is not in a position to supply all of the information required by Section 157.21(d), or to meet the timelines contemplated by Section 157.21(f). As a result, Denali requests that the staff and Denali jointly develop modifications to the normal informational and scheduling procedures in order to reflect and accommodate the Denali Project schedule attached in Exhibit A.

3. ***A detailed description of the project, including location maps and plot plans to scale showing all major project components. The maps and plot plans should not include CEII material (Section 157.21(d)(4)).***

The plans for the Denali Project include (i) transmission pipelines to transport gas from where produced to connections with other portions of the Denali system, (ii) a stand-alone gas treatment plant (GTP) on the Alaska North Slope where gas will be processed to remove impurities, as appropriate, and the residue gas chilled, and (iii) a 48 to 52 inch pipe capable of transporting approximately 4.0 bcf/d of gas at approximately 2,500 psi. The pipeline will generally follow the Dalton Highway south to Fairbanks where it will follow the Alaska Highway southeast to the Canadian border.

At the Canadian border, the pipeline will connect to a pipeline to be constructed by Denali affiliates in Canada that would be capable of transporting natural gas from the Canadian border into Alberta. If additional capacity is needed to accommodate the delivery of the gas into the U.S., the Canadian affiliates may also construct a pipeline from Alberta southeast to the U.S. border, in which case, the Project would include a pipeline from the U.S. border across parts of North Dakota, Minnesota, Iowa and Illinois to the Chicago area.

A general map of the preliminary pipeline route is attached as Exhibit B. At this early stage of the process, the Denali Project is not able to provide plot plans. These plot plans will be provided when available.

4. ***A list of the relevant federal and state agencies in the project area with permitting requirements (Section 157.21(d)(5)).***

A preliminary list of the federal and state agencies in the Denali Project area with permitting responsibilities is attached as Exhibit C. This list will be supplemented as the detailed route is developed and additional information becomes available.

5. ***A statement indicating that those agencies are aware of the prospective applicant's intention to use the pre-filing process (including contact names and telephone numbers) (Section 157.21(d)(5)(i)).***

Denali is notifying the agencies listed in Exhibit C that it has submitted to FERC a request to commence the pre-filing process by providing them with a copy of this letter.

6. ***A statement indicating that those agencies have agreed to participate in the process (Section 157.21(d)(5)(ii)).***

In June 2006, a Memorandum of Understanding (MOU) related to the Alaska Natural Gas Transportation Project was entered into by federal agencies regarding regulatory and other responsibilities relevant to an Alaska natural gas transportation project such as the Denali Project. As part of the MOU, the signatory agencies committed to participate in and work within a pre-filing time frame set by the Commission to identify and seek to resolve issues at the earliest stages of project development for an Alaska natural gas transportation project.

Potentially, there are some federal agencies with jurisdiction over portions of the project that are not a signatory to the MOU. Alaska state agencies also will have jurisdiction over some aspects of the Denali Project. Denali will supplement this statement as it identifies

and engages these additional agencies on their agreement to participate in the pre-filing process.

7. ***A statement indicating how the applicant has accounted for agency schedules for issuance of federal authorizations (Section 157.21(d)(5)(iii)).***

   Denali has not yet begun the agency involvement process. Denali will account for agency schedules for federal authorizations as the agency involvement process unfolds, and once completed, will supplement this statement.

8. ***A statement indicating when the applicant proposes to file with these agencies for their respective permits or other authorizations (Section 157.21(d)(5)(iv)).***

   Denali has not yet initiated the agency involvement process and, because of the extended initial preparation and design phases, is not yet able to provide this statement. Denali will supplement this statement as it identifies when it proposes to file with the relevant agencies for the appropriate permits or other authorizations.

9. ***A list and description of the interest of other persons and organizations who have been contacted about the project (including contact names and telephone numbers) (Section 157.21(d)(6)).***

   Although Denali has not yet developed a stakeholder engagement plan, Denali has contacted landowners and agencies along that portion of the pipeline corridor where Denali intends to conduct preliminary field studies in the summer of 2008. A list and description of the interest of such persons (including contact names and telephone numbers) is attached as Exhibit F. This request will be supplemented with a list and description of other persons and organizations that have been contacted about the Denali Project (including contact names and telephone numbers).

10. ***A description of what has already been done, e.g. contacting stakeholders, agency consultations, project engineering, route planning, environmental and engineering contractor engagement, environmental surveys/studies, and open houses (Section 157.21(d)(7)).***

    <u>Contacting stakeholders and agency consultations:</u>
    Denali will engage in preliminary field studies along portions of the anticipated pipeline corridor during the summer of 2008. Preparation

for the 2008 preliminary field studies required initiation of the following activities.

Landowner contacts:
ConocoPhillips, whose affiliate is one of the members of Denali, began contacting landowners along the portion of the preliminary route not co-located with TAPS (primarily from Delta Junction, Alaska to the US/Canada border) on behalf of the Denali Project in April 2008. These contacts continue at this time, and are made for the purpose of obtaining access and permission to conduct preliminary field studies.

