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Production

July 16, 2015

Cathy P. Foerster, Chair
Alaska Oil and Gas Conservation Commission
333 West 7th Avenue, Suite 100
Anchorage, Alaska 99501-3572

RE: Point Thomson Unit
Pool Rules Application

Dear Commissioner Foerster:

ExxonMobil Alaska Production Inc. (ExxonMobil) as operator and on behalf of the Point Thomson Unit (PTU) Working Interest Owners (WIOs) hereby submits to the Alaska Oil and Gas Conservation Commission (Commission) the attached application for pool rules for the proposed Thomson Oil Pool. The requested gas offtake rate of 1,100 million standard cubic feet per day annual average is premised on a major gas sales development plan that will produce gas for delivery to facilities of the Alaska LNG Project and produce liquid condensate for delivery to the Trans-Alaska Pipeline System.

The PTU WIOs believe the described development plan is prudent and will develop the Thomson reservoir hydrocarbon resources consistent with good oilfield practices and sound engineering in compliance with AOGCC statutes and regulations.

The application is being submitted at this time so the necessary approval will be in place to support the Alaska LNG Project and PTU engineering schedules. Approval of the gas offtake rate will provide a firm basis for the design work and to commit to the substantial associated engineering costs.

Please note that a portion of the application is requested to be held confidential pursuant to AS 31.05.035(d), 20 AAC 25.537(b), and AS 45.50.910 et seq. The confidential portion is enclosed in a separate envelope and marked as such.

The PTU WIOs appreciate the time and effort of the Commissioners and staff and respectfully request that a hearing be scheduled between August 31 and September 15. Our goal is to have a decision on the pool rules application by October 30, 2015. Please contact Keith Breiner at 832-624-3763 or via email at "keith.e.breiner@exxonmobil.com" if you have any questions.

Sincerely,

Cory Quarles

CEQ:jpc
Attachments

cc: PTU Working Interest Owners

Pool Rules Application

Point Thomson Unit

July 15, 2015

Pool Rules Application
Point Thomson Unit

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1.0 Introduction

This application for Pool Rules is submitted to the Alaska Oil and Gas Conservation Commission (Commission) in accordance with 20 AAC 25.520 to establish pool rules for development of the Thomson reservoir, including approval of gas offtake rates. The application is submitted by ExxonMobil Alaska Production Inc. (ExxonMobil) as operator on behalf of the Point Thomson Unit (PTU) Working Interest Owners (WIOs). **Figure 1.0-1** shows the general PTU vicinity and **Figure 1.0-2** shows the PTU boundaries and proposed Thomson Pool[1] superimposed on a section-township-range grid. The corresponding legal description is provided in proposed Rule 2, Table 14.0-1. The PTU WIOs will apply for a Participating Area to the Alaska Department of Natural Resources (DNR) as provided in DNR regulatory requirements.

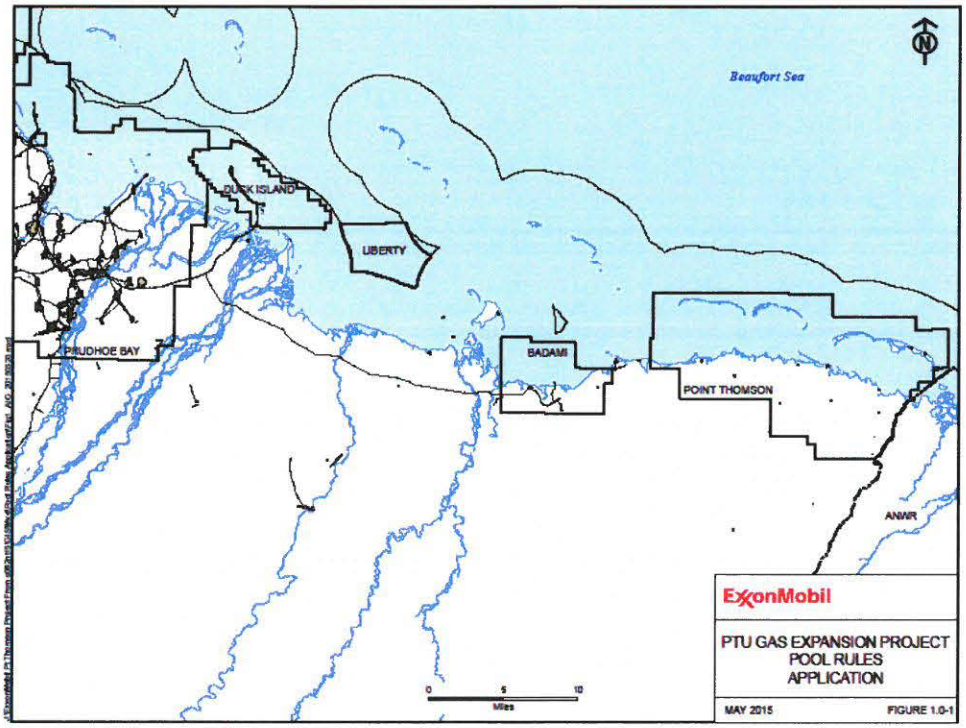


Figure 1.0-1 Point Thomson Unit General Vicinity

[1] While AOGCC regulations do not define an oil pool or gas pool, Point Thomson wells would be classified as oil wells. ExxonMobil would consider the Thomson reservoir to be a gas condensate reservoir or pool, but recognizes the AOGCC regulatory structure that could classify the Thomson reservoir as an Oil Pool.

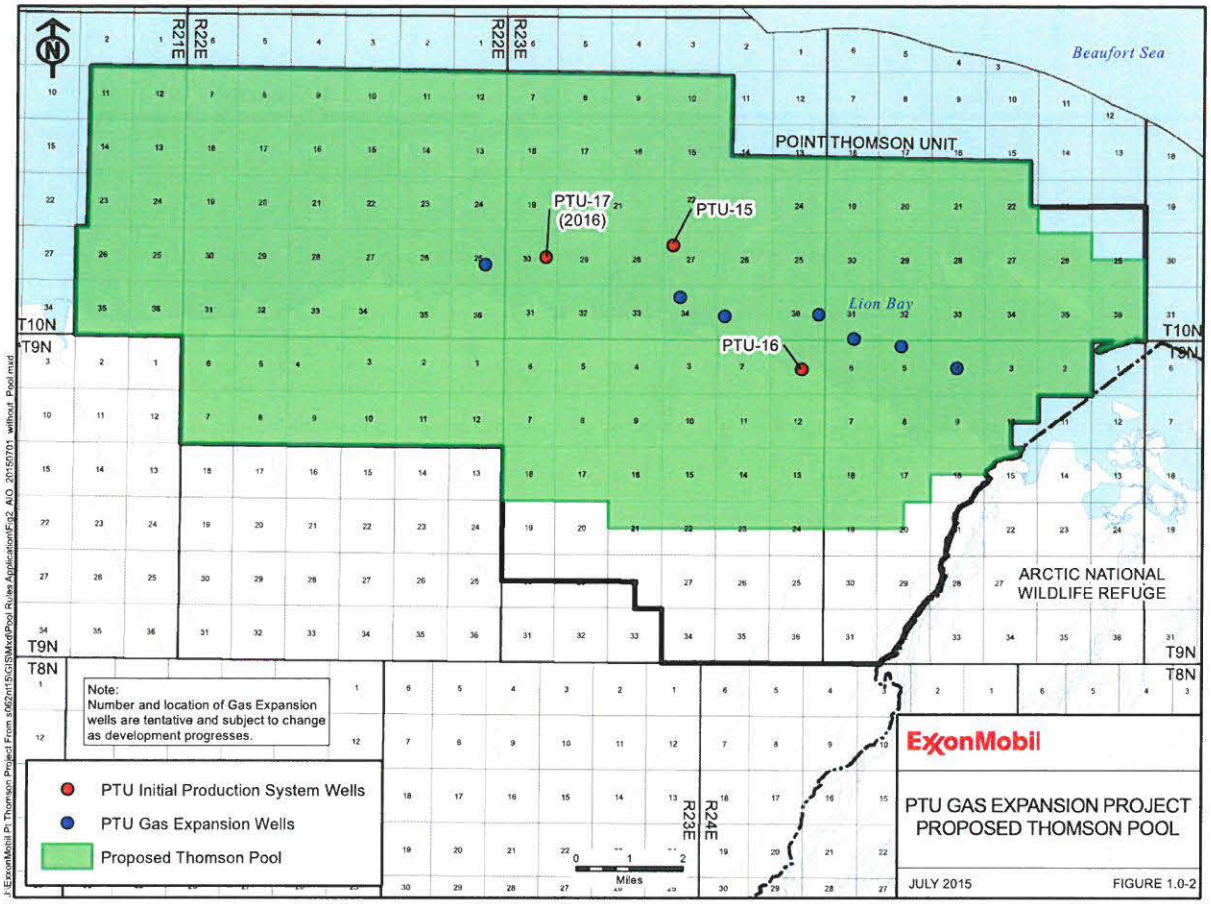


Figure 1.0-2 Proposed Thomson Pool

This application is premised on a major gas sales (MGS) development plan that will produce gas from the Thomson reservoir, extract condensate from the gas and deliver the gas into a gas transmission line and other facilities of an Alaska LNG project. This development plan is consistent with good oil field engineering practices.

The participants in the Alaska LNG (AKLNG) Project have been progressing plans for that project. Based upon the schedule provided to the Alaska legislature in January 2015, the AKLNG Project participants plan to decide whether to proceed to the next stage of that project, Front-End Engineering & Design (FEED), by 2Q 2016. FEED for the AKLNG Project will require a significant commitment of resources, and a key consideration for the project participants will be that sufficient gas supplies will be available to support the project.

