

**4/27/12
POINT
THOMSON
SETTLEMENT :
EVALUATION,
LITIGATION,
DNR RESPONSE**

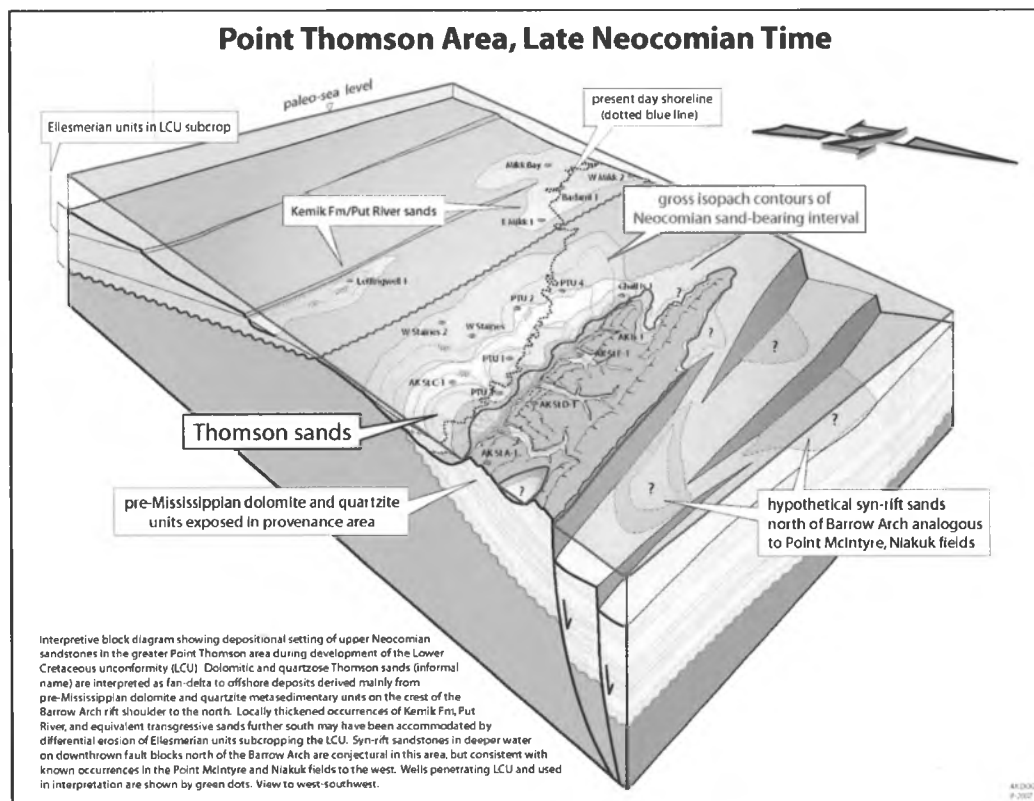
<TARGET><BILL></BILL><SUBJECT>4-27-12 POINT THOMSON
SETTLEMENT EVALUATION, LITIGATION, DNR
RESPONSE</SUBJECT><COMM>SJUD27</COMM></TARGET>

The Pt Thomson Settlement

Presented upon request of the Senate
Judiciary Committee

Mark Myers Ph.D., CPG

April 27, 2012



Presentation of Information Useful for Understanding the Settlement

- I. Technical Details of the Point Thomson field
- II. Description of a few previous development commitments
- III. Current Settlement
- IV. Summary

I. Point Thomson Technical Details

- Largest known remaining undeveloped, onshore Alaska, conventional field (petroleum liquids - oil and condensate)
- Combined reservoirs could contain more than 1,000,000,000 barrels of technically recoverable oil and condensate and 7 TCF gas
- 2 major hydrocarbon bearing zones
 - Flaxman sands D. 1975 - conventional oil
 - Thomson sands D. 1977)-retrograde condensate, oil and natural gas
- AOGCC classifies Pt Thomson is classified by as an **oil** not a gas field – liquids production should drive development
- **Because Point Thomson is a high-pressure retrograde condensate field the method of production, well and facility design is critical to maximizing recovery**

Unless the Point Thomson Sands are Developed Using Full Field Gas Cycling the Majority of the Recoverable Condensate and Oil **Will Be Wasted**

Blow Down	Full Field Cycling (20 yrs followed by blow down)	Difference
26% of the condensate 127-156 MMSTB	76% of the condensate 370-450 MMSTB	- 50% - 243-323 MMSTB
3-16% of the oil 30-150 MMSTB	43% of the oil 250-400 MMSTB	- 27%-40% - 220-230 MMSTB
70% of the gas 6-7 TCF	56% of the gas 4.8-5.9 TCF	+14% of the gas +1.1 to 1.2 TCF gas

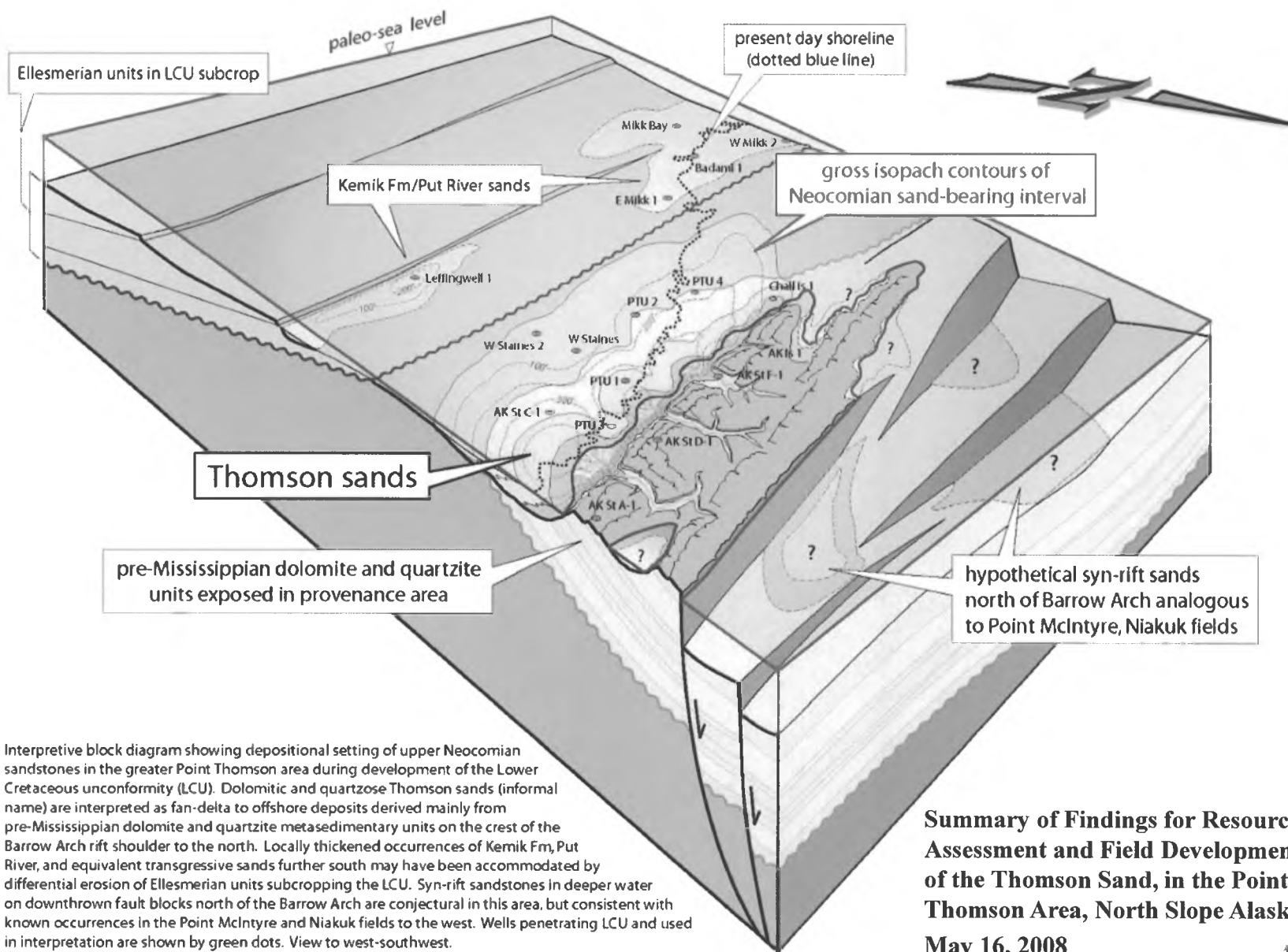
Key Findings from the only publically available study (commissioned by DNR DOG and completed by PetroTel Inc. in May 2008)

Resource owner (State DNR) and lessee/producer (WIOs) may not agree on method of production even if they agree on the geology, engineering, technology and costs

Why?

- Cycling costs more than blowdown and might have a lower – but still highly economic – rate of return
- Lessee/producer, not the state, bears the development and production costs as a requirement of the lease (somewhat offset by tax credits and potentially royalty relief)
- Lessee/producer has other options outside of Alaska where they can invest saved capital
- State (DNR) has a mission and a legal requirement as the resource steward and regulator to protect the public interest, promote conservation and promote the prevention of physical and economic waste –done primarily through the Unitization and Plan of Development (11AAC83.303(a)).

Point Thomson Area, Late Neocomian Time



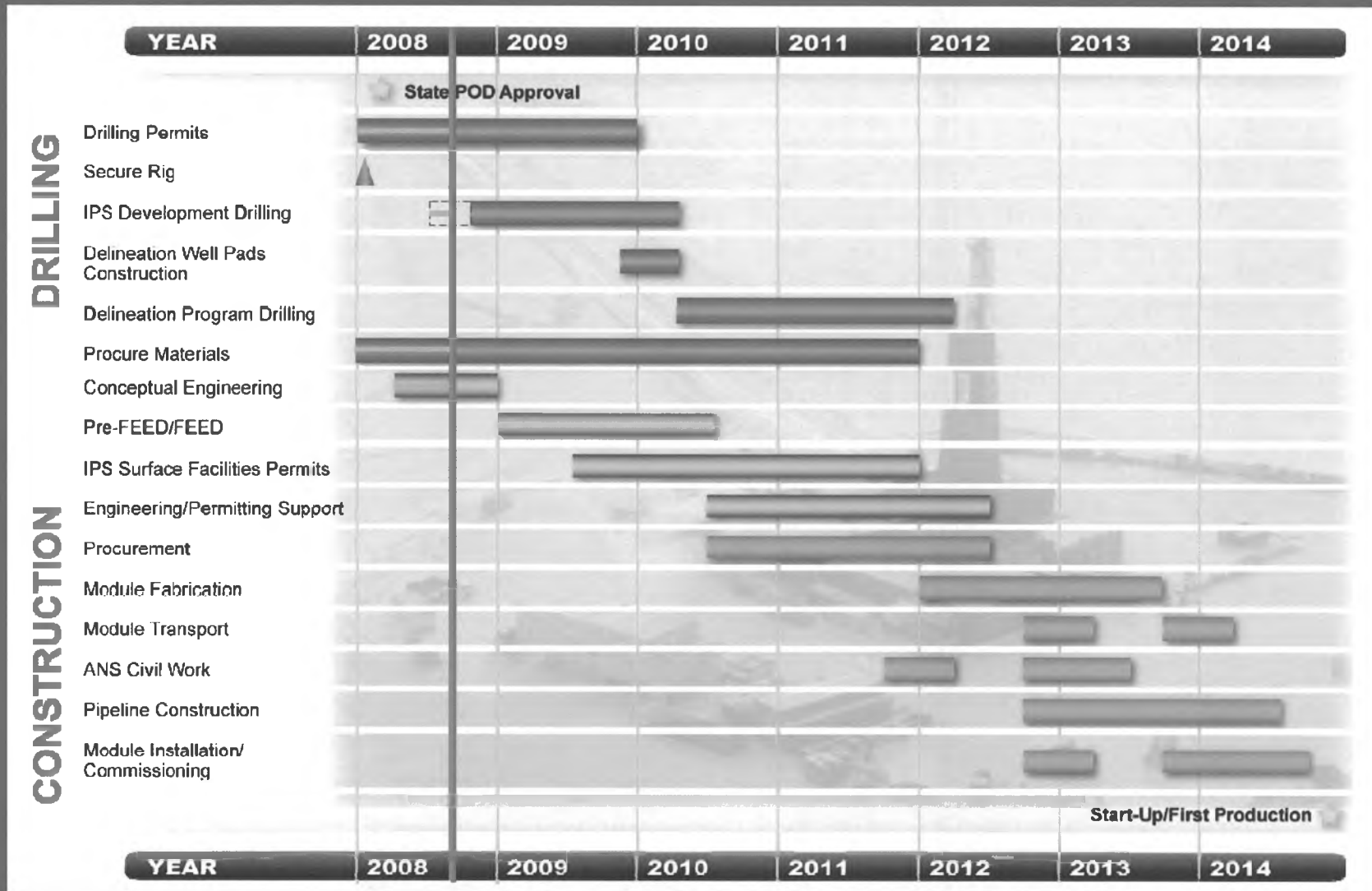
Interpretive block diagram showing depositional setting of upper Neocomian sandstones in the greater Point Thomson area during development of the Lower Cretaceous unconformity (LCU). Dolomitic and quartzose Thomson sands (informal name) are interpreted as fan-delta to offshore deposits derived mainly from pre-Mississippian dolomite and quartzite metasedimentary units on the crest of the Barrow Arch rift shoulder to the north. Locally thickened occurrences of Kemik Fm, Put River, and equivalent transgressive sands further south may have been accommodated by differential erosion of Ellesmerian units subcropping the LCU. Syn-rift sandstones in deeper water on downthrown fault blocks north of the Barrow Arch are conjectural in this area, but consistent with known occurrences in the Point McIntyre and Niakuk fields to the west. Wells penetrating LCU and used in interpretation are shown by green dots. View to west-southwest.

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

II. Description of a Few Previous Development Commitments

- Pt Thomson Unit formed in 1977, 1 1 Wells Drilled 1979-1983
- 2001 Expansion agreement:
 - Exxon agreed to drill well to test western end of field by June 2003
 - Commence development drilling by June 2006 or contract unit and pay \$20 Million
 - Complete 7 development wells by June 2008 or contract unit and pay \$27 million and increase royalty rates
 - Target project was a 75,000 Barrels of Condensate/Day full field cycling project
 - Wells were never drilled and Unit was ultimately defaulted in 2005
- 2009 Irwin Agreement that reinstated 2 of 31 leases
 - Exxon agrees to drill the PTU 15 and PTU 16
 - “Irwin said Tuesday he decided to reverse Banks and reinstate two leases because Exxon representatives said during the hearing that the company is ‘unconditionally committed’ to drilling two wells by 2010 and producing from those wells by 2014 “(ADN 27 Jan 2009)
 - Exxon builds wells, drills and tests wells and began permitting the pipeline

Point Thomson Project - Clear & Committed Timeline



PTU POD - Addressing DNR's Requests

- **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



- **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**

Point Thomson Project – Initial Development Phase

Project Illustration

- Production by YE 2014: 10,000 BPD, inject remaining gas
- Includes process facilities, liquids pipeline, airstrip, camp
- Delineates oil reservoirs, ability to produce
- Future expansion capability; ultimate gas sales development



[http://www.akrdc.org/membership/events/br
eakfast/0809/haymes.pdf](http://www.akrdc.org/membership/events/br
eakfast/0809/haymes.pdf)

III. The Current Settlement

- This settlement is extraordinarily significant in the impact and the breadth of issues that are settled.
- These issues are normally reserved for and resolved through statute and regulations using established public processes.

Some Major Issues

- Relinquishment of DNR's authority to manage the unit
- All development options are at the sole discretion of the WIO – none optimal for state
- Requirement for the State to take its gas in-kind prior to a major gas sale
- Deferral of Taxes on PTU gas injected into Prudhoe Bay

Major Issues Continued

- Contraction of unit is not automatic and through at least one of the pathways no drilling is required to keep acreage
- Most PA and tract allocations (which affects the state royalty share) are determined by the settlement and automatic – where is the technical review?

Major Issues Continued

- **Validity:** The Commissioner has determined that the terms of this agreement are necessary or advisable to protect the public interest – including RIK and blowing the reservoir down in spite of the huge oil and condensate loss
- **Further Assurances:** - DNR will not oppose an application to AOGCC to blow the reservoir down if consistent with the agreement and applicable state law

Unusual and Problematic Definitions

“Major Gas Sale (MGS)”

- Means a large-scale pipeline project having a design throughput of more than 500 MMCFD of gas that results in delivery of gas off the North Slope of Alaska”
- This is 9X less volume than the proposed AGIA line and 6X smaller than the proposed LNG project under AGIA or the Port Authority.
- Given the gas reserves at Prudhoe Bay, a MGS for an LNG project wouldn't need Point Thomson gas until the year 2040 for a 3 BCF line and the year 2146 MMCFD for a 500 MMCFD pipeline
- Why would state use this definition?

Unusual and Problematic Definitions Continued

“Without appeal”

- Any Party may dispute in court whether a specified event has occurred that would result in termination or release of acreage “Without Appeal” (Section 5.1.4)

Available Development Options

All Alternatives are at the Discretion of the WIO

ALTERNATIVE A

- “Sanction” a Major Gas Sale: defined as any pipeline > volume than bullet line – doesn’t require building it or connecting it to Point Thomson

ALTERNATIVE B

- Expanded Liquids Production into TAPS Only requires 20,000 to 30000 BOPD

ALTERNATIVE C

- Expanded Liquids Production into TAPS, Enhanced Prudhoe Bay Recovery, and Gas for In-State Use

ALTERNATIVE D

- Spend \$2 Billion dollars between year end 2007 and year end 2015 on “work activities set forth in this agreement” Abandon and keep most of the acreage. Keep it all with planning No production required.

Summary

- **None of the three development scenarios maximize economic oil and gas recovery from the field. In fact they all could/will lead to very significant physical and economic waste**
- **The settlement provides several pathways which require little to no actual production**
- **Settlement removes DNR's authority to manage the field through normal development procedures**
- **Some settlement terms step back from previous commitments of WIOs**

Summary Continued

- **None of the contemplated gas pipelines will require Pt Thomson gas for decades**
 - Linkages are made to a gas line that is so small that it could be kept full with Prudhoe Bay gas for 20-120 years. Pt Thomson gas won't be needed until 2040 and beyond: long after full field cycling for liquids would have been completed.
- **RIK – Why? and why no finding process?**
- **Major oil and gas decision of the decade made without public process**
- **Abandonment with no damages and minimal consequences**

Unless the Point Thomson Sands are Developed Using Full Field Gas Cycling the Majority of the Recoverable Condensate and Oil **Will Be Wasted**

Blow Down	Full Field Cycling (20 yrs followed by blow down)	Difference
26% of the condensate 127-156 MMSTB	76% of the condensate 370-450 MMSTB	- 50% - 243-323 MMSTB
3-16% of the oil 30-150 MMSTB	43% of the oil 250-400 MMSTB	- 27%-40% - 220-230 MMSTB
70% of the gas 6-7 TCF	56% of the gas 4.8-5.9 TCF	+14% of the gas +1.1 to 1.2 TCF gas

Key Findings from the only publically available study (commissioned by DNR DOG and completed by PetroTel Inc. in May 2008)

Excerpts from a Statement of the Alaska Oil and Gas Conservation Commission

To date, the Commission has received no application for pool rules from the PTU owners. Accordingly, the Thomson Sand Reservoir (TSR) is presumed to be an oil pool and will remain so unless and until the Commission establishes Pool Rules that provide otherwise.

As cited above, the Commission's responsibility is to prevent the physical waste of hydrocarbon resources. Maximizing value to the owners and the State at the possible expense of additional reserves is not a valid reason for committing waste. The owners have yet to demonstrate to the satisfaction of the Commission that developing the PIU as a gas field will be the only viable alternative for a prudent operator to pursue. Until they do, the Commission will continue to regard the PTU as an oil field and steps taken towards developing it as a gas field risk being viewed as steps taken towards wasting hydrocarbon resources. Point Thomson could be part of a gas line project and still cycle condensate first; if the operator makes prudent use of the time available.

In conclusion the Commission does not believe that the uncertainty that still exists about the potential development of the PTU can be used as justification for a decision that may promote waste of tens to hundreds of millions of barrels of oil and condensate. This is especially true in light of the fact that much of this uncertainty could have been eliminated already had the PTU owners adhered to the work commitments specified in previous POD's and agreements.

Submitted this 3rd day of November 2006.

<http://www.courts.alaska.gov/outreach/sci2012-anc-appellant-excerpts479-535.pdf>

AOGCC Explanation

- 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 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. the answer?**
- http://doa.alaska.gov/ogc/Gas/PtThompson_Pool_Rules.pdf

POINT THOMSON

SETTLEMENT OVERVIEW

**Senate
Judiciary
Committee**

**Joe Balash
Deputy
Commissioner**
*Alaska Department of
Natural Resources*

April 27, 2012



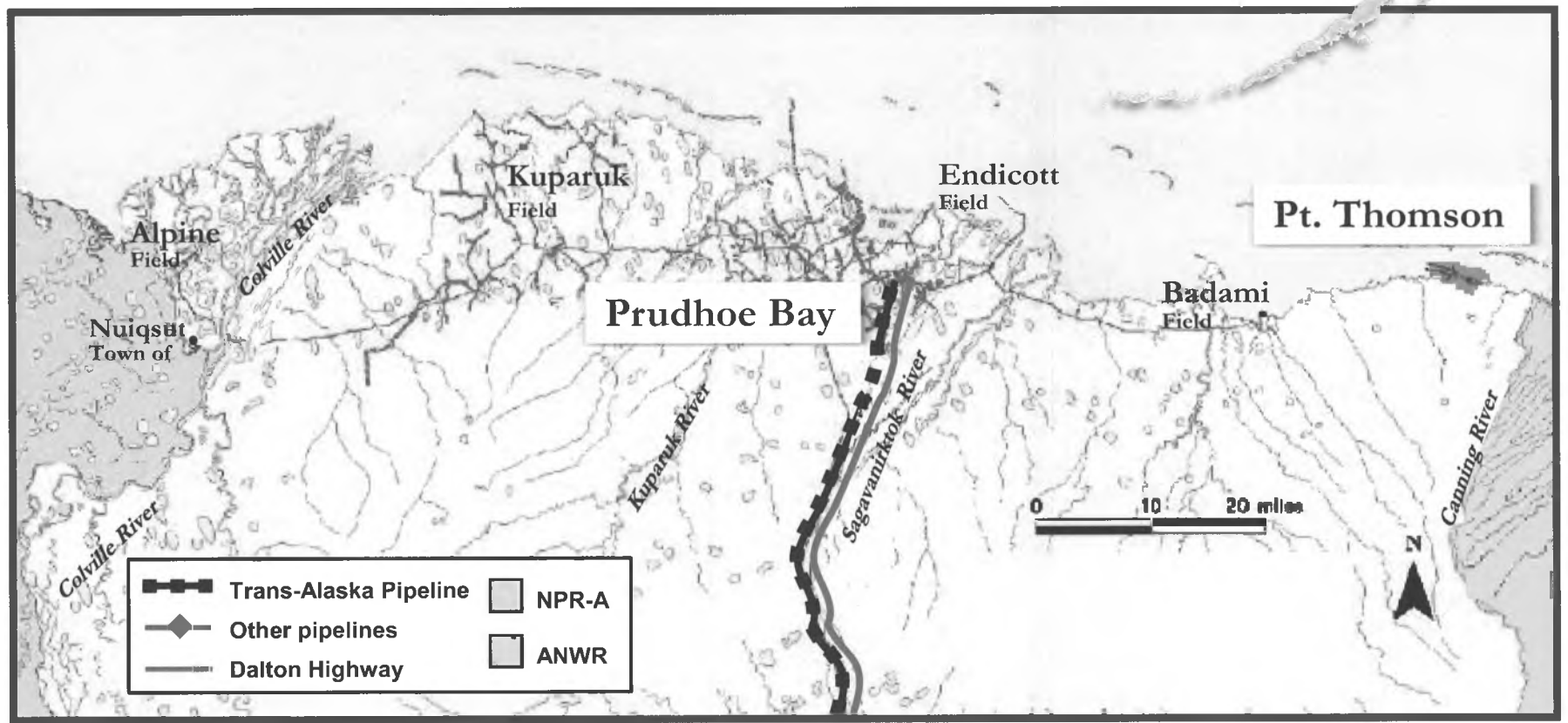
OUTLINE



- I. BACKGROUND
- II. LONG-STANDING GOALS RELATED TO POINT THOMSON
- III. HOW *the* SETTLEMENT ADVANCES ALASKA'S INTERESTS
- IV. COMPONENTS *of the* AGREEMENT

PT

BACKGROUND



PT

BACKGROUND

About Point Thomson

- Point Thomson (PT) is located approximately 60 miles east of Prudhoe Bay and is adjacent to the Arctic National Wildlife Refuge (ANWR)
- The first leases were acquired in 1965; oil discovered in 1975; gas discovered in 1977
- The PT unit formed in 1977
- The PT unit contains 38 state leases on approximately 93,000 acres of state land
- PT contains about 8 TCF of gas and hundreds of millions of barrels of oil
- PT has ~ 25% of known North Slope gas reserves
- PT unit has a massive Thomson Sands reservoir, a thin oil rim, and smaller Brookian oil accumulations
- The PT reservoir is a high-pressure retrograde condensate and natural gas reservoir that presents development challenges

About the Litigation

- In 2005, DNR defaulted the PT unit for lack of development
- In November 2006, DNR terminated the unit when the Producers failed to cure the default
- The Producers appealed to superior court; in December 2007, the court remanded the unit termination decision to DNR
- In April 2008, DNR rejected a new plan of development and again terminated the unit
- The Producers appealed to superior court, which ruled that DNR erred in terminating the unit
- The Alaska Supreme Court granted the State's Petition for Review, which halted the current superior court litigation – final court resolution is years away

PT

LONG-STANDING GOALS RELATED to POINT THOMSON

State of Alaska's Goal for Point Thomson:
Advance the State of Alaska's Strategic Interests

For years the State of Alaska has focused on these common goals related to PT:

- Begin producing PT hydrocarbons into TAPS—*no more warehousing*
- Keep development and production moving forward
- Incentivize and lay out clear path for full-field development
- Ensure significant consequences if the Producers fail to meet commitments
- Encourage commercialization of North Slope gas
- Create increased employment and economic opportunities for Alaskans





HOW *the* SETTLEMENT ADVANCES ALASKA'S INTERESTS

- Creates momentum on production and development
- Creates a near-term commitment of production into TAPS and increasing TAPS throughput
- Ends the warehousing of state resources
- Provides the quickest way to move PT into production by a certain date
- Opens the Eastern North Slope to new development opportunities by adding infrastructure and a 70,000 bpd common carrier pipeline connecting to TAPS ✓
- Incentivizes and lays out a clear path and alternatives for full-field development, each of which will require billions of dollars in investment if pursued
- Generates significant investment in Alaska, which will create increased employment and economic activity for Alaskans: strong Alaska hire provision
- Establishes significant consequences if near-term or longer-term development is not pursued
- Increases competition on the North Slope
- Provides potential for significant gas volumes for in-state use no later than 2019
- Positions North Slope gas for a large-scale gas pipeline project
 - Near term work on liquids production undertaken simultaneously with gas commercialization efforts
 - Liquids production work commitments are a pre-investment for North Slope gas commercialization
 - Ends the cloud of litigation over PT
 - Catalyst for alignment among the Producers and TransCanada
- Requires a commitment to develop a separate oil reservoir within PT
- Improves technical and geologic understanding of the complicated PT reservoir to help determine the best way to maximize state resources
- Animating principle: “earn your acreage” – the more work, more commitment, more investment, and more production that occur, the more PT acreage companies will retain

PT

COMPONENTS *of the* SETTLEMENT

I. Initial Production System (IPS)

II. Overview of Expanded Development Alternatives

A. ALTERNATIVE A:

Major Gas Sale

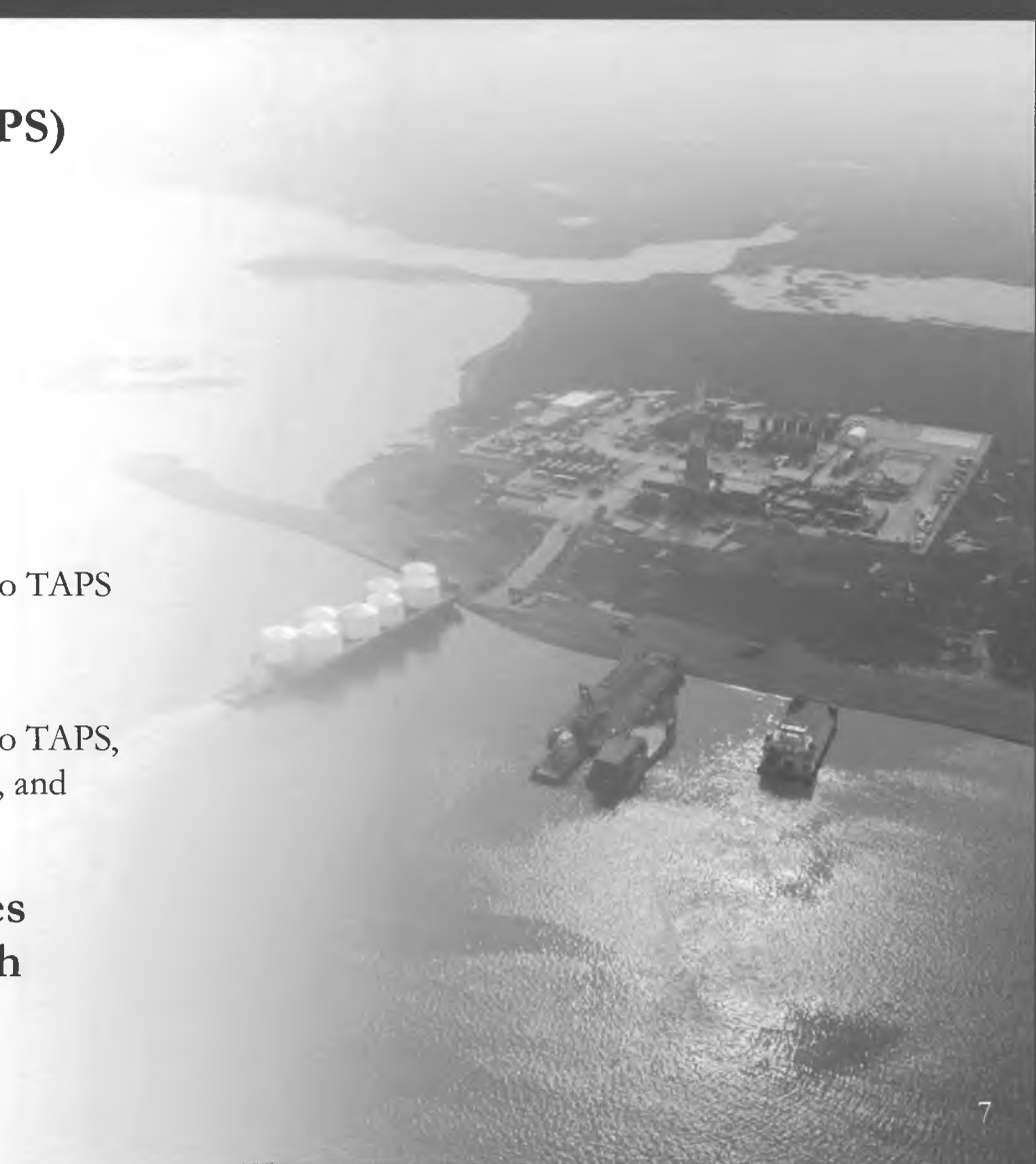
B. ALTERNATIVE B:

Expanded Liquids Production into TAPS

C. ALTERNATIVE C:

Expanded Liquids Production into TAPS,
Enhanced Prudhoe Bay Recovery, and
Gas for In-State Use

III. Consequences and Incentives Related to Development Path Taken





INITIAL PRODUCTION SYSTEM - COMMITMENTS *and* TIMELINES -

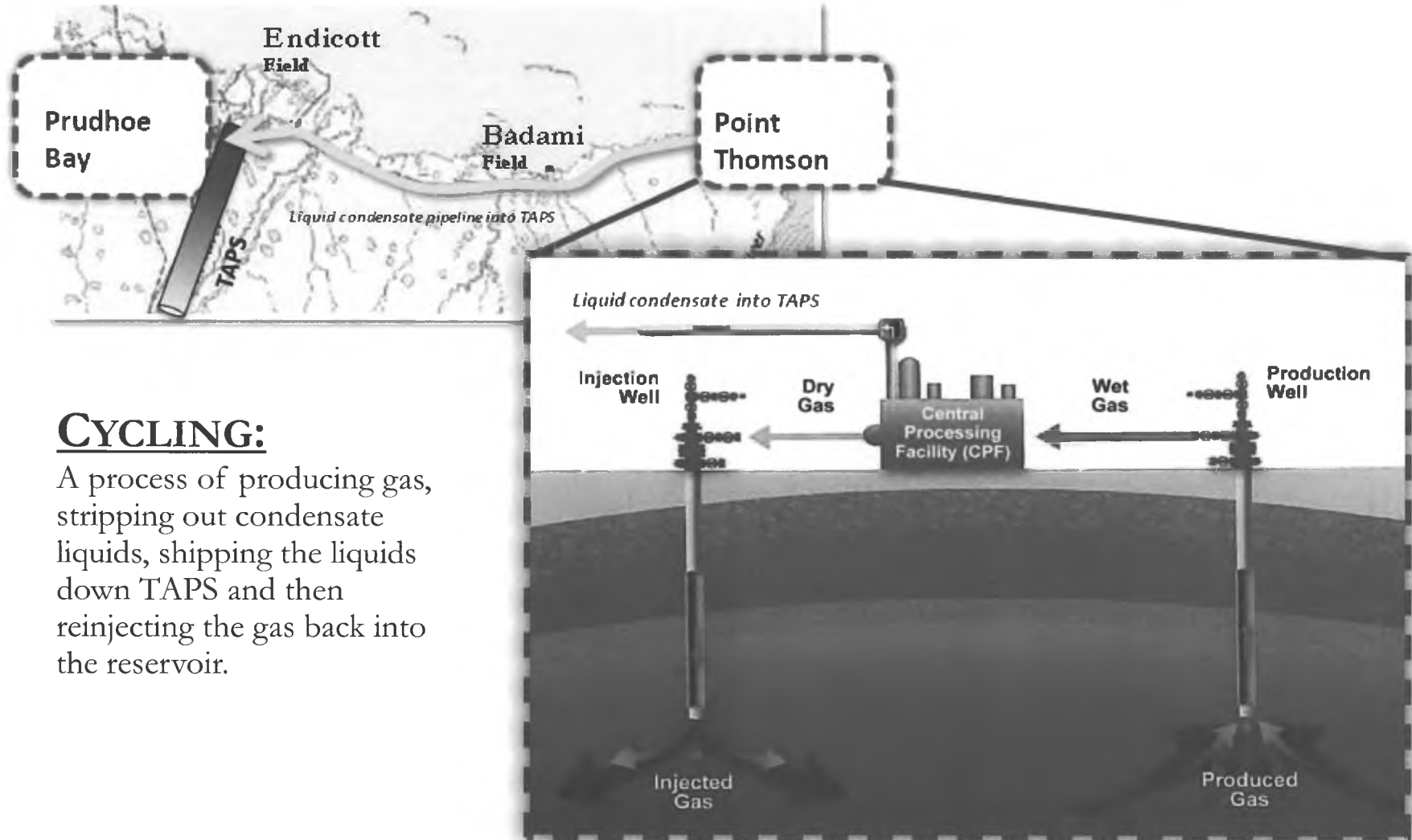


- Producers will work together to complete the Initial Production System (IPS), will produce ~10k BPD of liquid gas condensates and cycle ~200 mm CFD
- To install the IPS, the Producers will complete the following work commitments:
 - Drill PT 15 & 16 wells from the central pad (completed); world-class wells in a remote location
 - Construct facilities and install 70k BPD liquids, common carrier pipeline to TAPS
 - Put PT 15 & 16 on production by end of 2015-16 winter season utilizing IPS
 - Original, agreed-upon timeline was pushed back one year because of federal permitting delays
 - Drill west pad well by end of 2016-17 winter season
 - Permit two additional wells and the east pad
- IPS installs infrastructure necessary for full-field development and will provide critical information for the next phase of development
- Detailed work schedule incorporated into the agreement (see slide 11)
- DNR technical review confirmed reservoir complexity
- If the IPS is abandoned, acreage automatically contracts from the unit and is returned to the state
- Unfavorable economics/ROI of IPS cannot serve as an excuse for non-performance
- Once production starts, limited acreage is secured consistent with state law
- IPS development proceeds in parallel with gas commercialization work



INITIAL PRODUCTION SYSTEM

- OVERVIEW of CYCLING -



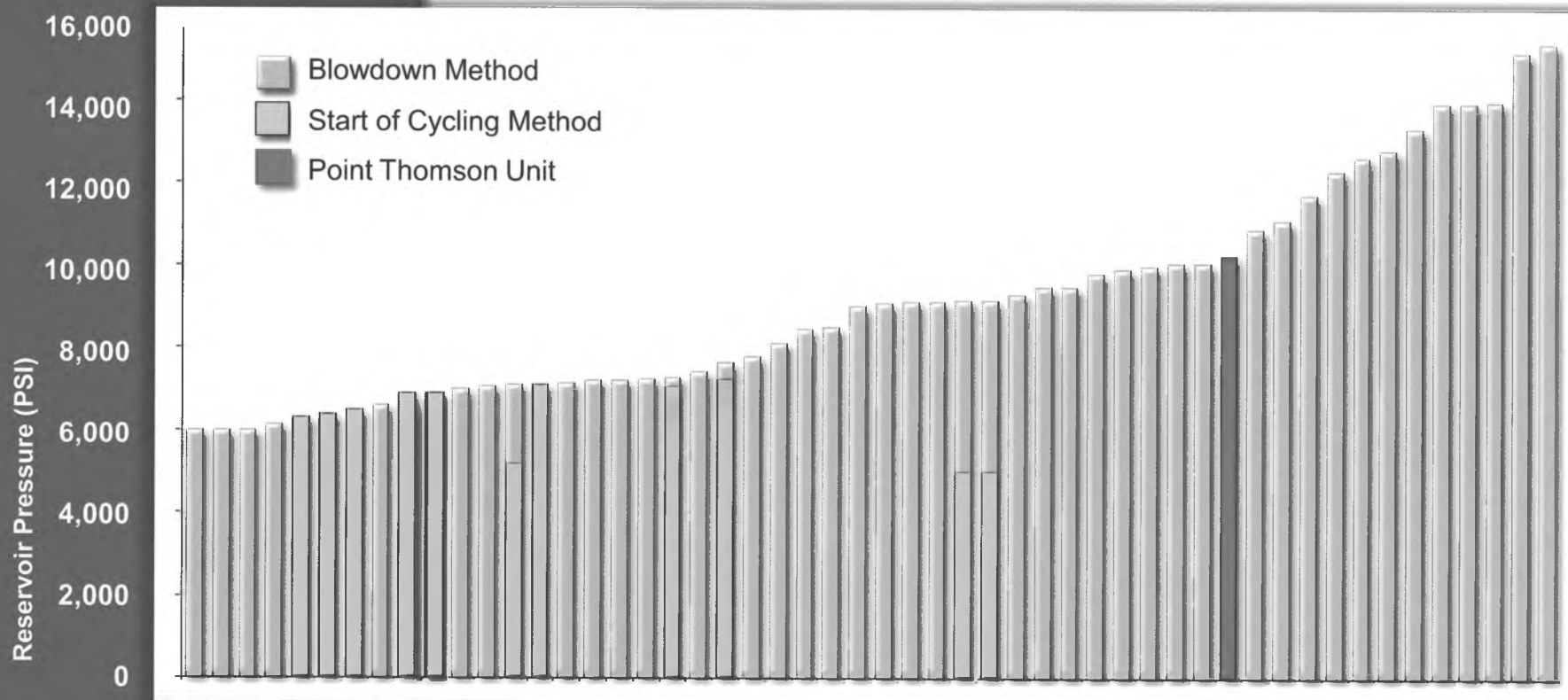
CYCLING:

A process of producing gas, stripping out condensate liquids, shipping the liquids down TAPS and then reinjecting the gas back into the reservoir.



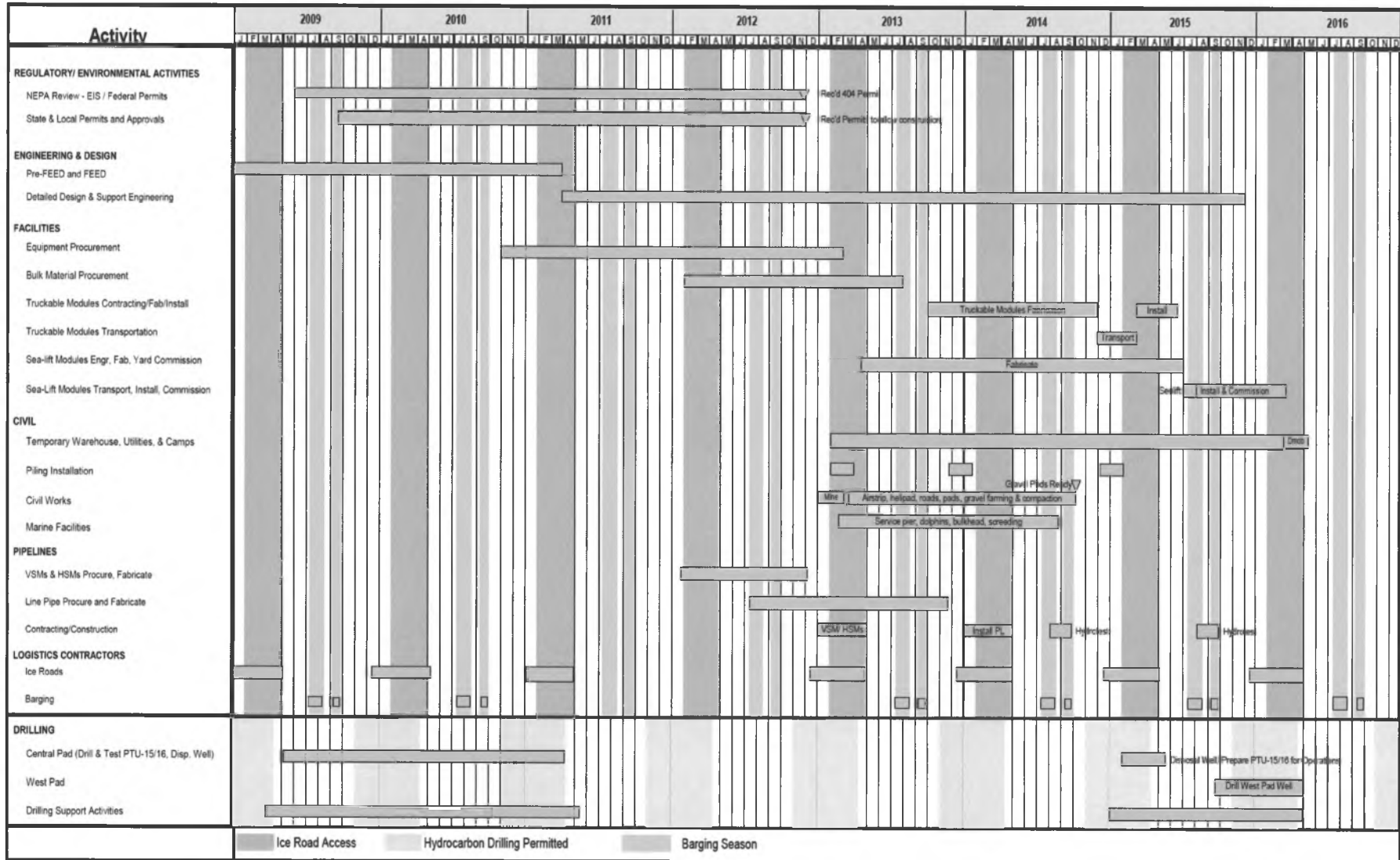
INITIAL PRODUCTION SYSTEM - CYCLING at HIGH-PRESSURE -

Comparison of World-Wide Gas-Condensate Reservoirs





IPS WORK SCHEDULE





OVERVIEW of EXPANDED DEVELOPMENT ALTERNATIVES

- In addition to the IPS production commitments and timeline, the settlement creates pathways, incentives, and benchmarks for full-field development of the PT reservoir – *critical component of the settlement*
- Once the IPS is on production, there are three alternatives to full-field development:
 - A. Major Gas Sale
 - B. Expanded Liquid Production into TAPS
 - C. Expanded Liquid Production into TAPS, Enhanced Prudhoe Bay Recovery, and Gas for In-State Use
- All three alternatives:
 - Can be pursued individually or simultaneously
 - Will require billions of dollars of additional investment to complete
 - Can only fully secure additional PT acreage once expanded production of hydrocarbons begins
- If none of the three expanded development alternatives are sanctioned or committed to, then the Producers automatically lose significant PT acreage
- Producers must also commit to Brookian oil formation production by 2018 or lose Brookian acreage
- A primary goal of the expanded development alternatives is commercializing North Slope gas
- But other full-field development scenarios—Alternatives B and C—are also available
 - Provides flexibility for the future: markets are hard to predict
 - State’s resources can be maximized depending on market conditions



ALTERNATIVE A: - MAJOR GAS SALE -

A. ALTERNATIVE A: Major Gas Sale

B. ALTERNATIVE B:

Expanded Liquids
Production into TAPS

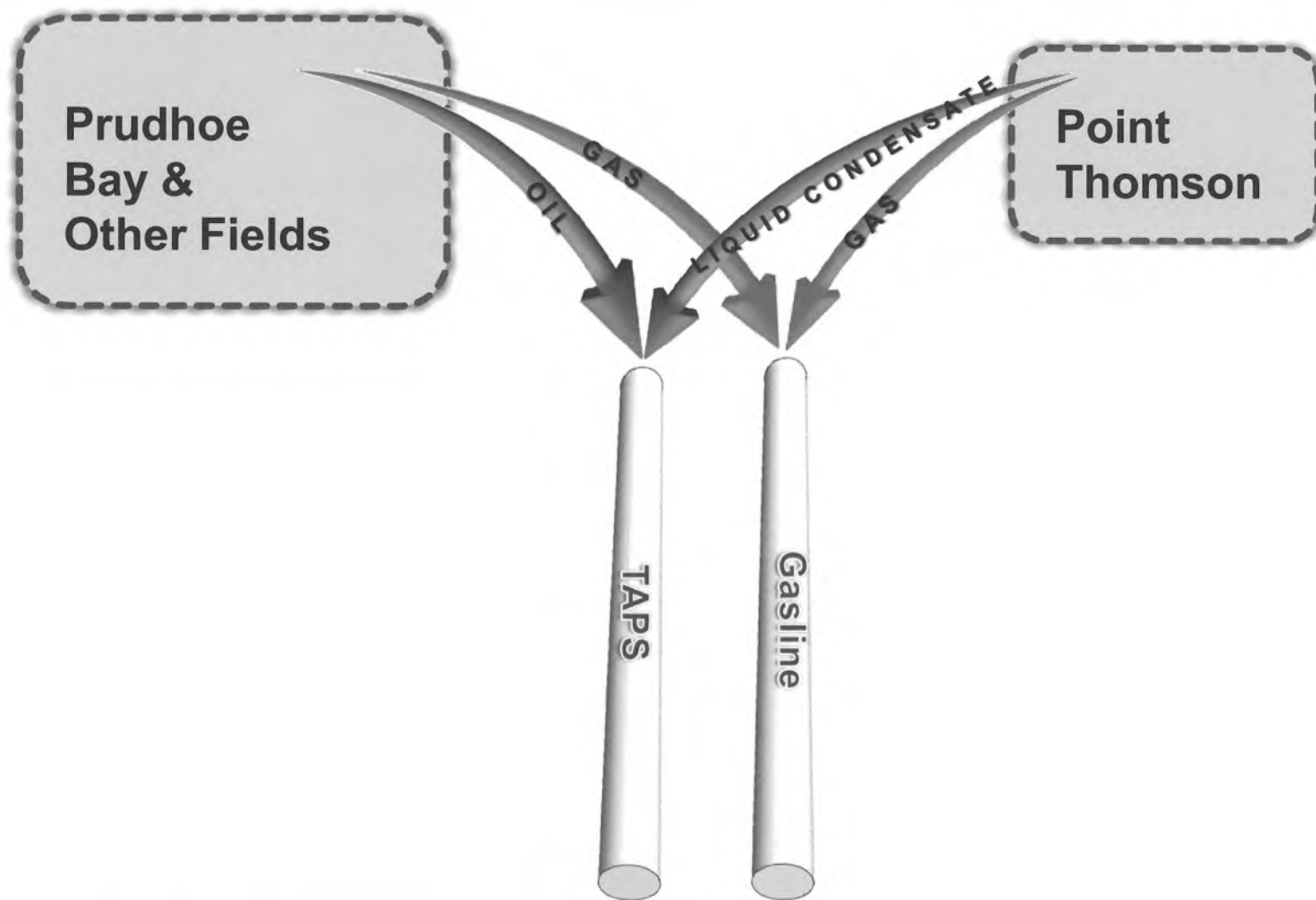
C. ALTERNATIVE C:

Expanded Liquids
Production into TAPS,
Enhanced Prudhoe Bay
Recovery, and Gas for In-
State Use

- A primary goal of this settlement is to incentivize commercialization of North Slope gas/Major Gas Sale (MGS)
 - MGS must exceed 500 million cubic feet/d on the North Slope
 - Provides flexibility to allow different MGS scenarios
- Work begins immediately on dual spending for IPS and MGS/LNG
- There are two windows to “sanction” a MGS: (1) from present to 2016 and (2) from 2016 to 2019
 - “Sanction” means that all required state and federal gas line permits have been issued and the pipeline sponsors have secured all necessary financing and received full corporate approval to proceed with pipeline construction
 - Getting to a sanctioned decision will likely require investing hundreds of millions/billions of dollars
- MGS production makes gas available for in-state use
- If a MGS is not sanctioned by June 2016, the Producers must begin engineering & permitting to expand PT production either through Alternative B or C
- Once MGS is sanctioned, the Producers will temporarily retain most of the PT unit; but the PT unit will only be fully secured once gas is flowing into a gas pipeline
- If a MGS is not sanctioned by 2019, the Producers will have had to commit to Alternative B or Alternative C or lose significant acreage

PT

ALTERNATIVE A: - GENERAL DEPICTION -





ALTERNATIVE B: - EXPANDED LIQUID PRODUCTION INTO TAPS -

A. ALTERNATIVE A:
Major Gas Sale

B. ALTERNATIVE B:
Expanded Liquids
Production into
TAPS

C. ALTERNATIVE C:
Expanded Liquids
Production into TAPS,
Enhanced Prudhoe Bay
Recovery, and Gas for In-
State Use

- Producers can expand the IPS cycling capacity and increase production to a minimum of approximately 30,000 bpd of liquids into TAPS
- Producers must commit to expanded cycling by 2019
- Production will likely exceed 30,000 bpd of liquids into TAPS—*lip of the funnel*
- Any expansion less than 30,000 bpd of liquids will result in certain acreage automatically contracting from the unit
- This alternative will likely result in the greatest long-term recovery of liquids from PT into TAPS, but PT gas will remain in the reservoir
- The enhanced understanding of the PT reservoir, gained from the IPS, will help determine the feasibility of this option
 - Will be influenced by factors such as condensate yield, reservoir connectivity and oil price forecasts
- Will require additional wells and larger gas processing and production facilities
- Once the Producers begin producing under this option, they will retain most of the unit acreage
- Producers can also pursue other alternatives simultaneously



ALTERNATIVE C:

- EXPANDED LIQUID PRODUCTION INTO TAPS, ENHANCED PRUDHOE BAY RECOVERY, AND GAS FOR IN-STATE USE -

A. ALTERNATIVE A:

Major Gas Sale

B. ALTERNATIVE B:

Expanded Liquids
Production into TAPS

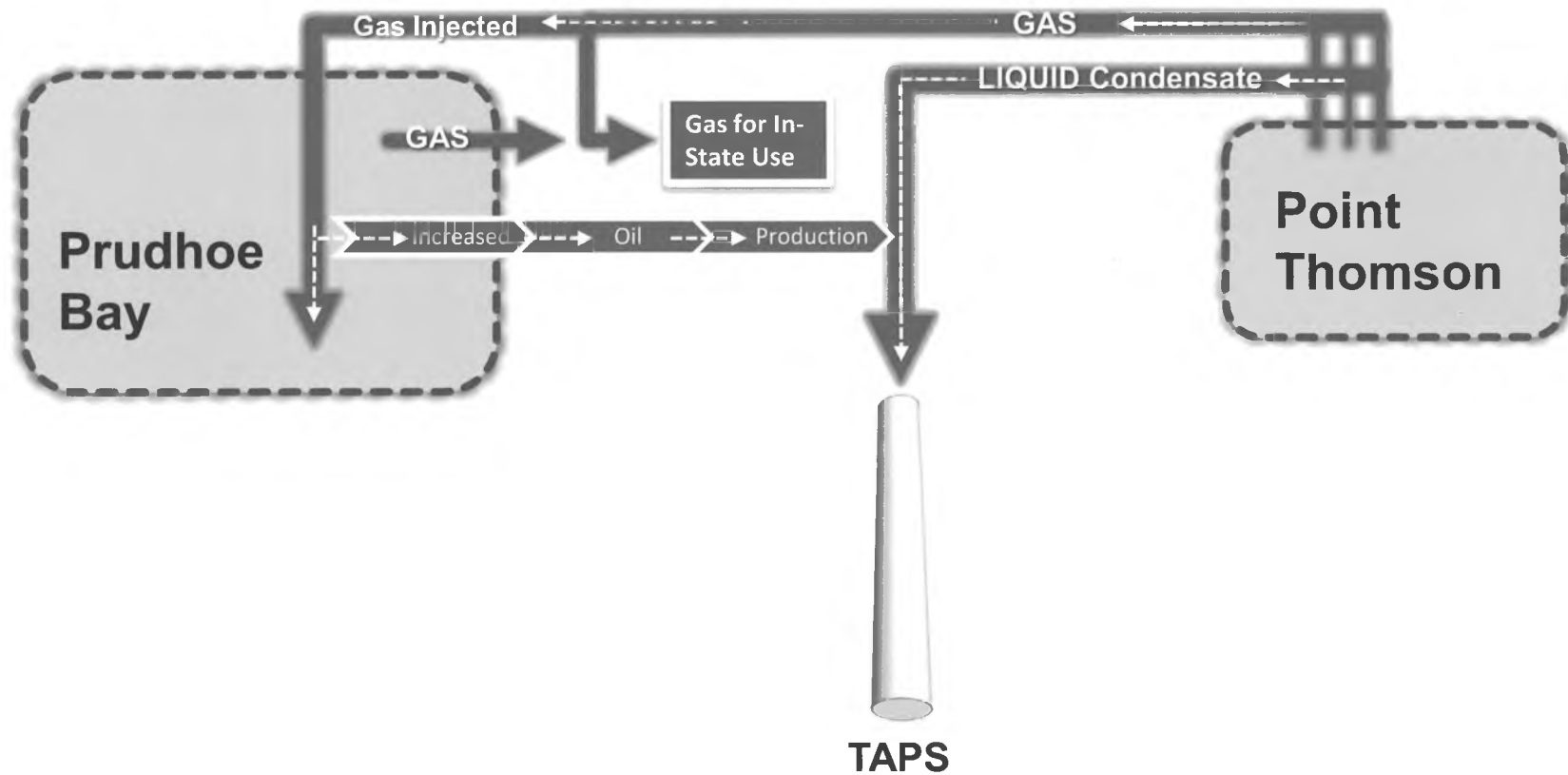
C. ALTERNATIVE C:

Expanded Liquids
Production into
TAPS, Enhanced
Prudhoe Bay
Recovery, and Gas
for In-State Use

- Requires complex reservoir integration between Prudhoe Bay and PT
 - PT dry gas produced, transported and injected into Prudhoe Bay
 - This will significantly increase oil production and enhanced oil recovery at Prudhoe Bay into TAPS
 - Includes significant liquids production from PT into TAPS
- Essentially a hybrid between Alternative A: MGS and Alternative B: Expanded Liquid Production
- Significantly increases TAPS throughput
- Major investment, infrastructure and hydrocarbon pre-positioning required for this alternative will facilitate North Slope gas commercialization
 - Completes installation of infrastructure, including PT gas pipeline to Prudhoe Bay and additional wells and production facilities
 - Prudhoe Bay becomes a central collection point for critical North Slope gas
- Alternative C also requires that significant volumes of gas be available for in-state use from Prudhoe Bay no later than 2019
- Once PT gas is transmitted to Prudhoe Bay, state Royalty-in-Kind (RIK) gas is made available for in-state use
- This provides the state with an opportunity to plan for large-scale, in-state gas-use projects, e.g. GTL, methanol, gas sales, etc.
- This alternative could take place prior to or in conjunction with Alternative A or B

PT

OVERVIEW of ALTERNATIVE C

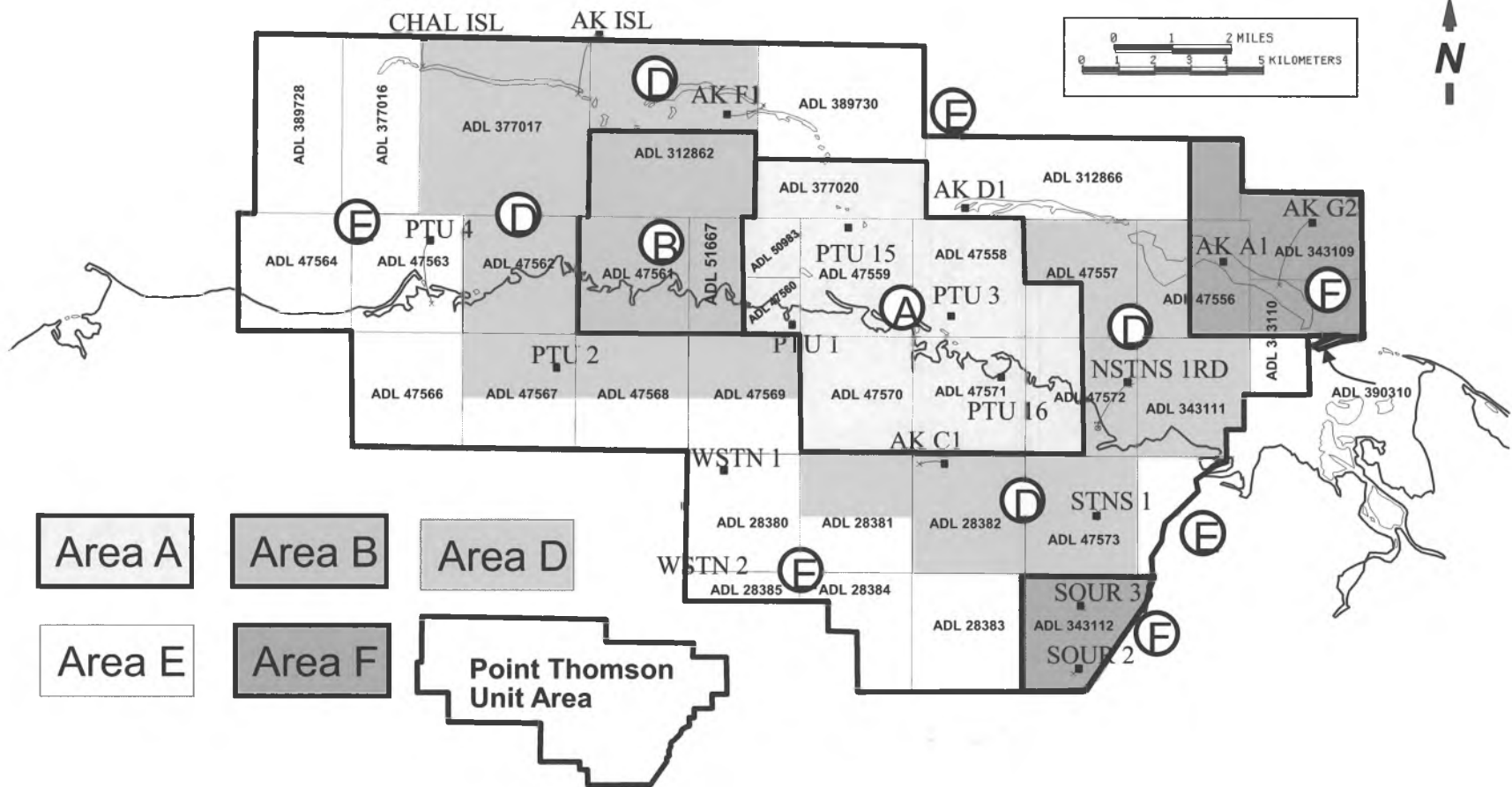


CONSEQUENCES & INCENTIVES RELATED *to* DEVELOPMENT PATH

- The settlement centers on one animating principle: Producers must *earn* acreage – more work, more commitments, more production secures more state acreage
- Key Goal: Keep parties focused on near-term production (IPS) and longer-term hydrocarbon production expansion (full-field development)
 - Settlement seeks to anticipate contingencies
 - Provides incentives for work completed
 - Provides for fair and expeditious dispute resolution
- The settlement also has severe consequences if the Producers fail to develop or expand development
- If Producers abandon the IPS/fail to keep the provisional work schedule, there will be a significant contraction of PT acreage by 2015
- If there is no IPS production and a MGS is not sanctioned by 2019, then the unit terminates and all acreage automatically returns to the state *without appeal*
 - This includes leases with capable wells
- If the Producers do not commit to expand production beyond the IPS, or do not sanction a MGS, then significant acreage contracts from the unit and automatically returns to the state *without appeal*
- If the Producers commit to expanded development, or sanction a MGS by 2019, but do not follow through, the unit will contract to the area in production
- If there is no commitment to Brookian oil formation production, then Brookian acreage automatically contracts in 2018 and returns to the state *without appeal*
- “*Without appeal*” is used throughout the agreement—it means that the Producers waive their right to appeal automatic termination of their leases to any tribunal in Alaska or the United States



POINT THOMSON UNIT



Area A	Area B	Area D
Area E	Area F	Point Thomson Unit Area

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

SEAN PARNELL, GOVERNOR

550 WEST 7TH AVENUE, SUITE 1400
ANCHORAGE, ALASKA 99501-3650
PHONE: (907) 269-8431
FAX: (907) 269-8918

Senator Hollis French
State Capitol, Rm. 417
Juneau, AK 99801

April 27, 2012

RE: Senate Judiciary Point Thomson Settlement Hearing

Dear Senator French:

I regret that I am unable to attend today's Point Thomson hearing. I am currently in Washington, D.C. meeting with senior executives and legislative branch officials to provide updates on Alaska gas opportunities and recent positive developments regarding commercializing North Slope gas. Another key focus of my meetings in Washington has been the Point Thomson EIS process. We are here to underscore the importance of ensuring that the federal government does not continue to delay the permitting process.

My discussions in Washington complement the conversations, meetings and outreach that my office has engaged in over the past several months, including my active engagement with private sector and government officials from Asia to educate them on the benefits and comparative advantages of Alaska natural gas.

We are entering a new era in the United States, with our nation now on the path to becoming the leading hydrocarbon resource producer. A window of opportunity has also opened for significantly increasing LNG exports to Asia. Demand for gas along the Pacific Rim is strong and there is a keen interest in Alaska gas. And, for the first time, the state's three producers on the North Slope are aligned with a state backed effort to move forward to commercialize North Slope gas and one of Alaska's largest gas fields is now moving forward with development after four decades of sitting idle.

We must be part of this new era. We have a massive hydrocarbon resource basin and are poised to advance a large-scale gas line that would benefit all Alaskans. But this window of opportunity will not be open for long and Point Thomson—which holds 25% of known gas reserves on the North Slope—plays a critical role. Just as the settlement agreement places the Point Thomson Working Interest Owners on a clock to move forward with timely development, the State of Alaska is also on a clock—we cannot afford another decade of this important hydrocarbon basin sitting idle.

Since we announced the Point Thomson settlement on March 30, 2012, we have sought to explain the details of the settlement to a variety of audiences and have been transparent in answering questions and clearing up misunderstandings about its provisions. I have been all over the state

"To responsibly develop Alaska's resources by making them available for maximum use and benefit consistent with the public interest."

doing this with community groups, Chambers of Commerce, editorial boards, and others. The Point Thomson settlement is complex and as I have stated numerous times, it is not perfect.

Like all settlements, it entails compromise and risk. It is important to note that in this case, there was significant risk to the state in staying the course on litigation that literally had no end in sight.

My Department is eager to answer all questions about this settlement agreement.

Sincerely,

A handwritten signature in cursive script, reading "Daniel S. Sullivan", followed by a horizontal line extending to the right.

Daniel S. Sullivan
Commissioner
Alaska Department of Natural Resources

STATE OF ALASKA

DEPARTMENT OF LAW

OFFICE OF THE ATTORNEY GENERAL

Sean Parnell, Governor

1031 WEST 4TH AVENUE, SUITE 200
ANCHORAGE, ALASKA 99501-5903
PHONE: (907)269-5100
FAX: (907)269-5110

April 26, 2012

VIA FAX TO (907) 278-7001 & 1ST CLASS MAIL

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

Re: Point Thomson Unit Settlement Agreement

Dear Mr. Walker and Mr. Richards:

I am in receipt of your letter to Department of Natural Resources Commissioner Dan Sullivan dated April 17, 2012 requesting reconsideration of the State of Alaska's entry into the March 29, 2012 settlement agreement with the Point Thomson working interest owners (the "Point Thomson Settlement"). Settlements entered into by the State of Alaska are not subject to administrative challenge, by reconsideration or otherwise. As the Attorney General for the State of Alaska, I have broad authority to enter into any settlement of litigation on behalf of the State of Alaska that I believe in the exercise of my discretion is in the best interests of the State. *See, e.g., Public Defender Agency v. Superior Court*, 534 P.2d 947, 950-51 (Alaska 1975). The exercise of this authority is not subject to administrative review.

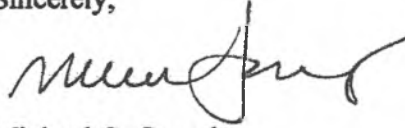
Commissioner Sullivan's signature to the Point Thomson Settlement and his findings in paragraph 5.8, recognize, among other things, that the Agreement addresses matters within the Department of Natural Resources' legislatively delegated authority and administrative expertise, and resolves disputed matters that arose as part of the agency's oversight of the Point Thomson Unit Agreement and the leases that encompass the unit. These findings do not give rise to a right to challenge or seek reconsideration of a settlement agreement entered into by the State of Alaska. The Point Thomson Settlement has been executed and all related litigation has been dismissed.

William Walker, Craig Richards
Re: Point Thomson Unit Settlement Agreement

April 26, 2012
Page 2

Thank you for your attention.

Sincerely,

A handwritten signature in black ink, appearing to read "Michael C. Geraghty". The signature is fluid and cursive, with a prominent vertical stroke on the right side.

Michael C. Geraghty
Attorney General

cc: Daniel Sullivan, Commissioner, Department of Natural Resources

CIRRICULUM VITA

MARK D. MYERS
9700 Tundra Loop Drive
Anchorage AK 99507
mdarmyers@gci.net
907 337-4863

QUALIFICATIONS

- Proven leadership skills and consensus building management style.
- Internationally recognized leader in energy and science policy.
- Senior executive and geologist with 23 years of Alaskan experience.
- Wide-ranging industry, state and federal government experience.
- Experienced at effectively communicating complex concepts to audiences ranging from grade school students to Governors, Congress, Cabinet Members and the President.

EDUCATION

Ph.D. Geology, University of Alaska Fairbanks, 1994.

Fields of Specialization: sedimentology, clastic depositional environments, surface and subsurface sequence analysis and sandstone petrography.

Dissertation: *Evolution of Late Cretaceous - Early Tertiary Depositional Sequences in the Beaufort-Mackenzie Basin, Canada.*

GPA 4.0

M.S. Geology, University of Wisconsin-Madison, 1981.

Fields of Specialization: stratigraphy, paleoecology, sedimentology.

Thesis: *The Stratigraphy and Sedimentology of the Upper Wonewoc Formation.*

Honors: Vilas Fellowship, Twenhofel Scholarship.

B.S. Geology and Geophysics, University of Wisconsin-Madison, 1977.

Honors: Sophomore Honors, Senior Honors Thesis, Graduation with Honors.

Military: Squadron Officers School
Air Command and Staff
Air War College
Air Force Pilot Training
Air Force Air Intelligence School

PROFESSIONAL LICENSES

Certified Professional Geologist – American Institute of Professional Geologists

Certified Petroleum Geologist – American Association of Petroleum Geologists

Licensed Geologist – State of Alaska

Commercial Pilot, land and sea, single and multiengine instrument airplane

WORK HISTORY

2011 Vice Chancellor for Research – University of Alaska Fairbanks

Oversee administration of the university's \$123-million-per-year research enterprise and supervises the university's standalone research institutes.

2009-2010 Alaska Natural Gas Inducement Act (AGIA) Coordinator

Served as the first Alaska Natural Gas Inducement Act Coordinator, a new position created under state statute and appointed by the governor. Responsible for building a new organization for overseeing and coordinating state agencies engaged in efforts to build a large diameter natural gas pipeline from the North Slope of Alaska to North American markets.

2006-2009 Director of the United States Geologic Survey

Appointed by President and confirmed by the Senate as the 14th Director of the United States Geological Survey (USGS). Managed the nation's largest water, earth, and biological science and civilian mapping agency. Responsible for nearly 9000 employees in 400 locations worldwide, with a total annual budget of more than \$1.4 billion. Some key accomplishments include revitalizing the USGS climate change and the national civilian mapping programs, implementing a new ten year interdisciplinary science strategy throughout the agency, advancing the development of the Landsat 8 (LDCM) satellite and releasing the entire 35 year Landsat data library at no charge to the public, implementing a new regional structure for the USGS, building strong partnerships with state and national organizations and agencies, and significantly increasing the USGS budget in a very challenged budget environment. Testified before Congress on many issues including water quality, geothermal energy, climate change, satellite operations, and the Department of the Interior budget. Served on many national and international science and environmental committees.

**2001-2005 State of Alaska Division of Oil and Gas Director/State Geologist/
Director of the State Division of Geological and Geophysical Surveys**

Appointed by Governors Knowles and Murkowski as the Director of the Division of Oil and Gas. Managed the State of Alaska's oil and gas resources. The division's responsibilities include resource evaluation, leasing, unitization, permitting, royalty accounting, auditing, sale of royalty oil and gas, permitting and inspecting. Managed a professional staff of approximately 90 professionals including geoscientists, engineers, land managers, accountants, commercial analysts and auditors. For FY 2005 petroleum revenue from assets managed by the division produced \$1.9 billion in royalties and lease sale bonuses and rents. Restructured the organization and nearly doubled the division's budget and staffing. This resulted in Alaska receiving significantly more income from its oil and gas resources, and a record amount of acreage under lease. Worked closely with the Alaska Legislature to develop and pass numerous oil and gas leasing, incentive and royalty modification statutes. Effectively managed relations with the public, industry, environmental organizations, native regional and village corporations, federal and local governments. Presented the concept of a North Slope natural gas hydrate evaluation program to the U.S. Senate. The proposal was strongly supported by the Alaska delegation and the Senate Energy and Natural Resources Committee and was incorporated into law with an authorization for \$70 million.

In addition to being the director of the Division of Oil and Gas, in 2005 I also served as state geologist and director of the Division of Geological and Geophysical Survey (the state survey). In that role I managed the state's geological and geophysical research organization of 38 scientists and support staff. The state survey generates, analyzes and interprets data on geologic resources and natural conditions; maps and inventories mineral and energy resources on state land for use by government, private industry, scientists, educators and the public.

**1998-2001 ARCO Alaska, Inc./Phillips Alaska Inc.
Sr. Staff Geologist - Exploration**

Developed Alaskan oil and gas exploration prospects for ARCO/Phillips, resulting in many lease purchases, wells drilled and three oil discoveries, two of which are producing today. Led and participated in North Slope geologic field programs.

**1990-1998 State of Alaska Division of Oil and Gas
Petroleum Geologist II**

Recognized expert on state oil and gas statutes, regulations and incentive programs. Hearing officer for the division. Authored numerous DNR commissioner and director decisions for discovery royalty, economic incentive credit, extended confidentiality and royalty reduction applications. Wrote regulations for and provided significant input on many key oil and gas bills before the legislature. Led and participated in geologic field programs. Performed pre-sale evaluation for oil and gas lease sales for the State of Alaska. Evaluated the oil and gas potential of federal onshore and offshore acreage for State of Alaska and provided expert testimony to U.S. Senate on ANWR. Managed statewide oil and gas evaluation of federal lands available for final state selection. My recommendations resulted in the state selecting over 3 million acres of additional land. Completed geological evaluations for State of Alaska in support of unitization, plan of development approval, and/or tract allocation factors for most North Slope oil fields.

**1987-1990 University of Alaska Fairbanks
Ph.D. Student and Intern with SOA Division of Oil and Gas**

**1985-1987 ARCO Alaska, Inc.
Development Geologist**

Development geologist responsible for two of the three production segments of the Kuparuk River oil field during the early stages of production. Created subsurface maps, developed drilling targets and extension exploration oil prospects, evaluated well results and seismic information.

**1983-1985 ARCO Alaska, Inc.
Exploration Geologist**

Developed exploration prospects in the Beaufort Sea. Well site geologist for wells on the North Slope, Beaufort Sea, Navarin Basin and Norton Sound. Led and participated in geologic field programs.

**1981-1983 ARCO Oil and Gas, Lafayette, LA
Extension Exploration Geologist**

Developed and evaluated extension exploration prospects and infield development wells in offshore and onshore Louisiana. Evaluated oil field properties for acquisition.

**1978 Chevron USA, New Orleans, LA
Exploration Geologist**

Performed regional subsurface geologic assessment of a large portion of the Louisiana Gulf of Mexico shelf.