Agency Consultations:
Also as part of obtaining access approvals for the preliminary field studies, a number of state and federal agencies have been contacted to discuss required permits for this activity. A list of these contacts is provided in Exhibit D.

Project Engineering, Route Planning, Contractor Engagement, Surveys and Studies:
The Denali Project will use and build upon a study conducted by the Alaska Gas Producers Pipeline Team (AGPPT) in 2001 and 2002.

Open Houses:
Open houses have not yet been scheduled for the Denali Project.

11. Identification of the environmental and engineering firms and sub-contractors under contract to develop the project (Section 157.21(d)(7)).

At this time, a number of environmental and engineering firms and sub-contractors are under contract specifically to assist with the 2008 preliminary summer field studies (Exhibit E). Exhibit E will be amended and supplemented to identity contractors and sub-contractors for future environmental and engineering work after those contracts are completed.

12. Proposals from at least three prospective third-party contractors from which Commission staff may make a selection to assist in the preparation of the requisite NEPA document, or a proposal for the submission of an applicant-prepared draft Environmental Assessment, as determined through the initial consultation (Section 157.21(d)(9)).

Denali commits to fund a third party contractor to assist the Commission in the development of the Environmental Impact Statement required under NEPA. Denali will initiate the selection

process for the contractor under the direction of Commission staff. We expect this will occur before the end of 2008.

13. Acknowledgement that a complete Environmental Report and complete application are required at the time of filing (Section 157.21(d)(10)).

In accord with Section 157.21(d)(10), Denali acknowledges that a complete Environmental Report and complete Certificate Application are required at the time of filing.

14. A description of a Public Participation Plan which identifies specific tools and actions to facilitate stakeholder communications and public information, including a project website and a single point of contact (Section 157.21(d)(11)).

Denali is committed to stakeholder communications and effective public outreach and is currently developing a Public Participation Plan that identifies the specific tools and actions used to facilitate stakeholder communications and public information. At this time, Denali has established a project website, but has not yet established a single point of contact. This request will be supplemented at the time the Public Participation Plan is completed.

All requests from, and responses to, federal and state permitting agencies will be appropriately addressed and responded to by Denali. As the lead agency, FERC will be copied by Denali on all pertinent correspondence.

At a minimum, the plan will include Denali's commitment to:

- Host public open houses;
- Distribute periodic news letters to affected landowners and interested stakeholders;
- Meet regularly with elected officials and community leaders in the project area;
- Maintain a stakeholder contact and public/agency correspondence log; and
- Post information in local newspapers and at local libraries.

The Denali Project website can be accessed at:

http://www.denali-thealaskagaspipeline.com/.

Once the Public Participation Plan is complete, this website will be expanded to include all the pertinent information on the Denali Project.

Until the Denali organization is staffed and a single point of contact is established, please contact both Lisa Pekich at ConocoPhillips (907-265-1173) and Gary "Gus" Gustafson at BP (907-339-4918). Once the organization is staffed, a single point of contact for stakeholder communications and public information will be established and the contact information for that person will be substituted.

In summary, we look forward to working closely and cooperatively with the Commission staff during the pre-filing process. Thank you for your timely consideration of this request.