The PTU WIOs are submitting the pool rules application at this time so the necessary approval will be in place by October 15, 2015, to support the AKLNG Project and PTU Gas Expansion (GE) Project engineering schedules. Approval of an allowable gas offtake rate is needed to commit

to the substantial PTU engineering costs required to progress this effort and to have a firm basis to design the PTU wells and facilities.

Gas recovery from the Thomson reservoir in an MGS scenario shows little to no sensitivity to the gas offtake rates, and based upon the technical definition work that has been performed, the WIOs request an allowable annual average offtake rate of 1,100 million standard cubic feet per day (MMSCFD). This rate will provide flexibility in design and operations of the PTU facilities and wells that will be used to deliver gas to the gas treatment plant being designed for the AKLNG Project and to account for seasonal variations. During normal operations, it is envisioned that the gas offtake rate from PTU will be approximately 920 MMSCFD at peak winter rates and approximately 820 MMSCFD on an annual average basis. As discussed in this application, ultimate hydrocarbon recovery from the Thomson reservoir for an MGS, such as the AKLNG Project, would be essentially the same as would be obtained from a combination of gas cycling and gas sales, and the timing of hydrocarbon recovery will occur much sooner under an MGS scenario.

This application addresses specific requirements associated with approval of gas offtake. As engineering design and field construction progress, additional pool rules may be sought if necessary to address other aspects of field development.

Background

The PTU was formed in 1977 and is operated by ExxonMobil. The approximate working interests of the WIOs are:

Exxon Mobil Corporation 62.24%
BP Exploration (Alaska) Inc. 32.04%
ConocoPhillips Alaska, Inc. 4.96%
21 other owners with a total combined working interest of less than 1%[2]

The State of Alaska is the landowner and the royalty interest owner of the PTU leases.

The Thomson reservoir was discovered in 1977 with the Point Thomson Unit No. 1 (PTU_1) well. The reservoir is a high-pressure gas condensate reservoir containing a thin oil column that underlies state lands onshore and state waters offshore. Following discovery, additional wells were drilled to confirm and delineate the field and initiate development. To date, a total of 22

[2] Assignment of working interest by three owners is awaiting approval by DNR, which would reduce the number of working interest owners.

wells in the PTU area have been drilled of which 18 have penetrated the Thomson reservoir or equivalent subsurface level.

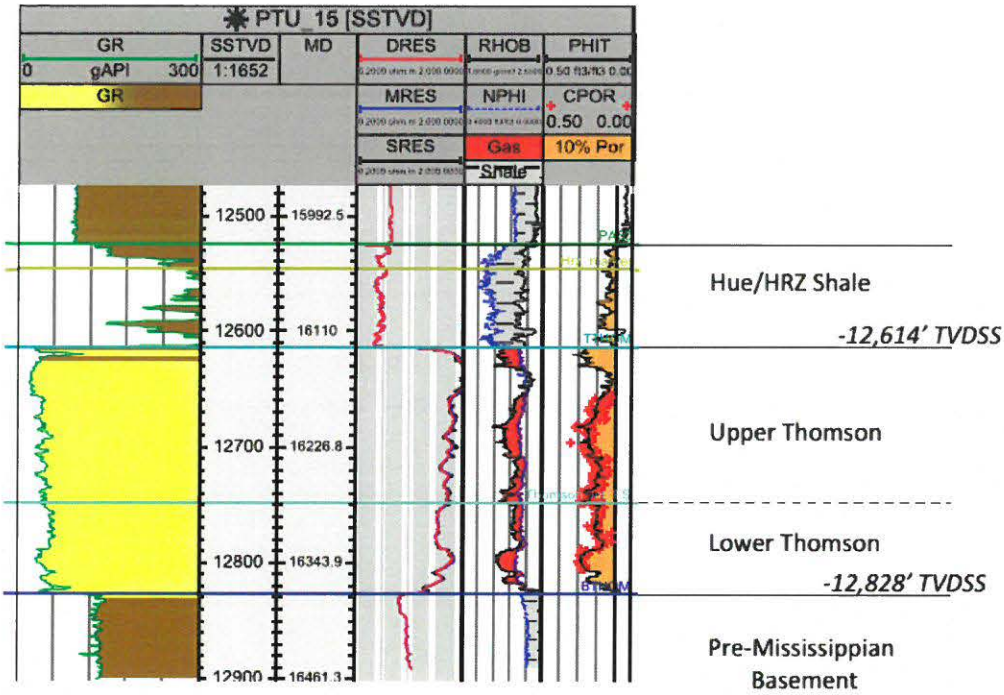
Since discovery, it has been recognized that the PTU gas field could best be developed through a North Slope gas sales project, but that it would require a number of years to develop the transportation and other infrastructure needed to bring the gas to market. Full field gas cycling has been considered, most recently in the early 2000s, but was not found to be viable.

The WIOs approved the Initial Production System (IPS) to initiate commercial development of the field and to provide the foundation for further development. The IPS will: 1) bring natural gas and condensate to the surface from the Thomson reservoir, 2) recover liquid condensate, and 3) re-inject the residual gas back into the reservoir. The condensate will be transported through the recently constructed Point Thomson Export Pipeline (PTEP) for delivery to the existing Badami, Endicott and Trans-Alaska Pipeline System common carrier pipelines.

The IPS Project includes drilling wells, installing and operating infield pipelines and processing facilities, and installing support infrastructure including the PTEP. In its full production mode in 2016, the IPS will have one producing well (PTU_17) and two gas injection wells (PTU_15 and PTU_16). Gas will be produced at the rate of approximately 200 MMSCFD and routed to the Central Processing Facility (CPF) where up to 10 thousand barrels per day (MBD) of condensate will be extracted from the gas. Some of the gas will be used as fuel for the processing facilities. The remainder of the gas will be injected back into the Thomson reservoir to help maintain reservoir pressure and conserve the gas for future development. The IPS will provide information about the effectiveness of gas condensate production and reservoir connectivity to assist in subsequent development plans. The wells and most of the IPS infrastructure were developed in a manner to support future gas production from the field.

2.0 Geoscience and Reservoir Description

The Thomson reservoir corresponds to depths 16,126' to 16,377' measured depth (MD) (-12,614' to -12,828 True Vertical Depth Subsea or TVDSS) on the PTU_15 type log which is a well drilled high on structure (**Figure 2.0-1**). This reservoir has about a five hundred foot thick gas cap and a thin, thirty-seven foot thick oil rim. Over part of the pool area, hydrocarbons (gas) lie directly on rock. In part of the field, the reservoir rock is fractured pre-Mississippian basement (**Figure 2.0-2**). The entire area is considered to be in pressure communication.



Track 1: Gamma ray and VShale
Track 2: Deep , medium, and shallow resistivity (0.2 – 2000 ohmm)
Track 3: Density (Rhob, 1.65-2.65 g/cm3) and Neutron Porosity (0-0.60)
Track 4: Total Porosity with core porosity points (0-0.50)

Figure 2.0-1: The Thomson sand interval in the PTU-15 well, shown with the overlying Hue/HRZ Shale and Canning Fm and the underlying pre-Mississippian basement. This well is high on structure, will be an injector well during IPS, and a producer during Gas Expansion

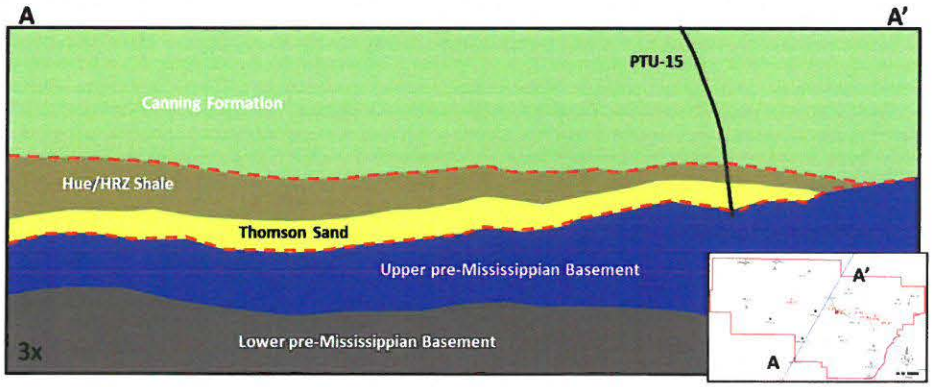


Figure 2.0-2: Schematic cross section, oriented approximately in a dip orientation, showing the Thomson Sand overlying Upper pre-Mississippian basement and overlain by the Hue/HRZ Shale. Two regional unconformities are represented by red dashed lines

2.1 Description

Generally, the hydrocarbon accumulation is defined by a gently dipping anticlinal closure with a stratigraphic barrier to the southwest part of the field. The gas cap is confined by the overlying Hue/HRZ Shale and the Canning Formation. The crest of the reservoir is approximately -12,400' TVDSS and extends to about -14,500' TVDSS in the Unit area. Reservoir pressure is about 10,100 psi at -12,700' TVDSS, the approximate midpoint of the gas cap. Average reservoir temperature is 220-230°F.

Twenty-two wells have been drilled in and near the Unit, including the recently drilled Class I disposal well. Eighteen wells penetrated the Thomson level. Sixteen of the eighteen wells encountered Thomson reservoir, and the Thomson is eroded in two wells. Four wells penetrated only the shallower sands in the Brookian section and provide valuable information for velocity modeling in the overburden. Further description of the distribution of Thomson reservoir across the Unit can be found in Section 2.3: Structural Setting.

