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

DNR Evaluation of the Thomson Sand

Geologic Model Results

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

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

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

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

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

Reservoir Simulation Results

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

Primary Depletion (Gas Blowdown)

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

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

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

Gas Cycling Followed by Gas Blowdown

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

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

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

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

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

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

Oil-rim Development

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

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

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

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

Mode…ıg 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 cı :ial. The difference in recovery from the oil-rim between primary depletion and a cycling project that maintains reservoir pressure can be as much as **35% more** of the total in-place volume.

Use of Offsite Gas

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

Gas from outside sources (offsite) could be imported and injected into the Thomson reservoir to help maintain reservoir pr sure. Offsite gas can be in the form of carbon dioxide (CO_2), inert gas such as nitrogen, methane or natural gas.

The use of CO_2 for pressure maintenance may have multiple benefits depending on the source and availability.

- CO_2 is commonly removed as a byproduct from produced gas in a gas treatment plant prior to sale.
- If enough CO_2 is available for pressure maintenance, it could allow sale of some Point Thomson gas before gas blowdown.
- CO_2 should be fully miscible with the Thomson oil and thus reduce the viscosity and further increase recovery.

CO_2 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 CO_2 re-injection costs.
Although the importation of offsite gas would require the construction of a gas line to Point Thomson, once gas cycling is completed, the line would be available for gas sales.

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

Conclusions from Geologic and Reservoir Modeling

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Acronyms and Abbreviations

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

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

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

Glossary

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

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

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

TERM	DEFINITION
	product has been designed.
FERC Open Season Regulations	The FERC regulations as set forth in 18 C.F.R. § 157, Subpart B (Open Seasons for Alaska Natural Gas Transportation Projects).
Firm Transportation Service	The transportation service provided to a Shipper on a pipeline system pursuant to a Transportation Services Agreement (TSA) between the Shipper and a pipeline whereby the pipeline agrees to make available to the Shipper on a firm basis the capacity on the pipeline system subscribed for in the TSA and the Shipper agrees to pay for such capacity as per the TSA whether the Shipper uses such capacity or not.
First Nations peoples	The Indian peoples of Canada, both Status and non-Status, as defined in the Indian Act, R.S., 1985, c. I-5.
Foothills System or Foothills Pre-Build or Pre-Build	The existing natural gas pipeline system built under certificates issued pursuant to Canada's Northern Pipeline Act that starts at Caroline, Alberta that branches into two legs, with one leg running south-east to Monchy, Saskatchewan and the other leg running south-west to Kingsgate, British Columbia, which is owned by Foothills Pipe Lines Ltd., a wholly-owned subsidiary of TransCanada Corporation.
Gas Cap	An oilfield term indicating the condition which occurs as oil is removed; the gas becomes mobilized and accumulates as a "gas cap" on the oil formation. Also, the portion of a reservoir occupied by free gas (gas not in solution).
Gas Treatment Plant (GTP)	In the TransCanada application, the GTP is necessary for treating some natural gas that is to be shipped via pipeline from the Alaska North Slope (ANS). The GTP will process over 5 billion cubic feet per day (bcf/d) of residue gas from the existing Central Gas Treatment Facility located at Prudhoe Bay. This residue gas would be treated by removing the undesirable constituents (e.g., CO2) by dehydration and filtration processes. The 4.5 bcf/d of sales gas would be chilled to 28°F and compressed to 2500 pounds per square inch gauge (psig) prior to shipping. The CO2 would be returned to the residue gas stream and re-injected into the Prudhoe Bay reservoir.
Guarantee	A financial guarantee in the form acceptable to TransCanada from a party with an Acceptable Credit Rating.
Henry Hub	The Henry Hub is a pipeline interchange located near Erath, Louisiana. The Henry Hub is the designated delivery point for the NYMEX Natural Gas futures contract. The Henry Hub is also a highly liquid trading point, with numerous buyers and sellers of both physical natural gas and financial derivatives. The Hub provides access to more than a dozen interstate and intrastate pipeline interconnects
Hub	A major natural gas receipt and delivery and/or trading point.
Hurdle Rate	The minimum rate of return producers must achieve to pursue a project.
In-Service Date	The date for Commencement of Commercial Operations of the Pipeline System.
In-State Shippers	Those Shippers that subscribe for transportation services with the Alaska Section for natural gas delivery to a delivery point within the

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

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

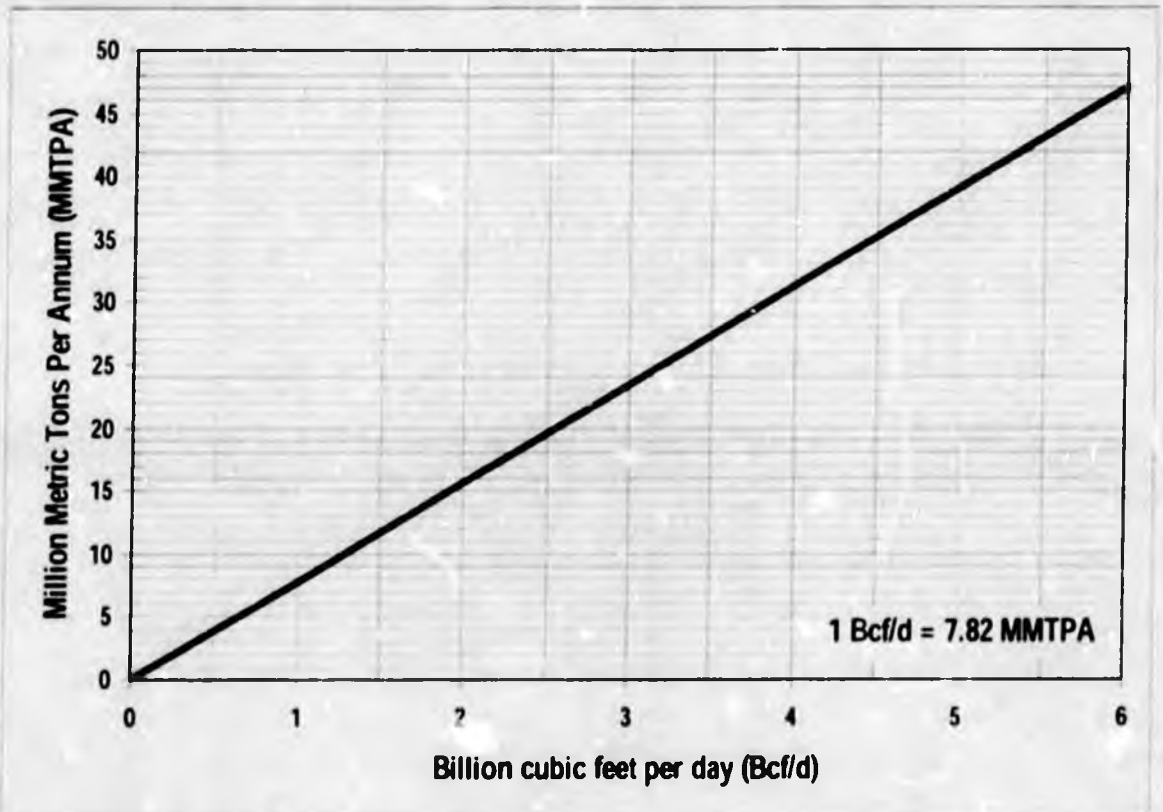
TERM	DEFINITION
	TransCanada's Alberta System, as applicable, which shall be superseded and replaced by the Transportation Services Agreement prior to the In-Service Date.
Proposal Sub-Phase	That portion of the Development Phase that begins with the award of the AGIA license and ends with the conclusion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