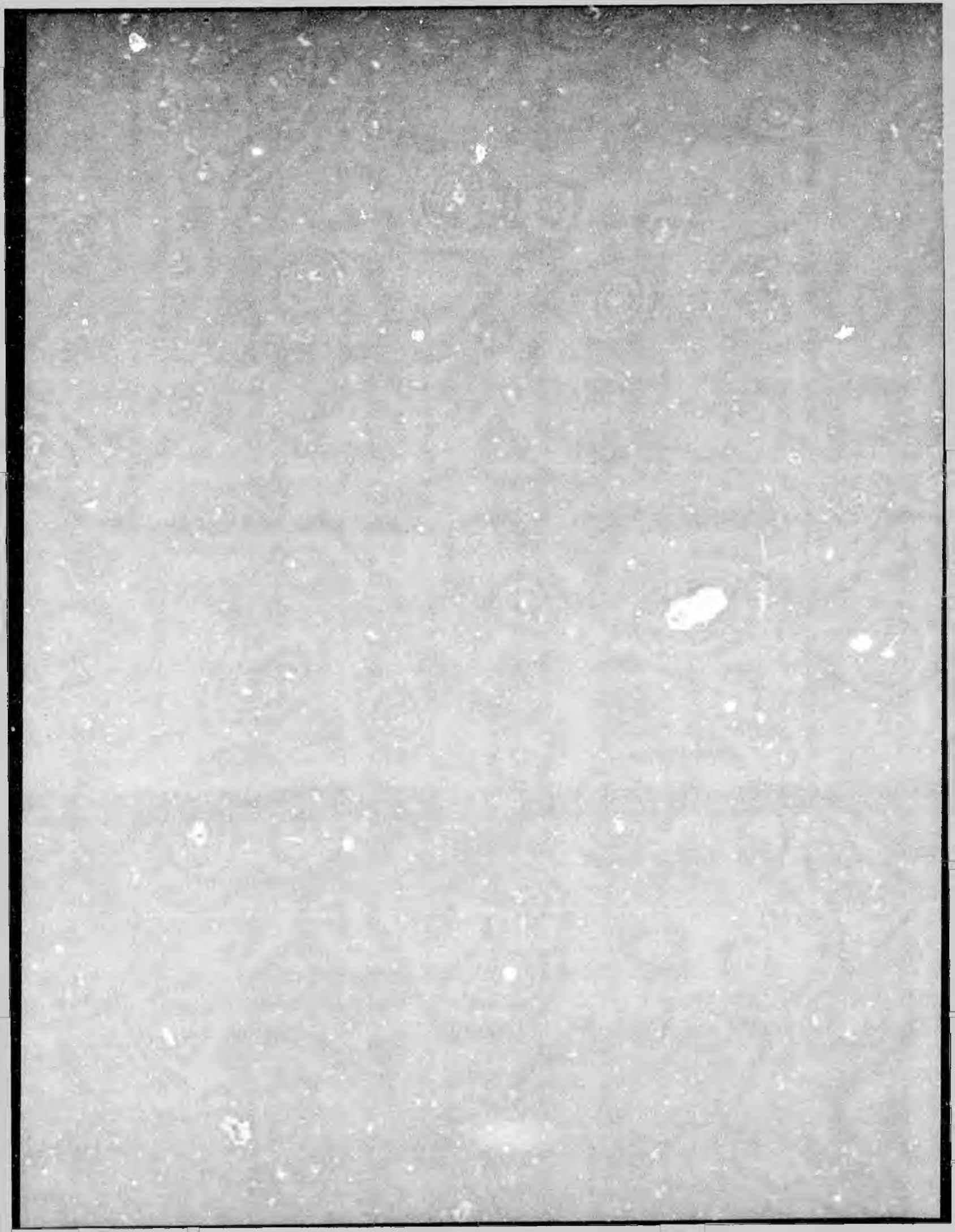
Sincerely,

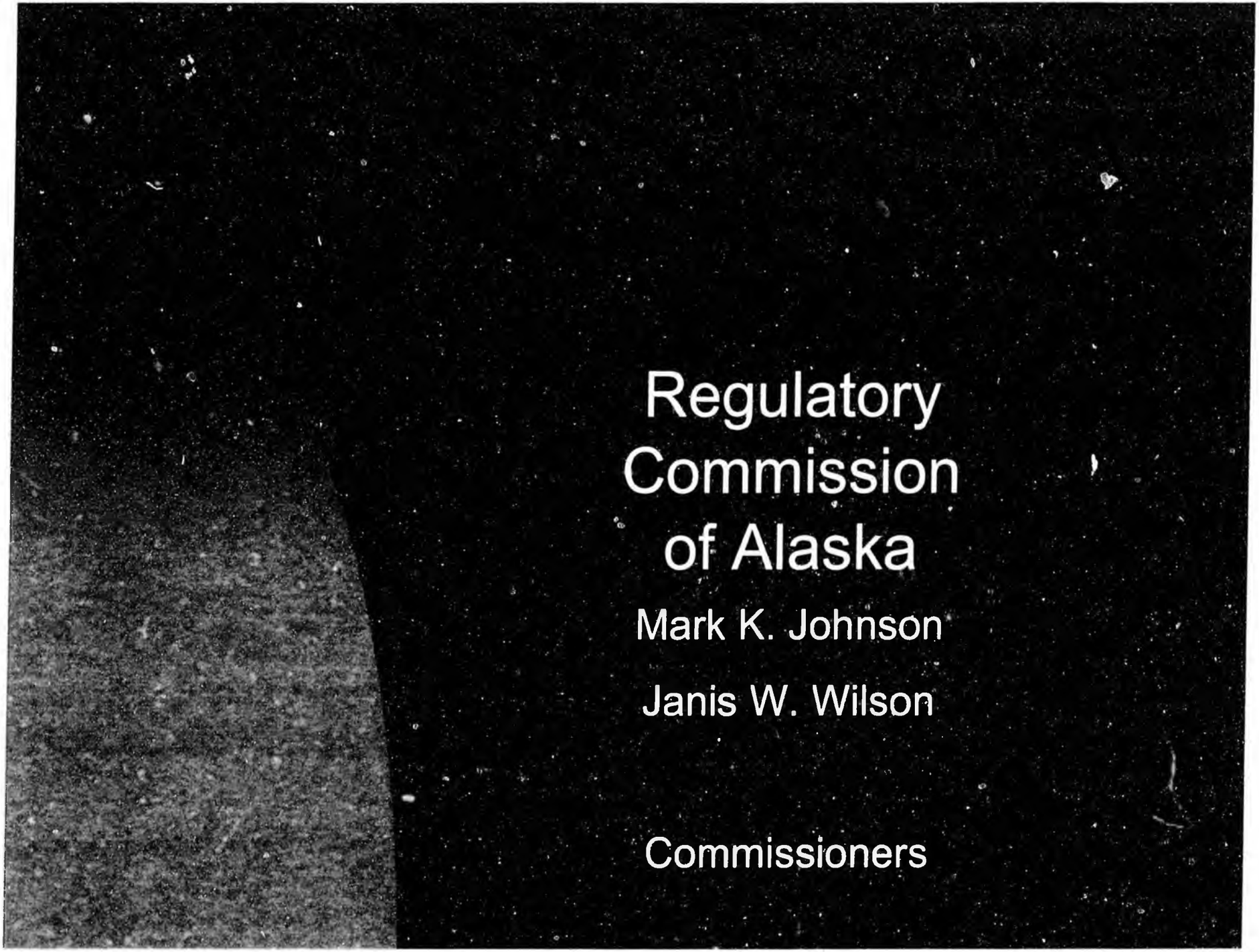
Bud E. Fackrell, President
Denali – The Alaska Gas Pipeline LLC