Over 1,750 feet of Thomson whole core has been obtained from twelve wells. The primary seismic dataset is a 3D cube acquired in 1989, which covers approximately 85% of the Unit area. This survey was reprocessed in 2013-2014 in order to improve imaging throughout the section (permafrost through basement).

2.2 Depositional Setting

The Thomson reservoir is a clastic reservoir deposited on a regionally extensive, Lower Cretaceous unconformity. The Thomson reservoir is interpreted to be a fan delta which prograded primarily in a southwest direction from a northwest – southeast trending paleo-high (Barrow Arch, **Figure 2.2-1**). Proximal Thomson reservoir, near the erosional limit, consists of poorly sorted alluvial fan breccias and subaqueous conglomerates which grade to the southwest into well-sorted clean sandstones. Distal reservoir comprises silty sandstones and siltstones. A conceptual stratigraphic trap lies along the south/southwest margin of the reservoir that is formed by an increase in shale content, decrease in porosity and permeability, and lack of hydrocarbons. The detrital composition is very similar to the pre-Mississippian lithology of dolomite, argillite, quartzite, and phyllite. Generally, coarser grained lithologies are dominated by carbonate lithics, and greater concentration of quartz and ductile grains are present in the distal portions. The Thomson reservoir is divided into Upper and Lower sub-units based on stacking patterns observed in core description and log character. The Lower Thomson exhibits a prograding character which is overlain by an overall, backstepping and retrogradational Upper Thomson (**Figure 2.2-2**).

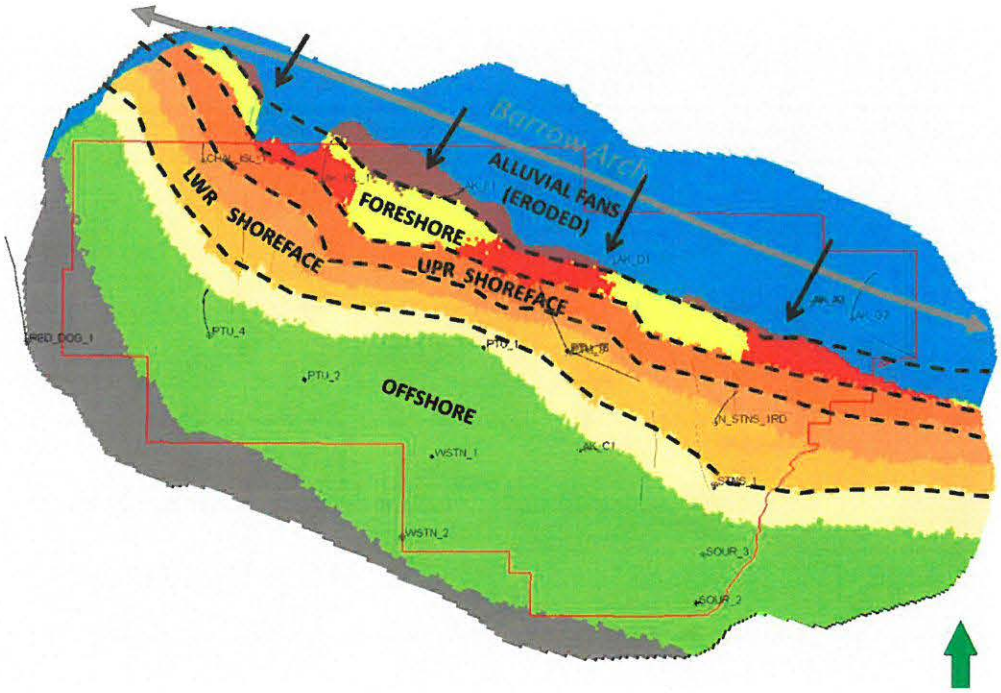


Figure 2.2-1: Schematic of fan delta environment for Point Thomson

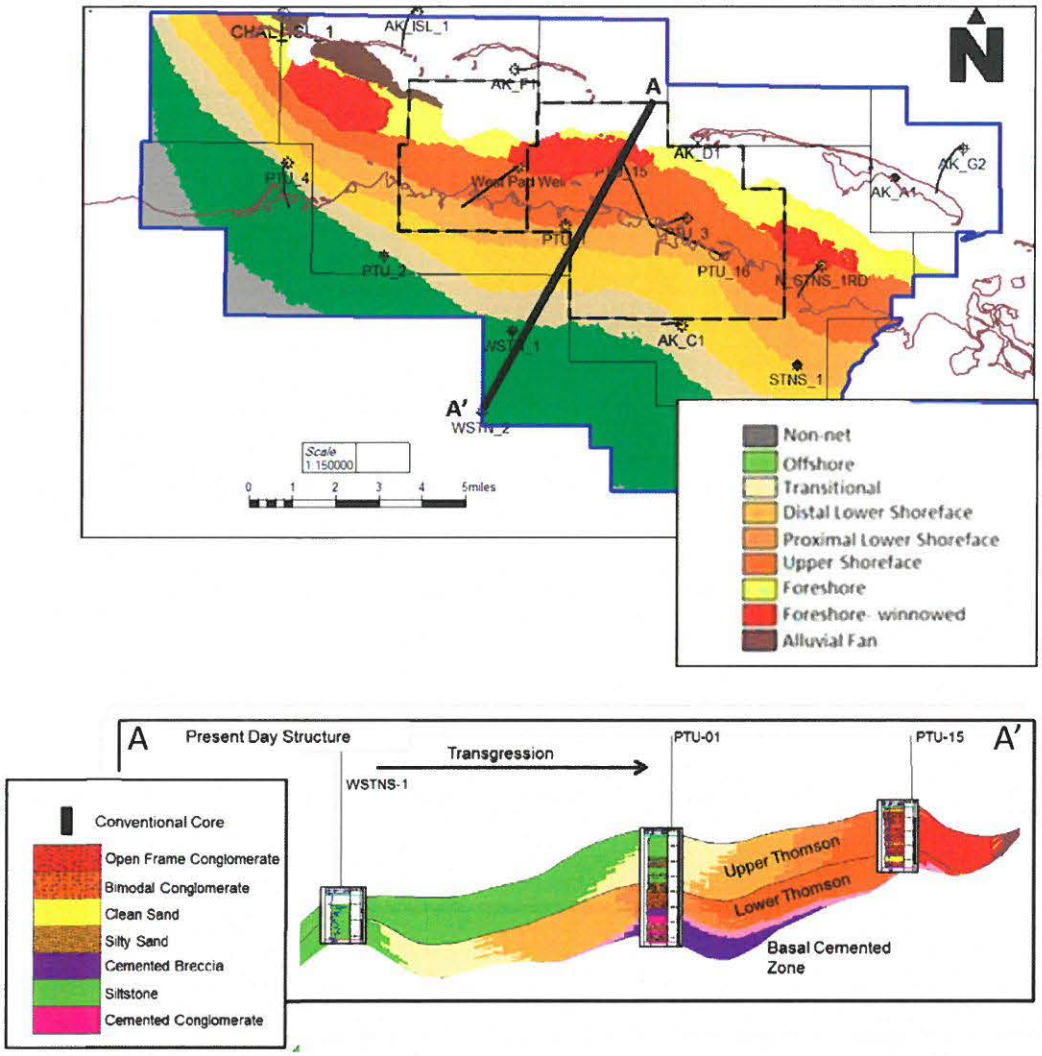


Figure 2.2-2: Top: view of Upper Thomson environments of deposition. Bottom: cross section through A-A' showing depositional environments with petrofacies described in core

Thomson Reservoir Petrofacies:

Six petrofacies are identified in core based primarily on grain size and modified where appropriate by degree of cementation, sorting, and ductile grain content (**Figure 2.2-3**). These six petrofacies also form logical groupings in a porosity and permeability plot. Conglomerates are divided into three petrofacies based on sorting and degree of cementation. Open Framework Conglomerate (PF-1), as the name implies, has framework clasts with very little sand or silt-sized particles as matrix. This Open Framework Conglomerate, to date only found

in the PTU_15 well, leads to excellent reservoir quality with porosity values up to 28% and permeability ranging from hundreds of millidarcy (mD) to tens of Darcies (D) (permeability measurements described in this section are ambient permeability relative to air). In contrast, the Bi-Modal Conglomerate (PF2) has a wide range of grain sizes, from boulder and pebble clasts to sand and silt size particles acting as matrix. Bi-modal Conglomerates still exhibit good reservoir quality, with average porosity ~14% and permeability ranging from ~1 mD to less than 10 D. Cemented Conglomerate & Breccia (PF5) have a similar grain size distribution as Bi-Modal Conglomerates, but a high degree of cementation (>10% calcium carbonate), making them poor quality reservoir rocks (less than 8% average porosity and 0.1 mD).