1977-2003 Lt. - Lt. Colonel, USAFR

Pilot and Senior Intelligence Officer in the Air National Guard and Air Force Reserve

SELECTED INVITED TALKS IN PAST THREE YEARS

“Geoscience, Ideology and the Politics of Energy: What is the Role of Geoscience in the Development and Implementation of a Rational and Sustainable Energy Policy?” Alaska Geological Society, Anchorage, AK. February 18, 2010.

“Alaska’s Natural Gas Pipeline-Moving Forward-Securing North America’s Energy Future.” Canadian Institute’s Alaska Oil and Gas Conference. Anchorage, AK. September 15, 2009.

“Ecosystem Change: Managing Resources in an Uncertain Future.” Interstate Oil and Gas Compact Commission 2009 Midyear Issues Summit. Anchorage, AK. May 12, 2009.

“Domestic Natural Gas and Its Role Building the Nation's Energy Future.” Pipeline Opportunities Conference. Houston, TX. March 11, 2009.

“Science for a Crowded Planet.” Clarke Forum for Contemporary Issues, Dickinson College. Carlisle, PA. February 26, 2009.

“USGS Involvement in National LiDAR.” Federal Geographic Data Committee, Steering Committee. Washington, DC. December 16, 2008.

“Why Are Ecosystems Services Important and What are the Challenges in Including Them in Decisions?” Plenary Panel, Aces: A Conference on Ecosystem Services. Naples, FL. December 9, 2008.

“Opening Remarks for the United Nations Special Event.” Launch of Africa: Atlas of Our Changing Environment. New York, NY. September 22, 2008.

“An Integrated Strategy for Government-Sponsored Science.” 33rd International Geological Congress. Oslo, Norway. August 11, 2008.

“Facing Tomorrow's Challenges: Integrated Science for the Everglades.” Keynote for Plenary Session, Greater Everglades Ecosystem Restoration, 2008. Naples, FL. July 29, 2008.

“USGS in the 21st Century: Climate Science and New Directions.” Cirmount Mtnclim 2008. Silverton, CO. June 9, 2008.

“A Strategy for Integrating Science to Inform Public Policy.” American Meteorological Society Summer Policy Colloquium. Washington, DC. June 6, 2008.

“Facing Tomorrow's Challenges - in Minerals.” Arizona Geological Society. Tucson, AZ. June 3, 2008.

“Elevating USGS Science with LiDAR.” Remarks at the Second National LiDAR Conference. Reston, VA. May 21, 2008.

“Science, Society, and the Importance of Earth Observations.” Maryland Space Business Roundtable. Greenbelt, MD. May 20, 2008.

“Integrating Data to Accelerate Integrated Science.” USGS GIS 2008, 7th Biennial GIS Workshop. Denver, CO. May 13, 2008.

“Building a More Resilient Nation.” National Earthquake Conference. Seattle, WA. April 23, 2008.

“Facing Tomorrow's Challenges.” Association of American Geographers 104th Annual Meeting. Boston, MA. April 16, 2008.

“Climate Change Perspectives and Advances in Mapping.” Eastern Lands and Resources Council & Western States Land Commissioners Association, Joint Spring Conference on Emerging Challenges for Public Land Managers. Washington, DC. April 7, 2008.

“USGS Integrated Science - In and Beyond Maine.” Maine Water Conference. Augusta, ME. March 19, 2008.

“Moving the National Map.” Alaska Surveying and Mapping Conference. Anchorage, AK. February 25, 2008.

"Science, Society, and the Future of Earth's Resources." Launch Event for the International Year of Planet Earth, UNESCO. Paris, France. February 12, 2008.

"An Enlightened Energy Future: Understanding the Challenge." Plenary Roundtable, Tackling Global Change: Key Energy and Technology Issues for Stabilization, 8th National Conference on Science, Policy and the Environment. Washington, DC. January 16, 2008.

"USGS Scientific Contributions to Understanding Global Energy Resources." International Symposium on Circum-Pacific Petroleum and Alternative Energy Resources. Beijing, China. October 17, 2009.

"Facing Tomorrow's Challenges, Science in the Coming Decade." Keynote presentation, American Institute of Professional Geologists 44th Annual Meeting. Travis City, MI. Oct 7, 2007.

"USGS Role in Framing the Climate Change Challenge." Tribal College Forum. Bismarck, ND. September 4, 2007.

"Restoration in the Spirit of Cooperation." National Conference on Ecosystem Restoration (NCER-07). Kansas City, KS. April 23, 2007.

"USGS Natural Hazards Science in the Coming Decade." Association of American Geographers Annual Meeting. San Francisco, CA. April 19, 2007.

"USGS Science: Facing Tomorrow's Challenges." Georgia Water Resources Conference. University of Georgia. Athens GA. March 28, 2007.

"Renewable and Non-renewable Energy Resources on the U.S. Landscape." North American Wildlife and Natural Resources Conference. Portland, OR. March 21, 2007.

"Opening Remarks for the International Polar Year National Launch Event." National Academy of Sciences. Washington, DC. February 22, 2007.

"Science to Support the Nation's Choices for its Natural Resources." Alaska Miners Association. Anchorage, AK. November 8, 2006.

PUBLICATIONS

Flores, R.M., Myers, M.D., Houseknecht, D.W., Stricker, G.D., Brizzolara, D.W., Ryherd, T.J., and Takahashi, K.I., 2007, Stratigraphy and facies of Cretaceous Schrader Bluff and Prince Creek Formations in Colville River Bluffs, North Slope, Alaska: *U.S. Geological Survey Professional Paper 1748*, 52 p.

Flores, R.M., Stricker, G.D., Decker, P.L., and Myers, M.D., 2007, Sentinel Hill Core Test 1—facies descriptions and stratigraphic reinterpretations of the Prince Creek and Schrader Bluff Formations, North Slope, Alaska: *U.S. Geological Survey Professional Paper 1747*, 31 p.

Myers, M.D., 2007, Forward, in Facing Tomorrow's Challenges, U.S. Geological Survey Science in the Decade 2007-2017: *USGS Circular 1309*, pp. v-vi.

Myers, M.D., 2007, USGS: Science to Understand and Forecast Change in Coastal Ecosystems: *Sea Technology*, v. 48, no. 1. pp. 11-12.

Myers, M.D. et al., 2007, USGS Goals for the Coming Decade: *Science*, v. 318, no. 5848, pp. 200-201.

Myers, M.D., 2002, Depositional architecture of slope-apron and basin-floor turbidite systems from the North Slope of Alaska to the Mackenzie Delta of Canada; examples from outcrops and oilfields: *AAPG Bulletin*, v. 86, no. 6, pp. 1154-1155.

Myers, M.D., 2001, Y2K+1: The Transformation of Alaska's Oil and Gas Industry (One Geologist's Perspective on Megatrends, Challenges, and Opportunities: *Alaska Geology*, v. 30, no. 7, pp. 1,4.

Flores, R.M., Myers, M.D, Stricker, G.D. Houle, J.A., 1999, Core lithofacies analysis and fluvio-tidal environments in the AK 94 CBM-1 well, near Wasilla, Alaska: *US Geological Survey Professional Paper 1614*, pp. 57-72.

Morris, W.R., Myers, M.D., Bannan, D.B., Hannon, R.C., 1998, Stratigraphic Architecture and Facies Association of the Turbidite Elements in Deep Water Slope Apron Deposits of the Cuesta Creek Member, NW Territories, Canada): *The Alaska Geological Society 1998 Science and Technology Conference "Cutting Edge in Alaska"*.

Myers, M.D., Flores, R.M., Stricker, G.D., Houle, J.A., 1998, Depositional Environments and Reservoir Characteristics of the Tertiary Tyonek Formation, Upper Cook Inlet, Alaska: *The Alaska Geological Society 1998 Science and Technology Conference "Cutting Edge in Alaska"*.

Nilsen, T.N., Myers, M.D., and Moore, T.E., 1998, Re-evaluation of the depositional environment of the Tingmerkpuk Sandstone (Neocomian), Northwestern DeLong Mountains: *Alaska Division of Geological and Geophysical Surveys, Public Data File report*.

Kornbrath, R.W., Myers, M.D., Krouskop, D.L., Meyer, J.F., Houle, J.A., Ryherd, T.J., Richter, K.N., 1997, Petroleum Potential of the Eastern National Petroleum Reserve- Alaska: *State of Alaska, Department of Natural Resources, Division of Oil and Gas Report*, 30 p.

Myers, M.D., 1996, Sedimentology of Coarse-grained Basinal Lowstand Deposits of the Middle Brookian Sequence: An Outcrop Based Study: *Alaska Geology*, v. 25, no. 5, pp. 1,4.

Bundtzen, T.K., Wiltse, M.W., Myers, M.D., 1995, The Role of Geology in the Selection of Alaska's Statehood Land: *Abstracts with Programs, Geological Society of America, Cordilleran Section*, v. 27, no. 5, p. 8.

Myers, M.D., 1995, Depositional Processes and Reservoir Continuity Within Coarse Grained Basinal Lowstand Deposits of the Middle Brookian Sequence: An Outcrop Study: *Abstracts with Programs, Geological Society of America, Cordilleran Section*, v. 27, no. 5, p. 67.

Myers, M.D., Smith, T.N., Krouskop, D.L., and Ryherd, T.J., 1995, Paleogeographic and Sequence Stratigraphic Reconstruction of the Cretaceous Nanushuk Group, Central North Slope, Alaska: Slope Mountain Outcrop to Lupine #1: *Abstracts with Programs, Geological Society of America, Cordilleran Section*, v. 27, no. 5, p. 67.

Myers, M.D., 1994, Alaskan Opportunities: State Hoping to Attract Independents: *The American Oil and Gas Reporter*, v. 37, no. 11, pp. 114-116.

Myers, M.D., Smith, T.N., Krouskop, D.L., and Ryherd, T.J., 1993, Sequence Stratigraphy of the Cretaceous Nanushuk Group, Central North Slope, Alaska: Slope Mountain Outcrop to Lupine #1 Well: *American Association of Petroleum Geologists 1993 Annual Convention Official Program*, p. 151.

Myers, M.D., 1992, Facies Variations in the Fish River Sequence: *American Association of Petroleum Geologists 1992 Annual Convention Official Program*, p. 95.

Myers, M.D., 1992, Depositional Environments and Sandstone Distribution Within the Fish River Sequence: *International Conference on Arctic Margins, ICAM Abstracts, Alaska Geological Society*, p. 40.

Riefenstahl, R.R., Myers, M.D., 1992, Kemik Sandstone: An Environment of Deposition Interpretation from a Canning River Section, North Slope, Alaska: *International Conference on Arctic Margins, ICAM Abstracts, Alaska Geological Society*, p. 51.

Myers, M.D., 1990, Sedimentology of the Maastrichtian Cuesta Creek Member, Tent Island Formation, northern Yukon and Northwest Territories: *Geological Association of Canada-Mineralogical Association of Canada Annual Meeting Program with Abstracts*, v. 15, p. A94.

Myers, M.D., and Smith, T.N., 1990, Secondary Porosity in immature Late Cretaceous and Tertiary sandstones, northeast Alaska and northwest Canada: *American Association of Petroleum Geologists Bulletin*, v. 74, no. 5, pp. 727-728.

Pessel, G.H., Robinson, M.S., Clough, J.G., Imm, T.A., Reifensstahl, R.R., Ryherd, T.J., Myers, M.D., and Mull, C.G., 1990, Preliminary Geologic Map of the Gilead Creek Area, Sagavanirktok A-2 Quadrangle, Arctic Foothills: *Alaska, Alaska Division of Geological and Geophysical Surveys, Public Data File 90-18*, 6 p., 1 sheet.

Robinson, M.S. and Myers, M.D., 1990, Colville River Geologic Transect: Vitrinite Reflectance, Palynology, TAI, and Fission Track Data, Central North Slope, Alaska: *Alaska Division of Geological and Geophysical Surveys, Public Data File 90-12*, 5 p., 1 sheet.

Myers, M.D., 1989, Petrography of Upper Cretaceous and Lower Tertiary Sandstones: Beaufort-Mackenzie Basin: *Alaska Division of Geological and Geophysical Surveys, Public Data File 89-27*, 16 p., 1 sheet.

Myers, M.D., Crowder, R.K., and McGowen, J.H., 1989, Sedimentology of Upper Cretaceous-Paleocene strata of the Beaufort-Mackenzie basin, Canada: *Abstracts with Programs, Geological Society of America*, v. 21, no. 5, p. 121.

PAST ORGANIZATIONAL LEADERSHIP POSITIONS

Co-Chair of the Plenary Session and Head of United States Delegation for Group on Earth Observation (GEO-V), Bucharest, Romania, November 19-20, 2008.

Member of the Interagency Coordinating Committee of the National Earthquake Hazard Reduction Program (NEHRP).

Ex-officio Member of the Roundtable on Environmental Health Sciences, Research, and Medicine, Institute of Medicine of the National Academies.

Member of the National Science and Technology Council (NSTC).

Member of the International Polar Year, U.S. Government Leadership Panel.

Principal of the United States Climate Change Science Program.

Member of the Interagency Arctic Research Policy Committee (IARPC).

Chairman of the Civil Applications Committee (CAC).

Past President/Board Member – Alaska Geological Society.

Member of the House of Delegates of the American Association of Petroleum Geologists.

AWARDS AND HONORS

The Meritorious Service Medal, United States Air Force

Medallion for Excellence, National Geospatial Intelligence Agency

Student Conservation Association Founders Medal

Outstanding Service and Exceptional Service Awards, Alaska Geological Society

Resolution of Congratulations and Commendation, Association of American State Geologists

Distinguished Alumni Award, University of Wisconsin-Madison, Dept of Geology and Geophysics

Wall of Excellence, LaCrosse Central High School

Index of Documents for
Presentation before Senate Judiciary Committee
April 27, 2012

1. Walker Letter 4-18-12
2. Walker Reconsideration PTU Settlement 4-17-12
3. PTU Settlement 3-29-12
4. BP, COP & XOM Letter 3-30-12
5. Definition Major Gas Sale Prudhoe Bay Operating Agreement 4-1-1977
6. AOGCC Rule 9 11-30-2001
7. Director Myer's Amended PTU Decision 10-27-05
8. Commissioner Irwin's Conditional Interim Decision 1-27-2009
9. PTU AGIA Findings (PetroTel) 5-16-2008
10. 11 AAC 83.303
11. Baxley Case 1998
12. Exxon Case 2001

1 & 2

BILL WALKER

2234 Kissee Court Anchorage, AK 99517
(907) 223-8530

E-mail: bill-wwa@ak.net

April 18, 2012

To Whom it May Concern:

On April 17, 2012, I moved for Commissioner Sullivan to reconsider his decision to enter into the Point Thomson settlement. The attached letter articulates the grounds for my appeal, which includes:

- No public notice or opportunity for public comment was provided in advance of the settlement being signed and announced.
- The agreement allows the working interest owners to retain development rights over the unit with no further work commitments.
 - One option allows the owners to maintain at least twenty-two of the leases indefinitely if they complete the 10,000 bbl/d gas cycling project that they had already made a firm commitment to construct in 2009 for the right to develop two leases.
 - A second option allows the owners to maintain the unit at least until the next decade, if they do no work at Point Thomson but permit without committing to construct a bullet line out of Prudhoe Bay. Since Prudhoe Bay has enough gas to fuel a bullet line for over a century, it does not make sense that such a project would excuse development at Point Thomson.
- Under the settlement, if the owners decide to develop the field, they have the discretion to blow down the reservoir without first undertaking a gas cycling project. The Department has previously concluded that depletion of the reservoir in that manner would result in the waste of approximately half a billion barrels of oil and condensates.
- The settlement purports to abrogate many of Commissioner Sullivan's statutory and regulatory obligations relating to field oversight, which the Alaska Supreme Court has held the Department may not do by contractual agreement.
- The Commissioner cannot agree to Exxon's acquisition of Chevron's interest in Point Thomson without further public process and findings.
- The agreement must be approved by the Legislature to be valid under Alaska law.

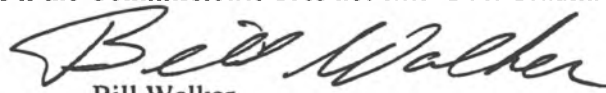
Consequently I have asked that the settlement be submitted to the Legislature for approval, with all the public process that necessarily follows, and that our Supreme Court has indicated is necessary. In the meantime, I requested that Commissioner Sullivan stay deciding

April 18, 2012

Page 2

reconsideration until such time as correspondence relating to the deal is made public and the Department publishes an explanation of the agreement sufficient for the public to understand its terms. Being well acquainted with the Point Thomson Unit Agreement, it appears that the State has given up far more than it would have, had it lost the lawsuit.

I encourage all Alaskans concerned about the manner in which the settlement was entered into, its terms or its legality, to submit written comments to the Commissioner by Monday, May 7th (at which time public comment will close if the Commissioner does not extend the deadline).


Bill Walker

WALKER & LEVESQUE, LLC

ATTORNEYS AT LAW
731 N Street
Anchorage, AK 99501
(907) 278-7000 ; Fax (907) 278-7001

DEPARTMENT OF
NATURAL RESOURCES

APR 17 2012

Email: craig-wwa@ak.net

April 17, 2012

COMMISSIONER'S OFFICE
ANCHORAGE

VIA PERSONAL SERVICE AND E-MAIL

Commissioner Dan Sullivan
Department of Natural Resources
State of Alaska
550 W. 7th Ave., Suite 1400
Anchorage, Alaska 99501
dnr.appeals@alaska.gov

Re: Reconsideration of the Point Thomson Settlement Agreement;
Former Superior Court Case No.: 3 AN-06-13751 CI (consolidated);
Former Supreme Court Case No.: S-13730 (consolidated);
Our File No.: 449-1.

Dear Commissioner Sullivan:

On March 29, 2012, the attorney general ("Attorney General") and commissioner ("Commissioner") of the Department of Natural Resources ("Department"), on behalf of the State of Alaska ("State") and acting through the Department, and the Point Thomson Unit ("PTU") working interest owners (each an "Owner" or "WIO" and collectively "Owner Group" or "WIOs"), finalized a settlement agreement ("Settlement" or "Agreement") relating to the Point Thomson Unit ("PTU").

The Settlement was the basis to dismiss ongoing litigation related to the Department's efforts to terminate the PTU. The parties before the Alaska Supreme Court, in Case No. S-13730 (consolidated), signed the Joint Stipulation for Dismissal of Petition for Review on March 27, 28 and 29, 2012.¹ That stipulation by stamp of the Court was filed at 3:20 p.m. on March 29, 2012 and by The Order Dismissing Petition for Review was granted on the same date. Similarly, the parties before the Alaska Superior Court, in Case No. 3AN-06-13751 CI (consolidated), filed a Joint Stipulation for Dismissal of Administrative Appeal on March 29, 2012, also granted by [Proposed] Order Dismissing Administrative Appeal on the same date by the Honorable Brian

¹ Susan Orlansky of Feldman Orlansky & Sanders signed on behalf of BP Exploration (Alaska), Inc. ("BP"), and Stephen M. Ellis of Delaney Wiles, Inc. on behalf of Chevron U.S.A. Inc. ("Chevron") signed on March 27, 2012; Spencer C. Sneed of Dorsey & Whitney LLP on behalf of ConocoPhillips Alaska, Inc. ("ConocoPhillips"), Barat M. LaPorte of Patton Boggs LLP on behalf of Exxon Mobil Corporation ("Exxon" or "Unit Operator"), David B. Rusk of David B. Ruskin, P.C. of Leede Operating Company, LLC ("Leede"), and Mathew T. Findley of Ashburn & Mason, P.C. on behalf of the State signed on March 29, 2012.

Clark, Superior Court Judge *pro tem*. That joint stipulation was signed by counsel for the parties on the same dates as the Joint Stipulation for Dismissal of Petition for Review before the Alaska Supreme Court. Also on March 29, 2012 the parties filed and were granted, by Judge Clark, a Joint Motion to Vacate February 11, 2010 Partial Stay; Request for Expedited Consideration, which had attached a copy of the Settlement signed by the parties on March 28 and 29, 2012.² The rushed nature of these dismissals is particularly concerning given Settlement ¶¶ 4.10.1 and 4.10.3.2 provided for vacating the cases in an orderly manner, within 10 days or so after execution of the Agreement. Yet it occurred in secret, by expedited motion, a day before the deal became public. Those pleading are attached as Exhibit 1.

On March 30, 2012 the Settlement was announced to the public via a press conference held by State Governor Sean Parnell and the Commissioner (audio file of the press conference attached as Exhibit 2), in which a letter dated March 30, 2012, signed by the respective Presidents of BP, Exxon and ConocoPhillips (Exhibit 3), announced a plan to mutually assess, in conjunction with the State and Alaska Gasline Inducement Act, AS 43.90 *et seq.* ("AGIA") licensee, a liquefied natural gas ("LNG") export project from South Central Alaska.

The Settlement broadly encompasses terms relevant to the future development of the PTU, Prudhoe Bay Unit ("PBU"), and an Alaska North Slope ("ANS") gas commercialization project. It purports to bring definitive resolution to such subjects as *inter alia*: (i) disputes as to the termination of the PTU and underlying leases; (ii) creation of participating areas within the PTU; (iii) the expansion and contraction of acreage into and out of the PTU; (iv) the plan of development ("POD") for the PTU; (v) certain terms in the event of a major gas sale; (vii) reinjection of PTU gas into the Prudhoe Bay Unit; (viii) the use of and accounting for the State's royalty gas out of the PTU and into the PBU after reinjection; (ix) the taxation of PTU gas; (x) advanced approval of reassignment of the WIOs interests in the PTU, presumably including Exxon's acquisition of Chevron's interests in the PTU; and (xi) the procedure for handling future disputes of these subjects.

As will be discussed further, upon initial review it does not appear to William M. Walker, a citizen taxpayer of the State ("Walker"),³ that the substantive terms of the settlement are advantageous to the future development of the PTU or ANS gas commercialization efforts. Additionally, the Department and Owner Group have attempted to settle a host of issues associated with ANS development, but have done so without any of the public process, regulatory action, and legislative approvals contemplated by Alaska law. Settlement ¶ 5.8 provides that the Agreement constitutes a finding of the Commissioner. So although the authority of the State to enter into the Settlement, and the correct procedures the State must follow to do so, are disputed, it appears the proper vehicle for Walker to challenge the Settlement is as a request for reconsideration under 11 AAC 2.010(f). Consequently Walker asks the

² Attorney General Michael C. Geraghty signed on March 28, 2012; Commissioner Daniel S. Sullivan, Randy L. Broiler of Exxon, John C. Minge of BP, Trond-Erik Johansen of ConocoPhillips, and John G. Leede of Leede signed on March 29, 2012.

³ Walker claims standing to bring this appeal, not only as a citizen taxpayer, but as a result of interest-injury, third-party, and any other form of standing recognized by the Alaska Supreme Court.

Commissioner to reconsider his decision to enter into the PTU Settlement as: (i) not in the best interests of the State; (ii) in contravention to State law and regulation; (iii) unconstitutional; and (iv) *ultra vires* without legislative approval. The specifics of Walker's points of appeal are detailed below.

Please serve any notice, decision or other correspondence to the following address:

Craig Richards
Walker & Levesque, LLC
731 N Street
Anchorage, Alaska 99501

- I. **The Settlement is Not in the Best Interests of the State of Alaska.**
 - A. **The State Has Not Previously and Should Not Now Enter into Bargains of This Magnitude With the Three Primary ANS Producers With No Public Process.**

It is irrefutable that ANS oil production is dominated and will continue to be dominated in the coming decades by affiliates of ConocoPhillips, Exxon and BP.⁴ Perhaps the most telling evidence of this phenomenon is that, even though TAPS has been in operation for three decades, there is only one independent shipper. It is equally clear that the same integrated producers expect to dominate ANS natural gas production when and if they concede to commercialization of that resource.⁵ This dynamic has resulted in an unflattering history where the companies have used their market dominance to negotiate, or attempt to negotiate, large scale concessions from the State outside of a traditional competitive process that should otherwise be expected in dealings with a sovereign government. Some of the more notorious of those deals are: (i) the TAPS Settlement Methodology; (ii) renegotiation of the North Star leases; (iii) BP's attempted acquisition of Atlantic Richfield Company's Alaska's assets, resulting after Federal Trade Commission intervention in the Charter for Development of the ANS;⁶ and (iv) the proposed Stranded Gas Development Act Contract negotiated by the Murkowski Administration.

But even these company specific deals pale in comparison to the Settlement in one material aspect. Never before has a deal of the magnitude of the Settlement been entered into by the State and ANS producers without public notice and the opportunity for public comment. It is simply unprecedented in the annals of Alaska history for the executive branch to attempt to bind

⁴ Amended Decision Upon Reconsideration Following Trial De Novo, 2006 Assessed Valuation of the Trans Alaska Pipeline System ("TAPS") at ¶ 104 (October 26, 2010) (Exhibit 4); Decision Following Trial De Novo, 2007, 2008, 2009 Assessed valuations of the TAPS at ¶ 70 (December 30, 2011) (Exhibit 5).

⁵ See, e.g., Exhibits 7.1, 7.2 and 7.3.

⁶ See State Department of Environmental Conservation website for documents related to the Charter, which are incorporated into the record by reference herein <available at <http://dec.alaska.gov/spar/ipp/nscharter.htm>>.

the citizenry to such a sweeping set of concessions, with no public involvement and without legislative approval.

B. Form of the Administrative Record.

Walker has had less than twenty days to review the Settlement, and has not had the opportunity to compare his understanding of its terms against that of the parties or review any of the correspondence between the State and Owner Group. Consequently Walker bases his understanding of it and the surrounding deal relating to gas pipeline development primarily on a reading of the document and the attached exhibits. Walker acknowledges that the reading of one or more of the portions of the Settlement, and intent behind them, may be incorrect. However, a thorough public vetting of the Agreement is the proper way to ensure the public has an understanding of its terms, it is in the best interests of the State, and it is legally entered into by the current administration.

Walker also incorporates herein, and requests the Department make part of the record of this motion to reconsider, the administrative record and court pleadings in the Point Thomson Cases (as that term is defined in Settlement ¶ 1.8) and 3AN-05-12486. Additionally, Walker requests that all correspondence between any member of the Parnell Administration and any WIO relating to the Settlement or a potential settlement of the Court Cases, dated on or after January 1, 2010, be included in the administrative record. As provided by 11 AAC 02.030(d), because public notice was not provided by the Department 30 days in advance of the Settlement, Walker intends to file additional written materials within the longer of 20 days or the term of the stay requested in Part III below. Walker also undertakes this action as a public interest litigant, and consequently requests that the administrative record be prepared at the State's expense. If the Commissioner will not agree to that request, please provide Walker with advance notice before any costs chargeable to him are incurred.

C. A Summary of Certain Terms of the Settlement That Demonstrate it is Not in the Best Interests of Alaska.

In this Subpart C Walker describes his understanding of the Settlement at a high level. Capitalized terms not otherwise defined are meant to have the meaning given them in the Settlement.

1. The Owner Group Will Maintain Most if Not All of the PTU Acreage With Little or No Additional Work Commitments.

The Settlement contemplates a myriad of confusing potential options and outcomes for development of the PTU. Time and time again, however, Exxon has shown it will pursue the smallest work commitment the Department allows. In the Settlement, that appears to be one of two options. The first option is to go forward with the IPS Project, which is the 10,000 barrel per day ("bbl/d") cycling project *already committed to in 2009 to keep two leases*. If that route is taken most, if not all, of Point Thomson will be held in perpetuity by the Owner Group. Walker does not believe that the Department surrendering those additional leases for no work commitments is in the State's best interests.

But of course the Settlement no longer even requires the WIOs to undertake the previously committed to IPS Project. The second option is to Sanction a Major Gas Sale for, but not necessarily build, a bullet line project out of Prudhoe Bay. That will obviate the need for the Owner Group to do any work at Point Thomson, or even connect it by pipeline to other ANS infrastructure, yet will preserve the Owner Group's right to the acreage well into the next decade. Walker does not believe it is in the State's best interests to allow a bullet line from Prudhoe Bay, which itself has sufficient gas for such a project for approximately 125 years, to result in the Owner Group being able to continue to warehouse Point Thomson resources. And when the field is developed, Walker does not believe it is in the State's best interests, given the current available evidence, to allow the Owner Group to blowdown the reservoir without cycling, which under the Department's previous analysis will result in the physical and economic waste of condensates and oil of a value greater than the Alaska Permanent Fund.

A discussion about specific portions of the Settlement related to development options follows:

a. Under Settlement ¶ 4.1.1 the Owner Group agreed as part of the IPS Project to drill the PTU 15 and PTU 16 wells, already completed by 2010, and has the option to put those wells into production at 10,000 bbl/d no later than May 1, 2016 and to construct the liquid hydrocarbon pipeline from the PTU to Badami. This option is the same development project that was previously a firm commitment, delayed from 2014, that the Owner Group made in January 2009 to secure two leases (ADL47559 and 47571).⁷ Thus the Owner Group has already been working on this project including the expected 10,000 bbl/d condensate production and 70,000 bbl/d hydrocarbons liquid line that will connect to Badami,⁸ only the formerly firm commitment is now an optional one under the Settlement.

b. Also part of the IPS Project, in Settlement ¶¶ 4.1.2 and 4.1.3, the WIOs have the option to drill a Thomson Sand well from the West Pad by May 1, 2017, and to continue permitting an East Pad well.

c. Under Settlement ¶ 4.2.2 the IPS Project commitments are not mandatory. If the Owner Group Abandons these projects by 2015 the Owners still maintain core unit acreage in the 9 leases listed in Area A of Exhibit C through year-end 2019 (and if they have spudded the West Pad well by year-end 2016 they will keep the acreage in the 3 leases listed in Area B of Exhibit C). Further, if between 2007 and year-end 2015 the Owners spend more than \$2.0 billion on Point Thomson Development, they will automatically keep the acreage in the 13 leases listed in Area D of Exhibit C also through year-end 2019.

⁷ Commissioner Irwin stated in his approval of the project that the WIOs "have unconditionally committed to bring those two wells on the two leases into production by 2014." Conditional Interim Decision (January 27, 2009) (Exhibit 8). *See also* Transcript of Hearings, Before Commissioner Thomas Irwin (January 12 to 16, 2009) (Exhibit 9).

⁸ *See, e.g.*, Testimony of Paul Carson, 3 AN-06-8446CI, Tr. 3149 – 50, 3190 – 93, 3212 – 14 (September 11, 2011) and Testimony of Charles Cicchetti, 3 AN-06-8446CI, Tr. 8444 – 8446 (October 13, 2011) (Exhibit 10).

d. By spending \$2.0 billion on Point Thomson Development, the Owner Group, with no firm development commitments, has the right to unitize and maintain some or all of 22 of the 38 leases, that overly the core acreage, through year-end 2019. Since no accounting of the amount spent from 2007 to date was provided in the Settlement, it is unclear if the Owners had met that spending threshold as of the date of the Agreement. However, based upon the fact that the spending amount is back dated, there are no rules for how to do the accounting, the State only gets the information on spending if the IPS Project is Abandoned, and the definition of what goes towards the \$2 billion is worded broadly enough to encompass work done since 2007 on various ANS projects outside the PTU or on a gas pipeline project,⁹ it can only be assumed the \$2 billion threshold will be met as a matter of course.¹⁰

e. If the WIOs keep their prior commitment made in 2009 to maintain ADL 47559 and 47571, and put the two wells drilled in 2010 into production by year-end 2019, then under Settlement ¶ 4.5.3 the Owners automatically get to keep all or part of the 23 leases now part of the PTU (9 or 12 leases if the \$2 billion was not spent depending on if the West Pad well is spudded).¹¹ Further, because the PTU would now be under production all of this acreage will be held in perpetuity by the WIOs under the habendum clause in Section 21(c) of the PTU Agreement.

f. The WIOs also get to wrap into the PTU and maintain indefinitely additional acreage if by year-end 2019 they expand liquid production by 10,000 bbl/d (and even more acreage if 20,000 bbl/d) or Sanction a Major Gas Sale, or if by year-end 2018 they have a POD for the Brookian formation underlying Area F of Exhibit C. Since all that maintaining the Brookian requires is an approved POD by 2019 under Settlement 4.7, the agreement effectively pushes off any decision on the development of the 5 leases in Area F of Exhibit C for half a decade, at which time the POD process starts over for that acreage.

g. Pursuant to Settlement ¶ 4.5.2 if by year-end 2019 IPS Project Start-UP has not occurred, or a Major Gas Sale Sanctioned, then the Department may theoretically terminate the PTU Without Appeal.

1) However, Settlement ¶¶ 4.4.2, 4.5.1 and 4.5.7 appear to provide if a Major Gas Sale is Sanctioned by year-end 2019 then the PTU is fully reconstituted to include all the acreage except the Brookian in Area F of Exhibit C (which will be separately maintained by simply filing for a POD by year-end 2018). When the definitions of Major Gas Sale and Sanction are reviewed in Settlement ¶¶ 2.16 and 2.28, all that is required for this outcome are

⁹ It is unclear from the Settlement what qualifies as "other work activities" under ¶ 2.19 that count toward the \$2 billion threshold, such as funds spent by the Owner Group on projects relating to Prudhoe Bay gas reinjection, the Badami oil system, or in furtherance of a Major Gas Sale (e.g., on the Denali Pipeline Project, Alaska Pipeline Project under the Alaska Gasline Inducement Act, a large diameter or bullet line liquefied natural gas project to tidewater).

¹⁰ Regardless, if the Owners spend less than \$2.0 billion they similarly lock up all or part either 9 or 12 of the most productive leases (depending on whether a the West Pad well is drilled).

¹¹ The exception is that under Settlement ¶ 4.5.3.1 the northern half of ADL 377017 will be released from the PTU.

receipt by the State of corporate approvals and firm transportation service agreements "sufficient to proceed to construction," and necessary regulatory approvals issued, for a "pipeline project having a design through put of more than 500 million cubic feet of gas per day that results in delivery of gas off the North Slope of Alaska." No construction commitments, or even a final investment decision, are mandatory. It is also worth noting that this option does not require development of the PTU given Major Gas Sale Sanction of a project relying solely on Prudhoe Bay gas satisfies these conditions. Yet once a Major Gas Sale is Sanctioned under Settlement ¶ 4.5.1 then the reconstituted PTU is in effect, and the POD process starts over again. It would consequently appear the WIOs, at the end of 2019, having done no work on the field, have maintained the entirety of the unit by getting the paperwork in order to undertake a bullet line or large diameter pipeline project (without any actual commitment to go forward) from Prudhoe Bay. This is notwithstanding a 500 million cubic feet per day off-slope pipeline would not need gas from a source, such as the PTU, other than the PBU for approximately 125 years.

2) It also seems, although the provisions are incredibly difficult to understand and vague, that a Major Gas Sale Sanction or an IPS Project is not necessary to keep the PTU alive past year-end 2019 if before that date an Expansion Project POD is submitted. It appears nothing requires the Expansion Project POD to result in any actual work under the definition of Commit at Settlement ¶ 2.4, so long as if before the Expansion POD is submitted some internal sanctioning has occurred which document an obligation to proceed diligently (sanctioning that can presumably be revoked at a later date). Walker has not yet been able to figure out which acreage survives under an Expansion Project POD past 2019, but the consequence seems to be to start the POD process anew in the post-2020 era.

Thus for little or no consideration beyond the work commitment to produce 10,000 bbl/d of condensates made in 2009 to maintain ADL 47559 and 47571, the State has agreed to allow the PTU to remain in effect indefinitely (with the potential for some acreage contracting out). Alternatively the WIOs can avoid the 2009 production commitment of 10,000 bbl/d but get the paperwork completed to undertake, but not actually commit to, a small or large diameter off-slope pipeline, or submit an Expansion Project POD, and at the end of 2019 restart the POD process on the entire PTU. And of course if the WIOs put the unit into production and Sanction a Major Gas Sale then, as confirmed by Settlement ¶ 4.5.6, the PTU now consists of all the leases, which are held in perpetuity by the 10,000 bbl/d of condensate production committed to in 2009 pursuant to the habendum clause in Section 21(c) of the PTU Agreement.

But the terms of the Settlement go even further.

2. The Settlement Attempts to Contract Around the Department's Regulatory Authority. Settlement ¶ 5.1.3 provides:

The Parties agree that this Agreement is a contract between the Parties. . . Application of standard administrative processes does not provide any right or basis for the State to alter the terms of this Agreement. DNR discretion and the authority to take action or make a decision regarding Point Thomson may only be exercised by DNR in a manner that . . . does not conflict with the terms of this Agreement.

It appears to be the intent of this provision to make the contractual terms of the Agreement control over the Department's regulations and other state law.

3. The Settlement Alters the Regulatory POD Process. Settlement ¶ 4.1.5 provides the IPS Project work plan laid out in the Settlement also acts as a substitute for plans of development otherwise mandatory under 11 AAC 83.343 and PTU Agreement Section 10. Thus rather than annual POD's, there will be no Departmental approvals of development plans until May 1, 2017 at the earliest. Then if a Major Gas Sale is Sanctioned, the process in 11 AAC 83.343 is again replaced with Settlement ¶¶ 4.6.1 and 4.6.4, such that the initial POD after Sanctioning "shall remain in effect for two years following that date and until a subsequent MGS POD is approved." Thus it appears the Department has lost the ability to terminate an otherwise non-producing unit by failing to approve a POD, and contractually altered the regulatory POD process for decades into the future. The Expansion Planning POD under Settlement ¶ 4.6.3 also substitutes an alternative process for that provided in 11 AAC 83.343 with apparently similar consequences if the WIOs go that route to maintain the PTU past year 2019. And not only has the Department forgone POD's through 2017, and contractually altered the regulatory process for later POD's, it has agreed that for most POD disputes, with several carve outs that the Department retains administrative decisional authority over, that the Department no longer has jurisdiction to hear them and instead under Settlement ¶ 5.1 disputes must be resolved by either the Superior Court or arbitration.

4. The Settlement Results in the Abrogation of the Commissioner's Obligation to Make Findings Under 11 AAC 83.303, Including Leaving the Method of Field Development to the WIOs. The net effect of the Settlement is that the Commissioner has used a contract to forgo his regulatory obligations to approve issues associated with the PTU. 11 AAC 83.303 provides that before the Commissioner can approve actions related to units he must evaluate and consider the proposed action in light of various factors, and then make particular findings.¹² Under .303(c) these findings must be explicitly made as to all unit approvals, including: "(1) an approval of a unit agreement; (2) an extension or amendment of a unit agreement; (3) a plan or amendment of a plan of exploration, development or operations; (4) a participating area; or (5) a proposed or revised production or cost allocation formula." Yet the sweeping Settlement contains numerous express and implied approvals without these findings, including one or more approvals as to each of items (2) to (5) in the prior sentence. Instead Settlement ¶ 5.8 contains a generic statement, "The Commissioner has determined that entry into

¹² The Commissioner must evaluate and consider that the proposed action will: "(1) promote conservation of all natural resources, including all or part of an oil or gas pool, field, or like area; (2) promote the prevention of economic and physical waste; and (3) provide for the protection of all parties of interest, including the state." 11 AAC 83.303(a). In evaluating those criteria the Commissioner must consider: "(1) the environmental costs and benefits of unitized exploration or development; (2) the geological and engineering characteristics of the potential hydrocarbon accumulation or reservoir proposed for unitization; (3) prior exploration activities in the proposed unit area; (4) the applicant's plans for exploration or development of the unit area; (5) the economic costs and benefits to the state; and (6) any other relevant factors, including measures to mitigate impacts identified above, the commissioner determines necessary or advisable to protect the public interest." *Id.* at 83.303(b).

this Agreement and individual terms and conditions set forth here are necessary or advisable to protect the public interest . . .”

For instance, the Commissioner’s obligation to approve development so as to promote conservation, and to prevent economic and physical waste, is a fundamental mandate of the Department.¹³ Yet the Settlement leaves the decision as to gas cycling (in terms of whether it occurs, in what volume, and for how long) to the discretion of the WIOs. The Department has not only abrogated its regulatory obligation to ensure the field is developed to promote conservation and prevent waste, but has agreed in Settlement ¶ 5.7 not to oppose the development approach ultimately selected by the WIOs before the Alaska Oil and Gas Conservation Commission (“AOGCC”).

It is incongruous that lengthy gas cycling or a gas blowdown can both be in the public interest, particularly in light of the long standing dispute between the Unit Operator and Department as the extent gas cycling is appropriate. Consider that in 2008 the report commissioned by the Department and adopted by Commissioner Irwin into the Alaska Gasline Inducement Act findings found: “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 for sale can be done at any time after gas cycling and recovery of the hydrocarbon liquids.”¹⁴ As to condensates, it was concluded cycling gas for 30 years will result in 86% recovery (420-415 million stock tank barrels (“MMSTB”)), 20 years of cycling 76% recovery (370-370 MMSTB), and 10 years of cycling 62% recovery (300-370 MMSTB).¹⁵ It further found that a gas blowdown will result in recovery of only 26% (127 to 156 MMSTB) of the in-place volume of condensates.¹⁶ The same study concluded recovery from the oil rim will also be substantially reduced by blowing down the reservoir early.¹⁷ In fact, under the Department’s analysis, a gas blowdown would result in the physical and economic waste of condensates and oil with a value that exceeds the Alaska Permanent Fund.

History, via innumerable past POD’s and testimony before the Department, demonstrates that the Unit Operator’s preferred method to develop the field is through a less capittally intense gas blowdown, yet the Department has previously concluded such a development approach will result in waste.¹⁸ There is nothing in the Agreement to support a finding that a gas blowdown could now be in the public’s interests, particularly if – as the Agreement allows – it does not occur for many years and no cycling project is commenced in the interim. The Settlement does not even provide for what has previously been viewed by the

¹³ 11 AAC 83.303(a).

¹⁴ Summary of Findings for Resource Assessment and Field Development Study of Thomson Sand, in the Point Thomson Area, North Slope Alaska at 3 (May 16, 2008) (Exhibit 11).

¹⁵ *Id.* at 14.

¹⁶ *Id.*

¹⁷ *Id.*

¹⁸ Denial of the Proposed Plans for Development of the Point Thomson Unit, Findings and Decision of the Director, Division Oil and Gas, Under Delegation of Authority from the Commissioner (September 30, 2005) (Exhibit 12).

Department as the only reasonable development scenario: long-term full field cycling followed by a gas blowdown. There is also no support or findings related to why PTU gas is necessary for a Major Gas Sale or why that development alternative obviates the need for cycling given, the way the term is defined in the Settlement, gas from PTU might not be necessary for a small diameter off-slope pipeline for over a century.

5. The Settlement Contemplates Future Royalty Relief Not Available Under Alaska Law. Settlement ¶ 4.8 allows the Owners to submit an application for royalty to relief through to the Department not “pursuant to Alaska statutory provisions . . .” It is unclear what this means.

6. The Settlement Pre-Approves Lease Assignments Such as Exxon’s Acquisition of Chevron’s Interest. In Settlement ¶ 4.9 the Department agreed to approve any lease assignment requested by ExxonMobil, BP Exploration (Alaska), Inc., Chevron U.S.A. Inc., and ConocoPhillips Alaska, Inc. submitted within 90 days of execution of this Agreement. This clause is presumably to provide advance approval of Exxon’s acquisition of the Chevron interests in the PTU, notwithstanding Governor Parnell acknowledged at the press conference on March 30, 2012¹⁹ the State had not been privy to the agreements.

7. Terms of Taxation on Injected Gas Are Established by Contract. In Settlement ¶ 4.16 the Department agreed “that any gas produced from a reservoir within the Point Thomson Unit and injected into a reservoir within the Prudhoe Bay Unit . . . is only subject to tax and royalty one time.” This provision attempts to establish terms of future taxation by contract. The Commissioner and Attorney General have also apparently usurped the authority of the Department of Revenue, and given a legal interpretation of 15 AAC 55.151(e) that reinjection of PTU gas into Prudhoe is a non-taxable event under current Alaska law, and made such a commitment without demanding continuing compliance with the affidavit requirements of 15 AAC 55.151(e)(5).

8. The State Waives its Right to Take Royalty In-Value and Substantially Encumbers its Rights Relating to the Taking of Royalty In-Kind. Settlement ¶ 4.16.1 states the State will elect to only take its gas in-kind if there is a completed Point Thomson Gas Development / Prudhoe Bay Enhanced Recovery Project, meaning it waives its right to take the royalty in-value. In addition to committing the State to such items as taking delivery at the PBU unit and bearing the cost of transportation (if the PTU to PBU pipeline is regulated), the Agreement adopts an accounting mechanism for handling the gas once it is injected into the PBU reservoir. Agreeing to the accrual of transportation costs, without detailed treatment of the rate mechanisms, is particularly concerning in light of the history of rate manipulation by ANS producers on oil transportation.

9. Dispute Resolution Is by Methods Different Than Those Provided by Alaska Law. As previously discussed, the Department in Settlement ¶ 5.1 has largely abrogated its regulatory mandate, and contractual rights under the PTU Agreement, to make agency determinations about issues relevant to future disputes involving the Agreement, including for instance relating to PODs. Additionally, arbitration, rather than resolution through the

¹⁹ Exhibit 2.

Department administrative process or Alaska's court system, is to be the forum under Settlement ¶ 4.2.3 to resolve whether the WIOs failure to perform was excused by circumstances outside their control. The terms of that arbitration are to "be decided following execution of this Agreement." It is also worth noting that factors outside of the WIOs control under Settlement ¶ 4.2.3, which result in their not being deemed to have Abandoned the IPS Project, includes design modifications, litigation by third parties, and permitting and regulatory delays, virtually guaranteeing an excuse to argue work has not been Abandoned and arbitration is required.

II. The Settlement Violates Alaska Law.

In addition to any reasons raised in other Subparts of this letter, Walker asserts the Settlement violates Alaska law in the following manner.

- Insufficient public notice and opportunity for public comment was provided in advance of execution of the Agreement. The Public Notice Clause of the Alaska Constitution provides, "No disposals or leases of state lands, or interests therein, shall be made without prior public notice and other safeguards of the public interest as may be prescribed by law." Alaska Const. art. VIII, § 10. "The Alaska Constitution does not express a requirement of pre-negotiation notice, and instead can be read to require notice before the State commits to an agreement requiring it to dispose of or lease state lands or interests in state lands." *Baxley*, 958 P.2d at 432. In *Baxley*, the Supreme Court held that the State could confidentially renegotiate oil and gas lease terms, in compliance with the Public Notice Clause, if "the public had ample opportunity to comment on the proposed lease amendments before the legislature authorized any binding changes. . ." *Id.* Since the Agreement purports to be binding upon execution, and without legislative approval, and the Settlement was announced without public notice and the opportunity for public input, it violates not only the Public Notice Clause but the very framework of AS 38.05 and 11.383 (among other regulatory, statutory and constitutional requirements).
- The Settlement, including Settlement ¶ 5.8, does not comply with the Commissioner's obligations to evaluate and make the findings necessary to approve this Settlement, including without limitation its terms that approve: (i) the extension and amendment of the PTU Agreement; (ii) the contained plans of development and operations; (iii) the formation, expansion and contraction of participating areas; and (iv) revised cost allocation formulas. 11 AAC 83.303. Those findings should have been sufficiently detailed in writing, orally at hearing, or in another manner that provided sufficient support to allow meaningful judicial review. *Button v. Haines Borough*, 208 P.3d 194, 2000 (Alaska 2009) (an agency's findings must be supported by substantial evidence, which is "such relevant evidence as a reasonable mind might accept as adequate to support a conclusion.").
- Compliance with the procedures provided by the legislature and by regulation to handle matters involving Alaska's public lands are mandatory and not at the discretion of the Department. The Settlement thus cannot contract around the Department's regulatory authority, either as to its current or future regulatory obligations. *Exxon Corp. v. State*, 40 P.3d 786, 796-97 (Alaska 2001) ("We disagree

with Exxon's first contention that the department can agree to contract terms that violate its regulations. . . . To allow such activity would be arbitrary; parties contracting with the department would not be held to the same regulations that non-contracting parties were required to comply with. And the department should never need to contract in violation of its own regulations, because it has the authority to change its regulations so long as the new regulation has a reasonable basis and is within the scope of the legislature's delegation of power to the department.""). Without limitation the following portions of the Settlement are improper.

- The Settlement cannot contract away the Commissioner's regulatory responsibilities to, in the future, approve unit actions that must be in the public's interests under 11 AAC 83.303. Among other items, this includes abrogating the Commissioner's obligation to ensure the ultimate method of field development promotes conservation and prevents waste (e.g., the Department cannot allow decisions as to gas cycling to be made at the discretion of the WIOs). Relying on the AOGCC to resolve conservation, waste, and reservoir management issues independent of the Department's administrative process, and without the Department's independent voice before the AOGCC, is not legally permissible and not in the State's best interests.
- The Settlement cannot contract around the POD process under 11 AAC 83.343, either by waiving the obligation to get POD's approved or by altering the POD approval process provided by statute and regulation.
- The Settlement cannot pre-commit to the continuation, expansion or term of the PTU without compliance with the public notice and other requirements of 11 AAC 83.311-.336 and .356.
- The Settlement cannot pre-commit, under 11 AAC 83.351, to the formation of participating areas, including expansion and contraction of the same, before various development commitments are final and contemporaneous data about field and reservoir characteristics are analyzed by the Department. This includes agreeing to the formation of participating areas substantially in advance of the 90 day period (before sustained production) contemplated by regulation.
- The Settlement cannot be used as a mechanism to pre-commit to any current or future amendments to the PTU operating agreement, such as any alternations associated with Chevron's withdrawal, under 11 AAC 83.366.
- The Settlement cannot by contract waive the Department's statutory and regulatory obligations to make agency determinations about issues relevant to future disputes involving the Agreement. That includes having disputes relating to the Agreement decided in the first instance by the Alaska Superior Court. Nor does the Commissioner have the power to waive the Departmental administrative process in favor of arbitration. Similarly, the Settlement cannot provide in its terms or by future agreement to allow arbitration to supplant

judicial review or otherwise alter the standard of judicial review exercised by Alaska's courts.

- The State must approve assignment of Chevron's leases after the sale. *See Baxley v. State of Alaska*, 958 P.2d at 426 n. 6 ("Oil and gas lessees often sell interests in leases without the State's involvement; the State may, however, be required to approve assignment resulting from the sale."). The Commissioner cannot issue a blanket approval, in advance of seeing the parties or terms, of any lease assignment brought to him in 90 days. Practically that means this Agreement is not sufficient to approve Exxon's acquisition and continued retention of Chevron's interest in the PTU.
- The Settlement is too vague and unclear to be enforceable against the State. *George v. Custer*, 862 P.2d 176, 179 (Alaska 1993); *Stenehjem v. Kyn Jin Cho*, 631 P.2d 482, 485 (Alaska 1981) ("A court cannot enforce a contract unless it can determine what it is. It is not enough that the parties think that they have made a contract; they must have expressed their intentions in a manner that is capable of understanding. It is not even enough that they have actually agreed, if their expressions, when interpreted in the light of accompanying factors and circumstances, are not such that the court can determine what the terms of that agreement are. Vagueness of expression, indefiniteness and uncertainty as to any of the essential terms of an agreement, have often been held to prevent the creation of an enforceable contract.") (Quoting 1 Arthur L. Corbin, *Corbin on Contracts* § 95, at 394 (1963 & Supp.1992) (footnote omitted)). The Settlement is also unenforceable on grounds of public policy. *State v. Public Safety Employees Ass'n*, 257 P.3d 151, 159 (Alaska 2011) ("A promise or other term of an agreement is unenforceable on grounds of public policy if legislation provides that it is unenforceable or the interest in its enforcement is clearly outweighed in the circumstances by a public policy against the enforcement of such terms.") (quoting Restatement (Second) of Contracts § 178(1) (1981)).
- The executive branch does not have the authority to consider royalty relief pursuant to a mechanism other than that provided by statute. *Baxley*, 958 P.2d at 427 (the Department cannot modify lease terms like royalty without either statutory authority or specific legislative approval).
- The executive branch cannot contract away the State's power of taxation. Alaska Const. art. IX, § 1. The Commissioner and Attorney General also cannot commit the Department of Revenue to an interpretation of State tax law or regulation, nor waive requirements contained therein.
- The Commissioner cannot, employing a non-competitive process, waive the State's right to take royalty in-value, and substantially encumber its rights relating to the taking of royalty-in kind, without the advanced findings and notices contemplated in AS 38.05.183 and 11 AAC 03.010-.070, without approval of the Royalty Board under AS 38.06.050, and without legislative approval as contemplated by AS 38.06.055. It is improper under Alaska law for the Commissioner, in a non-competitive process with no advanced findings or opportunity for public comment, to unilaterally and

potentially indefinitely waive the State's right to take royalty in-value and to so encumber the terms in which the State will take its royalty in-kind.

- This Agreement, which fundamentally alters the regulatory and contractual relationship currently existing between the State and WIOs, must be approved by the legislature under Alaska law. The Commissioner also does not have the power to affect by settlement what he does not have the authority to do by direct action. For example:
 - The Settlement violates the material amendments doctrine by creating a new contract without a new round of public bidding, and without the legislative hearing process the Supreme Court has previously held satisfies the policy considerations behind the rule when amending State oil and gas leases. *Baxley*, 958 P.2d at 434.
 - Alternatively, the State and WIOs could seek approval of the terms of the Settlement by contract through the process established by the Stranded Gas Development Act, AS 43.82 *et seq.* ("SGDA"). As recognized in prior PTU POD's, the WIOs worked with the State to enact the SGDA, which is the current statutory scheme in place to affect such a dramatic overhaul of the State's relationship with the WIOs.²⁰ But built into the SGDA are a series of procedural safeguards such as the requirement for preliminary findings, notice and comment regarding the contract, final findings, and legislative authorization, as well as a clear mechanism for judicial review. AS 43.82.400 – .440. However, the WIOs, having failed to achieve the goals of the Agreement through the SGDA during the Murkowski Administration,²¹ now seek to achieve many of the same goals via a litigation settlement agreement, but without the multi-faceted public process.²²
- The Settlement is not in any part or in whole in the best interests of the State or its citizens. By signing the Settlement the executive branch abused its discretion and failed to meet its fiduciary obligation to manage Alaska's natural resources for the common good of the public, thus violating the public trust doctrine. Alaska Const. art

²⁰ 15th PTU Plan of Development (June 5, 1998) ([“T]hree of the PTU Owners (Exxon, BP and Phillips) have worked with the State of Alaska's North Slope Gas Commercialization Team which has recommended that changes be made to the State's tax and royalty structure to improve the economic feasibility of a North Slope gas project. This work culminated in the Governor's introduction of Stranded Gas legislation (HB 393) earlier this year.”).

²¹ SGDA Interim Fiscal Interest Findings (November 16, 2006) <available at <http://www.revenue.state.ak.us/gasline/IFIF%2011-16-06.pdf>>; Proposed SGDA Contract (May 24, 2006) <available at http://www.revenue.state.ak.us/gasline/ContractDocuments/Main%20Documents/Fiscal%20Contract/SGDA_Contract_5%2024%2006%20final.pdf> (both documents are incorporated into the record by reference herein).

²² *Id.* (as a reference, Exhibit 13 contains certain excerpts from the SGDA Interim Fiscal Findings and Proposed SGDA Contract related to the PTU).

VIII, § 2; *Baxley*, 958 at 422 (citing *McDowell v. State*, 785 P.2d 1, 16 n.9 (Alaska 1989)).

III. Walker Seeks the Following Remedies.

For the above stated reasons, Walker seeks the following relief.

A. A stay of this request for reconsideration until 30 days after the Department: (i) assembles, makes public, and incorporates into this record all correspondence between any member of the Parnell Administration and any WIO relating to a potential settlement of the Point Thomson Cases, dated on or after January 1, 2010; and (ii) publishes summaries of the Settlement, including flow charts or other materials, to aid Walker and the public in understanding the terms of the Agreement.²³ The additional 30 days will allow Walker and public time to review the materials and submit public comment and additional materials before the Commissioner decides this request for reconsideration.

B. That the Settlement be approved by the legislature, either under the SGDA or by special legislation similar to the process followed to amend the terms of the leases in the North Star unit (which would include among other items authorization for the Commissioner to contract around his statutory and regulatory duties).

C. That the Commissioner undertake an inquiry, with an opportunity for public comment and best interests findings, regarding whether Exxon should be allowed to acquire and retain Chevron's interest in the PTU. At a minimum the Department should review all the agreements between the WIOs relating to the Settlement and agreements between Exxon and Chevron relating to the purchase, and issue detailed best interest findings. Such a review is not only advisable and even necessary under Alaska law, but it is consistent with past actions of the Department where agreements and realignments between working interest owners impacted the State's interests.²⁴

²³ Specifically, Walker requests an explanation of the various options the WIOs have to keep acreage past year-end 2019, including any associated work and study commitments, which are so complex and vague as to not be understandable even after detailed review.

²⁴ See, e.g., Findings of the Decision of the Commissioner, Application for Change of Unit Operator, Prudhoe Bay Unit, As Amended, with Errata Changes (June 27, 2000) and related documents (Exhibit 14).

Commissioner Sullivan
April 17, 2012
Page 16

WALKER & LEVESQUE, LLC
ATTORNEYS AT LAW

Sincerely,



William M. Walker
Citizen Taxpayer of the State of Alaska

WALKER & LEVESQUE, LLC



Craig Richards
Counsel for William M. Walker

Enclosures as listed on the attached List of Enclosures

INDEX OF EXHIBITS

Exhibits provided on CD or DVD only.

- Exhibit 1 Pleadings Dismissing the PTU Court Cases
- Exhibit 2 Governor and Commissioner Press Conference (March 30, 2012)
Provided on DVD
- Exhibit 3 BP, ConocoPhillips and Exxon CEO letter (March 30, 2012)
- Exhibit 4 Amended Decision re Reconsider Trial De Novo (Oct. 26, 2010)
- Exhibit 5 Decision Following Trial Do Novo (Dec. 30, 2012)
- Exhibit 6 [Reserved]
- Exhibit 7.1 Testimony of Charles Cicchetti (August 18, 2009)
- Exhibit 7.2 Alaska State Legislature House Resources Standing Committee (April 12, 2007)
- Exhibit 7.3 Testimony of Roger Marks (October 11, 2011)
- Exhibit 8 Conditional Interim Decision of the Commissioner (January 27, 2009)
- Exhibit 9.1 Transcript of Hearing (January 12, 2009) Vol. IV
- Exhibit 9.2 Transcript of Hearing (January 13, 2009) Vol. V
- Exhibit 9.3 Transcript of Hearing (January 14, 2009) Vol. VI
- Exhibit 9.4 Transcript of Hearing (January 15, 2009) Vol. VII
- Exhibit 9.5 Transcript of Hearing (January 16, 2009) Vol. VIII
- Exhibit 10 Testimony of Paul Carson (September 19, 2011) and Charles Cicchetti
(October 13, 2011)
- Exhibit 11 Summary of Findings for Resource Assessment (May 16, 2008)
- Exhibit 12 Denial of the Proposed Plans for Development of the Point Thomson Unit by the
Director (September 30, 2005)
- Exhibit 13 Excerpts from SGDA Interim Fiscal Findings and Proposed SGDA Contract
- Exhibit 14 Findings and Decision of the Alaska Department of Natural Resources
(June 27, 2000) and related documents
- Exhibit 15 News Articles
- Exhibit 16 Commissioner Presentation to FEDC (April 10, 2012)
- Exhibit 17 Point Thomson Settlement Fact Sheet
- Exhibit 18 Point Thomson Settlement Agreement (March 29, 2012)
- Exhibit 19 Press Release Point Thomson Litigation Resolved, Historic Alignment on Gasline
- Exhibit 20 Commissioner Presentation to the Legislature, Point Thomson Settlement
Overview (March 31, 2012)
- Exhibit 21 Video of the Presentation of the Point Thomson Settlement to the Alaska
Legislature (March 31, 2012) Provided on DVD

3

SETTLEMENT AGREEMENT

This Settlement Agreement (the "Agreement") is made by and between the State of Alaska (the "State"), acting through the Department of Natural Resources ("DNR"), on the one hand, and Exxon Mobil Corporation, as Point Thomson Unit Operator and pursuant to Section 22 of the Point Thomson Unit Agreement and as working interest owner and as successor in interest to Chevron U.S.A., Inc., ExxonMobil Oil Corporation, BP Exploration (Alaska) Inc., ConocoPhillips Alaska, Inc., and Leede Operating Company, L.L.C. (collectively the "Owner Group"), on the other hand. DNR and the Owner Group are at times hereinafter referred to collectively as the "Parties" and each individually as a "Party."

1. RECITALS

- 1.1 The Point Thomson leases were acquired beginning in 1965. Oil was discovered in 1975, and the Point Thomson Unit was formed in 1977. Following formation of the unit, the Point Thomson owners drilled additional wells and discovered additional oil and natural gas in paying quantities. The field is located 60 miles east of Prudhoe Bay in a remote arctic area. The Point Thomson reservoir is a high-pressure retrograde condensate and natural gas reservoir with abnormally-pressured formations, and presents unique engineering challenges with respect to development and production. Since the discovery of the field, the Point Thomson owners have drilled 19 exploration / delineation wells in the Point Thomson area, and recently completed the drilling of two additional wells, the PTU 15 and PTU 16, to initiate production from the Point Thomson Unit consistent with this Agreement.

- 1.2 On September 30, 2005 and October 27, 2005, the Director of the Division of Oil and Gas of DNR (“Director”) denied approval of the 22nd Plan of Development (a “POD”) submitted by the Working Interest Owners (“WIOs”) with respect to the Point Thomson Unit, and placed the Point Thomson Unit into default. The WIOs appealed this decision to the Commissioner of DNR (“Commissioner”), who affirmed the default decision, rejected the WIOs’ proposed POD, and terminated the Point Thomson Unit on November 27, 2006, which was affirmed upon reconsideration by the Commissioner on December 27, 2006. These decisions were affirmed in part, reversed in part, termination of the Point Thomson Unit was vacated, and the matter was remanded to DNR by the Superior Court of the State of Alaska on December 26, 2007.
- 1.3 On April 22, 2008, the Commissioner issued another decision terminating the Point Thomson Unit, affirmed upon reconsideration on June 11, 2008. On August 4, 2008, DNR issued lease expiration decisions related to leases within the Point Thomson Unit.
- 1.4 The Owner Group filed several appeals challenging these decisions. On January 11, 2010, the Superior Court of the State of Alaska reversed DNR’s April 22, 2008 decision terminating the Point Thomson Unit. On February 5, 2010, DNR filed in the Supreme Court of the State of Alaska a petition for review of the Superior Court’s January 11, 2010 decision, which was granted by the Supreme Court on May 28, 2010.
- 1.5 The Parties wish to resolve all pending litigation and administrative proceedings between them related to the Point Thomson Unit on the terms and conditions set forth in this Agreement.

- 1.6 This Agreement sets forth the WIOs' commitment to produce natural gas condensate liquids ("condensate") from the Point Thomson Reservoir for delivery into the TransAlaska Pipeline System ("TAPS"). The WIOs have committed to construct an Initial Production System ("IPS") which is to be completed by the end of the 2015-2016 winter season. The IPS facility is being designed to produce and re-inject (cycle) 200 million cubic feet per day of gas and to produce approximately 10,000 barrels per day of condensate. In addition, a liquid hydrocarbon pipeline is being designed that can transport approximately 70,000 barrels per day from Point Thomson to an existing pipeline interconnection at the Badami field, which will provide for final delivery of Point Thomson liquid hydrocarbons into TAPS. Operation and production from the IPS will provide data and information to assist in evaluation of additional development plans, including potential increased gas and condensate production from Point Thomson, and plans for the delivery of Point Thomson gas into a Major Gas Sale pipeline project.
- 1.7 In parallel with the work on the IPS, Parties and/or their affiliates to this Agreement will, upon execution of this Agreement, undertake work for commercialization of North Slope gas. This work will build on ongoing gas commercialization efforts. If a Major Gas Sale is Sanctioned prior to year-end 2016, the WIOs will begin work on a Point Thomson project associated with that Major Gas Sale. However, if a Major Gas Sale has not been Sanctioned by June of 2016, the WIOs have committed to begin engineering of a Point Thomson Expansion Project. An expanded cycling project would result in additional condensate production, totaling approximately 20,000 to 30,000 barrels per day into TAPS, depending on the level of expansion. Alternatively,

a project to deliver Point Thomson gas to Prudhoe Bay for injection would significantly increase the rate of condensate production at Point Thomson, serve as a pre-investment for a Major Gas Sale project, and essentially complete installation of the Point Thomson wells and facilities required for a Major Gas Sale. In addition, this option would materially increase production at Prudhoe Bay, and result in enhanced recovery at Prudhoe Bay.

- 1.8 The Agreement further establishes terms and conditions to facilitate development and provide benefits to the State of Alaska. Certain acreage within the Point Thomson Unit is secured when specified work activities are completed (e.g., the IPS is completed and producing) and key commitments or decisions are made (e.g., a Major Gas Sale is Sanctioned or WIOs Commit to a Point Thomson gas development / Prudhoe Bay enhanced oil recovery project or an IPS gas cycling expansion project). Likewise, the Agreement provides for the automatic release of certain acreage to the State if the IPS is not completed or if certain key commitments or decisions are not made (e.g., a Major Gas Sale is not Sanctioned or WIOs do not Commit to a Point Thomson gas development / Prudhoe Bay enhanced oil recovery project or an IPS gas cycling expansion project). Depending upon the work activities that occur, the Point Thomson Unit will remain in effect or may terminate.
- 1.9 Since 2009, work activities at Point Thomson have resulted in contracts with over 150 companies and the employment of hundreds of Alaskans.

- 1.10 In implementing the terms of this Agreement, the WIOs and the State anticipate there will be significant continued investment and employment opportunities for Point Thomson Unit development.
- 1.11 A Major Gas Sale off the North Slope of Alaska is a primary goal of the Parties. The Parties believe settlement of the Point Thomson litigation will assist in progressing a Major Gas Sale. It also allows for other development options that may be pursued independent of or in conjunction with a Major Gas Sale, and would allow for continued progress on permitting, regulatory, and engineering activities toward a Major Gas Sale. Progress toward a potential Major Gas Sale off the North Slope of Alaska and development of Point Thomson consistent with this Agreement should aid exploration and development opportunities of North Slope resources.

2. DEFINITIONS

Whenever the following terms are used in this Agreement, they shall have the meanings set forth in this Section 2:

- 2.1 “Abandon,” “Abandoned,” or “Abandonment” has the meaning provided in Paragraph 4.2.1.
- 2.2 “Authorization for Expenditure” means a formal approval or authorization of expenditures for a project or a phase of a project by the authorized corporate representative.
- 2.3 “Brookian” means the stratigraphic interval correlating with the sands and silts penetrated by the Sourdough 3 well (API No. 50-089-200260) between the interval 10,305 feet measured depth and 12,200 feet measured depth as measured by Dual

Induction Focused Log Run No. 3, dated March 6, 1996, or the sands and silts penetrated by the Flaxman Island A-1 well (API No. 50-089-200030) between the interval 11,848 feet measured depth and 12,643 feet measured depth as measured by Dual Induction Laterolog Run No. 4, dated August 7, 1975.

- 2.4 “Commit,” “Committed,” or “Commitment” in the context of a Point Thomson Expansion Project means documentation that the WIOs have conducted project evaluation and scoping and have obligated themselves to proceed diligently with the project through completion in accordance with the terms of this Agreement. The documentation to be provided shall include corporate authorization letters by the authorized corporate representative from the WIOs and any existing project Authorizations for Expenditure.

In addition, in the context of a Point Thomson Gas Development / Prudhoe Bay Enhanced Recovery Project, the documentation to be provided also includes documentation demonstrating the completion of Front End Engineering and Design (FEED) and filing of formal applications for major federal and state permits, authorizations, certificates, or rights of way associated with construction of the project, from the U.S. Army Corp of Engineers, DNR and the Alaska Oil and Gas Conservation Commission, including any related NEPA review (“Authorizations”).

After the WIOs “Commit,” as defined above, to a Point Thomson Gas Development / Prudhoe Bay Enhanced Recovery Project, upon receipt of Authorizations consistent with FEED design work and the applications filed by the WIOs, the WIOs will proceed

in a timely manner to enter into contracts necessary to proceed with construction of the project consistent with the POD requirements.

- 2.5 “Continuous Operations” in the context of the IPS Project means continuing operation of wells and facilities to produce oil or gas from the Thomson Reservoir into a pipeline or other means of transportation to market. “Continuous Operations” does not include testing, evaluation, or temporary production. “Continuous Operations” exist even when production temporarily ceases or temporarily declines due to and for the period of: (1) planned or unplanned maintenance or repairs; (2) operational upsets; or (3) circumstances beyond the control of the WIOs that impact ongoing operations.
- 2.6 “DNR Point Thomson Orders” means the following DNR orders: (1) the Director’s September 30, 2005 Denial of Proposed Plans of Development for the Point Thomson Unit and the Director’s October 27, 2005 Amended Decision - Denial of Proposed Plans of Development of the Point Thomson Unit; (2) the Commissioner’s November 27, 2006 Final Decision and the Commissioner’s December 27, 2006 Decision on Reconsideration; (3) the Commissioner’s April 22, 2008 Findings and Decision on Remand and the Commissioner’s June 11, 2008 Decision on Reconsideration; (4) the Director’s February 2007 and August 4, 2008 Decisions regarding thirty-one leases entitled Lease Expiration Due To Elimination From Unit; (5) the Commissioner’s August 4, 2008 Decision on Consolidated Appeals From the Director’s 2007 Decisions Terminating Thirteen State Oil and Gas Leases That Were Subject to the 2001 Point Thomson Unit Expansion Agreement; and (6) the Commissioner’s January 27, 2009 Conditional Interim Decision.

- 2.7 “East Pad” means the proposed drilling pad located east of the IPS in Area D and from which one or more wells could be drilled.
- 2.8 “Effective Date” has the meaning provided in Paragraph 4.10.2.
- 2.9 “Expansion Planning POD” has the meaning provided in Paragraph 4.6.2.
- 2.10 “Expansion Project POD” has the meaning provided in Paragraph 4.6.3.
- 2.11 “Future POD” has the meaning provided in Paragraph 4.6.
- 2.12 “Initial Participating Area” or “Initial PA” means the participating area (“PA”) formed for the Thomson Reservoir containing all or part of the leases listed in Area A on attached Exhibit C and contained in Area A of attached Exhibit D.
- 2.13 “Initial Production System” or “IPS” means the gas cycling facilities designed with capacity to produce and re-inject (cycle) 200 million cubic feet of gas per day utilizing reciprocal compression and with the objective of a minimum of 10,000 barrels per day of condensate for delivery into the TransAlaska Pipeline System (“TAPS”).
- 2.14 “IPS Project” means the project to construct and install the IPS, and includes a 12-inch liquid hydrocarbon pipeline from Point Thomson to an interconnection with the Badami Field liquid hydrocarbon pipeline.
- 2.15 “IPS Gas Cycling Expansion Project” means an expansion of the IPS that must be: (i) a minimum of an additional 10,000 barrels per day if reciprocal compression is used; or (ii) a minimum of an additional 20,000 barrels per day if centrifugal compression is

used for delivery into TAPS. The WIOs have the discretion to decide on (i) or (ii) above and whether they will Commit to any IPS Gas Cycling Expansion Project.

- 2.16 “Major Gas Sale” or “MGS” means a large-scale pipeline project having a design throughput of more than 500 million cubic feet of gas per day that results in delivery of gas off the North Slope of Alaska.
- 2.17 “MGS POD” has the meaning provided in Paragraph 4.6.1.
- 2.18 “Point Thomson Cases” means (1) the following cases consolidated with Case No. 3AN-06-13751 CI: Case Nos. 3AN-06-13760 CI, 3AN-06-13773 CI, 3AN-06-13799 CI, 3AN-07-04634 CI, 3AN-07-04620 CI, 3AN-07-04621 CI, and 3AN-08-09369 CI; (2) the expansion leases termination appeal, Case No. 3AN-08-10156 CI; (3) the appeal from the AOGCC’s decision dismissing involuntary unit petition, Case No. 3AN-09-07768 CI; (4) the Supreme Court appeal from denial of breach of contract damages claim, Case No. S-12743; (5) the appeal before the Department of Administration from DNR’s denial of damages claim, Case No. OAH No. 08-0409; (6) the appeal from Commissioner Irwin’s August 29, 2008 letter denying certain permit applications, Case No. 3AN-08-10825 CI; and (7) Chevron’s Public Records Act case, Case No. 3AN-08-11804 CI.
- 2.19 “Point Thomson Development” means the IPS Project, drill wells, and work plans described in Paragraph 4.1 and other work activities set forth in this Agreement.

2.20 “Point Thomson Expansion Project” means an IPS Gas Cycling Expansion Project or a Point Thomson Gas Development / Prudhoe Bay Enhanced Recovery Project. The WIOs have discretion on whether to Commit to any Point Thomson Expansion Project.

2.21 “Point Thomson Gas Development / Prudhoe Bay Enhanced Recovery Project” means a project to deliver Point Thomson gas to Prudhoe Bay for injection that would significantly increase the rate of condensate production at Point Thomson into TAPS, serve as a pre-investment for a Major Gas Sale, essentially complete installation of the Point Thomson wells and facilities required for a Major Gas Sale, and allow for continued efforts towards, and positions Point Thomson gas for, a Major Gas Sale. In addition, this project would materially increase oil production at Prudhoe Bay into TAPS and result in substantial enhanced recovery at Prudhoe Bay. A Point Thomson Gas Development / Prudhoe Bay Enhanced Recovery Project would result in production and recovery of liquids from Point Thomson and Prudhoe Bay that would be greater than production and recovery of liquids from Point Thomson from an IPS Gas Cycling Expansion Project of a minimum of an additional 20,000 barrels per day. Before Project Start-up required approvals from the Alaska Oil and Gas Conservation Commission must be obtained.

The project would consist of:

- (i) a newly constructed gas pipeline from Point Thomson to Prudhoe Bay with the capacity to transport significant volumes of Point Thomson gas in an amount that would position Point Thomson gas for a Major Gas Sale, for injection for:
 - (a) use in repressuring, stimulation of production, and increasing ultimate

recovery of Prudhoe Bay oil; and (b) for ultimate availability for a Major Gas Sale; and

- (ii) additional wells and facilities at Point Thomson to produce and process significant condensate production for delivery into TAPS through existing liquid hydrocarbon pipelines and pipelines constructed as part of the IPS Project. These facilities would also be used for a Major Gas Sale.