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

Units

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

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



ExxonMobil

Point Thomson Unit Development

ALASKA COMMITTEES ON AGIA / ENERGY

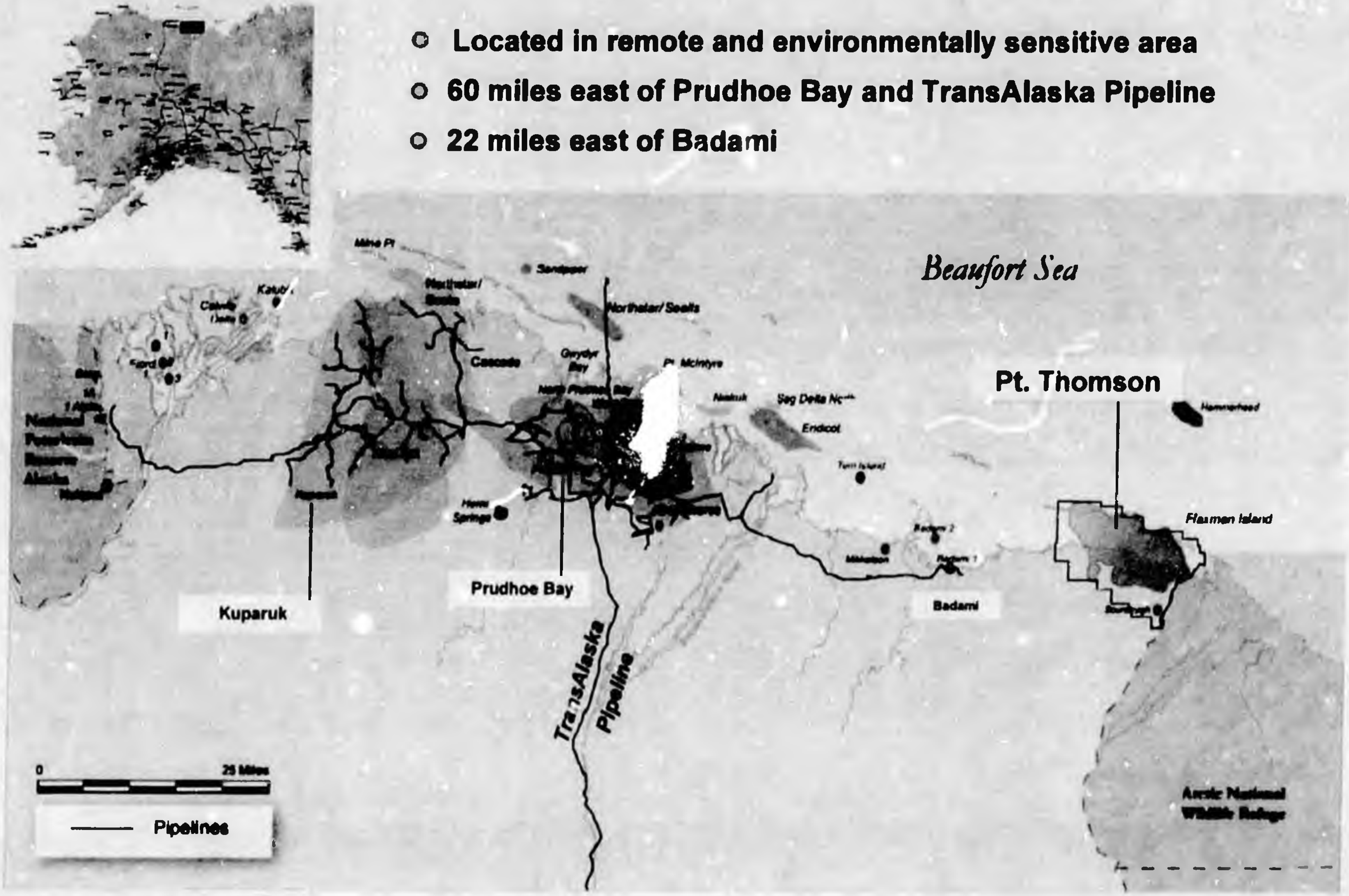
June 17, 2008

Craig A. Haymes
ExxonMobil Alaska Production Manager

Point Thomson – Isolated from Rest of North Slope

ExxonMobil

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

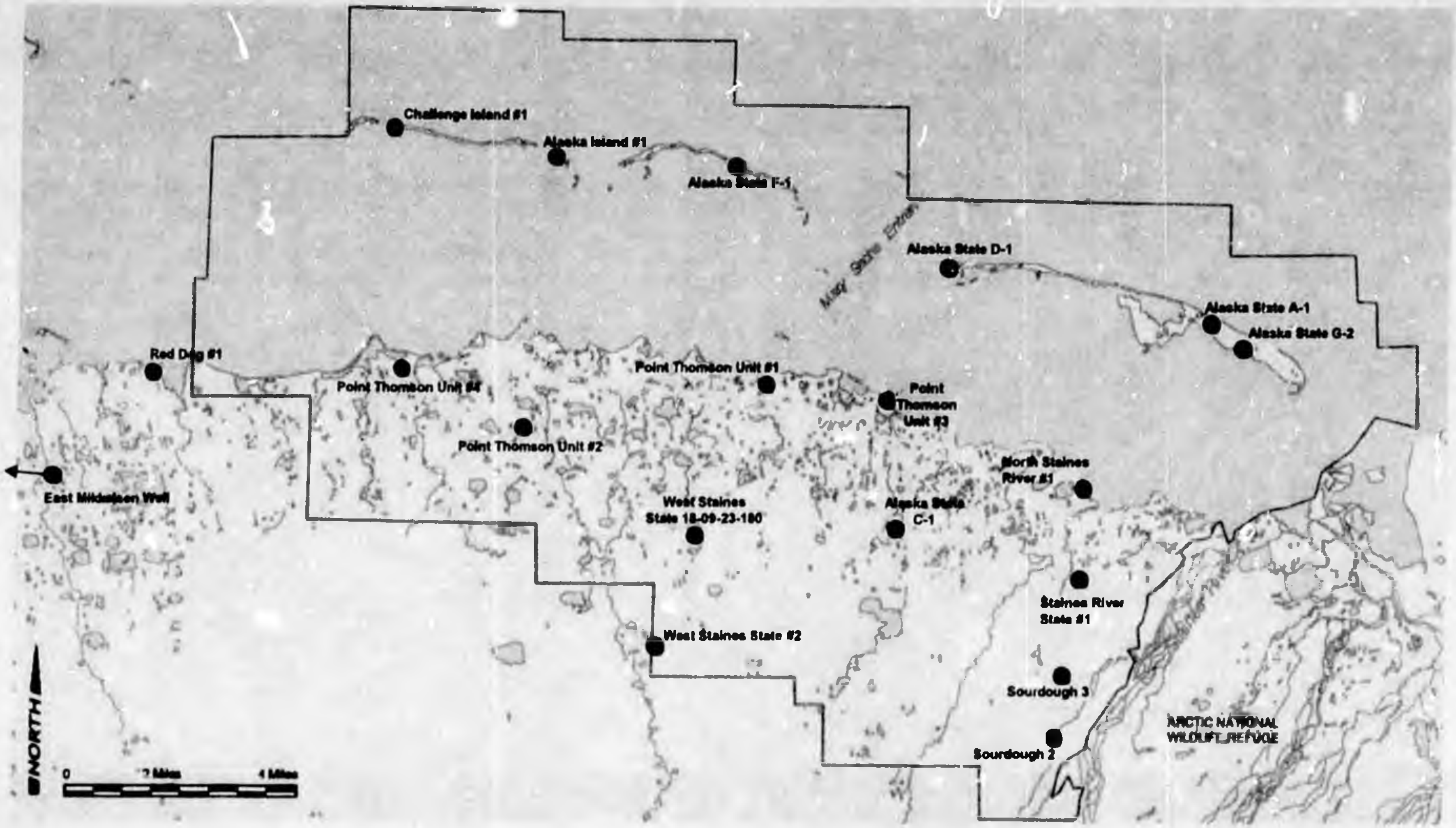


June 17, 2008

Point Thomson – Obtaining Information

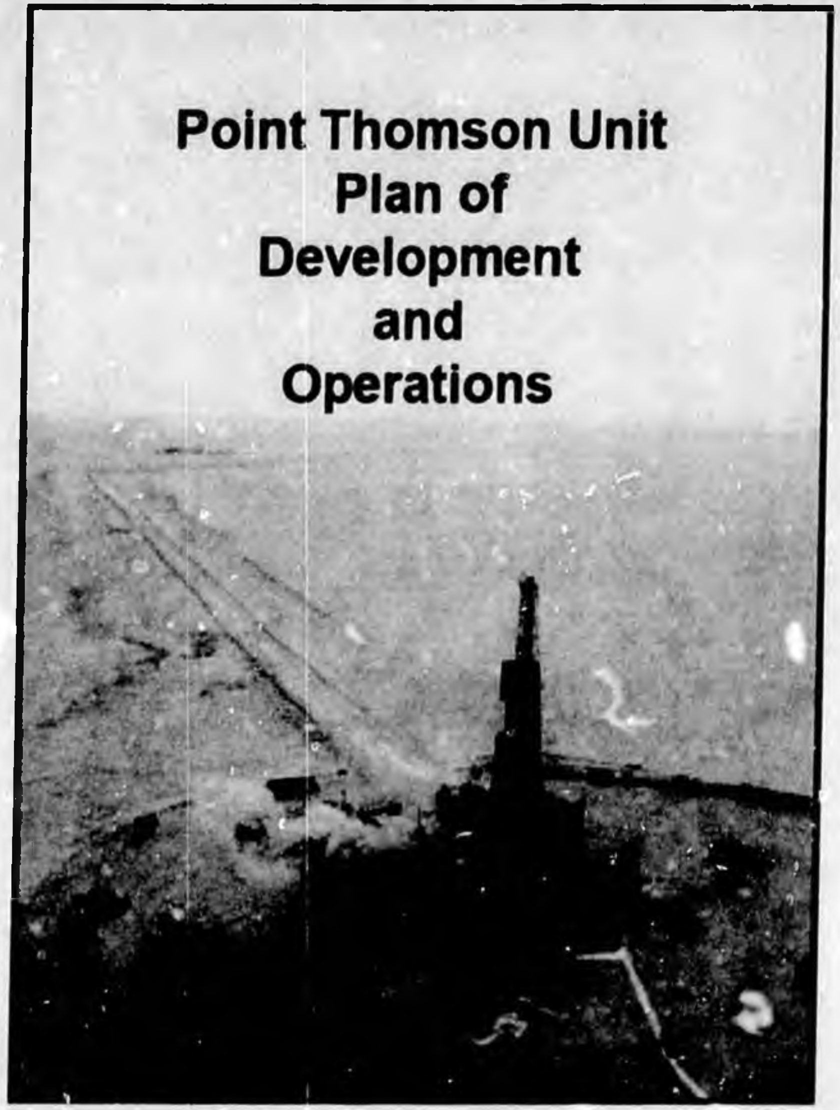
ExxonMobil

- 19 Exploratory Wells Drilled
- Eight 3D Seismic Acquisitions



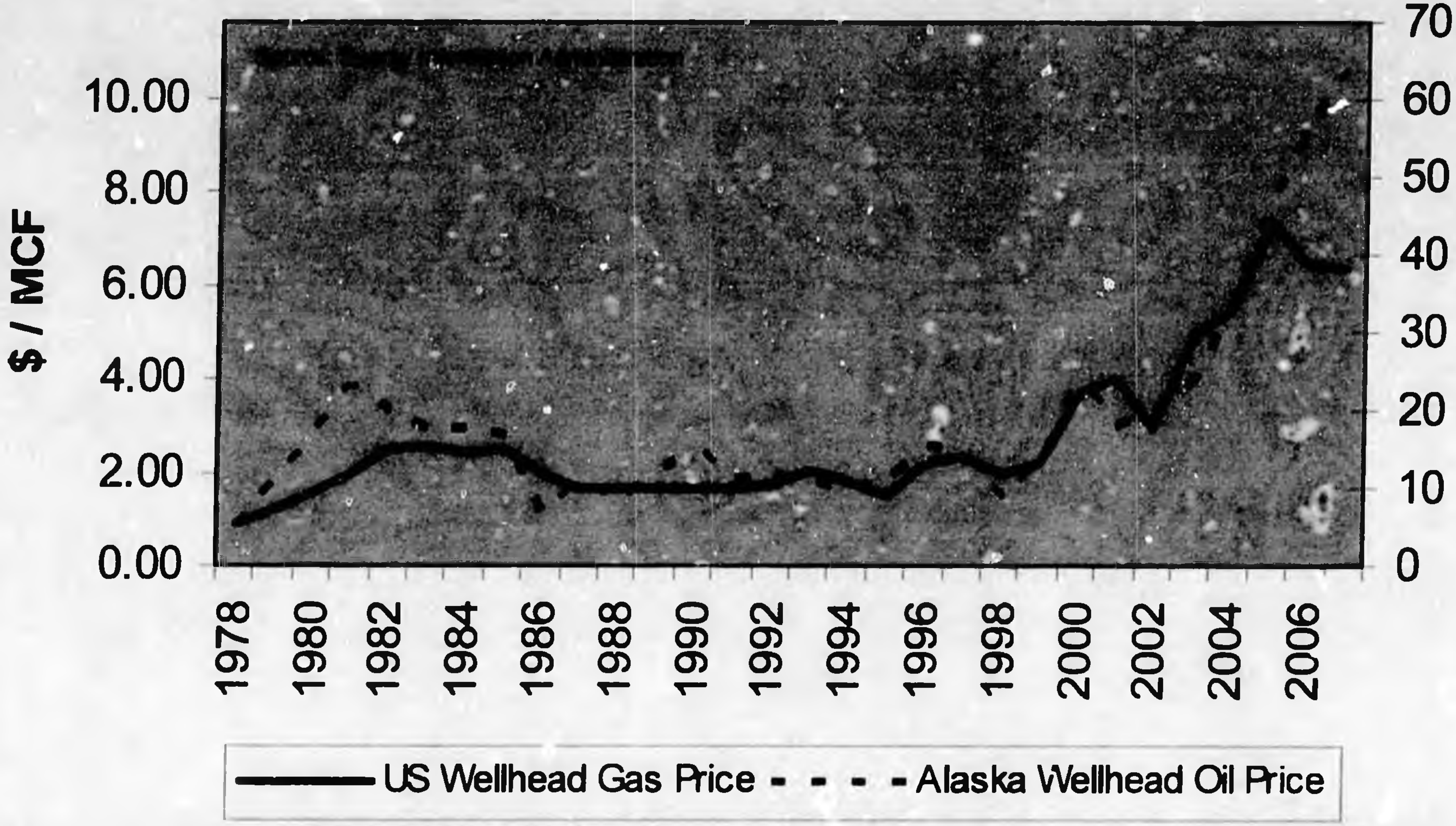
Point Thomson – POD Commitments

ExxonMobil


Point Thomson Unit
Plan of
Development
and
Operations

Historical Oil and Gas Prices

ExxonMobil



Point Thomson Plan of Development (POD)

ExxonMobil

$1.3 Billion Project

- Future Expansion Capability

Plan of Development (POD)