Cc: Mark Robinson, FERC
Lauren O'Donnell, FERC
Mike Boyle, FERC

Attachments:

Exhibit A – Denali Project Success Case Schedule
Exhibit B – General Denali Project Map
Exhibit C – State and Federal Agencies with Permitting Responsibilities
Exhibit D – List of Agency Consultations (2008 Summer Field Studies)
Exhibit E - List of Environmental/Engineering Contractors (2008 Summer Field Studies)
Exhibit F - List of Contacts for Preliminary 2008 Field Studies

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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 FREng CBE MA(Cantab)
Group Managing Director and
Chief Executive Exploration and Production

BP plc
1 St James's Square
London
SW1Y 4PD
United Kingdom

1 March 2003

Our Ref: AGI/DS/CB

Mr Thomas E Irwin
Commissioner
Department of Natural Resources
550 W. 7th Avenue, Suite 1400
Anchorage
Alaska 99501-3650

Direct +44 (0)20 7496 4457
Assist +44 (0)20 7496 4001
Fax +44 (0)20 7496 4656
e-mail address

Dear Commissioner Irwin

As Chief Executive of Exploration & Production, I write to assure you of BP's commitment to the Plan of Development recently proposed by the owners of the Point Thomson Unit. BP is fully committed to carrying out the Plan of Development and, on approval of the Plan of Development, will proceed to discharge all of the commitments contained therein.

Yours sincerely

A G Inglis

Andrew Inglis
Group Managing Director and
Chief Executive of Exploration and Production

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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 Pt 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 loss s. 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.

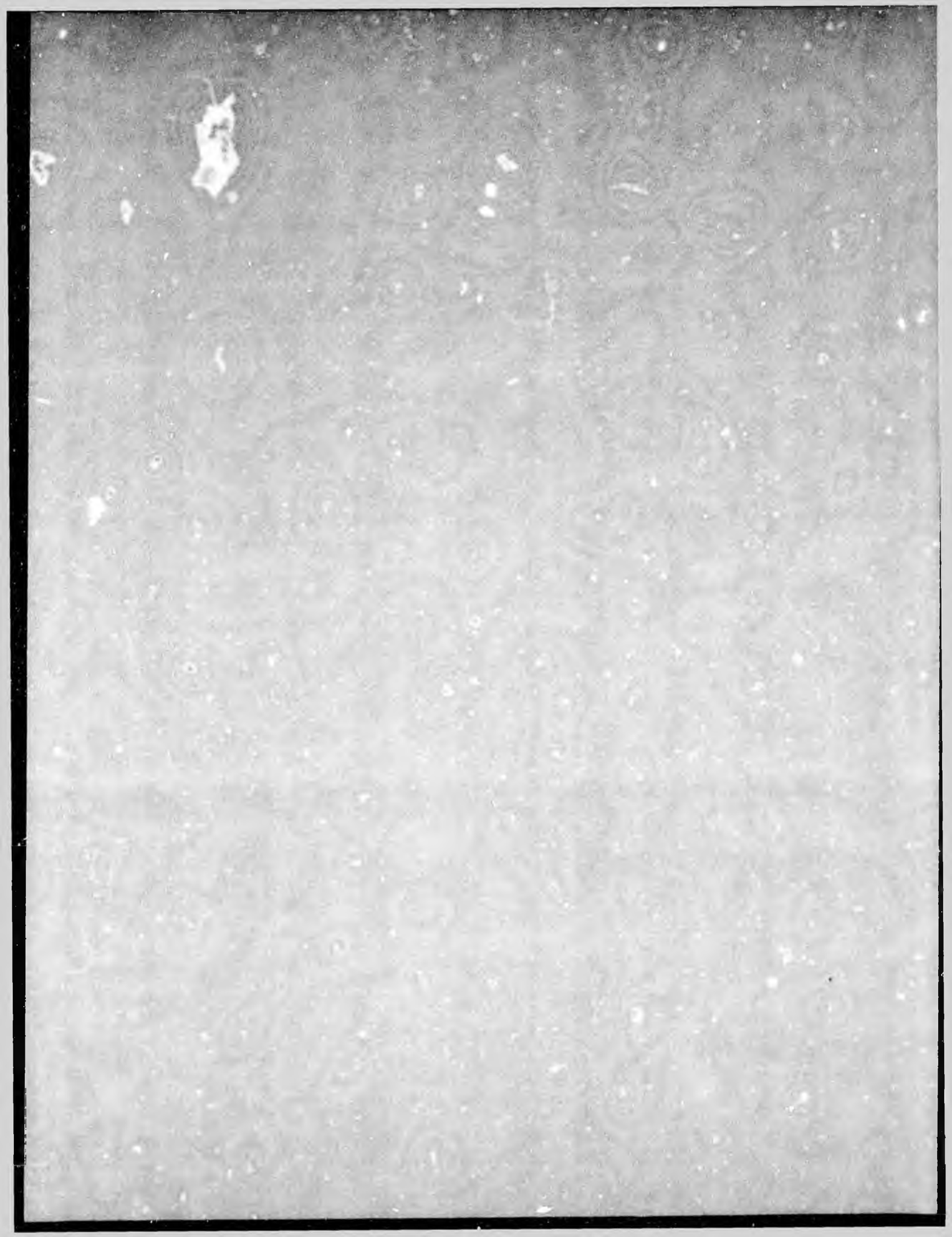
We do not typically dictate to an operator what he must do. Rather, the operator typically comes to us with a request for permission to do something and we allow it, disallow it, or allow some modification to the originally proposed plan. For instance, we do not tell an operator where or how deep to 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