To ensure DNR receives necessary information regarding a Point Thomson Gas Development / Prudhoe Bay Enhanced Recovery Project, in addition to information required under an Expansion Planning POD or an Expansion Project POD, the WIOs will meet and confer with DNR technical staff and schedule periodic reviews and workshops regarding reservoir and facility modeling results related to the project, and provide data and information to DNR for it to understand and track progress and evaluation of the project consistent with Section 16 of the PTUA. If the WIOs Commit to a Point Thomson Gas Development / Prudhoe Bay Enhanced Recovery Project, then at the State's request, the State and each individual WIO with a working interest in each Point Thomson Unit lease will negotiate a separate gas sales agreement that includes the terms set forth in Exhibit G. The Parties recognize that a Point Thomson Gas Development / Prudhoe Bay Enhanced Recovery Project will also be subject to Prudhoe Bay Unit agreements, including the Prudhoe Bay Unit plan of development approval process, which are not part of and would not be modified by this Agreement.

- 2.22 “Point Thomson Superior Court Case” means the case pending in the Superior Court of the State of Alaska, Case No. 3AN-06-13751 CI (Consolidated).
- 2.23 “Point Thomson Supreme Court Case” means the case pending in the Supreme Court of the State of Alaska, Case No. S-13730.
- 2.24 “Point Thomson Unit” has the meaning set forth in Section 3.
- 2.25 “Point Thomson Unit Agreement” or “PTUA” means the Unit Agreement for the Development and Operation of the Point Thomson Unit effective August 1, 1977, including all amendments thereto.
- 2.26 “Pre-Mississippian Section” means the interval of rock correlating with the Alaska State F-1 well (API No. 50-089-200190) below the depth of 13,846 feet measured depth as measured by the Dual Induction Laterolog Run No. 4, dated March 16, 1982, consisting of low grade metamorphic rocks containing argillite, phyllite, and quartzite along with intercalated beds of dolomite and limestone.
- 2.27 “Project Start-up” means the date of first production through facilities constructed as a result of the project in question but does not include testing, evaluation, or temporary production.
- 2.28 “Sanction” in the context of a Major Gas Sale means formal and explicit approval of a Major Gas Sale. A Major Gas Sale shall be considered “Sanctioned” under this Agreement upon receipt by the State of documentary evidence of: (1) corporate approvals by parties sufficient to proceed with construction of the project to completion; (2) firm transportation service agreements that have been entered into

sufficient to proceed with construction of the project to completion; and (3) necessary United States (and, if applicable, Canadian) federal regulatory certificates that have been issued and accepted.

- 2.29 “Thomson Reservoir” means the accumulation of hydrocarbon substances in the Thomson Sand and the Pre-Mississippian Section within the Point Thomson Unit.
- 2.30 “Thomson Sand” means the interval of rock correlating with the Point Thomson Unit No. 3 well (API No. 50-089-200070) between the depths of 13,657 and 13,932 feet measured depth as measured by the Dual Induction Laterolog Run No. 3, dated May 17, 1979, consisting of conglomerates, sandstones and siltstones.
- 2.31 “Unit Operator” means the Point Thomson Unit Operator designated in the PTUA and Point Thomson Unit Operating Agreement.
- 2.32 “West Pad” means the proposed drilling pad located west of the IPS in Area B and from which one or more wells could be drilled.
- 2.33 “West Pad Area” means the acreage containing all or part of the leases listed in Area B on Exhibit C and contained in Area B on Exhibit D.
- 2.34 “Without Appeal” means that the WIOs have waived any rights under the PTUA, individual lease terms, Alaska law and/or the laws of the United States of America, to file an application, petition, administrative appeal, or any cause of action before any administrative tribunal or state or federal court of law, and that the WIOs shall not file any such application, petition, administrative appeal, or cause of action. With regard to acreage that is released to the State Without Appeal under this Agreement, upon the

occurrence of the specified event resulting in the release of acreage, that release will occur immediately and automatically.

2.35 “Working Interest Owners” or “WIOs” means the working interest owners who are entitled to vote as to the applicable operation pursuant to, or who undertake a non-consent operation under, the Point Thomson Unit Operating Agreement.

3. UNIT CONFIGURATION

The Point Thomson Unit consists of the area and leases within the boundary set forth on the map attached as Exhibit A and the schedule of leases listed and identified on Exhibit B for a total acreage of 93,291.12 acres. The WIOs confirm that any leases not set forth on Exhibits A and B that formerly may have been included in the Point Thomson Unit have expired and the acreage has been released and returned to the State.

The map of the unit area reflecting the boundary of the Point Thomson Unit as set forth on Exhibit A and the schedule listing leases within the Point Thomson Unit area as set forth on Exhibit B are approved as Exhibit A and Exhibit B to the PTUA. The Unit Operator will file revised versions of Exhibits A and B when changes occur to the configuration or boundaries of the Point Thomson Unit area as set forth in this Agreement, with the revisions effective on the date the changes occur. Exhibit C is a listing of all or part of the leases listed on Exhibit A by area as referenced in this Agreement. Exhibit D is a map depicting the leases and areas set forth in Exhibit C. A reference to Exhibit C in this Agreement includes a reference to the corresponding area depicted in Exhibit D.

4. TERMS OF AGREEMENT

The Parties agree and understand as follows:

4.1 By signing this Agreement, the WIOs shall undertake and DNR approves the following work plan:

4.1.1 IPS Project.

4.1.1.1 The WIOs shall drill the PTU 15 and PTU 16 wells by the end of 2010, which work has been completed.

4.1.1.2 The WIOs shall put the PTU 15 and PTU 16 wells on production utilizing the IPS by the end of the 2015-2016 winter season and in any event no later than May 1, 2016. The work plan and activities associated with the IPS Project are set forth in Exhibit E. The PTU 15 and PTU 16 wells shall be placed on Continuous Operations either under production or gas injection. During the first year of production following IPS Project Start-up, the WIOs shall collect data and information regarding production, well and reservoir performance, IPS facility performance, and transportation system operations to aid in further development planning and decisions.

4.1.1.3 Additional wells shall be drilled and placed on production as needed to keep the IPS fully loaded with gas as set forth in Paragraph 2.13, to sustain the objective of a minimum of 10,000 barrels of condensate per day until the Thomson Reservoir is no longer able to sustain this objective.

- 4.1.1.4 After IPS Project Start-up, the WIOs shall identify and pursue debottlenecking work to increase the capacity of the installed facilities.

- 4.1.2 West Pad Well. The WIOs shall drill a Thomson Sand well from the West Pad by the end of the 2016-2017 winter season and in any event no later than May 1, 2017.

- 4.1.3 East Pad, East Pad Well, and Fifth Well. In addition to the wells and pads provided for in Paragraphs 4.1.1 and 4.1.2, the WIOs shall continue permitting for the East Pad, an East Pad well, and a fifth well, with the permitted location of the fifth well determined by the WIOs based on prior well results.

- 4.1.4 Wells to Target Thomson Sand Gas. All wells addressed in Paragraph 4.1 shall target Thomson Sand gas.

- 4.1.5 IPS POD. The work plans for the development and operation for the unitized land set forth in Paragraphs 4.1.1 through 4.1.4 shall constitute the drilling and operating obligations under Section 10 of the PTUA until May 1, 2017, unless IPS Project Start-up has not occurred due to factors outside the control of the WIOs under Paragraph 4.2.3 or force majeure under Paragraph 4.14, then until one year following IPS Project Start-up. The Unit Operator shall submit an annual report by March 1 of each year describing the operations conducted during the preceding year, but otherwise shall not be required to update the plan under 11 AAC 83.343.

- 4.1.6 Facility Expansion.

- 4.1.6.1 If a Major Gas Sale is Sanctioned by year-end 2019, then the WIOs are not obligated to pursue or continue to pursue the work plans for a Point Thomson Expansion Project set forth in Paragraphs 4.1.6.2, 4.6.2, or 4.6.3.
- 4.1.6.2 If a Major Gas Sale is not Sanctioned by June 1, 2016, the WIOs shall begin engineering and permitting of a Point Thomson Expansion Project. The WIOs shall incorporate these work plans into the Expansion Planning POD set forth in Paragraph 4.6.2 of this Agreement.

4.2 Completion of the IPS Project; Abandonment

- 4.2.1 Definition of Abandonment. For purposes of Paragraph 4.2, “Abandon,” “Abandoned,” or “Abandonment” means the WIOs are no longer diligently pursuing the IPS Project in good faith. Diligence is understood to mean the type of effort and activity demonstrated by the WIOs in drilling the PTU 15 and PTU 16 wells. The WIOs will have diligently pursued the IPS Project if the project work plans, activities, and pace are undertaken in a manner exemplified by the Point Thomson Provisional Schedule Level 1 work sheet attached as Exhibit E. Moreover, a lack of progress on project work plans, activities, and pace commensurate with the size and scale of the IPS Project over a one-year period is indicia of the WIOs’ decision to Abandon the IPS Project. The economics or costs of the IPS Project cannot be used as a rationale or justification for not completing the IPS Project and do not constitute a factor outside the WIOs’ control under Paragraph 4.2.3. To demonstrate diligence, the WIOs shall continue to provide to DNR documentation (e.g., spend reports, permit

applications, etc.) of their work activities and more detailed annual work plans to supplement the information in Exhibit E.

4.2.2 Consequences of Abandonment.

4.2.2.1 If the WIOs Abandon the IPS Project and have incurred costs for Point Thomson Development during the period between year-end 2007 and year-end 2015 of less than \$2.0 billion dollars, then all Point Thomson Unit area acreage except for acreage included in Area A and Area B on Exhibit C shall be released to the State Without Appeal at year-end 2015.

4.2.2.2 If the WIOs Abandon the IPS Project and: (a) have incurred costs for Point Thomson Development during the period between year-end 2007 and year-end 2015 of less than \$2.0 billion dollars; and (b) a West Pad well has not been spud by year-end 2016, then the Point Thomson Unit area acreage in Area B on Exhibit C shall be released to the State Without Appeal at year-end 2016.

4.2.2.3 If the WIOs Abandon the IPS Project and have incurred costs for Point Thomson Development during the period between year-end 2007 and year-end 2015 of \$2.0 billion dollars or more, then only acreage listed in Area E and Area F on Exhibit C shall be released to the State Without Appeal at year-end 2015.

4.2.2.4 If the WIOs Abandon the IPS Project, the WIOs shall provide the State with accounting information provided by the Unit Operator in joint interest

billings to the WIOs to verify the costs incurred for Point Thomson Development between year-end 2007 and year-end 2015.

4.2.3 Factors Outside the Control of the WIOs. The WIOs shall not be considered to have Abandoned the IPS Project if the WIOs are unable to continue moving forward because of factors outside the control of the WIOs due to:

- (a) circumstances addressed by Section 25 of the PTUA;
- (b) design modifications due to significant technological or environmental obstacles that cause substantial additional work;
- (c) litigation by third parties; or
- (d) permitting and regulatory delays.

At the time the WIOs assert that one or more of the factors outside of their control has prevented them from moving forward with the IPS Project, the WIOs shall provide written notice to DNR with a description of the circumstances that have occurred and information to support the basis for their position. The WIOs shall exercise due care and diligence to address a factor outside of their control and shall keep DNR updated on the steps they are taking and their progress to move forward with the IPS Project under the circumstances. The WIOs shall provide written notice when they are able to continue moving forward with the IPS Project. If DNR disagrees with the position taken in the written notice from the WIOs, or if DNR otherwise believes the WIOs have Abandoned the IPS Project, DNR shall provide the WIOs written notice of DNR's position. DNR and the WIOs shall meet and review their respective positions in an effort to resolve any

differences. If the parties are not able to resolve their different assessments, then any dispute on whether the WIOs have Abandoned the IPS Project and whether failure to spud a West Pad well by the date set forth in Paragraph 4.2.2.2 is due to circumstances addressed by Section 25 of the PTUA, shall be subject to expedited arbitration. The parties shall agree upon expedited arbitration with the principles to be decided following execution of this Agreement.

- 4.2.4 Term of Abandonment Provision. This Paragraph 4.2 expires upon IPS Project Start-up, but in no event extends beyond year-end 2019, which date is fixed and not subject to Paragraph 4.14.
- 4.2.5 Year-end 2019. The provisions in this Paragraph 4.2 do not modify the provisions regarding Point Thomson Unit contraction/termination at year-end 2019 in Paragraphs 4.5.2 and 4.5.7 of this Agreement.
- 4.3 Formation of Initial Participating Area (Initial PA). This Paragraph 4.3 describes how the Initial PA will be formed for the Point Thomson Unit.
- 4.3.1 Initial Participating Area for Thomson Reservoir. The Initial PA shall be the first participating area for the Point Thomson Unit. The Initial PA shall contain the leases listed as the Initial Participating Area on Exhibit C. At least ninety (90) days before the date of first production through the IPS Project, the Unit Operator shall submit documentation regarding the Initial PA as provided in Paragraph 4.4.5, including PA tract allocations for each lease in the PA which shall be set forth in a revision to Exhibit C. The Initial PA for the Thomson Reservoir shall be formed and is approved upon IPS Project Start-up effective the date of first

production through the IPS Project with delivery into TAPS. Within twenty (20) days following the month of first production through the IPS Project with delivery into TAPS, the Unit Operator shall provide notice to DNR of the date of first production through the IPS Project with delivery into TAPS.

- 4.4 Expansion of IPA and Formation of New PAs. This Paragraph 4.4 describes how the Point Thomson Unit Initial PA may be: (1) conditionally expanded to include acreage in Area B upon completion of certain work activities; (2) expanded to include acreage in Area B and Area D upon approval of a PA application pursuant to the PTUA including applicable State law based on technical information from drilling and IPS production; and (3) expanded to include up to the entire Point Thomson Unit area (except Area F) upon Project Start-up of a Point Thomson project resulting from Sanction of a Major Gas Sale, an IPS Gas Cycling Expansion Project of a minimum of an additional 20,000 barrels per day, or a Point Thomson Gas Development / Prudhoe Bay Enhanced Recovery Project. The leases in the Initial PA, and the leases included in Area B, have been identified for inclusion in the Thomson Reservoir PA by the Parties for the purposes of this Agreement. The inclusion of leases in the PA does not constitute a determination under Section 11 of the PTUA of the land that otherwise would be included in the PA. Development of Point Thomson Unit acreage in Area F (Brookian reservoirs) is subject to the provisions set forth in Paragraph 4.7.

- 4.4.1 Area B Expansion. If: (i) a West Pad well is drilled as provided in Paragraph 4.1.2 and casing set across the Thomson Sand; and (ii) an Authorization for Expenditure for a gathering line to the West Pad is approved, then the Initial PA formed as provided in Paragraph 4.3 shall automatically expand to include the

West Pad Area (Area B) acreage listed on Exhibit C. Within twenty (20) days following the month in which the last of the above conditions is accomplished, the Unit Operator shall submit documentation regarding the expanded PA as provided in Paragraph 4.4.5, including the PA tract allocations for each lease in the PA which shall be set forth in a revision to Exhibit C, and notice confirming that the conditions set forth in this Paragraph 4.4.1 have been met including a copy of the Authorization for Expenditure. Upon receipt of proper notification, expansion of the Initial PA is automatically approved effective the first day of the month in which the last of conditions (i) and (ii) was met.

- 4.4.2 PA Expansion to Entire Unit. If by year-end 2019, (i) a Major Gas Sale is Sanctioned or (ii) the WIOs Commit to an IPS Gas Cycling Expansion Project of a minimum of an additional 20,000 barrels per day or to a Point Thomson Gas Development / Prudhoe Bay Enhanced Recovery Project, then, upon Project Start-up of the project to develop the Point Thomson Reservoir for a Major Gas Sale, the IPS Gas Cycling Expansion Project of a minimum of an additional 20,000 barrels per day, or the Point Thomson Gas Development / Prudhoe Bay Enhanced Recovery Project, as applicable, the PA for the Thomson Reservoir shall expand to include the entire Point Thomson Unit area contained on Exhibit A and the leases listed and identified on Exhibit B, except acreage listed in Area F on Exhibit C or acreage that has contracted from the Point Thomson Unit if IPS Project Start-up has not occurred as provided under Paragraph 4.5.7. At least ninety (90) days before Project Start-up, the Unit Operator shall submit documentation regarding the expanded PA as provided in Paragraph 4.4.5,

including the PA tract allocations for each lease in the PA which shall be set forth in a revision to Exhibit C. Within twenty (20) days following the month of Project Start-up, the Unit Operator shall submit documentation confirming Project Start-up. Prior to the effective date of expansion of the PA, any acreage subject to this Paragraph 4.4.2 and not within the PA for the Thomson Reservoir shall be subject to the provisions of Paragraph 4.5.1.

4.4.3 PA Expansion Based on Technical Information. In addition to expansion of the PA for the Thomson Reservoir provided in Paragraph 4.4.1, prior to year-end 2019 the Unit Operator may submit an application for expansion of the PA pursuant to the PTUA including applicable State law based on drilling and IPS production results (i.e., technical information). This request could include acreage in Area B and Area D on Exhibit C. Any acreage included in the PA for the Thomson Reservoir as a result of this application shall be listed as a new Area C on Exhibit C and depicted as Area C on Exhibit D. The WIOs' rights to such an expansion of the PA and DNR's decisions regarding same shall be governed by the PTUA including applicable State law. The Parties acknowledge that any DNR decision on a technical PA submitted consistent with this Paragraph 4.4.3, including any appeal of a DNR decision to the Superior Court of the State of Alaska, may extend beyond year-end 2019.

4.4.4 Acreage Not Subject to Contraction. The following acreage shall not be subject to removal from a PA or contraction from the Point Thomson Unit:

- (a) acreage that has been included in the Initial PA pursuant to an IPS Project Start-up under Paragraph 4.3;
- (b) except as specifically provided in Paragraph 4.5.8, acreage that has been included in a PA pursuant to a PA expansion to include Area B under Paragraph 4.4.1;
- (c) acreage that has been included in a PA pursuant to a PA expansion to include the entire Point Thomson Unit (except Area F) under Paragraph 4.4.2; or
- (d) subject to 11 AAC 83.351(c), as applicable, and except as specifically provided in Paragraph 4.5.3, acreage that has been included in a PA pursuant to an approved PA expansion based on technical information under Paragraph 4.4.3.

Notwithstanding the above, this Paragraph 4.4.4 does not modify Section 20(c) of the PTUA should production cease from the PA.

4.4.5 PA Documentation. Information to be submitted to DNR under Paragraphs 4.3.1, 4.4.1 and 4.4.2 is provided in Exhibit F.

4.4.6 PA Dispute. Any dispute related to a PA under this Agreement shall be subject to Paragraph 5.1. A dispute regarding PA documentation or the tract allocation factors set forth in Exhibit C shall not impact formation or expansion of a PA under this Agreement, except as provided in Paragraph 4.4.3. Submittal of PA documentation under Paragraphs 4.3 and 4.4 shall be subject to the terms of the

PTUA including applicable State law. Approval of the tract allocation factors contained in Exhibit C shall be subject the terms of the PTUA including applicable State law. If the tract allocation factors submitted by the Unit Operator under Paragraphs 4.3 and 4.4 are disputed, the factors submitted by the Unit Operator shall take effect and apply until the dispute is finally resolved. Once resolved, the tract allocation factors will be retroactively adjusted.

4.5 Unit Contraction and Participating Area Reductions / Unit Status at Year-End 2019.

This Paragraph 4.5 describes various development scenarios that could be present at year-end 2019, and the implications for acreage in the Point Thomson Unit. Particularly, this paragraph sets forth the terms and conditions under which some or all of the acreage could contract out of the Point Thomson Unit and be released to the State Without Appeal, and some or all of the acreage could remain in the Point Thomson Unit and be included in a PA. Paragraph 4.5 does not address Area F; Paragraph 4.7 describes what will happen with Area F acreage.

4.5.1 Acreage Subject to Inclusion in PA. If by year-end 2019 a Major Gas Sale has been Sanctioned or the WIOs have Committed to a Point Thomson Expansion Project, acreage to be included in the PA for the Thomson Reservoir under Paragraphs 4.4.2, 4.5.4, or 4.5.7 shall be entitled to be included in the PA. Such acreage shall remain in the Point Thomson Unit following formation of the Initial PA, and thereafter shall be subject to elimination from the Point Thomson Unit in accordance with the terms of the PTUA including applicable State law, including Section 2(e). If IPS Project Start-up has not occurred and the Initial PA has not been formed, but a Major Gas Sale is Sanctioned, such acreage shall remain in the

Point Thomson Unit and shall be subject to elimination from the Point Thomson Unit in accordance with the terms of the PTUA including applicable State law, including Section 2(e), as if the Initial PA had been formed effective May 1, 2016.

4.5.2 No IPS or MGS.

4.5.2.1 If IPS Project Start-up has not occurred and a Major Gas Sale has not been Sanctioned by year-end 2019, the following shall occur: (1) subject to Paragraph 4.5.2.2, the Point Thomson Unit and the PTUA shall terminate Without Appeal; (2) except for leases subject to Paragraph 4.5.2.3, each WIO will immediately surrender its leases and all such acreage shall be automatically released Without Appeal to the State; (3) each WIO agrees that it will not apply to form a compulsory unit with the Alaska Oil and Gas Conservation Commission with respect to any lease formerly within the Point Thomson Unit; and (4) this Agreement shall terminate.

4.5.2.2 If IPS Project Start-up has not occurred and a Major Gas Sale has not been Sanctioned by year-end 2019, then the WIOs may submit an alternative POD for the Point Thomson Unit no later than sixty (60) days prior to year-end 2019. Submittal and approval of the alternative POD shall be subject to the terms of the PTUA including applicable State law. Nonetheless, DNR shall have sole discretion to accept or reject an alternative POD, and a final Commissioner decision on the alternative POD is Without Appeal. For purposes of this paragraph the WIOs agree not to assert that Section 21 of

the PTUA applies in any respect to review of or a decision on the proposed alternative POD.

4.5.2.3 If the Point Thomson Unit is terminated under Paragraph 4.5.2.1, the lessees of leases containing the PTU 15, PTU 16 and wells drilled after execution of this Agreement, and lessees of leases containing any other wells capable of producing in paying quantities, may submit a Plan of Operations (“POO”) for each lease to the Director within sixty (60) days of the date of Point Thomson Unit termination. The POO shall provide for placing the well on producing status within two (2) years of the date of approval of the POO. Approval or rejection of the POO shall be within the sole discretion of the DNR. If the Director denies approval of the POO, that decision may be appealed to the Commissioner. The Commissioner’s decision on the POO shall be Without Appeal. If the lessees fail to submit a POO for the leases within sixty (60) days following Point Thomson Unit termination, or the Commissioner denies approval of the POO, the leases shall terminate with acreage returning to the State Without Appeal. If the Director or the Commissioner approve the POO and the lessees fail to place the well on producing status within two years, the lease shall terminate with acreage returning to the State Without Appeal.

4.5.3 IPS Project - No Expansion and No MGS. If IPS Project Startup has occurred and the WIOs do not Commit to a Point Thomson Expansion Project and a Major Gas Sale has not been Sanctioned by year-end 2019, then:

- 4.5.3.1 The acreage in Area E and the northern half of ADL 377017 (ADL 377017(N) on Exhibit C), without regard to whether this acreage was included in a technical PA application or is included in the PA as the result of a technical PA expansion under Paragraph 4.4.3, shall be released to the State Without Appeal. The remaining acreage in Area D shall be subject to the PTUA including applicable State law.
- 4.5.3.2 If a technical PA application has been filed pursuant to Paragraph 4.4.3, then, subject to Paragraph 4.5.3.1, the acreage included in the application shall not be subject to contraction until a final decision on the technical PA application. Once a final decision has been made on the PA application, any acreage not included in a PA shall be eliminated from the Point Thomson Unit.
- 4.5.4 IPS Project Expansion by 10,000 Barrels per Day and No MGS. If the WIOs Commit to an IPS Gas Cycling Expansion Project of minimum of an additional 10,000 barrels per day by year-end 2019, but that expansion is less than minimum of an additional 20,000 barrels per day, then the acreage in the northern half of ADL 377017 (ADL 377017(N) on Exhibit C), without regard to whether this acreage was included in a technical PA application or is included in the PA as the result of a technical PA expansion under Paragraph 4.4.3, and the acreage listed as within ADLs 377016, 389728 and 389730 in Area E on Exhibit C, shall be released to the State Without Appeal. The remaining acreage listed within Area E on Exhibit C shall be included in the acreage listed in Area D on Exhibit C and subject to the terms of the PTUA including applicable State law.

- 4.5.5 IPS Project Expansion by 20,000 Barrels per Day or a Point Thomson Gas Development / Prudhoe Bay Enhanced Recovery Project and No MGS. If IPS Project Start-up has occurred and the WIOs have Committed to either: (1) an IPS Gas Cycling Expansion Project of a minimum of an additional 20,000 barrels per day; or (2) a Point Thomson Gas Development / Prudhoe Bay Enhanced Recovery Project by year-end 2019, then all acreage, except as set forth in Paragraph 4.7, shall remain in the Point Thomson Unit at year-end 2019 and shall be entitled to be included in a PA as set forth in Paragraphs 4.4.2 and 4.5.1.
- 4.5.6 IPS with MGS. If IPS Project Start-up has occurred and a Major Gas Sale has been Sanctioned by year-end 2019, then all acreage, except as set forth in Paragraph 4.7, shall remain in the Point Thomson Unit at year-end 2019 and shall be entitled to be included in a PA as set forth in Paragraphs 4.4.2 and 4.5.1.
- 4.5.7 MGS Sanctioned – No IPS Project. If IPS Project Start-up has not occurred and a Major Gas Sale is Sanctioned prior to year-end 2019, any acreage that contracts from the Point Thomson Unit under Paragraph 4.2 of this Agreement shall not be recommitted to the Point Thomson Unit. Acreage remaining in the Point Thomson Unit shall be subject to Paragraphs 4.4.2 and 4.5.1.
- 4.5.8 Area B. If (i) an expanded PA based on technical information has not been approved as provided in Paragraph 4.4.3 that includes all of Area B or (ii) if a gathering line is not constructed and the well on the West Pad is not placed on Continuous Operations into the IPS by year-end 2019, then any of the West Pad Area (Area B) acreage listed on Exhibit C that was originally included in the PA

for the Thomson Reservoir pursuant to Paragraph 4.4.1, but subsequently has not been included in the PA expansion as provided for in Paragraph 4.4.3, shall be removed from the PA and included within Area D on Exhibit C, and thereafter shall be subject to the terms of the PTUA including applicable State law.

4.5.9 Segregation of Leases Released to State or Contracted from the Unit. Any lease, a portion of which is released to the State under Paragraphs 4.2 or 4.5, shall be segregated into a separate and distinct lease as to the portion remaining within the Point Thomson Unit, which does not include the portion that contracts out of the Point Thomson Unit and is released to the State, and the provisions of the original lease shall apply to the segregated portion that remains in the Point Thomson Unit.

4.6 Plans of Development/Future Work Plans. The WIOs shall prepare plans of further development and operation for the Point Thomson Unit under Section 10 of the PTUA (“Future POD”) as provided in this Paragraph 4.6 for the periods set forth. Work plans for Point Thomson Unit acreage in Area F of Exhibit C shall be subject to the terms of Paragraph 4.7, not this Paragraph 4.6.

4.6.1 Major Gas Sale Sanction. If a Major Gas Sale is Sanctioned prior to year-end 2019, then within ninety (90) days following the Sanction date, the WIOs shall submit a Future POD that includes work plans and project activities to develop the Point Thomson Reservoir for a Major Gas Sale (the initial and each Future POD under this Paragraph 4.6.1 is hereinafter referred to as an “MGS POD”). Upon Project Start-up associated with an MGS POD, the obligations set forth in

Paragraph 4.1.1 shall terminate. The initial MGS POD shall be effective as of the date a Major Gas Sale is Sanctioned and shall remain in effect for two years following that date and until a subsequent MGS POD is approved. Subsequent MGS PODs shall be submitted to DNR within ninety (90) days before expiration of the prior MGS POD. Each MGS POD shall cover a period of two years and shall address the information contained in Paragraph 4.6.4. Following submittal of each MGS POD, DNR shall have sixty (60) days to review the MGS POD. Unless DNR provides the WIOs written notice that the MGS POD is inconsistent with the terms of this Agreement, the MGS POD is approved effective the date set forth above, even if DNR approval of the MGS POD occurs after that date.

- 4.6.2 Expansion Project Planning. Consistent with Paragraph 4.1.6.2, if a Major Gas Sale has not been Sanctioned by June 1, 2016, the WIOs must begin engineering and permitting of a Point Thomson Expansion Project. The WIOs shall submit a Future POD that includes work plans for evaluation and selection of an option for development of the Point Thomson Reservoir through a Point Thomson Expansion Project (“Expansion Planning POD”). The Expansion Planning POD shall be effective one year following IPS Project Start-up but no later than May 1, 2017, and shall remain in effect until the earlier of: (1) the effective date of an Expansion Project POD under Paragraph 4.6.3; (2) the effective date of an MGS POD under Paragraph 4.6.1; or (3) December 31, 2019 if a Major Gas Sale has not been Sanctioned and the WIOs do not Commit to a Point Thomson Expansion Project prior to that date. The Expansion Planning POD may supplement the work plans set forth in Paragraphs 4.1.1 through 4.1.4. The Expansion Planning

POD shall be submitted no later than ninety (90) days following the Expansion Planning POD effective date provided above and shall address the information contained in Paragraph 4.6.4. Following submittal of the Expansion Planning POD, DNR shall have sixty (60) days to review the Expansion Planning POD. Unless DNR provides the WIOs written notice that the Expansion Planning POD is inconsistent with the terms of this Agreement, the Expansion Planning POD is approved effective the date set forth above, even if DNR approval of the Expansion Planning POD occurs after that date.

4.6.3 Expansion Project Commitment. If a Major Gas Sale has not been Sanctioned by year-end 2019, and the WIOs Commit to a Point Thomson Expansion Project on or before year-end 2019, then the WIOs shall submit a Future POD based on the Expansion Planning POD work product that describes work plans and project activities to develop the Point Thomson Reservoir through a Point Thomson Expansion Project (the initial and each subsequent Future POD under this Paragraph 4.6.3 is hereinafter referred to as an "Expansion Project POD"). Upon Project Start-up of a Point Thomson Gas Development / Prudhoe Bay Enhanced Recovery Project, the obligations set forth in Paragraph 4.1.1 shall terminate. Upon DNR approval, the initial Expansion Project POD shall be deemed effective on January 1, 2020 unless the WIOs Commit to a Point Thomson Expansion Project and an Expansion Project POD is approved prior to year-end 2019, and shall remain in effect for two years following that approval and until a subsequent Expansion Project POD is approved. The initial Expansion Project POD shall be submitted no later than ninety (90) days following the date the WIOs Commit to a

Point Thomson Expansion Project. Subsequent Expansion Project PODs shall be submitted to DNR within ninety (90) days before expiration of the prior Expansion Project POD. Each Expansion Project POD shall cover a period of two years and shall address the information contained in Paragraph 4.6.4. Following submittal of each Expansion Project POD, DNR shall have sixty (60) days to review the Expansion Project POD. Unless DNR provides the WIOs written notice that the Expansion Project POD is inconsistent with the terms of this Agreement, the Expansion Project POD is approved effective the date set forth above, even if DNR approval of the Expansion Project POD occurs after that date.

4.6.4 POD Information. Consistent with this Paragraph 4.6, Future PODs shall include plans to address the following:

- (a) data acquisition and technical evaluations and qualifications to support the development plan;
- (b) well planning including identification of the number of drill wells, well locations, and completion plans;
- (c) project design basis and engineering plans for infrastructure, well pads, and process facilities;
- (d) acquisition of permits and other approvals to accommodate drilling, construction, production transportation, and operations;
- (e) operation and maintenance considerations;

- (f) construction and start-up including estimated timing to complete the work activities;
- (g) logistics; and
- (h) safety, security, health, and environmental considerations.

4.6.5 POD Implementation. Any dispute regarding a Future POD, including whether a Future POD is consistent with this Agreement, whether WIOs are diligently progressing a project to develop the Point Thomson Reservoir for a Major Gas Sale, or whether WIOs are diligently progressing a Point Thomson Expansion Project consistent with this Agreement shall be subject to Paragraph 5.1. Any dispute related to a Future POD shall not be used as the basis to seek Point Thomson Unit contraction or release of acreage, unless DNR asserts the WIOs are not diligently progressing a project to develop the Point Thomson Reservoir for a Major Gas Sale or a Point Thomson Expansion Project consistent with this Agreement.

4.7 Area F. If the WIOs submit a POD for the Brookian by year-end 2018 that is approved by DNR, the acreage listed in Area F on Exhibit C shall remain in the Point Thomson Unit after any Unit contraction at year-end 2019 and shall be maintained through approved PODs or formation of expanded or new PA(s) in accordance with the PTUA including applicable State law. If the WIOs do not submit a Brookian POD by year-end 2018 or if DNR does not approve the Brookian POD, the acreage listed in Area F on Exhibit C shall be released to the State Without Appeal.

4.8 Royalty. Following IPS Project Start-up, the WIOs may submit a royalty modification application requesting a royalty reduction. DNR denial of the application does not relieve the WIOs or the State of their commitments to abide by the terms of this Agreement.

4.8.1 If applicable, the application shall be submitted pursuant to Alaska statutory provisions and shall be submitted and evaluated pursuant to Alaska law.

4.8.2 If the application is not submitted pursuant to Alaska statutory provisions, the WIOs may apply for royalty modification under this Paragraph 4.8.2. The State shall evaluate this application in good faith and the WIOs shall provide DNR with sufficient information to process the application. A decision by DNR denying an application submitted under this Paragraph 4.8.2 for any reason, including a determination that DNR may not legally approve that application because it does not have the authority to do so, shall be Without Appeal.

4.9 Lease Assignments. Within ninety (90) days of the Effective Date, the State agrees to approve lease assignments for each of the leases identified on Exhibit B as PTU Tract No. 1 through Tract No. 38, in the manner requested in writing by ExxonMobil, BP Exploration (Alaska) Inc., Chevron U.S.A. Inc., and ConocoPhillips Alaska, Inc., who, as represented by those requesting parties, are the only lessees to those assignments.

4.10 Litigation.

4.10.1 Joint Motions. Within ten (10) days of the date this Agreement is executed, the Parties shall jointly and simultaneously file: (a) a motion to vacate the February 11, 2010 Order Granting Stay of Proceedings in the Point Thomson Superior Court Case; and (b) a motion to vacate the December 26, 2007 and January 11, 2010 decisions in the Point Thomson Superior Court Case (“Joint Motion”). A copy of this Agreement shall be included with the filings. The Joint Motion described in Paragraph 4.10.1(b) shall expressly affirm that the DNR Point Thomson Orders will be automatically withdrawn as set forth in Paragraph 4.10.3 if the Joint Motion described in Paragraph 4.10.1(b) is granted.

4.10.2 Effective Date of Agreement. The effective date of this Agreement (“Effective Date”) shall be the later of: (i) the date the Superior Court grants the Joint Motion described in Paragraph 4.10.1(b); (ii) the date of dismissal of the Point Thomson Supreme Court Case; and (iii) the date of dismissal of the Point Thomson Superior Court Case. If the Superior Court denies the Joint Motion described in Paragraph 4.10.1(b), or the Point Thomson Supreme Court Case and the Point Thomson Superior Court Case are not dismissed, this Agreement shall not become effective.

4.10.3 Other DNR Requirements.

4.10.3.1 Immediately upon the granting of the Joint Motion described in Paragraph 4.10.1(b), the DNR Point Thomson Orders shall be automatically withdrawn. Any authorization or approval issued by DNR as a result of any

of the DNR Point Thomson Orders allowing the WIOs to conduct activity within the Point Thomson Unit area shall not be affected by such action and shall remain valid and effective by its terms.

4.10.3.2 Within ten (10) days of the date the Superior Court grants the Joint Motion described in Paragraph 4.10.1(b), the Parties shall file a joint dismissal of the Point Thomson Supreme Court Case and the Point Thomson Superior Court Case pursuant to Alaska Appellate Rule 511.

4.10.4 Other Owner Requirements. Within ten (10) days of the Effective Date, the Owner Group shall file a release of Amended Notice of Lis Pendens in the Point Thomson Superior Court Case.

4.10.5 Other Joint Motions. Within ten (10) days of the Effective Date, the Parties shall jointly move to dismiss with prejudice the remaining Point Thomson Cases. A copy of this Agreement shall be included with each filing.

4.10.6 Costs and Fees. For purposes of this Paragraph 4.10, the State and the Owner Group shall each bear their own costs and attorney's fees.

4.11 Point Thomson Unit Status. By signing this Agreement, the Parties confirm that the Point Thomson Unit, the PTUA, and the Point Thomson Unit Operating Agreement have remained in effect since originally approved, and remain in effect as of the date of this Agreement as modified by this Agreement.

4.12 Interpretation. In the event of any conflict or inconsistency between this Agreement and the PTUA, this Agreement controls. Subject to and as modified by the terms of

this Agreement, the relationship between DNR and the WIOs shall continue to be governed by the PTUA including applicable State law.

4.13 Alaska Hire. Within the constraints of law, when the Unit Operator hires, it agrees to employ Alaska residents and contract with Alaska businesses to provide goods and services to support and work on construction, fabrication, or operation at Point Thomson to the extent Alaska residents or Alaska businesses are available, ready, willing, cost competitive, in compliance with all safety and environmental standards, qualified and able to accept employment at the time required, and are located in Alaska. The Unit Operator shall use, as far as is practicable, job centers and associated services operated by the Department of Labor and Workforce Development. The Unit Operator shall advertise for available positions locally and use, as far as practicable, Alaska job service organizations to notify the Alaskan public.

4.14 Force Majeure. The terms of this Agreement are subject to the unavoidable delay provisions of Section 25 of the PTUA. For the purposes of this Agreement, failure to timely receive permit approvals or other authorizations, despite the exercise of due care and diligence of the WIOs, is considered an unavoidable delay under Section 25 of the PTUA. Notwithstanding the foregoing, failure to obtain AOGCC approval related to the Point Thomson Gas Development / Prudhoe Bay Enhanced Recovery Project is not force majeure and will not be considered an unavoidable delay under Section 25 of the PTUA.

4.15 Dates Subject to Adjustment. Decisions, work activities, and dates associated with Thomson Reservoir development are interrelated. Except as specifically provided in

Paragraph 4.15.1, if one or more force majeure events result in an extension of the date for IPS Project Start-up by at least one full year from the date provided in Paragraph 4.1.1.2 as may be adjusted herein, regardless of the actual term of any single force majeure event, then for each full one-year period that IPS Project Start-up is delayed, the dates for future Thomson Reservoir decisions and work activities, including dates associated with a Point Thomson Expansion Project or Thomson Reservoir development for a Major Gas Sale, shall be extended by a corresponding period of time. This provision is applicable each and every time IPS Project Start-up is delayed by at least one additional full year. This Paragraph 4.15 shall apply in addition to any extension or adjustment to a date in this Agreement resulting from a force majeure event under Paragraph 4.14.

4.15.1 Dates Not Subject to Adjustment. The following dates are not subject to adjustment under Paragraphs 4.14 and 4.15:

- (a) the expiration date (year-end 2019) for the Abandonment provision under Paragraph 4.2.4;
- (b) the year-end 2007 to year-end 2015 time period for determination of project costs if the WIOs Abandon the IPS Project as provided under Paragraph 4.2;
- (c) the date (year-end 2018) for WIO submittal of a Brookian POD under Paragraph 4.7; and
- (d) the date for application of DNR standard administrative processes under Paragraph 5.1.3.1.

The number of days for submitting information or providing notice under this Agreement (e.g., “within ninety (90) days”) are not subject to adjustment under Paragraph 4.14, including the number of days for submitting and approving Future PODs under Paragraph 4.6.

- 4.16 Taxes and Royalty for Point Thomson Gas Development / Prudhoe Bay Enhanced Recovery Project. The Parties agree that any gas produced from a reservoir within the Point Thomson Unit and injected into a reservoir within the Prudhoe Bay Unit pursuant to a Point Thomson Gas Development / Prudhoe Bay Enhanced Recovery Project is only subject to tax and royalty one time.
- 4.16.1 Tax on Injected Gas. The Parties recognize that Alaska law regarding oil and gas production tax provides that gas produced from the Point Thomson Unit that would be used according to 15 AAC 55.151(e) in effect as of the Effective Date, and that would be injected into a reservoir within the Prudhoe Bay Unit in the course of operations of a Point Thomson Gas Development / Prudhoe Bay Enhanced Recovery Project for purposes of repressuring, including enhanced recovery, would be exempt from taxation at the time of its production from the Point Thomson Unit and would be subject to tax only at the time the gas would be ultimately produced for sale from the Prudhoe Bay Unit.
- 4.16.2 Royalty on Point Thomson Gas Development / Prudhoe Bay Enhanced Recovery Project Gas. If the WIOs Commit to and complete construction of a Point Thomson Gas Development / Prudhoe Bay Enhanced Recovery Project, then, upon Project Start-up, the State, as authorized by the Point Thomson leases and

applicable State law, will elect, for the period prior to Project Start-up of a Major Gas Sale, to take in-kind the State's royalty share of gas produced from the Point Thomson Unit when produced into the gas pipeline from Point Thomson to Prudhoe Bay referenced in Paragraph 2.21(i). Terms implementing this royalty in kind election are as follows.

4.16.2.1 Definitions. Whenever the following terms are used in this Paragraph 4.16.2, they shall have the meanings set forth in this Paragraph 4.16.2.1. Other capitalized terms shall have the meaning set forth in Paragraph 2 of this Agreement.

- (a) "Delivery Point" means: (1) the terminus of the PTU / PBU Gas Pipeline in the Prudhoe Bay Unit ("PBU Delivery Point") if the PTU / PBU Gas Pipeline has been exempted from the requirement of a right-of-way lease under AS 38.35 ("Unregulated PTU / PBU Gas Pipeline"); or (2) the point where Point Thomson gas is produced and first delivered into the PTU / PBU Gas Pipeline ("PTU Delivery Point") if the PTU / PBU Gas Pipeline has not been exempted from the requirement of a right-of-way lease under AS 38.35 ("Regulated PTU / PBU Gas Pipeline").
- (b) "Field Costs" means costs incurred by lessee that may be reimbursed or deducted from royalty gas under the Point Thomson leases and other applicable agreements.

- (c) "Fuel / Losses" means any fuel consumption or losses associated with transporting gas through the PTU / PBU Gas Pipeline.
- (d) "PBU" means the Prudhoe Bay Unit.
- (e) "PTU / PBU Gas Pipeline" means the gas pipeline to be constructed for a Point Thomson Gas Development / Prudhoe Bay Enhanced Recovery Project that will begin in the Point Thomson Unit and terminate in the Prudhoe Bay Unit.
- (f) "State RIK Gas" means the State's royalty share of gas produced from the Point Thomson Unit into the PTU / PBU Gas Pipeline that is taken by the State in kind, as described in this Paragraph 4.16.2.
- (g) "Transportation Costs" means costs for transporting gas through the PTU / PBU Gas Pipeline.

4.16.2.2 General Terms.

- (a) If the WIOs Commit to and complete construction of a Point Thomson Gas Development / Prudhoe Bay Enhanced Recovery Project, the State, as authorized by the Point Thomson leases and applicable State law, will elect to take in kind State royalty due when Point Thomson gas is produced into the PTU / PBU Gas Pipeline, with State RIK Gas delivered to the State at the Delivery Point.

- (b) The State may take all or any portion of State RIK Gas for sale or other use at the time it is delivered to the Delivery Point.
- (c) State RIK Gas not taken for sale or other use by the State at the time it is delivered to the Delivery Point will be injected into the PBU reservoir, where the gas will be used for enhanced liquids recovery.
- (d) The State will retain title and risk of material loss on State RIK Gas in the PBU reservoir, but will not be responsible for any costs, payments, or fees, or charged for fuel or other operational losses, associated with use of State RIK Gas in the PBU reservoir.
- (e) The State will not charge any costs, payments, or fees, nor require receipt of any other benefit for use of State RIK Gas that is delivered to the Delivery Point and injected into the PBU reservoir, beyond any royalty provided for under applicable PBU leases and other applicable agreements on liquids recovered from the PBU reservoir.

4.16.2.3 Transportation Costs, Field Costs, and Fuel / Losses. Except as interpreted or modified by the terms set forth in this Paragraph 4.16.2, any Transportation Costs, Fuel / Losses and Field Costs associated with State RIK Gas shall be addressed as set forth in the Point Thomson leases and other applicable agreements. The manner in which Transportation Costs, Fuel / Losses and Field Costs are addressed depends on whether the PTU /

PBU Gas Pipeline is a Regulated PTU / PBU Gas Pipeline or an Unregulated PTU / PBU Gas Pipeline at the time the State RIK Gas is produced and delivered into the PTU / PBU Gas Pipeline, recognizing that the status of the PTU / PBU Gas Pipeline may change. In addition, upon Project Start-Up of a Major Gas Sale, the treatment of these costs may change. No interest will be charged on any of the State's accrued Transportation Costs and Fuel / Losses prior to the due date under this Paragraph 4.16.2.

(a) Regulated PTU / PBU Gas Pipeline.

i. The State will pay Transportation Costs and be responsible for Fuel / Losses for State RIK Gas that is delivered to the State at the PTU Delivery Point pursuant to the terms of the approved transportation tariff for the PTU / PBU Gas Pipeline.

1. For State RIK Gas that is delivered to the State at the PTU Delivery Point and not injected into the PBU reservoir, the Transportation Costs will be paid by the State and deductions made for Fuel / Losses at the time of delivery to the State at the PTU Delivery Point.

2. For State RIK Gas that is delivered to the State at the PTU Delivery Point and is then injected into the PBU reservoir for enhanced liquids recovery, the Transportation Costs will accrue and deductions made for Fuel / Losses, but will not be

paid by the State until State RIK Gas is delivered from the PBU reservoir to the State for sale or other use.

- ii. For State RIK Gas produced prior to Project Start-up of a Major Gas Sale, the State will not be responsible for Field Costs for State RIK Gas that is delivered to the State at the PTU Delivery Point, regardless of whether the State RIK Gas is injected into the PBU reservoir. For Point Thomson gas produced after Project Start-up of a Major Gas Sale, the State will be responsible for Field Costs to the extent provided under the Point Thomson leases and other applicable agreements.

(b) Unregulated PTU / PBU Gas Pipeline.

- i. If costs for the Point Thomson Gas Development / Prudhoe Bay Enhanced Recovery Project, including the PTU / PBU Gas Pipeline, were entitled to and received deductions and credits under AS 43.55, with substantially the same credits / benefits as exists under AS 43.55 on the Effective Date, then the State will not be responsible for Transportation Costs or Fuel / Losses associated with delivery of State RIK Gas to the State at the PBU Delivery Point prior to Project Start-up of a Major Gas Sale.
- ii. If costs for the Point Thomson Gas Development / Prudhoe Bay Enhanced Recovery Project, including the PTU / PBU Gas Pipeline, were not entitled to or did not receive deductions and

credits under AS 43.55, with substantially the same credits/benefits as exists under AS 43.55 on the Effective Date, then the State will be responsible for Transportation Costs and Fuel / Losses associated with the delivery of State RIK Gas to the State at the PBU Delivery Point.

1. If State RIK Gas is not injected into the PBU reservoir, payment of Transportation Costs and deductions for Fuel / Losses will be due at the time of delivery of State RIK Gas to the State at the PBU Delivery Point.
 2. If State RIK Gas is injected into the PBU reservoir, payment of Transportation Costs and deductions for Fuel / Losses will be due from the State when State RIK Gas is delivered from the PBU reservoir to the State for sale or other use.
- iii. For State RIK Gas produced prior to Project Start-up of a Major Gas Sale, the State will not be responsible for Field Costs for State RIK Gas that is delivered to the State at the PTU Delivery Point, regardless of whether the State RIK Gas is injected into the PBU reservoir. For Point Thomson gas produced after Project Start-Up of a Major Gas Sale, the State will be responsible for Field Costs to the extent provided under the Point Thomson leases and other applicable agreements.

4.16.2.4 State RIK Gas Allocation Principles.

- (a) For State RIK Gas Injected into the PBU reservoir:
- i. Each WIO is responsible for delivery to the State and the State will take deliveries of State RIK Gas proportionately from each WIO.
 - ii. State RIK Gas will be subject to gas balancing agreement procedures that will be developed between the affected parties, including the State.
 - iii. State RIK Gas injected into the PBU reservoir will be available for delivery to the State from the PBU reservoir at any then-existing PBU facilities, including any facilities installed for a Major Gas Sale, at a location designated by PBU owners.
 - iv. Delivery of State RIK Gas to the State will not be unreasonably withheld.
 - v. Deliveries of State RIK Gas from the PBU reservoir may not unreasonably interfere with ongoing PBU operations.
 - vi. If delivery from the PBU reservoir is constrained at PBU delivery point(s), gas availability will be allocated 75% to PBU gas and 25% to Point Thomson gas. The allocation to Point Thomson gas will remain fixed even if other gas is injected into the PBU reservoir from another reservoir.

- (b) Specific Principles Before Project Start-up a Major Gas Sale. If the State is taking delivery of State RIK Gas for sale or other use for delivery into a facility or pipeline connected to the PTU / PBU Gas Pipeline, the State will preferentially take delivery of State RIK Gas that has not been injected into the PBU Reservoir; otherwise, subject to constraints listed above, the State may take delivery of State RIK Gas that has been injected into the PBU reservoir.

- (c) Specific Principles After Project Start-up of a Major Gas Sale.
 - i. For gas produced from Point Thomson after Project Start-up of a Major Gas Sale, the State from time to time may elect to take its royalty share in value or in kind pursuant to the Point Thomson leases, other applicable agreements and applicable State law.

 - ii. For State RIK Gas that was injected into the PBU reservoir prior to Project Start-up of a Major Gas Sale, the State may take delivery of its State RIK Gas from the PBU reservoir, or may from time to time, by notice consistent with the notice requirements of the Point Thomson leases and other applicable agreements, elect to take payment in-value as follows:
 - 1. Whether the State receives gas or a payment for its share of State RIK Gas produced from the PBU reservoir, the share will be measured in proportion to gas offtake allocated to Point Thomson gas injected into the PBU reservoir, adjusted

for any withdrawal of State RIK Gas and WIO Point Thomson gas prior to Project Start-up of a Major Gas Sale.

2. Whether the State receives gas or a payment for its share of State RIK Gas produced from the PBU reservoir, there will be no deduction for Field Costs, but the deductions for Transportation Costs and Fuel / Losses, as set forth in Paragraph 4.16.2.3, will apply.
3. If the State elects to receive a payment for its share of State RIK Gas that was injected into the PBU reservoir prior to Project Start-up of a Major Gas Sale, payment will be calculated based on the royalty in value basis for Point Thomson gas under the applicable leases, at the time the gas is withdrawn from the PBU reservoir.

5. MISCELLANEOUS PROVISIONS

5.1 Dispute Resolution. The following provisions shall apply to this Agreement:

- 5.1.1 Until the date set forth in Paragraph 5.1.3.1, with respect to any dispute regarding the Parties' rights and obligations under this Agreement, including any matter that otherwise would be subject to DNR standard administrative processes as set forth in 11 AAC 02.010-02.900, a Party may file an action in the Superior Court of the State of Alaska as set forth in Paragraph 5.5, except for matters set forth in Paragraph 5.1.2 or an Abandonment dispute via arbitration under Paragraph 4.2.3.

Thereafter, DNR standard administrative processes as set forth in 11 AAC 02.010-02.900 shall apply to any dispute regarding the Parties' rights and obligations under this Agreement as provided under the PTUA and applicable State law. Within the application of DNR's administrative processes the Parties do not waive any rights under applicable State law.

5.1.2 Decisions Subject to DNR Standard Administrative Processes.

(a) The following matters shall be subject to DNR standard administrative processes as set forth in 11 AAC 02.010-02.900, including the right of appeal to the Commissioner, the right of appeal to the Superior Court of the State of Alaska, and the right of appeal to the Supreme Court of the State of Alaska.

- i. Decisions regarding a technical PA application under Paragraph 4.4.3.
- ii. Decisions regarding inclusion of acreage in Area B and Area D in a PA and retention of that acreage in the Point Thomson Unit that are specifically governed by or subject to the PTUA including applicable State law as provided in Paragraphs 4.5.3, 4.5.4, and 4.5.8.
- iii. Decisions related to providing PA documentation and tract allocations as provided in Paragraph 4.4.6.

(b) The following matters shall be subject to DNR standard administrative processes as set forth in 11 AAC 02.010-02.900, including the right of

appeal to the Commissioner, but otherwise are Without Appeal, with no right of appeal to the Superior Court of the State of Alaska or to the Supreme Court of the State of Alaska. Any DNR decision that is Without Appeal shall not have any precedential effect in any other matter, case, or dispute.

- i. Decisions regarding the Brookian POD as provided in Paragraph 4.7.
- ii. Decisions associated with an alternative POD as provided in Paragraph 4.5.2.2.
- iii. Decisions associated with a royalty application as provided in Paragraph 4.8.2.
- iv. Decisions associated with a Plan of Operations for leases as provided in Paragraph 4.5.2.3.

5.1.3 The Parties agree that this Agreement is a contract between the Parties. Subject to Paragraph 5.1.3.2, DNR standard administrative processes as set forth in 11 AAC 02.010-02.900 shall include the right of any WIO to appeal a DNR decision or other action to the Superior Court of the State of Alaska, and the right to appeal any judgment of the Superior Court to the Supreme Court of the State of Alaska. Application of DNR standard administrative processes does not provide any right or basis for the State to alter the terms of this Agreement. DNR discretion and the authority to take action or make a decision regarding Point Thomson may only be

exercised by DNR in a manner that, consistent with Paragraph 5.7, does not conflict with the terms of this Agreement.

5.1.3.1 The date for application of DNR standard administrative processes as set forth in 11 AAC 02.010-02.900 and as provided in Paragraph 5.1.1 shall be the later of the following:

- (1) year-end 2019, if IPS Project Start-up occurs or a Major Gas Sale is Sanctioned before year-end 2019;
- (2) the date of IPS Project Start-up, if the date of IPS Project Start-up occurs after year-end 2019 due to force majeure under Paragraph 4.14; however, not later than year-end 2024, which date is fixed and not subject to adjustment even if IPS Project Start-up has not occurred by year-end 2024.

5.1.3.2 Paragraph 5.1.1 does not apply to DNR decisions referenced in Paragraph 5.1.2(b).

5.1.4 Any Party may dispute whether a specified event has occurred that pursuant to the terms of this Agreement would result in termination of the Point Thomson Unit Without Appeal or release of acreage Without Appeal under Paragraphs 4.2.2, 4.5.2.1, 4.5.3, or 4.5.4, with the dispute handled in accordance with Paragraph 5.1. In the event of such dispute, termination of the Point Thomson Unit Without Appeal or the release of acreage Without Appeal shall not be required until there has been a final judicial determination as to the occurrence of the specified event, or upon an Abandonment determination via arbitration under Paragraph 4.2.3.

This Paragraph 5.1.4 does not apply to DNR decisions referenced in Paragraph 5.1.2(b).

5.1.5 Any dispute that would be subject to the terms of the PTUA shall be determined in accordance with the PTUA including applicable State law.

5.2 No Admission. This Agreement does not constitute and shall not be deemed to be an admission by any Party about the merits, validity, or accuracy of any of the allegations, claims, or defenses of any Party.

5.3 Entire Agreement. This Agreement, including all exhibits attached hereto or referenced herein (all of which are hereby incorporated herein by this reference), represents the complete agreement of the Parties. This Agreement may not be modified, amended, or changed except by written instrument signed by each Party.

5.4 Term of Agreement. Unless earlier terminated in accordance with the provisions hereof, this Agreement shall remain in full force and effect until all obligations have been performed and all rights satisfied.

5.5 Enforcement. No Party shall contest: (a) the validity of this Agreement; (b) subject to Paragraph 5.1, the jurisdiction of the Superior Court of the State of Alaska to enforce this Agreement and its terms or the right of any Party to file an action in the Superior Court of the State of Alaska for enforcement of any of the terms of this Agreement or to enforce an arbitration decision; or (c) the authority of DNR to issue decisions as provided for in Paragraphs 5.1.1, 5.1.2, and 5.1.3.

- 5.6 Waiver. The failure by any Party at any time to require performance by any other Party or to claim a breach of any provision of this Agreement shall not be construed as affecting any subsequent breach or the right to require performance or to claim a breach with respect thereto.
- 5.7 Further Assurances. In proceedings before the Alaska Oil and Gas Conservation Commission regarding approvals related to the IPS Project, a Point Thomson Expansion Project, or a Point Thomson project related to a Major Gas Sale, the DNR agrees it will not oppose any such application submitted that is consistent with the terms of this Agreement and applicable State law.
- 5.8 Validity. The Commissioner has determined that entry into this Agreement and the individual terms and conditions set forth herein are necessary or advisable to protect the public interest, including a determination that the taking in kind of royalty as provided in Paragraph 4.16.2 will be in the best interests of the State. If any provision of this Agreement shall be held to be invalid or unenforceable, such provisions shall not affect in any respect the validity or enforceability of the remainder of this Agreement unless the invalidity materially affects the ability of any Party to perform as contemplated hereunder.
- 5.9 Order of Precedence. While the exhibits are an integral part of this Agreement, in the event any exhibit conflicts with a provision in the body of this Agreement, the provision in the body of this Agreement shall control, unless that provision of the exhibit expressly states that it supersedes a specifically identified section in the body of

this Agreement, in which case the specifically identified section shall be superseded only with respect to the specific provision of the exhibit.

- 5.10 Effect of Headings. The headings and subheadings of the sections and paragraphs of this Agreement are inserted for convenience of reference only and shall not control or affect the meaning or construction of any of the terms, covenants, and conditions of this Agreement in any manner.
- 5.11 Construction. The Parties agree that this Agreement was fully negotiated by the Parties and, therefore, no provision of this Agreement shall be interpreted against any Party because that Party or its legal representative drafted the provision.
- 5.12 Counterparts and Facsimile Signature. This Agreement may be executed in counterparts and each shall be deemed an original. This Agreement may also be executed by facsimile signature.
- 5.13 Governing Law. This Agreement shall be governed in all respects by the laws of the State of Alaska without regard to its choice of law or conflict of law provisions.
- 5.14 Venue. The Parties agree that any action arising out of or relating to this Agreement shall be brought only in a court of competent jurisdiction in the State of Alaska, with the understanding that the State of Alaska does not waive any right to object to federal court jurisdiction, including its rights under the 11th Amendment of the United States Constitution, nor does the State of Alaska agree to waive sovereign immunity.

5.15 Authority to Sign. Each undersigned representative of a Party to this Agreement certifies that he or she is fully authorized to enter into the terms and conditions of this Agreement and to execute and legally bind such Party to this Agreement.

AGREED, UNDERSTOOD, AND CONSENTED TO:

STATE OF ALASKA

ATTORNEY GENERAL
STATE OF ALASKA

Date _____

Michael C. Geraghty

COMMISSIONER OF DEPARTMENT OF
NATURAL RESOURCES
STATE OF ALASKA

Date _____

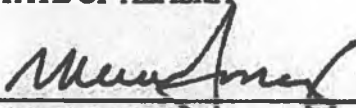
Daniel S. Sullivan

AGREED, UNDERSTOOD, AND CONSENTED TO:

STATE OF ALASKA

ATTORNEY GENERAL
STATE OF ALASKA

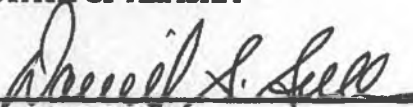
Date 3.28.12



Michael C. Geraghty

COMMISSIONER OF DEPARTMENT OF
NATURAL RESOURCES
STATE OF ALASKA

Date 3/29/12



Daniel S. Sullivan

OWNER GROUP

EXXON MOBIL CORPORATION,
Unit Operator and Working Interest Owner

Date _____

Randy L. Broiles

EXXONMOBIL OIL CORPORATION

Date _____

Randy L. Broiles

BP EXPLORATION (ALASKA) INC.

Date _____

John C. Minge

EXXON MOBIL CORPORATION,
as successor in interest to
CHEVRON U.S.A., INC.

Date _____

Randy L. Broiles

CONOCOPHILLIPS ALASKA, INC.

Date _____

Trond-Erik Johansen

LEEDE OPERATING COMPANY, L.L.C.

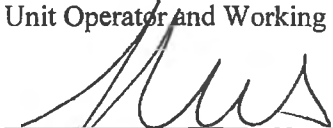
Date _____

John G. Leede, Manager

OWNER GROUP

EXXON MOBIL CORPORATION,
Unit Operator and Working Interest Owner

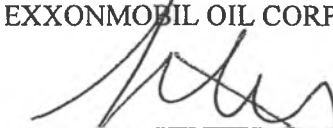
Date 29 MAR 12



Randy L. Broiles *CSB*

EXXONMOBIL OIL CORPORATION

Date 29 MAR 12



Randy L. Broiles *CSB*


BP EXPLORATION (ALASKA) INC.

Date _____

John C. Minge

EXXON MOBIL CORPORATION,
as successor in interest to
CHEVRON U.S.A., INC.

Date 29 MAR 12



Randy L. Broiles *CSB*

CONOCOPHILLIPS ALASKA, INC.

Date _____

Trond-Erik Johansen

LEEDE OPERATING COMPANY, L.L.C.

Date _____

John G. Leede, Manager

Settlement Agreement

March 29, 2012

OWNER GROUP

EXXON MOBIL CORPORATION,
Unit Operator and Working Interest Owner

Date _____

Randy L. Broiles


EXXONMOBIL OIL CORPORATION

Date _____

Randy L. Broiles

BP EXPLORATION (ALASKA) INC.

Date March 29, 2012



John C. Minge

pub

EXXON MOBIL CORPORATION,
as successor in interest to
CHEVRON U.S.A., INC.

Date _____

Randy L. Broiles

CONOCOPHILLIPS ALASKA, INC.

Date _____

Trond-Erik Johansen

LEEDE OPERATING COMPANY, L.L.C.

Date _____

John G. Leede, Manager

Settlement Agreement

March 29, 2012

OWNER GROUP

EXXON MOBIL CORPORATION,
Unit Operator and Working Interest Owner

Date _____

Randy L. Broiles

EXXONMOBIL OIL CORPORATION

Date _____

Randy L. Broiles

BP EXPLORATION (ALASKA) INC.

Date _____

John C. Minge

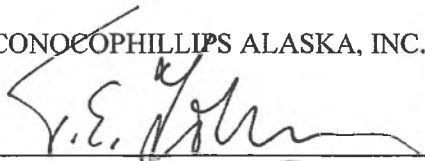
EXXON MOBIL CORPORATION,
as successor in interest to
CHEVRON U.S.A., INC.

Date _____

Randy L. Broiles

CONOCOPHILLIPS ALASKA, INC.

Date 29 March 2012


Trond-Erik Jøhansen *JEP*

LEEDE OPERATING COMPANY, L.L.C.

Date _____

John G. Leede, Manager

OWNER GROUP

EXXON MOBIL CORPORATION,
Unit Operator and Working Interest Owner

Date _____

Randy L. Broiles

EXXONMOBIL OIL CORPORATION

Date _____

Randy L. Broiles

BP EXPLORATION (ALASKA) INC.

Date _____

John C. Minge

EXXON MOBIL CORPORATION,
as successor in interest to
CHEVRON U.S.A., INC.

Date _____

Randy L. Broiles

CONOCOPHILLIPS ALASKA, INC.

Date _____

Trond-Erik Johansen

LEEDE OPERATING COMPANY, L.L.C.