Cooperative Owner Efforts

Development Planning

Learning from Worldwide Operations

Geological and Reservoir Modeling

Data Interpretation

3D Seismic Surveys

Drilled 19 Exploration Wells

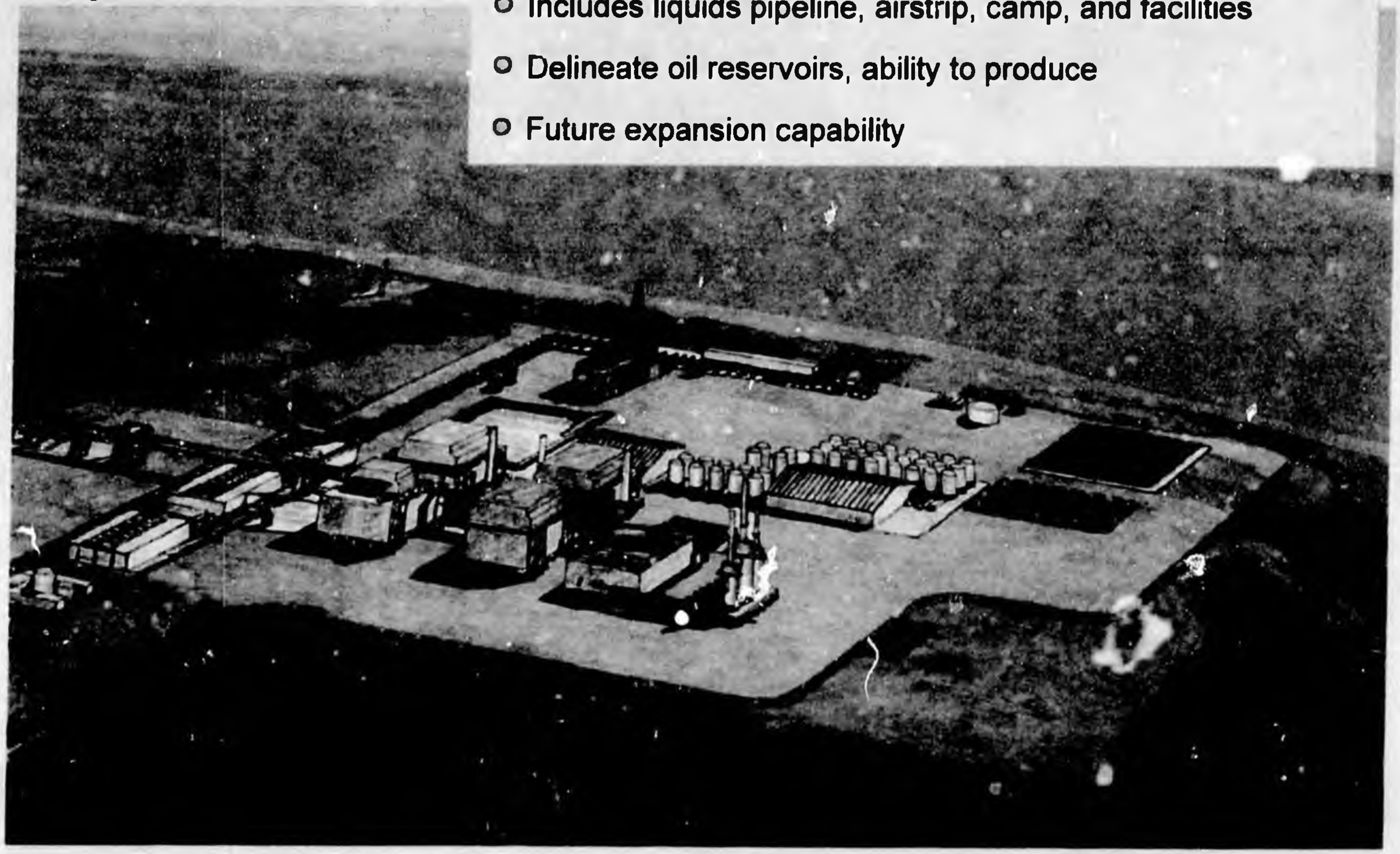
> $800 Million spent to date

PTU POD - Plan to Produce Condensate

ExxonMobil

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

Project Illustration



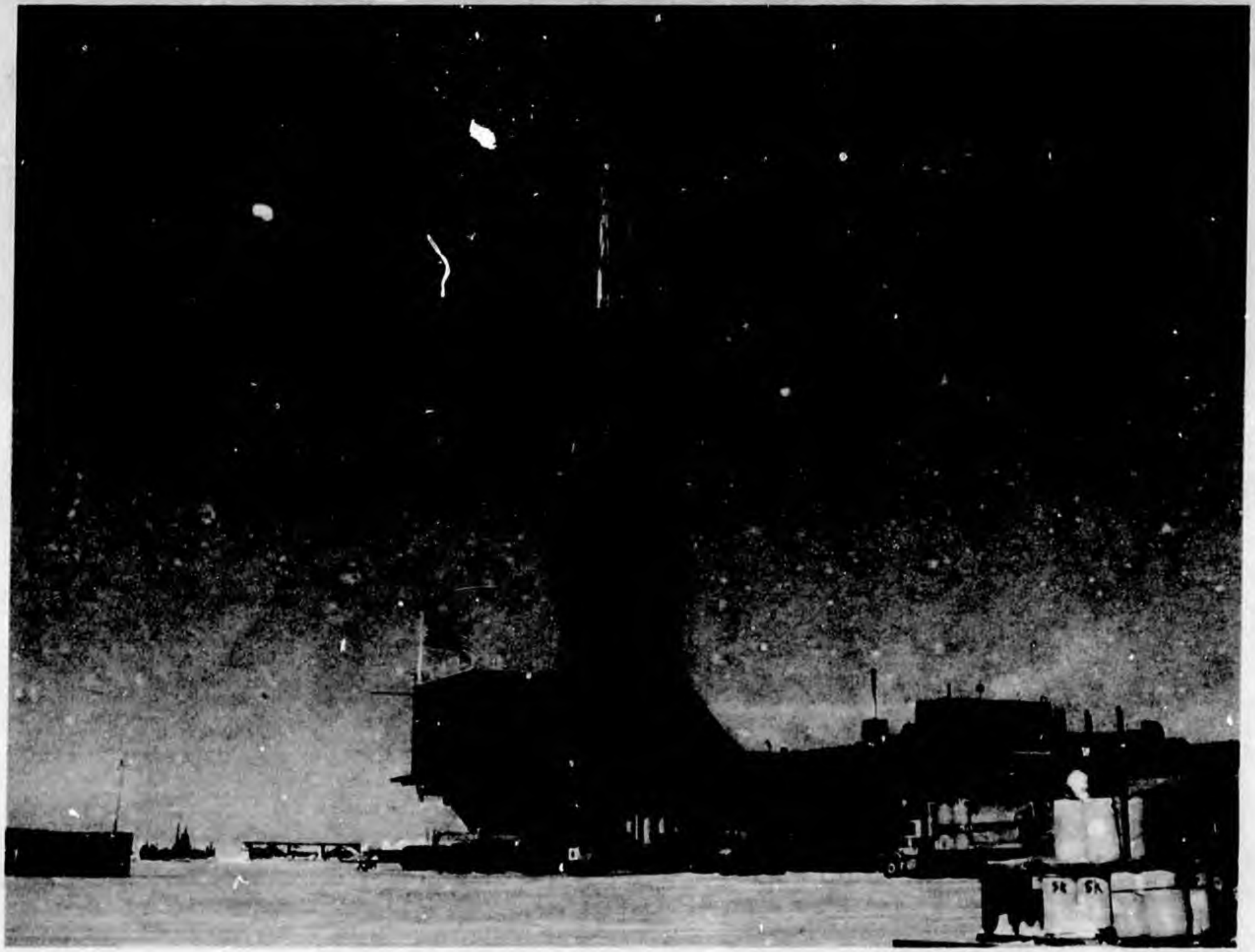
PTU – Project Activity Underway

ExxonMobil

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

PTU - Drilling Rig with Upgrades Underway

ExxonMobil



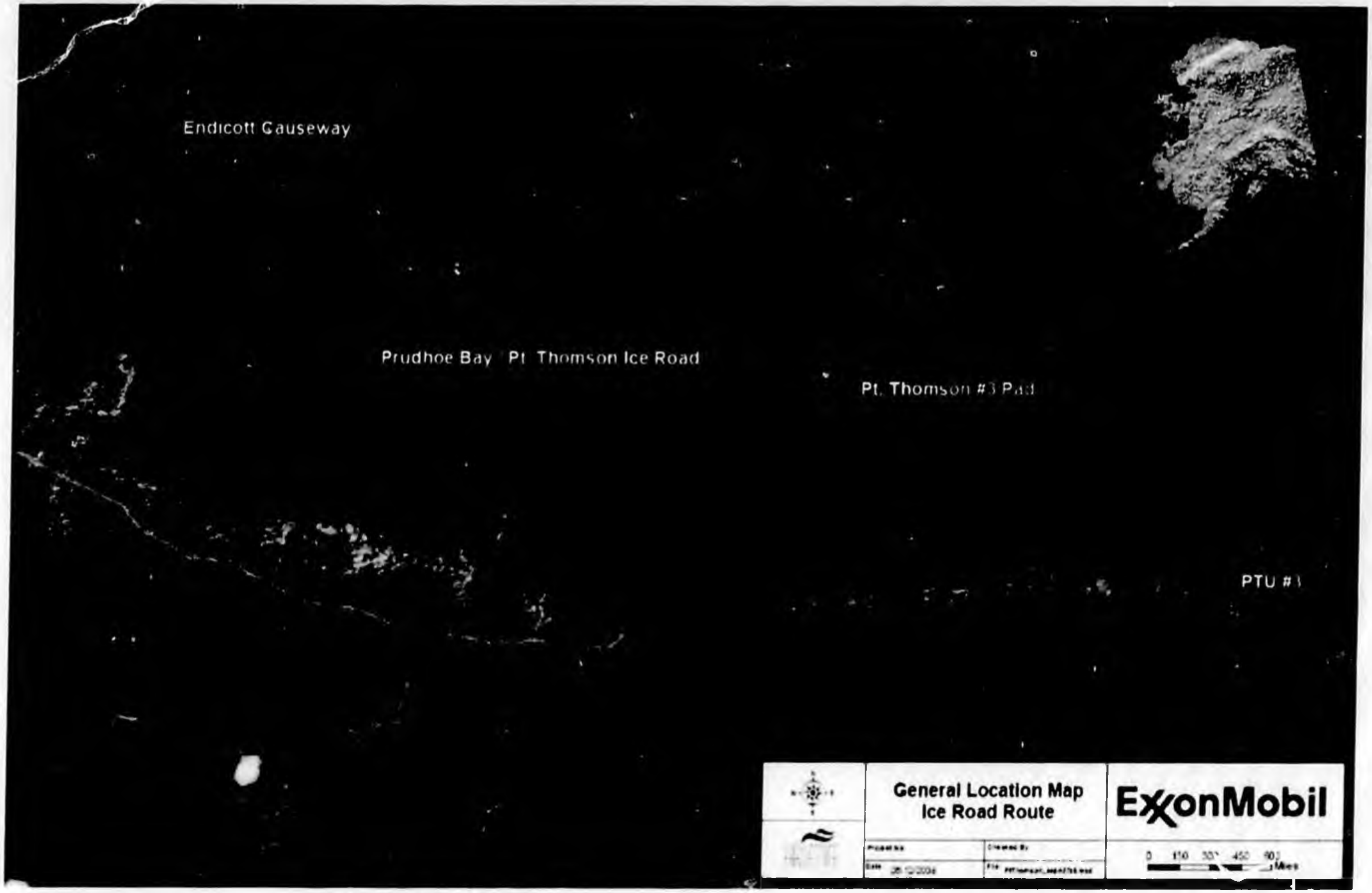
PTU – Project Activity Underway

ExxonMobil

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

PTU – 50 Mile Sea Ice Road

ExxonMobil



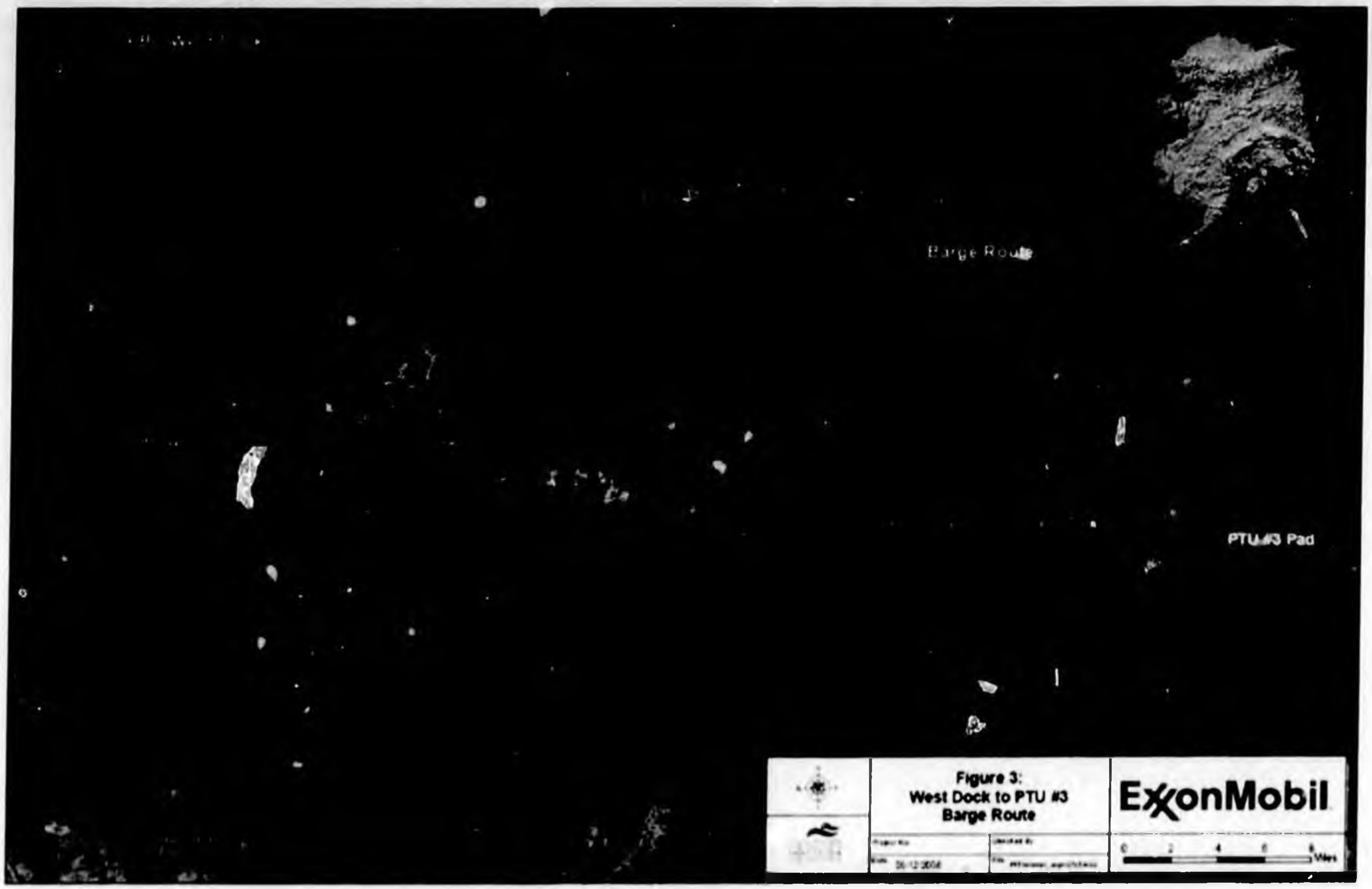
PTU – Project Activity Underway

ExxonMobil

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

PTU – Route for Summer Barge Activity

ExxonMobil



PTU – Summer Site Preparation Plan

ExxonMobil

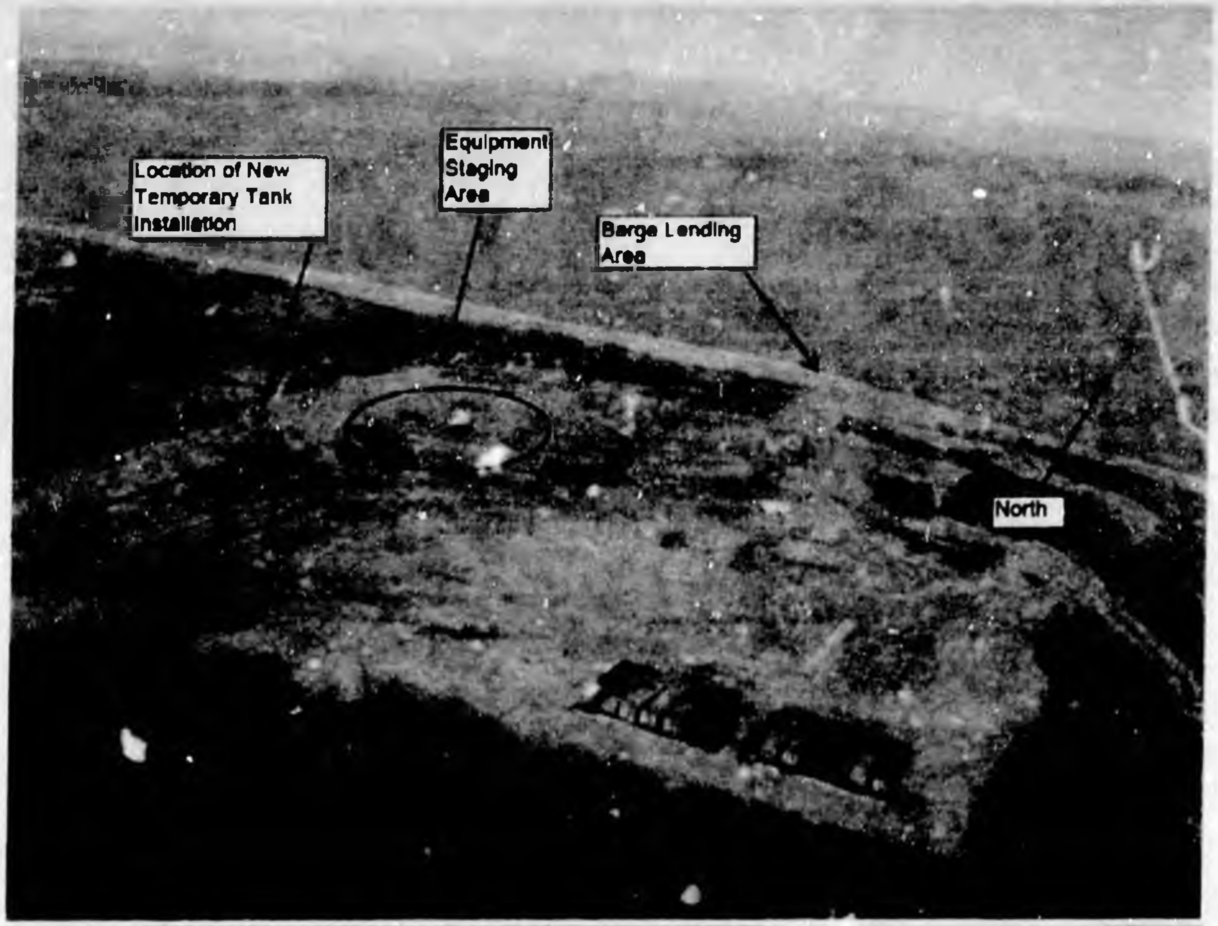


Figure 2
ExxonMobil
Point Thomson
Equipment Staging and Pad Preparation Project Schedule