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Sincerely,

Doug Suttles

cc: Alaska Legislature

[illegible] 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: AGI/DS/CL

Mr [illegible] Irwin
Commissioner
Department of Natural Resources
[illegible] W. 7th Avenue, Suite 1400
Anchorage
Alaska 99501-3650

Direct +44 (0)20 7496 4[illegible]
[illegible] +44 (0)2[illegible] 7496 [illegible]
Fax +44 (0)20 7496 [illegible]
[illegible]@bp.com

Dear Commissioner [illegible]

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

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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

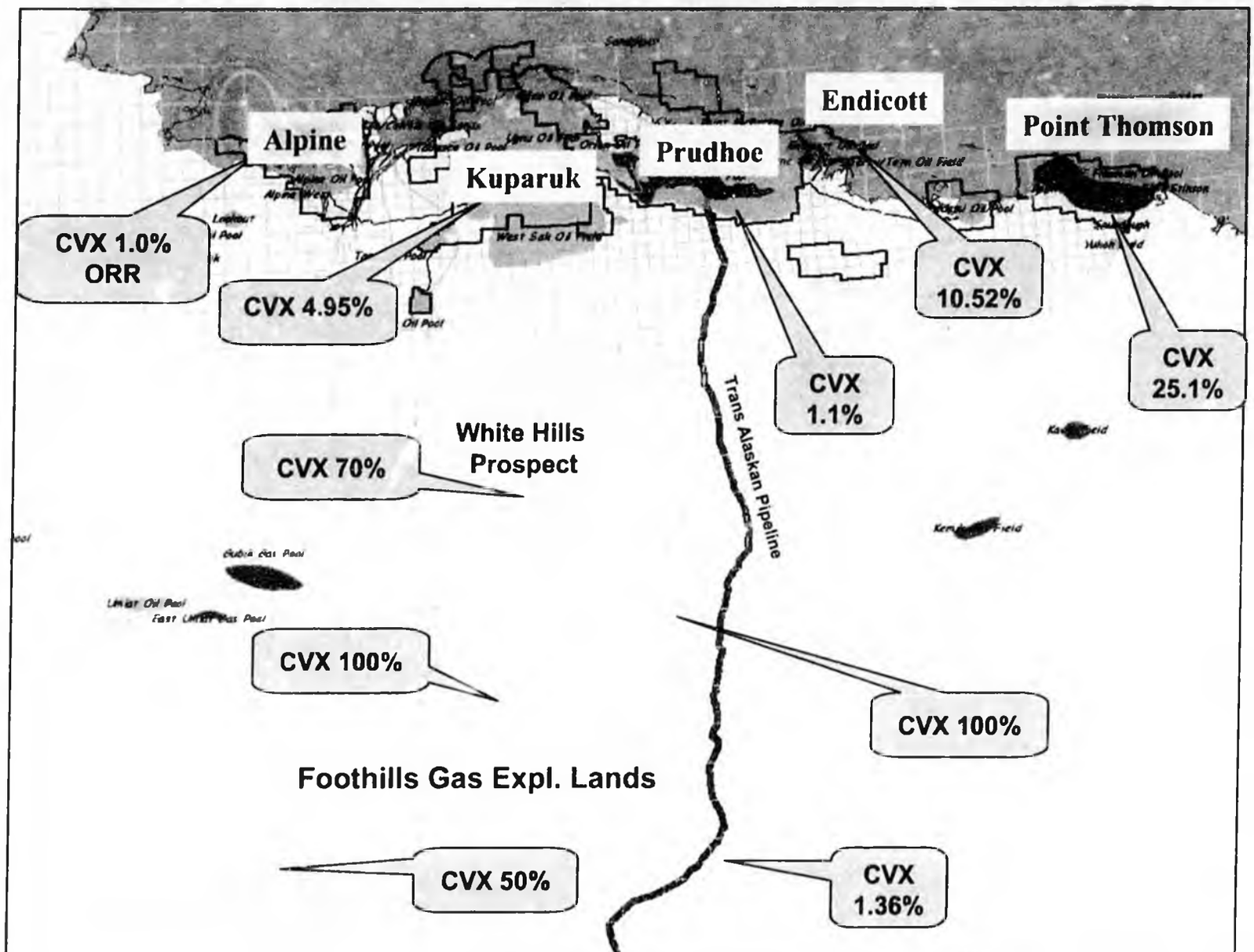