Date March 29, 2012

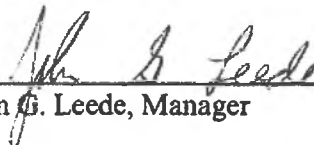

John G. Leede, Manager

EXHIBIT A

Point Thomson Unit

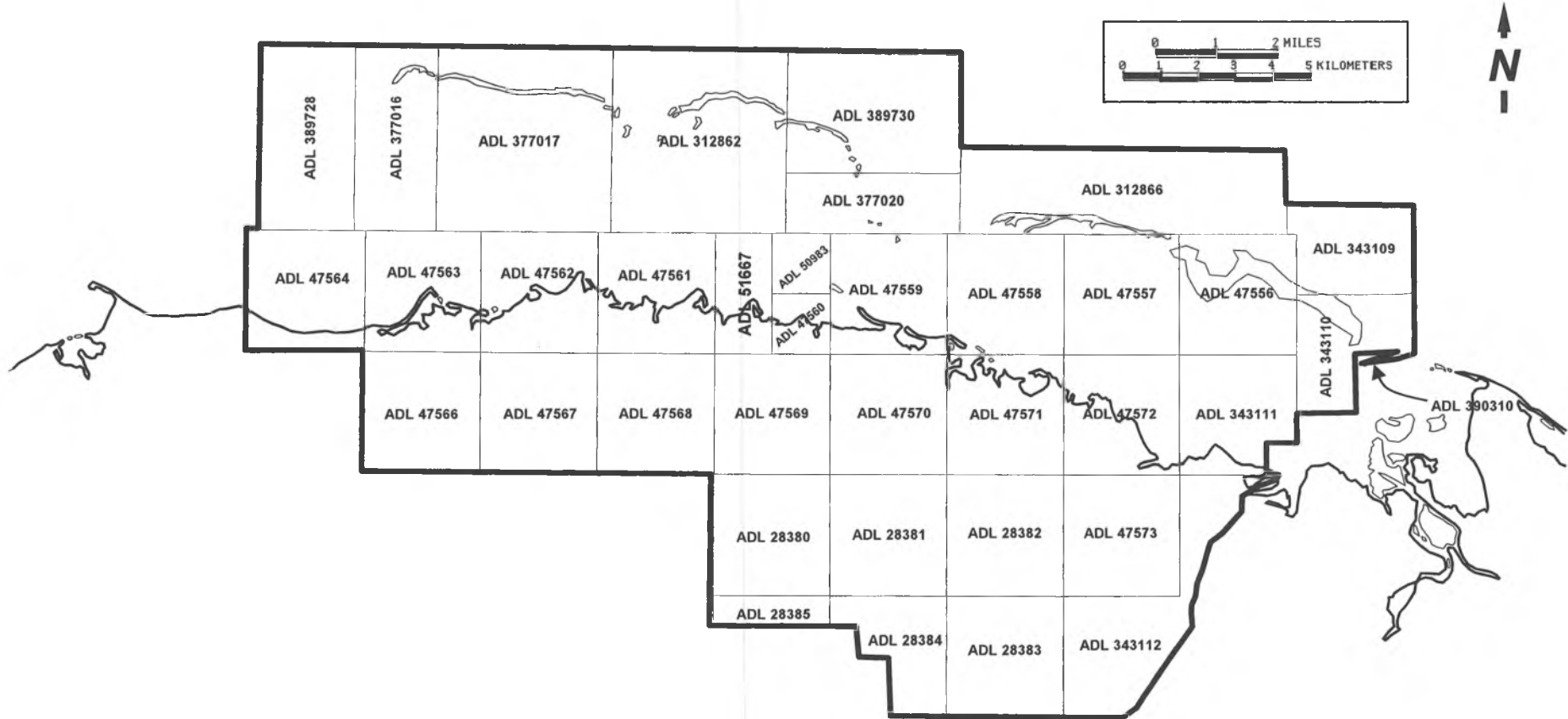


Exhibit B
Point Thomson Unit

New Tract No.	Original Tract No.	Description	Acres	ADL No.	Base Royalty % / NPS %	Lessee(s) of Record	Overriding Royalty Ownership		Working Interest Ownership		
							Owner	Percent	Owner	Percent	Description
1	1	T10N-R24E, UM Secs. 29, 30, 31, and 32	2,523.00	47557	12½/None	Mobil BP	None		Mobil	50.0000000%	All
									BP	50.0000000%	All
2	2	T10N-R23E, UM Secs. 25, 26, 35, and 36	2,560.00	47558	12½/None	Mobil BP ExxonMobil	None		Mobil	50.0000000%	Secs. 25 and 36
										25.0000000%	Secs. 26 and 35
									BP	50.0000000%	Secs. 25 and 36
										25.0000000%	Secs. 26 and 35
		ExxonMobil	50.0000000%	Secs. 26 and 35							
3	3	T10N-R23E, UM Secs. 27, 28, 33, and 34	2,560.00	47559	12½/None	ExxonMobil	None	ExxonMobil	100.0000000%	All	
4	4	T10N-R23E, UM Sec. 32	640.00	47560	12½/None	ExxonMobil COP Leede Pacific Donnelly, G. Hughes Chap-KDL, Ltd. Leede and Pine McConnell Searls, Jr. Donnelly, R. Holbrook O'Neill Donnelly, R.R. Peery, J.W.	Subject to Simasko Farm Out provisions and subsequent Assignment of interest to ExxonMobil		ExxonMobil	50.0000000%	All
									COP	20.1951200%	All
									Leede	10.0975600%	All
									Pacific	5.0000000%	All
									Donnelly, G.	0.5048780%	All
									Hughes	3.6000000%	All
									Chap-KDL, Ltd.	2.2719500%	All
									Leede and Pine	2.0195150%	All
									McConnell	1.5146350%	All
									Searls, Jr.	1.1359750%	All
									Donnelly, R.	0.7573180%	All
									Holbrook	0.7573180%	All
									O'Neill	0.5048780%	All
Donnelly, R.R.	0.5048780%	All									
Peery, J.W.	1.1359750%	All									
5	5	T10N-R22E, UM Secs. 25, 26, 35, and 36	2,560.00	47561	12½/None	ExxonMobil Chevron BP	None		ExxonMobil	75.0000000%	All
									Chevron	11.0000000%	All
									BP	14.0000000%	All
6	6	T10N-R22E, UM Secs. 27, 28, 33, and 34	2,560.00	47562	12½/None	ExxonMobil Devon Mobil Forest Trans World Two Four Six SNG Sunlite	Robert Meek Sabine Royalty Marvin D. Mangus Janet D. Fackler Nadene Pettijohn Donnell O. Wells Hilltop Community Church Peter J. Farrelly Little Sisters of the Poor	0.50000% 0.08313% 0.02771% 0.02771% 0.02771% 0.00354% 0.00236% 0.00236% 0.00236%	ExxonMobil	71.5315773%	All
									Devon	10.0000000%	All
									Mobil	9.5000000%	All
									Forest	5.2473820%	All
									Trans World	1.3289431%	All
									Two Four Six	1.3289431%	All
									SNG	0.5315773%	All
									Sunlite	0.5315773%	All
7	7	T10N-R22E, UM Secs. 29, 30, 31, and 32	2,523.00	47563	12½/None	ExxonMobil Mobil BP	None		ExxonMobil	50.0000000%	All
									Mobil	25.0000000%	All
									BP	25.0000000%	All

New Tract No.	Original Tract No.	Description	Acres	ADL No.	Base Royalty % / NPS %	Lessee(s) of Record	Overriding Royalty Ownership		Working Interest Ownership		
							Owner	Percent	Owner	Percent	Description
8	8	T10N-R21E, UM Secs. 25, 28, 35, and 36	2,560.00	47564	12 1/2 / None	ExxonMobil Mobil BP	None		ExxonMobil Mobil BP	50.00000000% 25.00000000% 25.00000000%	All All All
9	9	Contracted out of PTU									
10	10	T9N-R22E, UM Secs. 5, 6, 7, and 8	2,533.00	47566	12 1/2 / None	ExxonMobil Mobil BP	None		ExxonMobil Mobil BP	50.00000000% 25.00000000% 25.00000000%	All All All
11	11	T9N-R22E, UM Secs. 3, 4, 9, and 10	2,560.00	47567	12 1/2 / None	ExxonMobil Devon Mobil Forest Trans World Two Four Six SNG Sunlite	Robert Meek Sabine Royalty Marvin D. Mangus Janet D. Fackler Nadere Pettijohn Donnell O. Wells Hilltop Community Church Peter J. Farrelly Little Sisters of the Poor	0.500000% 0.08313% 0.02771% 0.02771% 0.02771% 0.00354% 0.00236% 0.00236% 0.00236%	ExxonMobil Devon Mobil Forest Trans World Two Four Six SNG Sunlite	71.5315773% 10.0000000% 9.5000000% 5.2473820% 1.3289431% 1.3289431% 0.5315773% 0.5315773%	All All All All All All All All
							Subject to Simasko Farm Out Agreement providing for assignment to ExxonMobil				
12	12	T9N-R22E, UM Secs. 1, 2, 11, and 12	2,560.00	47568	12 1/2 / None	Chevron BP ExxonMobil	ASRC - Secs 1 and 2 ASRC - Secs 11 and 12	0.500000% 0.250000%	Chevron BP ExxonMobil	44.00000000% 22.00000000% 56.00000000% 28.00000000% 50.00000000%	Secs. 1 and 2 Secs. 11 and 12 Secs. 1 and 2 Secs. 11 and 12 Secs. 11 and 12
13	13	T9N-R23E, UM Secs. 5, 6, 7, and 8	2,533.00	47569	12 1/2 / None	Chevron BP Mobil ExxonMobil	ASRC - Secs 5, 6 and 8 ASRC - Sec. 7	0.250000% 0.083333%	Chevron BP Mobil ExxonMobil	22.00000000% 7.33333000% 28.00000000% 26.00000000% 16.66667000% 50.00000000%	Secs. 5, 6, and 8 Sec. 7 Secs. 5, 6, and 8 Sec. 7 Sec. 7 Secs. 5, 6, 7, and 8
14	14	T9N-R23E, UM Secs. 3, 4, 9, and 10	2,560.00	47570	12 1/2 / None	Chevron BP ExxonMobil	ASRC	0.250000%	Chevron BP ExxonMobil	22.00000000% 28.00000000% 50.00000000%	All All All
15	15	T9N-R23E, UM Secs. 1, 2, 11, and 12	2,560.00	47571	12 1/2 / None	Chevron BP	ASRC	0.500000%	Chevron BP	44.00000000% 56.00000000%	All All
16	16	T9N-R24E, UM Secs. 5, 6, 7, and 8	2,533.00	47572	12 1/2 / None	Chevron BP Mobil	ASRC - Secs 5, and 8 ASRC - Secs. 6 and 7	0.200000% 0.500000%	Chevron BP Mobil	17.60000000% 44.00000000% 52.40000000% 56.00000000% 30.00000000%	Sec. 5 and 8 Sec. 6 and 7 Sec. 5 and 8 Sec. 6 and 7 Sec. 5 and 8

New Tract No.	Original Tract No.	Description	Acres	ADL No.	Base Royalty % / NPS %	Lessee(s) of Record	Overriding Royalty Ownership		Working Interest Ownership		
							Owner	Percent	Owner	Percent	Description
17	17	T10N-R23E, UM Sec. 29	640.00	50983	12 1/2 / None	ExxonMobil BP	Subject to a 1/3 net profits interest to: Leede; Leede and Pine; Phillips; BP; ExxonMobil; Chevron; Donnelly; Chaparral; Searls, Jr.; Hughes; Pacific; Searls, Jeanne; Searls, J.P.; Neidert, L.L.S.; Collier, S.J.S.	ExxonMobil BP	66.6700000% 33.3300000%	All All	
18	18	T10N-R23E, UM Secs. 30 and 31	1,243.00	51667	12 1/2 / None	ExxonMobil Mobil BP Chevron	Conoco Phillips; Leede; Leede and Pine; Donnelly; Hughes; Chaparral; Searls, Jr.; Peery; Pacific; Searls, Jeanne; Searls, J.P.; Neidert, L.L.S.; Collier, S.J.S. ASRC	6.25000% 0.083328%	ExxonMobil Mobil BP Chevron	50.0000000% 16.6670000% 25.9997400% 7.3332600% All All All All	
19	19	T9N-R23E, UM Secs. 17, 18, 19, and 20	2,544.00	28380	12 1/2 / None	Mobil Chevron ExxonMobil BP Woodbine	None	Mobil Chevron ExxonMobil BP Woodbine	54.0464100% 50.0000000% 33.3333350% 14.6666700% 3.2703880% 12.6742800% 51.999950% 29.9997220% 50.0000000% 0.0092000%	Sec. 19 Sec. 20 Sec. 17 and 18 Sec. 17 and 18 Sec. 19 Sec. 17 and 18 Sec. 19 Sec. 20 Sec. 19	
20	20	T9N-R23E, UM Secs. 15, 16, 21, and 22	2,560.00	28381	12 1/2 / None	Chevron BP ExxonMobil	None	Chevron BP ExxonMobil	22.0000000% 28.0000000% 50.0000000%	All All All	
21	21	T9N-R23E, UM Secs. 13, 14, 23, and 24	2,560.00	28382	12 1/2 / None	ExxonMobil Chevron BP	None	ExxonMobil Chevron BP	50.0000000% 22.0000000% 28.0000000%	All All All	
22	22	T9N-R23E, UM Secs. 25, 26, 35, and 36	2,560.00	28383	12 1/2 / None	ExxonMobil Chevron BP	None	ExxonMobil Chevron BP	50.0000000% 22.0000000% 28.0000000%	All All All	
23	23	T9N-R23E, UM Sec. 27, Sec. 28: N/2 and SE/4, Sec. 34	1,760.00	28384	12 1/2 / None	Mobil ExxonMobil Chevron BP Woodbine	None	Mobil ExxonMobil Chevron BP Woodbine	54.0464100% 12.6742800% 3.2703880% 29.9997220% 0.0092000%	All All All All All	
24	24	T9N-R23E, UM Sec. 29: N/2 Sec. 30: N/2	637.00	28385	12 1/2 / None	Mobil ExxonMobil Chevron BP Woodbine	None	Mobil ExxonMobil Chevron BP Woodbine	54.0464100% 12.6742800% 3.2703880% 29.9997220% 0.0092000%	All All All All All	

New Tract No.	Original Tract No.	Description	Acres	ADL No.	Base Royalty % / NPS %	Lessee(s) of Record	Overriding Royalty Ownership		Working Interest Ownership		
							Owner	Percent	Owner	Percent	Description
25	25	T10N-R24E, UM Secs. 27, 28, 33, and 34	2,560.00	47556	12½/None	ExxonMobil	None		ExxonMobil	100.0000000%	All
26	26	T9N-R24E, UM Secs. 17, 18, 19, and 20	2,544.00	47573	12½/None	Mobil BP	None		Mobil BP	50.0000000% 50.0000000%	All All
27	27	T10N-R22&23E, UM TRACT C30-110 (BF-110): A PORTION OF BLOCKS 753 AND 797 AS SHOWN ON THE "LEASING AND NOMINATION MAP" FOR THE FEDERAL/STATE BEAUFORT SEA OIL AND GAS LEASE SALE, DATED 1/30/79, MORE PARTICULARLY DESCRIBED AS FOLLOWS: THOSE LANDS LOCATED IN THE S1/2 OF BLOCK 753, BEING A PORTION OF BLOCK 753 ON THE AFORESAID LEASING AND NOMINATION MAP, CONTAINING 1152.00HECTARES, AND THOSE LANDS LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 23 AND 24, T10N, R22E; U.M., AK., AND LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 19 AND 20, T10N, R23E; U.M., AK., IN BLOCK 797 (BEING THE NORTHERLY PORTION) LISTED AS STATE AREA ON THE "SUPPLEMENTAL OFFICIAL O.C.S. BLOCK DIAGRAM" APPROVED 10/4/79, CONTAINING 1133.95 HECTARES.	5,648.68	312862	Sliding Scale 20-65/None	ExxonMobil	None		ExxonMobil	100.0000000%	All
28	28	T10N-R23&24E, UM TRACT C30-114 (BF-114): A PORTION OF BLOCKS 799 AND 800 AS SHOWN ON THE "LEASING AND NOMINATION MAP" FOR THE FEDERAL/STATE BEAUFORT SEA OIL AND GAS LEASE SALE, DATED 1/30/79, MORE PARTICULARLY DESCRIBED AS FOLLOWS: THOSE LANDS LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 23 AND 24, T10N, R23E; U.M., AK., AND LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 19 AND 20, T10N, R24E; U.M., AK., IN BLOCK 799 (BEING THE NORTHERLY PORTION) LISTED AS STATE AREA ON THE "SUPPLEMENTAL OFFICIAL O.C.S. BLOCK DIAGRAM" APPROVED 10/4/79, CONTAINING 1081.11 HECTARES, AND THOSE LANDS LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 20, 21, AND 22, T10N, R24E; U.M., AK., AND LYING WESTERLY OF 146 DEGREES 00'00" WEST LONGITUDE IN BLOCK 800 LISTED AS STATE AREA ON THE "SUPPLEMENTAL OFFICIAL O.C.S. BLOCK DIAGRAM" APPROVED 10/4/79, CONTAINING 916.21 HECTARES.	4,935.47	312866	20/52.352	ExxonMobil	None		ExxonMobil	100.0000000%	All
29	29	T10N-R24E, UM Sec 22: S/2 All lying easterly of 146°00'00" west Sec. 23: S/2; Sec. 24: S/2; Secs. 25 and 26	1,970.16	343109	12½/40	ExxonMobil BP Chevron	None		ExxonMobil BP Chevron	50.0000000% 28.0000000% 22.0000000%	All All All
30	30	T10N-R24E, UM Secs. 35 and 36 T9N-R24E, UM Sec. 2	1,920.00	343110	12½/40	Mobil BP	None		Mobil BP	50.0000000% 50.0000000%	All All
31	31	T9N-R24E, UM Secs. 3, 4, and 9 Sec. 10: N/2 and SW/4	2,400.00	343111	12½/40	BP Chevron	ASRC	0.50000%	BP Chevron	56.0000000% 44.0000000%	All All

New Tract No.	Original Tract No.	Description	Acres	ADL No.	Base Royalty % / NPS %	Lessee(s) of Record	Overriding Royalty Ownership		Working Interest Ownership		
							Owner	Percent	Owner	Percent	Description
32	32	T9N-R24E, UM Secs. 30 and 31 All, excluding ANWR, of Secs. 15,16,21,28,29, and 32	3,446.00	343112	12 1/2 / 40	Chevron BP	None		Chevron BP	44.00000000% 56.00000000%	
34	34	T10N-R21E, UM T10N-R22E, UM That portion of Tract 65-016, "TRACT 65-016 ENCOMPASSES ALL THOSE LANDS IN THE S1/2 OF BLOCK 751, OCS OFFICIAL PROTRACTION DIAGRAM NR 6-4 APPROVED 4/29/75, CONTAINING 1152.00 HECTARES, AND THOSE LANDS LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 23 AND 24, T. 10N., R. 21E., UMIAT MERIDIAN, ALASKA AND LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 19 AND 20, T. 10N., R. 22E., UMIAT MERIDIAN, ALASKA IN BLOCK 795 (BEING THE NORTHERLY PORTION) LISTED AS STATE AREA ON THE "SUPPLEMENTAL OFFICIAL OCS BLOCK DIAGRAM" APPROVED 10/4/79, CONTAINING 1167.58 HECTARES." lying within T. 10 N., R. 22 E., U.M., Alaska, and the E1/2E1/2 of Sections 1, 12, 13 and 24, T. 10 N., R. 21 E., U.M., Alaska.	2,779.16	377016	20.0 / None	BP COP	None		BP COP	50.00000000% 50.00000000%	All
35	35	T10N-R22E, UM T. 10N., R. 22E., UMIAT MERIDIAN, ALASKA TRACT 65-017 IS A PORTION OF OCS BLOCKS 752 AND 796 AS SHOWN ON THE "LEASING AND NOMINATION MAP" FOR THE FEDERAL/STATE BEAUFORT SEA OIL AND GAS LEASE SALE, DATED 1/30/79, AND MORE PARTICULARLY DESCRIBED AS FOLLOWS: TRACT 65-017 ENCOMPASSES ALL THOSE LANDS IN THE S1/2 OF BLOCK 752, OCS OFFICIAL PROTRACTION DIAGRAM NR 6-4 APPROVED 4/29/75, CONTAINING 1152 HECTARES, AND THOSE LANDS LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 20, 21, 22 AND 23, T. 10N., R. 22E., UMIAT MERIDIAN, ALASKA IN BLOCK 796 (BEING THE NORTHERLY PORTION) LISTED AS STATE AREA ON THE "SUPPLEMENTAL OFFICIAL OCS BLOCK DIAGRAM" APPROVED 10/4/79, CONTAINING 1153.17 HECTARES. THIS TRACT CONTAINS 5696.18 ACRES MORE OR LESS (2305.17 HECTARES MORE OR LESS).	5,696.18	377017	20.0 / None	ExxonMobil BP Chevron	None		ExxonMobil BP Chevron	66.66670000% 18.66664800% 14.66665200%	All
33	37	T10N-R23E, UM That portion of Tract 65-020, "TRACT 65-020 ENCOMPASSES ALL THOSE LANDS IN THE S1/2 OF BLOCK 754 OCS OFFICIAL PROTRACTION DIAGRAM NR 6-4 APPROVED 4/29/79, CONTAINING 1152 HECTARES, AND THOSE LANDS LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 20, 21, 22 AND 23, T. 10N., R. 23E., UMIAT MERIDIAN, ALASKA IN BLOCK 798 (BEING IN THE NORTHERLY PORTION), LISTED AS STATE AREA ON THE "SUPPLEMENTAL OFFICIAL OCS BLOCK DIAGRAM" APPROVED 10/4/79, CONTAINING 1109.94 HECTARES." lying southerly of Sections 14, 15, 16 and 17, T. 10 N., R. 23 E., U.M., Alaska in OCS Block 798.	1,909.74	377020	20.0 / None	ExxonMobil BP Chevron	None		ExxonMobil BP Chevron	66.66670000% 18.66664800% 14.66665200%	All

New Tract No.	Original Tract No.	Description	Acres	ADL No.	Base Royalty % / NPS %	Lessee(s) of Record	Overriding Royalty Ownership		Working Interest Ownership		
							Owner	Percent	Owner	Percent	Description
36	46	<u>T10N-R21E_UM</u> That portion of Tract 65-016, "TRACT 65-016 ENCOMPASSES ALL THOSE LANDS IN THE S1/2 OF BLOCK 751, OCS OFFICIAL PROTRACTION DIAGRAM NR 6-4 APPROVED 4/29/75, CONTAINING 1152.00 HECTARES, AND THOSE LANDS LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 23 AND 24, T. 10N., R. 21E., UMIAT MERIDIAN, ALASKA AND LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 19 AND 20, T. 10N., R. 22E., UMIAT MERIDIAN, ALASKA IN BLOCK 795 (BEING THE NORTHERLY PORTION) LISTED AS STATE AREA ON THE "SUPPLEMENTAL OFFICIAL OCS BLOCK DIAGRAM" APPROVED 10/4/79, CONTAINING 1167.58 HECTARES." lying within T. 10 N., R. 21 E., U.M., Alaska, excluding the E1/2E1/2 of Sections 1, 12, 13 and 24.	2,952.62	389728	16.6667 / None	BP COP	None		BP COP	50.0000000% 50.0000000%	All
37	47	<u>T10N-R23E_UM</u> That portion of Tract 65-020, "TRACT 65-020 ENCOMPASSES ALL THOSE LANDS IN THE S1/2 OF BLOCK 754 OCS OFFICIAL PROTRACTION DIAGRAM NR 6-4 APPROVED 4/29/79, CONTAINING 1152 HECTARES, AND THOSE LANDS LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 20, 21, 22 AND 23, T. 10N., R. 23E., UMIAT MERIDIAN, ALASKA IN BLOCK 798 (BEING IN THE NORTHERLY PORTION), LISTED AS STATE AREA ON THE "SUPPLEMENTAL OFFICIAL OCS BLOCK DIAGRAM" APPROVED 10/4/79, CONTAINING 1109.94 HECTARES." lying in the S1/2 of OCS Block 754, and lying northerly of Sections 20, 21, 22 and 23, T. 10 N., R. 23 E., U.M., Alaska in OCS Block 798.	3,684.31	389730	20.0 / None	ExxonMobil BP Chevron	None		ExxonMobil BP Chevron	66.6667000% 18.6666480% 14.6666520%	All
38	48	<u>T9N-R24E_UM</u> Sec. 1, ALL TIDE AND SUBMERGED LAND, EXCLUDING STATE OF ALASKA OIL AND GAS LEASE ADL 372256 AND THE ARCTIC NATIONAL WILDLIFE REFUGE, 15.80 ACRES	15.80	390310	20.0 / None	ExxonMobil BP Chevron COP	None		ExxonMobil BP Chevron COP	37.2750000% 32.3260000% 25.3990000% 5.0000000%	All
Total			93,291.12								

New Tract No.	Original Tract No.	Description	Acres	ADL No.	Base Royalty % / NPS %	Lessee(s) of Record	Overriding Royalty Ownership		Working Interest Ownership		
							Owner	Percent	Owner	Percent	Description
Notes											
		BP	means			BP Exploration (Alaska) Inc.					
		Chap-KDL, Ltd.	"			Chap-KDL, Ltd.					
		Chevron	"			Chevron USA Inc.					
		COP	"			ConocoPhillips Alaska Inc.					
		Devon	"			Devon Energy Corporation					
		Donnelly, R.	"			Richard Donnelly					
		Donnelly, R.R.	"			The Robert R. Donnelly 1991 Irrevocable Trust					
		Donnelly, G.	"			The George A. Donnelly III 1991 Irrevocable Trust					
		ExxonMobil	"			Exxon Mobil Corporation					
		Forest	"			Forest Oil Corporation					
		Holbrook	"			Mary Lou Holbrook (The Eastland Oil Company)					
		Hughes	"			Kingdon R. Hughes Family Partnership					
		Leede	"			Edward H. Leede					
		Leede and Pine	"			Leede and Pine, a Partnership					
		McConnell	"			Peggy D. McConnell (Eastland Property and Minerals)					
		Mobil	"			ExxonMobil Oil Corporation					
		O'Neill	"			Jan Donnelly O'Neill, Irrevocable					
		Pacific	"			Pacific Lighting Gas Development Company					
		Peery, J. W.	"			Estate of John W. Peery (Susan Jean Searls Collier, Linda Lou Searls Neidert, Jean Alice Searls and John Peery Searls)					
		SNG	"			Samson Resources Company (SNG Prod. Co.)					
		Searls, Jr.	"			Robert Searls, Jr. Testamentary Trust (Collier / Searls)					
		Sunlite	"			Sunlite International Inc.					
		Trans World	"			Trans World Oil and Gas Ltd.					
		Two Four Six	"			Two Four Six Exploration, Inc. (United Oil & Minerals Limited Partnership)					
		Woodbine	"			Woodbine Petroleum, Inc. (a subsidiary of Sunlite International Inc.)					

Exhibit C
Point Thomson Unit

Area A - Initial Participating Area

<u>Tract No.</u>	<u>ADL No.</u>	<u>Description</u>	<u>Acres</u>	<u>Initial PA Tract Allocation</u>	<u>Area A + B Tract Allocation</u>	<u>Unit Tract Allocation</u>
1	47557	<u>T10N-R24E, UM</u> Sec. 31, All, 623 acres	623.00			
2	47558	<u>T10N-R23E, UM</u> Sec. 25, All, 640 acres Sec. 26, All, 640 acres Sec. 35, All, 640 acres Sec. 36, All, 640 acres	2,560.00			
3	47559	<u>T10N-R23E, UM</u> Sec. 27, All, 640 acres Sec. 28, All, 640 acres Sec. 33, All, 640 acres Sec. 34, All, 640 acres	2,560.00			
4	47560	<u>T10N-R23E, UM</u> Sec. 32, All, 640 acres	640.00			
14	47570	<u>T9N-R23E, UM</u> Sec. 3, All, 640 acres Sec. 4, All, 640 acres Sec. 9, All, 640 acres Sec. 10, All, 640 acres	2,560.00			
15	47571	<u>T9N-R23E, UM</u> Sec. 1, All, 640 acres Sec. 2, All, 640 acres Sec. 11, All, 640 acres Sec. 12, All, 640 acres	2,560.00			
16	47572	<u>T9N-R24E, UM</u> Sec. 6, All, 625 acres Sec. 7, All, 628 acres	1,253.00			
17	50983	<u>T10N-R23E, UM</u> Sec. 29, All, 640 acres	640.00			
33 (37)	377020	<u>T10N-R23E, UM</u> That portion of Tract 65-020, "TRACT 65-020 ENCOMPASSES ALL THOSE LANDS IN THE S1/2 OF BLOCK 754 OCS OFFICIAL PROTRACTION DIAGRAM NR 6-4 APPROVED 4/29/79, CONTAINING 1152 HECTARES, AND THOSE LANDS LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 20, 21, 22 AND 23, T. 10N., R. 23E., UMIAT MERIDIAN, ALASKA IN BLOCK 798 (BEING IN THE NORTHERLY PORTION), LISTED AS STATE AREA ON THE "SUPPLEMENTAL OFFICIAL OCS BLOCK DIAGRAM" APPROVED 10/4/79, CONTAINING 1109.94 HECTARES." lying southerly of Sections 14, 15, 16 and 17, T. 10 N., R. 23 E., U.M., Alaska in OCS Block 798.	1,909.74			
Area A Acreage			15,305.74			

Exhibit C

Area B - West Pad Area

<u>Tract No.</u>	<u>ADL No.</u>	<u>Description</u>	<u>Acres</u>	<u>Area A + B Tract Allocation</u>	<u>Unit Tract Allocation</u>
5	47561	T10N-R22E, UM Sec. 25, All, 640 acres Sec. 26, All, 640 acres Sec. 35, All, 640 acres Sec. 36, All, 640 acres	2,560.00		
18	51667	T10N-R23E, UM Sec. 30, All, 620 acres Sec. 31, All, 623 acres	1,243.00		
27	312862	T10N-R22&23E, UM TRACT C30-110 (BF-110): A PORTION OF BLOCKS 753 AND 797 AS SHOWN ON THE "LEASING AND NOMINATION MAP" FOR THE FEDERAL/STATE BEAUFORT SEA OIL AND GAS LEASE SALE, DATED 1/30/79, MORE PARTICULARLY DESCRIBED AS FOLLOWS: THOSE LANDS LOCATED IN THE S1/2 OF BLOCK 753, BEING A PORTION OF BLOCK 753 ON THE AFORESAID LEASING AND NOMINATION MAP, CONTAINING 1152.00 HECTARES, AND THOSE LANDS LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 23 AND 24, T10N, R22E; U.M., AK., AND LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 19 AND 20, T10N, R23E; U.M., AK., IN BLOCK 797 (BEING THE NORTHERLY PORTION) LISTED AS STATE AREA ON THE "SUPPLEMENTAL OFFICIAL O.C.S. BLOCK DIAGRAM" APPROVED 10/4/79, CONTAINING 1133.95 HECTARES, <u>LESS AND EXCEPT</u> THE NORTH HALF OF THE AFOREMENTIONED TRACT.	2,824.34		
		Area B Acreage	6,627.34		
		Area A + B Acreage	21,933.08		

Exhibit C

Area D

<u>Tract No.</u>	<u>ADL No.</u>	<u>Description</u>	<u>Acres</u>	<u>Unit Tract Allocation</u>
1	47557	<u>T10N-R24E, UM</u> Sec. 29, All, 640 acres Sec. 30, All, 620 acres Sec. 32, All, 640 acres	1,900.00	
6	47562	<u>T10N-R22E, UM</u> Sec. 27, All, 640 acres Sec. 28, All, 640 acres Sec. 33, All, 640 acres Sec. 34, All, 640 acres	2,560.00	
11	47567	<u>T9N-R22E, UM</u> Sec. 3, All, 640 acres Sec. 4, All, 640 acres	1,280.00	
12	47568	<u>T9N-R22E, UM</u> Sec. 1, All, 640 acres Sec. 2, All, 640 acres	1,280.00	
13	47569	<u>T9N-R23E, UM</u> Sec. 5, All, 640 acres Sec. 6, All, 625 acres	1,265.00	
16	47572	<u>T9N-R24E, UM</u> Sec. 5, All, 640 acres Sec. 8, All, 640 acres	1,280.00	
20	28381	<u>T9N-R23E, UM</u> Secs. 15 and 16	1,280.00	
21	28382	<u>T9N-R23E, UM</u> Sec. 13, All, 640 acres Sec. 14, All, 640 acres Sec. 23, All, 640 acres Sec. 24, All, 640 acres	2,560.00	
25	47556	<u>T10N-R24E, UM</u> Sec. 28, All, 640 acres Sec. 33, All, 640 acres	1,280.00	
26	47573	<u>T9N-R24E, UM</u> Sec. 17, All, 640 acres Sec. 18, All, 631 acres Sec. 19, All, 633 acres Sec. 20, All, 640 acres	2,544.00	
27	312862	<u>T10N-R22&23E, UM</u> TRACT C30-110 (BF-110): A PORTION OF BLOCKS 753 AND 797 AS SHOWN ON THE "LEASING AND NOMINATION MAP" FOR THE FEDERAL/STATE BEAUFORT SEA OIL AND GAS LEASE SALE, DATED 1/30/79, MORE PARTICULARLY DESCRIBED AS FOLLOWS: THOSE LANDS LOCATED IN THE S1/2 OF BLOCK 753, BEING A PORTION OF BLOCK 753 ON THE AFORESAID LEASING AND NOMINATION MAP, CONTAINING 1152.00 HECTARES, AND THOSE LANDS LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 23 AND 24, T10N, R22E; U.M., AK., AND LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 19 AND 20, T10N, R23E; U.M., AK., IN BLOCK 797 (BEING THE NORTHERLY PORTION) LISTED AS STATE AREA ON THE "SUPPLEMENTAL OFFICIAL O.C.S. BLOCK DIAGRAM" APPROVED 10/4/79, CONTAINING 1133.95 HECTARES, <u>LESS AND EXCEPT</u> THE SOUTH HALF OF THE AFOREMENTIONED TRACT.	2,824.34	

Exhibit C

Area D (cont.)

<u>Tract No.</u>	<u>ADL No.</u>	<u>Description</u>	<u>Acres</u>	<u>Unit Tract Allocation</u>
31	343111	T9N-R24E, UM Sec. 3, Protracted, All, 640 acres Sec. 4, Protracted, All, 640 acres Sec. 9, Protracted, All, 640 acres Sec. 10, Protracted, N/2, SW/4, 480 acres	2,400.00	
ADL 377017(S)				
35	377017	T10N-R22E, UM T. 10N., R. 22E., UMIAT MERIDIAN, ALASKA TRACT 65-017 IS A PORTION OF OCS BLOCKS 752 AND 796 AS SHOWN ON THE "LEASING AND NOMINATION MAP" FOR THE FEDERAL/STATE BEAUFORT SEA OIL AND GAS LEASE SALE, DATED 1/30/79, AND MORE PARTICULARLY DESCRIBED AS FOLLOWS: TRACT 65-017 ENCOMPASSES ALL THOSE LANDS IN THE S1/2 OF BLOCK 752, OCS OFFICIAL PROTRACTION DIAGRAM NR 6-4 APPROVED 4/29/75, CONTAINING 1152 HECTARES, AND THOSE LANDS LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 20, 21, 22 AND 23, T. 10N., R. 22E., UMIAT MERIDIAN, ALASKA IN BLOCK 796 (BEING THE NORTHERLY PORTION) LISTED AS STATE AREA ON THE "SUPPLEMENTAL OFFICIAL OCS BLOCK DIAGRAM" APPROVED 10/4/79, CONTAINING 1153.17 HECTARES. THIS TRACT CONTAINS 5696.18 ACRES MORE OR LESS (2305.17 HECTARES MORE OR LESS), <u>LESS AND EXCEPT</u> THE NORTH HALF OF THE AFOREMENTIONED TRACT.	2,848.09	
ADL 377017(N)				
35	377017	T10N-R22E, UM T. 10N., R. 22E., UMIAT MERIDIAN, ALASKA TRACT 65-017 IS A PORTION OF OCS BLOCKS 752 AND 796 AS SHOWN ON THE "LEASING AND NOMINATION MAP" FOR THE FEDERAL/STATE BEAUFORT SEA OIL AND GAS LEASE SALE, DATED 1/30/79, AND MORE PARTICULARLY DESCRIBED AS FOLLOWS: TRACT 65-017 ENCOMPASSES ALL THOSE LANDS IN THE S1/2 OF BLOCK 752, OCS OFFICIAL PROTRACTION DIAGRAM NR 6-4 APPROVED 4/29/75, CONTAINING 1152 HECTARES, AND THOSE LANDS LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 20, 21, 22 AND 23, T. 10N., R. 22E., UMIAT MERIDIAN, ALASKA IN BLOCK 796 (BEING THE NORTHERLY PORTION) LISTED AS STATE AREA ON THE "SUPPLEMENTAL OFFICIAL OCS BLOCK DIAGRAM" APPROVED 10/4/79, CONTAINING 1153.17 HECTARES. THIS TRACT CONTAINS 5696.18 ACRES MORE OR LESS (2305.17 HECTARES MORE OR LESS), <u>LESS AND EXCEPT</u> THE SOUTH HALF OF THE AFOREMENTIONED TRACT.	2,848.09	
Area D Acreage			28,149.52	

Exhibit C

Area E

<u>Tract No.</u>	<u>ADL No.</u>	<u>Description</u>	<u>Acres</u>	<u>Unit Tract Allocation</u>
7	47563	<u>T10N-R22E, UM</u> Sec. 29, All, 640 acres Sec. 30, All, 620 acres Sec. 31, All, 623 acres Sec. 32, All, 640 acres	2,523.00	
8	47564	<u>T10N-R21E, UM</u> Sec. 25, All, 640 acres Sec. 26, All, 640 acres Sec. 35, All, 640 acres Sec. 36, All, 640 acres	2,560.00	
10	47566	<u>T9N-R22E, UM</u> Sec. 5, All, 640 acres Sec. 6, All, 625 acres Sec. 7, All, 628 acres Sec. 8, All, 640 acres	2,533.00	
11	47567	<u>T9N-R22E, UM</u> Sec. 9, All, 640 acres Sec. 10, All, 640 acres	1,280.00	
12	47568	<u>T9N-R22E, UM</u> Sec. 11, All, 640 acres Sec. 12, All, 640 acres	1,280.00	
13	47569	<u>T9N-R23E, UM</u> Sec. 7, All, 628 acres Sec. 8, All, 640 acres	1,268.00	
19	28380	<u>T9N-R23E, UM</u> Sec. 17, All, 640 acres Sec. 18, All, 631 acres Sec. 19, All, 633 acres Sec. 20, All, 640 acres	2,544.00	
20	28381	<u>T9N-R23E, UM</u> Secs. 21 and 22	1,280.00	
22	28383	<u>T9N-R23E, UM</u> Secs. 25, 26, 35, and 36	2,560.00	
23	28384	<u>T9N-R23E, UM</u> Sec. 27, All, 640 acres Sec. 28, N/2 and SE/4, 480 acres Sec. 34, All, 640 acres	1,760.00	
24	28385	<u>T9N-R23E, UM</u> Sec. 29: N/2, 320 acres Sec. 30: N/2, 317 acres	637.00	
28	312866	<u>T10N-R23&24E, UM</u> TRACT C30-114 (BF-114): A PORTION OF BLOCKS 799 AND 800 AS SHOWN ON THE "LEASING AND NOMINATION MAP" FOR THE FEDERAL/STATE BEAUFORT SEA OIL AND GAS LEASE SALE, DATED 1/30/79, MORE PARTICULARLY DESCRIBED AS FOLLOWS: THOSE LANDS LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 23 AND 24, T10N, R23E; U.M., AK., AND LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 19 AND 20, T10N, R24E; U.M., AK., IN BLOCK 799 (BEING THE NORTHERLY PORTION) LISTED AS STATE AREA ON THE "SUPPLEMENTAL OFFICIAL O.C.S. BLOCK DIAGRAM" APPROVED 10/4/79, CONTAINING 1081.11 HECTARES, AND THOSE LANDS LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 20, 21, AND 22, T10N, R24E; U.M., AK., AND LYING WESTERLY OF 146 DEGREES 00'00" WEST LONGITUDE IN BLOCK 800 LISTED AS STATE AREA ON THE "SUPPLEMENTAL OFFICIAL O.C.S. BLOCK DIAGRAM" APPROVED 10/4/79, CONTAINING 916.21 HECTARES. <u>LESS AND EXCEPT</u> THOSE LANDS IN SECTIONS 15 AND 22 OF T10N, R24E.	4,215.47	

Exhibit C
Area E (cont.)

<u>Tract No.</u>	<u>ADL No.</u>	<u>Description</u>	<u>Acres</u>	<u>Unit Tract Allocation</u>
30	343110	<u>T9N-R24E, UM</u> Sec. 2, Protracted, All, 640 acres	640.00	
32	343112	<u>T9N-R24E, UM</u> Sec. 15, Protracted, All excluding the Arctic National Wildlife Refuge, 139 acres Sec. 16, Protracted, All excluding the Arctic National Wildlife Refuge, 606 acres Sec. 21, Protracted, All excluding the Arctic National Wildlife Refuge, 304 acres	1,049.00	
34	377016	<u>T10N-R21E, UM</u> <u>T10N-R22E, UM</u> That portion of Tract 65-016, "TRACT 65-016 ENCOMPASSES ALL THOSE LANDS IN THE S1/2 OF BLOCK 751, OCS OFFICIAL PROTRACTION DIAGRAM NR 6-4 APPROVED 4/29/75, CONTAINING 1152.00 HECTARES, AND THOSE LANDS LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 23 AND 24, T. 10N., R. 21E., UMIAT MERIDIAN, ALASKA AND LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 19 AND 20, T. 10N., R. 22E., UMIAT MERIDIAN, ALASKA IN BLOCK 795 (BEING THE NORTHERLY PORTION) LISTED AS STATE AREA ON THE "SUPPLEMENTAL OFFICIAL OCS BLOCK DIAGRAM" APPROVED 10/4/79, CONTAINING 1167.58 HECTARES." lying within T. 10 N., R. 22 E., U.M., Alaska, and the E1/2E1/2 of Sections 1, 12, 13 and 24, T. 10 N., R. 21 E., U.M., Alaska.	2,779.16	
36 (46)	389728	<u>T10N-R21E, UM</u> That portion of Tract 65-016, "TRACT 65-016 ENCOMPASSES ALL THOSE LANDS IN THE S1/2 OF BLOCK 751, OCS OFFICIAL PROTRACTION DIAGRAM NR 6-4 APPROVED 4/29/75, CONTAINING 1152.00 HECTARES, AND THOSE LANDS LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 23 AND 24, T. 10N., R. 21E., UMIAT MERIDIAN, ALASKA AND LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 19 AND 20, T. 10N., R. 22E., UMIAT MERIDIAN, ALASKA IN BLOCK 795 (BEING THE NORTHERLY PORTION) LISTED AS STATE AREA ON THE "SUPPLEMENTAL OFFICIAL OCS BLOCK DIAGRAM" APPROVED 10/4/79, CONTAINING 1167.58 HECTARES." lying within T. 10 N., R. 21 E., U.M., Alaska, excluding the E1/2E1/2 of Sections 1, 12, 13 and 24.	2,952.62	
37 (47)	389730	<u>T10N-R23E, UM</u> That portion of Tract 65-020, "TRACT 65-020 ENCOMPASSES ALL THOSE LANDS IN THE S1/2 OF BLOCK 754 OCS OFFICIAL PROTRACTION DIAGRAM NR 6-4 APPROVED 4/29/79, CONTAINING 1152 HECTARES, AND THOSE LANDS LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 20, 21, 22 AND 23, T. 10N., R. 23E., UMIAT MERIDIAN, ALASKA IN BLOCK 798 (BEING IN THE NORTHERLY PORTION), LISTED AS STATE AREA ON THE "SUPPLEMENTAL OFFICIAL OCS BLOCK DIAGRAM" APPROVED 10/4/79, CONTAINING 1109.94 HECTARES." lying in the S1/2 of OCS Block 754, and lying northerly of Sections 20, 21, 22 and 23, T. 10 N., R. 23 E., U.M., Alaska in OCS Block 798.	3,684.31	
38 (48)	390310	<u>T9N-R24E, UM</u> Sec. 1, UNSURVEYED, ALL TIDE AND SUBMERGED LAND, EXCLUDING STATE OF ALASKA OIL AND GAS LEASE ADL 372256 AND THE ARCTIC NATIONAL WILDLIFE REFUGE, 15.80 ACRES	15.80	
		Area E Acreage	35,561.36	
		Area A + B + D + E Acreage	85,643.96	

Exhibit C

Area F

<u>Tract No.</u>	<u>ADL No.</u>	<u>Description</u>	<u>Acres</u>
25	47556	T10N-R24E, UM Sec. 27, All, 640 acres Sec. 34, All, 640 acres	1,280.00
28	312866	T10N-R23&24E, UM TRACT C30-114 (BF-114): A PORTION OF BLOCKS 799 AND 800 AS SHOWN ON THE "LEASING AND NOMINATION MAP" FOR THE FEDERAL/STATE BEAUFORT SEA OIL AND GAS LEASE SALE, DATED 1/30/79, MORE PARTICULARLY DESCRIBED AS FOLLOWS: THOSE LANDS LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 23 AND 24, T10N, R23E; U.M., AK., AND LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 19 AND 20, T10N, R24E; U.M., AK., IN BLOCK 799 (BEING THE NORTHERLY PORTION) LISTED AS STATE AREA ON THE "SUPPLEMENTAL OFFICIAL O.C.S. BLOCK DIAGRAM" APPROVED 10/4/79, CONTAINING 1081.11 HECTARES, AND THOSE LANDS LYING NORTHERLY OF THE SOUTH BOUNDARY OF SECTIONS 20, 21, AND 22, T10N, R24E; U.M., AK., AND LYING WESTERLY OF 146 DEGREES 00'00" WEST LONGITUDE IN BLOCK 800 LISTED AS STATE AREA ON THE "SUPPLEMENTAL OFFICIAL O.C.S. BLOCK DIAGRAM" APPROVED 10/4/79, CONTAINING 916.21 HECTARES. <u>LIMITED TO</u> those lands in Sections 15 and 22 of T10N, R24E.	720.00
29	343109	T10N-R24E, UM Sec 22: Protracted, S/2 lying easterly of 146°00'00" west longitude, 50.16 acres Sec. 23: Protracted, S/2, 320 acres Sec. 24: Protracted, S/2, 320 acres Sec. 25, Protracted, All, 640 acres Sec. 26, Protracted, All, 640 acres	1,970.16
30	343110	T10N-R24E, UM Sec. 35, Protracted, All, 640 acres Sec. 36, Protracted, All, 640 acres	1,280.00
32	343112	T9N-R24E, UM Sec. 28, Protracted, All excluding the Arctic National Wildlife Refuge, 123 acres Sec. 29, Protracted, All excluding the Arctic National Wildlife Refuge, 636 acres Sec. 30, Protracted, All, 636 acres Sec. 31, Protracted, All, 639 acres Sec. 32, Protracted, All excluding the Arctic National Wildlife Refuge, 363 acres	2,397.00
Area F Acreage			7,647.16

EXHIBIT D

Point Thomson Unit

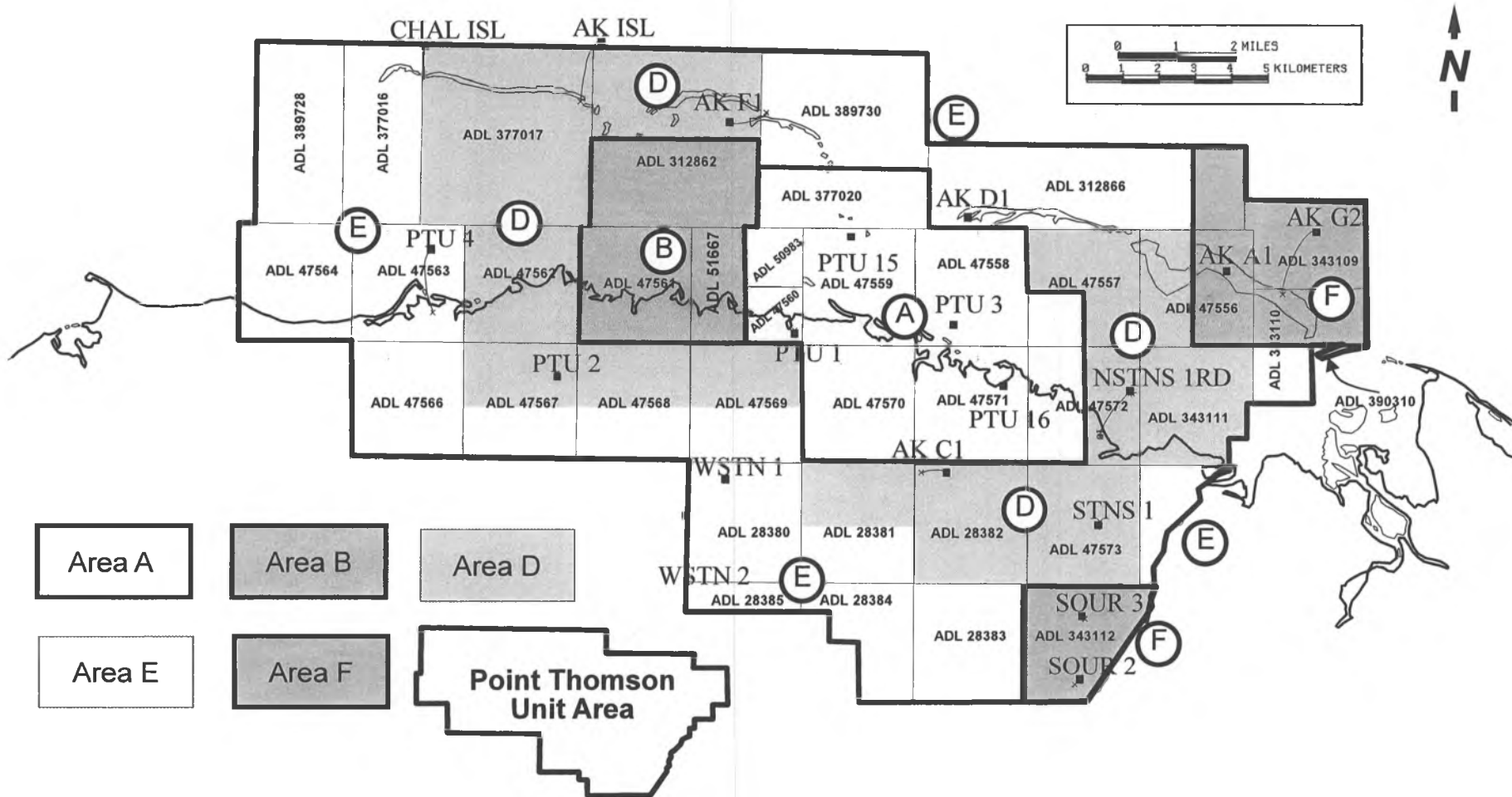
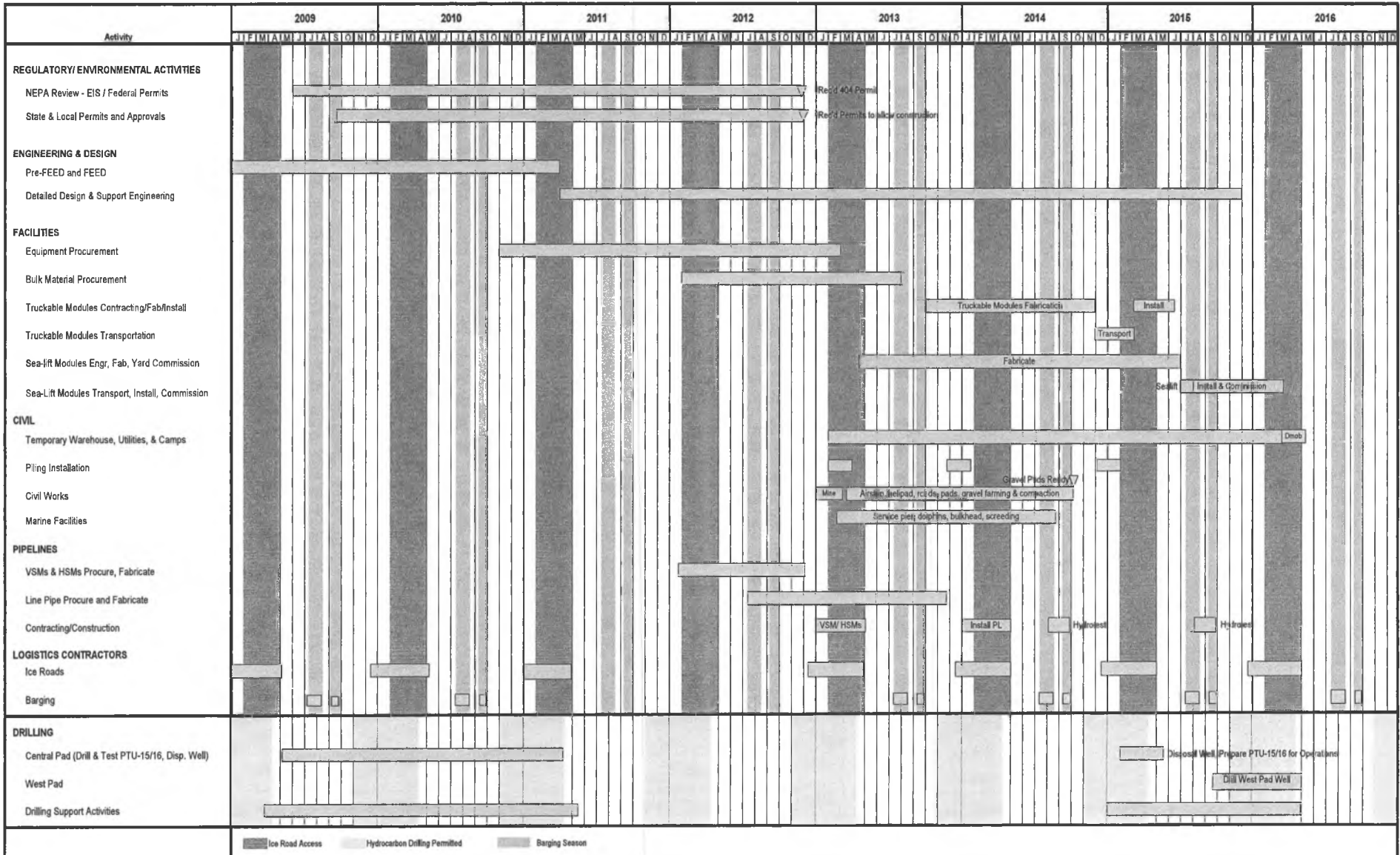


EXHIBIT E

Point Thomson Provisional Schedule Level 1 Work Sheet



NOTE: This schedule is indicative and subject to change.

Exhibit F**PA DOCUMENTATION**

DNR will keep information submitted in a PA application confidential as provided in AS 38.05.035(a)(8) and its applicable regulations. In accordance with AS 38.05.035(a)(8)(C), in order for geological, geophysical and engineering data to be held confidential, the Unit Operator must request confidentiality at the time the data is submitted by indicating "CONFIDENTIAL" on all confidential data items.

1. Depth Structure Maps and digital grids (including faults) for each producing horizon.
2. Gross Isochore Maps and digital grids for each producing horizon
3. Hydrocarbon Net Pay Maps and digital grids for each producing horizon. Also include any fluid contact maps and digital grids used in creation of the hydrocarbon net pay maps.
4. Average Porosity and Hydrocarbon Saturation Maps and digital grids for each producing horizon.
5. Hydrocarbon Pore Feet Maps and digital grids for each producing horizon.
6. Paper and digital copies of representative seismic lines to support the applied for action. Data submitted should include both strike and dip oriented lines, include picked horizons for all mapped surfaces, mapped faults, and wells demonstrating time-depth ties to well log formation picks. Lines should be clearly annotated with seismic survey

- ID, seismic volume, line number, picked horizon and well names. Map clearly showing location of all seismic and well sections provided.
7. Paper and digital copies of representative stratigraphic and structural well-log cross-sections. Cross-sections should include, log correlations for all mapped horizons, mapped faults, identified fluid contacts and deepest “oil down to” (ODT) and shallowest “water up to” (WUT) picks. Cross-sections should be of an appropriate scale that all annotations, picks, log curves and scales are clearly legible.
 8. Hydrocarbon formation volume factors (B_o , B_g) applied to each reservoir.
 9. Oil Gravity and/or Viscosity Maps and digital grids for each producing horizon.
 10. Digital file (ascii or Excel spreadsheet) of formation picks in measured depth (MD) and sub-sea true vertical depth (sstvd) for each well, including all plug backs and pilot holes. Picks should include top and base of each producing interval, all known fluid contacts and deepest “oil down to” (ODT) and shallowest “water up to” (WUT) picks.
 11. Digital files of calculated curve data from log analysis used in determining reservoir properties and in-place hydrocarbon volumes. Curve data should include total and/or effective porosity, water saturation, permeability, clay volume, and bulk volume water.
 12. Criteria /cutoffs (i.e. porosity, saturation, volume shale, permeability) used to determine net pay in each producing horizon.
 13. Digital file (ascii or Excel spreadsheet) of calculated rock properties of each producing interval for every well. Data to include, top and base depth of interval in measured

depth and sstvd, gross interval thickness (tvt), net sand thickness, net hydrocarbon pay thickness, net to gross ratio, average reservoir porosity, average reservoir water saturation (Sw), average permeability, permeability height (kh), and hydrocarbon pore feet

14. Location Map clearly showing all existing production, injection and planned wells. Horizontal wells should be shown as a line highlighting the existing and planned productive interval length. In addition, a digital file (ascii or Excel spreadsheet) provided with target x y coordinates for planned wells. For horizontal wells, x y coordinates for heel and toe locations should be provided for both existing and planned wells.
15. Summary of all oil and gas (including non-hydrocarbon constituents) compositional analyses, including gravity and viscosity data.
16. Paper and digital copies of all pressure build-up PTA and fluid PVT analyses.
17. Relative permeability curves for oil/water, gas/oil, and gas/water.
18. Paper and digital copies of all capillary pressure analyses, where available.
19. Calculated original oil and/or gas in place (OOIP and/or OGIP) volumes
20. Estimated ultimate recovery (EUR).
21. Proposed reservoir depletion plan set forth in the current POD.
22. Production forecast.

Exhibit G**GAS SALES AGREEMENT PROVISION**

In the event of any conflict, the language of this Exhibit G shall control and supersede the language of Paragraph 2.21 with respect to the gas sales agreement provision. If the WIOs intend to Commit to a Point Thomson Gas Development / Prudhoe Bay Enhanced Recovery Project, then at the State's request prior to the Commitment date, the State and each individual WIO with a working interest in each Point Thomson Unit lease will enter into negotiations for separate gas sales agreements, with sufficient lead time to ensure the terms below can be met, that include the following terms which the State has requested be common to all such agreements, with additional terms to be negotiated:

- (a) The daily volume of gas to be sold by each WIO will be equal to that WIO's proportionate share of the State's total expected daily volume of Point Thomson royalty gas to be delivered into the PTU / PBU Gas Pipeline.
- (b) The gas sales agreement would become effective if the WIOs Commit to a Point Thomson Gas Development / Prudhoe Bay Enhanced Recovery Project with gas to be available for delivery on the Commitment date.
- (c) The term of each sales agreement will continue until the earlier of: (1) Project Start-up of a Point Thomson Gas Development / Prudhoe Bay Enhanced Recovery Project, (2) Project Start-up of a Major Gas Sale as defined under the Settlement Agreement, or (3) 10 years following the Commitment date.

- (d) The delivery point for the gas will be at a mutually agreed location from Prudhoe Bay facilities.

- (e) The State and each WIO will establish the price of gas in their contract based on a price mutually agreed between the State and that WIO considering most recent, relevant Alaska North Slope gas sales agreements, including consideration for volume commitments and terms. The gas sales agreement will allow for periodic price re-openers to be negotiated. The initial re-opener may not be triggered sooner than one year after the start of gas sales.

- (f) Any royalty due on gas sold under this provision will be paid in value based on the contract price for that WIO.

4

ExxonMobil

ConocoPhillips



March 30, 2012

Governor Sean Parnell
550 West 7th Avenue, Suite 1700
Anchorage, Alaska 99501

Dear Governor Parnell,

Our three corporations, collectively and individually, value our relationship with Alaska and believe that its citizens across the state, as well as our shareholders around the world, share a common interest in responsible resource development. We write today to inform you of our progress in working together on the next generation of North Slope resource development.

Alaska's vast North Slope holds over 35 trillion cubic feet of discovered natural gas. To date, this gas has been used to enhance North Slope oil production, adding several billion barrels to Prudhoe and Kuparuk recoveries. However, under the right business climate, the full commercial potential of this world-class resource can be unlocked. North Slope gas commercialization will bring new job opportunities, increased state revenues, reliable in-state energy supplies and new exploration opportunities, which will further the development of North Slope oil and gas. This will be key toward reaching your goal of one million barrels of oil per day through the Trans-Alaska Pipeline System.

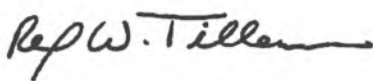
Serious discussions between our companies have taken place over the past several months, along with the Alaska Pipeline Project (APP) parties who are supporting the AGIA License. We have aligned on a structured, stewardable and transparent approach with the aim to commercialize North Slope natural gas resources within an AGIA framework. As a result of the rapidly evolving global market, large-scale liquefied natural gas (LNG) exports from south-central Alaska will be assessed as an alternative to gas line exports through Alberta. In addition to broadening market access, a south-central Alaska LNG approach could more closely align with in-state energy demand and needs. We are now working together on the gas commercialization project concept selection, which would include an associated timeline and an assessment of major project components including in-state pipeline routes and capacities, global LNG trends, and LNG tidewater site locations, among others.

Commercializing Alaska natural gas resources will not be easy. There are many challenges and issues that must be resolved, and we cannot do it alone. Unprecedented commitments of capital for gas development will require competitive and stable fiscal terms with the State of Alaska first be established. Appropriately structured, stable fiscal arrangements have opened new opportunities around the world, and will play a pivotal role in making Alaska competitive in the global market and unlocking the economic potential of North Slope resources.

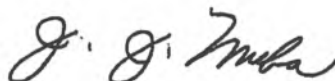
Point Thomson is an excellent example of a challenged, world-class resource. With approximately 25% of known North Slope natural gas, Point Thomson development is an important element in consideration of North Slope gas commercialization. However, economic models must span decades into an uncertain future to estimate economic returns. Your Administration has taken the lead in forging a Point Thomson settlement that will bring long-term resources, revenues and jobs to help Alaska's economy. With settlement now finalized, our companies are moving forward, as participating co-venturers, with the initial development phase at Point Thomson with confidence that North Slope gas development will ultimately bring the Point Thomson resource to market.

We agree the next generation of North Slope resource development is achievable, working together with the APP parties, as well as with the State of Alaska. Thank you for your leadership and your confidence in us to take on these challenges. We join you in a vision of prosperity and promise. There is much work to do and opportunities yet to discover.

Sincerely,



Rex Tillerson



Jim Mulva



Bob Dudley

5

**UNIT OPERATING AGREEMENT
PRUDHOE BAY UNIT
STATE OF ALASKA**

**VOLUME I
ARTICLES**

April 1, 1977

37A even if the revised fault location should diverge by a greater lateral distance than 500 feet, and in no event will the plane be shifted along that segment connecting the faults which is drawn along the Range 12 East, Range 13 East boundary.

Major Gas Pipeline is any pipeline and appurtenant equipment used to transport Separator Off-Gas off the North Slope of Alaska for purposes other than use or consumption as fuel for a Major Oil Pipeline.

Major Gas Sale. If the Forecasted Initial Gas Sales Rate, as defined in Section 40.002, equals or exceeds 2,000 MMScf/D, Major Gas Sale is 12.01 A.M. on the first day of the calendar month following the point in time when the first deliveries of Separator Off-Gas are made by any Working Interest Owner to a Major Gas Pipeline for transportation off the North Slope of Alaska for purposes other than use or consumption as fuel for a Major Oil Pipeline. If the Forecasted Initial Gas Sales Rate is less than 2,000 MMScf/D, Major Gas Sale is 12.01 A.M. on the first day of the calendar month following the first complete calendar month during which the average daily volume of Separator Off-Gas delivered to a Major Gas Pipeline for transportation off the North Slope of Alaska, for purposes other than use or consumption as fuel for a Major Oil Pipeline, has equaled or exceeded 1,750 MMScf/D.

Major Loss shall have the meaning given to it in § 32.002.

Major Oil Pipeline is any common carrier pipeline, together with suitable pump stations, tankage, terminals, docks, communication facilities and other facilities necessary and incident to the transportation of Separator Liquid Production off the North Slope of Alaska, including the pipeline from Prudhoe Bay to Valdez, Alaska.

Midperiod Allocated Solution GOR is the number calculated in accordance with Section 28.709 at each Modification Date.

Midperiod Bottomhole Pressure is the number calculated in accordance with Subsection 28.704.03 at each Modification Date.

6

ALASKA

ALASKA OIL AND GAS CONSERVATION COMMISSION

333 West 7th Avenue, Suite 100

Anchorage Alaska 99501

Re:THE APPLICATION OF BP)	Conservation Order 341D
EXPLORATION (ALASKA) INC.)	
Prudhoe Oil Pool - Modification to)	Prudhoe Oil Pool
pool rules - Conservation Order)	Prudhoe Bay Field
341C, for injection of water into the)	
Prudhoe Bay Gas Cap)	
)	November 30, 2001

IT APPEARING THAT:

1. By letter dated September 21, 2001, BP Exploration (Alaska), Inc. ("BPXA") on behalf of the Working Interest Owners ("WIOs") of the Initial Participating Areas of the Prudhoe Bay Unit ("PBU") has applied for a modification of certain rules of Conservation Order 341C ("CO 341C") in conjunction with a proposed project named the Gas Cap Water Injection Project ("GCWI").
2. The Commission published notice of opportunity for public hearing in the Anchorage Daily News on September 29, 2001.
3. The Commission held a public hearing October 30, 2001 at 9:00 am at the Alaska Oil and Gas Conservation Commission at 333 West 7th Avenue, Suite 100, Anchorage, Alaska 99501.
4. The Commission received no protests to BPXA's application or to the public testimony.
5. Pre-filed testimony of representatives of BP Exploration (Alaska), Inc., Phillips Alaska, Inc. and ExxonMobil Production Company is included in the record (revised October 30, 2001). All additional information requested by the Commission at the hearing was received November 1, 2001 and November 6, 2001.

FINDINGS:

1. Authority 20 AAC 25.520, 20 AAC 25.540

Commission regulation 20 AAC 25.420 provides authority to issue orders prescribing rules to govern the proposed development and operation of a pool. The commission will, in its discretion, amend pool orders in accordance with procedures set forth in 20 AC 25.540.

2. Gas Cap Water Injection Project - Overview

Currently, reservoir pressure is declining at 25 to 35 psi/year. The WIOs have studied options to mitigate pressure decline and have annually reported the progress of these studies to the Commission, based upon rulings in CO 290 (2/21/92), which were incorporated into CO 341C, Rule 12(d). As a result of these studies, the WIOs sanctioned the Gas Cap Water Injection project in June 2001. This project represents a new element in the depletion strategy of the Prudhoe Bay Oil Pool with the dual goals to mitigate reservoir pressure decline and improve recovery.

3. Proposed Modifications to Conservation Order 341C

The most current rules governing Prudhoe Bay Field, Prudhoe Oil Pool are contained in CO 341C, dated June 12, 1997. CO 341C is a consolidation of all conservation orders in effect for the Prudhoe Bay Field, Prudhoe Oil Pool at that point in time. Specific to CO 341C, BPXA is requesting the following modifications:

- a) Revoke paragraph (d) of Rule 12 that requires the Operator to continue to investigate options to mitigate pressure decline and to provide an annual report to the Commission. With the implementation of GCWI, BPXA claims pressure decline will be mitigated.
- b) Modification of Paragraph (c) in Rule 12 which currently provides that the Operator maintain a pressure differential of at least 250 psi between the minimum miscibility pressure of the miscible injectant and the prevailing reservoir pressure. BPXA claims that as GCWI will mitigate pressure decline, a more appropriate pressure differential of 100 psi is appropriate and will allow BPXA to better optimize both the composition and volume of the miscible injectant.
- c) Modification of Rule 11, which describes the Prudhoe Oil Pool surveillance report, to include the results of GCWI surveillance.

4. GCWI Project Overview

The project scope calls for ramping up to 650,000 barrels per day of seawater injection into the eastern portion of the gas cap from a new injection site located at the East Dock Staging Pad. Initial projected rates are 500,000 barrels per day. Water injection will increase over time with increased availability of seawater and decreased seawater demand in other projects, such as the Flow Station 2 and Point McIntyre waterfloods and Grind and Inject. Water injection is anticipated to continue for twenty years, with a final injected water volume of near four billion barrels. Increased hydrocarbon recovery of 150-200 million barrels is projected by BPXA.

a) Facilities Requirements

Facility construction is planned for this winter, followed by start-up of injection in mid 2002. To implement the Gas Cap Water Injection project, a new seawater pipeline from Flow Station 2 to the East Dock Staging Pad will be constructed. The new line will have a 32" diameter and a

total length of approximately 18,000 feet. It will tie-in to the existing 32" seawater line running from the Eastern Seawater Injection Plant to Flow Station 2. A heated pig receiver/manifold module and well houses will be installed at the East Dock Staging Pad to accommodate five to seven new injection wells.

b) GCWI Well Locations

Current plans for the GCWI include drilling of up to seven water injection wells into the eastern portion of the PBU, Ivishak formation gas cap. BPXA indicates the well locations were strategically chosen to allow for sufficient Ivishak pay at the bottom hole locations of the injectors, while maintaining sufficient distance from the gas injection and oil producing areas.

c) GCWI Well Completion

Each gas cap water injector will be completed with 13 3/8" surface casing cemented to surface, 9 5/8" intermediate casing with cement brought to 1000' above the shoe, and a fully cemented 7" injection liner. The tubing will be 7 5/8" and will include a 7" subsurface safety valve and two 7" profiles. The tubing is large to accommodate the high volume of water to be injected. The tubing will also be plastic coated to help minimize the friction losses. Average surface pressure for these new injection wells will be approximately 2700 psi. Maximum injection pressure is expected to be approximately 3100 psi.

5. Project Benefits

a) Reservoir Pressure

Average reservoir pressure in the Prudhoe Bay field is declining at a rate of 25-35 psi/year. The declining pressure reduces efficiency of every recovery mechanism operating in the field. The GCWI project is designed to arrest pressure decline and maintain the reservoir pressure until water injection ends in 2022. Current average reservoir pressure is approximately 3450 psi (@ 8800' ss datum).

b) Reservoir Simulation of Recovery

The GCWI incremental oil recovery was predicted using BPXA's Full Field Compositional Reservoir Model, comprised of a sixty (60) acre areal grid of the Prudhoe Bay field. It includes the oil that initially was in the gas cap and is immobile. The recovery calculated by the full field model was validated using mechanistic studies of GCWI using fully compositional 1D, 2D, strip, and pattern models. The increased pressure resulting from GCWI improves every recovery mechanism operating in the field. The benefits are characterized for three regions of the field; Gas Cap, Gravity Drainage, and Waterflood/EOR.

The incremental net additional recovery from GCWI is approximately 200 MMB in the full field model. The total reflects a reduction of 20 MMB in the Gas Cap region with increases of 200 MMB in the Gravity Drainage region, and 20 MMB in the waterflood/EOR region.

(1) Gas Cap Area

In total, there is a net reserves reduction of about 20 MMB in the Gas Cap region. In the original gas cap, not invaded by water, BPXA projects 30 MMB additional reserves from

vaporization of residual oil and retrograde condensate. In the water invaded area, some hydrocarbon liquids will be trapped and remain immobile to injected water, preventing vaporization by injected gas, which reduces liquid recovery by approximately 50 MMB.

(2) Gravity Drainage Area

BPXA projects improved vaporization and gravity drainage processes will yield about 200 MMB of incremental recovery from the Gravity Drainage region. Vaporization of residual oil and retrograde condensate by the injected gas is more efficient at higher pressure. Higher reservoir pressure reduces oil shrinkage and oil viscosity. Both of these effects increase oil mobility and result in more efficient gravity drainage.

(3) Waterflood and EOR Area

The waterflood/EOR benefits are approximately 20 MMB. The projected benefits result from: 1) higher reservoir pressure increasing well production capacity; 2) lowered oil shrinkage; and 3) the higher reservoir pressure allowing leaner miscible injectant, thus greater supply, leading to more EOR recovery.

6. Water Movement

The potential for water to interfere with the various recovery mechanisms has been extensively studied by the WIOs. In particular, the potential for water to finger through the gas cap, and interfere with the gravity drainage area was a prime concern. WIO studies showed that because gas is 100 times more mobile than the water that displaces it, a piston-like displacement is anticipated. Water saturations in simulation of water displacing oil were compared to simulation of water displacing gas in a reservoir containing a high permeability (5 Darcy) thief zone. In the case of water displacing oil, water fingered through the high perm streak to the producer. In the case of water displacing gas, a piston-like displacement occurred.

Areal water saturation maps from BPXA's full field model were presented, showing the movement of water over time. The water is projected to move in a relatively radial to oblong shaped front. At the end of GCWI injection in 2022, water is projected to reach the waterflood area in the eastern part of the field, and the northern oil producers in the gravity drainage area. However, the western portion of the gas cap, and the major portion of the gravity drainage area are not expected to be invaded with water. Shut-down of GCWI is expected in 2022. Review of model projections through 2031 indicates little lateral movement of the water, again due to the low mobility of the water to the gas in the area.

7. GCWI - Major Gas sale Relationship

The WIOs addressed the interaction of the GCWI project with potential major gas sales and how gas sales would impact the estimated benefits of the GCWI project and how gas cap water injection is expected to impact ultimate gas recovery.

a) Major Gas Sale Effect on GCWI Recovery

A gas sale will reduce the incremental oil recovery from gas cap water injection. While the rate and timing have not been determined for major gas sales, a case to demonstrate the effect

was shown. Assuming a 4 BCF/D gas sales rate beginning in 2008, the incremental production derived from GCWI is reduced from about 200 MMB to about 135 MMB. The reduction in the recovery results from three mechanisms:

- * With a major gas sale the volume of gas available for injection is reduced in order to meet the gas sale demand. This reduces vaporization recovery for gas cap water injection;
- * The ability of the injected gas to vaporize the oil it contacts diminishes as reservoir pressure decreases.
- * Gas sale will lower reservoir pressure, making the oil more viscous, which decreases efficiency of oil production and reduces oil produced by gravity drainage.

b) Effect of GCWI on Gas Recovery of Major Gas Sales

The WIOs state that ultimate gas recovery should not be reduced by GCWI. Major Gas Sales off-take will require a large water free area from which to produce the gas. The simulation projections presented for the GCWI project suggest that the water will be localized and a significant portion of the gas cap will be free from water to allow blow-down of the gas reserves.

Without GCWI, gas recovery is expected to exceed 80% of the original gas cap gas in place when the pressure is reduced from the original 4400 psi to about 850 psi. With GCWI, gas is expected to be trapped at a saturation of 25% within the area of water injection. When reservoir pressure is subsequently reduced during "blow down", the trapped gas expands and once again becomes mobile. In the example shown by the WIOs, at a reservoir pressure of 1500 psi the gas recovery was projected at 90% with GCWI, while by pressure depletion alone the pressure has to be blown down to 500 psi to achieve the same recovery.

8. Surveillance BPXA presented plans to monitor injection well conformance, water movement and reservoir pressure. The major components of the GCWI surveillance plan are:

- * Injection wells will be monitored in a manner similar to other water injection wells within the Prudhoe Bay pool.
- * Pulsed Neutron Logs (PNLs) in existing wells will provide downhole and regional data on the water movement.
- * 4-D gravity will provide a general view of water movement.
- * Reservoir pressure monitoring will be done according to current Prudhoe Bay pool rules.

a) Injection Well Monitoring

Injection well monitoring will be conducted to ensure that the water injection is contained in the desired reservoir interval. The injection wells will be monitored with surface measured temperature, pressure and injection rate. These measurements will be similar to other injection wells within the Prudhoe Bay pool. With these measurements it is possible to monitor injection characteristics, particularly changes in the injectivity indices. The injectivity indices provide direct evidence of changes in well performance. Downhole measurements will provide

confirmation of the surface measurements and will also help describe reservoir properties and hydraulic performance. Downhole temperature logs will provide verification of injection conformance and confirm that fracture height growth is confined within the Ivishak. Downhole pressure measurements will be used to determine tubular pressure drops and hydraulic performance. Pressure falloff tests will be undertaken to determine reservoir properties and wellbore skin.

b) Water Movement Surveillance with Pulsed Neutron Logs:

The leading edge of the waterflood will be detected primarily with pulsed neutron logs. BPXA identified more than nine wells surrounding the injection areas in which pulsed neutron logs can be run to monitor the movement of water. These wells are primarily Lisburne producing wells. BPXA indicated that there are no known cement problems that would prevent confinement of injection to the Ivishak. Pulsed neutron logs, specifically the RST logs, were chosen because they can be run in Lisburne wells completed with 2 7/8 inch tubing. Also, they can be run in two modes to collect data for discerning a major change in fluids (sigma & Carbon/Oxygen). The RSTs will help locate the leading edge of the waterflood, by detecting the change in saturation as water invades the Ivishak gas cap interval at the wellbore. It will also provide data in determining the regional waterflood coverage. BPXA indicated that the statistical variations seen in the RST log measurements should not substantially affect the ability to detect movement of water into the gas zones.

c) 4D Gravity Technique

The 4D Gravity technique utilizes very sensitive surface gravity measurements taken periodically. The method measures small changes in gravity as the low-density gas is replaced with the higher density water. Baseline measurements will be taken prior to water injection. Subsequent measurements will be made at discrete time intervals and compared to the baseline measurements. An increase in the density of the fluids in the gas cap indicates the presence of water. BPXA anticipates the 4D Gravity technique will allow them to map general water movement, determine an average waterflood front, and provide a means to perform a mass balance of the injected water. The major limitations of the 4D gravity technique are that it cannot detect small horizontal or vertical flood fronts and it cannot provide any downhole zonal information. Gravity measurements coupled with material balance and PNL measurements can aid validation of simulation predictions and fine tune history match calculations.

9. Proposed change to Rule 12(c)

BPXA requested in the rules for GCWI that the requirements for minimum miscibility pressure stipulated in Rule 12(c) should be modified. Currently this rule stipulated that the Operator maintain a pressure differential of at least 250 psi between the minimum miscibility pressure of the miscible injectant and the prevailing reservoir pressure. The 250 psi differential had been initially proposed by the WIOs in testimony provided 10/9/91, and approved in CO 290 dated February 21, 1992. This differential was based upon the assumption that the reservoir pressure will decline 100-150 psi during the time in which a cycle of MI is in the reservoir. A safety factor of 100 psi in addition was added to this. With GCWI pressure will be maintained in the injection patterns. As such 100 psi differential is sufficient until such time that the reservoir pressure is stabilized. This change will allow some additional flexibility of the Operator to increase overall MI volumes, and disperse MI to other areas of the field, leading to better optimization of MI throughout the field. This will not have a negative impact upon overall

recovery.

10. Mitigation of Risks

Studies indicate that not implementing or further delaying GCWI will result in less recovery over the remaining life of the field. The studies and analysis appear thorough and technically sound. Though outweighed by the expected benefits to overall hydrocarbon recovery, there remain some risks that must be managed through ongoing surveillance. Oil reserves are potentially at risk if the injected water moves too far, too fast and enters the sensitive Gravity Drainage area of the field. Numerous reservoir simulation and studies show a likely tendency for the injected water to be concentrated in the eastern portion of the gas cap where it is more likely to improve oil recovery from up dip oil zone waterfloods already in progress or planned. In addition, model studies have consistently shown that water will move in a piston-like way through the gas cap, regardless of heterogeneities. Therefore, sweep efficiency of the process will be high and the water should move downdip slowly. GCWI is a recovery technique, which, though well studied, is untried at Prudhoe Bay. Despite the lack of precedents, risks to hydrocarbon reserves can be controlled. The WIOs have designed a process and outlined overall surveillance plans that should minimize losses and ensure greater ultimate hydrocarbon recovery.

11. Blowout Prevention Equipment and Practice

The provisions of Rule 4 of CO 341C are obsolete and inconsistent with current Commission regulations as stated in 20AAC 25 and current North Slope operator practice.

CONCLUSIONS:

1. The application requirements of 20 AAC 25.520 have been met.
2. The GCWI project is expected to significantly increase overall hydrocarbon recovery from the Prudhoe Bay Oil Pool.
3. The GCWI project will mitigate pressure decline within the Prudhoe Bay Oil Pool.
4. With the planned implementation of GCWI, further investigation of options to mitigate pressure decline and annual report of these investigations is no longer necessary.
5. Further implementation of paragraph (d) of Rule 12, is unnecessary so long as the GCWI project is in operation.
6. Decreasing the minimum pressure differential requirement of Paragraph (c) of Rule 12 from 250 psi between the minimum miscibility pressure and the average reservoir pressure in the EOR injection areas will allow the Operator flexibility to provide more MI volume, and will not negatively impact recovery. Potential for increased rate and recovery exists through optimization of the MI injectant.
7. Adequate surveillance of the GCWI project is required to determine that water movement within the reservoir is confined as intended and does not negatively impact overall hydrocarbon recovery, and to determine if the project is successful in stabilizing reservoir pressure.

8. The Commission needs to be apprised of surveillance plans and results on a yearly basis.

9. The conclusions in CO 341C and the amendments thereto are incorporated herein to the extent not inconsistent with this order.

10. Rule 4 of CO 341C is no longer current and has been superseded by 20 AAC 25.035, 25.036, 25.037, 25.285, 25.286, 25.287, and 25.288.

NOW, THEREFORE, IT IS ORDERED THAT

- (1) Conservation Order 341D supersedes Conservation Order 341C dated June 12, 1997;
- (2) Rule 4 of Conservation Order No. 341C is revoked, Rules 11, 12, and 16 are amended, and new Rule 17 is added; and
- (3) In addition to statewide requirements under 20AAC 25 (to the extent not superseding these rules), the following rules now apply to the Prudhoe Oil Pool within the following described area (referred to in this order as the affected area):

UMIAT MERIDIAN

Township	Range	Section
T. 10N.,	R. 12E.,	1, 2, 3, 4, 10, 11, 12
T. 10N.,	R. 13E.,	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 24
T. 10N.,	R. 14E.,	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22, 23, 24, 25, 26, 27, 28, 36
T. 10N.,	R. 15E.,	all
T. 10N.,	R. 16E.,	5, 6, 7, 8, 17, 18, 19, 20, 29, 30, 31
T. 11N.,	R. 11E.,	1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 24, 25
T. 11N.,	R. 12E.,	all
T. 11N.,	R. 13E.,	all
T. 11N.,	R. 14E.,	all
T. 11N.,	R. 15E.,	all
T. 11N.,	R.	17, 18, 19, 30, 31, 32

	16E.,	
T. 12N.,	R. 10E.,	13, 24,
T. 12N.,	R. 11E.,	15, 16, 17, 18, 19, 20, 21, 22, 25, 26, 27, 28, 29, 30, 32, 33, 34, 35, 36
T. 12N.,	R. 12E.,	23, 24, 25, 26, 27, 28, 29, 30, 31, 32, 33, 34, 35, 36
T. 12N.,	R. 13E.,	19, 20, 21, 22, 23, 26, 27, 28, 29, 30, 31, 32, 33, 34, 35, 36
T. 12N.,	R. 14E.,	25, 26, 27, 28, 29, 31, 32, 33, 34, 35, 36
T. 12N.,	R. 15E.,	25, 26, 27, 28, 29, 30, 31, 32, 33, 34, 35, 36

(Source: C. O. 145, page 7, expansions/contractions of initial participating area based on November 20, 1987 letter, Wade and Nelson to Eason, Re: Prudhoe Bay Unit Exhibits, Exhibit C, Part I Oil Rim Participating Area and Part II Gas Cap Participating Area.)