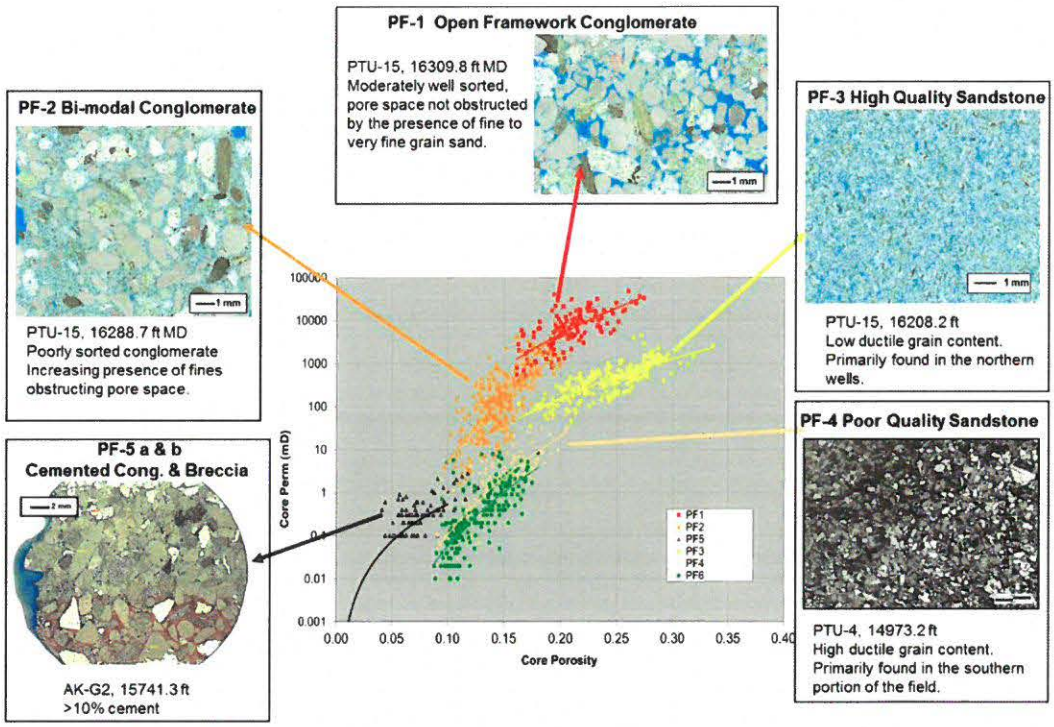


Figure 2.2-3: Petrofacies observed at Point Thomson: core porosity and permeability for six petrofacies, and photomicrographs or whole core photo are shown for five petrofacies (Siltstone petrofacies not pictured).

There are two sandstone petrofacies: Clean Sand (PF-3) and Silty Sand (PF-4). Clean Sand petrofacies generally has <10% ductile grain content, and is of very good quality with an average porosity of 24% and permeability in the range of hundreds of mD to less than 10 D. The Silty Sand petrofacies contain > 15% ductile fragments, and are poorer quality reservoir

(average porosity 12%, permeability less than 10 mD). Siltstone is the sixth petrofacies (PF-6), and, similar to Cemented Conglomerate & Breccia, makes very poor quality reservoir (permeability less than 1 mD). A marine setting is indicated by trace fossils including *Helminthopsis*, *Terebellina*, *Diplocriterian*, and *Asterosoma;* these are observed in fine-grained sandstones and siltstones.

Thomson Reservoir Depositional Environment:

In general, there is an overall trend of coarse-grained to fine-grained rocks from NE to SW. Cemented conglomerates and breccias are found in Alaska Island #1 (AK ISL_1), Alaska State F-1 (AK_F1), and Alaska State G-2 (AK_G2), and are interpreted to be remnant alluvial fan deposits of the most updip portion of the fan delta system. Another distribution of cemented conglomerate and breccia is found at the base of the Lower Thomson, centered around the PTU_1 and spread in a NW-SE elongate form (**Figure 2.2-4**); the areal distribution of this deposit is aided by seismic mapping as a phase reversal on the base Thomson (trough converts to a peak where cemented conglomerate is present). These cemented facies are interpreted to be an early, severely eroded alluvial fan that was transgressed by the main section of Thomson reservoir. The less cemented conglomerates and clean sandstones also form an elongate strip in the middle portion of the field (e.g. PTU_1, PTU_3, and PTU_16, Staines River State #1 [STNS_1]), and the silty sandstones and siltstones are found along the southwest fringe (PTU_4, West Staines State #1 (WSTN_1) and #2 (WSTN_2).

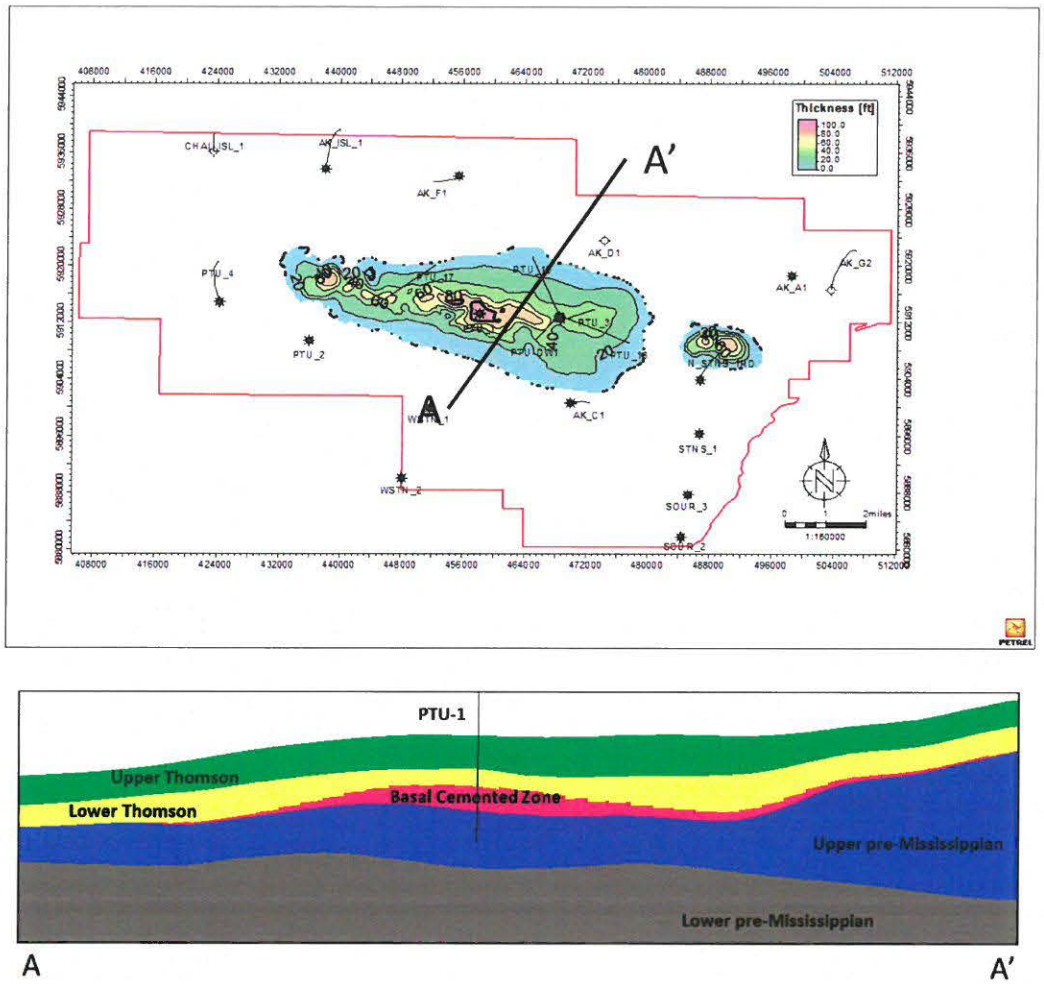
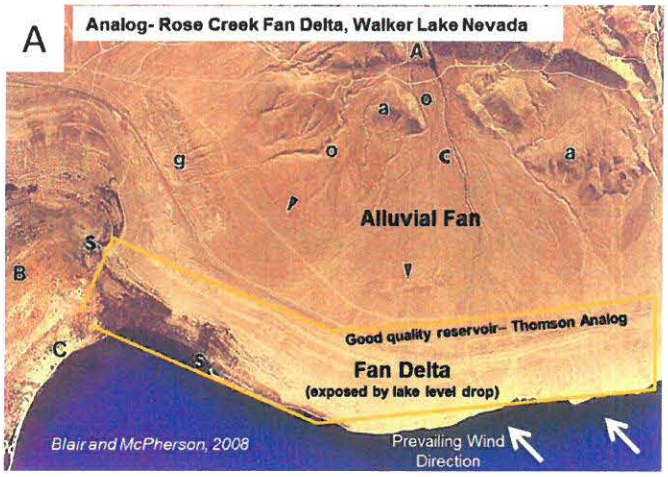
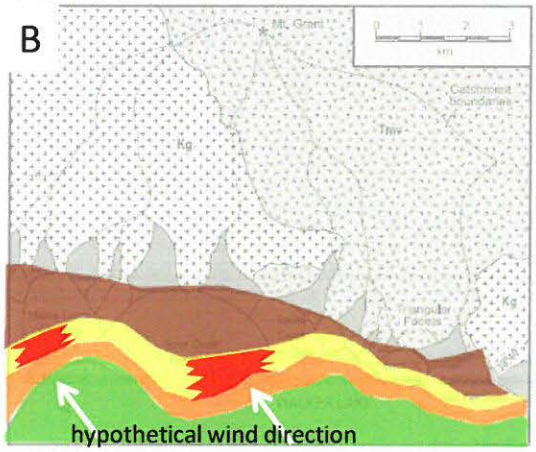


Figure 2.2-4: Isochore map of the Basal Cemented Zone.