Anchorage, Alaska
June 17, 2008

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

Chevron

#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

- 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

Chevron

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

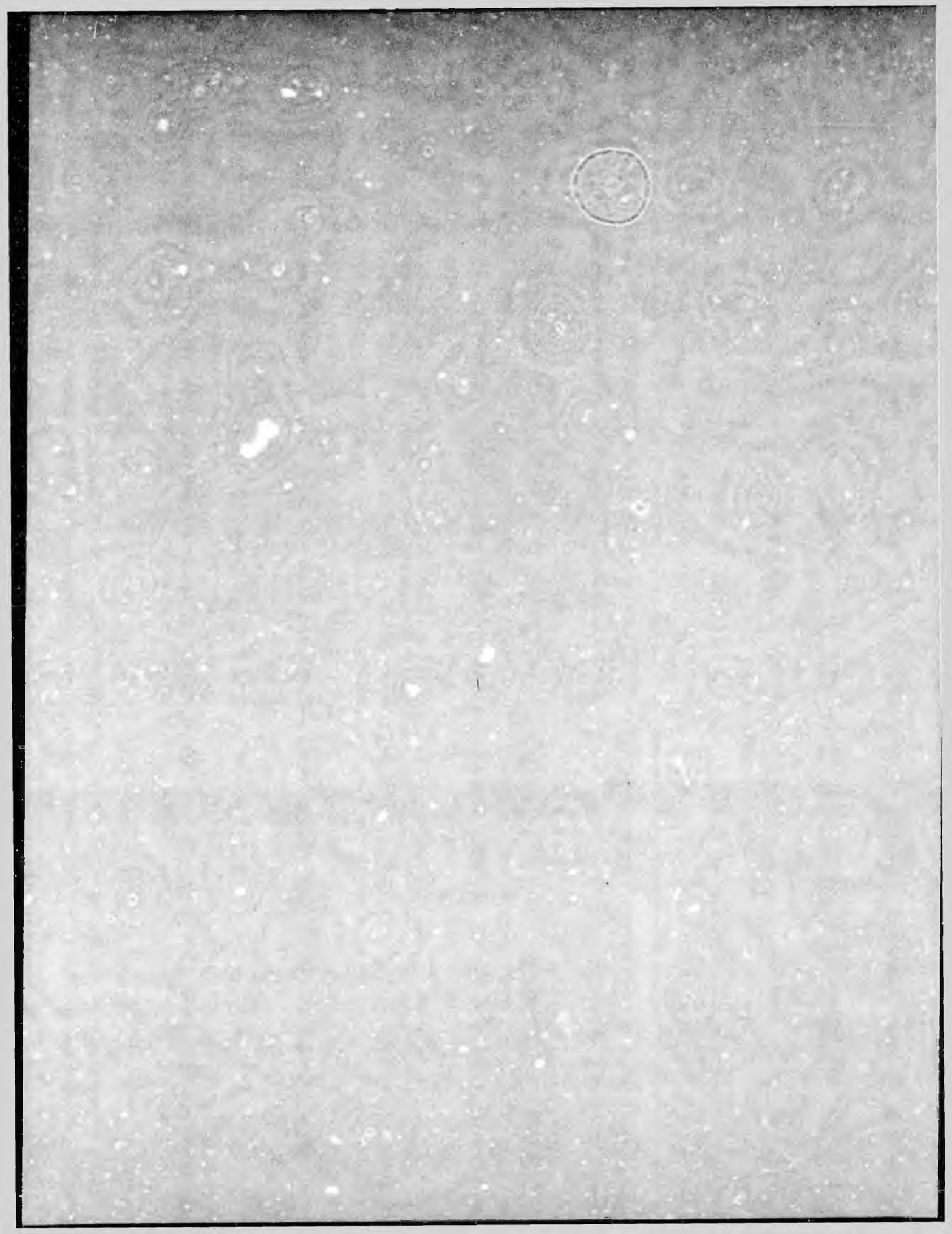
- PTU is critical to any major gas pipeline.
- PTU development should begin as soon as possible; the proposed POD is the right plan.
- The DNR should have approved the proposed PTU plan on its merits. Why didn't it . . . ?
- The current lessees can and will (if allowed) develop Point Thomson better and 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.