Rule 1 Pool Definition and Changing the Affected Area (ref. C.O. 145)

(a) The Prudhoe Oil Pool is defined as the accumulations of oil that are common to and which correlate with the accumulations found in the Atlantic Richfield - Humble Prudhoe Bay State No. 1 well between the depths of 8,110 feet and 8,680 feet. (Source: C.O. 145, Rule 1)

(b) The Commission may adjust the description of the affected area to conform to future changes in the initial participating area by administrative approval. (Source: C. O. 145, Rule 12)

Rule 2 Well Spacing (ref. C.O. 145, 174)

There shall be no restrictions as to well spacing except that no pay shall be opened in a well closer than 500 feet to the boundary of the affected area. (Source: C.O. 174, Rule 2)

Rule 3 Casing and Cementing Requirements (ref. C.O. 145, 238)

(a) Conductor casing shall be set at least 75 feet below the surface and sufficient cement shall be used to fill the annulus behind the pipe to the surface. Rigid high-density polyurethane foam may be used as an alternate to cement, upon approval by the Commission. The Commission may also administratively approve other sealing materials upon application and presentation of data which show the alternate is appropriate based on accepted engineering principles. (Source: C.O. 238, Rule 3a)

(b) Surface casing to provide proper anchorage for equipment, to prevent uncontrolled flow, to

withstand anticipated internal pressure, and to protect the well from the effects of permafrost thaw-subsidence or freeze-back loading shall be set at least 500 feet, measured depth, below the base of the permafrost but not below 5000 feet true vertical depth. Sufficient cement shall be used to fill the annulus behind the casing to the surface. The surface casing shall have minimum axial strain properties of 0.5% in tension and 0.7% in compression. (Source: C.O. 238, Rule 3b)

(c) Alternate casing programs may be administratively approved by the Commission upon application and presentation of data, which show the alternatives, are appropriate, based upon accepted engineering principles. (Source: C.O. 238, Rule 3c)

Rule 4 Blowout Prevention Equipment and Practice (revoked C.O. 341D).

Rule 5 Automatic Shut-in Equipment (ref. C.O. 145, 333, 363)

(a) Each well shall be equipped with a Commission approved fail-safe automatic surface safety valve system (SVS) capable of preventing uncontrolled flow by shutting off flow at the wellhead and shutting down any artificial lift system where an over pressure of equipment may occur.

(b) The safety valve system (SVS) shall not be deactivated except during repairs, while engaged in active well work, or if the pad is manned. If the SVS cannot be returned to service within 24 hours, the well must be shut in at the well head and at the manifold building.

1. Wells with a deactivated SVS shall be identified by a sign on the wellhead stating that the SVS has been deactivated and the date it was deactivated.

2. A list of wells with the SVS deactivated, the dates and reasons for deactivating, and the estimated re-activation dates must be maintained current and available for Commission inspection on request.

(c) A representative of the Commission will witness operation and performance tests at intervals and times as prescribed by the Commission to confirm that the SVS is in proper working condition.

(d) The SVS must be maintained in working condition at all times unless the well is shut in and secured, or the well is being operated in conformance with other sections of this rule.

(e) Upon proper application or its own motion, the Commission may administratively waive or amend the requirements of this rule as long as the change does not promote waste, jeopardize correlative rights or compromise ultimate recovery, and is based on sound engineering principles.

(f) Nothing in this rule precludes the installation of a SSSV in wells designated by the operator. If a SSSV is installed, it must be maintained in working order and is subject to performance testing as part of the SVS.

Rule 6 Pressure Surveys (ref. C.O. 145, 165, 192, 208, 213, 220, AA 220.1, 341B)

(a) Prior to regular production, a static bottom hole or transient pressure survey shall be taken on at least one in three wells drilled from a common drilling site. (Source: C.O. 220, Rule 1,

C.O. 341B)

(b) An annual pressure surveillance plan shall be submitted to the Commission in conjunction with the Annual Prudhoe Pool Reservoir Surveillance Report by April 1, each year. The plan will contain the number of pressure surveys anticipated for the next calendar year and be subject to approval by the Commission by May 1. These surveys are needed to effectively monitor reservoir pressure in the Prudhoe Oil Pool. The surveys required in (a) of this rule may be used to fulfill the minimum requirements. (Source: C.O. 220, Rule 6, C.O. 341B)

(c) Data from the surveys required in (a) and (b) of this rule shall be submitted with the Annual Prudhoe Oil Pool Reservoir Surveillance Report by April 1 each year. Data submitted shall include rate, pressure, time depths, temperature, and any well condition necessary for the complete analysis of each survey. The datum for the pressure surveys is 8800 feet subsea. Transient pressure surveys obtained by a shut in buildup test, an injection well pressure fall-off test, a multi rate test or an interference test are acceptable. Other quantitative methods may be administratively approved by the Commission. (Source: C.O. 220, Rule 7, C. O. 341C.001)

(d) Results and data from any special reservoir pressure monitoring techniques, tests, or surveys shall also be submitted as prescribed in (c) of this rule. (Source: C.O. 220, Rule 8)

(e) By administrative approval the Commission may grant time extensions and waive requirements of this rule, and by administrative order the Commission may require additional pressure surveys in (b) of this rule. (Source: C.O. 220, Rule 5)

Rule 7 Gas-Oil Contact Monitoring (ref. C.O. 145, 165, 192, 208, 213, AA 213.39)

(a) Prior to initial sustained production, a cased or open hole neutron log shall be run in each well. (Source: C.O. 165, Rule 9a) This requirement is waived for waterflood/EOR areas encompassed by the expanded Prudhoe Bay Miscible Gas Project outlined in C.O. 290, and for those areas not expected to have significant GOC movement or gas encroachment from the gravity drainage area defined by the Commission through Administrative Approval. (Source: AA 213.39, excerpts from paragraph 1)

(b) A minimum of 40 repeat cased hole neutron log surveys shall be run annually. (Source: C.O. 208, Rule 4)

(c) The neutron logs run on any well and those required in (a) and (b) of this rule shall be filed with the Commission by the last day of the month following the month in which the logs were run. (Source: C.O. 165, Rule 9d)

(d) By administrative approval, the Commission may delay, modify or waive the logging requirements of this rule or may require additional wells to be logged. (Source: C.O. 213, Rule 3)

Rule 8 Productivity Profiles (ref. C.O. 145, 165, 192, 208, 213, AA 213.40)

(a) A spinner flow meter or tracer survey shall be run in each well during the first six months the well is on production. (Source: C.O. 165, Rule 11a) This requirement is waived for wells completed with a single perforated interval, or with perforations in a single reservoir zone including highly deviated (greater than 65 degrees) and horizontal wells. (Source: AA 213.40)

paragraph 3)

(b) Follow-up surveys shall be performed on a rotating basis so that a new production profile is obtained on each well periodically. Nonscheduled surveys shall be run in wells which experience an abrupt change in water cut, gas-oil ratio, or productivity. (Source: C.O. 165, Rule 11b)

(c) The complete spinner flow meter or tracer data and results shall be recorded and filed with the Commission by the last day of the month following the month in which each survey is taken. (Source: C.O. 165, Rule 11c)

(d) The Commission may administratively approve alternate methods and time periods in the enforcement of this rule provided that the data obtained is appropriate for monitoring the Prudhoe Oil Pool or may waive the requirements of (a), (b) and (c). By administrative order the Commission may specify additional surveys other than the surveys submitted under (a), (b) and (c) of this rule. (Sources: C.O. 208, Rule 8 and C.O. 213, Rule 2)

Rule 9 Pool Off-Take Rates (ref. C.O. 145, 214)

The maximum annual average oil offtake rate is 1.5 million barrels per day plus condensate production. The maximum annual average gas offtake rate is 2.7 billion standard cubic feet per day, which contemplates an annual average gas pipeline delivery sales rate of 2.0 billion standard cubic feet per day of pipeline quality gas when treating and transportation facilities are available. Daily offtake rates in excess of these amounts are permitted only as required to sustain these annual average rates. The annual average offtake rates as specified shall not be exceeded without the prior written approval of the Commission.

Annual average offtake rates mean the daily average rate calculated by dividing the total volume produced in a calendar year by the number of days in the year. However, in the first calendar year that large gas offtake rates are initiated, following the completion of a large gas sales pipeline, the annual average offtake rate for gas shall be determined by dividing the total volume of gas produced in the calendar year by the number of days remaining in the year following initial delivery to the large gas sales pipeline.

Rule 10 Facility Gas Flaring revoked (ref. C. O. 341C)

Rule 11 Annual Surveillance Reporting (ref. C.O. 165, 186, 195, 208, 223, 224, 279, AA 279.1)

(a) An annual Prudhoe Oil Pool surveillance report will be required by April 1 of each year. The report shall include but is not limited to the following:

1. Progress of enhanced recovery project(s) implementation and reservoir management summary including engineering and geotechnical parameters.
2. Voidage balance by month of produced fluids, oil, water and gas, and injected fluids, gas, water, low molecular weight hydrocarbons, and any other injected substances (which can be filed in lieu of monthly Forms 10-413 for each EOR project). (Source C.O. 279, Rule 7 and AA 279.1 excerpt from paragraph 3)

3. Analysis of reservoir pressure surveys within the field.
4. Results and where appropriate, analysis of production logging surveys, tracer surveys and observation well surveys.
5. Results of gas movement and gas-oil contact surveillance efforts including a summary of wells surveyed and analysis of gas movement within the reservoir. The analysis shall include map(s) and/or tables showing the locations of various documented gas movement mechanisms as appropriate. (Source: C.O. 279, Rule 7)

6. Progress of the Gas Cap Water Injection project with surveillance observations including;

- (a) volume of water injected,
- (b) reservoir pressure results, maps, and analysis (in conjunction with (a) 3 of this rule),
- (c) water movement and zonal conformance maps derived from surveillance (such as Pulsed Neutron Logs and 4-D gravity surveys)
- (d) results of reservoir evaluations of performance (such as material balance and reservoir simulation studies),
- (e) surveillance plans for the upcoming year, and
- (f) any plans for change in project operation.

(b) Upon its own motion or upon written request, the Commission may administratively amend this rule so long as the change does not promote waste nor jeopardize correlative rights and is based on sound engineering principles. (Source: C.O. 279, Rule 8)

Rule 12 Prudhoe Bay Miscible Gas Project (PBMGP) (ref. C.O. 195, 290)

(a) Expansion of the PBMGP and infill expansion of miscible gas injection in the NWFB is approved for the 59,740 acre portion of the Prudhoe Oil Pool defined in the record. (Source: C.O. 290, Rule 1, AA 290.1)

(b) An annual report must be submitted to the Commission detailing performance of the PBMGP and outlining compositional information for the current miscible injectant (MI) necessary to maintain miscibility under anticipated reservoir conditions. (Source: C.O. 290, Rule 2)

(c) The minimum miscibility pressure (MMP) of the Miscible Injectant must be maintained at least 100 psi below the average reservoir pressure in the Prudhoe Bay Miscible Project area. When the Operator demonstrates that the reservoir pressure is no longer declining within the Prudhoe Bay Miscible Project Area (as evidenced by reservoir pressure measurements), the MMP may be maintained at or below the average reservoir pressure in the Prudhoe Bay Miscible Project area. (Source: C.O. 290, Rule 4; amended C.O. 341D)

(d) Revoked (C.O. 341D).

(e) Upon its own motion or upon written request, the Commission may amend this rule by administrative action if the change does not promote waste, violate correlative rights, nor jeopardize ultimate recovery, and is based on sound engineering principles. (Source: C.O. 290, Rule 6)

Rule 13 Waiver of GOR Limitation (ref. 8/22/86 letter)

The Commission waives the requirements of 20 AAC 25.240(b) for all oil wells in the Prudhoe Oil Pool of the Prudhoe Bay Field so long as the gas from the wells is being returned to the pool, or so long as the additional recovery project is in operation. (Source: Letter 8/22/86, L. Smith to Heinze/Nelson, paragraph 3)

Rule 14 Waiver of "Application for Sundry Approval" Requirement for Workover Operations (ref. C.O. 258)

The requirements of 20 AAC 25.280(a) are waived for development wells in the Prudhoe Oil Pool of the Prudhoe Bay Field. (Source: C.O. 258)

Rule 15 Waterflooding (ref. 3/20/81 letter Hamilton to Nelson/Norgaard)

The commission approves the December 1980 additional recovery application for waterflooding in the Prudhoe Oil Pool subject to the requirements listed in Rule 11 above.

Any proposed changes must be submitted to the Commission for approval. (Source: Letter 3/20/81, Hamilton to Nelson/Norgaard)

Rule 16 Orders Revoked

The following Conservation Orders and associated Administrative Approvals and letter approvals are hereby revoked. Conservation orders 78, 83B, 85, 87, 88, 96, 97, 98B, 117, 117A, 118, 130, 137, 138, 139, 140, 141, 143, 145, 145A, 148, 155, 160, 164, 165, 166, 167, 169, 174, 178, 180, 181, 183, 184, 185, 186, 188, 189, 192, 194, 195, 195.1, 195.2, 195.4, 197, 199, 200, 204, 208, 213, 214, 219, 220, 223, 224, 238, 258, 259, 279, 290 and 333, 341, 341A, 341B, 341C, and March 20, 1981 and August 22, 1986 letter approvals.

The hearing records of these orders are made part of the record for this order.

Rule 17 Gas Cap Water Injections

The Gas Cap Water Injection Project as described in the operator's application and testimony is approved. Ongoing reservoir surveillance is required to determine that water movement within the reservoir is confined as intended and does not negatively impact overall hydrocarbon recovery, and to determine that the project has resulted in stabilization of reservoir pressure.

DONE at Anchorage, Alaska and dated November 30, 2001.

Cammy Oechsli Taylor, Chair
Alaska Oil and Gas Conservation Commission

Daniel T. Seamount, Jr., Commissioner
Alaska Oil and Gas Conservation Commission

Julie M. Heusser, Commissioner
Alaska Oil and Gas Conservation Commission

7

AMENDED DECISION

DENIAL OF THE PROPOSED PLANS FOR DEVELOPMENT OF THE
POINT THOMSON UNIT

October 27, 2005

Findings and Decision of the Director, Division of Oil and Gas
Under Delegation of Authority from the
Commissioner, Department of Natural Resources, State Of Alaska

The Division of Oil and Gas (the Division) hereby amends the decision entitled *Denial of the Proposed Plans for Development of the Point Thomson Unit* dated September 30, 2005 (the Decision). The Decision included notice that the Division would hold a hearing under Article 21 of the Point Thomson Unit Agreement. The Decision is amended to remove certain items of work and all references to Article 21 because they do not apply to the Division's evaluation of the Unit Operator's proposed plans for development of the Point Thomson Unit.

I. SUMMARY OF DECISION

This is the final Decision of the Alaska Department of Natural Resources, Division of Oil and Gas (the Division) on the Twenty-second Plan of Development (22nd POD) for the Point Thomson Unit (PTU) submitted by the PTU Operator, Exxon Mobil Corporation (Exxon), on August 31, 2005. The Division finds that the PTU Agreement is in default for Exxon's failure to submit an acceptable unit plan of development.

The PTU is underlain by a massive undeveloped gas and gas condensate reservoir that was discovered nearly 30 years ago, but the PTU oil and gas lessees have determined that production of the unitized substances is, in their view, not commercially viable. The 22nd POD proposes additional studies to determine if the PTU lessees can design a commercially viable production project.

The 22nd POD states that PTU development is not possible without modifying the current laws regarding the State's right to taxes and royalties on oil and gas production and on construction of a North Slope gas pipeline. The PTU Operator proposed integrating the lessees' PTU development obligations into negotiations for a fiscal contract with the State and proposed a two year delay of the development commitments made by the lessees in connection with an expansion of the PTU in 2001, both of which would make PTU development uncertain. The current fiscal contract negotiations may or may not lead to construction of a North Slope gas pipeline.

The premise that the PTU can only be developed if a North Slope gas pipeline is built is inappropriate. In addition to dry gas, the unit contains 100s of millions of barrels of hydrocarbon liquids. These hydrocarbon liquids could be produced using mostly existing oil pipelines without construction of a North Slope gas pipeline. Therefore, potential PTU development is not, in fact, limited to dry gas production. In addition, the PTU Agreement, which requires timely exploration, delineation, development, and production of unitized substances, does not guarantee the lessees' commercial success or provide for indefinite extension of the leases.

1. The 22nd POD is disapproved because it does not set out a plan to bring the PTU into commercial production within a reasonable time frame.
2. Failure to obtain approval of the unit plan is grounds for default under the PTU Agreement and the State oil and gas regulations. Effective October 1, 2005, the PTU Agreement is in default. Exxon has 90 days, until December 29, 2005 to cure the default by submitting a unit plan that commits to timely development and production of unitized substances.

3. In addition, the Division denies Exxon's request for a one-year deferral of the Expansion Agreement commitments. If Exxon does not commence drilling within the PTU by June 15, 2006, the PTU boundary will contract and the contracted leases will no longer be held by unitization.

II. BACKGROUND

The details of the PTU history set out below can be summarized as follows. Some of the PTU leases were issued over 40 years ago and the unit has been in existence for 28 years. The Division certified 7 exploration wells within and around the unit area as capable of producing hydrocarbons in paying quantities, but it has been 20 years since the last well was drilled. The Thomson Sand Reservoir is known to contain at least 8 trillion cubic feet of gas and 200 million barrels of gas condensate and oil. The PTU also contains 100s of millions of barrels of oil in the shallower Brookian reservoirs. The PTU lessees have not yet determined whether they can commercially produce PTU resources, and they have not committed to timely explore, delineate, or develop PTU oil, gas, or gas condensate. The unit operator has consistently proposed that more studies or workshops are needed before putting the PTU into production and, since 1983, has periodically asserted that production cannot begin until a North Slope gas pipeline is built.

The PTU is located on the North Slope of Alaska. The western unit boundary is approximately 3 miles east of the Badami Unit and 30 miles east of the Prudhoe Bay Unit (PBU), and the eastern unit boundary lies west of the western boundary of the Arctic National Wildlife Refuge (ANWR). The southern PTU boundary is onshore, and the northern boundary is offshore in the Beaufort Sea, adjacent to or near the three-mile territorial sea boundary that separates state from federal Outer Continental Shelf (OCS) lands. The PTU consists of 45 state oil and gas leases encompassing approximately 106,200.55 acres. The state owns the entire subsurface estate within the unit area.

Twenty-five lessees hold working interest ownership in the PTU (PTU Owners), and Exxon is the designated Unit Operator. Ownership is calculated based on a lessee's percent of working interest ownership in each lease multiplied by the lease acreage, as a percentage of the total unit acreage. On a surface acreage basis, the Major PTU Owners hold 98.9056% of the PTU: Exxon 52.5779%¹, BP Exploration (Alaska) Inc. (BPXA) 29.1943%, Chevron U.S.A. Inc. (Chevron) 14.3125%, and ConocoPhillips Alaska, Inc. (CPAI) 2.821%. The Minor PTU Owners include twenty entities that hold the remaining 1.0944% interest in the PTU.

The Division approved the PTU Agreement effective August 1, 1977, with a five-year Initial Plan of Exploration. The original unit area included 18 state oil and gas leases comprising approximately 40,768 acres. The PTU Owners drilled 11 wells in and around the unit area between 1978 and 1983, and the Division certified six of those wells as capable of producing hydrocarbons in paying quantities under the regulations² and the PTU Agreement.³

¹ Exxon Mobil Corporation holds 43.2361% working interest ownership in the PTU and ExxonMobil Oil Corporation holds 9.3418%, jointly referred to as Exxon.

² 11 AAC 83.361. Certification of Well Test Results. "For the purposes of 11 AAC 83.301 – 11 AAC 83.395, a well will be considered capable of producing hydrocarbons in paying quantities, as defined in 11 AAC 83.395, when so certified by the commissioner following application by the lessee or unit operator. The commissioner will require the submission of data necessary to make the certification, including all results of the flow test or tests, supporting geological data, and cost data reasonably necessary to show that the production capability of the well

On March 26, 1984, the Division approved an application to expand the unit area on condition that the PTU Owners drill a well on one of the two southern expansion leases by March 31, 1985, and a well on one of the ten northern expansion leases by February 1, 1990. The expansion added approximately 94,152 acres within 25 leases to the PTU. The PTU Owners failed to meet both drilling commitments; therefore, the two southern expansion leases and nine northern expansion leases contracted out of the PTU.⁴

In 1998, the Division denied a unit expansion application, which was submitted by Exxon as the owner of the proposed expansion lease, rather than as the PTU Operator; because it was not supported by the other PTU Owners. The Division found that adding a lease to a unit where the owners have demonstrated a lack of cooperation may discourage, rather than encourage, unit development. The Division's denial of Exxon's 1998 PTU expansion application instigated negotiations between the Division and the PTU Owners to redefine the unit boundary. Supporting technical data indicated that the Thomson Sand Reservoir extended beyond the existing unit boundary and that other portions of the unit were not underlain by known hydrocarbons.

On February 2, 2001, Exxon applied to simultaneously expand and contract the PTU boundary. On July 31, 2001, the Division and the PTU Owners entered into an agreement in which the Division approved an expansion of the unit area in return for the PTU Owners' commitment to do certain items of work. This agreement also provided that the expansion leases would contract out of the unit and the PTU Owners would pay the State certain sums of money if the work was not done. This "*Agreement Resolving All Pending Point Thomson Unit Expansion/Contraction Matters and Proceedings*" (Expansion Agreement) identified seven Expansion Areas and one Work Commitment Area (WCA) outside of the preexisting PTU (All together referred to as "Expansion Acreage"). The Expansion Agreement included the following work commitments by the PTU Owners:

1. WCA Drilling Commitment: Drill a well through the Thomson Sand interval within the Work Commitment Area by June 15, 2003, or the WCA acreage would automatically contract out the PTU on that date. Drilling a new well or deepening the Red Dog #1 Well would have fulfilled the WCA Drilling Commitment

satisfies the economic requirements of the paying quantities definition." 11 AAC 83.395. Definitions. "Unless the context clearly requires a different meaning, in 11 AAC 83.301 – 11 AAC 83.395 and in the applicable unit agreements, ... (4) 'paying quantities' means quantities sufficient to yield a return in excess of operating costs, even if drilling and equipment costs may never be repaid and the undertaking considered as a whole may ultimately result in a loss; quantities are insufficient to yield a return in excess of operating costs unless those quantities, not considering the costs of transportation and marketing, will produce sufficient revenue to induce a prudent operator to produce those quantities;"

³ PTU Agreement, Article 9, Drilling to Discovery. "Within 6 months after the effective date hereof, the Unit Operator shall begin to drill an adequate test well at a location approved by the Director, ... and thereafter continue such drilling diligently until the top 100 feet of the Pre-Mississippian formation has been tested or until at a lesser depth unitized substances shall be discovered which can be produced in paying quantities (to wit: quantities sufficient to repay the costs of drilling, and producing operations, with a reasonable profit) ..."

⁴ One of the northern expansion leases remained committed to the PTU because a well drilled on that lease in 1982 was certified as capable of producing in paying quantities.

2. 2006 Development Drilling Commitment: Commence development drilling in the PTU by June 15, 2006, or all of the Expansion Acreage would automatically contract out of the unit effective that date, and the PTU Owners would pay the State \$20,000,000 by July 1, 2006, to compensate for the unrealized bonus payments during the period that the Expansion Acreage was withheld from leasing.
3. 2008 Development Drilling Commitment: Complete drilling seven development wells in the PTU by June 15, 2008, or all of the Expansion Acreage would automatically contract out of the unit effective that date, and the PTU Owners would pay the State \$27,500,000 by July 1, 2008, to compensate for the unrealized bonus payments during the period that the Expansion Acreage was withheld from leasing.
4. Participating Area Commitment: Allocate production to the Expansion Acreage within a participating area approved by the Division by certain deadlines. The participating area commitment date is June 15, 2008, for Expansion Acreage primarily underlain by the Thomson Sand Reservoir; and June 15, 2010, for Expansion Acreage primarily underlain by a Brookian prospect.

In addition, the Expansion Agreement imposed contraction provisions and charges of up to \$27,500,000 if the PTU Owners failed to meet the drilling commitments. The Agreement also increased royalty rates on eight of the twelve expansion leases; from 12.5% to 16.66667% on one lease, and from 16.66667% to 20% on the other seven leases.

The May 24, 2002 Findings and Decision contains the Division's evaluation of the Expansion Agreement, which resulted in the Second Expansion and Third Contraction of the PTU. The Expansion Agreement added approximately 40,353 acres within 12 leases to the PTU, and excluded all or portions of 4 leases, containing approximately 7,572 acres; an overall increase in the unit area of 39 percent. The revised unit area encompassed approximately 116,607 acres within 46 leases.

The PTU Owners based the Expansion Agreement on their assumption that they could engineer and develop a commercially viable gas cycling project. In a gas cycling project natural gas is produced, gas condensates are removed, and the dry gas is re-inject back into the reservoir for later production. The PTU Owners would need to build a pipeline from the PTU to connect with the Badami Unit pipeline to ship the gas condensates through the existing Trans-Alaska oil pipeline for sale. The Expansion Agreement provided that if PTU Owners found, in their view, the project to be uneconomic by June 15, 2003 (the Contraction Election Deadline), the PTU Owners could elect to contract all of the Expansion Acreage out of the PTU, pay the State \$8,000,000 to compensate for the unrealized bonus payments during the period that the acreage was withheld from leasing, and be released from the remaining obligations in the Expansion Agreement.

The Division approved subsequent unit plans that described the PTU Owner's proposed plans for development of a gas cycling project including: facility design, preliminary engineering, updating the PTU geologic model, and initiating the permitting process. However, in the Nineteenth POD, approved effective October 1, 2002, Exxon stated that the PTU Owners could

not justify drilling an exploration well in the WCA, the first drilling commitment in the Expansion Agreement, due to their findings that the costs would be higher and the potential accumulation smaller than they had previously anticipated.

On January 29, 2003, the Division found that the geological and geophysical data supported Exxon's proposal to transfer ADL 389728 from the WCA to Expansion Area #1. This amendment of the Expansion Agreement increased the applicable royalty rate for ADL 389728 from 16.66667% to 20% and the PA Extension Charge for Expansion Area #1 from \$17,031,000 to \$21,289,000.

Under the terms of the Expansion Agreement, the two remaining leases in the WCA contracted out of the PTU and the PTU Owners relinquished their interest in the leases effective January 21, 2003 and the PTU Owners paid the State \$940,000 because they failed to fulfill the first drilling commitment.

On April 24, 2003, Exxon requested a two-year extension of the next three deadlines in the Expansion Agreement: the Contraction Election Deadline, the 2006 Development Drilling Commitment, and the 2008 Development Drilling Commitment.

On May 15, 2003, the Division approved a one-month extension of the Contraction Election Deadline, but the Development Drilling Commitments were unchanged. On June 20, 2003, the PTU Owners requested an additional six-month extension of the Contraction Election Deadline. On July 14, 2003, the Division approved the Twentieth POD for the period October 1, 2003 through September 30, 2004, during which time, Exxon planned to acquire the necessary permits and approvals for the gas cycling project while evaluating the Thomson reservoir structure and reserve estimates to move the gas cycling project toward the next phase of funding approval. This decision also extended the Contraction Election Deadline until January 15, 2004 as follows:

- a) On or before July 15, 2003, the Working Interest Owners may elect to contract all of the Expansion Acreage out of the PTU, pay the State of Alaska \$8,000,000 to compensate for the unrealized bonus payments during the period that the acreage was withheld from leasing (Extension Charge), and be released from the remaining obligations imposed in the Decision. The Extension Charge will be due on August 1, 2003.
- b) Notwithstanding the foregoing, the above described deadline for election is hereby extended for a period of six months, until January 15, 2004, in exchange for an increase of the Extension Charge by the sum of \$2,000,000, provided that, at any time during such six-month extended period, the PTU Owners may provide notification of their election hereunder, in which event the total Extension Charge of \$10,000,000 shall be reduced by an amount equal to 1/12 of \$4,000,000 for each full month of such six-month period remaining.

The Division agreed to extend the Contraction Election Deadline on May 15 and again on July 14, 2003, to allow additional time for the PTU Owners to further evaluate their proposed gas cycling project. The PTU Owners presented their current interpretation of the PTU geologic model and updated in-place and recoverable hydrocarbons estimates to the Division on October

16, 2003. Unfortunately, the PTU Owners' assessment of their proposed gas cycling project indicated higher costs and lower liquid recovery than they had previously estimated.

In a letter dated December 18, 2003, Exxon stated that engineering and resource evaluation work confirmed that, in their view, development of the resource at PTU is challenged. The resource evaluation work resulted in a significant reduction in condensate recovery under the PTU Owners' conceptual design for a gas cycling project. In addition, they found that their engineering design, along with permitting and environmental requirements added significant cost to the gas cycling project. After evaluating potential cost reduction measures and alternate development plans, Exxon concluded "that a standalone project prior to gas sales is not economically viable under the current fiscal system." Exxon's letter went on to request a further extension of the Contraction Election Deadline, until June 15, 2006. The Division's denial of Exxon's requested extensions provides in part:

"Over the past year, the Owners reviewed the geologic model, recalculated the recoverable liquid hydrocarbons, refined the engineering design to better estimate the cost of development, began evaluating the environmental impacts through the federal permitting process, and considered alternate development scenarios. Through these activities, the Owners determined that the gas cycling project is currently uneconomic and suspended the permitting process indefinitely. Representatives from ExxonMobil met with division staff on December 2, 2003, to discuss possible revisions to the State's current fiscal system that might make the gas cycling project commercially viable. However, the Owners have not made any specific proposals that would warrant a further extension of the Contraction Election Deadline.

Without a commercially viable project, the Owners may surrender the expansion acreage, pay the \$10 million Extension charge, and be released from the remaining obligations in the Decision. If the Owners do not exercise this option, they must begin development drilling in the PTU by June 15, 2006, or all of the Expansion Acreage will automatically contract out of the PTU and the Owners will pay \$20 million to the State of Alaska. We trust that the Owners will continue to evaluate options to economically produce the known hydrocarbon resources underlying the PTU, and look forward to reviewing the proposed PTU Twenty-First Plan of Development in July 2004."

Although the PTU Owners found the gas cycling project to be uneconomic, they did not exercise their option to contract the Expansion Acreage out of the PTU prior to the January 15, 2004 Contraction Election Deadline.

The Twenty-first POD, dated August 31, 2004, stated that the PTU Owners were unable to identify a viable gas cycling project under the current fiscal terms and they planned to focus on gas sales rather than gas cycling. The Twenty-first POD included a proposal to share with the Division the results of the PTU studies including reserve estimates, distributions, and mapping for the Thomson Sand Reservoir as well as the Brookian and Pre-Mississippian reservoirs within the unit area and provide financial and technical information so the Division could conduct an independent economic evaluation of the PTU Owners' gas cycling project. But the WIOs would

only provide this information if the Division executed an extraordinary confidentiality agreement.

North Slope producers Exxon, BPXA, and CPAI (Sponsor Group), three of the Major PTU Owners, submitted an application to the State under the Stranded Gas Development Act (SGDA), which proposed a fiscal contract that may or may not lead to construction of a major North Slope gas pipeline. The Sponsor Group does not officially represent the PTU, the PBU or any other unitized area on the North Slope. During the Twenty-first POD, the PTU Owners planned to evaluate the technical and commercial issues necessary for the PTU Owners to participate in a future open season for major gas sales from the North Slope.

On September 23, 2004, the Division approved the Twenty-first POD, on condition that Exxon provide the Division with existing technical information, costs, and other fiscal assumptions necessary for the Division to conduct an economic analysis of the PTU Owners' gas cycling project. The Division reminded Exxon of the statutory and regulatory confidentiality protections accorded sensitive information, and notified Exxon that the Division would not execute the proposed confidentiality agreement. The Division requested that Exxon provide copies of all of the requested data no later than November 15, 2004. In addition, the Division's approval of the Twenty-first POD required that the 22nd POD contain specific plans to fulfill the 2006 drilling commitment set forth in the Expansion Agreement.

Exxon appealed the Division's decision on the Twenty-first POD to the Commissioner of the Department of Natural Resources (the Commissioner). But on November 15, 2004, Exxon hand delivered a set of technical data to the Division. The Commissioner affirmed the Division's Twenty-first POD decision on November 24, 2004.

On June 21, 2005, Exxon proposed amending the Expansion Agreement such that the Expansion Acreage leases would remain within the PTU while the State and Sponsor Group continue negotiations over a fiscal contract and for the duration of any resulting fiscal contract. On July 1, 2005, the Division received Exxon's proposed 22nd POD, which included an update on activities during the term of the Twenty-first POD and planned activities during the one-year term of the 22nd POD. Exxon reported that the PTU Owners had incorporated the results of the prior geologic model, updated reservoir simulation, facility design, and cost estimates into a conceptual depletion plan for the PTU gas sales project. Under that plan, the PTU Owners would produce PTU gas and send it to the PBU for further processing before shipping it via a North Slope gas pipeline for sale, but did not specify a time-frame for development.

The 22nd POD did not commit to timely development or production of unitized substances. Instead, it proposed further development of the gas sales conceptual depletion plan so the PTU Owners would be prepared to participate in some future open season for nominations to a North Slope gas pipeline. The 22nd POD provides that the exact timing of the open season will be dependent, in part, upon the successful completion of a fiscal contract under the SGDA. During the term of the 22nd POD, the PTU Owners planned to monitor the progress of the negotiations under the SGDA and adjust the PTU work schedule as necessary to participate in an open season. The 22nd POD included the items of work summarized as follows:

1. Incorporate geologic modeling of the Thomson Sand aquifer uncertainty and the Pre-Mississippian bedded facies in the reservoir simulation model to form the basis of a major gas sales depletion plan.
2. Initiate more detailed facility design or Conceptual Engineering.
3. Determine optimum drillsite and well locations and update drilling and completion plan costs to estimate total project costs and timing.
4. Share the results of the above tasks with the Division.
5. Begin planning the permitting process for the PTU gas sales project.
6. Continue working to obtain all PTU Owners' approval of a new PTU Operating Agreement.
7. Assist the Division with its independent assessment of the commercial viability of the gas cycling project.

The Division's July 27, 2005 response indicated that it would not accept Exxon's proposal to amend the Expansion Agreement by tying it to the SGDA negotiations or relieve the PTU Owners of the work commitments they made in return for including the Expansion Acreage in the PTU. However, the Division indicated that it would be willing to extend the 2006 and 2008 Development Drilling Commitments, if the PTU Owners agreed to drill an exploration/delineation well, in lieu of a development well, by June 15, 2006 that could provide pertinent information pertaining to appropriate development of the western portion of the Thomson Sand Reservoir. The Division gave Exxon ten days to submit an acceptable plan, which should include the following items:

1. ExxonMobil shall drill an exploration/delineation well within the PTU by June 15, 2006.
2. The well must be drilled to the Mississippian basement and located to
 - a. delineate the Thomson Reservoir west of the PTU #1 well,
 - b. evaluate connectivity and continuity within the Thomson Reservoir, and
 - c. evaluate the extent of and the hydrocarbon properties within the oil rim.
3. ExxonMobil shall apply to the Alaska Oil and Gas Conservation Commission for Pool Rules and a depletion plan for the Thomson Reservoir.
4. ExxonMobil shall prepare a schedule of activities to obtain the necessary permits for construction of the PTU facilities and pipelines.
5. ExxonMobil shall compare core samples from the Badami wells with the appropriate PTU wells to evaluate the Brookian reservoirs within the PTU.

Division staff discussed the requested modifications to the 22nd POD with the PTU Owners on July 27, 2005, and on August 1, Exxon indicated that they would respond to the Division by the end of the month.

On August 31, 2005, Exxon submitted a revised 22nd POD and a letter requesting a one-year deferral of both the 2006 and 2008 Development Drilling Commitments, rather than an indefinite extension under the SGDA. The 22nd POD stated that the PTU Owners could not justify drilling an exploration well, but Exxon offered to hold a workshop with Division staff to evaluate whether drilling exploration/delineation wells could provide valuable information that would reduce the uncertainty associated with the western portion of the Thomson Sand Reservoir. Other than a commitment to drill an exploration/delineation well by June 15, 2006, the revised 22nd POD included the other modifications that the Division had requested. However, without a commitment to drill an exploration/delineation well within the PTU while requesting deferral of the Development Drilling Commitments and tying development activities in the 22nd POD to the SGDA, the PTU Owners' plans for development of the PTU are unacceptable.

III. STATE STATUTES, REGULATIONS, AND PTU AGREEMENT PROVISIONS RELEVANT TO EVALUATION OF THE PTU OWNERS' PLANS FOR DEVELOPMENT OF THE PTU

The standards and criteria for approval of unit plans are primarily set out in the State statute, regulations, and the applicable unit agreement.

A. State Statute and Regulations

The Commissioner, or his designee, may approve a unit plan if he determines it is necessary or advisable in the public interest.⁵ The following statutes and regulations govern approval of unit plans:

AS 38.05.180(p) provides, in part:

To conserve the natural resources of all or part of an oil or gas pool, field, or like area, the lessees and their representatives may unite with each other, or jointly or separately with others, in collectively adopting or operating under a cooperative or unit plan of development or operation of the pool, field, or like area, or part of it, when determined and certified by the commissioner to be necessary or advisable in the public interest. . . . The commissioner may require oil and gas leases issued under this section to contain a provision requiring the lessee to operate under a reasonable cooperative or unit plan, and may prescribe a plan under which the lessee must operate. The plan must adequately protect all parties in interest, including the state. ”

Under State regulation 11 AAC 83.303(a), the Director will approve a unit plan of development upon finding that it will: 1) promote the conservation of all natural resources; 2) promote the prevention of economic and physical waste; and 3) provide for the protection of all parties of

⁵ By memorandum dated September 30, 1999, the Commissioner approved a revision of Department Order 003 that delegated this authority to the Director of the Division of Oil and Gas.

interest, including the State. Subsection .303(b) sets out six factors that the Director will consider in evaluating a proposed unit plan.

11 AAC 83.343, Unit Plan of Development, provides as follows:

(a) A unit plan of development must be filed for approval as an exhibit to the unit agreement if a participating area is proposed for the unit area under 11 AAC 83.351, or when a reservoir has become sufficiently delineated so that a prudent operator would initiate development activities in that reservoir. All development operations must be conducted under an approved plan of development. A unit plan of development must contain sufficient information for the commissioner to determine whether the plan is consistent with the provisions of 11 AAC 83.303. The plan must include a description of the proposed development activities based on data reasonably available at the time the plan is submitted for approval as well as plans for the exploration or delineation of any land in the unit not included in a participating area. The plan must include, to the extent available information exists:

- (1) long-range proposed development activities for the unit, including plans to delineate all underlying oil or gas reservoirs, bring the reservoirs into production, and maintain and enhance production once established;
- (2) plans for the exploration or delineation of any land in the unit not included in a participating area;
- (3) details of the proposed operations for at least one year following submission of the plan; and
- (4) the surface location of proposed facilities, drill pads, roads, docks, causeways, material sites, base camps, waste disposal sites, water supplies, airstrips, and any other operation or facility necessary for unit operations.

(b) The commissioner will approve the unit plan of development if it complies with the provision of 11 AAC 833.303. If the proposed unit plan of development is disapproved, the commissioner will, in his discretion, propose modifications which, if accepted by the unit operator, would qualify the plan for approval.

(c) The unit plan of development must be updated and submitted to the commissioner for approval at least 90 days before the expiration date of the previously approved plan, as set out in that plan. The update must describe the extent to which the requirements of the previously approved pan were achieved; if actual operations deviated from or did not comply with the previously approved pan, an explanation of the deviation or noncompliance must be included in the update. ... After the commissioner has determined that an updated unit plan of development is complete as submitted, or as modified by the unit operator following the commissioner's suggestions, the commissioner will have an

additional 60 days in which to approve or disapprove the plan; if no action is taken by the commissioner, the update of the unit plan of development is approved.

(d) The unit operator shall submit an annual report to the commissioner describing the operations conducted under the unit plan of development during the preceding year.

(e) The unit operator may, with the approval of the commissioner, amend an approved pan of development.

B. The PTU Agreement Provisions

The following PTU Agreement provisions are relevant to the Division's evaluation of the PTU Owners' plans for development of the PTU.

Article 10, Plan of Further Development and Operation, provides as follows:

Within six months after completion of a well capable of producing unitized substances in paying quantities, the Unit Operator shall submit for the approval of the Director an acceptable plan of development and operation for the unitized land which, when approved by the Director, shall constitute the further drilling and operating obligations of the Unit Operator under this agreement for the period specified therein. Thereafter, from time to time before the expiration of any existing plan, the Unit Operator shall submit for the approval of the Director a plan for an additional specified period for the development and operation of the unitized land. The Unit Operator expressly covenants to develop the unit area as a reasonably prudent operator in a reasonably prudent manner.

Any plan submitted pursuant to this section shall provide for the exploration of the unitized area and for the diligent drilling necessary for determination of the area or areas thereof capable of producing unitized substances in paying quantities in each and every productive formation and shall be as complete and adequate as the Director may determine to be necessary for timely development and proper conservation of oil and gas resources of the unitized area, and shall:

- (a) specify the number and location of any wells to be drilled and the proposed order and time for such drilling; and,
- (b) to the extent practicable, specify the operating practices regarded as necessary and advisable for the proper conservation of natural resources.

Separate plans may be submitted for separate productive zones, subject to the approval of the Director.

Said plan or plans shall be modified or supplemented when necessary to meet changed conditions, or to protect the interests of all parties to this agreement.

Reasonable diligence shall be exercised in complying with the obligations of the approved plan of development. ...

Article 16, Conservation, states:

Operations hereunder and production of unitized substances shall be conducted to provide for the most economical and efficient recovery of said substances without waste, as defined by or pursuant to state law or regulation.

Article 20, Effective Date and Term, provides in part:

This agreement shall become effective upon approval by the Commissioner or his duly authorized representative as of the date of approval by the Commissioner and shall terminate five (5) years from said effective date unless:

- (a) such date of expiration is extended by the Commissioner, or
- (b) it is reasonably determined ... that the unitized land is incapable of production of unitized substances in paying quantities ... or
- (c) a valuable discovery of unitized substances has been made or accepted on unitized land during the said initial term or any extension thereof, in which event the agreement shall remain in effect for such term and so long as unitized substances can be produced in quantities sufficient to pay for the cost of producing same from wells on unitized land and, should production cease, so long thereafter as diligent operations are in progress for the restoration of production or discovery of new production and so long thereafter as the unitized substances so discovered can be produced as aforesaid, or
- (d) it is terminated as heretofore provided in this agreement. ...

IV. ANALYSIS OF THE PTU OWNERS' PLANS FOR DEVELOPMENT OF THE PTU

A discussion of the subsection 11 AAC 83.303(b) criteria, as they apply to the PTU Owners' plans for development of the PTU, is set out directly below, followed by the Director's findings relevant to the subsection .303(a) criteria, and the Director's decision.

1. Prior Exploration Activities and Geological and Engineering Characteristics of the PTU

The Thomson Sand Reservoir is the primary reservoir in the PTU, consisting of the Lower Cretaceous Thomson Sand interval trending generally west-northwest across the unit, and between approximately -12,780' and -13,128' tvdss⁶ in the Point Thomson Unit #1 discovery well (PTU1) drilled by Exxon in 1977. Exxon estimates that the Thomson Sand Reservoir

⁶ Total vertical depth subsurface (below sea level).

contains approximately 8 trillion cubic feet (TCF) of gas and over 200 million barrels (MMB) of recoverable gas condensate with a discontinuous heavy-oil rim. The reservoir pressure is extremely high, around 13,000 pounds per square inch (psi). Other potentially productive reservoirs present in the PTU include Brookian Lower Tertiary turbidite sands and what are informally referred to as the "Pre-Mississippian" carbonates. Although the Sourdough well data remain confidential, in 2001 BPXA disclosed that the wells encountered recoverable reserves of approximately 200 MMB in the Brookian section. All three reservoirs are, or may be, over-pressured throughout much of the PTU.

A subsurface ridge-like structural feature constrains the northern edge of the Thomson Sand accumulation. While Thomson Sand presence, hydrocarbon charge, and thickness are uncertain on the north flank of the feature, it is possible that the Thomson Sand Reservoir is present north of the feature within Expansion Area #6.

Eighteen exploration wells have been drilled within and around the PTU. At the request of the Unit Operator, the Division certified seven PTU wells as capable of producing hydrocarbons in paying quantities and granted five wells extended confidentiality⁷. The public PTU well data is summarized in Attachment 1 to this decision.

The available well data allows the Thomson Sand Reservoir to be described as very fine-grained sand along the southern margin of the unit coarsening northward to a conglomeratic facies and exhibiting an average porosity of about 16%. Permeability within the reservoir varies from 10 millidarcies (md) to more than 1,000 md.

The PTU Owners also acquired extensive seismic data over the unit. They merged and began prestack depth migration processing of four 3D seismic surveys, which cover essentially the entire unit area: the Point Thomson Unit, Flaxman Lagoon, Island Corridor West, and Challenge Island surveys. Merging the seismic data sets produced a more unified interpretation of the extent of the Thomson Sand Reservoir over the greater unit area. The well and geophysical data indicate that much of the PTU is underlain or is potentially underlain by oil, natural gas and gas condensate deposits in the Thomson Sand Reservoir, and by Brookian oil deposits. There also appears to be a thin and potentially discontinuous oil leg at the bottom of the Thomson Sand Reservoir. The PTU owners incorporated the well and seismic data into a common database, which is the basis for the PTU Owners' Thomson Sand Geologic and Reservoir Simulation Models.

The Sixteenth POD, submitted by Exxon on July 30, 1999, included a commitment to conform the unit boundary to consensus maps of the potential reservoirs. During the term of the Sixteenth POD, the PTU Owners developed consensus structure and isochore maps of the

7 20 AAC 25.537. Public and Confidential Well Information. "(d) Except as provided by (a) of this section, the reports and information required by this chapter to be filed by the operator will be kept confidential by the commission for 24 months following the 30-day filing period after well completion, suspension, or abandonment unless the operator gives written and unrestricted permission to release all of the reports and information at an earlier date. Upon notification that the commissioner of the Department of Natural Resources has made a finding that the required reports and information from a well contain significant information relating to the valuation of unleased land in the same vicinity, the commission will hold the reports and information confidential beyond the 24-month period and until notified by the commissioner of the Department of Natural Resources to release the reports and information."

Thomson Sand Reservoir and five potential Brookian accumulations; and initiated unit expansion discussions with adjacent leaseholders. On July 31, 2001, the Division and the PTU Owners executed the Expansion Agreement, which restructured the unit boundary in exchange for the PTU Owners' exploration and development commitments.

The Eighteenth POD, approved effective October 1, 2001, included activities toward fulfilling the Expansion Agreement, including selecting a location and contracting for a rig to drill an exploration/delineation well in the WCA. During the term of the Eighteenth POD, the PTU Owners completed prestack depth migration of the combined PTU 3D data set (Point Thomson Unit, Challenge Island, Island Corridor West and Flaxman Lagoon) over the redefined unit area. Exxon continued to pursue facility design, engineering and geological studies, and environmental analysis toward development of the Thomson Sand Reservoir, and initiated the federal permitting process for a gas cycling project, which moved from conceptual engineering to front-end engineering and facility design during the Eighteenth POD.

In the Nineteenth POD, dated August 8, 2002, Exxon notified the Division that the PTU Owners would not drill an exploration well prior to the WCA Drilling Commitment deadline of June 15, 2003. The State and Exxon executed a Memorandum of Understanding to facilitate the State permitting process for the gas cycling project and Exxon proceeded with engineering design of the surface facilities during the term of the Nineteenth POD. On June 24, 2003, the PTU Owners presented their updated stratigraphic and structural interpretation of the Thomson Sand Reservoir, based on the merged PTU seismic data, to Division staff.

During the term of Twentieth POD, October 1, 2003 through September 30, 2004, the PTU Owners completed a number of technical studies to evaluate Thomson Reservoir quality, fault seal, and structural framework; which, to the PTU Owners, indicated a chance of greater compartmentalization and a higher risk of sand production. The PTU Owners also studied alternative facility designs and identified cost reduction measures for their proposed gas cycling project. The PTU Owners stated that, in their view, their proposed gas cycling project is not commercially viable. Exxon suspended all permitting activities for their proposed gas cycling project and deferred evaluation of the Pre-Mississippian formation that underlies the Thomson Sand Reservoir. The PTU Owners incorporated the results of the prior geologic model, updated reservoir simulation, facility design, and cost estimates into a depletion plan for a conceptual PTU gas sales project.

Despite rigorous analyses of seismic data, the depth of the subsurface geological structure of the Thomson Sand Reservoir west of the PTU1 well remains suspect and introduces substantial uncertainty about reservoir connectivity and continuity, fluid contacts, and the character of the underlying oil rim between the eastern and western areas of the PTU. An exploration/delineation well in this area would provide geologic and reservoir data that could confirm or reduce the structural uncertainty and aid the subsequent determination of recoverable reserves and development options for the PTU.

The PTU Owners' prior exploration activities identified several hydrocarbon accumulations within the unit area that are capable of production in paying quantities. The geological and engineering data indicate that the PTU is underlain by the Thomson Sand Reservoir, which contains significant oil, gas, and gas condensate reserves, and several Brookian oil reservoirs. However, there has been no further delineation of the known accumulations or exploration

within the PTU since BPXA drilled the Sourdough #3 well in 1996. The PTU Owners have not yet begun development or production of the known hydrocarbon resources within the unit, and the 22nd POD does not contain any commitments to do so. Therefore, the criteria in 11 AAC 83.303(b)(2) and .303(b)(3), do not support approval of the 22nd POD.

2. The PTU Owners' Plans for Development of the PTU

Although the Thomson Sand Reservoir was discovered in 1977 and the PTU contains several known hydrocarbon accumulations that are capable of producing in paying quantities, the PTU Owners have not committed to put the unit into commercial production. Instead, the PTU Owners propose that more studies are needed and a fiscal contract changing the State's royalty and tax share is required before they can begin development of the PTU.

According to Exxon, the focus of the 22nd POD is on preparing for a potential open season for major gas sales from the North Slope. The 22nd POD states

The timing of the open season process will be dependent upon successful completion of a fiscal contract between the Sponsor Group and the SoA under the Stranded Gas Development Act (SGDA). During the next year, the Owners will monitor progress of the contract negotiations under the SGDA and be prepared to adjust the work schedule to ensure the necessary work is conducted in sufficient time to allow the Owners to prepare for an open season for an Alaska gas pipeline while maximizing the efficiency of the work processes and sequence.

The Sponsor Group consists of only three of the Major PTU Owners: Exxon, BPXA, and CPAI, and does not officially represent the PTU lessees. The State is also negotiating with two other applicants that submitted proposals to build a North Slope gas pipeline. Depending on the progress of the negotiations, it is unlikely that a North Slope gas pipeline will be in operation before 2012, and the Sponsor Group has not yet made a public commitment to ever build a North Slope gas pipeline. However, regardless of the status of those negotiations, the PTU Owners have an obligation to diligently explore, delineate, and develop the hydrocarbon resources underlying the unit area.

The 22nd POD states that field activities associated with development drilling should begin three to three and one-half years before field startup, but it does not indicate when, if ever, an open season might occur or when, if ever, Exxon anticipates the commencement of development or production. At this point in time, the PTU Owners do not control if or when a North Slope gas pipeline will ever be operational. Reliance on third parties, beyond the control of the PTU Owners, is not grounds for the delay of PTU development and production.

While previous plans focused on developing unitized substances through a gas cycling project, the PTU Owners stated that project was not commercially viable and redirected their efforts to evaluate PTU development through gas sales. The 22nd POD describes several activities that the PTU Owners plan to execute during the next year to evaluate a conceptual PTU gas sales project, but those activities are all contingent on the Sponsor Group successfully negotiating a fiscal contract with the State under the SGDA.

The 22nd POD outlines the unit operator's plans for one year beginning October 1, 2005. Exxon plans to update the PTU geologic model and incorporate the results in the reservoir simulation to identify potential upside gas production from the Pre-Mississippian section. The technical studies will be the basis for a gas sales depletion plan followed by conceptual engineering for detailed facility design. The 22nd POD anticipates completing the depletion plan in April 2006 and initiating conceptual engineering, a 9 to 12 month process that must be completed in time for the PTU Owners to be prepared to nominate gas in an open season, should one occur. During the conceptual engineering process, the PTU Owners plan to determine optimum drillsites and well locations, and update drilling and completion costs to estimate total project costs and timing. PTU conceptual engineering will also include provisions for Brookian development, which Exxon anticipates will occur after it develops the Thomson Sand Reservoir. However, the 22nd POD did not identify a firm date for the start of production.

During the 22nd POD, the PTU Owners plan to assess the permitting requirements for PTU gas sales. They will review the previous permitting activities undertaken for the gas injection project, evaluate the need for additional data and studies, and assess the interrelationship between permitting for PTU development and for the Alaska gas pipeline project. The PTU Operator will also apply to the AOGCC for a conservation order that addresses gas offtake and depletion plans for the Thomson Sand Reservoir and discuss other conservation orders needed for PTU development. Based on the permitting assessment, Exxon will update the project timeline and prepare a schedule of activities to obtain the permits and conservation orders needed to drill the PTU wells and to construct and operate the facilities and pipelines.

To address the Division's concern about reservoir uncertainty in the western unit area, the 22nd POD includes Exxon's offer to hold a workshop to evaluate whether drilling delineation wells could provide valuable information that would reduce the uncertainty associated with the western Thomson Sand Reservoir. The 22nd POD also includes plans to compare core samples from PTU and Badami wells to evaluate potential development of Brookian prospects within the PTU.

While there is some benefit to the proposals in the 22nd POD, it does not contain sufficient plans or commitments to timely develop and produce unitized substances. The PTU Owners are not entitled to condition development of the PTU on the construction of a pipeline by a third party or on modification of the state's royalty and tax rights. PTU Owners' plans for delineation and development of the unit area do not justify approval of the 22nd POD or the PTU Owners' request for extension of the 2006 and 2008 Development Drilling Commitments. The 22nd POD does not meet the criteria in section 11 AAC 83.303(b)(4).

3. Economic Costs and Benefits of the PTU Owners' Plans for Development of the PTU.

The cost to the state and the public of approving the 22nd POD is that the known underlying hydrocarbons will not be timely delineated and produced and the remainder of the unit area will not be timely explored. Moreover, the 22nd POD conditions PTU development on amending the State's existing tax and royalty structure in the Sponsor Group's fiscal contract and construction of a North Slope gas pipeline, which are an inappropriate basis upon which to condition PTU development.

In the short-term, development of the PTU could create additional jobs and in the long-term, development would create additional employment and income to State residents. The State and the public are primarily interested in timely oil and gas production from State leases. Every year that production is delayed costs the State millions of dollars in unrealized interest on production revenue and delays the secondary benefits associated with PTU development. If the PTU Owners developed and began production from the PTU, the State would earn royalty and tax revenues over the long-term life of the field. Royalties, corporate income taxes, property taxes, and severance taxes would benefit the local and state economy, and provide revenue to the State's general, school, and permanent funds. The PTU Owners may reinvest revenues from PTU production in new exploration and development in the State.

Development of the PTU would also increase demand for goods and services supplied by local businesses, retailers, and service providers. An increased property tax base would benefit the residents and communities within the North Slope Borough and along the Trans-Alaska Pipeline corridor. Timely development and production from the PTU will lead to additional development and production from other reservoirs in the unit area and could provide an infrastructure base for exploration, development, and production outside of the unit area.

The Division's May 24, 2002 evaluation of the Expansion Agreement, found that the economic benefits of including the Expansion Acreage in the PTU outweighed the costs because the PTU owners made meaningful commitments to explore and develop the Thomson Sand Reservoir by drilling adequate exploration and development wells by dates certain, and agreed to increased royalty rates for some of the leases to compensate the state for lost opportunities to re-lease the acreage. If the Applicants fail to follow through with those commitments as scheduled, the Expansion Acreage will automatically contract out of the unit, and the PTU Owners must compensate the State for the lost opportunity to receive bonus payments in past lease sales. However, the PTU Owners have requested a one-year deferral of the Development Drilling Commitments. The 22nd POD, unlike the Eighteenth POD and subsequent plans, does not contain activities toward fulfilling the commitments in the Expansion Agreement.

In addition to the Development Drilling Commitments, the Expansion Agreement also contains the PTU Owners commitments to allocate production under an approved participating area by June 15, 2008, for Expansion Areas primarily underlain by the Thomson Sand Reservoir; and by June 15, 2010, for Expansion Areas underlain by Brookian prospects. If the PTU Owners ultimately fail to drill the required development wells, approval of a one-year deferral of the Development Drilling Commitments would delay receipt of any payments to compensate for withholding the Expansion Acreage from leasing, and if they do ultimately develop the PTU, deferral would delay receipt of facility and production related payments.

There are currently 45 state oil and gas leases committed to the PTU Agreement.⁸ Most of the PTU leases had a 10-year primary term, except the four most recent leases, which were issued with 7-year primary terms. All but two of the PTU leases are beyond their primary term, but under Article 18 (d) of the PTU Agreement they are all extended for the duration of the unit term.⁹

⁸ Six of the PTU leases were effective in 1965, nineteen in 1969, three in 1970, two in 1979, four in 1982, one in 1988, eight in 1991, one in 1993, two in 1997, and one each in 2000 and 2002.

⁹ PTU Agreement, Article 18 (d) states "Each lease, sublease or contract relating to the exploration, drilling, development or operation for oil or gas of lands, committed to this agreement, which, by its terms might expire prior

In addition, the primary terms of seven PTU leases are extended because the Division certified wells located on those leases as capable of production in paying quantities. The PTU leases with certified wells are: ADL 28382, ADL 47556, ADL 47560, ADL 47567, and ADL 47573, which were issued on lease form DL-1 revised October 1963; ADL 312862 issued on DMEM-1-79B (Sliding Scale Royalty) revised November 5, 1979; and ADL 343112, issued on DMEM 1-82 (Net Profit Share) revised April 7, 1982. The primary term of these leases are extended under the individual lease agreements and State regulation 11 AAC 83.135, Shut-in Production.

The lessees have had twenty to thirty years to delineate, develop, and commence production from the hydrocarbon accumulations underlying these leases, which contain wells that are certified as capable of production in paying quantities. If the Division notifies the lessees that they must commence production, and they fail to do so within the time allowed, the leases will no longer be held by shut-in production, although the primary terms may continue to be extended by unitization or other extension provisions in the lease agreements.

If the PTU Agreement terminates and the leases expire, the Division could re-offer the acreage for lease in future lease sales and impose work commitments in the new leases.¹⁰ Re-offering the PTU acreage would also replace older lease forms with a more modern updated lease form. The Division received bonus bids totaling nearly \$146 million when the State originally issued the current PTU leases, and could attract significantly higher bid bonuses today.

Another benefit the state could realize by re-offering the unit acreage is the potential for increased royalty rates. Most of the leases in the core unit area have royalty rates of 12.5%. If the Division were to re-offer the acreage, it could impose higher royalty rates. The PTU Owners agreed to increased royalty rates for some leases in the Expansion Areas, ensuring that the State would receive the benefit of higher royalties on production from those leases without releasing the acreage. The royalty rate increased from 16.66667% to 20% for seven of the leases and from 12.5% to 16.66667% for one lease.

If the PTU is terminated and the Division re-offered the PTU acreage for bid, it might attract new lessees who may bring new ideas and energy as well as new geologic interpretations, engineering, development timelines, and marketing perspectives to develop the area. At this point, the current PTU Owners have had the leases for far beyond their primary term, and their conclusion today is simply that they cannot make enough money to justify development. It is time for the PTU Owners to develop and produce or give new lessees had a chance to develop the known hydrocarbon resources within the PTU.

In summary, the economic costs outweigh the benefits that might be gained by approving the 22nd POD. Therefore, the Division's evaluation of the section .303(b)(5) economic criteria does not support approval of the 22nd POD.

to the termination of this agreement, is hereby extended beyond any such term so provided therein so that it shall be continued in full force and effect for and during the term of this agreement."

¹⁰ "The Commissioner may include terms in any oil and gas lease imposing minimum work commitment on the lessee. These terms shall be made public before the sale, and may include appropriate penalty provisions to take effect in the event the lessee does not fulfill the minimum work commitment." AS 38.05.180 (h).

4. Environmental Costs and Benefits of the PTU Owners' Plans for Development of the PTU.

The PTU Owners do not propose any exploration, delineation, or development operations within the PTU. Therefore, the section 11 AAC 83.303(b)(1) environmental criteria neither supports nor condemns approval of the PTU Owners' plans for development of the PTU.

5. Other Relevant Factors to Protect the Public Interest

The PTU contains wells certified as capable of production in paying quantities. Considering the facts, it is now time to develop and produce the underlying hydrocarbons. If the PTU Owners have been unable to identify a commercial project in nearly 30 years, it is time to terminate the unit and re-offer the acreage to new lessees who will have the opportunity to develop the State's resources in a timely manner.

The Division has given the PTU Owners many opportunities over many years to develop the PTU. It is not in the public interest to grant a state lessee an indefinite extension on development merely because development in their view is not currently profitable enough or is too risky.

The intent of oil and gas leases is to give producers an opportunity to explore, develop, and produce within the primary term of the lease. That intent has been met and exceeded in this case. It is not in the public interest to change leasehold intent by allowing a lessee's parochial interests to supersede the State interest for orderly and reasonably prompt development.

The state's primary interest in oil and gas leases is development of hydrocarbons which yield oil and gas revenue. The state's interest is not met by allowing the producers to delay production until such time as the lessee determines that it is the lessee's optimum time to develop a known resource or the State agrees to compromise its tax and royalty system.

It is not fair to the public or other potential lessees to allow the current PTU Owners to continue to hold the leases, thereby precluding others from the opportunity to develop the resource.

V. FINDINGS

The PTU Owners' Plans for Development of the PTU fail to meet the criteria in 11 AAC 83.303(a) as follows.

A. Promote the Conservation of All Natural Resources.

If the Unit Operator proposed any operations under the 22nd POD, there would be environmental impacts associated with reservoir development. However, unitized development of the unit area would reduce the disruption of land and fish and wildlife habitat that would occur under individual lease development. This reduction in environmental impacts and preservation of subsistence access would, when taken in isolation, be in the public interest. While unitized operations conserve natural resources when compared to lease-by-lease development, development on a lease basis maybe preferable to no development at all. However, development of the Thomson Sand Reservoir is possible under a new unit agreement.

Additionally, before undertaking any specific operations, the unit operator must submit a unit plan of operations to the Division and other appropriate state and local agencies for review and approval, and the lessees may not commence exploration or development operations until all agencies have granted the required permits. The Division may condition its approval of a unit plan of operations and other permits on performance of mitigation measures in addition to those in the leases, if necessary or appropriate. Compliance with the mitigation measures would minimize, reduce or completely avoid adverse environmental impacts. Lease-by-lease operations would also require agency approvals, including mitigation measures.

B. Promote the Prevention of Economic and Physical Waste.

Exxon submitted geological, geophysical, and engineering data to support its interpretation of the hydrocarbon accumulations underlying the unit area. The available data indicates the PTU encompasses all or part of one or more hydrocarbon accumulations, but the PTU Owners' plans do not provide for delineation and timely development of those resources.

The PTU Owners stated that a gas cycling project was not commercially viable and the 22nd POD focuses on evaluating gas sales, but does not commit to produce and sell PTU gas. There is uncertainty regarding continuity of the reservoir in the western unit area, which could be addressed by drilling additional delineation wells. The Unit Operator has not adequately considered alternate development scenarios that incorporate both gas sales and gas cycling. Nor has Exxon evaluated the cumulative benefits of simultaneously developing the multiple hydrocarbon accumulations within the unit area. Timely development and production from the PTU does not preclude PTU gas sales at a later date. Focusing on gas sales at the exclusion of all other development options may result in waste of natural resources.

Gas cycling theoretically allows the recovery of significantly more liquids than would be recovered in a pure gas blow down project. In a gas blow down scenario, oil and gas condensates that remain in the field following gas sales may be largely unrecoverable. In addition, delaying timely production also constitutes waste. The Division and AOGCC must determine whether the proposed development will promote the conservation of oil and gas, but the Unit Operator has yet to apply to AOGCC for conservation orders and to the Division for approval of a depletion plan. The Director has the authority to modify the rate of development to achieve the conservation objectives under the PTU Agreement, and I find that increasing the rate of development in the PTU is necessary and advisable.

C. Provide for the Protection of All Parties of Interest, Including the State

A majority of the State's general fund revenue is derived from North Slope oil and gas operations in the form of royalty, net profit shares, production tax, property tax, and corporate income tax. Failure to develop and produce known hydrocarbon accumulations deprives the State of incremental revenue, economic activity and jobs. Should the PTU terminate, the area could be re-leased and unitized again under an acceptable unit plan of development that includes commitments to develop and produce the underlying hydrocarbon accumulations.

Continuing this 30-year record of non-development and delay of an oil and gas lessee's obligations to develop and produce its oil and gas leases makes a mockery of the statutory,

regulatory and contractual protections for the State as owner of the oil and gas estate. Therefore, the 22nd POD is unacceptable.

VI. DECISION

The 22nd POD fails to meet the requirements of 11 AAC 83.303 and .343 because it does not provide for the reasonable delineation and timely development of the hydrocarbon accumulations in the unit area. Nearly 30 years ago, lessees discovered the Thomson Sand Reservoir underlying the PTU, which to date has not been developed or put into commercial production. The PTU contains significant gas condensate and oil resources. Eighteen wells have been drilled within and around the PTU, but the most recent PTU well was drilled by BPXA nearly 10 years ago. Although some of the leases are more than 40 years old, and several hydrocarbon accumulations within the unit area contain wells that are certified as capable of producing in paying quantities, the Unit Operator has not stated that production from the PTU is economic and has not committed to development and commercial production. To the contrary, the Unit Operator has stated the production from the unit is not economic.

1. The 22nd POD makes no commitment to timely develop and produce PTU oil, gas, or gas condensate. The 22nd POD is hereby denied.
2. Failure to obtain approval of the unit plan is grounds for default under the PTU Agreement and the State oil and gas regulations. The PTU Owners are hereby notified that effective October 1, 2005, the PTU Agreement is in default.
3. To cure the default, the Unit Operator shall submit an acceptable POD within 90 days, by Thursday, December 29, 2005.
 - a) An acceptable unit plan must contain specific commitments to timely delineate the hydrocarbon accumulations underlying the PTU and develop the unitized substances. The following commitments represent an example of an acceptable PTU plan of development:
 - Development activities for the unit, including plans and deadlines to delineate the Thomson Sand Reservoir, bring the reservoir into commercial production, maximize oil, condensate, and gas recovery, and maintain and enhance production once established; and plans for the exploration or delineation and production of other hydrocarbon accumulations and lands that lie stratigraphically above or below the Thomson Sand Reservoir;
 - The PTU Owners shall sanction a commercial PTU development project by October 1, 2006, and provide the Division with evidence of corporate approval and commitment of project funding.
 - The PTU Operator shall begin commercial production of unitized substances from the PTU by October 1, 2009.

- Details of the proposed operations to fulfill the 2006 Development Drilling Commitment, including the proposed surface location of the drill pad, bottom-hole location for the well, testing plan, and schedule of activities. The consequences of failure to fulfill the 2006 drilling commitment are specified in the Expansion Agreement.

4. Failure to submit an acceptable plan of development is grounds for termination of the PTU.

A person affected by this decision may appeal it, in accordance with 11 AAC 02. Any appeal must be received within 20 calendar days after the date of "issuance" of this amended decision, as defined in 11 AAC 02.040 (c) and (d), and may be mailed or delivered to Thomas E. Irwin, Commissioner, Department of Natural Resources, 550 W. 7th Avenue, Suite 1400, Anchorage, Alaska 99501; faxed to 1-907-269-8918; or sent by electronic mail to dnr_appeals@dnr.state.ak.us. This decision takes effect immediately. If no appeal is filed by the appeal deadline, this decision becomes a final administrative order and decision of the department on the 31st day after issuance. An eligible person must first appeal this decision in accordance with 11 AAC 02 before appealing this decision to Superior Court. A copy of 11 AAC 02 may be obtained from any regional information office of the Department of Natural Resources.

Original signed by Mark D. Myers, Director

October 27, 2005

Mark D. Myers, Director
Division of Oil and Gas

Date

cc: Thomas E. Irwin, Commissioner DNR
John Norman, Chair AOGCC
Richard Todd, Senior Assistant Attorney General

Point Thomson Unit Leases

Lease Number	PTU Tract #	PTU Area	Acres	Effective Date	Well Completion Date	Certified Well	BROOKIAN TEST DATA	THOMSON SAND TEST DATA
28380	019	Core	2,544.00	9/1/1965	West Staines St. No.1 1970		GCM with trace OIL	DST#3,4&5: negligible GCM
28384	023	Core	1,760.00	9/1/1965				
28385	024	Core	637.00	9/1/1965				
28381	020	Core	2,560.00	10/1/1965				
28382	021	Core	2,560.00	10/1/1965	Alaska State C-1 1981	Y	DST#4: 50 bbls O&GCM	DST#2: 1.75 MMCFGD, 455 BCPD (37.3 API)
28383	022	Core	2,560.00	10/1/1965				
47568	012	Core	2,560.00	10/1/1969				
47569	013	Core	2,533.00	10/1/1969				
47570	014	Core	2,560.00	10/1/1969				
47571	015	Core	2,560.00	10/1/1969				
47572	016	Core	2,533.00	10/1/1969	N Staines River 1 1982		CONFIDENTIAL	CONFIDENTIAL
47562	006	Core	2,560.00	10/1/1969				
47567	011	Core	2,560.00	10/1/1969	PTU Well No.2 1978	Y	DST#5&6: 248 BOPD and 124 MCFGD	NONE
47556	025	Core	2,560.00	10/1/1969	Alaska State A-1 1975	Y	DST#2&3: 2,507 BOPD (23.1 API) and 2.17 MMCFGD	NONE
47559	003	Core	2,560.00	10/1/1969				
47561	005	Core	2,560.00	10/1/1969				
47557	001	Core	2,523.00	10/1/1969				
47558	002	Core	2,560.00	10/1/1969	PTU Well No.3 1979		NONE	DST#2: 6.348 MMCFGD and 476 BCPD (38 API)
47563	007	Core	2,523.00	10/1/1969	PTU Well No.4 1980		DST#3: 20 bbls O&GCM	DST#1: 306 BWPD
47564	008	Core	2,560.00	10/1/1969				
47566	010	Core	2,533.00	10/1/1969				
47573	026	Core	2,544.00	10/1/1969	Staines R. St. No.1 1979	Y	CONFIDENTIAL	CONFIDENTIAL
47560	004	Core	640.00	4/1/1970	PTU Well No.1 1977	Y	DST#3: 2.25 MMCFGD and 132 bbls (44.4 API)	DST#1: 2,283 BOPD (18.4 API) and 13.307 MMCFGD DST#2: 3.86 MMCFGD and 170 bbls (45.4 API)
50983	017	Core	640.00	4/1/1970				
51667	018	Core	1,243.00	4/1/1970				
312862	027	Core	5,648.68	2/1/1980	Alaska State F-1 1982	Y	DST#3: 73 MCFGD and 41 BCPD (35-50 API) DST#5C: 141 MCFGD and 145 BOPD (22.1 API)	DST#1: 3.02 MMCFGD and 152 BCPD (35.3 API) DST#2: 4.6 MMCFGD and 286 BCPD
312866	028	Core	4,935.47	2/1/1980	Alaska State D-1 2/16/1982		NONE	NONE
343110	030	Core	1,920.00	8/1/1982				
343111	031	Core	2,400.00	8/1/1982				
343112	032	Core	3,446.00	8/1/1982	Sourdough No. 2 1994 Sourdough No.3 1996	Y	CONFIDENTIAL	CONFIDENTIAL
343109	029	Core	1,970.16	8/1/1982	Alaska State G-2 1983		CONFIDENTIAL	CONFIDENTIAL
372256	038	3	1,412.00	12/1/1988				
375064	043	4	1,062.00	4/1/1991				
377015	033	1	3,554.30	8/1/1991	Challenge Is. No.1 1981		NONE	BLOWOUT ... OIL below 12,963'
389727	045	6	2,143.39	8/1/1991				
377016	034	1	2,779.16	8/1/1991				
389728	046	1	2,952.62	8/1/1991				
377017	035	1	5,696.18	8/1/1991				
377020	037	2	1,909.74	8/1/1991				
389730	047	6	3,684.31	8/1/1991				
382101	042	5	1,280.00	7/1/1993				
388425	039	6	1,162.08	1/1/1998	Alaska Island No.1 1982		NONE	2.9 MMCFGD and 185 BCPD (36 API)
388426	040	6	821.74	1/1/1998				
389716	036	7	1,473.92	6/1/2001				
390310	048	Core	15.80	4/1/2003				
45			106,200.55					

8

STATE OF ALASKA

SARAH PALIN, GOVERNOR

□ 550 WEST 7TH AVENUE, SUITE 1400
ANCHORAGE, ALASKA 99501-3650
PHONE: (907) 269-8431
FAX: (907) 269-8918

DEPARTMENT OF NATURAL RESOURCES
OFFICE OF THE COMMISSIONER

January 27, 2009

Appeal by Exxon Mobil Corporation,
BP Exploration (Alaska) Inc., Chevron USA,
Inc., ConocoPhillips Alaska, Inc. and Exxon
Mobil Oil Corporation, Working Interest
Owners, of the Notice of the Director,
Division of Oil and Gas, dated August 4, 2008,
entitled Lease Expiration Due To Elimination
From Unit for Oil and Gas Leases ADL 28380
et al.

CONDITIONAL INTERIM DECISION

This is a conditional interim decision in appeals from the August 4, 2008, decision of the DNR Director of Oil and Gas that 31 of the leases included in the former Point Thomson Unit had expired. BP Exploration (Alaska) Inc., Chevron USA, Inc., ConocoPhillips Alaska, Inc., and ExxonMobil Corporation appealed from that decision. The initial phase of the evidentiary hearing was held on January 12 through 16, 2009, and the hearing is continued to February 12, 2009.

I am issuing this conditional interim decision because, in part, Appellants offered testimony that their development plans to drill a well during this winter season could still go forward if DNR provided them with an ice road permit before the end of this month and authorized drilling activities on the leases. For this reason, I have decided to issue this decision.