The depositional setting of the Thomson reservoir is interpreted as a fan delta system: alluvial fan sediment gravity flows have prograded into subaqueous environment where material has been re-worked in an environment dominated by marine shoreface processes (**Figure 2.2-1).** Evidence for this setting includes: (1) overall poor sorting and high clast angularity, (2) presence of large grain sizes, including localized boulders, (3) presence of cohesive debris flow facies and (4) the presence of a narrow belt of conglomerates near the source terrain with rapid facies transition down-dip. A modern analog which exhibits the same petrofacies assemblages and distribution is the Rose Creek fan at Walker Lake, Nevada (**Figure 2.2-5**, Blair and McPherson, 2008[3]).

[3] Blair, T. C., and McPherson, J. G., 2008, Quaternary sedimentology of the Rose Creek fan delta, Walker Lake, Nevada, USA, and implications to fan - delta facies models, Sedimentology, v. 55, p 579 - 615.





(after: Blair and McPherson, 2008)

Figure 2.2-5 : A: Aerial photo of Rose Creek fan and exposed fan delta . B: schematic of Rose Creek fan with Thomson Sand EODs superimposed.

With the exception of the Cemented Conglomerates & Breccias, reservoir rocks for the Thomson reservoir are interpreted to be re-worked alluvial fan deposits in a deltaic, marine environment. The Open Framework Conglomerates are interpreted to be the result of rigorously re-worked foreshore deposits, a process which winnows away the interstitial fine sand component. In the analog from Walker Lake, seasonal winds focused energy in specific areas of the foreshore; a similar scenario is envisioned for the Thomson reservoir. These Open Framework conglomerates are interbedded with bi-modal conglomerates and clean sandstones, which are interpreted to be part of the same foreshore environment. The upper shoreface depositional environment is defined by a dominance of bi-modal conglomerate, clean

sandstone, and minor siltstone. The proximal to distal portion of the lower shoreface is defined by minor conglomerate and clean sandstone updip to mostly sand to silty sand downdip. A "transitional zone" is defined by mostly silty sand and siltstone, and the offshore environment is dominated by siltstone; both of these environments are also characterized by marine trace fossils.

Pre-Mississippian Basement Description:

Few data are available which describe the reservoir quality and the distribution of reservoir for the basement. Basement lithology, as indicated by cuttings and available core, comprise dominantly dolomite, quartzite and phyllite. Drill stem tests recovering gas in the AK_F1 and AK_ISL_1 wells, and gas and water recovery in the Alaska State A-1 (AK_A1) well suggest that some permeability exists in the basement, possibly in a fracture or karsted system. Due to the limited amount of data, the upper pre-Mississippian zone has been treated with uniform properties. Minimal reservoir properties have been assigned to an upper layer of basement rocks: 1% porosity, horizontal permeability of 1 mD, and a vertical permeability of 78 mD. Higher vertical permeability is a function of fractured basement.

2.3 Structural Setting

The top Thomson depth map is derived from seismic interpretation on a 3D time volume, converted to depth using a velocity model, and tied to picks in wells. Minor faults are observed in seismic, but they do not completely offset the Thomson reservoir; several do not even penetrate the top Thomson surface. Based on pre-reprocessed seismic (2001 processing), the average throw across faults is 65' to 95', and maximum throw values (near the fault mid-point) are 100-200'. The reprocessed seismic (2014) has slightly higher frequency content; therefore the presence, location, and throw of faults in the geologic model were re-examined. The number and location of faults was found to be very similar. Throw values were found to be lower in the reprocessed seismic, but the geologic model was not reconstructed (significant effort required to redesign and limited value added).

The regional Paleocene unconformity ("PA50") has severely eroded the HRZ/Hue Shale and Thomson reservoir near the crest of the structure **(Figure 2.0-2).** Although three wells have penetrated the Thomson to the north of the limit (AK_F1, AK_ISL_1, AK_G2), these sand accumulations are interpreted to be erosional remnants; they are either not connected with the main part of the reservoir or the sand is below the hydrocarbon contact.

Time to depth conversion is challenging at Point Thomson due to the position of the field straddling the coastline, the presence of permafrost and sea ice, and probable anisotropic behavior in the lower Brookian strata. The velocity model was updated in 2011, after drilling the PTU_15 and PTU_16 wells, and includes five strata intervals (**Figure 2.3-1**). The model

begins at the OG75 surface, which is a gentle northeast-dipping horizon relatively easily mapped in seismic and shallow enough to be tied to all wells in the unit. Hanging the velocity model from the OG75 surface also reduces uncertainty by eliminating velocity variations in the permafrost. For the next two intervals, OG75-EO25 and EO25-PA50, a V_0k function was used which estimates the velocity with increasing depth. For the last two thinner intervals, PA50-top Thomson, and for the Thomson interval (top to base Thomson), a simpler average interval velocity was used. One of the key improvements in the 2011 velocity model is recognizing the importance of the EO25 surface, which represents a major Eocene unconformity. The EO25 has 2,000' relief across the Unit, and below this surface, abnormal pressure begins to build, affecting the velocity structure.

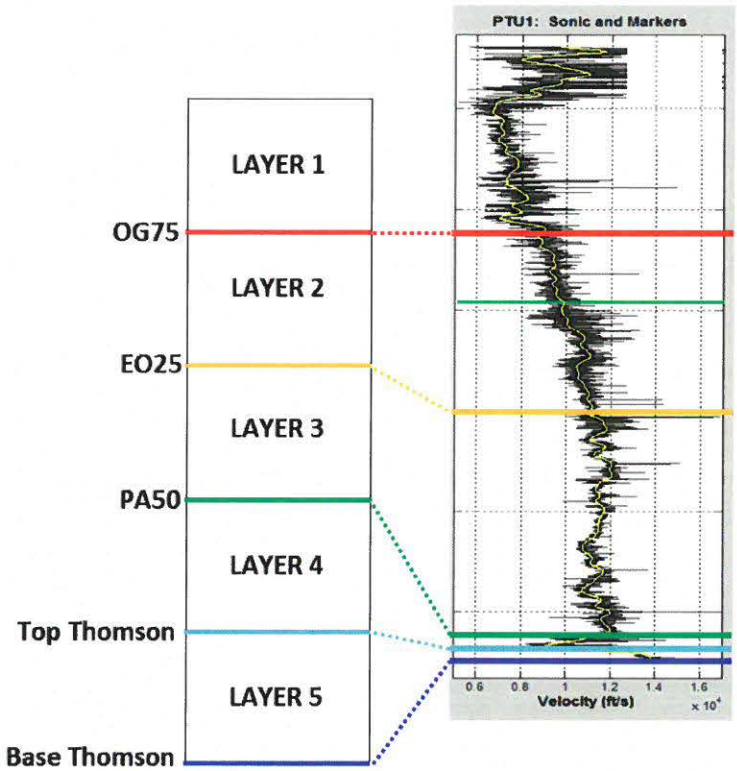


Figure 2.3-1: 2011 velocity model layers: Surface to OG75, OG75-EO25, EO25-PA50, PA50-Top Thomson, and Top Thomson – Base Thomson

2.4 Fluid Contacts

The Oil-Water contact is estimated at -13,012' TVDSS and is based upon confidential well tests and log data. The contacts are discussed below, but further information is contained in the confidential exhibit.

Gas-Oil and Oil-Water fluid contacts (GOC and OWC) are estimated using a combination of drill stem tests (DSTs) from the exploration program, modular dynamic tests (MDTs), fluid samples from the recently drilled PTU_15 and PTU_16 wells, and, to a limited extent, well logs. Petrophysical logs in most Thomson reservoir penetrations can only provide supporting data toward defining the contact because only half of these wells cover the contact range and most are in poor reservoir quality (silty or silty-sandstone petrofacies).

The GOC is estimated to be -12,975 TVDSS. The GOC was identified in the PTU_15 and PTU_16 wells with MDT fluid samples and fluid identification sensors which analyzed gas at -12,973' TVDSS and oil at -12,979' TVDSS (**Figure 2.4-1**). The fluid samples identified in PTU_16 revealed a GOC 30' deeper than previously estimated, which reduced the oil rim thickness from 67' to 37'. In parts of the field, at the crest, gas-filled Thomson reservoir overlies basement rock.

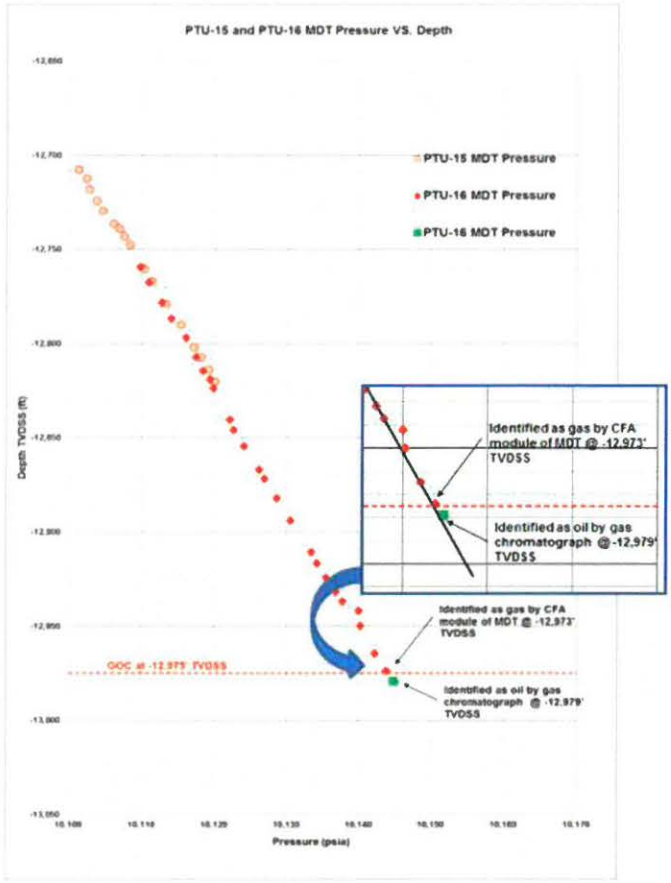


Figure 2.4-1: Results from the MDT pressure tests from the PTU-15 and PTU-16 , and fluid sample results from the PTU-16.