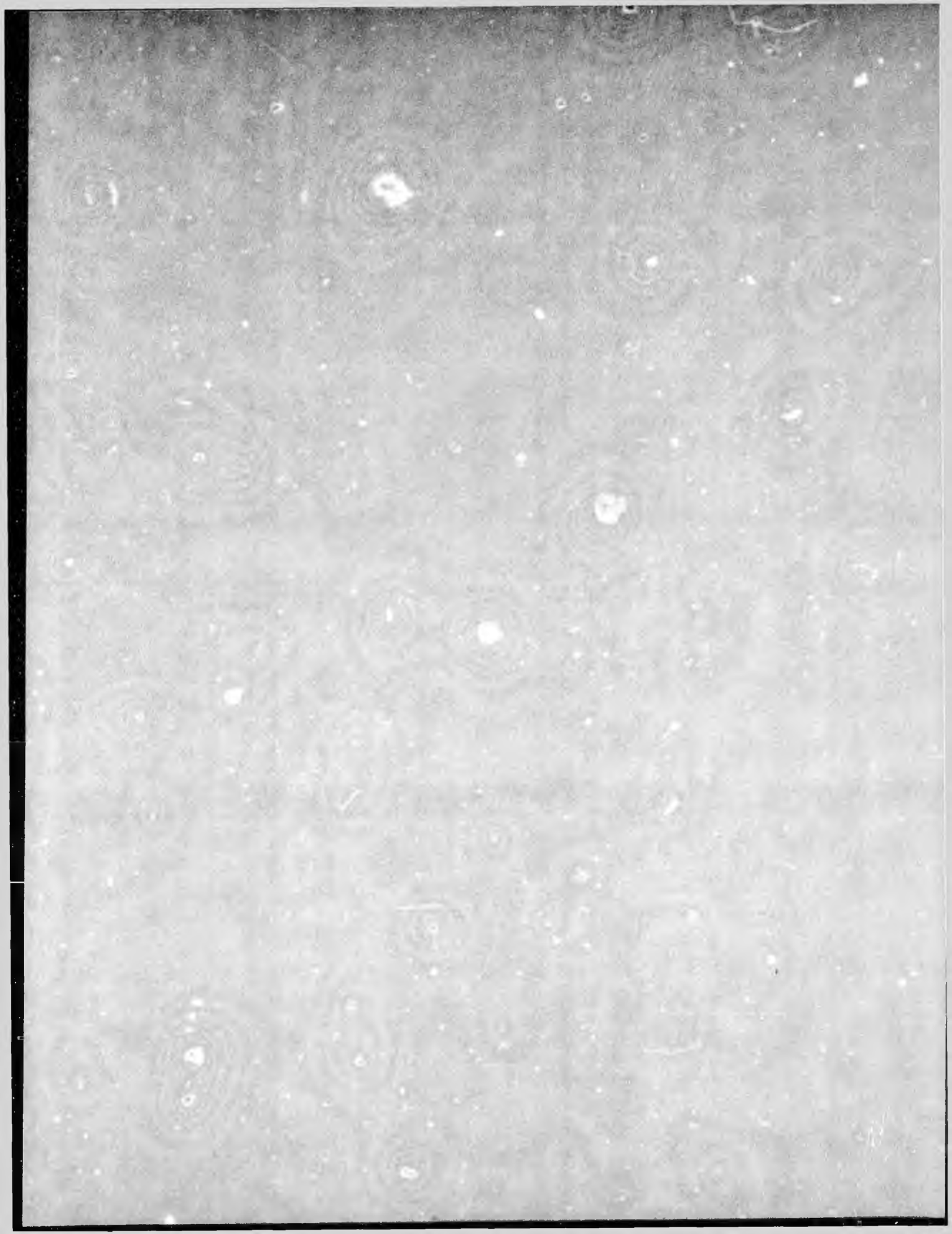
For example, the remaining useful life and increasing operating cost of the aging North Slope infrastructure will impact this balance between losing oil and stranding gas. Much of the North Slope infrastructure that was put in place thirty years ago for oil production will still be necessary for gas 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

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Summary of findings prepared by

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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 of 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 CO2, 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),

[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.