At the initial phase of the hearing, Appellants offered testimony and evidence regarding their plans for development of certain leases in the former Point Thomson Unit, referred to by Appellants as the "Point Thomson Project." Appellants have testified that this project provided for the drilling and producing from wells by 2014. Appellants have specifically testified that they are unconditionally committed to the initiation and continuation of drilling during this 2008 and 2009 winter season, including drilling a well out of the conductors with a rig capable of drilling through the Thomson Sands on that lease, and completing the drilling of two wells, both penetrating the Thomson Sands reservoir, by 2010. Appellants testified that in furtherance of this commitment, they have: (1) mobilized equipment and materials to the North Slope to support the operations; (2) retained subcontractors to support this operation; (3) modified a drill rig to make it suitable for the high pressure Thomson Sands reservoir; and (4) applied for and pursued all necessary permits. Given this testimony, I find that it is in the public interest to authorize Appellants to drill these two wells. If Appellants provide the documents listed below, the record will be adequate to support reinstatement of the two leases and issuance of permits to authorize drilling of these two wells.

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

I am not, however, ruling on whether any of the remaining 29 leases are engaged in drilling operations, or are extended by another lease provision, because the record is incomplete and there are many outstanding questions that Appellants need to address.

Nonetheless, assuming Appellants can provide the documentation listed below, I find that Appellants have demonstrated that ADL 47559 and ADL 47571 have been extended by the drilling operations savings clause because they have: (1) testified that they are unconditionally committed to the initiation of drilling during this winter season, including drilling a well out of the conductors with a rig capable of drilling through the Thomson Sands on that lease, and completing the drilling of two wells on these two leases, both penetrating the Thomson Sands reservoir, by 2010; (2) mobilized equipment and materials to the North Slope to support these operations and awarded subcontracts; and (3) unconditionally committed to bring those two wells on the two leases into production by 2014.

Based on the testimony and evidence presented at the hearing, I have decided to:

- (1) direct my staff to issue the ice road permit as soon as possible so that the rig can be mobilized to the drill pad this winter;
- (2) direct my staff to process all permits necessary for drilling these two wells that are pending before DNR;
- (3) inform local, state, and federal agencies that Appellants are authorized to drill these two wells on the two leases; and
- (4) reinstate ADL 47559 and ADL 47571 on the following conditions:
 - a. Appellants must abide by their unconditional commitments they made on the record including: (1) initiate drilling during this winter season, including drilling a well out of the conductors with a rig capable of drilling through the Thomson Sands on that lease; (2) completing these two wells on these two leases, both penetrating the Thomson Sands reservoir, by 2010; (3) continue to diligently move towards production by constructing the necessary facilities for processing and transporting hydrocarbons from these leases to market; and (4) commence sustained commercial production and transportation of hydrocarbons from these two wells on these two leases to market by 2014;
 - b. Appellants must obtain AOGCC and DNR approval for the precise location and bottom hole of each well;
 - c. Appellants must obtain DNR's approval for its Plan of Operations for the drilling of these two wells;
 - d. Appellants must diligently pursue all necessary permits, including working in good faith with all permitting agencies; and

CONDITIONAL INTERIM DECISION

January 27, 2009

Page 3 of 3

- e. Appellants must provide, within two weeks, all of the answers and documentation I requested during the initial phase of the hearing regarding Appellants' drilling plans for these two wells, including the precise well locations, drilling dates and production dates for each well. Appellants must also include a drill rig contract for each well, unconditional AFEs for each well signed by all parties, an AFE for the production infrastructure, and affidavits from each Appellant stating its willingness to pay its share of the costs for each well and for the production infrastructure.¹

Additionally, unitization of these leases will likely be appropriate in order to properly conserve natural resources. I will address unitization issues in a final decision once the record is complete.

This conditional interim decision is intended to effect more expeditious production of state oil and gas resources. However, I remind Appellants that, under the terms of these two leases, the failure to diligently pursue drilling operations in good faith for the purpose of production will result in the automatic termination of these leases.

This interim decision will be followed by a final agency decision in the lease appeals once the record is complete, setting out my findings, rationale, and decision in detail. The time for appeal to the superior court will run from the date of issuance of the final agency decision.

In summary, I am issuing this conditional interim decision because Appellants have offered testimony and evidence that they are engaged in "drilling operations" for the purpose of diligently working in good faith to bring ADL 47559 and ADL 47571 into production, and that they will proceed with the project this winter season. The decision is conditional upon Appellants abiding by the conditions set forth above. I still need to review contracts and other documents that I have requested in order to make a final agency decision.



Thomas E. Irwin
Commissioner

Jan. 27, 2009

Date

¹ Compliance with this condition does not relieve Appellants from providing all of the other answers and documentation requested during the initial phase of the hearing.

9

**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 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 Handbook¹ 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 blowdown² 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.

² Blow-down (also Blowdown) "A term applied to the commencement of production of gas for sale after the completion of 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.

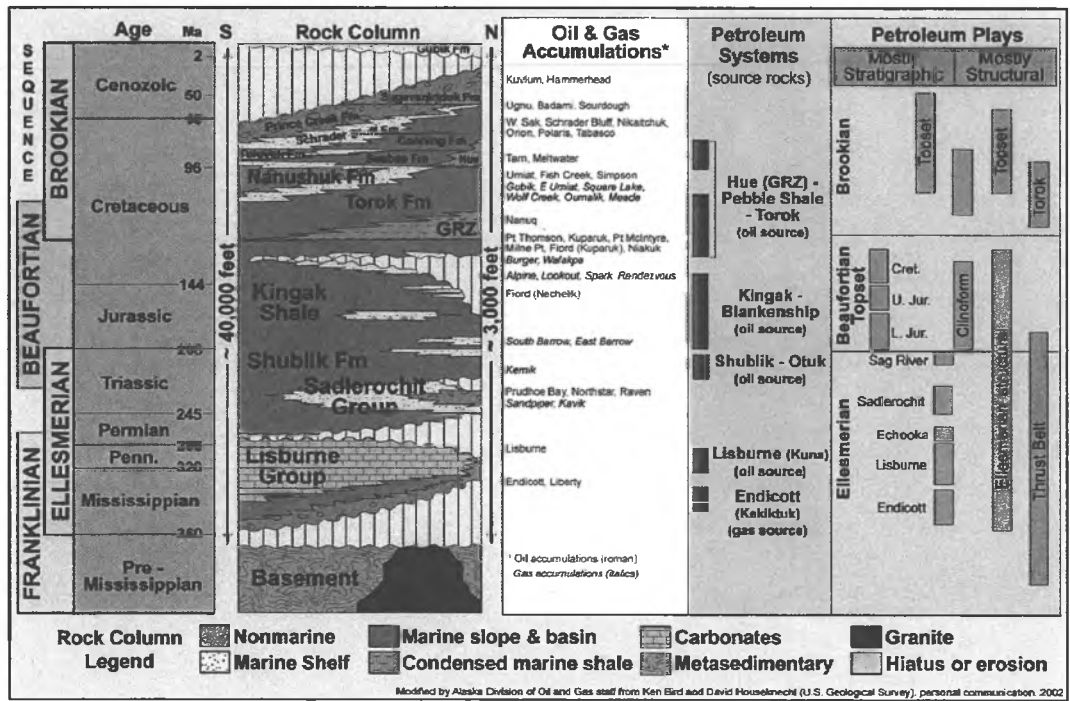


Figure 1, Alaska North Slope Stratigraphic Column

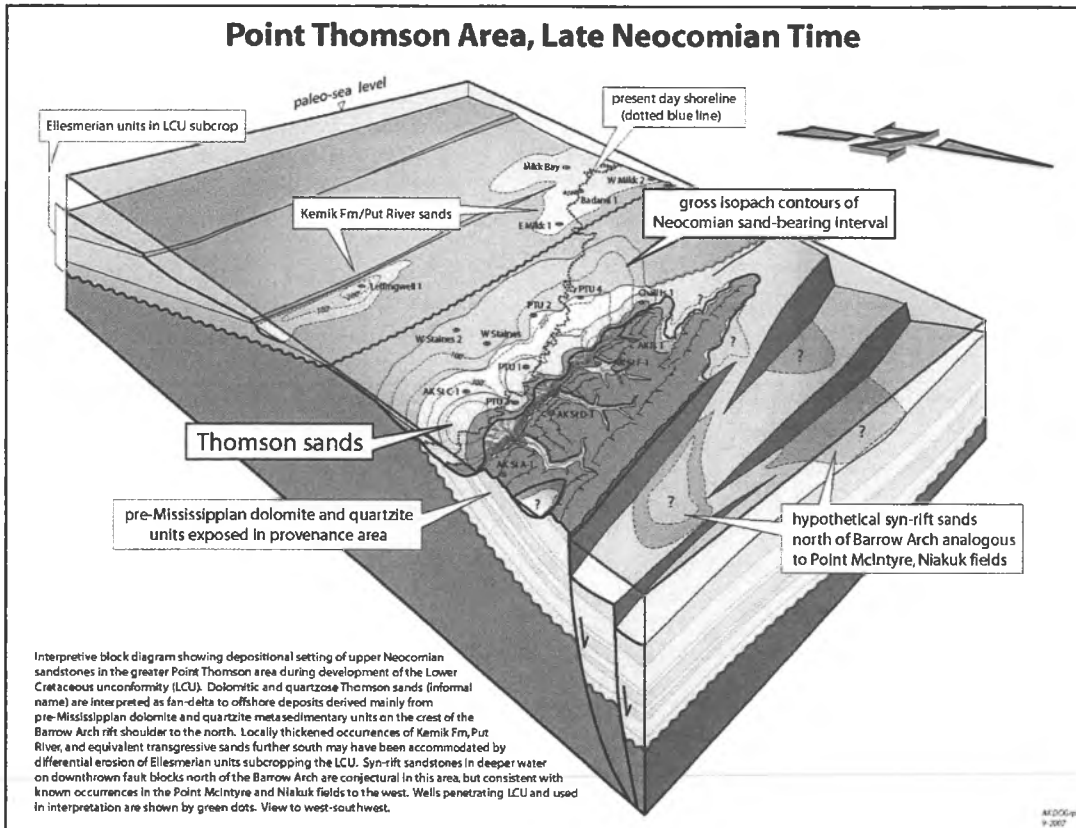


Figure 2, Block diagram of Point Thomson area in Late Neocomian time

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.

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/D⁷. 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.

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.

Modeling 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 crucial. 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 pressure. 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 thirty 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 were 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.

10

11 AAC 83.303. Criteria

(a) The commissioner will approve a proposed unit agreement for state oil and gas leases if he makes a written finding that the agreement is necessary or advisable to protect the public interest considering the provisions of AS 38.05.180 (p) and this section. The commissioner will approve a proposed unit agreement upon a written finding that it will

(1) promote conservation of all natural resources, including all or part of an oil or gas pool, field, or like area;

(2) promote the prevention of economic and physical waste; and

(3) provide for the protection of all parties of interest, including the state.

(b) In evaluating the above criteria, the commissioner will consider

(1) the environmental costs and benefits of unitized exploration or development;

(2) the geological and engineering characteristics of the potential hydrocarbon accumulation or reservoir proposed for unitization;

(3) prior exploration activities in the proposed unit area;

(4) the applicant's plans for exploration or development of the unit area;

(5) the economic costs and benefits to the state; and

(6) any other relevant factors, including measures to mitigate impacts identified above, the commissioner determines necessary or advisable to protect the public interest.

(c) The commissioner will consider the criteria in (a) and (b) of this section when evaluating each requested authorization or approval under 11 AAC 83.301 - 11 AAC 83.395, including

(1) an approval of a unit agreement;

(2) an extension or amendment of a unit agreement;

(3) a plan or amendment of a plan of exploration, development or operations;

(4) a participating area; or

(5) a proposed or revised production or cost allocation formula.

History: Eff. 9/5/74, Register 51; am 7/22/79, Register 71; am 6/28/81, Register 78; am 3/18/83, Register 85

11

958 P.2d 422, 139 Oil & Gas Rep. 461
(Cite as: 958 P.2d 422)

▷

Supreme Court of Alaska.

Clyde BAXLEY, individually, and on behalf of the citizens of the State of Alaska, and The Republican Moderate Party, a political group, on behalf of the citizens of the State of Alaska, Appellants,

v.

STATE of Alaska, and John Shively, Commissioner, Department of Natural Resources, and BP Exploration (Alaska), Inc., Appellees.

No. S-8155.
May 15, 1998.

Citizen-taxpayers brought action challenging constitutionality of statute authorizing amendment of “net profit share” (NPS) provisions of state oil and gas leases. The Superior Court, Third Judicial District, Anchorage, Michael J. Wolverton, J., entered summary judgment in favor of defendants, and plaintiffs appealed. The Supreme Court, Eastaugh, J., held that: (1) plaintiffs had standing to bring action; (2) Uniform Application Clause did not apply to statute; (3) statute was not unconstitutional special legislation; (4) Commissioner of the Alaska Department of Natural Resources (DNR) did not exceed his authority under the Alaska Land Act when he negotiated amendment; (5) statute was not enacted in violation of the Public Notice Clause; and (6) statute did not violate rule against material amendments to state contracts awarded through a public bidding process.

Affirmed.

West Headnotes

[1] Mines and Minerals 260  79.1(2)

260 Mines and Minerals

260II Title, Conveyances, and Contracts

260II(C) Leases, Licenses, and Contracts

260II(C)3 Construction and Operation of Oil and Gas Leases

260k79 Rent or Royalties

260k79.1 In General

260k79.1(2) k. Nature and Dis-

tinctions; Bonus. Most Cited Cases

“Royalty” is a share of the product or profit reserved by the owner of land for permitting another to develop his land for oil or gas.

[2] Mines and Minerals 260  79.1(2)

260 Mines and Minerals

260II Title, Conveyances, and Contracts

260II(C) Leases, Licenses, and Contracts

260II(C)3 Construction and Operation of Oil and Gas Leases

260k79 Rent or Royalties

260k79.1 In General

260k79.1(2) k. Nature and Distinctions; Bonus. Most Cited Cases

Royalties are usually expressed as fractions, and they usually continue throughout the life of oil and gas lease, whether the lessee reaps a net profit or not.

[3] Mines and Minerals 260  79.1(2)

260 Mines and Minerals

260II Title, Conveyances, and Contracts

260II(C) Leases, Licenses, and Contracts

260II(C)3 Construction and Operation of Oil and Gas Leases

260k79 Rent or Royalties

260k79.1 In General

260k79.1(2) k. Nature and Distinctions; Bonus. Most Cited Cases

A “bonus” is a definite sum, not a fraction of production, to be paid in cash or out of production, for the execution of oil and gas lease.

[4] Mines and Minerals 260  79.1(2)

260 Mines and Minerals

260II Title, Conveyances, and Contracts

260II(C) Leases, Licenses, and Contracts

260II(C)3 Construction and Operation of Oil and Gas Leases

260k79 Rent or Royalties

958 P.2d 422, 139 Oil & Gas Rep. 461
(Cite as: 958 P.2d 422)

260k79.1 In General

260k79.1(2) k. Nature and Distinctions; Bonus. Most Cited Cases

A “net profit share” (NPS), like a royalty, is a percentage of the oil and gas lessee's production; the lessor, however, only collects on the NPS interest when the lessee's operations yield a profit, after the lessee has recouped its expenditures for exploration and development. Alaska Admin. Code title 11, §§ 83.207-83.219.

[5] Constitutional Law 92 990

92 Constitutional Law

92VI Enforcement of Constitutional Provisions

92VI(C) Determination of Constitutional Questions

92VI(C)3 Presumptions and Construction as to Constitutionality

92k990 k. In General. Most Cited Cases
(Formerly 92k48(1))

Constitutional Law 92 1002

92 Constitutional Law

92VI Enforcement of Constitutional Provisions

92VI(C) Determination of Constitutional Questions

92VI(C)3 Presumptions and Construction as to Constitutionality

92k1001 Doubt

92k1002 k. In General. Most Cited Cases
(Formerly 92k48(3))

Constitutional Law 92 1030

92 Constitutional Law

92VI Enforcement of Constitutional Provisions

92VI(C) Determination of Constitutional Questions

92VI(C)4 Burden of Proof

92k1030 k. In General. Most Cited Cases
(Formerly 92k48(1))

A party raising a constitutional challenge to a statute bears the burden of demonstrating the constitutional violation; a presumption of constitutionality

applies, and doubts are resolved in favor of constitutionality.

[6] Constitutional Law 92 695

92 Constitutional Law

92VI Enforcement of Constitutional Provisions

92VI(A) Persons Entitled to Raise Constitutional Questions; Standing

92VI(A)3 Particular Questions or Grounds of Attack in General

92k695 k. In General. Most Cited Cases
(Formerly 92k42.3(2))

Individual had standing as a citizen-taxpayer to challenge constitutionality of statute authorizing amendment of “net profit share” (NPS) provisions of state oil and gas leases; individual raised issues of public significance, had interests adverse to those of State and lessee, was adequately represented, and could advocate his position competently. AS 38.05.180(j).

[7] Municipal Corporations 268 987

268 Municipal Corporations

268XIV Taxpayers' Suits and Other Remedies

268k987 k. Nature and Scope in General. Most Cited Cases

A plaintiff must meet two requirements in order to establish citizen-taxpayer standing: first, the case must be one of public significance; second, the plaintiff must be an appropriate party to bring the case.

[8] Municipal Corporations 268 987

268 Municipal Corporations

268XIV Taxpayers' Suits and Other Remedies

268k987 k. Nature and Scope in General. Most Cited Cases

Appropriateness requirement for citizen-taxpayer standing has three main facets: the plaintiff must not be a “sham plaintiff” with no true adversity of interest; he or she must be capable of competently advocating his or her position; and he or she may still be denied standing if there is a plaintiff more directly affected by the challenged conduct in question who has or is likely to bring suit.

958 P.2d 422, 139 Oil & Gas Rep. 461
(Cite as: 958 P.2d 422)

191 Appeal and Error 30 ↪893(1)

30 Appeal and Error

30XVI Review

30XVI(F) Trial De Novo

30k892 Trial De Novo

30k893 Cases Triable in Appellate

Court

30k893(1) k. In General. Most Cited

Cases

Supreme Court reviews de novo a finding of standing.

1101 Action 13 ↪13

13 Action

13I Grounds and Conditions Precedent

13k13 k. Persons Entitled to Sue. Most Cited

Cases

The mere possibility that another party might sue does not necessarily justify a denial of standing.

111 Constitutional Law 92 ↪3697

92 Constitutional Law

92XXVI Equal Protection

92XXVI(E) Particular Issues and Applications

92XXVI(E)12 Trade or Business

92k3681 Licenses and Regulation

92k3697 k. Mining and Excavation;

Oil and Gas. Most Cited Cases

(Formerly 92k240(8))

Mines and Minerals 260 ↪5.2(1)

260 Mines and Minerals

260I Public Mineral Lands

260I(A) Reservation and Disposal in General

260k4.5 Leases by Government

260k5.2 State Leases

260k5.2(1) k. In General. Most Cited

Cases

Uniform Application Clause of State Constitution did not apply to statute authorizing amendment of "net profit share" (NPS) provisions of state oil and gas

leases; sole lessee of the leases was uniquely situated with respect to the statute. Const. Art. 8, § 17.

112 Constitutional Law 92 ↪3060

92 Constitutional Law

92XXVI Equal Protection

92XXVI(A) In General

92XXVI(A)6 Levels of Scrutiny

92k3059 Heightened Levels of Scrutiny

92k3060 k. In General. Most Cited

Cases

(Formerly 92k213.1(1))

In recognition of the importance of citizens' equal access to natural resources the Uniform Application Clause of State Constitution is interpreted to require legislation dealing with natural resources to satisfy a heightened level of equal protection scrutiny. Const. Art. 8, § 17.

113 Constitutional Law 92 ↪3043

92 Constitutional Law

92XXVI Equal Protection

92XXVI(A) In General

92XXVI(A)5 Scope of Doctrine in General

92k3038 Discrimination and Classification

tion

92k3043 k. Statutes and Other Written Regulations and Rules. Most Cited Cases

(Formerly 92k211(1))

The protections of the Uniform Application Clause of State Constitution extend only to persons similarly situated with respect to the subject matter and purpose of the legislation. Const. Art. 8, § 17.

114 Appeal and Error 30 ↪170(2)

30 Appeal and Error

30V Presentation and Reservation in Lower Court of Grounds of Review

30V(A) Issues and Questions in Lower Court

30k170 Nature or Subject-Matter of Issues or Questions

30k170(2) k. Constitutional Questions. Most Cited Cases

Whether statute authorizing amendment of "net

958 P.2d 422, 139 Oil & Gas Rep. 461
(Cite as: 958 P.2d 422)

profit share” (NPS) provisions of state oil and gas leases was unconstitutional special legislation could be addressed for first time on appeal in action brought by citizen taxpayer challenging statute as violation of Uniform Application Clause; issue did not depend on new facts and was closely related to Uniform Application Clause argument. Const. Art. 2, § 19; Art. 8, § 17.

[15] Statutes 361 ↪77(1)

361 Statutes

361II General and Special or Local Laws

361k77 Laws of Special, Local, or Private Nature in General

361k77(1) k. In General. Most Cited Cases

Supreme Court evaluates challenges under constitutional provision prohibiting special legislation according to the test applied to nonsuspect classifications in equal protection cases. Const. Art. 2, § 19.

[16] Mines and Minerals 260 ↪5.2(1)

260 Mines and Minerals

260I Public Mineral Lands

260I(A) Reservation and Disposal in General

260k4.5 Leases by Government

260k5.2 State Leases

260k5.2(1) k. In General. Most Cited

Cases

Statutes 361 ↪77(1)

361 Statutes

361II General and Special or Local Laws

361k77 Laws of Special, Local, or Private Nature in General

361k77(1) k. In General. Most Cited Cases

Statute authorizing amendment of “net profit share” (NPS) provisions of state oil and gas leases reflected unique nature of the leases and substantially related to legitimate state purposes, and thus was not unconstitutional special legislation; leases were State’s only oil and gas leases auctioned with NPS as the bid variable and were only State leases with NPS terms greater than 85%, giving lessee incentive to abandon field before extracting all the oil, and development of field required new technology, including the first

undersea pipeline in the Artic Ocean. Const. Art. 2, § 19

[17] Mines and Minerals 260 ↪5.2(1)

260 Mines and Minerals

260I Public Mineral Lands

260I(A) Reservation and Disposal in General

260k4.5 Leases by Government

260k5.2 State Leases

260k5.2(1) k. In General. Most Cited

Cases

Commissioner of the Alaska Department of Natural Resources (DNR) did not exceed his authority under the Alaska Land Act when he negotiated a proposed reduction in “net profit share” (NPS) provisions of state oil and gas leases, then sought legislative approval. AS 38.05.180(i).

[18] Mines and Minerals 260 ↪5.2(1)

260 Mines and Minerals

260I Public Mineral Lands

260I(A) Reservation and Disposal in General

260k4.5 Leases by Government

260k5.2 State Leases

260k5.2(1) k. In General. Most Cited

Cases

Statute authorizing amendment of “net profit share” (NPS) provisions of state oil and gas leases was not enacted in violation of the Public Notice Clause of the Alaska Constitution; Commissioner of the Alaska Department of Natural Resources (DNR) presented the proposed amendments to the legislature, and nearly five weeks of spirited debate followed. Const. Art. 8, § 10.

[19] Appeal and Error 30 ↪170(2)

30 Appeal and Error

30V Presentation and Reservation in Lower Court of Grounds of Review

30V(A) Issues and Questions in Lower Court

30k170 Nature or Subject-Matter of Issues or Questions

30k170(2) k. Constitutional Questions. Most Cited Cases

958 P.2d 422, 139 Oil & Gas Rep. 461
(Cite as: 958 P.2d 422)

Whether Commissioner of the Alaska Department of Natural Resources (DNR) violated constitutional provisions governing state mineral leases by not requiring lessee to forfeit state oil and gas leases after lessee announced its intention not to proceed with development would not be addressed for first time on appeal in citizen-taxpayer's action challenging constitutionality of statute authorizing amendment of "net profit share" (NPS) provisions of the leases; issues presented new constitutional theory that could not be gleaned from pleadings. Const. Art. 8, §§ 8, 11.

[20] Appeal and Error 30 ↪ 172(1)

30 Appeal and Error

30V Presentation and Reservation in Lower Court of Grounds of Review

30V(A) Issues and Questions in Lower Court

30k172 Grounds of Action or Relief

30k172(1) k. In General; Asserting New or Inconsistent Grounds. Most Cited Cases

Whether lessee anticipatorily breached state oil and gas lease agreements and State should have responded by rescinding the leases would not be addressed for first time on appeal in citizen-taxpayer's action challenging constitutionality of statute authorizing amendment of "net profit share" (NPS) provisions of the leases; resolution of issue depended on the outcome of potential fact disputes and a different body of case law.

[21] Appeal and Error 30 ↪ 170(2)

30 Appeal and Error

30V Presentation and Reservation in Lower Court of Grounds of Review

30V(A) Issues and Questions in Lower Court

30k170 Nature or Subject-Matter of Issues or Questions

30k170(2) k. Constitutional Questions. Most Cited Cases

Whether statute authorizing amendment of "net profit share" (NPS) provisions of state oil and gas leases unlawfully infringed on the domain of the courts and violated separation of powers principles would not be addressed for first time on appeal in citizen-taxpayer's action challenging constitutionality of statute; plaintiff's argument was not closely related

to his argument at trial that Commissioner of the Alaska Department of Natural Resources (DNR) lacked authority to negotiate lease amendments, and could not have been gleaned from the pleadings.

[22] Mines and Minerals 260 ↪ 5.2(1)

260 Mines and Minerals

260I Public Mineral Lands

260I(A) Reservation and Disposal in General

260k4.5 Leases by Government

260k5.2 State Leases

260k5.2(1) k. In General. Most Cited

Cases

Statute authorizing amendment of "net profit share" (NPS) provisions of state oil and gas leases did not violate rule against material amendments to state contracts awarded through a public bidding process; rule did not apply to contracts amended by legislature.

[23] Public Contracts 316A ↪ 18

316A Public Contracts

316AI In General

316Ak18 k. Modification or Rescission. Most Cited Cases

In general, competitively bid contracts involving state resources cannot be materially amended.

[24] Public Contracts 316A ↪ 18

316A Public Contracts

316AI In General

316Ak18 k. Modification or Rescission. Most Cited Cases

Material amendments doctrine, prohibiting amendments to competitively bid contracts involving state resources, does not apply to amendments approved by the legislature.

[25] Appeal and Error 30 ↪ 172(1)

30 Appeal and Error

30V Presentation and Reservation in Lower Court of Grounds of Review

30V(A) Issues and Questions in Lower Court

958 P.2d 422, 139 Oil & Gas Rep. 461
(Cite as: 958 P.2d 422)

30k172 Grounds of Action or Relief

30k172(1) k. In General; Asserting New or Inconsistent Grounds. Most Cited Cases

Whether statute authorizing amendment of “net profit share” (NPS) provisions of state oil and gas leases violated the public trust doctrine would not be addressed for first time on appeal in citizen-taxpayer's action challenging constitutionality of statute; plaintiff's argument turned on a new body of case law, concerning fiduciary duty, and on new fact questions, concerning possible abuse of the fiduciary's discretion, and could not have been gleaned from the pleadings.

*424 Jody Patrick Brion, Leutwyler, Brion & Associates, Anchorage, for Appellants.

Lawrence Z. Ostrovsky, Jeffrey D. Landry, Camille Oechsli, Assistant Attorneys General, Anchorage, and Bruce M. Botelho, Attorney General, Juneau, for Appellees, State of Alaska and John Shively.

Jeffrey M. Feldman and Susan Orlansky, Young & Feldman, Anchorage, and Alan L. Sullivan, Van Cott, Bagley, Cornwall & McCarthy, Salt Lake City, Utah, for Appellee BP Exploration (Alaska), Inc.

John E. Havelock, Ely & Havelock, Anchorage, for Amicus Curiae Oilwatch, Alaska, Inc.

Before MATTHEWS, C.J., and COMPTON, EASTAUGH, FABE, and BRYNER, JJ.

OPINION

EASTAUGH, Justice.

I. INTRODUCTION

Citizen-taxpayers filed suit challenging a legislative enactment approving and giving effect to modifications of four State oil and gas leases in the Northstar Oil Field. Reasoning that the modifications were a narrowly tailored response to a unique situation, and that the legislature had not given the lessee preferential treatment, the superior court granted summary judgment for the defendants.*425 Because we agree with that analysis, we affirm.

II. FACTS AND PROCEEDINGS

A. Facts

The Northstar Unit is an oil field in the Beaufort Sea, approximately six miles from Prudhoe Bay. It contains tracts of land now subject to five State and two federal oil and gas leases. In 1979 Amerada Hess submitted the winning bid in a sale of four of the State's leases. They are the subject of this litigation.

The four leases were unusual, partially because the “net profit share” was the bid variable for the 1979 auction. When the State sells oil and gas leases, the Commissioner of the Alaska Department of Natural Resources (DNR) analyzes the tracts of state land to be leased and determines, in advance of the sale, which lease terms to establish as fixed or variable. AS 38.05.180(f)(1), (3); Hammond v. North Slope Borough, 645 P.2d 750, 763-64 (Alaska 1982). The Commissioner determines which bidding method (the combination of fixed and variable lease terms) is in the state's best interest. AS 38.05.180(f)(1); see also Hammond, 645 P.2d at 763-64 (discussing some of the factors the Commissioner considers when selecting bidding methods); Kelly v. Zamarello, 486 P.2d 906, 912-13 (Alaska 1971). Typically, the bid variable is the bonus, the royalty share, the net profit share, or some combination of those terms. AS 38.05.180(f)(3)(A)-(G).

[1][2][3] A royalty is “a share of the product or profit reserved by the owner of land for permitting another to develop his land for oil or gas.” Earl A. Brown, *The Law of Oil and Gas Leases* § 6.00 (1967). Royalties are usually expressed as fractions (such as a royalty of one-eighth of production), and they usually continue throughout the life of the lease, whether the lessee reaps a net profit or not. Kelly, 486 P.2d at 913 (citing Griffith v. Taylor, 156 Tex. 1, 291 S.W.2d 673, 676 (1956)); see also Richard W. Hemingway, *The Law of Oil and Gas* § 2.5, at 57-58 (3d ed.1991). A bonus is a definite sum (not a fraction of production), to be paid in cash or out of production, for the execution of the lease. Kelly, 486 P.2d at 913; Hemingway, *The Law of Oil and Gas* § 2.4, at 56.

[4] A net profit share (NPS), like a royalty, is a percentage of the lessee's production. 5 Eugene Kuntz, *A Treatise on the Law of Oil and Gas* § 63.5, at 254 (1991) [hereinafter Kuntz]. The lessor, however, only collects on the NPS interest when the lessee's operations yield a profit, after the lessee has recouped its expenditures for exploration and development. 11

958 P.2d 422, 139 Oil & Gas Rep. 461
(Cite as: 958 P.2d 422)

Alaska Administrative Code (AAC) 83.207-219; see also Kuntz § 63.5, at 254. The Alaska Administrative Code allows lessees to establish special development accounts to recover all of their development costs before any NPS payments become due to the State. 11 AAC 83.207-214.

The State and BP Exploration (Alaska), Inc. argue that NPS terms allow the lessor to reap the benefits of rising oil prices in the future, especially if the lessee finds cost-effective ways of developing the field and extracting the oil. According to the State and BP (collectively, the State), leases with high NPS terms are the most risky for the lessor, because the lessor will receive little or nothing if the field is unprofitable, or if the lessee develops the field in an inefficient manner. See, e.g., Kuntz § 63.5, at 258 (“[T]he owner of the [net profit] interest is dependent upon the activity of the lessee to generate net profits.”).

During a brief period in the late 1970s, some lessors experimented with NPS terms, which were, and still are, controversial.^{FN1} The State notes that some observers theorize that leases with high NPS terms have a fundamental problem: under these leases, the lessors' and lessees' interests are misaligned because “the oil company [has] no incentive to develop the leases promptly or to economize costs during the development.” Furthermore, lessees receive very little income after the NPS payments begin; for instance, *426 according to the State, the Northstar lessee was predicted to receive a profit of less than fifty cents per barrel once the NPS payments began. When the lessee begins paying a large percentage of its profits to the State, along with taxes and royalties, it has very little incentive to operate efficiently. The lessee also may be tempted to discontinue its operations and abandon the field prematurely, because it retains only a small portion of the profits after it has recouped its development costs.

^{FN1}. Philip E. Sorenson, then-visiting Professor of Economics at the University of California, Santa Barbara, addressed the Alaska House of Representatives in 1979, prior to the Beaufort Sea lease sale. He analyzed NPS interests in detail and urged the legislature not to use NPS as the bid variable in the Northstar auction.

In the late 1970s, however, oil prices had been

rising, and experts predicted that they would climb to \$60 to \$100 per barrel. In addition, research indicated that the Northstar Unit contained massive reserves of oil—perhaps up to one billion barrels.^{FN2} Thus, in 1979 the State chose to auction four of its Northstar lease tracts using NPS as the bid variable.

^{FN2}. In 1996 the Commissioner stated that the Northstar Unit's reserves were estimated to contain 130 million barrels. The State's Brief of Appellee, filed in 1997, asserts that oil prices had settled around \$18 per barrel.

The four leases auctioned in 1979 had a fixed cash bonus and a fixed royalty of 20%.^{FN3} Amerada Hess submitted the winning bids, with NPS terms ranging from 85.26% to 93.2%.^{FN4} The winning NPS figure averaged about 89%, meaning that after the leaseholder recovered its expenses, the State would receive 89% of the profits.

^{FN3}. The State auctioned its fifth Northstar lease in 1983, using a bonus as the variable term, a fixed royalty of 12.5%, and a fixed NPS of 40%.

^{FN4}. Amerada Hess had the largest, but not the only, share of the four Northstar leases. The other original lessees were Shell Oil Co., Enterprise Oil Co., and Murphy Oil Co. Amerada Hess bought Enterprise's interest for \$2 million in 1990.

According to the State, from 1979 to 1994 Amerada Hess invested approximately \$260 million in attempting to develop the Northstar Unit. Because of the NPS terms (which allowed the lessee to recoup all of its development costs before beginning to make net profit share payments to the State), the State's chances of receiving the NPS payments seemed increasingly slim, as Amerada Hess invested in development with little prospect of producing. A 1993 study by the federal Department of Energy concluded that “Northstar was uneconomic largely due to the net profit provision.” Amerada Hess estimated that its development costs would approach \$1.4 billion. The combination of the development costs, the 89% NPS, and the fact that optimistic projections of Northstar's reserves and world oil prices had not materialized convinced Amerada Hess to abandon its plans to develop its Northstar holdings. Amerada Hess did not submit a

958 P.2d 422, 139 Oil & Gas Rep. 461
(Cite as: 958 P.2d 422)

required development plan to the State, and DNR issued a notice of default to Amerada Hess in November 1994.

Instead of curing the default, Amerada Hess sold its interest in the leases to BP in 1995.^{FN5} The State was not involved in the sale negotiations, nor were the terms or prices disclosed to the public.^{FN6} BP submitted a brief plan of development to DNR, which extended the time for submitting a more detailed plan. In March 1995 BP submitted, and DNR approved, a revised and more comprehensive three-year development plan.^{FN7} The revised plan increased the development time from two years to three years. Under this plan, production would probably not begin until 2002.

FN5. Shell also sold its interests to BP.

FN6. Oil and gas lessees often sell interests in leases without the State's involvement; the State may, however, be required to approve assignments resulting from the sale.

FN7. The plan called for data gathering, 3-D seismic acquisition, and construction permit acquisition. The projected three-year cost of these steps was \$12 million.

Both DNR and BP asserted that BP's development of the Northstar leases would be profitable under the original lease terms. BP, however, has estimated that its rate of return later in the life of the field would be 21% without the NPS lease terms, and only 10% with the NPS terms. According to an Arthur D. Little Co. report cited in findings of fact issued by the Senate Resources Committee, oil companies tend to look for rates of return around 15%. In early 1995 BP intimated*427 to DNR that it hoped to revise the NPS terms. BP and DNR, however, decided not to pursue that issue at that time.

Later that year, BP's president testified that

with the net profit arrangement in place, at the level that it exists, BP would not be prepared to go ahead with the development of a Northstar project, even though, if you run the economics, you can show that the return on investment for the project is a sound sort of return on investment.

BP made this announcement after DNR had approved the plan of development (which included a three-year period in which very little development would occur).^{FN8}

FN8. All of the State's oil and gas leases contain an implied covenant for lessees "to diligently explore and develop their leases." BP, however, could probably fulfill that obligation by meeting the requirements of its DNR-approved three-year plan.

DNR's Petroleum Investment Manager stated that, to his knowledge, this was the first time that a lessee had ever informed the State "that it would be economical to produce a field, but that it is unwilling to do so unless the State renegotiates its competitively bid terms."^{FN9}

FN9. The lease between Amerada Hess and the State allowed assignment and conveyance, but required the new lessee to be bound by all of the terms of the original lease. The lease provides, in part:

This lease, or any undivided interest herein, may, with the approval of the State, be assigned, subleased or otherwise transferred.... No assignment, sublease or other transfer of an interest in this lease, including assignments of working or royalty interests and operating agreements and subleases, shall be binding upon the State unless approved by the State.... All covenants, conditions and agreements contained in this lease shall extend to and be binding upon the heirs, administrators, successors, and assigns of the State and/or Lessee.

In the fall of 1995, after BP's announcement, DNR and BP conducted confidential negotiations regarding possible amendments to the leases. The negotiations yielded the following proposed amendments: the State's NPS (which had averaged 89%) would be eliminated; the State's royalties would be at least 20% for all of the leases, and a variable "supplemental royalty" of 7.5% could be added to that; a "use it or lose it" provision would be added, allowing the State to terminate the leases (without litigation) if

958 P.2d 422, 139 Oil & Gas Rep. 461
(Cite as: 958 P.2d 422)

BP did not begin development within a certain period; and BP committed to employing Alaskans in the construction and operation of its facilities.

The Commissioner has the statutory authority to make changes to royalty provisions of oil and gas leases without obtaining the legislature's approval. AS 38.05.180(j).^{FN10} But the statute is silent on whether the Commissioner may amend NPS provisions. The Commissioner therefore negotiated proposed terms with BP and presented the negotiated proposed lease amendments to the Alaska legislature for consideration. The lease amendments were to take effect only upon approval by the legislature. After investigation by committees in the House and Senate, and testimony from DNR, BP, and the public, a bill for an act authorizing amendment of the Northstar Unit leases (the Act) passed both houses in May 1996. Governor Knowles signed the bill into law in July 1996. Since then, BP has approved development of the tracts covered by the leases.

FN10. AS 38.05.180(j) provides, in part:

The commissioner

(1) may provide for an increase or decrease or otherwise modify royalty, to allow for production that would not otherwise be economically feasible, on individual leases....

(2) may not grant a royalty modification unless the lessee or lessees requesting the modification make a clear and convincing showing that a modification of royalty meets the requirements of this subsection and is in the best interests of the state....

B. Proceedings

This case began in January 1997 when Clyde Baxley and the Republican Moderate Party brought a declaratory judgment action against the State and John Shively, Commissioner of the Department of Natural Resources.^{FN11} Baxley and the Party (collectively *428 Baxley) asserted that they had citizen-taxpayer standing to challenge the Act. Baxley argued that the Act violates the Uniform Application Clause and the Public Notice Clause of the Alaska Constitution, and that it violates competitive bidding statutes and laws proscribing material amendments to competitively bid

contracts.^{FN12} Baxley also contended that the Commissioner lacked the authority to modify the leases. BP intervened as a party defendant under Alaska Rule of Civil Procedure 24.

FN11. The Republican Moderate Party claims to be a nonprofit political group. The Republican Party of Alaska asserted below that the Republican Moderate Party admits it is not a political party, and that it has no relation to the Republican Party of Alaska. The Republican Party of Alaska has disclaimed interest in this case.

FN12. Baxley also asserted, but later withdrew, a claim that the Act violated the Privileges and Immunities Clauses of the Alaska and United States Constitutions, and the Commerce Clause of the United States Constitution.

The State moved to dismiss for lack of standing. Both sides then filed motions for summary judgment. The superior court found that all plaintiffs had standing as citizen-taxpayers. It denied Baxley's motion for summary judgment and granted the State's motion for summary judgment. The court concluded that the rule against material amendments did not apply to amendments by the legislature. The court also reasoned that the legislature had conducted adequate public hearings, had not given BP privileged status, and, in passing the Act, had created a narrowly tailored response to a unique problem. Baxley appeals.

III. DISCUSSION

A. Standard of Review

We review a grant of summary judgment with our independent judgment. Reeves v. Alyeska Pipeline Serv. Co., 926 P.2d 1130, 1134 (Alaska 1996). We will affirm a grant of summary judgment if the evidence in the record, viewed in the light most favorable to the non-moving party, fails to disclose a genuine issue of material fact, and the moving party is entitled to judgment as a matter of law. Metcalfe Inv., Inc. v. Garrison, 919 P.2d 1356, 1360 (Alaska 1996).

[5] A party raising a constitutional challenge to a statute bears the burden of demonstrating the consti-

958 P.2d 422, 139 Oil & Gas Rep. 461
(Cite as: 958 P.2d 422)

tutional violation. A presumption of constitutionality applies, and doubts are resolved in favor of constitutionality. *A. Fred Miller, Attorneys at Law, P.C. v. Purvis*, 921 P.2d 610, 618 (Alaska 1996); *Bonjour v. Bonjour*, 592 P.2d 1233, 1237 (Alaska 1979).

B. Standing

[6] Following vigorous debate on the issue, the superior court held that Baxley had standing as a citizen-taxpayer to present the issues raised in his complaint. The State suggests on appeal that we may resolve Baxley's Uniform Application Clause claim "on standing grounds, without reaching the merits."

[7][8][9] We decline to disturb the superior court's finding that Baxley has standing as a citizen-taxpayer.^{FN13} A plaintiff must meet two requirements in order to establish citizen-taxpayer standing. First, the case "must be one of public significance." *Trustees for Alaska v. State*, 736 P.2d 324, 329-30 (Alaska 1987). A plaintiff who raises constitutional issues is likely to meet this requirement. *Id.* Second, the plaintiff must be an "appropriate" party to bring the case. *Id.* Appropriateness has three main facets: the plaintiff must not be a "sham plaintiff" with no true adversity of interest; he or she must be capable of competently advocating his or her position; and he or she may still be denied standing if "there is a plaintiff more directly affected by the challenged conduct in question who has or is likely to bring suit." *Id.* The citizen-taxpayer standing requirements ensure that the plaintiff will serve as a true and strong adversary, even if the conduct in question did not directly affect the plaintiff.

FN13. We review de novo a finding of standing. *Earth Movers of Fairbanks, Inc. v. Fairbanks N. Star Borough*, 865 P.2d 741, 742 n. 5 (Alaska 1993) (citing *Langdon v. Champion*, 745 P.2d 1371, 1372 n. 2 (Alaska 1987)).

[10] Baxley argues that the Act violates constitutional provisions, may reduce the State's income, undermines public confidence in the integrity of the bidding system, and *429 violates the public trust. Those issues have public significance.^{FN14} The State asserted below that Baxley is not an appropriate plaintiff; it suggested that a competing oil company, for instance, would have been a more appropriate challenger. The mere possibility that another party

might sue, however, does not necessarily justify a denial of standing. See *Trustees*, 736 P.2d at 330. Baxley's interests are sufficiently adverse to those of the State and BP. He is adequately represented and can advocate his position competently. We conclude that the superior court did not err in determining that Baxley has citizen-taxpayer standing.

FN14. See, e.g., *Trustees for Alaska v. State*, 736 P.2d 324, 330 (Alaska 1987) (granting citizen-taxpayer standing to a coalition of environmental, Native, and fishing groups challenging the State's mineral leasing system); *State v. Lewis*, 559 P.2d 630, 634-36 (Alaska 1977) (granting citizen-taxpayer standing for challenge of a three-way land trade involving the State, the federal government, and a Native corporation).

C. The Uniform Application Clause

[11] Baxley contends that the Act violates the Uniform Application Clause of the Alaska Constitution. That clause provides, "Laws and regulations governing the use or disposal of natural resources shall apply equally to all persons similarly situated with reference to the subject matter and purpose to be served by the law or regulation." Alaska Const. art. VIII, § 17.

[12] In recognition of the importance of citizens' equal access to natural resources, we interpret the Uniform Application Clause to require legislation dealing with natural resources to satisfy a heightened level of equal protection scrutiny. *Gilbert v. State*, 803 P.2d 391, 398 (Alaska 1990); *Baker v. State*, 878 P.2d 642, 644 (Alaska App.1994).

[13] The protections of the Uniform Application Clause, however, extend only to persons similarly situated with respect to the subject matter and purpose of the legislation. Alaska Const. art. VIII, § 17; *Reichmann v. State*, 917 P.2d 1197, 1200 (Alaska 1996). "Concluding that two classes are not similarly situated necessarily implies that the different legal treatment of the two classes is justified by the differences between the two classes." *Shepherd v. State*, 897 P.2d 33, 44 n. 12 (Alaska 1995).^{FN15}

FN15. The State argues that no other entity is similarly situated with respect to the Act.

958 P.2d 422, 139 Oil & Gas Rep. 461
(Cite as: 958 P.2d 422)

Baxley argues that similarly situated persons disadvantaged by the Act include: “1) all original bidders on Northstar; 2) all possible bidders at a potential rebidding of Northstar; 3) all potential bidders who might wish to bid for the rights given to BP ... and 4) all citizen-taxpayers of the State of Alaska, who have a personal and individual stake in the fair allocation of Alaska resources.”

The superior court held that the Uniform Application Clause does not apply because it found that BP's status as sole lessee of the Northstar leases rendered it uniquely situated with respect to the Act.^{FN16} The superior court also held that, even if the Uniform Application Clause did apply, the Act would satisfy the clause's equal protection requirements.

FN16. We apply our independent judgment to the question whether BP is uniquely situated with respect to the Act. See Luedtke v. Nabors Alaska Drilling, Inc., 834 P.2d 1220, 1223 (Alaska 1992) (noting that we review a trial court's application of law to facts with our independent judgment).

We agree that the Uniform Application Clause does not apply. Land use statutes, for instance, sometimes favor existing land users over others. See, e.g., AS 38.05.035(b)(5), .035(f). We also allow some changes to existing lessees' competitively bid contracts without requiring new public auctions. See KILA, Inc. v. State, 876 P.2d 1102, 1108-09 (Alaska 1994) (upholding State's decision to negotiate with successful bidder and accept a substitute site for government building); Kenai Lumber Co. v. LeResche, 646 P.2d 215, 218-22 (Alaska 1982) (allowing non-material modifications to a long-term timber contract).

Not all persons in the state with an interest in a resource are similarly situated for purposes of the Uniform Application Clause.^{FN17} BP, as sole lessee of the Northstar *430 leases, is uniquely situated with respect to the Act. Because no other entity is similarly situated, we hold that the Act does not violate the Uniform Application Clause.

FN17. See, e.g., Reichmann v. State, 917 P.2d 1197, 1200 (Alaska 1996) (upholding differential treatment of residential and rec-

reational users of lakeshore land); Shepherd v. State, 897 P.2d 33, 43-44 (Alaska 1995) (upholding Alaska Board of Game regulations giving hunting preference to residents over nonresidents); Tongass Sport Fishing Ass'n v. State, 866 P.2d 1314, 1318 (Alaska 1994) (upholding salmon harvesting regulation giving preference to commercial fishers because sport and commercial fishers are not similarly situated); Gilbert v. State, 803 P.2d 391, 399 (Alaska 1990) (upholding distinction in harvest quotas for two fisheries based on “biological spawning patterns”).

D. Special Legislation

[14] Baxley next argues that the Act was special legislation prohibited by article II, section 19 of the Alaska Constitution. Although we ordinarily do not consider on appeal issues not presented to the lower court,^{FN18} we choose to address Baxley's special legislation argument. It does not depend on new facts, and it could have been gleaned from the pleadings because it is closely related to Baxley's Uniform Application Clause argument that the State gave BP privileged status. The issue therefore satisfies the requirements of Zeman v. Lufthansa German Airlines, 699 P.2d 1274, 1280 (Alaska 1985) (discussing bases for reaching appellate issues not preserved in lower court). Moreover, the State has not suggested that it has been prejudiced by introduction of this argument on appeal; on the contrary, it has conceded that the court may properly consider this issue.

FN18. See Brooks v. Brooks, 733 P.2d 1044, 1053 (Alaska 1987).

[15] The Alaska Constitution states: “The legislature shall pass no local or special act if a general act can be made applicable. Whether a general act can be made applicable shall be subject to judicial determination.” Alaska Const. art. II, § 19. We evaluate challenges under this provision according to the test applied to unsuspect classifications in equal protection cases.^{FN19} State v. Lewis, 559 P.2d 630, 643 (Alaska 1977) (upholding a threeway exchange of land, and the minerals it contained, among the State of Alaska, the United States, and a regional Native corporation); Boucher v. Engstrom, 528 P.2d 456, 463 (Alaska 1974) (“The classification must bear a reasonable and proper relationship to the purposes of the act and the problem sought to be remedied.”). Thus,

958 P.2d 422, 139 Oil & Gas Rep. 461
(Cite as: 958 P.2d 422)

when the legislature has singled out an area or group, we examine the

FN19. Baxley is correct in pointing out that this court has adopted a sliding scale analysis to determine the level of scrutiny to apply to equal protection claims. *See State v. Enserch Alaska Constr.*, 787 P.2d 624, 631 (Alaska 1989). He asserts that the court should use the sliding scale when analyzing his special legislation challenge. Baxley argues that, to determine where on the sliding scale the state and individual interests fall, the court should apply the Uniform Application Clause, which, he reasons, requires a showing of an important state interest and no less restrictive alternative to further it.

Our decisions interpreting article II, section 19 of the Alaska Constitution, however, have applied the less rigorous test used for nonsuspect classifications in equal protection cases. *See Lewis*, 559 P.2d at 643; *Abrams v. State*, 534 P.2d 91, 94-95 (Alaska 1975). We will analyze this claim under the standard applied in *Abrams* and *Lewis* because they deal specifically with article II, section 19 challenges instead of equal protection challenges.

legislative goals and the means used to advance them [to] determine whether the legislation bears a “fair and substantial relationship” to legitimate purposes. If this standard is satisfied, the bill will not be invalid because of incidental local or private advantages. Legislation need not operate evenly in all parts of the state to avoid being classified as local or special.

Lewis, 559 P.2d at 643 (footnotes omitted). This is the “minimum level of equal protection scrutiny in Alaska”; it is more demanding than its federal counterpart. *Principal Mut. Life Ins. v. State*, 780 P.2d 1023, 1026 (Alaska 1989).

[16] The State argues that the Act is not local or special legislation because it “addresses a matter of statewide concern,” and that, even though the Act focuses on one locality, it is constitutional because the high NPS terms made these leases unique and made general legislation inappropriate.

We conclude that the Act is not special legislation. Several features of the Northstar leases distinguish them from the State's other oil and gas leases. The Northstar *431 leases were the State's only oil and gas leases auctioned with NPS as the bid variable. They are also the only State leases with NPS terms greater than 85%. (NPS terms in most State leases average about 30% to 40%.) The high NPS terms present the State with a unique problem: in the later years of the lease, the lessee would reap only a slight profit from continuing to extract oil, giving the lessee a strong incentive to abandon the field before extracting all the oil.^{FN20}

FN20. BP's president stated, “Once the net profit interest cuts in, ... some 90% or so of the revenue stream to the [Northstar lessee] would effectively dry up, and that would lead to the premature shut-down of the field.” He asserted that “it would not be acceptable for BP, or I believe any other reputable oil company to continue to operate the field.”

Other features of the Northstar Unit distinguish these leases. The development account the Northstar lessees amassed over seventeen years is evidence of the difficulty of developing the fields. Development of the Northstar Unit will require new technology, including the first undersea pipeline in the Arctic Ocean—a technological advance that the legislature predicts will increase the value of other North Slope leases and increase State revenues. No State lessee had previously been obliged to develop such holdings under such lease terms.

The legislature conducted numerous public hearings and debates on the propriety of the proposed Act. It concluded that, if the leases were not amended, production in the Northstar Unit would probably not begin before 2002. It found that amending the leases “will maximize the economic benefits of oil and gas production to the people of the state by encouraging timely production from the unit.” It also concluded that BP's timely development of the Northstar unit “may result in technological breakthroughs and other cost savings that may make other development opportunities in Alaska economically feasible.” These legislative findings express the legitimate purposes of encouraging and providing for development of state resources for the benefit of the people. *See Alaska Const. art. VIII, §§ 1-2.*^{FN21}

958 P.2d 422, 139 Oil & Gas Rep. 461
(Cite as: 958 P.2d 422)

FN21. Article VIII, section 1 of the Alaska Constitution provides: “It is the policy of the State to encourage the settlement of its land and the development of its resources by making them available for maximum use consistent with the public interest.”

Article VIII, section 2 of the Alaska Constitution states: “The legislature shall provide for the utilization, development, and conservation of all natural resources belonging to the State, including land and waters, for the maximum benefit of its people.”

Because the Act's exclusive focus on the Northstar leases reflects their unique nature, and because the Act fairly and substantially relates to legitimate state purposes, we hold that it is not special legislation. See Lewis, 559 P.2d at 643.

E. *The Commissioner's Authority*

[17] Baxley asserts that the Commissioner did not “have statutory authority under AS 38.05.180(i) to unilaterally reduce the net profit share in any Alaska oil lease.” ^{FN22} Baxley argues that, although the Commissioner has statutory authority to change royalty payments, the Commissioner has no statutory authority to change NPS payments.

FN22. AS 38.05.180(i) is set out, in part, at note 10, *supra*.

Baxley's argument, however, depends on our acceptance of his characterization of the Commissioner's actions. The Commissioner did not unilaterally reduce the NPS terms. The Commissioner merely negotiated a proposed reduction, which the legislature then approved. The negotiations would have had no binding effect unless the legislature approved the proposed amendments.

Baxley correctly notes that the Alaska Land Act (AS 38.05) does not grant or deny the Commissioner authority to negotiate proposed changes in the NPS terms. But particular provisions of the Alaska Land Act suggest that the Commissioner at least had the authority to negotiate the amendments, whether or not the Commissioner could have approved the lease

amendments absent the 1996 Act here at issue. The Commissioner has broad supervisory power over the “administration of the division of lands.” AS 38.05.020(a). The Commissioner may “enter into agreements considered necessary to carry out the purposes of this chapter, including *432 agreements with federal and state agencies.” AS 38.05.020(b)(2). The Commissioner may also “exercise the powers and do the acts necessary to carry out the provisions and objectives of this chapter.” AS 38.05.020(b)(4). The Commissioner's broad powers appear to us to include the authority to negotiate with a lessee wishing to change the terms of its lease; such negotiations with respect to a given lease and the pertinent circumstances may be acts necessary to further the objectives of the Alaska Land Act. We do not interpret AS 38.05.180(i) to prevent, expressly or impliedly, the Commissioner from negotiating proposed NPS amendments subject to legislative approval. ^{FN23}

FN23. We do not decide here whether the Commissioner would have had the authority to modify the NPS terms without legislative approval.

The Commissioner's broad statutory powers authorized these negotiations; subsection .180(j) did not preclude them. We hold that the Commissioner did not exceed his authority.

F. *Public Notice Clause*

[18] Baxley argues that the Act violates the Public Notice Clause of the Alaska Constitution, which provides, “No disposals or leases of state lands, or interests therein, shall be made without prior public notice and other safeguards of the public interest as may be prescribed by law.” Alaska Const. art. VIII, § 10. Baxley concedes that the public received notice of the legislature's approval of the proposed amendments. ^{FN24} He argues that the public should have received notice before the negotiations, and that, at the public hearings, other options (besides the proposed amendments negotiated by DNR and BP) should have been presented.

FN24. Baxley argues, “The only aspect of Northstar for which the public received notice was the subsequent legislative ratification of a deal already struck, an agreement already made.”

958 P.2d 422, 139 Oil & Gas Rep. 461
(Cite as: 958 P.2d 422)

The Alaska Constitution does not express a requirement of pre-negotiation notice, and instead can be read to require notice before the State commits to an agreement requiring it to dispose of or lease state lands or interests in state lands. We assume for sake of discussion that amendment of the lease terms was a disposal or lease of an interest in state land. Regardless of the exact extent and timing of the notice required by the Public Notice Clause, we think that the process followed here satisfied that clause. The Commissioner presented the proposed amendments to the legislature, and nearly five weeks of spirited debate followed. We disagree with Baxley's contention that the "ink on the agreement was dry before it was submitted to the legislature": the public was still free to comment on the bill, and the legislature was still free to reject it. Because the public had ample opportunity to comment on the proposed lease amendments before the legislature authorized any binding changes, *see* Part III.D., *supra*, at 18, we conclude that the State did not violate the Public Notice Clause.

G. Remaining Issues

1. Constitutional requirement of forfeiture provisions

[19] Baxley argues that the Commissioner violated article VIII, sections 8 and 11 of the Alaska Constitution by not requiring BP to forfeit the leases after BP announced its intention not to proceed with development. ^{FN25} *433 We decline to consider this issue because Baxley did not preserve it below. *See Brooks v. Brooks*, 733 P.2d 1044, 1053 (Alaska 1987). This issue presents a new constitutional theory and raises new fact questions about whether the leases' forfeiture provisions satisfied sections 8 and 11 and whether BP and the State complied with them. Because we believe that the State could not have gleaned this new constitutional argument from the pleadings, we decline to address it. *See Zeman*, 699 P.2d at 1280 (discussing bases for reaching on appeal issues not preserved below).

FN25. Article VIII, section 8 of the Alaska Constitution provides:

The legislature may provide for the leasing of, and the issuance of permits for exploration of, any part of the public domain or interest therein, subject to reasonable concurrent uses. Leases and permits shall

provide, among other conditions, for payment by the party at fault for damage or injury arising from noncompliance with terms governing concurrent use, and for forfeiture in the event of breach of conditions.

Article VIII, section 11 of the Alaska Constitution provides, in part:

Discovery and appropriation shall be the basis for establishing a right in those minerals reserved to the State which, upon the date of ratification of this constitution by the people of Alaska, were subject to location under the federal mining laws. Prior discovery, location, and filing, as prescribed by law, shall establish a prior right to these minerals and also a prior right to permits, leases, and transferable licenses for their extraction. Continuation of these rights shall depend upon the performance of annual labor, or the payment of fees, rents, or royalties, or upon other requirements as may be prescribed by law.

2. Anticipatory breach

[20] Baxley contends that BP anticipatorily breached the lease agreements, and that the State should have responded by rescinding the leases. This contract law argument turns on new facts and could not have been gleaned from the pleadings. *See Zeman*, 699 P.2d at 1280. Whether BP committed an anticipatory breach would depend on the outcome of potential fact disputes and a different body of case law. For example, it would raise the question of whether BP's communication to the State was a definite and unconditional repudiation of the contract, or merely an expression of concern with certain provisions in the lease. *See, e.g., Holiday Inns of Am., Inc. v. Peck*, 520 P.2d 87 (Alaska 1974). We therefore decline to address this argument.

3. Separation of powers

[21] Baxley argues that the legislature unlawfully infringed on the domain of the courts and violated separation of powers principles. This argument is not closely related to Baxley's superior court argument that the Commissioner lacked the authority to negotiate lease amendments; instead, it attacks the legislature's authority to consider the proposed amendments.

958 P.2d 422, 139 Oil & Gas Rep. 461
(Cite as: 958 P.2d 422)

This argument could not have been gleaned from the pleadings. We therefore decline to address it. *See Zeman*, 699 P.2d at 1280.

Moreover, Baxley seems to assume that the legislature made a legal determination that the Commissioner's negotiations with BP were constitutional. It appears, however, that the Commissioner presented the legislature with proposed legislation, and that the legislature conducted its own investigation and debates on the propriety of the proposed Act and amendments. It does not appear that the legislature impermissibly intruded on judicial domain.

4. Rule against material amendments

[22] Baxley asserts that the Act violates the rule against material amendments to state contracts awarded through a public bidding process. He reasons that the Act may undermine public confidence in the integrity of the bidding process because it changes the leases' terms instead of rescinding them and offering them in a new auction.

[23] In general, competitively bid contracts involving state resources cannot be materially amended. *Kenai Lumber Co. v. LeResche*, 646 P.2d 215, 221 (Alaska 1982). The rationale behind this judicially created rule is that the amendment effectively produces a new contract, which the State should award only after a new round of public bidding. *McKinnon v. Alpetco Co.*, 633 P.2d 281, 287 (Alaska 1981).^{FN26}

FN26. We have explained:

This rule has been judicially imposed in order to guard against circumvention of competitive bidding requirements. Competitive bidding itself is designed to ensure that government obtains the most favorable terms possible in its contracts, and to protect the public from the possibility of favoritism, fraud, and corruption on the part of public officials.

Kenai Lumber Co. v. LeResche, 646 P.2d 215, 220 (Alaska 1982).

[24] We have never applied the rule to bar contract amendments approved by the legislature.^{FN27} The superior court held that, "where the legislature itself

amends a competitively bid contract, employing the committee and public hearing process, the need for the judiciary to protect legislative policy is essentially obviated." The superior court *434 also reasoned that, because the legislature has the authority to create DNR and pass the leasing statutes, it would be illogical to conclude that the legislature lacks the authority to amend the leases. We agree. We believe the legislature's hearing process satisfies the policy considerations behind this rule. Therefore, we conclude that the material amendments doctrine does not apply to amendments approved by the legislature. We reject Baxley's challenge.

FN27. *See, e.g., KILA, Inc. v. State*, 876 P.2d 1102 (Alaska 1994); *Kenai Lumber*, 646 P.2d at 217-23; *McKinnon v. Alpetco Co.*, 633 P.2d 281, 285 (Alaska 1981)

5. Public trust

[25] Finally, Baxley argues that the amendments violate the public trust doctrine. Baxley argues that the executive branch violated the public trust by not determining whether similarly situated parties existed before allocating resources to BP, by not "telling BP to develop the field or lose it," and by not offering the Northstar leases in another sale in January 1995.^{FN28} He asserts that he raised this claim in the superior court, but he fails to cite where in the record he did so. Baxley did not raise this argument in his points on appeal and made only passing references to it in the superior court in connection with his Uniform Application Clause argument. The State contends that Baxley has raised this issue for the first time on appeal.

FN28. Baxley also seems to suggest that the legislature breached the public trust. Because he does not develop this argument, we decline to address it. *See State v. O'Neill Investigations, Inc.*, 609 P.2d 520, 528 (Alaska 1980) (declining to consider an inadequately briefed argument).

The public trust doctrine provides that the State holds certain resources (such as wildlife, minerals, and water rights) in trust for public use, "and that government owes a fiduciary duty to manage such resources for the common good of the public as beneficiary." *McDowell v. State*, 785 P.2d 1, 16 n. 9 (Alaska 1989). We apply basic principles of trust law to public

958 P.2d 422, 139 Oil & Gas Rep. 461
(Cite as: 958 P.2d 422)

land trusts. *State v. Weiss*, 706 P.2d 681, 683 n. 3 (Alaska 1985). One basic principle is that, when a trustee has discretion, a court will only review the trustee's acts for abuse of discretion. See William F. Fratcher, 3 *Scott on Trusts* § 187, at 14-19 (4th ed.1988); see also *Restatement (Second) of Trusts* § 187 (1959).

Baxley's argument consequently turns on a new body of case law, concerning fiduciary duty, and on new fact questions, concerning possible abuse of the fiduciary's discretion. Because this argument is not closely related to Baxley's trial court arguments and could not have been gleaned from the pleadings, we decline to address it. See *Zeman*, 699 P.2d at 1280.

IV. CONCLUSION

Because we reject Baxley's challenges to the Act, we AFFIRM the superior court's grant of summary judgment to BP and the State.

Alaska, 1998.
Baxley v. State
958 P.2d 422, 139 Oil & Gas Rep. 461

END OF DOCUMENT

12

40 P.3d 786, 151 Oil & Gas Rep. 317
(Cite as: 40 P.3d 786)

H

Supreme Court of Alaska.
EXXON CORPORATION, Appellant,
v.
STATE of Alaska, Appellee.

No. S-9164.
Oct. 12, 2001.
Rehearing Denied Feb. 21, 2002.

Oil company appealed decision of Department of Natural Resources denying expansion of area covered by oil and gas lease unit agreement, which agreement allowed oil company to deduct field costs before paying state royalties, to include additional oil reservoir. The Superior Court, Third Judicial District, Anchorage, John E. Reese, J., affirmed Department's decision, and oil company appealed. The Supreme Court, Carpeneti, J., held that: (1) agreement provided Department with discretion to deny expansion of unit area, and (2) Department's decision did not violate settlement agreement on royalty payments due from unit area.

Affirmed.

West Headnotes

[1] Administrative Law and Procedure 15A
⚡683

15A Administrative Law and Procedure
15AV Judicial Review of Administrative Decisions

15AV(A) In General
15Ak681 Further Review
15Ak683 k. Scope. Most Cited Cases

When the superior court reviews an agency decision and acts as an intermediate court, Supreme Court directly reviews the administrative agency decision under consideration.

[2] Administrative Law and Procedure 15A
⚡796

15A Administrative Law and Procedure
15AV Judicial Review of Administrative Decisions
15AV(E) Particular Questions, Review of
15Ak796 k. Law Questions in General.
Most Cited Cases

Supreme Court applies a substitution of judgment standard of review for agency decisions on questions of law where no expertise is involved.

[3] Administrative Law and Procedure 15A
⚡796

15A Administrative Law and Procedure
15AV Judicial Review of Administrative Decisions
15AV(E) Particular Questions, Review of
15Ak796 k. Law Questions in General.
Most Cited Cases

Interpretation of a contract is a question of law that is not within an administration agency's special expertise or skill.

[4] Contracts 95 ⚡176(1)

95 Contracts
95II Construction and Operation
95II(A) General Rules of Construction
95k176 Questions for Jury
95k176(1) k. In General. Most Cited Cases

Where there is no conflict in extrinsic evidence, the interpretation of contract is a question of law.

[5] Appeal and Error 30 ⚡1010.1(10)

30 Appeal and Error
30XVI Review
30XVI(I) Questions of Fact, Verdicts, and Findings
30XVI(I)3 Findings of Court
30k1010 Sufficiency of Evidence in

40 P.3d 786, 151 Oil & Gas Rep. 317
(Cite as: 40 P.3d 786)

Support

30k1010.1 In General

30k1010.1(8) Particular Cases
and Questions

30k1010.1(10) k. Contracts in
General; Sales; Landlord and Tenant. Most Cited
Cases

When the finder of fact must determine the meaning of a contract based on extrinsic evidence that raises conflicting inferences, Supreme Court's inquiry on appeal is limited to determining whether the finder of fact's choice of inferences is supported by substantial evidence.

[6] Mines and Minerals 260 ⚡92.79

260 Mines and Minerals

260III Operation of Mines, Quarries, and Wells

260III(A) Statutory and Official Regulations

260k92.78 Unitization

260k92.79 k. In General; Procedure.

Most Cited Cases

Supreme Court reviewed Department of Natural Resources' interpretation of oil and gas lease unit agreement between state and oil company for substantial evidentiary support, as determination of meaning of contract was based on extrinsic evidence, and such evidence raised conflicting inferences.

[7] Mines and Minerals 260 ⚡92.79

260 Mines and Minerals

260III Operation of Mines, Quarries, and Wells

260III(A) Statutory and Official Regulations

260k92.78 Unitization

260k92.79 k. In General; Procedure.

Most Cited Cases

Oil company did not waive right to argue on appeal that geological condition necessary to allow expansion of area covered by oil and gas lease unit agreement was met, when it signed agreement that allowed oil production to begin on additional reservoir pending resolution of legal dispute; express intent of agreement was to preserve oil company's right to appeal and so interpreting agreement would eviscerate such right.

[8] Contracts 95 ⚡147(1)

95 Contracts

95II Construction and Operation

95II(A) General Rules of Construction

95k147 Intention of Parties

95k147(1) k. In General. Most Cited

Cases

Goal when interpreting contracts is to give effect to the reasonable expectations of the parties.

[9] Mines and Minerals 260 ⚡92.79

260 Mines and Minerals

260III Operation of Mines, Quarries, and Wells

260III(A) Statutory and Official Regulations

260k92.78 Unitization

260k92.79 k. In General; Procedure.

Most Cited Cases

Unit agreement unitizing oil leases provided Department of Natural Resources discretion on whether to allow expansion of area covered by agreement; though text of agreement alone did not unambiguously indicate if oil company or Department had authority to expand area, agreement stated that Director "shall" render a decision on expansion, when agreement created a right that oil company could exercise word "shall" was used, agreement expressly provided that it was subject to valid state laws, rules, regulations and orders, and past conduct of oil company in requesting changes in areas of oil and gas lease units indicated Department had discretion to deny expansion.

[10] Contracts 95 ⚡143.5

95 Contracts

95II Construction and Operation

95II(A) General Rules of Construction

95k143.5 k. Construction as a Whole. Most

Cited Cases

In interpreting a contract, courts should interpret the contract in a manner that makes the contract internally consistent.

[11] Contracts 95 ⚡170(1)

40 P.3d 786, 151 Oil & Gas Rep. 317
(Cite as: 40 P.3d 786)

95 Contracts

95II Construction and Operation

95II(A) General Rules of Construction

95k170 Construction by Parties

95k170(1) k. In General. Most Cited

Cases

The conduct of the parties to a contract is properly considered as evidence of the parties' intent.

[12] Mines and Minerals 260 ☞ 92.79

260 Mines and Minerals

260III Operation of Mines, Quarries, and Wells

260III(A) Statutory and Official Regulations

260k92.78 Unitization

260k92.79 k. In General; Procedure.

Most Cited Cases

Regulation did not provide Department of Natural Resources with authority to contract away its discretion to consider state's best interest in approving expansion of areas covered by unit agreements unitizing oil and gas leases; regulation regarding conflicts between new regulations and existing leases did not make existing Department regulations inapplicable to new unit agreements, and allowing Department to contract outside of its regulations would allow Department to be arbitrary. Alaska Admin.Code title 11, §§ 83.301(b), 83.303.

[13] Mines and Minerals 260 ☞ 92.79

260 Mines and Minerals

260III Operation of Mines, Quarries, and Wells

260III(A) Statutory and Official Regulations

260k92.78 Unitization

260k92.79 k. In General; Procedure.

Most Cited Cases

Refusal of Department of Natural Resources to expand area covered by unit agreement to include additional oil reservoir did not violate express terms of settlement agreement with oil company on royalties to be paid from original area, nor violate Department's implied covenant of good faith and fair dealing with regards to such settlement; though refusal to allow expansion prevented oil company from deducting field costs from royalty payments due state from new reservoir, Department had the discretion not to allow

expansion, actual field costs incurred by oil company were much lower than those allowed by settlement agreement, and oil company had enjoyed a substantial benefit from settlement agreement.

[14] Constitutional Law 92 ☞ 2701

92 Constitutional Law

92XXII Obligation of Contract

92XXII(B) Contracts with Governmental Entities

92XXII(B)2 Particular Issues and Applications

92k2701 k. Leases. Most Cited Cases (Formerly 92k121(1))

Mines and Minerals 260 ☞ 92.79

260 Mines and Minerals

260III Operation of Mines, Quarries, and Wells

260III(A) Statutory and Official Regulations

260k92.78 Unitization

260k92.79 k. In General; Procedure.

Most Cited Cases

Refusal of Department of Natural Resources to expand area covered by unit agreement, under which oil company made smaller royalty payments to state, to include additional oil reservoir did not unconstitutionally impair oil company's contractual rights, where Department had the discretion under unit agreement with oil company to approve changes to the unit. U.S.C.A. Const.Amend. 5.

[15] Estoppel 156 ☞ 62.2(2)

156 Estoppel

156II Equitable Estoppel

156III(A) Nature and Essentials in General

156k62 Estoppel Against Public, Government, or Public Officers

156k62.2 States and United States

156k62.2(2) k. Particular State Officers, Agencies or Proceedings. Most Cited Cases

Department of Natural Resources was not estopped from ordering contraction and denying expansion of area covered by oil and gas lease unit agreement, under which oil company was entitled to make smaller royalty payments to state; though agreement

40 P.3d 786, 151 Oil & Gas Rep. 317
(Cite as: 40 P.3d 786)

provided that area could be expanded based on geologic factors, agreement provided Department with discretion to deny expansion.

*787 William F. Cronin and Johnathan E. Mansfield, Corr Cronin LLP, Seattle, and Douglas J. Serdahely and Kevin Callahan, Patton Boggs LLP, Anchorage, for Appellant.

Virginia B. Ragle, Assistant Attorney General, and Bruce M. Botelho, Attorney General, Juneau, for Appellee.

Before FABE, Chief Justice, MATTHEWS, EASTAUGH, BRYNER, and CARPENETI, Justices.

OPINION

CARPENETI, Justice.

I. INTRODUCTION

In 1988 Exxon discovered the Point McIntyre oil reservoir, a bonanza with an estimated value of \$4,783,800,000. Now, Exxon and the State of Alaska dispute who will absorb \$24 million in field costs associated with the reservoir based on their opposing interpretations of a contract, the Prudhoe Bay Unit Agreement. We conclude that the state has the discretion under the terms of the agreement to consider the public interest according to state law and to deny the expansion of the Prudhoe Bay Unit to include the Pt. McIntyre reservoir. This conclusion is dispositive of the numerous arguments raised on appeal. We therefore affirm the commissioner's decision.

*788 II. FACTS AND PROCEEDINGS

In the late 1960's the predecessors of Exxon and Arco acquired several oil and gas leases on the Alaska North Slope.^{FN1} Each lease had a ten-year term and provided a royalty to the state-twelve and one-half percent of all oil and gas production. These leases provided that the state could take its royalty in oil or gas products (in kind) or in equivalent dollar value (in value). If the state took its royalty in kind, the lease provided that the lessees could deduct only their cleaning and dehydration field costs.^{FN2} The leases did not mention field cost deductions when the state took its royalty in value.

^{FN1}. Appendix A contains a map that marks the various lease parcels, the Pt. McIntyre reservoir, and the Prudhoe Bay Unit. Exxon and Arco obtained the rights to Alaska Divi-

sion of Lands leases 34626, 34627, 34624, 28297, 28298, and 34622. We adopt the parties' shorthand reference of "ADL" followed by the lease number. Tracts 5, 6, 7, and 8 correspond to those portions of ADLs 34626, 34627, 34624, and 28297, respectively, that were within the original PBU boundary. Tracts 115 and 116 correspond to ADLs 28298 and 34622. BP later acquired ADL 365548 (tract 117).