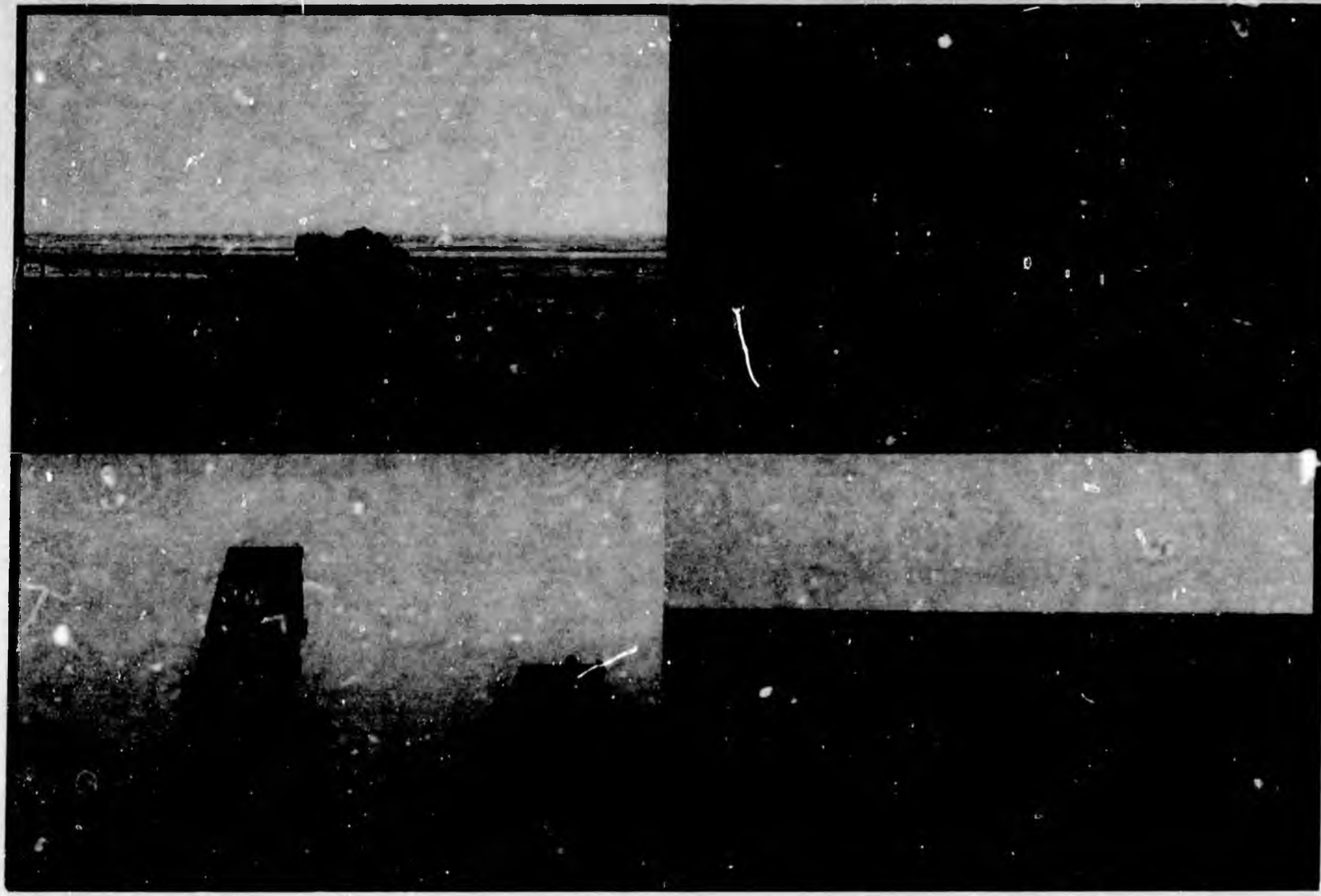
ID	Task Name	Start	Finish
1	Barging of Equipment and Materials	7/15/08	8/30/08
2	Camp Setup	7/15/08	7/20/08
3	Gravel Hauling	7/21/08	7/30/08
4	Pad Preparation	8/1/08	8/15/08
5	Onsite Equipment Backhaul	8/16/08	8/17/08
6	Final Equipment Staging	8/16/08	8/30/08
7	Security Crew Standby	9/2/08	1/31/09

PTU – Project Activity Underway

ExxonMobil

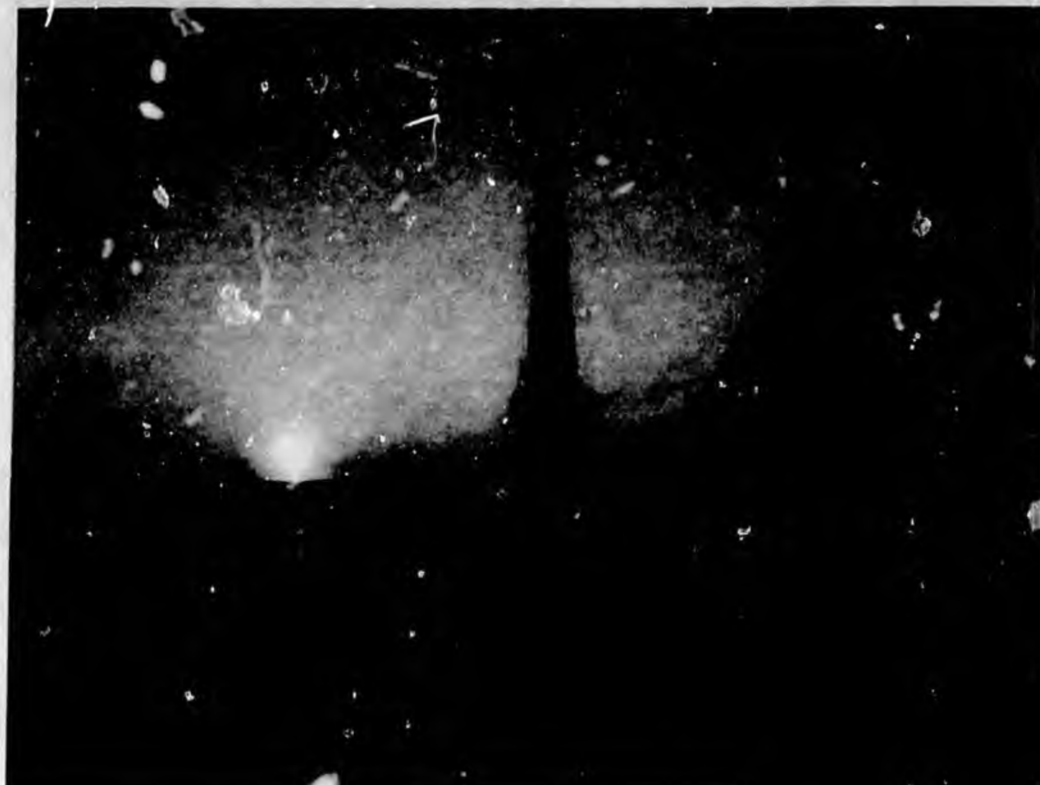
- Nabors Rig 27E contracted
- Rig upgrades ($20M) commenced – Anchorage, North Slope
- Long lead drilling materials ordered
- 50 mile ice road and airstrip contracted to Alaskan company
- Drilling/Project site survey week of 6/23
- Permitting applications in June
- Barging of ice facilities and pad equipment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

PTU – Ice Road Construction & Maintenance ExxonMobil



PTU – Rig Move Over Ice Road

ExxonMobil



PTU – Project Activity Underway

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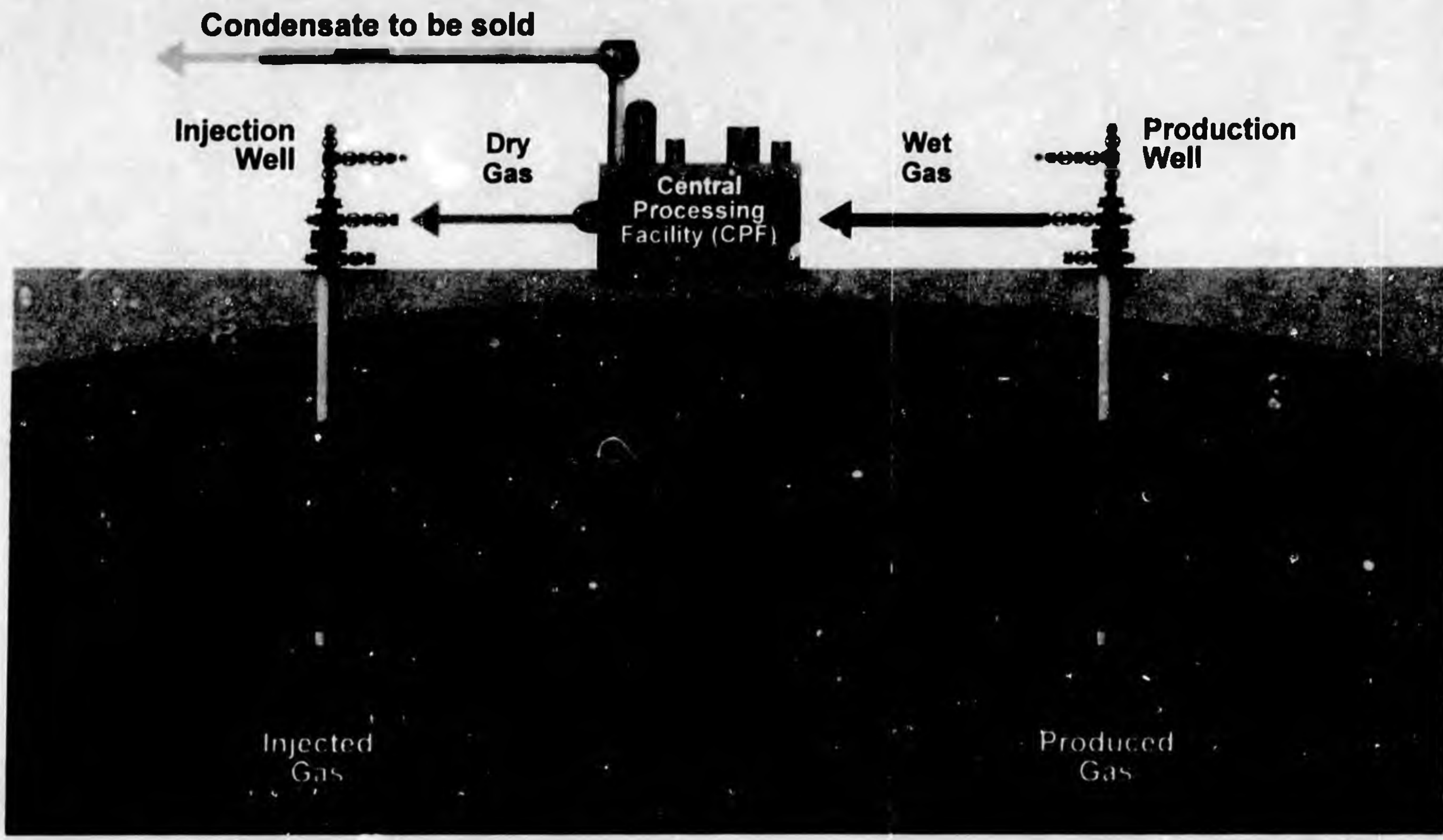
- Barging of ice facilities and pad equipment in July/August
- Construct ice road and mobilize rig to PTU in December/January
- **Spud 1st well February 2009**