The two fluid contacts are assumed to be constant across the field. This assumption is based on lack of compelling evidence for compartments and supported by the continuity in pressure v. depth profile both within and between the PTU-15 and PTU-16 wells **(Figure 2.4-1)**.

2.5 Porosity Permeability transform

Porosity v. permeability transforms were derived for each of the six petrofacies in the Thomson reservoir based on routine core analysis on core plugs (**Figure 2.2-3**). Most core plugs are from whole core; PTU_16 data were derived from sidewall cores. The permeability property in the geologic model is air permeability; relative permeability is estimated in the reservoir simulation model. Permeability values in the upper pre-Mississsippian basement are not strictly tied to porosity; as mentioned above, upper pre-Mississippian basement vertical permeability is 78 mD and horizontal permeability is assigned 1 mD.

3.0 Gas In Place

Gas in place was computed using a 3D geocellular model constructed in Petrel software. The model contains five zones defined by six horizons: Upper Thomson, Lower Thomson, Basal Conglomerate, Upper pre-Mississippian, and Lower pre-Mississippian. Cell size is 400' x 400' with a 20° NE trend. Layer thickness in the Thomson intervals is five feet, and thickness in the pre-Mississippian intervals is distributed fractionally with finer layers near the top and thicker layers near the base (average thickness is ~80'). The model includes 15 faults, but, as mentioned in Section 2.3, they do not significantly offset the Thomson reservoir.

Modeling workflow begins with defining the structural framework, populating the model with petrofacies guided by the depositional environments, estimating porosity and permeability by petrofacies, then calculating saturation using saturation height functions and the fluid contacts.

3.1 Gross Rock Volume

Gross rock volume is derived from the top and base surfaces of the Thomson reservoir and from the hydrocarbon contacts. The top and base Thomson surfaces are derived from seismic mapping in a 3D cube using the 2011 velocity model and tied to well data. These depth surfaces include the erosional limit of the Thomson and are input into the geologic model.

3.2 Porosity (by facies)

Porosity is modeled through a process that begins with mapping environments of deposition (EOD) (described in Section 2.2). Petrofacies targets are assigned within each EOD and populated using proximal to distal trends (**Figure 3.2-1**). For example, the upper shoreface environment (USF) has a mix of Open Framework Conglomerate (2%), Bi-modal Conglomerate (75%), Clean Sandstone (20%), and minor Silty Sandstone (3%), but the Open Framework Conglomerate is distributed in the updip portion of the USF environment and Silty Sandstone percentage increases downdip. Each cell in the Thomson reservoir is assigned a petrofacies based on the petrofacies targets and trends. The porosity value is then selected from a range of porosities for that petrofacies. Histograms of porosity for each of the petrofacies is shown in **Figure 3.2-2** and for all petrofacies in the Thomson reservoir in **Figure 3.2-3**.

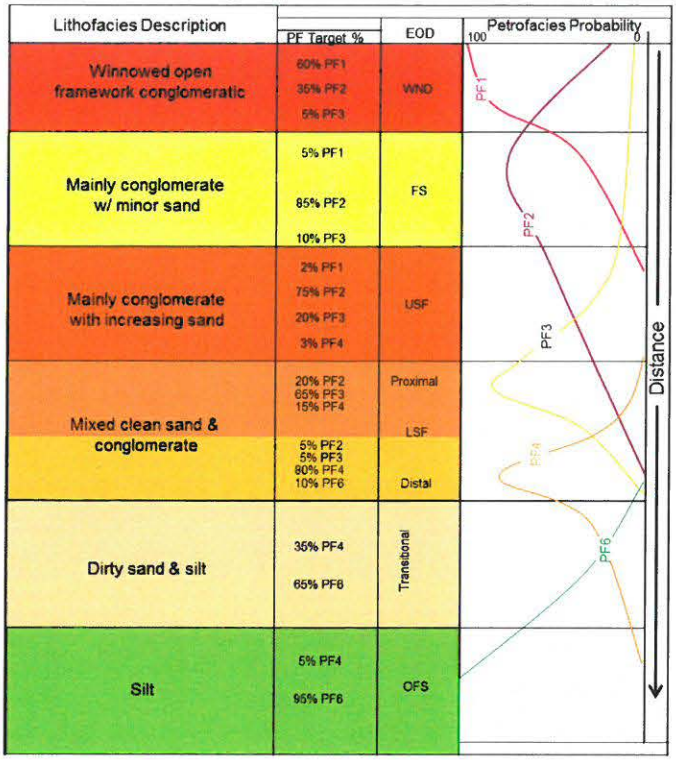


Figure 3.2-1: Petrofacies percentage targets for each EOD with proximal to distal trends

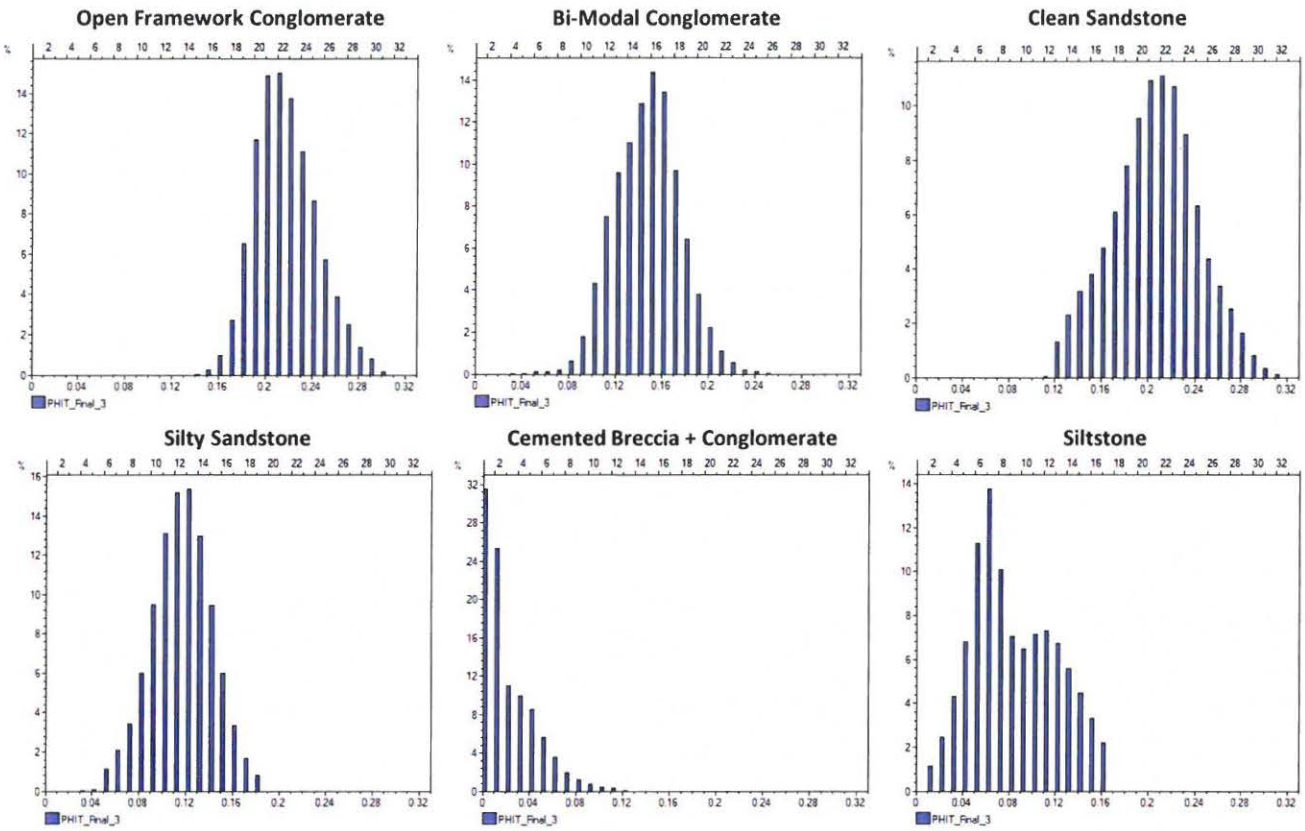


Figure 3.2-2: Histogram of porosity for Thomson Sand cells in the model for each of the petrofacies. X-axis for all graphs is from 0 – 33%; Y- axis is % of cells in model and the values are variable.

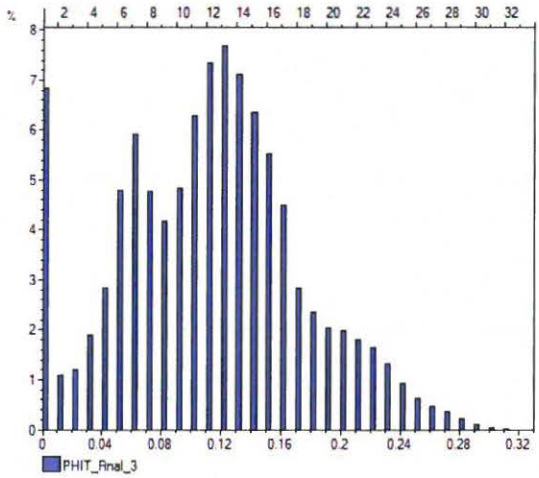


Figure 3.2-3: Histogram for all petrofacies in the Thomson Sand, throughout the geologic model

The average porosity for the Upper and Lower Thomson shows the general trend of very good porosity in the proximal position with a decreasing trend to the southwest (**Figure 3.2-4**). The thin rim of low porosity at the extreme updip edge is the cemented conglomerate and breccias that make up the alluvial fan environment. The double row of high porosity (red, orange, and yellow color bands) represents the distribution of good-quality open framework conglomerates and the clean sand petrofacies. This porosity distribution is the basis for the saturation models and the permeability transforms used in the reservoir simulation.