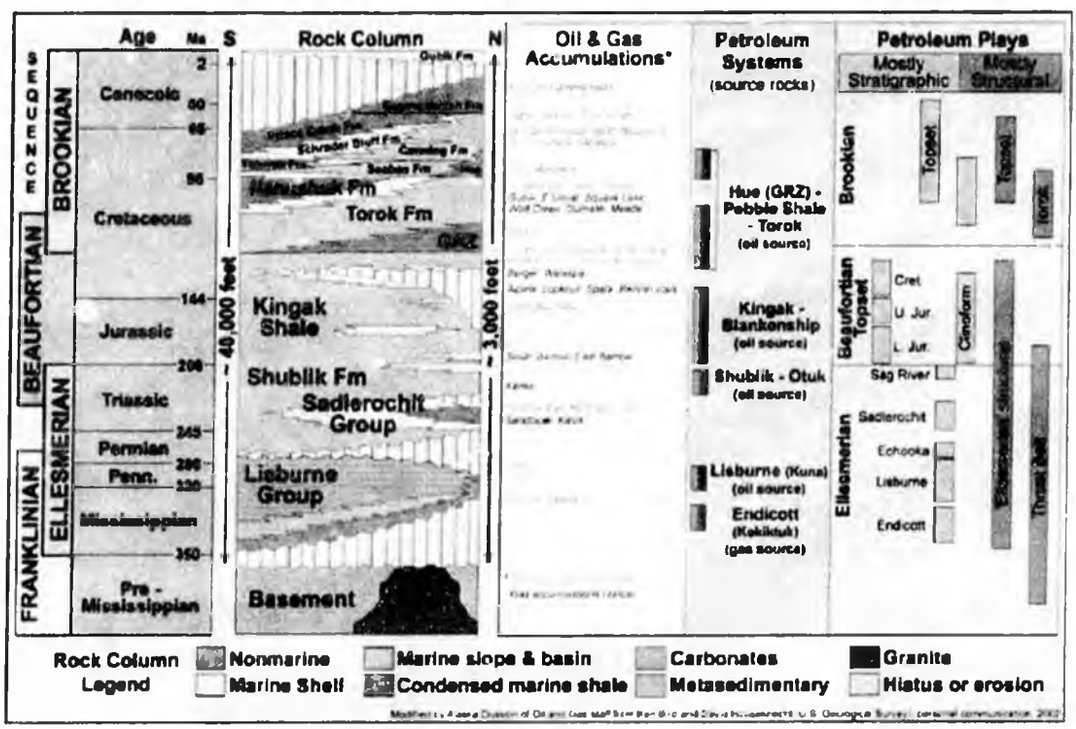

Figure 1, Alaska North Slope Stratigraphic Column

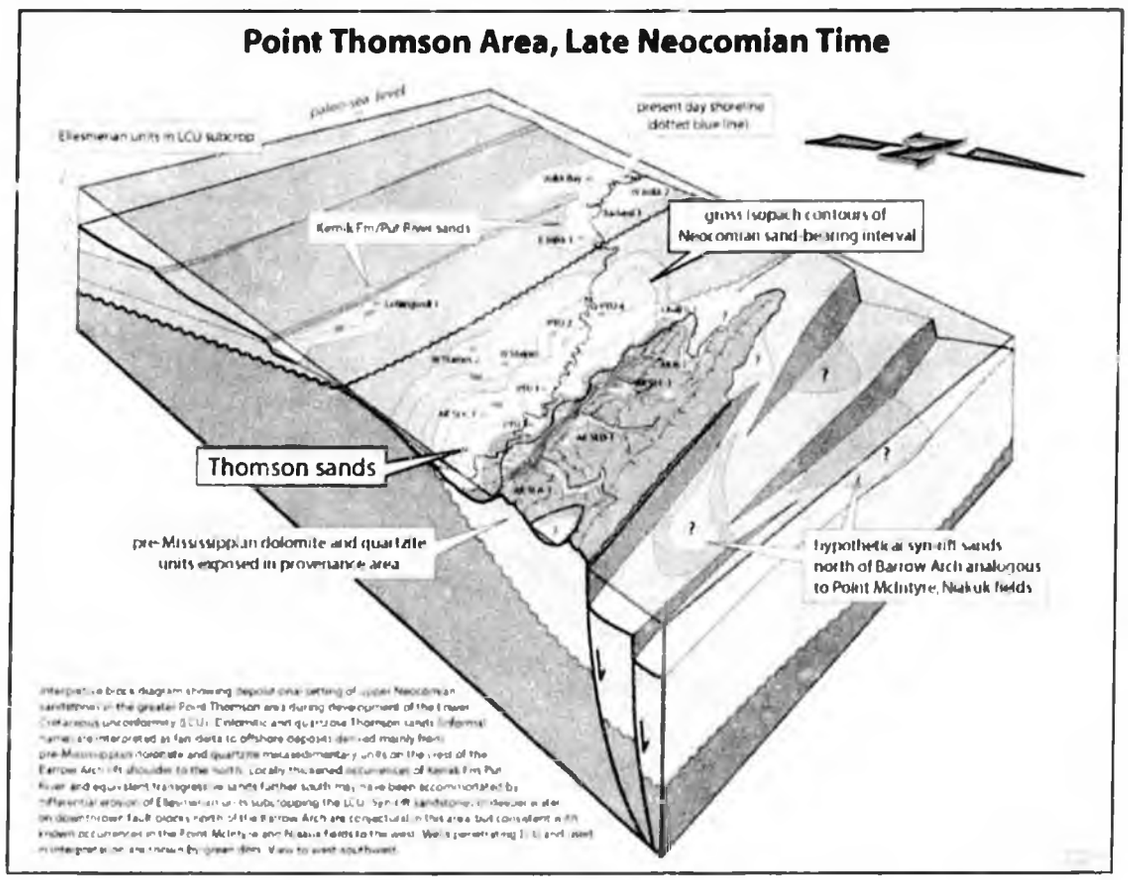

Figure 2, Block diagram of Point Thomson area in Late Neocomian time

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.