Point Thomson - Produce Condensate by Cycling Gas ExxonMobil



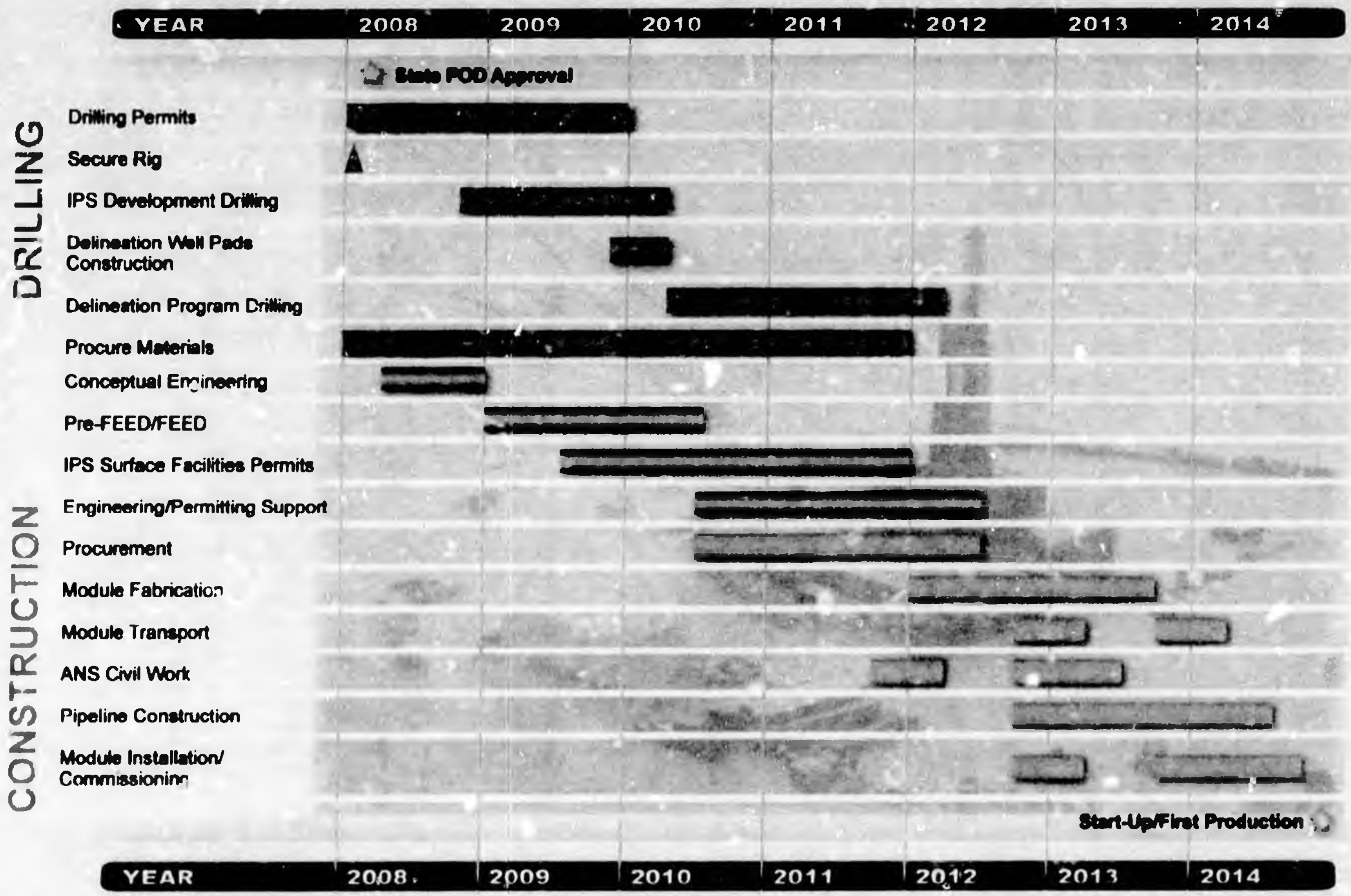
PTU POD - Addressing DNR's Concerns

ExxonMobil

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

PTU POD - Clear and Committed Timeline

ExxonMobil



June 17, 2008

PTU POD - Addressing DNR's Concerns

ExxonMobil

- Engineering & Drilling Starts 2008
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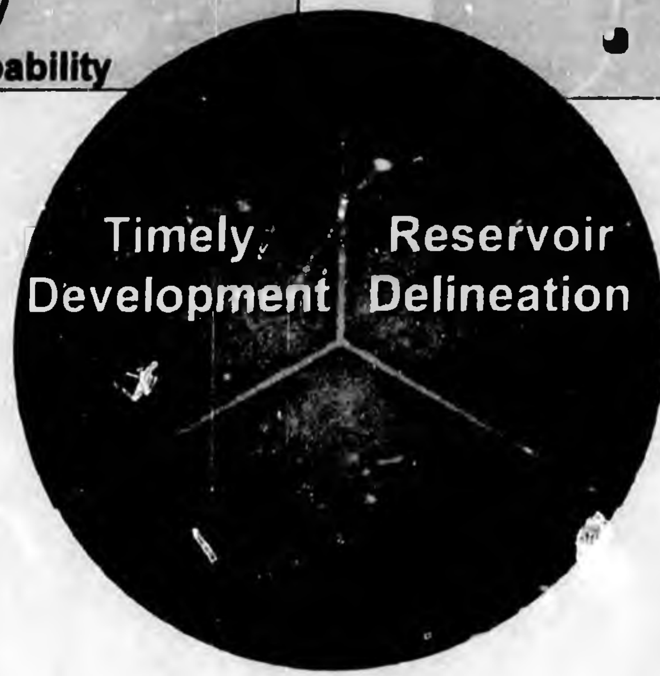
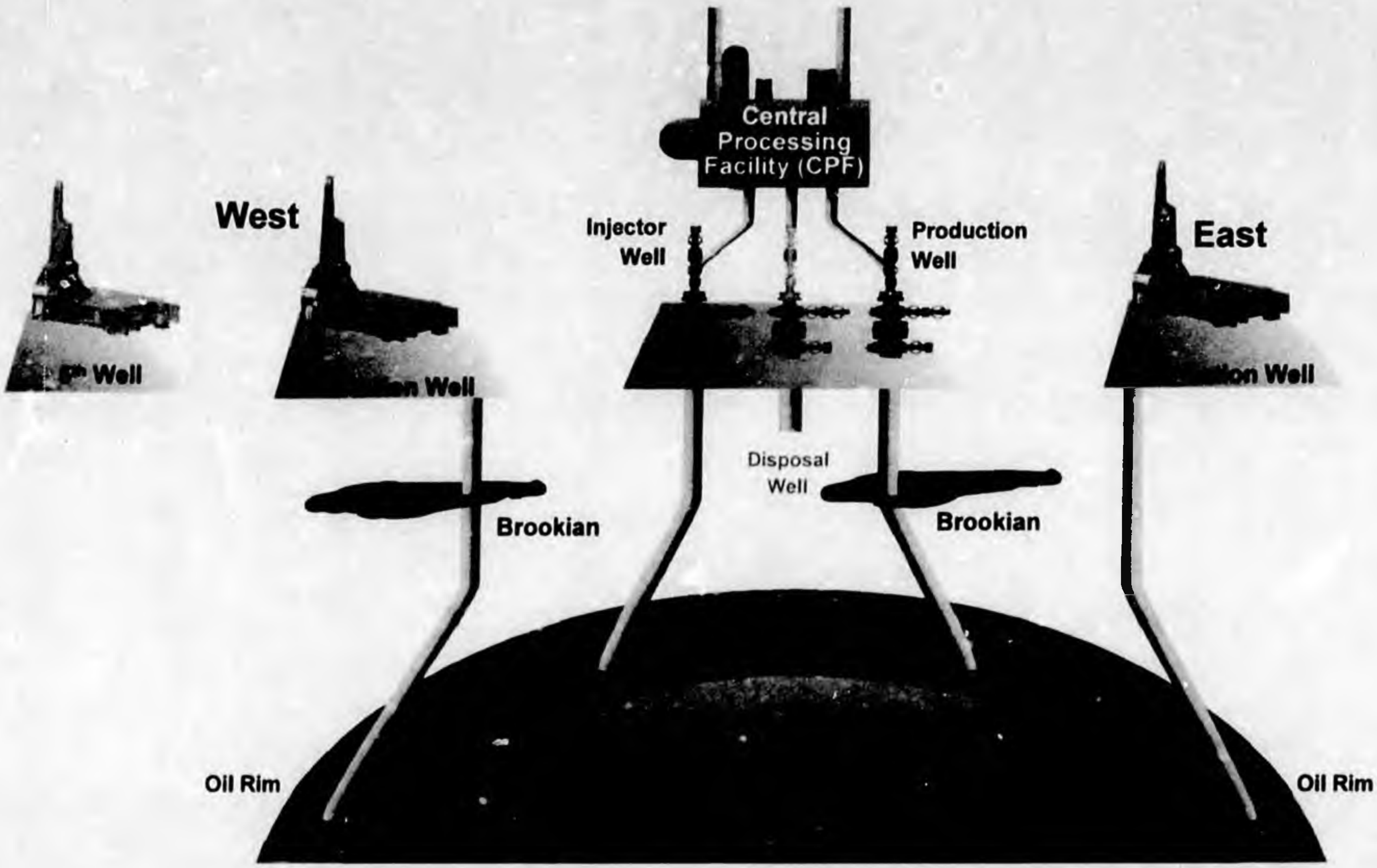
- 10,000 Barrels per Day
- Future Expansion Capability

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



PTU POD - Plan to Develop and Delineate

ExxonMobil



PTU POD - Addressing DNR's Concerns

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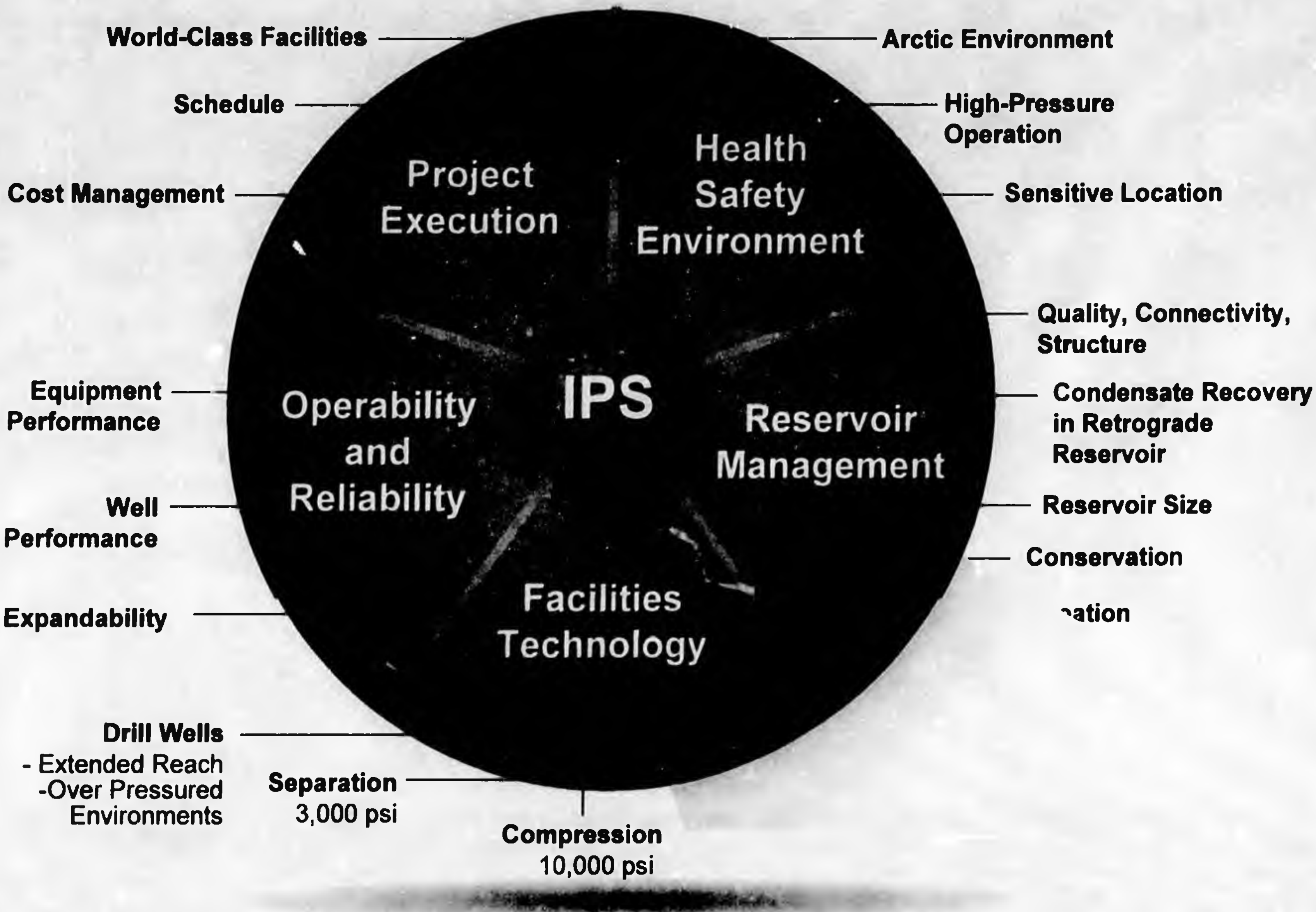
  - 3 oil / gas delineation wells
  - Additional Wells if required