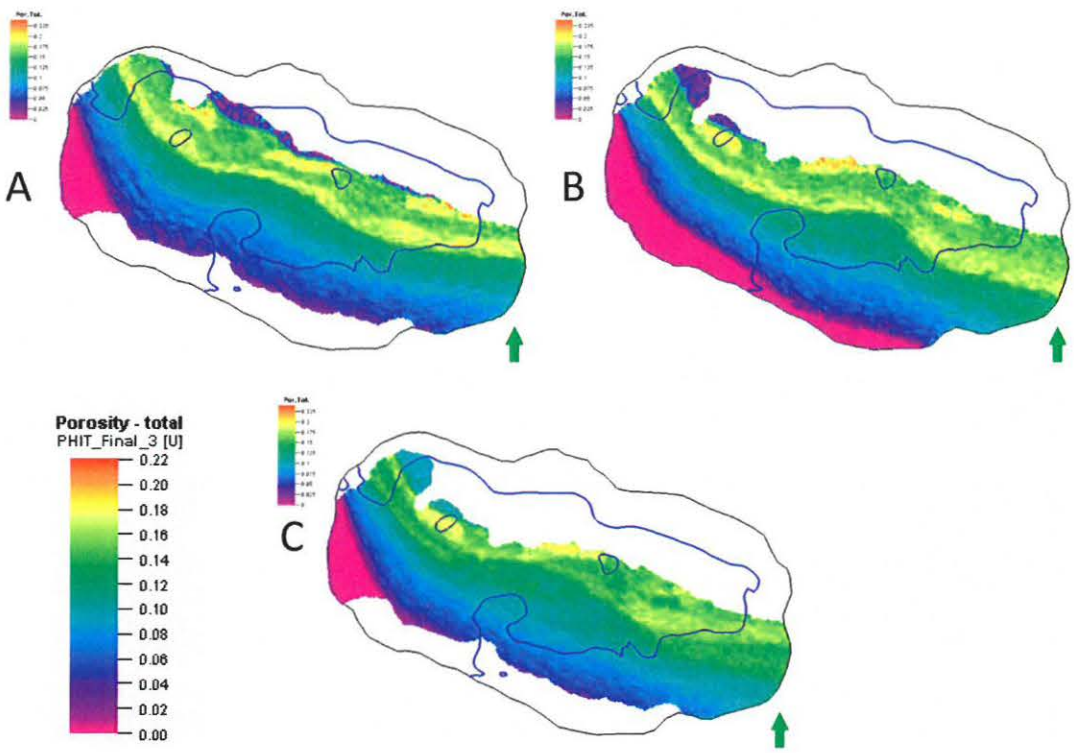


Figure 3.2-4: Average porosity from the geologic model. A= Upper Thomson, B= Lower Thomson (without basal cemented zone), C= Combined Upper and Lower Thomson

3.3 Saturation

Hydrocarbon saturation is derived from the formula:

(% Water Saturation) + (% Oil Saturation) + (% Gas Saturation) = 100%

Water saturation is calculated for each of the six petrofacies, utilizing the various porosity-permeability relationships exhibited in the core data (**Figure 2.2-3**) and the saturation height functions. The saturation height function uses the J Function method to correlate capillary pressure data, assuming that all capillary pressure data for a given rock type can be represented by a dimensionless J curve. In the geologic model, therefore, water saturation calculation for each cell uses:

- the porosity value based on the petrofacies assigned to the cell
- permeability from a porosity-permeability transform for that facies
- the capillary pressure, based on height above the free water level
- interfacial tension
- J-curve constants for the petrofacies, established from Thomson core

The resulting water saturation v. J curve graph shows relative saturation models for the six petrofacies (**Figure 3.3-1**); the silty sandstone and siltstone facies use the same J-curve parameters.

Water Saturation **Relict Oil Saturation**

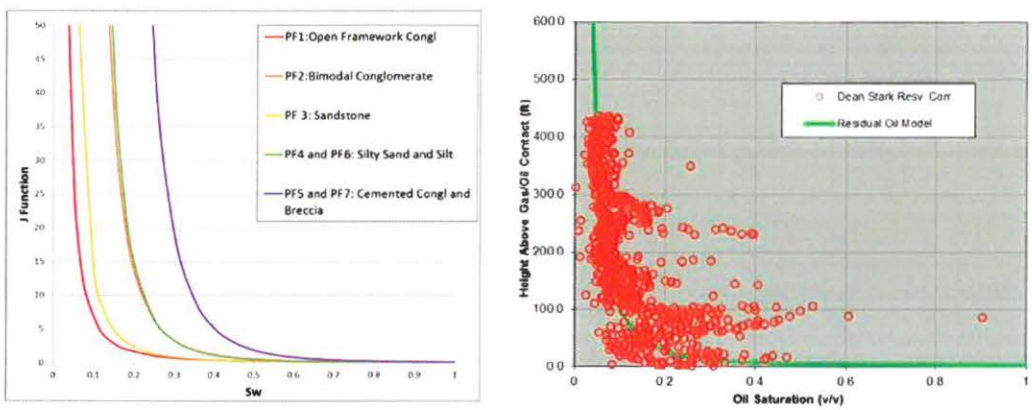


Figure 3.3-1: Left: J-curve functions for the six petrofacies (Sw v J function) Right: oil saturation v. height above the GOC using Dean Stark measurements

The J curve equations are helpful to calculate saturations for different rock types in a geologic model, especially when the rock types are defined using porosity-permeability relationships. The J curve approach is also important when lower-quality rocks are included as reservoir (e.g., siltstone). Listed below are approximate average water saturations in the gas cap for the six

petrofacies. These average saturations, in addition to the calculation above, also reflect the petrofacies distribution in the geologic model and their height above the OWC.

- Open Framework Conglomerate (PF1): 5%
- Clean sands (PF3): 15%
- Bimodal conglomerate (PF2): 25%
- Silty sand and Siltstone (PF4, PF6): 70%
- Cemented Conglomerate and Breccia (PF 5a,b): 90%

A "relict" oil saturation exists in the gas cap due to multiple heavy oil migrations through the reservoir in the geologic past. Oil saturations from Dean Stark measurements (using only wells drilled with water-based mud) were plotted by height above the GOC to develop a saturation height curve for relict oil in the gas cap (**Figure 3.3-1**). These data are not categorized by petrofacies so only one saturation height function is used throughout the gas cap. The relict oil saturation increases towards the gas-oil contact. Average oil saturation in the gas cap is approximately 10%.

Gas saturation is the remainder of the simple saturation equation stated above.

3.4 Formation Volume Factors

Formation volume factors represent the volumetric difference between the fluids in the reservoir and at the surface, and are used to convert volumes between "standard cubic feet" and "reservoir cubic feet." The volume factor used for gas volumetric calculations is 0.0029 rcf/scf (gas expansion factor 344 scf/rcf). Formation volume factors are calculated from the gas PVT characterization generated from fluid data collected from PTU_15, PTU_16, and STNS_1. These formation volume factors vary with composition and pressure, and the single values provided are volume-weighted to the fluids as they exist in the reservoir such that a volumetric calculation would result in the correct gas-in-place values.

3.5 Results

The geologic model generates a volume using the 3D geocellular grid populated with properties for porosity, permeability, saturation, and formation volume factors as described above. Original gas in place (OGIP) for the Point Thomson Unit is approximately 8 TCF. This volume is stored mostly in the Thomson reservoir (but includes minor volume in the pre-Mississippian basement) and comprises free gas in the gas cap, solution gas from relict oil in the gas cap, and solution gas from the oil rim. Gas cap volumes have been rigorously analyzed with Monte Carlo analyses, calibrated with deterministic geologic models.

4.0 Description of Reservoir Model

The Point Thomson reservoir simulation model utilizes finite-element simulation software developed by ExxonMobil to predict the subsurface physics, well behavior, and surface facilities integration with the field.

The simulation model is based on the most current geologic interpretation and incorporates the six petrofacies seen in core (Open-Framework Conglomerates, Bimodal Conglomerates, Sandstones, Silty Sandstones, Siltstones, Cemented Breccia) and the pre-Mississippian basement. Each petrofacies is assigned unique properties for initialization: permeability, porosity, capillary pressure data, relative permeability data, and irreducible water saturations. The model is initialized using a gravity equilibrium algorithm that predicts gravity-stable fluid contacts and transition zones throughout the field. The model uses a 19-component Peng-Robinson density shifted equation of state that incorporates PVT analyses performed on the high-quality well test fluid samples from PTU_15 and PTU_16, and relict oil analysis from the STNS_1. The composition of the reservoir fluids is specified as a function of depth in the model to account for the fluid contacts, transition zones, and gas composition variance due to gravity segregation. An average composition of the gas and relict oil in the middle of the gas column is displayed in Table 4.0-1. In addition to the components and pseudo-components listed in the table, the Point Thomson gas contains as much as 30 ppm hydrogen sulfide (H2S) encountered during the PTU_16 well test. H2S is not included in the fluid characterization due to its immaterial impact on the fluid flow behavior in the reservoir.