^{FN2}. Field costs are all of the costs of production incurred from the wellhead to the custody transfer meters into the Trans Alaska Pipeline. Field costs generally include gathering, separation, cleaning, dehydration, compression, and other handling costs.

In 1977 Exxon, Arco, and the state, through the Department of Natural Resources, entered into the Prudhoe Bay Unit Agreement (PBUA). A unit agreement is a contract between the department and lessees that allows for the efficient development of a reservoir that underlies multiple leases owned by different lessees. The various lessees join together in exploration and drilling, and allocate costs and production. The PBUA was not based on the state's model unit agreement; the lessees drafted the PBUA. The state approved the PBUA effective April 1, 1977.

The PBUA unitized 111 leases, including portions of the five previously mentioned ^{FN3} Exxon and Arco leases. The Prudhoe Bay Unit (PBU) includes most of the land described by these leases. The PBUA also had expansion and contraction provisions; these provisions allowed the selective increase and decrease of the lands and natural resources controlled by the agreement.

^{FN3}. See *supra* n. 1.

Expansion of the unit would extend the terms of the PBUA to additional lands. Expansion was generally thought to be desirable by both the state and the lessees because it allowed efficient administration under the existing agreement and efficient shared production with existing facilities. Expansion under the PBUA required that the "geologic condition" was met-that the additional lands contained a reservoir any portion of which was within the PBU.

40 P.3d 786, 151 Oil & Gas Rep. 317
(Cite as: 40 P.3d 786)

Contraction excluded nonproductive lands from the unit agreement. The threat of contraction was a stimulus for the lessee to discover oil and develop production into paying quantities or to lose the lease and the opportunity to discover and produce oil. The PBUA required that all lands not included in a participating area,^{FN4} or entitled to be included in a participating area, would be contracted out of the PBUA after ten years.

FN4. "Participating areas" are portions of the unit "reasonably known to be underlain by hydrocarbons and known or reasonably estimated ... to be capable of producing or contributing to production of hydrocarbons in paying quantities." 11 Alaska Administrative Code (AAC) 83.351(a) (1996).

The PBUA extended the original leases until April 1, 1987. Once production began, the terms of the PBUA would continue in force for so long as oil or gas was being produced in paying quantities.

Shortly after the PBU lessees began paying royalties based on their interpretation of the lease terms, the state sued the lessees. In *State v. Amerada Hess*,^{FN5} one issue was whether the lessees could deduct field costs when the state took its royalty in value. On motions for partial summary judgment, the superior court ruled that the lessees could not.^{FN6} It held further that the state could *789 take its royalty in kind only if the market value of the oil or gas exceeded the royalty in value because only then would taking the royalty in kind be "in the best interests of the state and for the maximum benefit of its people."

FN5. No. 77-847 Ci. (Alaska Super., 1st Dist., Juneau, complaint filed September 2, 1977).

FN6. No. 77-847 Ci. (Alaska Super., 1st Dist., Juneau, April 6, 1979).

This ruling apparently pleased neither the lessees nor the state, because soon after the ruling, the parties settled the dispute on terms that differed significantly from the court's partial summary judgment ruling. Under the 1980 Royalty Settlement Agreement, the state agreed to pay a field cost allowance for its PBU royalty whether in value or in kind. The field cost allowance was initially set at forty-two cents per barrel

but was to be adjusted annually based on the Producer Price Index. (By 1993 the cost had increased to seventy-nine cents per barrel.) The superior court approved the settlement and allowed it to supersede the court's previous ruling on the merits.

During the *Amerada Hess* litigation, the legislature amended AS 38.05.180(f) to make it clear that the lessees could not deduct field costs from the state's royalty share under the existing, standard-form state oil and gas leases.^{FN7} Subsequent leases expressly disallowed all field costs deductions. In addition, all but one of all unit agreements approved after 1978 disallowed field cost deductions.

FN7. See ch. 155, § 1, SLA 1978 (currently codified at AS 38.05.180(f)(2)); ch. 160, § 16, SLA 1978 (currently codified at AS 38.05.180(z)).

In early 1984 the director of the Division of Oil and Gas, acting for the commissioner of the Department of Natural Resources, allowed an expansion of the PBU. The director's decision was based on geological, royalty and rental, and public interest considerations. The director also conditioned the expansion on two changes to one of the affected leases.

In early 1985 the director approved an expansion of the Duck Island Unit and a corresponding contraction of the PBU. The director's decision again noted several factors: environmental costs and benefits of unitized development; geological characteristics of the reservoir; prior exploration activities; applicant's development plans; and the economic costs and benefits to the state.

In late 1985 BP acquired the oil and gas lease to the remaining portion of the yet-to-be-discovered Pt. McIntyre reservoir. Following the amended AS 38.05.180(f), the BP lease expressly disallowed all field costs deductions.

In late 1986 Exxon and Arco applied to defer contraction of the PBU for five years. They invoked a department regulation, 11 AAC 83.356(b),^{FN8} as authority to defer contraction, because the PBUA had no provisions for deferral of contraction. The lessees argued that a delay was justified by both the public interest criteria of 11 AAC 83.303^{FN9} *790 and geological considerations. In early 1987 the director

40 P.3d 786, 151 Oil & Gas Rep. 317
(Cite as: 40 P.3d 786)

granted a conditional deferral ^{FN10} of the PBU contraction. The parties now dispute the terms of this deferral and whether the lessees met the conditions.

FN8. 11 AAC 83.356(b) (1996) gives the department authority to delay contraction of unit under certain circumstances:

(b) 10 years after sustained unit production begins, the unit area must be contracted to include only those lands then included in an approved participating area and lands that facilitate production including the immediately adjacent lands necessary for secondary or tertiary recovery, pressure maintenance, reinjection, or cycling operations. The commissioner will, in the commissioner's discretion, after considering the provisions of 11 AAC 83.303, delay contraction of the unit area if the circumstances of a particular unit warrant. If any portion of a lease is included in the participating area, the portion of the lease outside the participating area will neither be severed nor will it continue to be subject to the terms and conditions of the unit. The portion of the lease outside the participating area will continue in full force and effect so long as production is allocated to the unitized portion of the lease and the lessee satisfies the remaining terms and conditions of the lease.

FN9. 11 AAC 83.303 (1996) states the criteria to consider in determining the public interest:

(a) The commissioner will approve a proposed unit agreement for state oil and gas leases if he makes a written finding that the agreement is necessary or advisable to protect the public interest considering the provisions of AS 38.05.180(p) and this section. The commissioner will approve a proposed unit agreement upon a written finding that it will

(1) promote conservation of all natural resources, including all or part of an oil or gas pool, field, or like area;

(2) promote the prevention of economic and physical waste; and

(3) provide for the protection of all parties of interest, including the state.

(b) In evaluating the above criteria, the commissioner will consider

(1) the environmental costs and benefits of unitized exploration or development;

(2) the geological and engineering characteristics of the potential hydrocarbon accumulation or reservoir proposed for unitization;

(3) prior exploration activities in the proposed unit area;

(4) the applicant's plans for exploration or development of the unit area;

(5) the economic costs and benefits to the state; and

(6) any other relevant factors, including measures to mitigate impacts identified above, the commissioner determines necessary or advisable to protect the public interest.

(c) The commissioner will consider the criteria in (a) and (b) of this section when evaluating each requested authorization or approval under 11 AAC 83.301-11 AAC 83.395, including

(1) an approval of a unit agreement;

(2) an extension or amendment of a unit agreement;

(3) a plan or amendment of a plan of exploration, development or operations;

(4) a participating area; or

(5) a proposed or revised production or

40 P.3d 786, 151 Oil & Gas Rep. 317
(Cite as: 40 P.3d 786)

cost allocation formula.

FN10. The director's decision stated in relevant part:

This approval is conditioned on the following terms:

(A) A well to delineate the hydrocarbon reserves underlying [ADL] 34626 and ADL 34627 must be drilled and completed prior to April 1, 1992; and

(B) A commitment by the lessees to drill a second well to delineate the hydrocarbon reserves underlying ADL ... 28297 and ADL 34624 must be made by April 1, 1992.

Should these leases not be included within an approved participating area on April 1, 1992, or should the required well not be completed or the commitment for the second well not secured by that date, ADLs 28297, 34624, 34626, and 34627 will be contracted out of the Prudhoe Bay Unit as of that date.

In January 1992 the lessees presented the department with their plans to seek deferral of contraction until September 1, 1993; they also sought expansion of the PBU to include the Pt. McIntyre reservoir. On February 28, 1992, the lessees asked the department for a second deferral pursuant to 11 AAC 83.356(b).

On March 25, 1992, the director stated that the department would "delay a decision on the contraction request" until it had the opportunity to review the additional well data. The lessees informed the department that, due to technical problems, they were unable to provide the department with the requested well data until September 1992. The department indicated that it would "further delay a decision to defer contraction of the Prudhoe Bay Unit ... until September 30, 1992." Continuing technical problems caused Arco to ask for a further postponement of its deadline to provide the well data. The department responded that it was "unwilling to delay a decision regarding the original deferral of contraction request beyond the

first quarter of 1993."

On March 1, 1993, the lessees requested that the department establish the Pt. McIntyre participating area. On March 18, 1993, the lessees petitioned the department to expand the PBU to include the Pt. McIntyre reservoir. The first sentence of that letter suggested that the authority to expand the PBU was based on the PBUA and the department's regulations: "Pursuant to the provisions of Section 5.3 and Section 9.1 of the Prudhoe Bay Unit Agreement and 11 AAC 83.351 and 11 AAC 83.356, ARCO Alaska, Inc., for itself and on behalf of Exxon Corporation and BP Exploration, Inc., hereby petitions the Department of Natural Resources to expand the boundaries of the Prudhoe Bay Unit ..." (Parentheticals omitted.)

On March 31, 1993, the lessees petitioned for further deferral of contraction of the PBU. By 1993, the lessees claimed to have spent more than \$287 million to develop the Pt. McIntyre and West Beach reservoirs for production.

In two separate decisions the director denied the lessees' requests to defer contraction and to expand the PBU.^{FN11} On April 14, 1993, the director denied the lessees' request *791 to defer contraction of the PBU. Because of the delays and based on the criteria of 11 AAC 83.303, the director contracted tracts 5, 6, 7, and 8 from the PBU effective April 1, 1993.

FN11. Exxon had asked that the department consider the expansion and contraction issues together. At one point, Exxon raised the issue of whether the director's refusal to consider the issues together was arbitrary and capricious. Because no further argument of this issue appears in Exxon's brief, we conclude that Exxon has waived the issue. See Martinson v. Arco Alaska, Inc., 989 P.2d 733, 737 (Alaska 1999).

On August 18, 1993, the director denied the expansion of the PBU. He applied 11 AAC 83.303 and considered factors including the environmental costs and benefits, the geological characteristics and previous exploration, the lessees' plans for development, and the economic costs and benefits to the state. A large portion of the decision focused on field costs.

The lessees appealed both decisions to the com-

40 P.3d 786, 151 Oil & Gas Rep. 317
(Cite as: 40 P.3d 786)

missioner.

The lessees negotiated with the director and developed an amended application to expand the PBU to include the Pt. McIntyre reservoir, which the director granted. In the amended application, BP and Arco withdrew their appeals of the director's contraction and expansion decisions and waived any right to a field cost deduction except for production attributable to the small portion of the Pt. McIntyre reservoir that underlay the original boundary of the PBU. Exxon did not agree to waive its rights to a field cost deduction on Pt. McIntyre production. However, Exxon did agree to forego the deduction pending the final resolution of the issue, subject to later recoupment from the department. The amended application expressly noted Exxon's right to appeal or commence litigation in the superior court and specifically limited Exxon's arguments on appeal. The parties dispute exactly what arguments Exxon waived by this agreement.

On November 12, 1993, the commissioner upheld the director's decision to contract the PBU. He initially focused on the lessees' substantial delays in developing tracts 5, 6, 7, and 8. The commissioner interpreted the director's actions prior to the director's decision to contract the PBU as delaying the decision to contract rather than granting a deferral of contraction. He found the authority to delay contraction under 11 AAC 83.356(b), which, he concluded, required him to consider the criteria specified in 11 AAC 83.303. The commissioner noted that unitization of the Pt. McIntyre leases was generally in the public interest, but the public interest in conservation of natural resources could be equally served by deferring contraction of the PBU or by contracting the PBU and forming a new unit that used the PBU's excess processing capacity. The commissioner then concluded that deferring contraction of the PBU was not in the public interest based on environmental costs and benefits, geological and engineering considerations, prior exploration activities, and economic costs and benefits to the state. Because the commissioner found that any deferral of the contraction was not in the public interest, he decided that the original request for deferral should have been denied and denied the deferral retroactive to April 2, 1992.

On December 2, 1994, the commissioner affirmed the director's denial of PBU expansion. He expressly did not adopt two points: that the state

would never allow a field cost deduction, and that PBU expansion should be denied in part because the state has paid more under the 1980 settlement than it ever intended to pay. He noted that, while under some circumstances a field cost deduction might be allowed, it depended on the public interest analysis. The commissioner also stated that using the state's discretionary powers to recoup perceived losses under prior agreements was not good public policy and expressly disclaimed reliance on this rationale for denying expansion of the PBU.

The commissioner specifically concluded that Exxon did not have an absolute right to expansion for two reasons. First, the geologic requirements of the PBUA were not met. The PBUA requires that any additional lands to be incorporated into the PBU contain a reservoir, any portion of which is within the PBU. No part of the Pt. McIntyre reservoir was within the PBU on March 18, 1993, because the contraction decision previously removed tracts 6, 7, and 8 from the PBU effective April 1, 1992. Second, the department had discretion to deny expansion of the PBU in the public interest according to state statute and the PBUA. In considering the public interest, the commissioner first generally stated "that the public interest with respect to non-economic and even some economic matters would be served at least as *792 well if not better by the creation of a new unit as it would by expansion of the PBU to include the [Pt. McIntyre reservoir]." He then specifically noted that the field cost allowance under the 1980 settlement exceeded Exxon's likely actual field costs and concluded that allowing Exxon to make a profit at the state's expense was not in the public interest. The commissioner also noted that the public interest favored treating Exxon like the other lessees of the Pt. McIntyre area, who were not permitted a field costs deduction.

Exxon appealed both of the commissioner's decisions. The appeals were consolidated before Superior Court Judge John E. Reese. On May 19, 1999, Judge Reese affirmed the commissioner's decision. Exxon appeals the following issues: (1) whether the department retained discretion under the PBUA to deny expansion of the PBU; (2) whether the department breached the PBUA by contracting the PBU; (3) whether the decision to deny expansion violated the 1980 settlement; (4) whether the department violated Exxon's constitutional rights; and (5) whether the department was equitably estopped from denying

40 P.3d 786, 151 Oil & Gas Rep. 317
(Cite as: 40 P.3d 786)

expansion or ordering contraction of the PBU.

III. STANDARD OF REVIEW

[1] When the superior court acts as an intermediate court, we directly review the administrative agency decision under consideration.^{FN12}

FN12. See *Handley v. State, Dep't of Revenue*, 838 P.2d 1231, 1233 (Alaska 1992).

[2][3][4] We apply a substitution of judgment standard of review for agency decisions on questions of law where no expertise is involved.^{FN13} Interpretation of a contract is a question of law that is not within the department's special expertise or skill. "Where ... there is no conflict in extrinsic evidence, the interpretation of contract is a question of law."^{FN14}

FN13. See *id.*

FN14. *Leisnoi, Inc. v. Stratman*, 956 P.2d 452, 454 (Alaska 1998).

[5][6] But when the finder of fact must determine the meaning of a contract based on extrinsic evidence that raises conflicting inferences, "our inquiry is limited to determining whether the trier of fact's choice of inferences is supported by substantial evidence."^{FN15} In this case, almost all of the extrinsic evidence raises conflicting inferences. Thus, we review the commissioner's choice of inferences for substantial evidentiary support.

FN15. *Zito v. Zito*, 969 P.2d 1144, 1147 n. 4 (Alaska 1998) (quoting *Wahl v. Wahl*, 945 P.2d 1229, 1232 n. 3 (Alaska 1997)).

IV. DISCUSSION

Exxon's arguments on appeal are based on one critical contention: that the PBUA abrogated the department's discretion to deny expansion and to order contraction of the PBU. Exxon's additional claims that the department breached the 1980 settlement, unconstitutionally impaired the PBUA contract, unconstitutionally worked a taking, and should be equitably estopped all derive from the department's exercise of discretion in making the contraction and expansion decisions. The state disputes Exxon's view that the PBUA destroyed its power over expansion and contraction. As discussed in greater detail below, our

conclusion that the department had the discretion to deny expansion of the PBU in the public interest and in accord with state law is dispositive of this matter.

A. *Exxon Did Not Waive the Argument that the Pt. McIntyre Reservoir Was Partially within the Boundaries of the PBU.*

As a preliminary matter, we address the state's contention that Exxon waived its right to make certain arguments on appeal. The state argues that in the amended application for PBU expansion Exxon agreed to present its position as if the geologic condition—that the Pt. McIntyre reservoir was at least partially within the boundaries of the PBU—was not met. Exxon argues that the state's interpretation*793 of the amended application is incorrect because it would render Exxon's express right to appeal meaningless, because Exxon can prevail on appeal only if it can prove that the geologic condition was met. Neither side disputes that a small portion of the Pt. McIntyre reservoir actually underlies the original PBU and thus meets the geologic condition.

The amended application for PBU expansion summarizes the parties' positions and agreement as follows:

Exxon disagrees with the State regarding their respective rights. To allow production of the Pt. McIntyre Participating Area to begin while preserving Exxon's rights and the State's rights, the Applicants propose the following procedure:

....

iii. Exxon may appeal to or commence litigation in (or both) the Alaska Superior Court, and/or may appeal to the Commissioner, to contend among other things that the Commissioner's Contraction Decision (assuming he affirms the Contraction Decision) and other DNR decisions concerning the Pt. McIntyre Participating Area and the Contracted Acreage^{FN16} were incorrect. Any such appeal or litigation is collectively referred to as the "Contest."

FN16. "Contracted Acreage" referred to tracts 5, 6, 7, and 8.

In the Contest, ... Exxon shall not challenge the legality of DNR's established procedures or

40 P.3d 786, 151 Oil & Gas Rep. 317
(Cite as: 40 P.3d 786)

DNR's power and authority to act and make decisions concerning the contraction or expansion of the PBU, the Pt. McIntyre Participating Area, or the Contracted Acreage, but may claim, for example, that the established procedures were not followed or that the DNR decisions or actions are not consistent with applicable law. Also, Exxon shall not claim that the DNR is disqualified from acting because the State could realize a gain as a result of the DNR's actions.

....

iv. Exxon must present its position in the Contest as if the Contracted Acreage were not in the PBU ... until Exxon obtains a final, non-appealable ruling that the Contracted Acreage should not have been contracted out of the PBU. If Exxon obtains such a ruling, it may use the ruling in presenting its position in the Contest. Exxon, however, shall not at any time ... argue or claim that it is entitled to field costs or any other costs or relief because ... the Pt. McIntyre Participating Area [is] in the PBU as a result of granting this Amended Application or the Production Application. Exxon recognizes and agrees that such an argument would be "bootstrapping."

....

vi. By filing this Amended Application and pursuing any relief permitted by it, Exxon does not waive any rights which it may have to field and other costs under the terms of the Pt. McIntyre Participating Area leases....

vii. All appellate rights of the State and Exxon, if any, are preserved.

The commissioner interpreted the "no bootstrapping" paragraph as a waiver of Exxon's argument that the geologic condition was met, because Exxon had to present its position as if tracts 5, 6, 7, and 8 were not in the PBU. If tracts 6, 7, and 8 are not in the PBU, the geologic condition cannot be met.

[7][8] We think the commissioner read the waiver too broadly for two reasons: first, the parties intended to preserve the status quo on the field costs issue while

simultaneously allowing development of the Pt. McIntyre reservoir; second, the state's interpretation eviscerates Exxon's right to appeal the field costs issue. Our goal when interpreting contracts is to "give effect to the reasonable expectations of the parties."^{FN17} The relevant section of the agreement begins with a statement of intent: "To allow production of the Pt. McIntyre Participating Area to begin while preserving Exxon's rights and *794 the State's rights." The express intent of the amended agreement was to avert an impasse by isolating the field costs issue for separate resolution on appeal.

FN17. *Stepanov v. Homer Elec. Ass'n*, 814 P.2d 731, 734 (Alaska 1991) (quoting *Mitford v. de Lasala*, 666 P.2d 1000, 1005 (Alaska 1983)).

Moreover, we have repeatedly noted that "[a] court should not interpret an agreement in a manner which would give meaning to one part of an agreement at the cost of annulling another part."^{FN18} Exxon expressly retained a right to "appeal to or commence litigation in (or both) the Alaska Superior Court." Interpreting the "no bootstrapping" paragraph as a general waiver of an argument required for Exxon to prevail on appeal effectively eliminates Exxon's right to appeal. Instead, we read the agreement to give Exxon a meaningful right of appeal while preserving the "no bootstrapping" provision. Accordingly, Exxon may argue in this appeal that the geologic condition was met because the facts so indicate but not because the state approved the amended application for expansion.

FN18. *Betz v. Chena Hot Springs Group*, 657 P.2d 831, 835 (Alaska 1982); see also *Earth Movers, Inc. v. State, Dep't of Transp. & Pub. Facilities*, 824 P.2d 715, 717-18 (Alaska 1992) (interpreting contract based on document as a whole).

B. The Department of Natural Resources Has the Authority to Deny Expansion of the PBU Under the PBUA.

While the parties dispute numerous aspects of the expansion and contraction decisions,^{FN19} we find one issue dispositive-whether the department had the authority to consider the state's best interests in making a decision on expansion of the PBU.

40 P.3d 786, 151 Oil & Gas Rep. 317
(Cite as: 40 P.3d 786)

FN19. Concerning the contraction decision, for example, the parties dispute: the meaning of the PBUA text; whether the director's amended 1987 deferral superceded the PBUA contraction provisions; whether the lessees met the conditions of the 1987 deferral; and whether the director granted a second deferral.

Exxon argues that the department has no discretion to determine unit expansion; rather, Article 9 of the PBUA controls. Exxon interprets the PBUA to give itself a unilateral right to expand the PBU so long as the lands to be added contained a reservoir that was partially within the PBU. If this "geologic condition" was met, Exxon argues, the department had no discretion to deny expansion.

The state argues that the department has discretion to consider the public interest when deciding to expand the PBU under the PBUA and department regulations.

We first consider the text of the PBUA. We then look at extrinsic evidence.

1. *The text of the PBUA*

Article 9.1 of the PBUA discusses possible expansion of the PBU:

The Unit Area may be enlarged from time to time so as to include any additional lands reasonably determined to be within any Reservoir any portion of which is within the Unit Area. The lands to be included shall be based on such subdivisions of the public land surveys as may be approved by the Director, but not less than the area approved by the well-spacing order affecting such lands for such Reservoir....

Exxon argues that the first sentence indicates that Exxon may enlarge the unit area, so long as the additional lands meet the condition. The state argues that the first sentence is ambiguous, but the rest of the PBUA indicates that the department has the power to expand the PBU.

The state is correct that the language is ambiguous. The passive voice can be ambiguous.^{FN20} The text alone does not indicate whether Exxon or the de-

partment has the authority to expand the PBU. However, the subsections following the contested statement help to clarify it. Subsections (a) through (d) indicate the process for expansion of the PBU. The final step indicates that "after due consideration of all pertinent information, the Director shall render his decision." This text, and the absence of text *795 indicating that Exxon was meant to have the right to expand, strongly favors the state's interpretation that the director has the authority to decide expansion of the PBU.

FN20. See *Plate v. State*, 925 P.2d 1057, 1065 (Alaska App.1996) (finding evidence rule in passive voice ambiguous and resolving ambiguity by resort to commentary to rules); see also *E.I. du Pont de Nemours and Co. v. Train*, 430 U.S. 112, 128, 97 S.Ct. 965, 51 L.Ed.2d 204 (1977) (resorting to other portions of federal statute to resolve ambiguous passive language).

Both sides argue that the use of the permissive "may" supports their interpretation. Exxon argues that the permissive had to be used to preserve Exxon's option of expansion. If the mandatory "shall" was used, Exxon would have been required to expand the PBU if the condition was met.

The state contends that use of the permissive indicates the department's discretion. The state notes that in four other articles of the PBUA, Articles 4.4, 5.4, 16.4, and 18.1, when the agreement intended to create a right that could be exercised by the lessees, it used the language "shall have the right" or "shall be entitled to."

[9][10] The state's interpretation is the most logical. In interpreting a contract, courts should "interpret the contract in a manner that makes the contract internally consistent."^{FN21} Exxon's interpretation that Article 9.1 creates a right to expansion with the language "may" conflicts with other portions of the PBUA that use "shall have the right" or "shall be entitled to" to create a lessees' right.

FN21. *Brobeck, Phleger, & Harrison v. Telex Corp.*, 602 F.2d 866, 872 (9th Cir.1979).

Finally, the state notes that Article 12.1 of the

40 P.3d 786, 151 Oil & Gas Rep. 317
(Cite as: 40 P.3d 786)

PBUA expressly indicates that the PBUA “shall be subject to all valid applicable federal and state laws, rules, regulations and orders.” Former 11 AAC 83.340 and former 11 AAC 83.345, state regulations in effect at the time the parties entered the PBUA, required the director's approval, based on a determination of necessity or advisability in the public interest, for a modification of an approved unit agreement.^{FN22} Accordingly, the state argues that the PBUA required the director's approval for any modification of the agreement. Exxon has no response to this. This express statement also favors the state's interpretation that the department has discretion to deny expansion of the PBU. In sum, the text of the PBUA strongly indicates that the department had discretion to deny expansion as specified by its own regulations.

FN22. Former 11 AAC 83.345 (eff. 9/20/74) provided:

Any modification of an approved unit agreement is subject to the director's approval in the same manner and upon the same determination as the original unit agreement.

Former 11 AAC 83.340 (eff. 9/20/74) provided in relevant part:

A unit agreement will be approved by the director if he determines that the agreement is necessary or advisable in the public interest, is for the purpose of more properly conserving natural resources, and adequately protects all parties in interest including Alaska.

2. Extrinsic evidence

Extrinsic evidence provides substantial support for the commissioner's decision. The parties' course of performance of the PBUA and the existence of departmental regulations that are inconsistent with Exxon's view of the PBUA strongly support the conclusion that the department had discretion to deny expansion of the PBU.

a. Exxon's and the department's course of performance

The state argues that Exxon's and the department's course of performance of the PBUA shows that Exxon understood that the department retained dis-

cretion. Exxon offers no argument in response.

[11] The conduct of the parties is properly considered as evidence of the parties' intent.^{FN23} In the course of performance of the PBUA, Exxon has previously requested contraction of the PBU and corresponding expansion of another unit. Exxon's application for the change in the PBU requested the director's approval under provisions including 11 AAC 83.301-.395 and argued that the change was in “the public interest in accordance with AS 38.05.180(p) and 11 AAC 83.303.” Exxon has also requested expansion of the PBU and contraction of another unit. In both cases, the director's decisions to grant the change included an analysis of the best interests factors listed in 11 AAC 83.303.

FN23. See, e.g., *Peterson v. Wirum*, 625 P.2d 866, 872-74 (Alaska 1981).

*796 Furthermore, Exxon's application for the Pt. McIntyre expansion—the denial of which forms the main issue here—requested the director to expand the PBU “pursuant to the provisions of Section 5.3 and Section 9.1 of the [PBUA] and 11 AAC 83.351 and 11 AAC 83.356.” The application expressly noted that the expansion “meets the criteria of 11 AAC 83.303” and listed three reasons. Exxon's and the department's prior course of performance of the PBUA contradicts Exxon's current position and strongly indicates that the department had discretion to deny expansion.

b. The department's inability to contract around its regulations

[12] Exxon argues that the department's own regulations allow the department to enter contracts that differ from existing regulations and provide that later-enacted regulations will not apply to preexisting contracts.^{FN24} It also notes that the department has no statutory authority to alter a unit agreement without consent by the contracting parties.^{FN25} Exxon claims that it drafted the PBUA to eliminate the department's discretion. Why, Exxon asks, would it draft an agreement that simply restates the department's regulations?

FN24. See 11 AAC 83.301(b) (1996) (“[The unitization regulations] apply to an existing oil and gas lease or approved unit agreement where not inconsistent with the lease or unit agreement or regulations in effect on the ef-

40 P.3d 786, 151 Oil & Gas Rep. 317
(Cite as: 40 P.3d 786)

fective date of the lease or unit agreement.”).

FN25. See AS 38.05.180(p) (“The commissioner may, with the consent of the holders of leases involved, establish, change or revoke drilling, producing, and royalty requirements of the leases and adopt regulations with reference to the leases, with like consent on the part of the lessees, in connection with the institution and operation of a cooperative or unit plan as the commissioner determines necessary or proper to secure the proper protection of the public interest.”).

We disagree with Exxon's first contention—that the department can agree to contract terms that violate its regulations. The only authority cited for this proposition is 11 AAC 83.301(b), which states that the department's regulations “apply to an existing oil and gas lease or approved unit agreement where not inconsistent with the lease or unit agreement or regulations in effect on the effective date of the lease or unit agreement.” This merely applies the department's later-enacted regulations as default rules to existing leases or unit agreements when there is no conflict.

Subsection .301(b) does not make existing department regulations inapplicable to new unit agreements. Former 11 AAC 83.340 and .345 existed before the approval of the PBUA. Former section .345 stated that “[a]ny modification of an approved unit agreement is subject to the director's approval in the same manner and upon the same determination as the original unit agreement.”^{FN26} Former section .340 required that “[a] unit agreement will be approved by the director if he determines that the agreement is necessary or advisable in the public interest, is for the purpose of more properly conserving natural resources, and adequately protects all parties in interest including Alaska.”^{FN27} Thus, 11 AAC 83.301(b) does not affect the applicability of the best interests analysis for expansions of the PBUA according to former 11 AAC 83.340 and .345.^{FN28}

FN26. Former 11 AAC 83.345 (eff. 9/20/74).

FN27. Former 11 AAC 83.340 (eff. 9/20/74).

FN28. When the department repealed 11 AAC 83.340 and .345 on June 28, 1981, the department adopted 11 AAC 83.303, which

contained a similar (but more detailed) consideration of “the public interest” in approving changes to unit agreements. 11 AAC 83.303 (1996).

Moreover, 11 AAC 83.301(b) does not confer authority for the converse: to contract outside of the department's regulations. To allow such activity would be arbitrary; parties contracting with the department would not be held to the same regulations that non-contracting parties were required to comply with. And the department should never need to contract in violation of its own regulations, because it has the authority to change its regulations so long as the new regulation has a reasonable basis and is within the scope of the legislature's delegation of power to the department.^{FN29} Because we conclude*797 that 11 AAC 83.301(b) does not allow the department to contract outside of its regulations, Exxon's argument that the department contracted away its regulatory discretion fails.

FN29. See *United Steelworkers of America Local Union 14534 v. NLRB*, 983 F.2d 240, 244-45 (D.C.Cir.1993) (“An agency may alter its interpretation of substantive law so long as its new interpretation does not conflict with the statute, and so long as the agency supplies a ‘reasoned analysis’ for ‘changing its course.’” (citation omitted)).

In sum, the text of the PBUA and the extrinsic evidence support the conclusion that the department had discretion to deny expansion. The department did not, and could not, contract away its discretion to consider the state's best interests in approving expansions of the PBUA. Exxon did not have a unilateral right to expansion under the PBUA.

C. The Commissioner's Decision To Deny Expansion Because of the Excessive Field Cost Allowance Did Not Violate the 1980 Royalty Settlement Agreement.

Exxon argues that the department's failure to expand the PBUA violated the 1980 settlement because the 1980 settlement's resolution of field costs expressly applied to all lands covered by the PBUA “and, in addition, all other land to which the [PBUA] may hereafter be extended as therein provided.”

Exxon's argument is premised on its interpretation of the PBUA that Exxon had a unilateral right to

40 P.3d 786, 151 Oil & Gas Rep. 317
(Cite as: 40 P.3d 786)

expand the PBU if the geologic condition was met. If the department had the discretionary authority to deny expansion, Exxon had no right to force application of the 1980 settlement to lands outside the PBU, and the argument fails. Consistent with our previous conclusion that Exxon had no unilateral right to expansion of the PBU, we conclude that the commissioner did not breach the 1980 settlement.

Exxon argues further that the department breached the implied covenant of good faith and fair dealing of the 1980 settlement because the department's failure to allow expansion deprived Exxon of the benefit of its bargain and rendered the settlement a nullity. Exxon argues that for the commissioner to decide as he did "*solely because these [field cost] deductions will apply*" deprives it of the benefit it bargained for in the 1980 settlement. (Emphasis in original.) But the commissioner's decision does not support Exxon's argument that was denied solely because field cost deductions applied. The commissioner first stated "that the public interest with respect to non-economic and even some economic matters would be served at least as well if not better by the creation of a new unit as it would by expansion of the PBU to include the [Pt. McIntyre reservoir]." The commissioner expressly disclaimed both that field costs would never be allowed and that the amount paid under the 1980 settlement was a permissible consideration. Rather, the commissioner appeared to be concerned that Exxon would unfairly profit by overcharging field costs. According to his calculations, Exxon's actual field cost expenses were in the range of six to seventeen cents per barrel, far less than the seventy-nine cents per barrel allowed by the 1980 Royalty Settlement Agreement. The commissioner requested that Exxon justify the magnitude of the field cost, but Exxon did not respond. Presumably, if Exxon could show special production costs that warranted the substantial field costs, a deduction may have been allowed. The commissioner also noted the unfairness of allowing Exxon, but not other similarly situated lessees, a field cost deduction. The commissioner did not deny PBU expansion solely because the field costs would apply.

[13] Exxon also argues that the department's consideration of field costs in the denial of expansion rendered the 1980 settlement a nullity. If the 1980 settlement only concerned field costs deductions for production from expansions of the PBU, the problems

of illusory contracts and lack of consideration might arise as Exxon argues. But the 1980 settlement applies primarily to existing PBU production, and Exxon has enjoyed a substantial and continuing benefit from the 1980 settlement—a field cost deduction of seventy-nine cents per barrel of oil produced from the PBU. Exxon's claim that "no rational settling party would agree" to the 1980 settlement if its field cost allowance *798 were limited to the existing PBU is quite unpersuasive given the facts that the legislature expressly declared that paying field costs was not in the best interests of the state,^{FN30} that most unit agreements did not allow for field costs deductions,^{FN31} and that Exxon's co-lessees for the disputed tracts waived their rights to any field cost deductions. Accordingly, we conclude that the department breached neither the express terms of the 1980 settlement nor its implied covenant of good faith and fair dealing by exercising discretion to consider the public interest in denying expansion of the PBU.

^{FN30}. See AS 38.05.180(f)(2) (enacted 1978).

^{FN31}. The department allowed field cost deductions for the Duck Island Unit ("Endicott"), signed before the 1980 Settlement, and the Kuparuk River Unit. All other unit agreements did not allow field cost deductions. See, e.g., the Milne Point Unit; the North Star Unit; and the Thetis Island Unit.

D. The State Did Not Violate Exxon's Constitutional Rights.

Exxon argues that the department's regulations unconstitutionally impair the obligations of contracts. This argument is premised on its interpretation of the PBUA. Because the department bargained away its discretion to change the PBU in the PBUA, Exxon argues, applying regulations that reinstate that discretion impairs the PBUA.

In addition, Exxon argues that the department's requirement that Exxon waive its right to field cost deductions under the PBUA for Pt. McIntyre production is an unconstitutional taking. Again, this argument is premised on Exxon's interpretation of the PBUA. For there to be a taking, Exxon must have a property interest in the field cost deduction for production from lands that may be added to the PBU.^{FN32} In turn, this requires that Exxon have a right to ex-

40 P.3d 786, 151 Oil & Gas Rep. 317
(Cite as: 40 P.3d 786)

pansion of the PBU to include these lands.

FN32. See *Bowen v. Public Agencies Opposed to Soc. Security Entrapment*, 477 U.S. 41, 55-56, 106 S.Ct. 2390, 91 L.Ed.2d 35 (1986).

The state argues simply that the department did not violate any of Exxon's contractual rights because the department has discretion to deny expansion and order contraction under the PBUA. First, because the department did not bargain away its discretion to change the PBU, it has not impaired the contract by using its discretion to deny the changes to the PBU. Second, Exxon has no right to expansion under the PBUA; thus, it has no property right in a field cost deduction from lands that only might be added to the PBU.

[14] As we determined previously, the state has the discretionary authority under the PBUA to approve changes to the PBU. Exxon's constitutional arguments therefore fail.

E. The Department Is Not Equitably Estopped from Denying Expansion or Ordering Contraction of the PBU.

Exxon argues that the state should be estopped from ordering contraction and denying expansion of the PBU because Exxon detrimentally relied upon the department's alleged agreement in the PBUA to expand and contract the PBU based solely on geologic factors and without exercise of its discretion. The state argues that the commissioner found the evidence insufficient to establish estoppel and that his finding is supported by substantial evidence.

We have stated that estoppel may apply against the government and in favor of a private party if four elements are present: "(1) the governmental body asserts a position by conduct or words; (2) the private party acts in reasonable reliance thereon; (3) the private party suffers resulting prejudice; and (4) the estoppel serves the interest of justice so as to limit public injury." ^{FN33} Whether estoppel applies in any given situation is a legal conclusion. ^{FN34}

FN33. *Crum v. Stalnaker*, 936 P.2d 1254, 1256 (Alaska 1997).

FN34. See *id.* at 1258 ("We determine that the Board erred in its legal conclusion that equitable estoppel is unavailable under the facts of this case.").

[15] Like Exxon's constitutional arguments, its estoppel argument hinges on its interpretation of the PBUA. Because we conclude that the department has discretion *799 under the PBUA, Exxon has not been prejudiced by the department's use of its discretion to deny the expansion to the PBU. Thus, estoppel does not apply here.

V. CONCLUSION

The commissioner had discretionary authority to deny expansion of the PBU. For that reason, and because the decision to deny expansion did not violate the 1980 Royalty Settlement Agreement, the decision did not violate Exxon's constitutional rights, and the department was not equitably estopped from making that decision, we AFFIRM in all respects.

APPENDIX "A"

<- Image not available via Offline Print ->

Alaska,2001.
Exxon Corp. v. State
40 P.3d 786, 151 Oil & Gas Rep. 317

END OF DOCUMENT

IN THE SUPERIOR COURT FOR THE STATE OF ALASKA
THIRD JUDICIAL DISTRICT AT ANCHORAGE

EXXON MOBIL CORPORATION,)
Operator of the Point Thomson Unit;)
BP Exploration (Alaska) Inc.;)
Chevron U.S.A., Inc.; and)Case No. 3AN-06-13751 CI
ConocoPhillips Alaska, Inc.,) (Consolidated)
)Case No. 3AN-06-13760 CI
)Case No. 3AN-06-13773 CI
Appellants,)Case No. 3AN-06-13799 CI
)Case No. 3AN-07-04634 CI
v.)Case No. 3AN-07-04620 CI
)Case No. 3AN-07-04621 CI
STATE OF ALASKA, Department of)
Natural Resources,)
)
Appellee.)

DECISION ON APPEAL

This case is before the superior court in its capacity as an appellate court on appeal from administrative determinations by the Department of Natural Resources (DNR) with respect to the Point Thomson Unit Agreement. See AS 22.10.020(d).

Factual and Procedural Background

In 1977, the Point Thomson Unit Agreement (PTUA) was entered into between Exxon (now ExxonMobil) and the Commissioner of the Department of Natural Resources for the State of Alaska for the purpose of facilitating the production of oil and gas at Point Thomson. [R. 1253-1271] ExxonMobil, which holds the largest percentage of leasehold interests at Point Thomson, is

identified in the PTUA as the Unit Operator. The other appellants in this action all have leasehold interests within the unit.

The following paragraphs of the unit agreement are particularly relevant to this appeal:

1. **ENABLING ACT AND REGULATIONS.** The Alaska Land Act (AS 38.05.005--370) and all valid and pertinent oil and gas statutes and regulations including the oil and gas operating statutes and regulations in effect as of the effective date hereof or hereafter issued thereunder governing drilling and producing operations, not inconsistent with the terms hereof or the laws of the State of Alaska, are hereby accepted and made a part of this agreement.

...

10. **PLAN OF FURTHER DEVELOPMENT AND OPERATION.** Within six months after completion of a well capable of producing unitized substances in paying quantities, the Unit Operator shall submit for the approval of the Director an acceptable plan of development and operation for the unitized land which, when approved by the Director, shall constitute the further drilling and operating obligations of the Unit Operator under this agreement for the period specified therein. Thereafter, from time to time before the expiration of any existing plan, the Unit Operator shall submit for the approval of the Director a plan for an additional specified period for the development and operation of the unitized land. The Unit Operator expressly covenants to develop the unit area as a reasonably prudent operator in a reasonably prudent manner.

Any plan submitted pursuant to this section shall provide for the exploration of the unitized area and for the diligent drilling necessary for determination of the area or areas thereof capable of producing unitized substances in paying quantities in each and every productive formation and shall be as complete and adequate as the Director may determine to be necessary for timely development and proper conservation of the oil and gas resources of the unitized areas, and shall:

- (a) specify the number and location of any wells to be drilled and the proposed order and time for such drilling; and,
- (b) to the extent practicable, specify the operating practices regarded as necessary and advisable for the proper conservation of natural resources. ...

Said plan or plans shall be modified or supplemented when necessary to meet changed conditions, or to protect the interests of all parties to this agreement. Reasonable diligence shall be exercised in complying with the obligations of the approved plan of development. ...

16. CONSERVATION. Operations hereunder and production of unitized substances shall be conducted to provide for the most economical and efficient recovery of said substances without waste, as defined by or pursuant to state law or regulation.

...

20. EFFECTIVE DATE AND TERM. This agreement shall become effective upon approval by the Commissioner or his duly authorized representative as of the date of approval by the Commissioner and shall terminate five (5) years from said effective date unless:

- (a) such date of expiration is extended by the Commissioner, or
- (b) it is reasonably determined prior to the expiration of the fixed term or any extension thereof that the unitized land is incapable of production of unitized substances in paying quantities in the formations tested hereunder ... or
- (c) a valuable discovery of unitized substances has been made or accepted on unitized land during said initial term or any extension thereof, in which event the agreement shall remain in effect for such term and so long as unitized substances can be produced in quantities sufficient to pay for the cost of producing same from wells on unitized land ~~within any participating area established hereunder~~ and, should production cease, so long thereafter as diligent operations are in progress for the restoration of production or discovery of new production and so long thereafter as the unitized substances so discovered can be produced as aforesaid ...

21. RATE OF PROSPECTING, DEVELOPMENT AND PRODUCTION. The Director is hereby vested with authority to alter or modify from time to time in his discretion the quantity and rate of production under this agreement when such quantity and rate is not fixed pursuant to state law or does not conform to any statewide voluntary conservation or allocation program which is established, recognized and generally adhered to by the majority of operators in such state, such authority being hereby limited to alternation [sic] or modification in the public interest, the purpose thereof and the public interest to be served thereby to be stated in the order of alternation or modification. Without regard to the foregoing, the Director is also hereby vested with

authority to alter or modify from time to time at his discretion the rate of prospecting and development and the quantity and rate of production under this agreement when such alternation or modification is in the interest of attaining the conservation objectives stated in this agreement and is not in violation of any applicable state law.

Powers in this section vested in the Director shall only be exercised after notice to Unit Operator and opportunity for hearing to be held not less than ~~fifteen (15)~~ *thirty (30)* days from notice, *and shall not be exercised in a manner that would (i) require any increase in the rate of prospecting, development or production in excess of that required under good faith and diligent oil and gas engineering and production practices; or (ii) alter or modify the rates of production from the rates provided in the approved plan of development and operations then in effect or, in any case, curtail rates of production to an unreasonable extent, considering unit productive capacity, transportation facilities available, and conservation objectives; or (iii) prevent this agreement from serving its purpose of adequately protecting all parties in interest hereunder, subject to applicable conservation laws and regulations.*

The language that is struck out in Sections 20 and 21 above was deleted, and the italicized language in Section 21 was added in 1985 amendments to the PTUA. [R. 794, 1253-1268, 9448]

As set forth in Section 1 of the unit agreement, the regulations in effect at the time of the agreement's inception were "accepted and made a part of [the unit] agreement." *See also Exxon Corp. v. State*, 40 P.3d 786 (Alaska 2001).

Three of those regulations have particular bearing on this case.

Former 11 AAC.83.315 provided as follows:

RATES OF PROSPECTING AND PRODUCTION. The director [of the former State Division of Lands] may require that any unit agreement contain a provision vesting authority in the director or other person, committee, or agency as may be designated in the agreement and satisfactory to the director, to alter or modify from time to time the rate of prospecting and development and the quantity and rate of production under the agreement.

Former 11 AAC 83.340 provided in relevant part as follows:

APPROVAL OF UNIT AGREEMENT. A unit agreement will be approved by the director if he determines that the agreement is necessary or advisable in the public interest, is for the purpose of more properly conserving natural resources, and adequately protects all parties in interest including Alaska ...

Former 11 AAC 83.345 provided as follows:

MODIFICATION OF UNIT AGREEMENTS. Any modification of an approved unit agreement is subject to the director's approval in the same manner and upon the same determination as the original agreement.

In addition to the above-quoted regulations, there was also a chapter of procedural regulations that were in effect in 1977 that applied to unit agreements. This chapter, entitled "Practice and Procedure," applied to several other chapters of the natural resources regulations, including the unitization chapter. It contained several provisions regarding administrative adjudications, including a provision for judicial appeals to the superior court of administrative decisions and actions.¹ But these former regulations did not contain any provision that required or authorized a unit termination or default action to be initiated by judicial proceedings. Former 11 AAC 88.100 – .185 (Eff. 9/20/74)

There are two subsections of the Alaska Land Act as it was in effect in 1977 that relate to unit agreements:

Former AS 38.05.180(m) provided as follows:

To conserve the natural resources of all or a part of an oil or gas pool, field, or like area, (whether or not the part is then subject to a cooperative or unit plan of development or operation), lessees and their representatives may unite with each other, or jointly or separately with others, in collectively adopting or operating under a

¹ Former 11 AAC 88.160 (Eff. 9/20/74).

cooperative or a unit plan of development or operation of the pool, field, or like area, or a part of it, whenever determined and certified by the commissioner to be necessary or advisable in the public interest. The commissioner may, with the consent of the holders of the leases involved, establish, alter, change, or revoke drilling, producing, rental minimum royalty, and royalty requirements of the leases and make regulations with reference to the leases, with like consent on the part of the lessees, in connection with the institution and operation of a cooperative or unit plan as he determines necessary or proper to secure the proper protection of the public interest. The commissioner may provide that oil and gas leases issued under this section shall contain a provision requiring the lessee to operate under a reasonable cooperative or unit plan, and he may prescribe a plan under which the lessee shall operate. The plan shall adequately protect all parties in interest, including the state.

Former AS 38.05.180(n) provided in relevant part as follows:

A plan authorized by (m) of this section, which includes lands owned by the state, may contain a provision vesting the commissioner, or a person, committee, or state agency with authority to alter or modify from time to time the rate of prospecting and development and the quantity and rate of production under the plan ...

The Alaska Land Act also accords broad authority to the Commissioner of the Department of Natural Resources. Specifically, AS 38.05.020 provides that “[t]he commissioner may establish reasonable procedures and adopt reasonable regulations necessary to carry out this chapter,” and the commissioner may “exercise the powers and do the acts necessary to carry out the provisions and objectives of this chapter.” These statutory provisions were in effect in 1977 and remain in effect today.

Overlying the entire statutory and regulatory construct is Article VIII, Section 2 of the Alaska Constitution, which provides, “[t]he legislature shall

provide for the utilization, development and conservation of all natural resources belonging to the State, including land and waters, for the maximum benefit of its people.”

Several current regulations have been discussed by the parties extensively in this appeal, including 11 AAC 83.303; 11 AAC 83.336; 11 AAC 83.361; and 11 AAC 83.374. None of these regulations was in effect when the PTUA became effective in 1977. They were all originally adopted in 1981.

The history of the Point Thomson Unit has been thoroughly set out in the record before this court, including in the decisions issued at the administrative level. [See, e.g., R. 629-635] Since the unit’s formation in 1977, eighteen exploration wells have been drilled within and around the PTU. At the request of the Unit Operator, the Division of Oil and Gas of the Department of Natural Resources (Division) certified seven wells within the PTU as capable of producing hydrocarbons in paying quantities. [R. 640] With one exception, all of those certifications were issued, and the wells all then abandoned, prior to 1987. [R. 5681] The last well was certified in 1994 and abandoned the following day. [Id.]²

The PTU Lessees are required to submit Plans of Development (PODs) at specified intervals to the Division that set out their development plans for the unit. The current controversy arises from the Department of Natural Resources’

² However, the certification letter for the last well dated April 26, 1994 indicated, “It should be noted, however, that the well is not capable of producing in paying quantities as that phrase is defined in section 9 of the Point Thomson Unit Agreement.” [R. 5681]

refusal to approve the Lessees' proposed 22nd Plan of Development for the Point Thomson Unit. [R. 1966-1976] The Division rejected the Lessees' first proposed 22nd Plan of Development in a decision dated September 30, 2005. [R. 12282] That proposed 22nd Plan, as described by the Division, conditioned PTU development on amending the State's existing tax and royalty structure and construction of a North Slope gas pipeline. [R. 12297] The Division found "the current PTU Owners have had the leases for far beyond their primary term, and their conclusion today is simply that they cannot make enough money to justify development. It is time for the PTU Owners to develop and produce or give new lessees ... a chance to develop the known hydrocarbon resources within the PTU." [R. 12303] That initial decision held that "[f]ailure to submit an acceptable plan of development is grounds for termination of the PTU." [R. 12305] The initial decision then referenced Section 21 of the PTUA, and held that "the PTU Operator shall commence development operations within the PTU by October 1, 2007. The PTU Owners shall have an opportunity for hearing regarding this notice to modify the rate of PTU development." [*id.*] The initial decision also required that "the PTU Operator shall begin commercial production of unitized substances from the PTU by October 1, 2009." [R. 12304]

Shortly after the issuance of the September 2005 decision, the Division issued an Amended Decision on October 27, 2005. [R. 12282] The Amended Decision removed all references to Section 21 of the PTUA, because, according to the Amended Decision, that section does "not apply to the Division's

evaluation of the Unit Operator's proposed plans for development of the Point Thomson Unit." [*Id.*]³ The Amended Decision of October 2005 accorded the Unit Operator 90 days within which to submit an acceptable POD. The Amended Decision also modified the initial decision to provide that the development and production deadlines previously specified in the initial decision were "*an example of an acceptable PTU plan of development.*" [R. 12304; emphasis added] The Amended Decision eliminated the reference to the opportunity for a hearing regarding the proposed modification of the rate of PTU development. [R. 12305] But the Amended Decision retained the language from the initial decision that "[f]ailure to submit an acceptable plan of development is grounds for termination of the PTU." [R.12305]

The initial decision and the Division's Amended Decision of October 2005 both noted that the Division had certified seven wells on the unit as capable of producing hydrocarbons in paying quantities. [R. 12295] Nothing in either the initial decision or the Amended Decision of the Division purported to decertify those wells. To the contrary, the Division's Amended Decision stated, "the PTU contains wells certified as capable of production in paying quantities." [R. 12302]

The Division's October 2005 Amended Decision recognized that negotiations between State representatives and some of the PTU Lessees for

³ See also State's Br. at 49, n. 56. There, the State asserts that Section 21 "relates to the Director's authority to change the rate of prospecting and development once Lessees are operating under an approved POD," and is not applicable with respect to the approval of the POD itself, which the State asserts is governed solely by Section 10 of the PTUA. *But see* Section 21 as amended, paragraph 2, and the reference there excluding applicability of portions of that section to approved plans of development. [R. 794]

the construction of a gas pipeline were ongoing at that time, but clearly indicated that such negotiations would not serve as a basis to delay PTU development: "At this point in time, the PTU Owners do not control if or when a North Slope gas pipeline will ever be operational. Reliance on third parties, beyond the control of the PTU Owners, is not grounds for the delay of PTU development and production." [R. 642]

The ninety-day deadline for submission of an acceptable modified 22nd POD was extended by the Division until October 20, 2006, during which time negotiations continued with respect to the development of a gas pipeline. The resultant proposed Fiscal Contract for a gas pipeline included certain provisions dealing with the PTU. Specifically, the proposed Fiscal Contract provided that if certain PTU Lessees undertook designated actions with respect to the development of a gas pipeline, the State agreed not to terminate the PTU. [App. 125]

In May 2006, the proposed Fiscal Contract was submitted to the Alaska Legislature for its consideration as required by the Stranded Gas Development Act. [App. 125] On October 18, 2006, while the Fiscal Contract was still under legislative consideration, ExxonMobil submitted a modified 22nd POD to the Commissioner. [R. 3089-3105] The modified 22nd POD did not propose to put the unit into production by 2009, a commitment that had been delineated by the Division as a component of an acceptable plan of development in the Division's Amended Decision of October 2005. [R. 667] The Lessees have asserted that

the modified 22nd POD was consistent with the terms of the proposed Fiscal Contract. [App. 126] However, the Fiscal Contract had not been approved by the Legislature at that time, and indeed, has not ever been approved by the Legislature.

Oral argument before the Commissioner on the modified proposed 22nd POD was held on November 20, 2006. No participant requested an evidentiary hearing. However, approximately 5,000 pages of documents regarding the modified proposed POD were submitted to the Commissioner prior to the November 2006 hearing. [R. 5672]

The Commissioner issued a Decision on Appeal on November 27, 2006. [R. 5670-5689] As summarized in the decision itself, the Decision on Appeal:

(1) denies the request for modification of the 2001 Expansion Agreement, as amended, which affects only the expansion leases; (2) affirms the Director's Decision in all respects to the extent it is consistent with this Commissioner's Decision, but the Director's Decision is disapproved to the extent that it can be read to mean the PTU contains certified wells; (3) adopts and incorporates into the Commissioner's Decision the findings and rationale of the Director's Decision as modified by this Decision; (4) rejects the cure or revised 22nd PTU POD submitted by the Lessees on October 18, 2006; and (5) terminates the PTU.

[R. 5671]

The Commissioner rejected the Lessees' contention that the modified proposed 22nd POD should be evaluated pursuant to the Reasonably Prudent Operator Standard. He characterized the "lessees' appeal [as] based on the premise that they do not have to produce because a Reasonably Prudent Operator would not produce." [R. 5684] The Commissioner acknowledged that

Section 10 of the PTUA included a covenant by the Lessees to “develop the unit area as a reasonably prudent operator in a reasonably prudent manner.” But he added, “Section 10 says much more.” [i.d.] He noted the PTU was not in production even though “massive PTU reserves were found in the early 1980s.”

[R. 5686] Then he added,

I specifically find that the Reasonably Prudent Operator standard does not apply to this Commissioner's Decision involving a long standing unit with leases far beyond their primary term and Lessees which unambiguously refuse to adequately explore, delineate, or produce massive known hydrocarbon reserves. The Reasonably Prudent Operator language of section 10 of the unit agreement does not supersede the other provisions of that section, or the applicable statutes, regulations or leases. Section 10 contains significant detail on what an acceptable POD must contain and the Director's Decision asked the Lessees to comply. Instead, they ask for the protection of the RPO standard, but on these facts, it matters not what a Reasonably Prudent Operator would do, the state is entitled to terminate the PTU.

[R. 5686-87]

In his decision, the Commissioner noted that seven wells in the PTU had been previously certified by DNR as “capable of producing in paying quantities.”

But he then held as follows:

Whatever the merits of the certifications when they were originally issued, the suggestions in the Director's Decision that certified wells exist today or that the prior certifications of now non-existent exploration wells indefinitely extend the term of the leases upon which they were drilled or that the PTU should be treated as a unit with certified wells is disapproved and reversed in this Commissioner's Decision. Those suggestions are not supported by the facts. There are no certified wells in the unit capable of producing in paying quantities. All wells which were certified have been plugged and abandoned. Inconsistent findings and statements in the Director's Decision on certified wells are hereby disapproved.

[R. 5682]

The Commissioner affirmed the Director's Amended Decision "in all respects to the extent it is consistent with this Commissioner's Decision, but it is disapproved to the extent it can be read to mean the PTU contains certified wells." [R. 5688] The Commissioner rejected the revised 22nd POD because it did "not commit to put the unit into production." He concluded that "[t]he PTU is terminated." [R. 5688, 5689]

Some of the PTU Lessees sought reconsideration of the Commissioner's Decision. The primary issue on reconsideration addressed the propriety of the Commissioner's determination that the PTU contains no wells certified as capable of producing in paying quantities. From there, the Lessees asserted that since the wells remained certified, the unit could only be terminated through judicial proceedings, citing 11 AAC 83.374(d). The Lessees also asserted that they did not receive fair notice that the certified well status of the PTU wells was at issue, and requested that DNR reopen the administrative proceedings for that reason. [R. 9287]

On December 27, 2006, Acting Commissioner Marty Rutherford issued an 11-page Decision on Reconsideration, which affirmed the Commissioner's Decision of November 27, 2006 in all respects. [R. 9286-9298] The Reconsideration Decision expressly distinguished between the well decertification component of the November 2006 decision and the termination component of that same decision. The Reconsideration Decision characterized

the certified well status as a "collateral finding" to the termination decision. [R.

9288] Specifically, the Reconsideration Decision found:

The certified well finding is not the basis of the November 27, 2006 unit termination decision. The unit termination decision is based primarily on two independent grounds neither one of which regards certified wells.

One ground for unit termination is that DNR is entitled to terminate a unit which has been known to contain massive hydrocarbon reserves for more than 30 years, but which has never been put into production, when the lessees of the state oil and gas leases making up the unit unequivocally state that they still cannot find a way to put the unit into production. DNR is entitled to terminate a unit because the purpose of forming a unit is to effect production. Units are not formed for the purpose of simply holding properties until such time as the Lessees think production will be profitable enough to commence. On these facts, when the Lessees say they cannot put the unit into production, DNR can terminate the unit as a matter of law.

The second primary ground for unit termination is the failure to submit an acceptable Plan of Development. . . .

[R. 9289-90]

The Reconsideration Decision also addressed, but did not directly resolve, the Lessees' argument that 11 AAC 83.374(d) requires the agency to pursue unit termination through court proceedings, and not by administrative determination. In this regard, the decision notes, "[e]ven if the PTU contains certified wells, the November 27, 2006 Decision is an appropriate DNR action which facilitates court review." [R. 9292] The Reconsideration Decision acknowledges that it is undisputed that the decertification approach "reverses longstanding DNR Oil and Gas Director's Decisions that certify non-existent or non-production wells." [R.

9295] But the Acting Commissioner indicates that the longstanding policy was “poor policy” which it was incumbent on the Commissioner to correct. [R. 9296]

The Reconsideration Decision also held that the Lessees’ own submissions to the Commissioner demonstrated that the Lessees had adequate notice that decertification was an issue before the Commissioner. [R. 9294-95] The Acting Commissioner also found that the State was not estopped from decertifying the wells and that it had not breached the covenant of good faith and fair dealing under the Unit Agreement. [R. 9296-97]

Four of the PTU Lessees appealed the Commissioner’s Decision and the Reconsideration Decision. The appeals were all consolidated to this court, sitting in its appellate capacity pursuant to AS 22.10.020(d).

In March 2007, the Appellants filed a motion with this court seeking to stay the administrative determinations pending appeal. They asserted that because the Division had certified wells in the unit as capable of producing hydrocarbons in paying quantities, subsection (d) of 11 AAC 83.374 applied such that the Division was required to “seek to terminate the unit agreement by judicial proceedings,” and was precluded from administratively terminating the unit. By order dated May 1, 2007, this court denied the stay. While this court found that the Appellants had made a “clear showing of probable success on the merits” that the administrative termination of the unit did not comply with 11 AAC 83.374(d), this court also found that granting the stay would be contrary to the public interest, and particularly the benefit of according to DNR the opportunity to

appropriately address the related lease termination proceedings in the first instance. However, this court did query the parties at the end of those proceedings whether there was any significance to the fact that 11 AAC 83.374 was adopted in 1981 – after the PTUA was entered into in 1977 – an issue that was not the focus of the parties' briefing on the stay motion.

In a separate order issued on May 7, 2007, this court held that Alaska Gasline Port Authority and Jim Whitaker would not be considered parties to this appeal. However, they were permitted to, and did submit amicus curiae briefing to this court.

Oral argument on the appeal was held on October 5, 2007. At oral argument, the Appellants each indicated they were not pursuing an appeal with respect to the Commissioner's decision on the expansion leases. Thereafter, ExxonMobil and Chevron USA filed a motion to dismiss those claims on appeal. The State filed a limited objection, focused primarily on the language of the proposed order of dismissal of that portion of the appeal. That motion is addressed below.

Standard of Review

Four different standards apply to a court's review of the merits of an agency's rulings: "(1) the 'substantial evidence test' for questions of fact; (2) the 'reasonable basis test' for questions of law involving agency expertise; (3) the 'substitution of judgment test' for questions of law involving no agency expertise,

and (4) the 'reasonable and not arbitrary test' for review of administrative regulations." *ConocoPhillips v. DNR*, 109 P.3d 914, 919 (Alaska 2005)(footnote omitted).

While the issue of contract interpretation "generally presents a question of law,"⁴ where a contract specifies that certain determinations are to be made through an administrative process, then the court's review of those determinations "would need to be appropriately deferential"⁵ such that the reasonable basis test would apply. See also *Usibelli Coal Mine, Inc., v. State, Dept. of Natural Res.*, 921 P.2d 1134, 1146 (Alaska 1996). Under the reasonable basis standard of review for administrative decisions involving complex issues involving agency expertise, the court is to give deference to the agency's determination so long as it is reasonable, supported by evidence in the record as a whole, and there is no abuse of discretion. *Ellis v. State, Dept. of Natural Resources*, 944 P.2d 491, 493 (Alaska 1977).

In this case, the parties generally agree that the regulations that DNR adopted in 1981 are applicable to the PTUA to the extent those regulations are "not inconsistent with the ... unit agreement or regulations in effect on the effective date of the lease or unit agreement." 11 AAC 83.301(b). Section 1 of the PTUA expressly provides:

The Alaska Land Act (AS 38.05.005--370) and all valid and pertinent oil and gas statutes and regulations including the oil and gas operating statutes and regulations in effect as of the effective

⁴ *ConocoPhillips*, 109 P.3d. at 920.

⁵ *Id.*

date hereof or hereafter issued thereunder governing drilling and producing operations, not inconsistent with the terms hereof or the laws of the State of Alaska, are hereby accepted and made a part of this agreement.

See also Exxon Corp. v. State, 40 P. 3d 786, 796-797. Where the parties to this appeal disagree is as to which of the 1981 regulations are consistent with the PTUA and which are inconsistent.

In *Exxon Corp. v. State*, 40 P.3d 786 (Alaska 2001), the Alaska Supreme Court addressed the Prudhoe Bay Unit Agreement (PBUA), which, like the PTUA, became effective in 1977. Although the issue the court confronted in that case – whether the lessees had an absolute right to expansion of that unit – is dissimilar to that here, many of the legal principles discussed there by the Supreme Court are applicable when analyzing the legal issues presented in this case.

In the Prudhoe Bay case, Exxon asserted that the PBUA eliminated DNR's discretion to refuse to expand the Prudhoe Bay Unit (PBU). The Department argued that it had the authority to consider the State's best interests in making a decision on whether to expand the PBU. DNR relied not only on the contract language, but also on the regulations in effect at that time, and specifically former 11 AAC 83.340 and former 11 AAC 83.345 – regulations which the court held "required the director's approval, based on a determination of necessity or advisability in the public interest, for a modification of an approved unit agreement." 40 P.3d at 795 (footnote omitted). Exxon then asserted that DNR had agreed to contract terms that were binding upon the agency even if

those terms violated DNR's regulations. But the Supreme Court held that an agency does not have the authority to contract outside of its own regulations. "To allow such activity would be arbitrary; parties not contracting with the department would not be held to the same regulations that non-contracting parties were required to comply with." 40 P. 3d at 796.

The Prudhoe Bay *Exxon* case teaches that the interpretation of the PTUA contract in this case must be governed by the language of the contract itself, as well as the regulations and statutes that were in place when the contract was adopted. Thus, to the extent that Section 1 of the PTUA could be read to limit the applicability of regulations that were in effect at the time of the PTUA's adoption, that reading is contrary to Alaska law and must be rejected. All of the applicable regulations in effect at the time of the PTUA's adoption apply to the PTUA agreement. Secondly, the current regulations and statutes apply to the PTUA "where not inconsistent with the ... unit agreement or regulations in effect on the effective date of the ... unit agreement." 11 AAC 83.301(b).

Discussion

There are two primary administrative determinations that are before the court in this appeal – (1) the Department's rejection of the Lessees' proposed modified 22nd Plan of Development for the Point Thomson Unit, and (2) the Department's termination of the Point Thomson Unit.

I. DNR's rejection of the proposed 22nd Plan of Development

A. DNR has the authority to administratively determine whether a proposed plan of development should be accepted or rejected.

The PTUA, when read in conjunction with the regulations in effect in 1977, clearly accorded to DNR the ability to administratively determine whether the Unit Operator is in compliance with Section 10 of the Unit Agreement. That section provides, among other statements, that any development plan submitted by the Unit Operator "shall be as complete and adequate as *the Director may determine* to be necessary for timely development and proper conservation of the oil and gas resources of the unitized areas." [R. 1260, emphasis added] Moreover, former 11 AAC 88.160 accords to the Unit Operator the right to appeal to the superior court a "decision or other action" by DNR. To the extent that the Appellants are asserting that the more recently adopted regulation 11 AAC 83.374 requires that rejection or acceptance of a proposed POD must be made in the first instance in judicial proceedings, as opposed to by DNR, that regulation would be inconsistent with the PTUA and former regulation and is accordingly inapplicable to this agreement.

B. What is the appropriate standard for the Department to apply when determining the adequacy of a plan of development?

The Appellants' primary assertion with respect to DNR's rejection of the proposed modified 22nd Plan of Development is that the agency applied the wrong legal standard when reviewing the proposed POD. The Appellants assert that as a matter of law, DNR is required to apply a reasonably prudent operator

(RPO) standard. They assert this standard is mandated based on the following sentence in Section 10 of the PTUA: “The Unit Operator expressly covenants to develop the unit area as a reasonably prudent operator in a reasonably prudent manner.” [R. 1260] The Appellants assert that this contractual language, in conjunction with applicable statutes, “makes clear that DNR may not require the Operator to carry out a plan that is not reasonable from the perspective of the Operator, because it does not adequately protect the lessees’ interests.”⁶

The State asserts that the PTUA’s reference to the reasonably prudent operator “acts primarily as a covenant *by the lessee* to act as a RPO and does not alter how DNR is to administer the PTUA. It defines the Lessees’ commitment rather than limiting DNR’s authority.” [State’s Br. at 46, emphasis in original] Accordingly, the State asserts that this court should affirm DNR’s determination which rejected the 22nd Plan of Development because, as found by the Commissioner, both the original plan and the revised plan “suffered from the same defects” as each proposal did not commit to put the unit into production but instead contained the “unequivocal statement that the lessees cannot find a way to put the unit into production.” [R. 9290, 9291]

Generally, issues of contract interpretation are legal issues as to which a court is to apply its independent judgment. But here, the disputed section of the PTUA – Section 10 – expressly confers upon the Division the authority to require a plan from the Lessees that “shall be as complete and adequate as the Director

⁶ Jt. Br. at 54, *citing* AS 38.05.180.

may determine to be necessary for timely development and proper conservation of the oil and gas resources of the unitized area . . .” [R. 1260] Accordingly, this court’s review of those determinations “would need to be appropriately deferential” such that the reasonable basis test should apply. *ConocoPhillips v. DNR*, 109 P.3d 914, 919 (Alaska 2005)(footnote omitted); *see also Usibelli Coal Mine, Inc., v. State, Dept. of Natural Res.*, 921 P.2d 1134, 1146 (Alaska 1996); *Pan American Petroleum Corp. v. Shell Oil Co.*, 455 P.2d 12, 22-23 (Alaska 1969).

Adoption of the Appellants’ interpretation of the contract to mandate the RPO standard would run counter to the regulatory and statutory provisions that were in effect at the time of the contract’s creation. The applicable effective regulation at the time of contracting in 1977 required a determination by the State “that the agreement is necessary or advisable in the public interest... and adequately protects all parties in interest including Alaska.” Former 11 AAC 83.340. Likewise, former 11 AAC 83.345 provides that this same standard applied to modifications of approved unit agreements. To interpret Section 10 of the PTUA to focus on the Lessee’s perspective, so as to preclude rejection of any plan of development that the Lessees asserted was unreasonable for them, irrespective of the public interest, would be inconsistent with this regulatory directive. *See also* former AS 38.05.180(m).

In this regard, the current regulation, 11 AAC 83.303, is not inconsistent with Section 10 of the PTUA or the former regulations. That regulation requires

the DNR Commissioner to approve a proposed plan of development upon a written finding that it will “(1) promote conservation of all natural resources ... (2) promote the prevention of economic and physical waste; and (3) provide for the protection of all parties of interest, including the state.” 11 AAC 83.303(a), (c)(3). In evaluating these criteria, the regulation specifies that the Commissioner is to consider several factors, including “the geological and engineering characteristics of the potential hydrocarbon accumulation,” “prior exploration activities in the proposed unit area,” and “the applicant’s plans for exploration or development of the unit area.” 11 AAC 83.303(b). DNR thoroughly addressed these criteria when it rejected both of the Lessees’ proposed 22nd Plans of Development. [See, e.g., R. 12297-12303] DNR consistently rejected the fundamental tenet of both of the 22nd PODs that the Lessees proposed – that unit development should be conditioned upon the construction of a North Slope gas pipeline. [R. 12299]

Accordingly, this court finds that DNR did not err when it declined to review the modified POD under a reasonably prudent operator standard. In evaluating the POD, DNR also considered whether the proposed POD provided adequate protection of the public interest in light of the history of limited development in the unit area over its 30-year history. DNR’s approach was consistent with Section 10’s grant of authority to the Director to require a plan of development “as complete and adequate as the Director may determine to be necessary for timely development and proper conservation of the oil and gas

resources of the unitized areas,” and complies with the applicable statutes and regulations.⁷

C. Substantial Evidence Supports DNR's Determination to Reject the 22nd POD

The Appellants also assert that even if judged by a different standard that the RPO, the modified 22nd POD should have been approved. They note that their modified plan called for an appraisal well to be drilled for the winter of 2008-2009. [Jt. Br. at 61] But with regard to this proposed well, DNR responded that under the Appellants' modified POD, they would pay the State \$40 million if they did not drill the well as planned. [R. 3096] The Commissioner found “the value of the well to the state greatly exceeds \$40,000,000 because a well or wells are needed to adequately appraise the PTU.” [R. 5678] DNR, looking at the history of the unit, determined that “[t]he proposed payment is no substitute for adequate delineation of the PTU hydrocarbon accumulations, now long overdue and repeatedly requested by DNR.” [R. 5683]

Further, the 22nd modified plan indicated that production would require a gas pipeline. [R. 3093] In rejecting that plan, DNR concluded that “neither the oil nor the gas condensate [within Point Thomson] require a gas pipeline to produce” -- a finding that is not directly refuted by the Appellants. [R. 9296]

⁷ *But see* Section 21, second paragraph, of the PTUA as modified in 1985. [R. 794] That revision specifies that the Department may not require any increase in the rate of production or development “in excess of that required under good and diligent oil and gas engineering and production practices.” This section may well have applicability when determining the appropriate remedy when DNR rejects a proposed plan of development. See discussion, *infra*.

In sum, there is substantial evidence in the record as a whole to support DNR's determination to reject the modified 22nd Plan of Development based on DNR's finding that the plan contained "no commitment to develop the unit and no firm commitment to adequately delineate the reservoirs." [R. 5677-78]

D. The Impact of the Fiscal Contract Negotiations

The Appellants that participated in the gas pipeline negotiations⁸ have asserted that the DNR Commissioner acted in bad faith in rejecting the modified POD in light of the State's course of conduct during the negotiations for the Fiscal Contract for a gas pipeline. The Appellants also assert that the DNR Commissioner "breached the obligation of subjective good faith" based on the Commissioner's statements at a press conference that occurred the day he issued his November 2006 decision in this case. [App. 130-31] And these Appellants assert these same facts support a claim of estoppel against the State. Specifically, they assert that they relied on those provisions of the proposed Fiscal Contract that relieved the Lessees of submitting PODs for so long as the fiscal contract was in place. [R. 2247]

The State asserts that any reliance by the Appellants that is based on the proposed Fiscal Contract is unreasonable because that contract was never finalized when legislative approval was not forthcoming. The Appellants point to no assertion outside the context of the Fiscal Contract negotiations in which the State indicated that it would accept a modified POD that did not commit the unit

⁸ Chevron was not a participant in these negotiations. [Exxon Br. at 62, n. 122]

into production. For example, the Commissioner's letter to Exxon of August 31, 2006, which accorded to Exxon the final extension of the appeal period, made no reference at all to the Fiscal Contract. [R. 3081]

The parties agree that this court should consider these claims de novo, since technically there is no administrative determination on these issues for this court to review. *See generally Danco Exploration v. State*, 924 P.2d 432, 434 (Alaska 1996).

To the extent the Appellants relied upon the proposed Fiscal Contract when they presented the modified POD, such reliance was unreasonable. Although the Fiscal Contract, had it been accepted by the Legislature, would have permitted the PTU to be developed in conjunction with the construction of a gas pipeline, the Fiscal Contract was never approved. DNR made no definitive statements that the Appellants would be relieved of their obligations under the PTUA even if the Fiscal Contract was not approved. To the contrary, DNR advised the Appellants that the agency would not delay a drilling commitment for so long as the Fiscal Contract negotiations were occurring. [R. 1958] In these circumstances, DNR is not estopped from rejecting the 22nd POD based on its determination that the POD did not propose an adequate development plan for the unit. *See, e.g., Mortvedt v. State, Dept. of Natural Res.*, 941 P.2d 126, 130 (Alaska 1997).