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

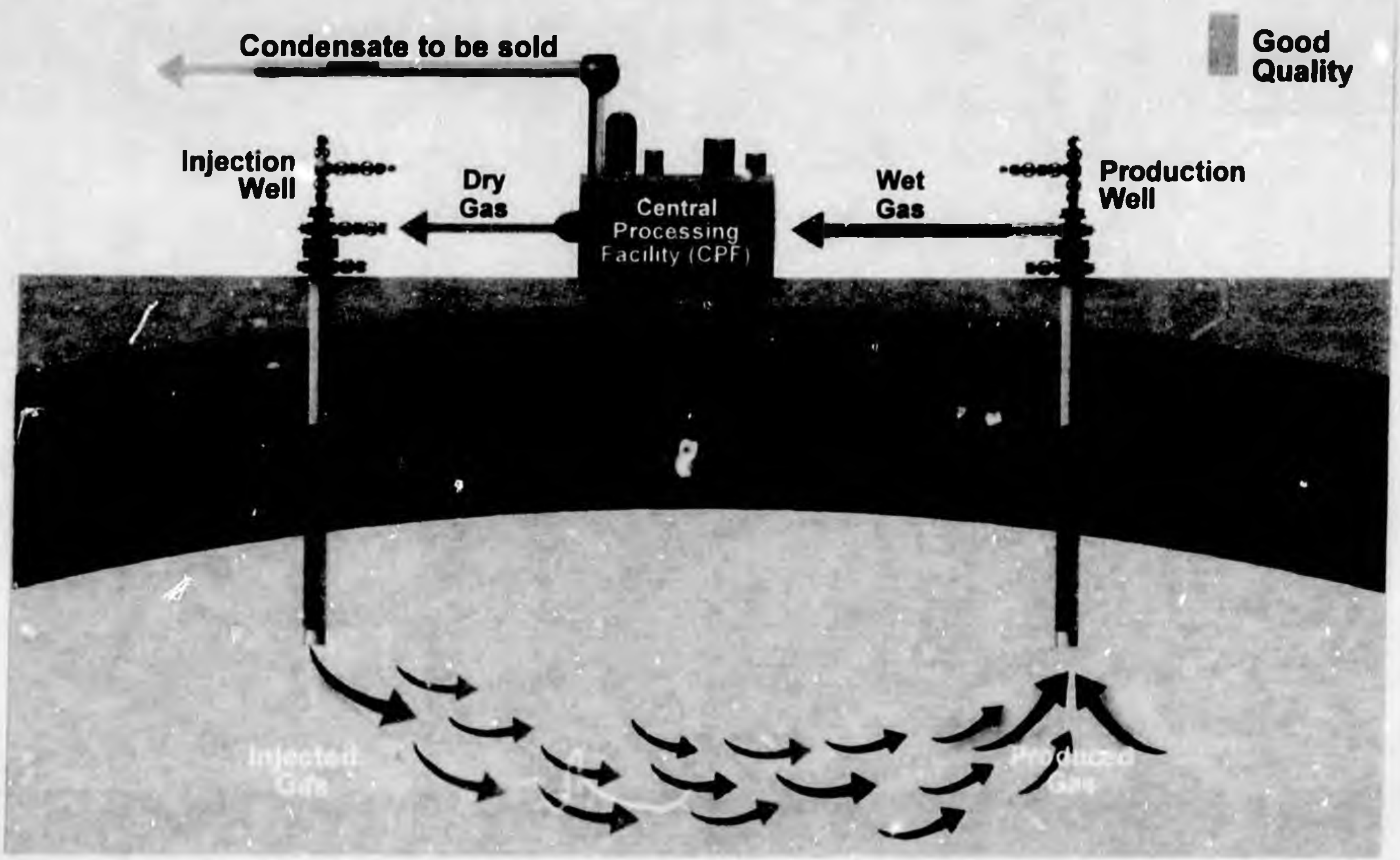
PTU POD - Prudently Manages Risk

ExxonMobil



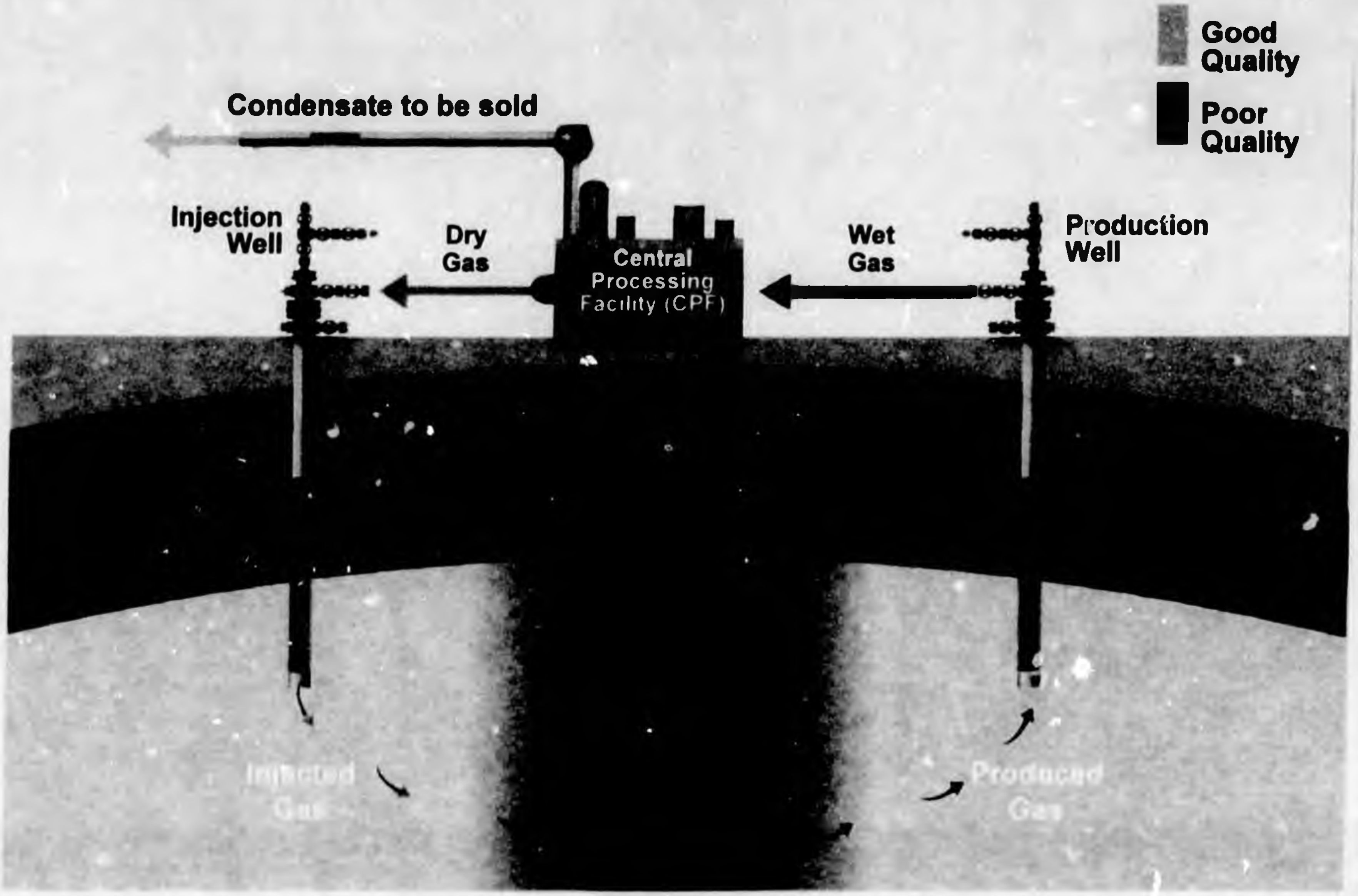
PTU - Reservoir Quality and Performance

ExxonMobil



PTU - Reservoir Quality and Performance

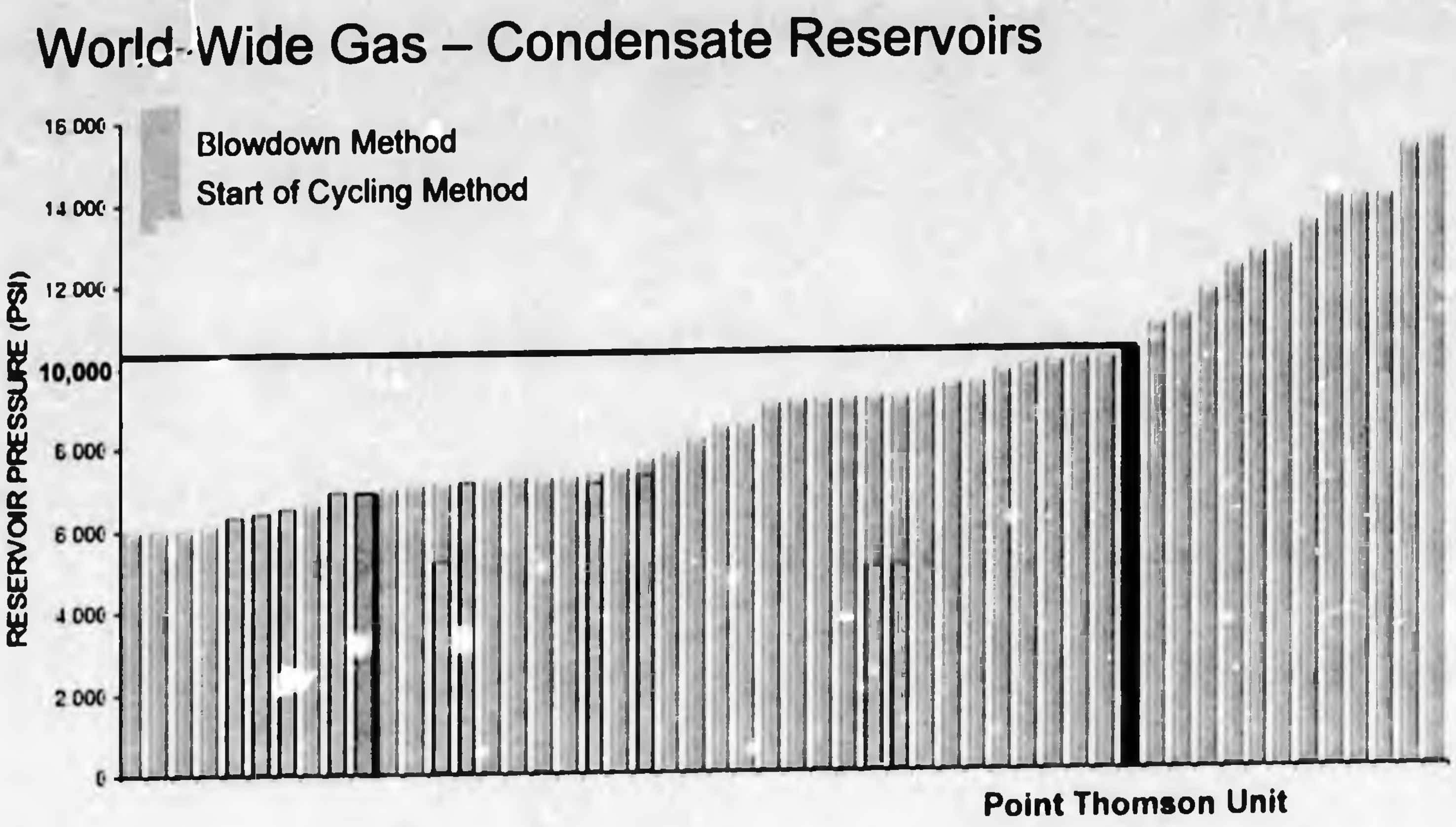
ExxonMobil



June 17, 2008

Cycling at High-Injection Pressure

ExxonMobil



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

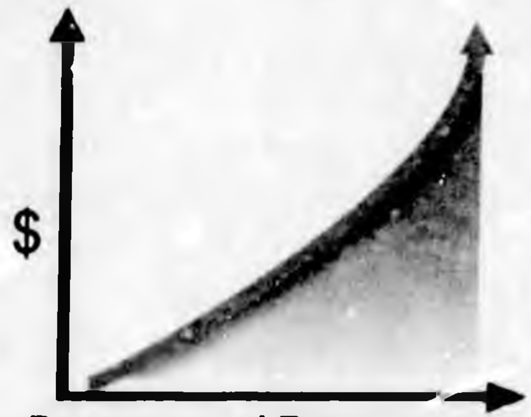
Wells Required for High-Pressure Operations

ExxonMobil

Point Thomson Well

Point Thomson Drilling

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



PTU POD - Phased Approach Mitigates Risk

ExxonMobil

Operations

- Over Pressured
- Long Reach

Apply Critical Learnings

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

POD

Facilities

- Utilize Proven Technology
  - Compressors and Separators

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

Management

- Targets Reservoir "Heart"