Nor can the Appellants maintain their claim for breach of the covenant of good faith and fair dealing. This covenant is intended to effectuate the reasonable

expectations of the parties under an existing contract. It "cannot be interpreted to prohibit what is expressly permitted" in the contract. *Casey v. Semco Energy, Inc.*, 92 P.3d 379, 384-385 (Alaska 2004), quoting *Ramsey v. City of Sand Point*, 936 P.2d 126, 133 (Alaska 1997). Here, the covenant cannot be applied to preclude DNR's rejection of the modified 22nd Plan of Development, because the authority to insist on a plan of development that is "as complete and adequate as the Director may determine to be necessary" is expressly accorded to DNR under the PTUA. [R. 1260]

Based on the foregoing analysis, DNR's rejection of the modified proposed 22nd Plan of Development is affirmed.

II. Did DNR have the authority to administratively terminate the PTUA?

The Director's Amended Decision of October 27, 2005 rejected the 22nd POD, but it did not purport to terminate the unit agreement. Rather, it stated that "the PTU Agreement is in default," and listed certain commitments that represented "an example of an acceptable PTU plan of development" to cure the default. [R. 12304] The Director's Amended Decision also indicated that "[f]ailure to submit an acceptable plan of development is grounds for termination of the PTU." [R. 12305]

The Commissioner's Decision and Decision on Reconsideration, issued one year later and after a modified POD proposal had been submitted to DNR by the Lessees, not only rejected the modified 22nd POD proposal – it terminated

the unit. The Appellees have asserted that DNR does not have the authority to administratively terminate the unit, but must instead seek to terminate the agreement through judicial proceedings.

The State has asserted several bases to support its authority to administratively terminate the PTUA when it has rejected a proposed Plan of Development for the unit. Each of these bases is discussed below.

A. Section 20(c) of the PTUA is not applicable.

One potential basis for the PTUA's administrative termination is pursuant to Section 20 of the agreement itself. This section of the PTUA, termed a "habendum clause," specifies certain bases upon which the unit agreement automatically terminates. There is no reference to this specific clause of the PTUA in any of the agency determinations in this matter. Moreover, at oral argument before this court in October 2007, counsel for the State made clear that the State was not seeking to invoke this clause to support the agency's termination decision. [See Transcript of Oral Argument of 10/5/07 at 34] Accordingly, any authority to administratively terminate or cancel the unit agreement must derive either from other provisions within the PTU Agreement itself or the regulations and statutes that are applicable to this particular agreement.

B. Other sections of the PTUA regarding termination

Section 9 of the PTUA delineates the parties' obligations prior to the discovery of hydrocarbons at the unit. Since hydrocarbons were discovered at

the unit decades ago, it is inapplicable to the current controversy. But Section 9 of the agreement is noteworthy in that it expressly provides that if the Unit Operator fails to diligently drill until hydrocarbons are discovered, "the Commissioner may, after 15 days notice to the Unit Operator, declare this unit agreement terminated." [R. 1259] In contrast, Section 10 of the PTUA, which applies after a well capable of producing unitized substances in paying quantities has been completed, is silent on the rights of either party to terminate or cancel the contract. It does not expressly accord to the DNR a right to administratively terminate the unit – nor does it eliminate any such right.

Section 20, discussed above, specifies when the PTUA shall *automatically* terminate. This court does not interpret that habendum clause and Section 9 of the PTUA to preclude the cancellation or termination of the contract under any other circumstance apart from those listed there. *See generally Law of Federal Oil and Gas Leases*, Vol. 1 at §14.19[1](1992)(distinguishing cancellation through affirmative agency action from automatic termination by operation of law). Indeed, the parties in this action recognize that the State could seek to cancel the contract based on an alleged breach of Section 10 by the Lessees. [See, e.g., Jt. Reply at 9] At issue is whether that cancellation proceeding would need to be initiated in state court or if the agency could seek to cancel the contract in an administrative proceeding. This court does not read the PTUA to preclude an administrative cancellation proceeding when the Director has determined that a

proposed plan of development is incomplete or inadequate under Section 10 of the PTUA.

C. *The Statutes and Regulations in Effect in 1977*

A fundamental question thus arises – did DNR have the implied authority to administratively terminate the PTUA under the statutes and regulations in effect when the PTUA was entered into in 1977? The Appellants assert that no such authority existed, such that the State “like parties to contracts generally, [must] seek relief by way of a claim of default in court.” [CPA at 21] The State and the Port Authority assert that when the PTUA is silent, the agency has the inherent authority to administratively terminate the unit unless judicial action is specifically required by statute or applicable regulation. [Port Auth. Supp. at 1]

“Administrative agencies rest their power on affirmative legislative acts. They are creatures of statute and therefore must find within the statute the authority for the exercise of any power they claim.” *McDaniel v. Cory*, 631 P.2d 82, 88 (Alaska 1981). The Alaska Land Act, as cited above, accorded broad authority to DNR’s Commissioner to “establish reasonable procedures” and “exercise the powers and do the acts necessary to carry out the provisions and objectives” of the Act. AS 38.05.020(b). Those powers included the ability to authorize and certify unit agreements “whenever determined and certified by the

Commissioner to be necessary or advisable in the public interest." Former AS 38.05.180(m).⁹

The State and the Port Authority both cite to the United States Supreme Court case of *Boesche v. Udall*, 373 U.S. 472, 478 (1963), which held that the Department of Interior had a "traditional administrative authority" to cancel a federal lease unless such authority had been specifically withdrawn by federal law. Similarly, in *White v. State, Dept. of Natural Resources*, 14 P.3d 956 (Alaska 2000)(*White II*), the Alaska Supreme Court held that a lessee's breach of contract claim against the State "fit[s] comfortably within the scope of an ordinary administrative claim" and should be pursued before the administrative agency. 14 P.3d at 960. See also *Danco Exploration v. State*, 924 P.2d 432, 434 (Alaska 1996)("Oil and gas lessees and lease bidders which have grievances with the State must pursue the administrative procedures provided by [regulation].") Although there was no express statutory grant to DNR to terminate unit agreements in 1977, this court finds that this specified procedure falls "within the scope of an ordinary administrative claim" that is within the agency's broad statutory powers. *White v. State*, 14 P.3d at 960.

As discussed above, there were two chapters of regulations that were in effect in 1977 that applied to unitization agreements on state lands. One of these

⁹ When the unit agreement included lands owned by the state, the Alaska Land Act provided that the unit agreement "may contain a provision vesting the commissioner ... with authority to alter or modify from time to time the rate of prospecting and development and the quantity and rate of production under the plan." Former AS 38.05.180(n). Section 21 of the PTUA corresponds to this statutory grant of authority.

chapters addressed only unitization agreements. Former 11 AAC 83.300 *et seq.* (Eff. 9/20/74). The other chapter, entitled "Practice and Procedure," applied to several chapters of the natural resources regulations, including the unitization chapter. It contained several provisions regarding administrative adjudications, including a provision for judicial appeals to the superior court of administrative decisions and actions.¹⁰ These former regulations neither required nor authorized that a unit termination be initiated by judicial proceedings. Former 11 AAC 88.100 – 145 (Eff. 9/20/74).

Under the regulatory scheme as it was in existence in 1977, the administrative authority to terminate the unit agreement had not been restricted or withdrawn. And the statutory regimen accorded broad powers to the commissioner to manage state land. As correctly noted by the Port Authority, "[a]t the time the PTUA was adopted, no statute or regulation abrogated the Department's authority to administratively cancel a unit ..." [Port Auth. Supp. at 2] Instead, the procedural regulations in effect at that time expressly contemplated agency determination and judicial review of all issues. This court finds that DNR possessed the authority to administratively terminate the Point Thomson Unit Agreement when that agreement was adopted in 1977 under the statutory and regulatory structure as it existed at that time.

¹⁰ Former 11 AAC 88.160 (Eff. 9/20/74).

D. To what extent are the current regulations applicable to the Point Thomson Unit Agreement?

In 1981, the State adopted several regulations that more comprehensively address unitization. With some modifications, most of these regulations remain in effect today. The parties in this action dispute both the interpretation of the current regulations and the extent to which those later-adopted regulations apply to the PTUA. Under Alaska law, the later-enacted regulations do not apply to the PTUA to the extent they conflict with either the terms of the PTU Agreement or with regulations that were in effect in 1977, when the PTUA was adopted. *Exxon v. State*, 40 P.3d 786 (Alaska 2001). While the parties to this appeal all generally agree with this principle, they have considerable disagreement as to which of the current regulations are consistent, and which are inconsistent, with the PTUA and former regulations.

1. 11 AAC 83.374 is not applicable when the basis for termination is the rejection of a plan of development, as opposed to failure to comply with an approved unit agreement.

One regulation at issue that was adopted after the PTUA, 11 AAC 83.374(d), specifies that if the Division determines that a default has occurred with respect to a unit in which there is a certified well, "the commissioner will, in his discretion, seek to terminate the unit agreement by judicial proceedings." This regulation was the focus of the stay proceedings in this case earlier this year, although at that time the parties had not addressed the fact that this regulation was adopted in 1981, after the PTUA's effective date of 1977.

This regulation is cited in the agency's decisions in this case only in the Decision on Reconsideration. There, the Acting Commissioner referenced the regulation, but indicated that the unit termination "is an appropriate DNR action which facilitates court review" and could be undertaken "[r]egardless of whether the unit contains certified wells." [R. 9292] Although the parties have provided extensive analysis of this statute in their briefing to this court, it does not appear that DNR relied upon this regulation as the basis for its termination decision.

11 AAC 83.374(a) provides that the "failure to comply with ... any plans of exploration, development or operation which are a part of the unit agreement, is a default under the unit agreement," thereby making the balance of that regulation applicable. As Exxon noted in its briefing to the agency on appeal of the Director's Amended Decision in November 2006, "failure to receive DNR approval of a plan of development does not constitute default under DNR regulations. . . ." Instead, as noted by Exxon, "11 AAC 83.374(a) provides that failure to comply with the terms of an *approved* plan of development is a default under the unit agreement, not the failure to obtain approval." [R. 705, emphasis added]

Similarly, the Alaska Gasline Port Authority, in its amicus brief, has asserted that Section 374 should not apply in this case, where the issue is the agency's rejection of a proposed plan of development, as opposed to a lessee's failure to comply with an approved plan of development. [Amicus Br. at 29] In this court's view, upon close reading of the regulation, that position, espoused

both by Exxon in 2006 and by the Port Authority before this court, has merit. 11 AAC 83.374(a) does not apply to cases such as this in which DNR has rejected a proposed plan of development.

Moreover, even if the rejection of a modified plan of development were to constitute a “default” under Section 374, then that regulation would be inconsistent with the unit agreement, to the extent that this more recent regulation imposes a requirement of judicial termination proceedings that was not administratively or statutorily required in 1977.

The Appellants assert, however, that even if inconsistent with the PTUA, the 1981 regulation should nonetheless apply to the PTUA, because this later-enacted regulation impairs only DNR’s rights, not the private parties to the PTUA, and is thus binding on the State so as to require judicial termination proceedings. In response to this court’s request for supplemental briefing, the Appellants have asserted that under Alaska law, “[r]egulations that benefit those who are regulated are applied retroactively even if inconsistent with previous regulations.” [CPA Supp. at 4] In support of this proposition, the Appellants cite to Atlantic Richfield Company v. State, 705 P. 2d 418, 424, n. 17 (1985). But in this court’s view, the Appellants are reading the cited footnote in the *Arco* decision too broadly. In that case, the retroactive interpretation of a regulation was the only way in which that newly enacted regulation could be “meaningfully applied,” such that the Supreme Court found an intent by the Department for that regulation to have retroactive effect. *Id.* Absent such unique circumstances, which are not

present here given the expected continuing creation of unit agreements throughout Alaska, neither the State nor the Appellants should be bound by subsequent regulations that are inconsistent with the State's prior contractual agreement or regulations in effect at the time of contracting.

Because this court finds that 11 AAC 83.374 is inapplicable to this case, this court will not issue a final determination with respect to DNR's purported "decertification" of the wells. As noted in the Commissioner's Decision on Reconsideration, [t]he certified well finding [was] not the basis of the November 27, 2006 unit termination decision." [R. 9289] In light of this court's rulings as set forth above, a decision on the decertification question is no longer essential to resolving the issues presented in this particular appeal. The Supreme Court instructs that an appellate court should generally not resolve legal issues when they are rendered moot. *Clark v. State, Dept. of Corrections*, 156 P.3d 384, 347 (Alaska 2007). Accordingly, apart from this court's statements on the decertification issue as set forth in the Order re Motion for Stay dated May 1, 2007, no further opinion on the propriety of the purported decertification of the seven wells is expressed by this court.

2. Does 11 AAC 83.336(a)(1) apply?

The State and Port Authority have advanced a different current regulation to support DNR's termination decision -- 11 AAC 83.336(a)(1). This regulation, adopted in 1981, provides as follows:

A unit agreement becomes effective upon approval by the commissioner and automatically terminates five years from the

effective date unless (1) a unit well in the unit area has been certified as capable of producing hydrocarbons in paying quantities, in which case the unit agreement will remain in effect for so long as hydrocarbons are produced in paying quantities from the unit area, or for so long as hydrocarbons can be produced in paying quantities and unit operations are being conducted in accordance with an approved unit plan of exploration or development, or, should production cease, for so long after that as diligent operations are in progress to restore production and then so long after as unitized substances are produced in paying quantities...

This regulation is not referenced anywhere in the Commissioner's termination decision or in the Decision on Reconsideration. But the State asserts on appeal that although the specific reference to the regulation to support the unit termination was not made at the agency level, the requisite elements of the regulation to support termination are all "contained within the findings made by the Commissioner." [10/5/07 Oral Arg. Transcript at 36]

On appeal, the State and the Port Authority assert that Section 336 is "essentially a habendum clause," such that if a plan of development is not approved, "the failure means [the] Unit Agreement simply terminated." [State's Br. at 95] In response, the Appellants assert that Section 336(a) "is inconsistent with the PTU Agreement and the effective date regulations and thus cannot apply in this case." The inconsistency, in their view, is that Section 336 would "graft onto the PTU Agreement a new event of termination: DNR approval of a plan of development." [CPA Reply at 28; see also Jt. Reply at 25] The Appellants correctly note that Section 20(c) of the PTUA contains no reference to an agency-approved plan of development as a condition for the unit agreement to remain in effect.

DNR notes that Section 20(c) of the Agreement was modified in 1985, and asserts that "because the PTUA modification occurred after the promulgation of section 336, Article 20(c) [of the PTUA] must conform to the [1981] regulation" [State's Br. at 98, n. 172; see R. 787-795] But the Appellants note that Section 1 of the PTUA was not amended in 1985. That section precludes the application of inconsistent regulations enacted after the effective date of the PTUA. This court finds the Appellants' assertion on this point persuasive. [Jt. Reply at 26] The 1985 amendments did not graft onto the PTUA the provisions of 11 AAC 83.336(a).

Section 336, as interpreted by the parties in this case, would result in the *automatic* termination of the PTUA whenever a proposed unit plan was rejected by the DNR. As such, it is inconsistent with the PTUA and the regulations that were in effect when the PTUA was executed in 1977. For although, as discussed by this court in the preceding portion of this opinion, DNR may seek to administratively terminate the PTU, neither the PTUA nor the applicable regulations and statutes in effect in 1977 permitted an automatic termination whenever a POD was unacceptable to the State. At oral argument, counsel for the State asserted that Section 336 was not inconsistent with the PTUA, because "[a]n acceptable plan of development is an express condition contained with the Point Thomson Unit Agreement." [10/5/07 Oral Arg. at 48] The State noted that Section 10 of the PTUA accords to the Director the authority to specify a plan of development that "shall be as complete and adequate as the Director may

determine to be necessary for timely development and proper conservation of the oil and gas resources of the unitized area." [R. 1260] As discussed above, this court has found that this provision of the contract accords to DNR the administrative authority to reject proposed plans of development. But rejection of a proposed plan of development does not result in automatic termination under the PTUA. Rather, a separate administrative determination as to the appropriate remedy is required in such instance. To the extent Section 336 would permit the automatic termination of the PTUA whenever a POD was rejected by the State, it is inconsistent with the PTUA and inapplicable to this unit.

E. The Appellants' Right to Due Process

The right to due process, under both the state and federal constitutions, prohibits the State from depriving any person of "life, liberty, or property, without due process of law." U.S. Const. amend. XIV, § 1; Alaska Const. Art. I, §7. The State acknowledges that the Appellants are entitled to due process with respect to their interests at Point Thomson. [State's Br. at 99]

The Appellants assert that their due process rights were violated when the Commissioner terminated the PTU on appeal from the Director's Decision. They assert that the only issues over which the Commissioner had jurisdiction were whether the Director had properly rejected the 22nd POD and whether the modified POD should be approved. [Exxon Br. at 47] The Appellants maintain that the Director's Decision, which stated simply that "[f]ailure to submit an acceptable plan of development is grounds for termination of the PTU," was

Instead, the reconsideration motion and decision were primarily focused on the decertification issue, not the termination decision. [See R. 9288, 9291]

The Alaska Supreme Court's decision in *White v. State, Dept. of Natural Resources*, 984 P.2d 1122 (Alaska 1999)(*White I*) is instructive on these issues. In that case, White had requested a hearing before DNR on a disputed factual issue with respect to an oil and gas lease. DNR refused to grant him a hearing on the issue. The Supreme Court reversed and remanded, and held that the due process clause accorded to White the opportunity for a hearing on that issue before an agency determination was made that precluded the automatic extension of the lease. 984 P.2d at 1128.

Likewise, albeit in a quite different context, the Supreme Court found that a trial court had violated a parent's right to due process when the trial court entered a *permanent* child custody order after conducting a hearing that had been scheduled to determine *interim* custody. *Cushing v. Painter*, 666 P. 2d 1044, 1046 (Alaska 1983). Due process requires that parties are accorded "sufficient written notice, specifying the nature of the dispute and the relief requested." *Hickel v. Halford*, 872 P.2d 171,180 (Alaska 1994).

Here, the State did not seek termination under Section 20(c) of the PTUA. Rather, it sought to terminate the unit after it rejected the Appellants' proposed Plan of Development. Nothing in the PTUA nor the regulatory framework in place in 1977 mandated or authorized automatic termination of the unit when DNR rejected the proposed POD. And while this court has concluded that the

PTUA and then-existing regulations did not preclude DNR from pursuing termination at the administrative level, the Appellants were constitutionally entitled to a clear written notice that DNR was considering this remedy when it rejected the POD, and should have been accorded the opportunity to be heard with respect to the appropriate remedy when the modified 22nd POD was rejected. See *generally* former 11 AAC 88.155. The Director's statement that "[f]ailure to submit an acceptable plan of development is grounds for termination of the PTU" is not constitutionally adequate notice that a termination would be administratively declared by the Commissioner on appeal of the Director's Decision rejecting the 22nd POD.

Accordingly, this matter is remanded to the DNR for the purpose of according to the Appellants a hearing on the appropriate remedy to the State upon DNR's rejection of the proposed 22nd Plan of Development. On remand, the agency should also consider the import of Section 21 of the PTUA, as amended in 1985, in determining the appropriate remedy.

III. The Expansion Leases

A separate component of the administrative determinations focused on the Expansion Agreement entered into in 2001 between the Appellants and the State. That agreement expanded the PTU on the condition that the PTU Lessees performed certain work at the PTU and put the unit into production with at least seven development wells by 2008. [R. 5678] The agreement also provided that

if the Lessees failed to perform the work in a timely manner, the expansion leases would automatically contract out of the unit and the Lessees would owe DNR certain sums of money. [*d.*]

The Appellants did not complete the work contemplated under the Expansion Agreement. Instead, in October 2006, ExxonMobil proposed a modification of the Expansion Agreement. DNR characterized the proposed modification as allowing it "to retain the most valuable portions of the Expansion Acreage without putting the unit into production." [R. 5680]

In the Commissioner's November 2006 decision, the Lessees' request to modify the Expansion Agreement was denied. The Commissioner's decision also stated that "the state is entitled to have the Expansion Leases back and to receive payment." [R. 5688-89]

The Appellants originally appealed this aspect of the Commissioner's decision, but later abandoned this particular claim and in June 2007 paid the State the \$20,000,000 payment plus interest then due as specified in the Expansion Agreement. On October 19, 2007, the Appellants filed a motion to dismiss the claims on appeal with respect to the Expansion Agreement. The State filed a partial opposition to the motion, disputing the language in the proposed order on these claims. Specifically, the Appellants' proposed order simply provided that all claims regarding the Expansion Agreement "are hereby dismissed as expressly abandoned by all Appellants and, in the alternative, as moot." The State's proposed order was broader, and sought to affirm a final

agency decision, effectively returning the expansion leases to the State. In reply, the Appellants asserted that the language from the Commissioner's decision that "the state is entitled to have the Expansion Leases back" should be considered dicta, and not a final agency determination with respect to the underlying leases in the expansion acreage. [R. 5689]

This court agrees with the Appellants that the validity of the leases encompassed within the expansion acreage was not directly before the Commissioner in this administrative proceeding, and thus is not properly before this court on appeal. With respect to mootness, this court agrees with the State's position that the claims related to the Expansion Agreement are more properly characterized as dismissed rather than moot.

Accordingly, with respect to the Expansion Agreement claims, all of the Appellants' claims concerning the Expansion Agreement are hereby dismissed as they have been expressly abandoned by all Appellants.

//

//

//

//

//

//

//

//

Conclusion

DNR's rejection of the Lessees' proposed modified 22nd Plan of Development, including DNR's interpretation of Section 10 of the Point Thomson Unit Agreement, is affirmed.

DNR's determination as set forth in the Commissioner's Decision and the Decision on Reconsideration that terminated the Point Thomson Unit is reversed and remanded, so as to accord to the Appellants notice and an opportunity to be heard before the agency as to the appropriate remedy when the Department has rejected the proposed modified 22nd Plan of Development for the Point Thomson Unit.

All of the Appellants' claims concerning the Expansion Agreement are dismissed as they have been expressly abandoned by all Appellants.

Dated this 26th day of December, 2007.

Sharon Gleason
Sharon Gleason
Judge of the Superior Court

I certify that on 12-26-07 a copy
of the above was mailed/faxed to each of the
following at their addresses of record
[Signature]
Official Assistant

Al- Todd
Ashburn / Crosby
Orlowsky
Keithley
Serdabelys
Rozell

Dawn
Ellis
Ballew / Ashley
Haynes / Phillips
Sneed

IN THE SUPERIOR COURT FOR THE STATE OF ALASKA

THIRD JUDICIAL DISTRICT AT ANCHORAGE

EXXON MOBIL CORPORATION,)	
Operator of the Point Thomson Unit;)	
BP Exploration (Alaska) Inc.;)	
Chevron U.S.A., Inc.; and)	Case No. 3AN-06-13751 CI
ConocoPhillips Alaska, Inc.,)	(Consolidated)
)	Case No. 3AN-06-13760 CI
)	Case No. 3AN-06-13773 CI
Appellants,)	Case No. 3AN-06-13799 CI
)	Case No. 3AN-07-04634 CI
v.)	Case No. 3AN-07-04620 CI
)	Case No. 3AN-07-04621 CI
STATE OF ALASKA, Department of)	
Natural Resources,)	
)	
Appellee.)	

DECISION AFTER REMAND

This case is before this Court on appeal for the second time following an administrative determination on remand by the Commissioner of the Department of Natural Resources (DNR) terminating the Point Thomson Unit. Because the contractual agreement between DNR and the Appellants precludes the termination of the Point Thomson Unit in these circumstances without consideration of "good and diligent oil and gas engineering and production practices,"¹ and because DNR failed to accord the Appellants their constitutional right to procedural due process in the remand proceeding, DNR's decision is reversed.

¹ PTU REC at 794 (Section 21, paragraph 2 of the Point Thomson Unit Agreement). Given the procedural history of this matter, portions of the record are paginated multiple times. In this decision, citations to particular pages of the record are to the page numbers provided by the "PTU REC" pagination.

FACTS AND PROCEDURAL HISTORY

In March 1977, Exxon Corporation (now ExxonMobil) and the Commissioner of DNR entered into the Point Thomson Unit Agreement (PTUA).² The agreement was intended to facilitate the production of oil and gas at Point Thomson, an area on the North Slope of Alaska.³ ExxonMobil holds the largest percentage of leasehold interests at Point Thomson and is identified in the PTUA as the Unit Operator. The other Appellants -- BP Exploration (Alaska) Inc., Chevron U.S.A., Inc. and ConocoPhillips Alaska, Inc. -- each have leasehold interests within the Point Thomson Unit (PTU).

In 1977, when the parties entered into the PTUA, Section 21 of the agreement provided:

21. RATE OF PROSPECTING, DEVELOPMENT AND PRODUCTION.

The Director is hereby vested with authority to alter or modify from time to time in his discretion the quantity and rate of production under this agreement when such quantity and rate is not fixed pursuant to state law or does not conform to any statewide voluntary conservation or allocation program which is established, recognized and generally adhered to by the majority of operators in such state, such authority being hereby limited to alternation [sic] or modification in the public interest, the purpose thereof and the public interest to be served thereby to be stated in the order of alteration or modification. Without regard to the foregoing, the Director is also hereby vested with authority to alter or modify from time to time at his discretion the rate of prospecting and development and the quantity and rate of production under this agreement when such alteration or modification is in the interest of attaining the conservation objectives stated in this agreement and is not in violation of any applicable state law.

Powers in this section vested in the Director shall only be exercised after notice to Unit Operator and opportunity for hearing to be held not less than fifteen (15) days from notice.

² "Unit agreements . . . are organizational schemes approved by the [DNR] to efficiently extract oil from a common reservoir that is the subject of multiple leases." *ConocoPhillips Alaska, Inc. et al. v. State, Dep't of Natural Res.*, 109 P.3d 914, 917 n.16 (Alaska 2005), *reh'g denied*.

³ See PTU REC at 1253-1271.

PTU REC at 1268.

During the first several years of the PTU's existence, DNR concluded that the Appellants had been "diligent in exploring the unit area." *Id.* at 9464.⁴ By January 1982, a discovery well had indicated that the PTU was capable of producing in paying quantities, seven wells had been drilled within or near the PTU, and four more wells were then being drilled. *Id.*

But in October 1983, Exxon submitted its seventh proposed Plan of Development (POD) to DNR. This plan proposed that there be "no further drilling activities" in the PTU for the next five years, unless "contracts for actual construction of a feasible transportation system for the gas are let" before that time. *Id.* at 11252. On November 29, 1983, DNR approved this seventh POD but noted that "[a]pproval of the seventh plan does not relieve any lessee of a drilling commitment or other work commitment that may be attached to the lease as a condition for approval of an expansion of the Point Thomson Unit to include the lease in the unit area." *Id.* at 11250. Several months later, in March 1984, DNR conditionally granted an application to add more leases to the PTU. DNR's decision to grant the expansion application included several express conditions, one of which was that a well be drilled on lands covered by certain expansion leases by March 31, 1985. *Id.* at 10040. Another condition was that the Appellants submit to DNR acceptable proposed amendments to the PTUA aimed

⁴ Kay Brown, then the Acting Director of DNR's former Division of Minerals and Energy Management, wrote this in a January 1982 memorandum to John Katz, DNR Commissioner at that time. *Id.* at 9463-64.

primarily at addressing the inclusion of additional leases within the PTU with royalty rates other than the standard 12.5%. *Id.* at 10039.

Against this backdrop, in late 1984 Exxon submitted proposed amendments to the PTUA to DNR. *Id.* at 790-95. In January 1985, DNR approved a number of these amendments. *Id.* at 787-88. Included among these amendments was a rewording of the second paragraph of Section 21 of the PTUA as follows:

Powers in this section vested in the Director shall only be exercised after notice to Unit Operator and opportunity for hearing to be held not less than . . . thirty (30) days from notice, and shall not be exercised in a manner that would (i) require any increase in the rate of prospecting, development or production in excess of that required under good and diligent oil and gas engineering and production practices; or (ii) alter or modify the rates of production from the rates provided in the approved plan of development and operations then in effect or, in any case, curtail rates of production to an unreasonable extent, considering unit productive capacity, transportation facilities available, and conservation objectives; or (iii) prevent this agreement from serving its purpose of adequately protecting all parties in interest hereunder, subject to applicable conservation laws and regulations.

Id. at 794 (amended language underlined).⁵

On March 12, 1985, the lessees of certain of the expansion leases notified DNR that “efforts to promote the drilling of a well on the subject lessees have been unsuccessful and the required well [due by March 31, 1985] will not be drilled.” *Id.* at 10026.

The instant dispute began over twenty years later, in August 2005, when the Appellants submitted their proposed 22nd POD to DNR. The Director of DNR’s Division of Oil and Gas initially rejected the proposed 22nd POD on September 30, 2005. In this

⁵ Before the Appellants submitted their proposed amendments, DNR had notified them that “the State would find acceptable” this amendment to Section 21. *Id.* at 10039, 10051.

initial decision, the Director concluded that “[f]ailure to submit an acceptable plan of development is grounds for termination of the PTU.” *Id.* at 8948. Referring expressly to Section 21 of the PTU, the Director’s initial decision provided:

This decision provides notice under Article 21 of the PTU Agreement that Exxon must initiate development operations within the PTU by October 1, 2007. The Division will contact Exxon to schedule a hearing on this issue, which will be held not less than 30 days from the date of this decision. . . . The PTU Owners shall have an opportunity for hearing regarding this notice to modify the rate of PTU development.

Id. at 8927, 8948.

One month after issuing the September 2005 initial decision referencing Section 21, the Director issued an amended decision on October 27, 2005. The amended decision concluded that the Appellants had defaulted under the PTUA and applicable oil and gas regulations and accorded the Appellants an opportunity to cure the default by submitting an acceptable POD. *Id.* at 12304. But the amended decision also held that Section 21 does “not apply to the Division’s evaluation of the Unit Operator’s proposed plans for development of the Point Thomson Unit.” *Id.* at 12282. Accordingly, the amended decision deleted the requirement contained in the initial decision that the Appellants commence development operations at the PTU by October 1, 2007 and deleted the provision that the Appellants would have an opportunity for a hearing under Section 21 of the PTUA regarding modification of the rate of PTU development. *Id.* at 12305. Instead, the amended decision shifted the burden to the Appellants to propose an acceptable POD, stating that “[a]n acceptable unit plan must contain specific commitments to timely delineate the hydrocarbon accumulations underlying the PTU and develop the unitized substances.” *Id.* at 12304-05.

The Appellants were granted extensions of time to appeal from the Director's decision during negotiations with the State under the Stranded Gas Development Act. On October 18, 2006, the Appellants submitted a modified 22nd POD, *id.* at 3089-3105, and oral argument on the proposed modified 22nd POD was held before the Commissioner of DNR on November 20, 2006. Although the Appellants did not request an evidentiary hearing at that time, over 5,000 pages of documents regarding the modified proposed 22nd POD were submitted to the Commissioner prior to the hearing.

The Commissioner issued a Decision on Appeal on November 27, 2006. As summarized by the Commissioner at that time, that decision:

(1) denies the request for modification of the 2001 Expansion Agreement, as amended, which affects only the expansion leases; (2) affirms the Director's Decision in all respects to the extent it is consistent with this Commissioner's Decision, but the Director's Decision is disapproved to the extent that it can be read to mean the PTU contains certified wells; (3) adopts and incorporates into the Commissioner's Decision the findings and rationale of the Director's Decision as modified by this Decision; (4) rejects the cure or revised 22nd PTU POD submitted by the Lessees on October 18, 2006; and (5) terminates the PTU.

Id. at 5671.

After the Commissioner denied their request for reconsideration, the Appellants appealed the Commissioner's decision to this Court. In a decision issued on December 26, 2007, this Court affirmed in part and reversed in part. *Exxon Mobil Corp. et al. v. State, Dep't of Natural Res.*, 3AN-06-13751 CI (Consolidated) (Dec. 26, 2007) (hereinafter, "2007 Decision").

This Court affirmed DNR's rejection of the proposed modified 22nd POD under Section 10 of the PTUA. Section 10 of the PTUA provides:

10. PLAN OF FURTHER DEVELOPMENT AND OPERATION. Within six months after completion of a well capable of producing unitized substances in paying quantities, the Unit Operator shall submit for the approval of the Director an acceptable plan of development and operation for the unitized land which, when approved by the Director, shall constitute the further drilling and operating obligations of the Unit Operator under this agreement for the period specified therein. Thereafter, from time to time before the expiration of any existing plan, the Unit Operator shall submit for the approval of the Director a plan for an additional specified period for the development and operation of the unitized land. The Unit Operator expressly covenants to develop the unit area as a reasonably prudent operator in a reasonably prudent manner.

Any plan submitted pursuant to this section shall provide for the exploration of the unitized area and for the diligent drilling necessary for determination of the area or areas thereof capable of producing unitized substances in paying quantities in each and every productive formation and shall be as complete and adequate as the Director may determine to be necessary for timely development and proper conservation of the oil and gas resources of the unitized areas, and shall:

- (a) specify the number and location of any wells to be drilled and the proposed order and time for such drilling; and,
- (b) to the extent practicable, specify the operating practices regarded as necessary and advisable for the proper conservation of natural resources. . . .

Said plan or plans shall be modified or supplemented when necessary to meet changed conditions, or to protect the interests of all parties to this agreement. Reasonable diligence shall be exercised in complying with the obligations of the approved plan of development.

PTU REC at 600-01. The Appellants had asserted that the "reasonably prudent operator" language contained in the first paragraph of Section 10, in conjunction with applicable statutes, "ma[d]e clear that DNR may not require the Operator to carry out a plan that is not reasonable from the perspective of the Operator, because it does not adequately protect the lessees' interests." 2007 Decision at 21 (quoting Jt. Br. at 54). This Court rejected that argument and concluded instead that Section 10 grants to DNR the authority to reject a proposed POD without regard to the reasonably prudent operator standard: "To interpret Section 10 of the PTUA to focus on the Lessee's perspective, so as to preclude rejection of any plan of development that the Lessees

asserted was unreasonable for them, irrespective of the public interest, would be inconsistent with" the applicable regulations and statutes. *Id.* at 22. But this Court strived to make clear that the contractual rights of the parties were not fully resolved under Section 10 of the PTUA, concluding that "rejection of a proposed plan of development does not result in automatic termination under the PTUA . . . [and] a separate administrative determination as to the appropriate remedy is required in such instance." *Id.* at 39. Accordingly, this Court reversed the termination of the PTU and remanded the matter to DNR as follows:

DNR's rejection of the Lessees' proposed modified 22nd Plan of Development . . . is affirmed. DNR's determination as set forth in the Commissioner's Decision and the Decision on Reconsideration that terminated the Point Thomson Unit is reversed and remanded, so as to accord to the Appellants notice and an opportunity to be heard before the agency as to the appropriate remedy when the Department has rejected the proposed modified 22nd Plan of Development for the Point Thomson Unit.

Id. While the Court left open what standard to apply in the remand proceeding, the 2007 Decision did provide that: "on remand, the agency should also consider the import of Section 21 of the PTUA, as amended in 1985" *Id.* at 42.

Promptly after this Court issued its December 2007 decision, the Commissioner sent a letter to the Appellants notifying them that DNR "is specifically considering the remedy of termination of the Point Thomson Unit." PTU REC at 30505. The Commissioner invited the Appellants to submit briefing on the following issues: "(1) whether the remedy of unit termination is the appropriate remedy for the Appellants' failure to submit an acceptable 22nd POD; and (2) if termination is not appropriate, what remedy would be an appropriate response to the Appellants' failure to submit an acceptable 22nd POD." *Id.* The Commissioner also alerted the Appellants that DNR's

planned remand proceedings would consist of oral argument and the submission of written briefs unless the Appellants requested and were accorded additional proceedings. *Id.* at 30505-06.

The Appellants responded with a number of procedural requests. *Id.* at 30507-11. The Appellants contended, among other things, that due process required that an independent hearing officer conduct the remand hearing, that the Commissioner institute procedures to prevent *ex parte* contacts with DNR staff on the subject of the remand hearing, and that DNR participate as an adversary during the proceeding. The Appellants also asserted that the hearing should be conducted in accordance with Section 21 of the PTUA. *Id.* at 30507-10, 30519. In that regard, they requested notice under Section 21 “of the specific nature and timing of the development activity DNR now finds necessary and proper . . . and the reasons for that belief.” *Id.* at 30517. While the Commissioner denied most of the Appellants’ requests, he did grant their request to present witnesses during the remand proceeding. *Id.* at 30513.

On February 19, 2008, the Appellants submitted a 23rd POD as a proposed remedy for DNR’s rejection of the 22nd POD. *Id.* at 30000-19. An administrative hearing was then held from March 3 through 7, 2008, during which the Appellants called multiple witnesses to testify and submitted additional written materials. The Commissioner presided at the hearing and also designated Nanette Thompson, an employee of DNR’s Division of Oil and Gas, to participate as the hearing officer. See *id.* at 30514. Ms. Thomson had previously appeared as DNR’s representative before this Court during the 2007 administrative appeal. During the remand hearing, the

Commissioner was also advised by the same attorneys who had defended the agency in the original appeal.⁶

On April 22, 2008, the Commissioner issued a 75 page decision and concluded: "The 23rd POD proposed by Appellants as the remedy for rejection of the 22nd POD does not meet the standards in 11 AAC 83.303 and does not serve the public interest. It is not adequate to insure timely development as required by Section 10 of the PTUA. The Point Thomson Unit is terminated." *Id.* at 31465. In his decision, the Commissioner explained that the 23rd POD "does not adequately develop all of the known hydrocarbon resources in the unit area." *Id.* at 31464. The Commissioner also concluded, "most importantly, the public's interest would not be protected if I approve the 23rd POD because I do not believe, based on this record, that the Appellants will perform as promised this time." *Id.* at 31465.

The Commissioner's decision on remand expressly considered the import of Section 21, as instructed by this Court, and found that section of the PTUA inapplicable:

Section 21 does not apply to my evaluation of Appellants' proposed remedy. Section 21 only applies where there is ongoing prospecting, development, or production operations. In this case, there are no ongoing operations. . . . The most recent drilling activity by the unit operator was in 1982, twenty-six years ago. The last seismic data was gathered almost a decade ago, in 1999. Thus, Section 21 is not implicated because there is currently no prospecting, development or production. This construction is most consistent with the PTUA as a whole

Moreover, Section 21 does not supersede the applicable statutes and regulations which authorize unitization only when it is in the public interest. It does not trump Section 10 and the regulations, which give DNR the discretion to determine the adequacy of a proposed POD. Thus, Appellants' argument that if DNR rejects the 23rd POD, Section 21 shifts

⁶ See Order Denying Motion for Partial Trial de Novo dated January 13, 2009 at 8-9.

the responsibility to DNR to design an acceptable POD is inappropriate as a matter of public policy and inconsistent with DNR's authority.

Id. at 31455-56.

The Appellants sought reconsideration, and in a decision on reconsideration issued on June 11, 2008, the Commissioner affirmed. *Id.* at 31520-44. The Commissioner again rejected the Appellants' proposition that Section 21 applied to these proceedings: "Appellants' efforts to make the decision on remand turn on a DNR presentation of an acceptable POD under section 21 of the unit agreement and the reasonably prudent operator standard is inappropriate because the issue at hand is whether, given Judge Gleason's decision that DNR properly rejected the 22nd POD, it is in the public interest for the unit to continue." *Id.* at 31523.

The Appellants appealed the Commissioner's decision on remand to this Court. See AS 22.10.020(d). The parties' briefing on this second appeal was completed on May 26, 2009, and oral argument was held on July 20, 2009.

In their briefing to this Court, the Appellants summarized their primary issues on appeal as follows:

- The procedures followed by the Commissioner on remand were constitutionally inadequate.
- Before proceeding to termination, DNR needed to comply with its obligations under Section 21 and its duty of cooperation.
- The Commissioner's decision must be reversed since no adjudication of the fundamental issue of material breach has yet occurred.
- DNR's change of development policy did not give rise to a material breach of the unit agreement by the Appellants and could not have provided a basis to terminate.
- Termination was unavailable as a remedy since there was no uncured material breach.

The Commissioner committed legal error in evaluating the 23rd plan of development.

Br. of Appellants at i-iii.

DISCUSSION

A. Standard of Review

Four different standards apply to a court's review of the merits of an agency's rulings: "(1) the 'substantial evidence test' for questions of fact; (2) the 'reasonable basis test' for questions of law involving agency expertise; (3) the 'substitution of judgment test' for questions of law involving no agency expertise; and (4) the 'reasonable and not arbitrary test' for review of administrative regulations." *ConocoPhillips*, 109 P.3d at 919 (footnote omitted).

For the reasons explained below, this Court finds that the interpretation of Section 21 of the PTUA is dispositive of this appeal. The Appellants contend that DNR was required to comply with the provisions of Section 21 on remand, while DNR argues that Section 21 was inapplicable to the remand proceedings. The interpretation of this contract provision does not require DNR's administrative expertise. Accordingly, on remand this Court should substitute its own judgment to determine this legal issue.⁷ *Quality Asphalt Paving, Inc. v. State, Dep't of Transp. & Pub. Facilities*, 71 P.3d 865, 872 n.10 (Alaska 2003) ("[W]e will substitute our own judgment for questions of law not

⁷ In contrast, this Court applied the reasonable basis standard of review in its December 2007 decision as to DNR's determination to accept or reject a POD under Section 10 of the PTUA because that determination involved the exercise of agency expertise. 2007 Decision at 17.

involving agency expertise, such as contract interpretation.”); *Alaska Hous. Fin. Corp. v. Salvucci*, 950 P.2d 1116, 1119 (Alaska 1997) (“Interpretation of a contract is a question of law on which this court substitutes its own judgment.”).⁸

When interpreting a contract, this Court is “to give effect to the reasonable expectations of the parties.” *Exxon Corp. v. State*, 40 P.3d 786, 793 (Alaska 2001) (citation omitted), *reh’g denied*. Those expectations should be determined “by looking to the words of the contract and any extrinsic evidence regarding intentions when they entered into a contract, including evidence of the parties’ subsequent conduct.” *Kay v. Danbar, Inc.*, 132 P.3d 262, 269 (Alaska 2006). The language of the contract is the “most important evidence of [the parties’] intention.” *Id.* Unless words are defined otherwise within the contract, they are to be given their “ordinary, contemporary, common meaning.” *Norville v. Carr-Gottstein Foods Co.*, 84 P.3d 996, 1001 n.3 (Alaska 2004).

B. Are the Appellants Entitled to a Section 21 Hearing?

Section 21 of the PTUA accords to DNR’s Director of the Division of Oil and Gas⁹ the authority to “alter or modify from time to time in his discretion the quantity and rate of

⁸ It bears noting that this Court’s 2007 Decision remanded the legal issue of the applicability of Section 21 to the agency to address in the first instance, consistent with the principle of primary agency jurisdiction. See *Eidelson v. Archer*, 645 P.2d 171, 176 (Alaska 1982) (“If [a complaining party] is required to pursue his administrative remedies, the courts may never have to intervene. And notions of administrative autonomy require that the agency be given a chance to discover and correct its own errors. Finally, it is possible that frequent and deliberate flouting of the administrative processes could weaken the effectiveness of an agency by encouraging people to ignore its procedures.”) (quoting *McKart v. United States*, 395 U.S. 185, 194-195 (1969)).

⁹ The PTUA references the Director of DNR’s Division of Lands, a division which has been eliminated since the parties entered into the contract. PTU REC at 595; see Revisor’s Notes to AS 38.05 (LexisNexis 2008) (“Through administrative reorganization, the Department of Natural Resources was reorganized into the Department of Land and Minerals.”) (*Exxon Mobil et al. v. State*, 3AN-06-13751 CI (Consolidated) *Decision After Remand*

production when such alteration or modification is in the interest of attaining the conservation objectives stated in [the PTUA]" and not in violation of state law. PTU REC at 1268. However, under the amendments to Section 21 agreed to by DNR and the Appellants in 1985, the Director may not exercise this power

in a manner that would (i) require any increase in the rate of prospecting, development or production in excess of that required under good and diligent oil and gas engineering and production practices; or (ii) alter or modify the rates of production from the rates provided in the approved plan of development and operations then in effect or, in any case, curtail rates of production to an unreasonable extent, considering unit productive capacity, transportation facilities available, and conservation objectives; or (iii) prevent this agreement from serving its purpose of adequately protecting all parties in interest hereunder, subject to applicable conservation laws and regulations.

Id. at 794 (underlining in original). Section 21 also expressly provides that the Appellants are entitled to notice and a hearing whenever the Director seeks to exercise the powers vested in him by that section. *Id.*

The Appellants argue that they were entitled to a hearing under Section 21 on remand because "the entire thrust of DNR's position, from its initial consideration of POD 22 through its most recent brief, has been that the rate of development at Point Thomson has not been fast enough, so that the rate of development needs to be increased and production needs to be obtained." Reply Br. of Appellants at 30-31 (*citing* Br. of Appellee at 2-7).

DNR argues Section 21 is not applicable for several reasons. Its position can be parsed into five arguments: (1) "Section 21 is only triggered when DNR takes unilateral action and seeks to order a change in the rate of prospecting, development or

Resources has eliminated the division of lands. Duties and responsibilities given to the division of lands under this chapter have been assigned to other divisions of the department.").

production” and does not apply when DNR simply rejects a POD;¹⁰ (2) Section 21 does not apply when “there are no ongoing operations, and thus no existing functioning infrastructure;”¹¹ (3) a Section 21 hearing is precluded by this Court’s December 2007 decision;¹² (4) to accord a Section 21 hearing to the Appellants in these circumstances would undermine the authority conferred upon DNR by certain statutes and regulations;¹³ and (5) according the Appellants a Section 21 hearing in these circumstances would inappropriately shift the burden of establishing a development plan to DNR, or, as stated by DNR in its brief: “the Appellants are trying to manipulate Section 21 in a manner requiring that DNR devise a remedy measurable against Section 21’s standards.”¹⁴ Each argument is addressed in turn.

1. Is Section 21 Triggered by the Rejection of a Proposed POD?

DNR argues that Section 21 is inapplicable to the remand proceedings because Section 21 does not apply when DNR has rejected a proposed POD. For the following reasons, the Court disagrees.

First, the language of Section 21 itself indicates that its application is not limited to only those situations where DNR seeks to modify an existing POD. When interpreting a contract, a court should strive to give effect and reasonable meaning to all provisions of the instrument. *Alaska Constr. & Eng’g, Inc. v. Balzer Pac. Equip. Co.*,

¹⁰ Br. of Appellee at 48.

¹¹ *Id.* at 47.

¹² *Id.* at 49.

¹³ *Id.* at 51-53.

¹⁴ *Id.* at 50.

130 P.3d 932, 937 (Alaska 2006), *reh'g denied*. Here, subsection (ii) of the second paragraph of Section 21 provides that DNR's powers under Section 21 "shall not be exercised in a manner that would . . . alter or modify the rates of production from the rates provided *in the approved plan of development* and operations then in effect *or, in any case, curtail rates of production to an unreasonable extent . . .*" PTU REC at 794 (emphasis added). Thus, subsection (ii) applies not only to situations in which DNR seeks to change the terms of approved POD but also to "any case" – which would include cases in which there is no approved POD. Additionally, subsection (i) of that same paragraph provides that DNR's powers under Section 21 "shall not be exercised in a manner that would . . . require any increase in the rate of prospecting, development or production in excess of that required under good and diligent oil and gas engineering and production practices" and makes no mention of applying only to approved POD's. *Id.* To interpret Section 21 of the PTUA as applicable only when DNR seeks to alter the terms of an approved POD would be inconsistent with the language of both subsections (i) and (ii) of the second paragraph of Section 21.

Second, as the Appellants noted in their reply brief, throughout the proceedings before both the DNR and this Court, DNR has repeatedly expressed its dissatisfaction with the rate of development of the PTU as a basis for its determinations.¹⁵ In both the initial and amended decisions rejecting the 22nd POD, the Director wrote, "The Director has the authority to modify the rate of development to achieve the conservation objectives under the PTU Agreement, and *I find that increasing the rate of development in the PTU is necessary and advisable.*" PTU REC at 8947, 12328 (emphasis added).

¹⁵ Reply Br. of Appellants at 30-31 (*citing* Br. of Appellee at 2-7).

On appeal from the Director's amended decision, the Appellants submitted a revised 22nd POD. In rejecting this revised POD and ultimately terminating the PTU, the Commissioner largely adopted and incorporated the findings and rationale of the Director's amended decision, *see id.* at 5671, and characterized the Appellants' conduct as "unambiguously refus[ing] to *adequately* explore, delineate, or produce massive known hydrocarbon reserves." *Id.* at 5686 (emphasis added). And after this Court affirmed the Commissioner's decision to reject the revised 22nd POD under Section 10 and remanded the matter to the Commissioner, the Appellants submitted a proposed 23rd POD as an alternative to termination of the PTU. In rejecting this proposed POD, the Commissioner found that the 23rd POD was "*not adequate* to insure timely development" of the PTU. *Id.* at 31465 (emphasis added).

Third, a Section 21 hearing is the natural progression from the rejection of a POD under Section 10 when the proposed 23rd POD was rejected because DNR seeks to increase production in the Point Thomson Unit. This Court's December 2007 Decision addressed the standard under which DNR may reject proposed PODs pursuant to Section 10 of the PTUA and held DNR is accorded the authority under Section 10 to reject a proposed POD based solely upon consideration of the factors set forth in 11 AAC 83.303(a).¹⁶ This Court rejected the Appellants' position that the reasonably prudent operator (RPO) standard should apply to DNR's assessment of a POD, reasoning that Section 10's reference to the RPO standard only obligated the Appellants to act as reasonably prudent operators – it did not obligate DNR to apply that standard when evaluating a proposed Plan of Development. 2007 Decision at 22-24.

¹⁶ 2007 Decision at 22-23.

But when Section 10 is interpreted in that manner, it cannot be the basis for establishing a material breach of the PTUA by the Appellants. Stated differently, in December 2007 this Court recognized that the rejection of a proposed POD under Section 10 of the PTUA does not of itself constitute an act of default or a material breach of the PTUA by the Appellants. *Id.* at 34-35.

2. Does Section 21 Apply if the Current Rate of Prospecting, Development, or Production is Zero?

DNR next argues that Section 21 does not apply because there is no ongoing production in the PTU. By its terms, Section 21's applicability is limited to where DNR seeks to "alter or modify . . . the quantity and rate of [the PTU's] production[.]" PTU REC at 1268. DNR asserts that, "[w]here, as here, there are no ongoing operations, and thus no existing functioning infrastructure (such as active wells, production facilities and pipelines) Section 21 is not the proper provision of the PTUA" to apply to this proceeding. Br. of Appellee at 47.

The question presented is whether "rate of production" as used in Section 21 includes the rate of zero production. Nowhere in Section 21 is there an express limitation of its applicability to DNR proceedings undertaken only when the PTU is actively producing oil or gas. Further, the term "rate" is not defined in the PTUA. Therefore, this Court will look to the "ordinary, contemporary, common meaning" of the word "rate" to discern whether Section 21 of the PTUA should be interpreted to apply where there is no ongoing production in the unit and DNR seeks to increase that rate from zero so as to require production. *Kay*, 132 P.3d at 269.

"Rate" is a word with a variety of meanings. For example, it may refer to the price paid for a particular good or service, Black's Law Dictionary 1375 (9th ed. 2009)

(definition 2 of "rate *n*") (i.e., a hotel room rate), or it may be used as a verb, meaning "to set an estimate on" or "to determine or assign the relative rank or class of." Webster's Ninth New Collegiate Dictionary 976 (1990) (definitions 3a and 3b of "rate *vb*") (i.e., to rate an athlete's abilities). But in Section 21 of the PTUA, it is apparent from the context in which the term is used that "rate" refers to the amount or speed of production in the PTU. Black's Law Dictionary defines "rate" as a "[p]roportional or relative value; the proportion by which quantity or value is adjusted." Black's Law Dictionary 1375 (9th ed. 2009). Other dictionaries provide the following relevant definitions: "a fixed ratio between two things," Webster's Ninth New Collegiate Dictionary 976 (1990) (definition 3a of "rate *n*"), "a quantity, amount, or degree of something measured per unit of something else," *id.* (definition 4a of "rate *n*"), "[a] stated numerical amount of one thing corresponding proportionally to a certain amount of some other thing," The New Shorter Oxford English Dictionary on Historical Principles Vol. 2 2481 (1993) (definition 4 of "rate *n*¹"), and "[s]peed of movement, change, etc., the rapidity with which something takes place; frequency of a rhythmic action." *Id.* (definition 5 of "rate *n*¹").

Each of these ordinary, contemporary, and common definitions of "rate" lead this Court to conclude that "rate of production," as used in Section 21 of the PTUA encompasses not only situations in which there is active production, but also the situation in which the rate of production is zero. The referenced dictionary definitions of "rate" provide that the term refers to a proportional value or ratio. In the context of oil production, the common proportional measure of the rate of production is barrels per day, *see, e.g., Amber Res. Co. v. U.S.*, 87 Fed. Cl. 16, 20 (Fed. Cl. 2009); *Trees Oil Co. v. State Corp. Comm'n*, 105 P.3d 1269, 1274 (Kan. 2005); *Harken Sw. Corp. v. Bd. of*

Oil, Gas & Mining, 920 P.2d 1176, 1180 (Utah 1996), and, in the context of gas production, the common proportional measure of the rate of production is cubic feet per day. See, e.g., *Exxon Mobil Corp. v. State, Dep't of Revenue*, 219 P.3d 128, 132 (Wyo. 2009); *Cimarron Oil Corp. v. Howard Energy Corp.*, 909 N.E.2d 1115, 1120 (Ind. Ct. App. 2009). These definitions of "rate" encompass the possibility that oil may be produced at a "rate" of zero barrels per day and gas may be produced at a "rate" of zero cubic feet per day. This reading of "rate" is in line with the usage of the term "rate" in decisions from other courts.¹⁷ See *Amara v. Cigna Corp.*, 534 F.Supp.2d 288, 324 n.18 (D. Conn. 2008) (emphasis added) (referencing an Internal Revenue Service ruling mentioning "a period of zero annual rate of accrual"); *State Bd. of Health v. Godfrey*, 290 S.E.2d 875, 877 (Va. 1982) (emphasis added) (referencing an expert witness's testimony regarding "slow or *nil* rates of absorption"); *Nw. Pipeline Corp. v. Adams County*, 131 P.3d 958, 960 (Wash. Ct. App. 2006) (emphasis added) (referencing the possibility that a company would have a "zero growth rate"). This Court concludes that the fact that the PTU currently has a zero rate of production does not preclude the applicability of Section 21.

3. Does This Court's December 2007 Decision Preclude a Section 21 Hearing?

DNR also contends that the Appellants were not entitled to a Section 21 hearing on remand because this Court's December 2007 decision precludes such a hearing. DNR argues that this Court's prior decision remanded to the agency for a "remedy"

¹⁷ The Court's research has not located any Alaska appellate cases construing the word "rate." However, as noted above, DNR's Director of the Oil and Gas Division initially applied Section 21 in this case to a production rate of zero. See p. 5, *supra*.

proceeding. DNR maintains that this Court has already found the Appellants in default of the PTUA and limited the scope of the remand proceedings to giving the Appellants an opportunity to cure a material breach. DNR contends:

[T]he court has already determined 'what happens' after DNR properly rejects a proposed POD under Section 10 of the PTUA: 'this matter is remanded to the DNR for the purpose of according to the Appellants a hearing on the appropriate remedy to the State upon DNR's rejection of the proposed 22nd Plan of Development.' . . . The court did *not* remand to give Appellants another chance to cure their material breach. Rather, because this court affirmed DNR's rejection of the revised 22nd POD and confirmed that the agency applied the proper legal standards in doing so, the sole issue on remand was 'the appropriate *remedy* to the State upon DNR's rejection of the proposed 22nd Plan of Development.

Br. of Appellee at 49, 78.

DNR accords too broad of an interpretation to the use of the term "remedy" in this Court's December 2007 decision. As explained above, this Court's 2007 Decision did not find that DNR's rejection of a POD under Section 10 constituted a material breach of the PTUA by the Appellants.¹⁸ Rather, in that decision, this Court interpreted Section 10 to accord to DNR the right to reject a POD based primarily on a consideration of the public's interest and remanded the case to address the appropriate remedy in that circumstance. "Remedy," as used in the December 2007 decision, meant the following dictionary definition of the term: "[t]he means of enforcing a right." Black's Law Dictionary 1407 (9th ed. 2009). A Section 21 hearing is the contractual means by which DNR may enforce its right to seek increased production in the PTU. Stated differently, DNR has the right to seek increased production in the PTU, but it can only enforce that right in accordance with the provisions of the PTUA, including Section 21.

¹⁸ *Supra* at 17.

4. Does the application of Section 21 after DNR rejects a proposed POD undermine DNR's authority conferred by statutes and regulations?

DNR also asserts that if Section 21 is applicable when DNR rejects a proposed POD, it would undermine the agency's authority to reject a POD under the applicable statutes and regulations. In this regard, DNR asserts:

Section 21's "good and diligent" practices standards, which Appellants assert should have been applied on remand, are very different in kind from the criteria set out in Section 10 and 11 AAC 83.343. The phrase "good faith and diligent oil and gas engineering and production practices" was added as part of the 1985 amendments to the PTUA, and thus must be read consistently with 11 AAC 83.343 which was in existence in 1985 ... Injecting Section 21 standards into this analysis would have taken away the Commissioner's ability to consider the unit agreement, statutory, and regulatory POD criteria.¹⁹

DNR adds, "If section 21 [were] applied in the manner advocated by Appellants, its 'good and diligent' practices standard would be impermissibly elevated over the 'public interest.'"²⁰

This Court finds DNR's argument in this regard to be unavailing. Rather, this Court agrees with the Appellants' analysis of the applicable statutory and regulatory provisions that apply when DNR rejects a proposed POD on the basis that it does not increase the rate of prospecting, development, or production to a level satisfactory to DNR.²¹ And while this Court's 2007 Decision held that Section 10 of the PTUA accords DNR considerable discretion to reject a proposed POD, Section 21 accords specific contractual rights that the Appellants may then exercise to protect their interest in the

¹⁹ Br. of Appellee at 53 (footnotes omitted).

²⁰ *Id.* at 54.

²¹ See generally Reply Br. of Appellants at 29-31, including footnotes therein.

PTU. This contractual interpretation is consistent with the underlying statutes that were in place when the PTU was created in 1977 and incorporated into Section 1 of the PTUA. *See former AS 38.05.180(m) and (n).*²²

5. Does a Section 21 Hearing Impermissibly Shift the Burden to DNR to Determine the Appropriate Rate of Production?

DNR's final argument with respect to the applicability of Section 21 asserts that the agency would be inappropriately "saddled with the burden of designing an adequate POD" at Point Thomson if the PTUA is interpreted to require a Section 21 hearing whenever a POD is rejected. *Br. of Appellee at 52.* But this Court finds that the provisions of Section 21 are reasonable contractual burdens that DNR knowingly assumed both in both 1977 and again when the PTUA was amended in 1985.²³

For the foregoing reasons, upon DNR's rejection of the 22nd POD under Section 10, the Appellants are entitled to a hearing in accordance with Section 21 of the PTUA.

C. Further Proceedings and the Appellants' Right to Due Process

This Court having determined that the Appellants did not receive the Section 21 hearing that they should have been accorded under the PTUA, it is clear that further proceedings are necessary. The Appellants have taken the position that "it is now

²² *See also* 11 AAC 83.343, adopted in 1981, which indicates that if the POD is disapproved, the Commissioner of DNR may propose modifications that would qualify the POD for approval, but is otherwise silent on how such modifications are to be proposed. *Cf.* 11 AAC 83.336, adopted in 1981, discussed in this Court's 2007 Decision at 36-39.

²³ Moreover, it would appear that the burden on DNR may well be considerably less onerous in a case such as this in which no production has been occurring, given the language contained in Section 20(c) of the contract, which provides that after a valuable discovery of unitized substances has been made, the PTUA shall remain in effect only for "so long as unitized substances can be produced in quantities sufficient to pay for the cost of producing same from wells on unitized lands within any participating area established hereunder" PTU REC at 608-09, 9448.

necessary that the dispute be referred to an independent hearing officer." Reply Br. of Appellants at 15 (citing AS 44.64.030(b)). Alternatively, the Appellants asserted in their opening brief that this Court should grant a trial *de novo*. Br. of Appellants at 94. For its part, DNR asserted that briefing of any remedy issues should be deferred until this Court has determined whether further proceedings are necessary. It maintains that if this Court finds a due process violation, "it makes the most sense to wait until the court identifies how DNR violated due process and exactly what process is due Appellants before the parties argue whether trial *de novo* or remand is the best way to address any deficiencies." Br. of Appellee at 43.

Accordingly, analysis of the due process issues raised by the Appellants is clearly necessitated.²⁴ The Appellants have identified several procedures that the Commissioner employed on remand that they assert were constitutionally inadequate. They maintain that DNR failed to separate the advocacy of its proprietary interests from its quasi-judicial adjudicatory functions by permitting the same staff and counsel who had defended the first appeal to assist the Commissioner in the remand proceeding. Br. of Appellants at 24-27. They also assert that DNR failed to accord the Appellants an adversarial hearing with the minimum procedural protections consistent with a fair proceeding. Specifically, they maintain that they were not accorded a neutral decision maker, adequate notice and adequate discovery, an appropriate burden of proof, an adversarial hearing in which DNR staff participated as a party, and a preclusion on *ex parte* contacts between the decision maker and any party. *Id.* at 27-33.

²⁴ The Court should address constitutional issues on appeal "only when a case cannot be fairly decided on other grounds." *Frost v. Spencer*, 218 P.3d 678, 682 (Alaska 2009).

This Court previously found in its 2007 Decision that DNR does have the authority to administratively adjudicate disputes related to the PTUA.²⁵ But it must do so consistent with the constitutional protections that are to be accorded to all litigants. "An impartial tribunal is basic to a guarantee of due process."²⁶ While an administrative agency may perform adjudicatory functions, it must do so in a way that adequately separates the adjudicatory function from the agency's administrative and investigatory functions so as to insure that all parties appearing before the agency are accorded their constitutional right to due process.²⁷

In this case, it is undisputed that during the remand proceedings before the agency, the Commissioner, acting in an adjudicative role, was advised by the same attorneys who had represented the agency in the first appeal to this Court. Those attorneys are also representing the agency in this second appeal. In addition, the Commissioner appointed Ms. Thompson to serve as the hearing officer at the remand proceedings. She had previously been DNR's representative when the agency was defending its first decision in the 2007 appeal before this Court.

The Appellants assert that when the same attorneys who had defended the agency in the first appeal, together with Ms. Thompson, provided legal guidance to the Commissioner in private during the remand proceedings, it constituted a deprivation of their constitutional right to due process, citing *In re Robson*, 575 P.2d 771. In *Robson*, an attorney faced disciplinary proceedings before the Disciplinary Board of the Alaska

²⁵ 2007 Decision at 20.

²⁶ *In re Robson*, 575 P.2d 771, 774 (Alaska 1978) (citations omitted).

²⁷ *Id.* at 774.

Bar Association. A member of the Bar Association's Executive Director's staff had investigated Mr. Robson's alleged attorney misconduct and prosecuted the case before the Board. The Executive Director was then present during the Disciplinary Board's private deliberations, although there was no indication that she actually took any active part in the deliberations. The Bar asserted that she was present during deliberations "to advise [the Board] on procedural matters, should the need arise."²⁸

Mr. Robson then appealed the Board's decision to suspend his license to practice law, contending that he was deprived of procedural due process because the Executive Director had been present during the Board's deliberations. The Alaska Supreme Court agreed and held:

When an administrative official has participated in the past in any advocacy capacity against the party in question, fundamental fairness is normally held to require that the former advocate take no part in rendering the decision. The purpose of this due process requirement is to prevent a person with probable partiality from influencing the other decision-makers.²⁹

The Appellants assert that just as the Executive Director in *Robson* had participated in an advocacy capacity against Mr. Robson, so had the attorneys and Ms. Thompson previously participated in an advocacy capacity against the Appellants in this case, such that their assistance to the Commissioner during the remand proceedings constituted a violation of the Appellants' constitutional right to due process.³⁰

²⁸ *Id.* at 775.

²⁹ *Id.* at 774. See also *In re Brion*, 212 P.3d 748, 754-55 (Alaska 2009); *Amerada Hess Pipeline Corp. v. Regulatory Comm'n of Alaska*, 176 P.3d 667, 677 (Alaska 2008) (per curiam); *In re Walton*, 676 P.2d 1078, 1082 (Alaska 1983). Cf. *Caperton v. A.T. Massey Coal Co.*, 129 S.Ct. 2252, 2262 (2009).

³⁰ Br. of Appellants at 26-27.

DNR asserts that *Robson* is distinguishable. It asserts that DNR's lawyers at the Attorney General's Office and private outside counsel "only provided legal guidance to the agency and were not 'advocates' or participants at the hearing"³¹ and that Ms. Thompson's role on remand was not problematic because "Ms. Thomson was *not* the decision maker in the remand proceedings."³²

This Court finds DNR's arguments on this issue to be unavailing. The advocates for DNR in the first appeal before this Court were advising the Commissioner during the subsequent remand proceedings before the agency. As DNR's attorneys before this Court in the first appeal, they "participated in the past in an advocacy capacity against the [Appellants]."³³ Furthermore, the hearing officer appointed by the Commissioner to assist him at the remand proceedings defended DNR's position in the original appeal before this Court, participating on behalf of the agency as the agency's unit manager for the PTU.³⁴ Under *Robson* and the due process requirement articulated by the Alaska Supreme Court in that decision, these advocates were precluded from providing legal guidance or, as was the case in *Robson*, simply being present whenever the Commissioner deliberated on remand. As such, the private interaction of these advocates with the Commissioner in the course of the remand proceeding resulted in a denial of due process to the Appellants, as it failed to "assure both the fact and

³¹ Br. of Appellee at 30.

³² *Id.* at 44 (emphasis in original).

³³ *Robson*, 575 P. 2d at 774.

³⁴ See audio recording of April 17, 2007 hearing. Media Number 3AN-6307-62.

appearance of impartiality in the [agency's] decisional function." *Robson*, 575 P.2d at 775.

DNR argues that any procedural infirmity was rectified by the Commissioner's issuance of a written decision on remand.³⁵ In this regard, it asserts that "the case that is more applicable to these facts is *Alyeska Pipeline Service Company v. State, Department of Environmental Conservation*."³⁶ But the *Alyeska* decision involved the propriety of an administrator making a written fee determination on an \$8,073 fee invoice for costs incurred by the administrator related to a permit challenge – a circumstance quite distinct from the termination of the PTU that is at issue in this litigation. See *Alyeska*, 145 P.3d at 563-64; see also *Mathews v. Eldridge*, 424 U.S. 319, 334-35 (1976) (one factor in determining the extent of process that is due is the nature of the private interest at stake).

Just as the Alaska Supreme Court found in *Robson*, there is no indication that the advocates in this case took any active part in the substantive deliberations of the Commissioner, and this Court has no doubt that the purpose of their private meetings with the Commissioner during the remand proceeding was entirely ethical.³⁷ Nonetheless, in order to assure both the fact and appearance of impartiality when the Commissioner was exercising his decisional function, DNR's litigation counsel should not have been providing legal guidance to the Commissioner at the remand hearing, nor

³⁵ Br. of Appellee at 31.

³⁶ *Id.* (citing 145 P. 3d 561, 572 (Alaska 2006)).

³⁷ See *Robson*, 575 P. 2d at 775.

should DNR's agency representative in the first appeal have served in the position of hearing officer at the remand proceeding.

The remainder of the alleged due process violations would appear to be substantially mooted by this Court's rulings as set forth above concerning the applicability of Section 21 and the constitutional entitlement of each party to a proceeding in conformance with the dictates of procedural due process.

In light of the foregoing, the parties are invited to provide the Court with further briefing regarding whether this Court should again remand this matter for an administrative proceeding³⁸ or retain jurisdiction and conduct a *de novo* proceeding. With respect to a *de novo* proceeding, the parties' briefing may address whether the appointment of a special master pursuant to Civil Rule 53 is appropriate. The parties shall each have thirty days from the date of this decision to submit additional briefing on these issues. No responsive briefing shall be filed thereafter unless otherwise ordered.

CONCLUSION

For the foregoing reasons, the DNR Commissioner's Findings and Decision on Remand is REVERSED. The parties shall have thirty days from the date of this decision to submit additional briefing as set forth above. This Court shall retain jurisdiction over this matter pending further order of the Court.

ENTERED at Anchorage, Alaska this 11th day of January 2010.

I certify that on 1-11-10 a copy of the above was mailed to each of the following at their address of record (list name if not an agency)

CSED AG PD DA

[Signature]
Deputy Clerk / Secretary

AG
Sordabely
Ashburn Forestry
Keithley

[Signature]
SHARON L. GLEASON
Superior Court Judge

³⁸ As the Appellants note in their brief, Alaska Statute 44.64.030(b) permits DNR to request that the Office of Administrative Hearings conduct the hearing. Br. of Appellants at 35.

sneed
orensky
Lyle
d'aurm

ballew/ashley
Nuskin
nozell

IN THE SUPERIOR COURT FOR THE STATE OF ALASKA
 THIRD JUDICIAL DISTRICT AT ANCHORAGE

ExxonMobil Corporation, Operator)	
of the Point Thomson Unit; BP)	
Exploration (Alaska) Inc.; Chevron U.S.A. Inc.; ConocoPhillips Alaska, Inc.,)	Case No.: 3AN-06-13751 CI
)	(Consolidated Appeals)
)	Case No. 3AN-06-13760 CI
Appellants,)	Case No. 3AN-06-13773 CI
)	Case No. 3AN-06-13799 CI
vs.)	Case No. 3AN-07-04634 CI
)	Case No. 3AN-07-04620 CI
State of Alaska,)	Case No. 3AN-07-04621 CI
Department of Natural Resources,)	
)	
Appellee.)	

**ORDER DENYING APPELLANTS' MOTION TO SUPPLEMENT
 OR AUGMENT RECORD ON APPEAL**

This Court, having considered Appellants' Motion to Supplement or Augment the Record and Appellees' Opposition, and ~~any reply thereto~~, hereby DENIES the motion. *It is moot in light of this court's issuance of the Decision on Remand on this date.*

DATED: 1-11-10

Sharon L. Gleason
 The Honorable Sharon L. Gleason
 SUPERIOR COURT JUDGE

I certify that on 1-11-10 a copy of the above was mailed to each of the following at their address of record (list name if not an agency)
 CSED AG PD DA
[Signature]
 Deputy Clerk / Secretary

ashburn/crosby
AG Todd
Sordacheley
Keithley
inced
or zowsky

lyfe
dawn
ballen/ustley
reskin
royle

JAN - 5 2010
 ASHBURN MASONIC LAWYERS
 1227 WEST 9TH AVENUE, SUITE 200 ANCHORAGE, ALASKA 99501
 TEL 907.276.4331 FAX 907.277.8235

CERTIFICATE OF SERVICE

I certify that a copy of the foregoing was hand delivered faxed mailed on the 5th day of January, 2010 to:

Attorney for BP Exploration (Alaska) Inc.
Susan Orlansky
FELDMAN ORLANSKY & SANDERS
500 L Street, Suite 400
Anchorage, AK 99501

Attorney for ExxonMobil Corp.
Douglas J. Serdahely
PATTON BOGGS LLP
601 West Fifth Avenue, Suite 700
Anchorage, AK 99501

Attorney for Chevron U.S.A. Inc.
Stephen M. Ellis
DELANEY WILES, INC.
1007 West Third Avenue, Suite 400
Anchorage, AK 99501

Attorney for State of Alaska
Richard Todd
Assistant Attorney General
1031 W. Third Avenue, Suite 200
Anchorage, AK 99501

Attorney for ConocoPhillips Alaska, Inc.
Spencer C. Sneed
DORSEY & WHITNEY, LLP
1031 W. Fourth Avenue, Suite 600
Anchorage, AK 99501

Attorney for BP Exploration (Alaska), Inc.
Bradford G. Keithley
Perkins Coie LLP
1029 West Third Avenue, Suite 300
Anchorage, AK 99501

Attorney for BP Exploration (Alaska), Inc.
George R. Lyle
GUESS & RUDD
510 L Street, 7th Floor
Anchorage, AK 99501

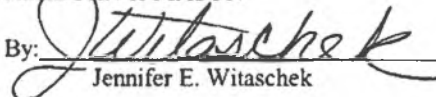
P. Jefferson Ballew
G. Luke Ashley
THOMPSON & KNIGHT, LLP
1722 Routh Street, Ste. 1500
Dallas, TX 75201-2533

David B. Ruskin
601 W. 5th Avenue, Suite 700
Anchorage, AK 99501

William B. Rozell
P.O. Box 20730
Juneau, AK 99802

John F. Daum
O'MELVENY & MEYERS, LLP
400 So. Hope St.
Los Angeles, CA 90071

ASHBURN & MASON

By: 
Jennifer E. Witaschek

P: Clients' 10578 Remand Appeal December 2009 Motion to Supplement ORDER-Opposition to Supplement.doc

ASHBURN & MASON, P.C.
LAWYERS
1227 WEST 9TH AVENUE, SUITE 200
ANCHORAGE, ALASKA 99501
TEL 907.276.4331 FAX 907.277.8235

Cindy Smith

From: Tempel, Esther (DNR) <esther.tempel@alaska.gov>
Sent: Thursday, April 26, 2012 5:09 PM
To: Cindy Smith
Subject: Pt Thomson hearing

Hi Cindy,

Just wanted to let you know that Matt Findley, Attorney with Ashburn & Mason, will be calling in for tomorrow's hearing.

Also, Joe Balash (Dep. Comm) and Jon Katchen (Inter-governmental Coordinator, Commissioner's Office) of DNR will be available. As will the Attorney General, Michael Geraghty.

Please let me know if I can be of further assistance.

Esther Cha Tempel

Legislative Liaison
Office of the Commissioner
Department of Natural Resources
(907) 465-4730
esther.tempel@alaska.gov