Proposed Plan of Development for Point Thomson

ExxonMobil

- **Provides for Production**
  - Commence Engineering 2008
  - Commence Drilling Program Winter '08–'09
  - Provides Jobs – Over 200 People Employed Next Winter
  - 10,000 Barrels Condensate Per Day - 2014
- **Further Delineates Reservoirs**
  - Producer and Injector Wells
  - 3 oil/gas Delineation Wells
  - Additional wells if required
- **Provides Information About Reservoirs**
  - Reservoir Quality, Performance, and Size
  - Prudently Manages Risk – Reservoir & Technology
- **Conservation**
  - Cycling Enhances Resource Recovery
- **Minimizes Environmental Impacts**
  - IPS Utilizes Existing Gravel Pad
  - Offshore Drilling from Onshore Pad
  - Utilization of Ice Roads
- **Expandability**
  - Cycling, Oil Production, and Major Gas Sales

Importance of PTU Gas to Gas Pipeline

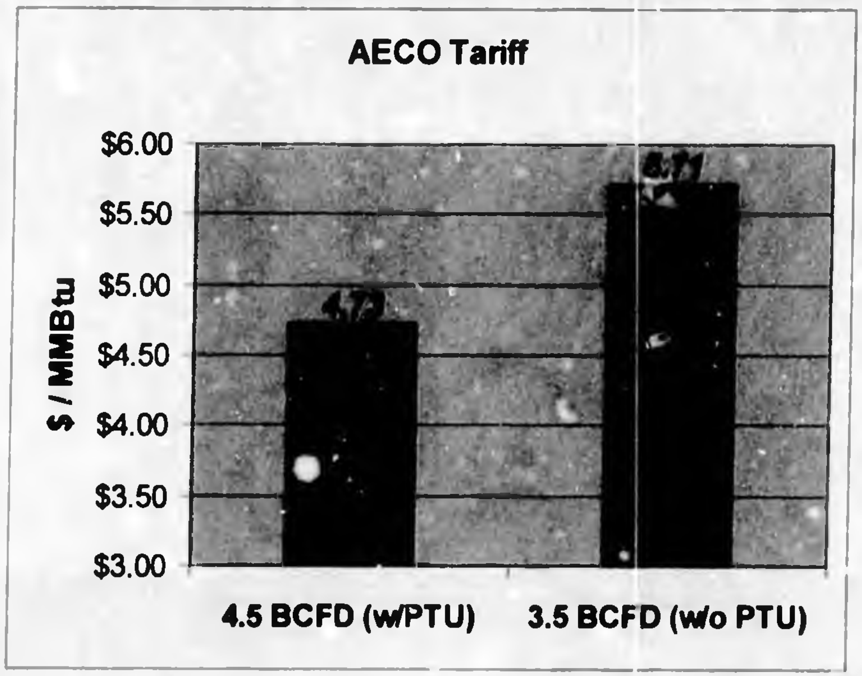
ExxonMobil

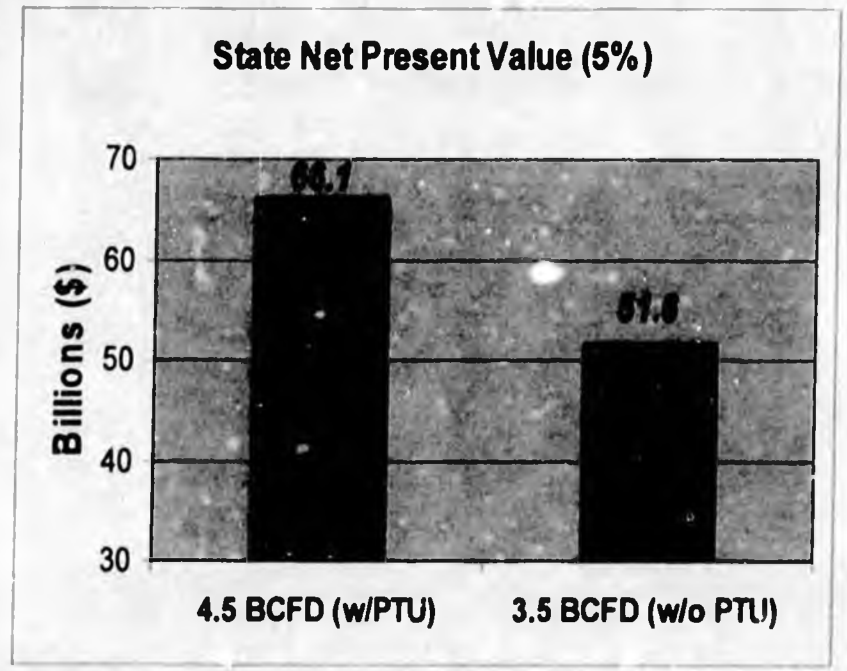
- **PTU Gas represents ~25% of the discovered North Slope gas resource**
- **Supports critical firm transportation commitments ("FT") necessary to secure project financing**
- **Provides security of supply for downstream consumers**
  - Not relying solely on Prudhoe Bay Unit gas or "yet to find" gas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

Importance of PTU Gas to Gas Pipeline

ExxonMobil

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





Source: Black and Veatch – Alaska Gasline Determination Forum

PTU – DNR Summary of PetroTel's Assessment ExxonMobil

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

Point Thomson Project

ExxonMobil

ExxonMobil

Taking on the world's toughest energy challenges.

Background on the Point Thomson Unit and Litigation History and Status

Testimony of DNR before Special Session of Alaska Legislature

June 17, 2008

Nan Thompson, Units Manager, Division of Oil and Gas

1) Background on Point Thomson Unit-The efforts to encourage development have be n ongoing for years.

   a) The essence of an oil and gas lease is timely production. The state agrees to lease its land to a developer in exchange for a share of the production; which is paid as royalties. Oil and gas leases contain a commitment that the lessee will diligently explore and develop the property. When a lessee fails to fulfill this duty, the lease is forfeited. Article 8, Section 8 of the Alaska Constitution mand_tes that a lessee's breach of his duty to develop results in forfeiture.

   b) An oil and gas lease is a temporary (commonly 5 to 10 years) right to explore for and develop hydrocarbon resources. The purpose of the primary term of a lease is to allow the Lessee sufficient time to explore, delineate, and produce the hydrocarbon resources. Leases expire at the end of their primary term unless the lease is producing oil or gas or the lease has become part of a unit.

   c) Units are formed when a group of lessees apply to the state to form a unit because their leases overlay a common geologic formation that holds recoverable oil or gas. There are about 48 units in Alaska, 14 on the North Slope and 34 in Cook Inlet. Unitization extends the term of lease so that the discovered resources can be produced in an efficient and coordinated manner that will maximize recovery and minimize waste.

d) ExxonMobil acquired several leases in the Point Thomson area in 1965. ExxonMobil and Chevron acquired 14 more leases in 1969 and 1970. The majority of the remaining leases were acquired in the 1980s and early 1990s.

e) The Point Thomson Unit was formed in 1977 with 18 leases comprising approximately 41,000 acres of state land. The boundaries have been expanded and contracted several times in the last 30 years. Unit boundaries can be expanded to include lands proven to overlay a producible resource. Unit boundaries are periodically contracted to exclude leases the unit operator fails to develop. The state's form unit agreement requires that all lands not included in a participating area (a process used to allocate production for royalty accounting purposes) within five years of formation of the unit contract out of the unit.

f) The Point Thomson Unit included 45 leases with approximately 106,000 acres of state land when Commissioner Menge issued his decision to terminate it in November 2006. The leasehold interests were held by ExxonMobil-52%, BP-29%, Chevron-14%, Conoco 2.8% and other minor interest holders. [1]

g) The working interest owners elect a unit operator to manage the unit's business; ExxonMobil has been the unit operator throughout this unit's history. Under the Unit Agreement, ExxonMobil was primarily responsible

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

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

h) During the first five year of the unit's existence, ExxonMobil submitted five one-year PODs and drilled several exploration wells. The first POD promised"[i]f oil is discovered in sufficient quantities to warrant future development, the Prudhoe Bay to Valdez oil pipeline will be the probable marketing outlet for the area." Since the early 1980s, ExxonMobil has known about the existence of significant quantities of oil and gas condensate, but has not produced anything.

i) Despite significant uncertainty about the unit's resources, the unit operator drilled no more wells after 1982. New wells would yield geophysical data that would resolve the remaining uncertainties about the reservoir. Two wells were drilled by BP and Chevron in the 1990s and several other wells were drilled by other producers on lands outside of the unit boundary.

j) The unit agreement originally provided that it would expire after five years if Lessees failed to form a participating area. Participating areas are formed before production begins to allocate the production to the appropriate lease. Thus, when the parties signed the unit agreement, they expected that the unit would begin production by 1983. Because ExxonMobil was unable to commit to production by then, DNR agreed to remove the PA formation requirement to prevent the unit from terminating. The amendment extended rather than removed the obligation to produce. When DNR agreed to amend the unit agreement it expected that production would begin by the late 1980s.

k) The years since 1983 can be characterized as a struggle between the state and the unit operator, with DNR demanding development activity and ExxonMobil either insisting that it was not economic or promising to drill wells that were never drilled. The remand decision and decision on reconsideration detail the history.

l) In 1985 and 1990, DNR contracted leases from the unit because Lessees failed to drill promised wells. In 1995 DNR rejected the 12th POD because it did not include a development commitment.

m) Significant quantities of oil were discovered by ExxonMobil in 1975, and by BP and Chevron in 1994. The unit plans have never included development of this oil.

n) By the time the 13th POD was due, the Division of Oil and Gas had a new director who accepted ExxonMobil's promise to develop the unit lands with "farm-out" agreements. Then Director Boyd clearly stated the Division's objective: "Most importantly the division wants a fair and honest attempt to get this acreage explored and be appraised of efforts to develop and produce the Pt. Thomson sands accumulation itself."

o) When the negotiations over the Stranded Gas Development Act became active in 1997, ExxonMobil linked Point Thomson development with construction of a gas pipeline. ExxonMobil suggested that before the construction of a gas line, it would produce the hundreds of millions of barrels gas condensates through a gas cycling program. In 2001, Exxon also promised that the PTU's considerable oil reserves would be produced starting in 2010. From the late 1990s until 2005, DNR approved PODs with the expectation that wells would be drilled to further delineate the unit's resources and that ExxonMobil was progressing towards production with development drilling to begin by 2006. During this period, ExxonMobil drilled no wells.

2) Unit Litigation-DNR has been successful so far and the litigation will probably continue to the Alaska Supreme Court.

   a) The basis for the litigation was the 2001 2nd Expansion agreement and the 18^{th} though 22^{nd} PODs that were designed to implement the commitments made in that agreement.

   b) In 2001 ExxonMobil asked DNR to expand the unit and filed the 18th POD. They repeated their commitment to develop the land by saying "The Owners have endeavored in the attached response to unambiguously demonstrate our commitment to the development of the Point Thomson Unit. We are committing to an aggressive work program and the expenditure of substantial funds that will put us in a position to initiate project execution activities as early as possible." That "unambigous' commitment was to expedite permitting and engineering studies, drill an exploration well by 2003, a production well by 2006 and seven more production wells by 2007. DNR agreed to expand the unit based on these commitments, but none of the proposed development activity occurred. ExxonMobil eventually paid a penalty of $20 Million, plus interest, for failure to perform the promised work.

   c) Since the 21st POD expired in September of 2005, this unit has not been operated under an approved plan of development. The first proposed 22nd POD was submitted and rejected because it did not contain adequate work commitments. Intense negotiations ensued, but the revised POD submitted months later was also rejected. The unit was put in default. The working interest owners asked for reconsideration and appealed to the Commissioner. At the end of the Murkowski administration, Commissioner Menge terminated the unit because ExxonMobil submitted a POD that did not comply with Director Myers' criteria for what an acceptable POD must contain. Acting Commissioner Rutherford affirmed Commissioner Menge's decision when the lessees asked for reconsideration after the new Governor was sworn in.

d) The litigation began with lawsuits filed in Superior Court that were eventually consolidated before Judge Gleason. ExxonMobil also separately filed an action for damages and injunctive relief that was dismissed by Judge Michalski. ExxonMobil appealed the dismissal, but never filed their brief with the Alaska Supreme Court.

e) Judge Gleason ruled in December 2007 that DNR properly rejected the 22nd POD and that it had the legal authority to terminate the unit, but remanded the case to the agency because she found that DNR had not given the parties enough notice that the unit might terminate and the opportunity to argue about other alternative remedies.

f) DNR had a hearing earlier this year on the 23rd POD, the remedy proposed by ExxonMobil. Commissioner Irwin found that the proposal did not meet the statutory criteria for approval and did not protect the state or public interests. Commissioner Irwin also found that the Lessees' failed to explain why termination was not an appropriate remedy given the unit's history. When asked to reconsider, he came to the same conclusion. The remand record will soon be sent back to Judge Gleason.

g) Judge Gleason has not set a hearing or told the parties whether she would like briefs and/or oral arguments on DNR's decision. It is likely that her final decision will be appealed to the Alaska Supreme Court.

3) Lease Actions-The timing and process for reclaiming the 45 leases varies according to the historical level of activity on those lands.

a) Almost all of the leases are beyond their primary terms, and thus held because they were a part of the unit. After the initial unit termination decision, DNR began the process of terminating the leases in February 2007 and the leaseholders appealed. Further action on the lease appeals was delayed until the status of the unit was resolved. Thus, agency action on the status of all 45 leases is pending.

b) 18 of the leases have no wells and are beyond their primary terms and therefore expire when they are no longer part of a unit.

c) On the leases with wells that were once "certified" there is a factual dispute about whether the wells are still capable of production that is likely to be litigated.

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

Commissioned by

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

PetroTel Inc.

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Alaska Division of Oil and Gas

Jack Hartz – Reservoir Engineer
Julie Houle – Petroleum Geologist
Steve Moothart – Petroleum Geologist

Point Thomson Reservoir Study
Purpose / Scope

- PetroTel Inc. conducted an independent evaluation of the Point Thomson reservoir to determine the resources contained in the reservoir and analyze possible recovery methods

- Two main objectives:
  - Construct three-dimensional (3D) geologic models to evaluate the proven and potential hydrocarbon resource
  - Dynamic reservoir simulation to test potential development and off-take scenarios
    - Determine the impact on ultimate recovery of both gas, associated condensate and oil

- Focused on the Thomson sand and does not include resources tested from the underlying Pre-Mississippian strata or overlying Brookian accumulations

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Point Thomson Reservoir Study
Geology / In-Place Volumetrics

- Eleven 3D geologic models were constructed

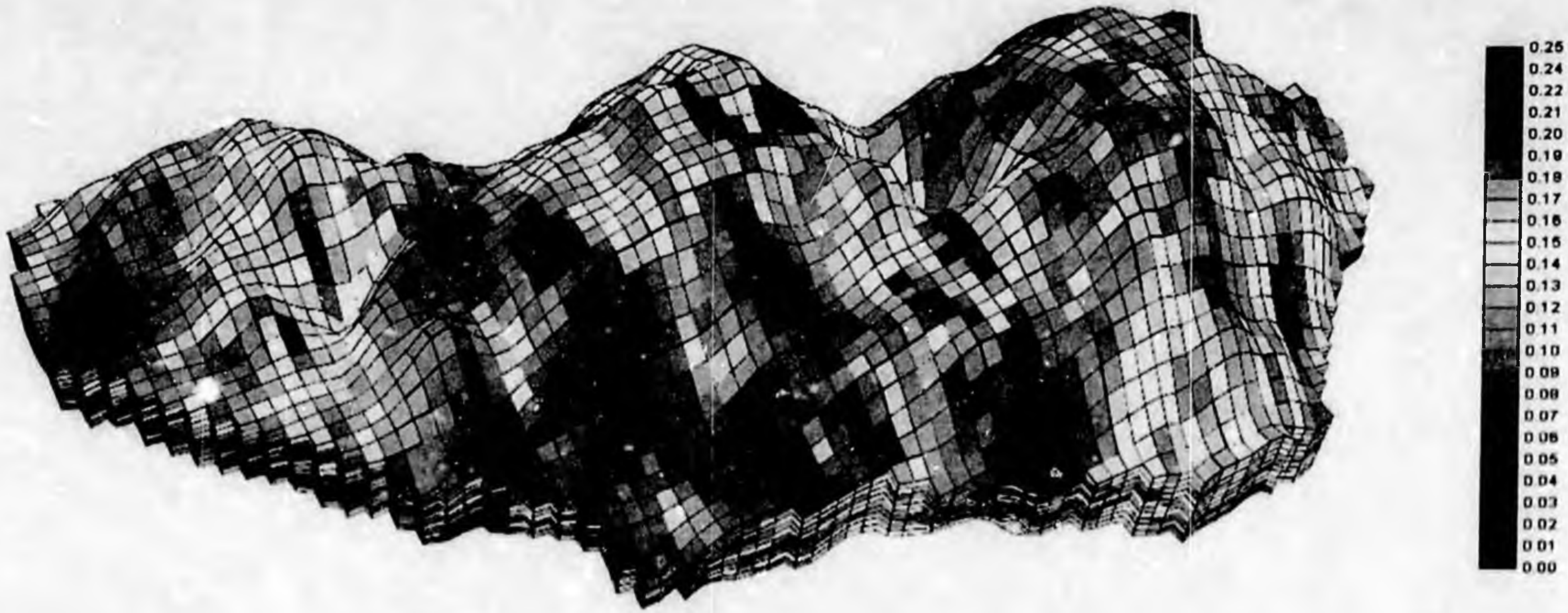
- In addition to gas and condensate, Thomson sand also contains a thin and potentially discontinuous oil-rim that tested over 18º API gravity oil

- No definitive, production test exists in the oil-rim of the Thomson reservoir

- Range of volume in the oil-rim varied in the models due to uncertainty of the depth of fluid contacts

- Original in-place hydrocarbon volumes from geologic models:
  - Gas = 8.5 – 10.4 trillion standard cubic feet (TSCF)
  - Associated condensate = 490 – 600 million stock tank barrels (MMSTB)
  - Potential oil (oil-rim) = 580 – 950 MMSTB

Simulation Model Porosity



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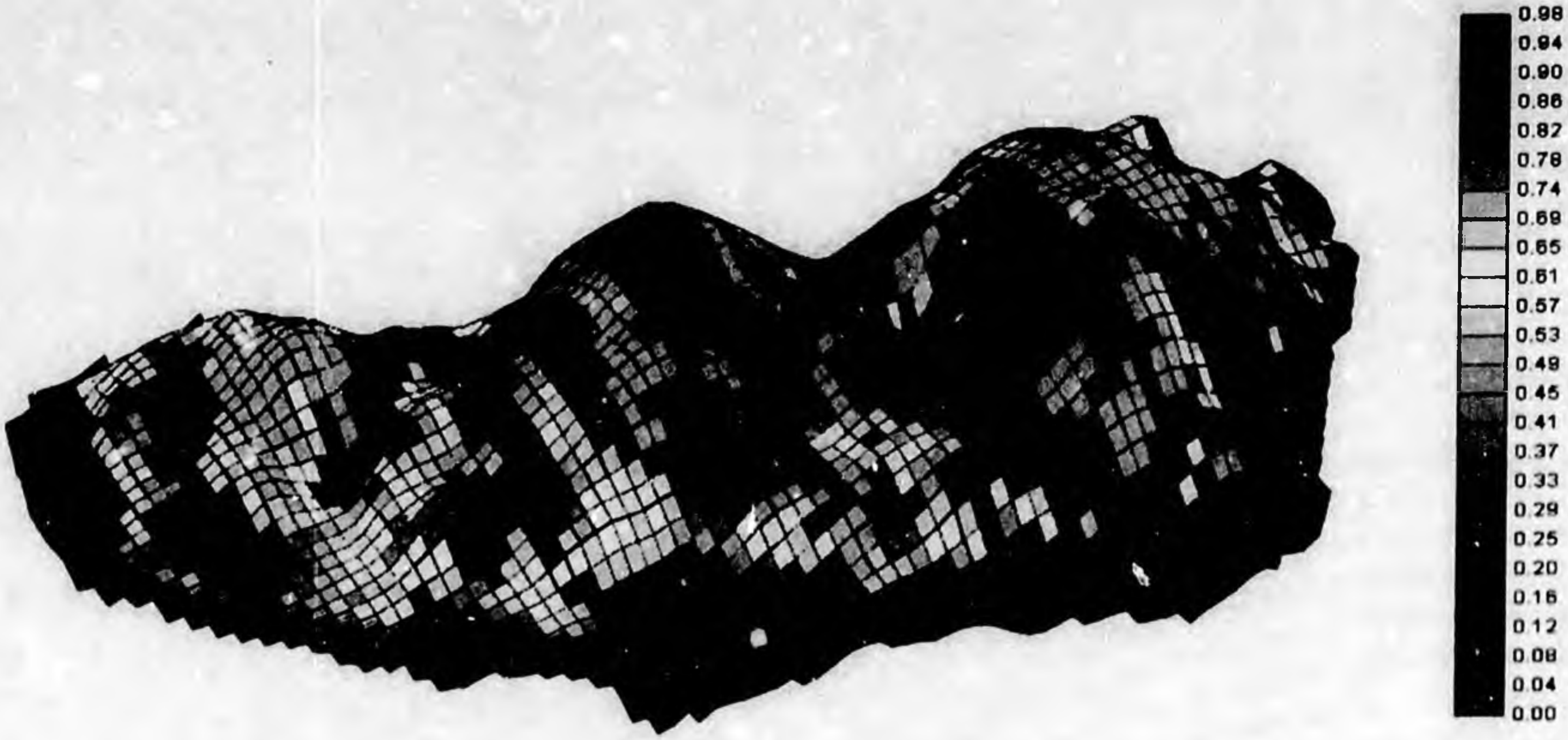
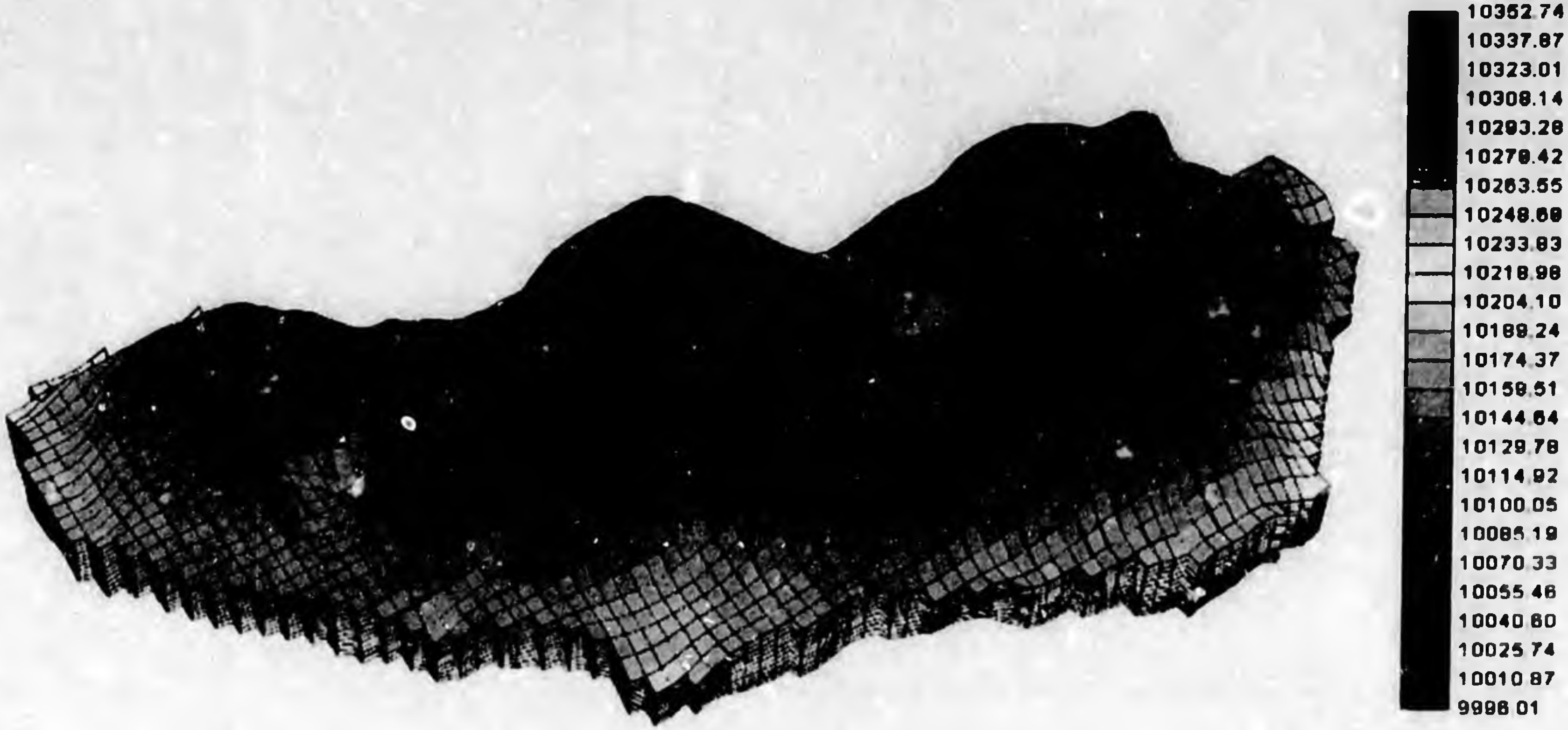
Simulation Model - Sg



Simulation Model - Pressure



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Point Thomson Reservoir Study
Reservoir Modeling- Over 70 simulations

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

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Point Thomson Reservoir Study
Reservoir Simulation - Primary Depletion

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

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Point Thomson Reservoir Study
Reservoir Simulation - Gas Cycling

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

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

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

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

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

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Point Thomson Reservoir Study
Reservoir Simulation - Oil Rim Development

- Oil-rim not adequately delineated or tested
  - Additional wells are needed
- Oil Rim Production:
  - Would likely require of horizontal wells
  - Requires pressure maintenance to sustain maximum oil producibility
    - Gas cycling, direct lean gas injection, miscible gas injection (CO_2), water injection or aquifer encroachment
  - Gas injection helps reduce the viscosity, improve swelling, and mobilize oil
  - Use of offsite gas, such as dry gas or waste CO_2 from Prudhoe, may maximize recovery
- In primary depletion potential oil-rim recoveries varied from 3-16% (30-150 MMSTB) of original oil in place depending on number of wells drilled
    - Gas cycling for 20 years could potentially recover close to 45% (250-400 MMSTB) of the in-place volume of the oil-rim
- Uncertainty in the original oil-rim volume and potential ultimate recovery
- Delineation of the oil-rim during gas cycling will determine the scale of development

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Oil Production Rate and Cumulative Oil Production

BHP=3000 psi