TABLE 4.0-1 Average Composition of Gas and Relict Oil (asterisks indicate pseudo components)

Phs	Vapor	Liquid
Comp Mole Frac		
C1	84.88%	66.68%
C2	3.85%	3.83%
C3	1.66%	1.85%
IC4	0.34%	0.40%
NC4	0.52%	0.65%
IC5	0.29%	0.38%
NC5	0.33%	0.46%
C6*	0.35%	0.59%
C7*	0.42%	0.80%
C8*	0.44%	0.96%
C9*	0.31%	0.75%
C12*	0.95%	3.03%
C17*	0.65%	3.48%
C27*	0.39%	3.97%
C42*	0.12%	3.43%
C65*	0.01%	2.35%
C86+*	0.00%	2.23%
N2*	0.93%	0.60%
CO2*	3.56%	3.59%

The reservoir simulator also incorporates wellbore hydraulics and surface facilities constraints. For each well, the simulator calculates the pressure required to lift gas, condensate, and water to the surface to determine the wellhead pressures. Based on the first stage separator pressure, the simulator can determine how much each well must be choked back to allow for a stable gas plateau rate from the overall facility. The sum of the gas, condensate, and water produced from each well determines the total facility rates. The simulator can optimize the individual chokes to prioritize or de-prioritize production from any given well (e.g., increase production from wells with higher condensate rates, decrease production from wells with high water rates). This allows for realistic simulation model prediction to mimic operating conditions throughout the life of the field.

5.0 Reservoir Development Plan

5.1 Reference Case Development Plan

Development of the Thomson reservoir through a Point Thomson GE Project will be implemented with approximately seven new directional gas producing wells drilled through the Thomson reservoir from three onshore pad locations. The two IPS gas injectors (PTU_15 and PTU_16) will be converted to producers and the IPS producing well (PTU_17) will remain in production for a total of approximately ten producing wells (**Figure 1.0-2**). The reference development plan includes one additional well at West Pad, three additional wells at the Central Pad and three new wells at East Pad. The number of wells may change as optimization studies are completed and reservoir information and new well data are acquired.

The PTU GE Project will produce natural gas, liquid condensate, and formation water. The nominal peak gas export rate from the field will be approximately 920 MMSCFD, with an annualized average export rate of approximately 820 MMSCFD. The condensate-gas-ratio (CGR) is a function of separation pressure. For the PTU GE Project, the initial CGR is anticipated to be approximately 60-65 stock tank barrels (STB) per million standard cubic feet (MMSCF), with an initial annual average condensate rate of approximately 50 thousand stock tank barrels per day (MSTBD). As gas and condensate are produced from the reservoir, the pressure in the reservoir will decline. This decline in the reservoir pressure will result in a decreasing condensate yield over time because some liquids will condense from the gas as the pressure is reduced and will remain in the reservoir. The proposed offtake rate balances production volumes, plateau life, and timing of potential boost compression, while providing sufficient gas for the AKLNG Project major gas sales opportunity.

As described later in the application, condensate and gas recovery modeling show little to no sensitivity to gas offtake rates. To account for seasonal variations and provide flexibility in design and operations, the WIOs are requesting an allowable gas offtake rate of 1,100 MMSCFD. All gas volumes discussed in this application include carbon dioxide (CO2) and nitrogen (N2).

5.2 Possible Compression Facilities

The wells will be allowed to flow until reservoir pressure can no longer deliver gas at plateau rates at the facility inlet conditions, at which point the field will go into decline. Current planning includes installation of compression facilities to lower the facility inlet pressure to extend gas and condensate plateau rates and potentially improve gas and condensate recoveries. A decision on whether to install compression facilities will be made after startup of the PTU GE Project.

6.0 Wells

6.1 IPS Wells

The development of the Point Thomson IPS Project will be implemented with three directional wells drilled through the Thomson reservoir from two onshore pad locations. One of the wells will be a gas producer, and the other two wells will be gas injectors. The gas injector wells (PTU_15 and PTU_16) were drilled, cased, tested, and temporarily suspended at the Central Pad during 2009 and 2010. The PTU_17 producing well will be drilled from the West Pad in 2015-2016. The PTU_15 well may temporarily be in producing service to allow startup of the CPF while the PTU_17 well is being drilled.

All three IPS wells will be completed using a Cased Hole Gravel Pack (frac pack) design to provide sand control for the high production rate wells. The injection wells are designed to ultimately be in gas production service. The IPS injection wells are capable of being converted to production service without requiring any downhole well work.

A Class I disposal well (PTU_DW1) has been drilled from the Central Pad for drilling waste, produced water, and other waste liquids.

6.2 Gas Expansion Wells

The reference development plan includes drilling approximately seven directional gas producing wells through the Thomson reservoir from three onshore pad locations. The two IPS gas injectors (PTU_15 and PTU_16) will be converted to producers and the IPS producing well (PTU_17) will remain in production service for a total of approximately 10 producing wells.

The new wells in the reference development plan include one additional well at the West Pad, three additional wells at the Central Pad, and three wells at a new East Pad. All new wells are currently planned to be completed with similar frac pack designs to the three IPS wells. Studies are being conducted on open hole gravel pack completions that may improve well performance and reduce well count. Specific well designs will be addressed in drilling permit applications, which will be submitted to the Commission closer to the planned start of the drilling program.

An additional Class I waste disposal well is also planned to be drilled from the Central Pad to serve as a backup disposal well.

6.3 Well Spacing

The Thomson Pool will be developed on an irregular well spacing pattern as a function of reservoir architecture and reservoir quality. Wells at PTU are anticipated to comply with the well spacing requirements of 20 AAC 25.055, and no exceptions are requested.

7.0 Surface Facilities

7.1 Existing Infrastructure / Initial Production System

The Point Thomson IPS infrastructure includes the Central Pad, the West Pad and the air strip, all connected by infield gravel roads, and marine facilities for sealift and seasonal barging. The Central Pad will contain the IPS CPF, two injection wells as described above, and a Class I waste disposal well. The Central Pad also has an operations center and associated buildings and space for drilling laydown/operations. The Central Pad was constructed to provide space for drilling additional wells.

The West Pad will have the PTU_17 well and chemical injection facilities required for start-up. The West Pad was also designed and constructed to provide space for drilling additional wells. A gathering line connecting the West Pad to the Central Pad and a condensate export line to Badami have been installed on vertical support members (VSM).

7.2 Gas Expansion

The reference development plan currently consists of installing new processing facilities, new gathering lines and drilling new wells, all of which will be integrated with existing IPS facilities, wells and infrastructure as necessary. The Central Pad gravel footprint will be expanded to accommodate new processing facilities, and an East Pad and connecting road will be constructed.

At the Central Pad, new facilities for liquid/vapor separation, gas dehydration, gas conditioning, condensate stabilization, and produced water injection will be installed. In addition, a new utility module will be installed. These facilities will expand and/or replace existing IPS facilities at the CPF. The IPS Service Pier and Sealift Bulkhead at the Central Pad will support the GE Project. New mooring dolphins will likely need to be installed to support GE Project module offloading activities. Other new infrastructure associated with module offloading may also be required.

The GE Project facilities are being designed to yield peak rates of approximately 60 MBD of associated condensate and approximately 920 MMSCFD of exported gas. At the CPF, a single process separation train will be coupled with two 50% tri-ethylene glycol (TEG) dehydration units and two 50% Low Temperature Separation Units (Expander and re-compressor units). The inlet separator will operate at approximately 1400 pounds per square inch gauge (psig), and the recovered liquids will be flashed by two additional lower pressure separators before being stabilized and cooled for export.

The GE Project facilities are planned for co-location on the Central Pad with the IPS facilities, and operation of the IPS processing facilities will be discontinued prior to the GE Project startup. Power for the GE Project facilities will be provided by the IPS power generation, which includes normal operations, power for essential loads when the CPF is shutdown, and standby power. The IPS utilities module will be supplemented with a new utilities module as part of the GE Project.

The stabilized condensate will be exported in the existing common carrier Point Thomson Export Pipeline to the common carrier pipeline system at Badami.

A gas transmission pipeline to carry PTU gas to a central gas treating plant (GTP) in the Prudhoe Bay area is included within the AKLNG Project scope.

As discussed in Section 5.2, compression facilities are being considered to extend the plateau rate and potentially improve hydrocarbon recovery. If installed, these facilities will be needed later in field life and will not be part of the initial PTU GE Project.

8.0 Model Results

8.1 Reference Case Depletion Plan

The reference case depletion plan includes an annual average rate of approximately 820 MMSCFD that the simulation model predicts can be sustained for approximately 14 years at the current GE facility design inlet pressure. Approximately 65% of the total gas recovered occurs during the 14 year plateau period prior to booster compression installation. After the plateau period, the gas rate will decline because the reservoir no longer has enough energy (pressure) to lift the gas, condensate, and water to the surface at the inlet facility conditions. Therefore, the well rates decline and the overall facility export rates also decline. To extend the plateau period and potentially improve hydrocarbon recovery, installation of booster compression is being evaluated. Current modeling suggests that the addition of booster compression could extend the plateau life by 1-2 years. The predicted flow streams from the simulation model are shown in **Figure 8.1-1** below. This figure displays annualized average gas, condensate, and water production for 30 years of gas sales and includes booster compression installation, which occurs around year 14.

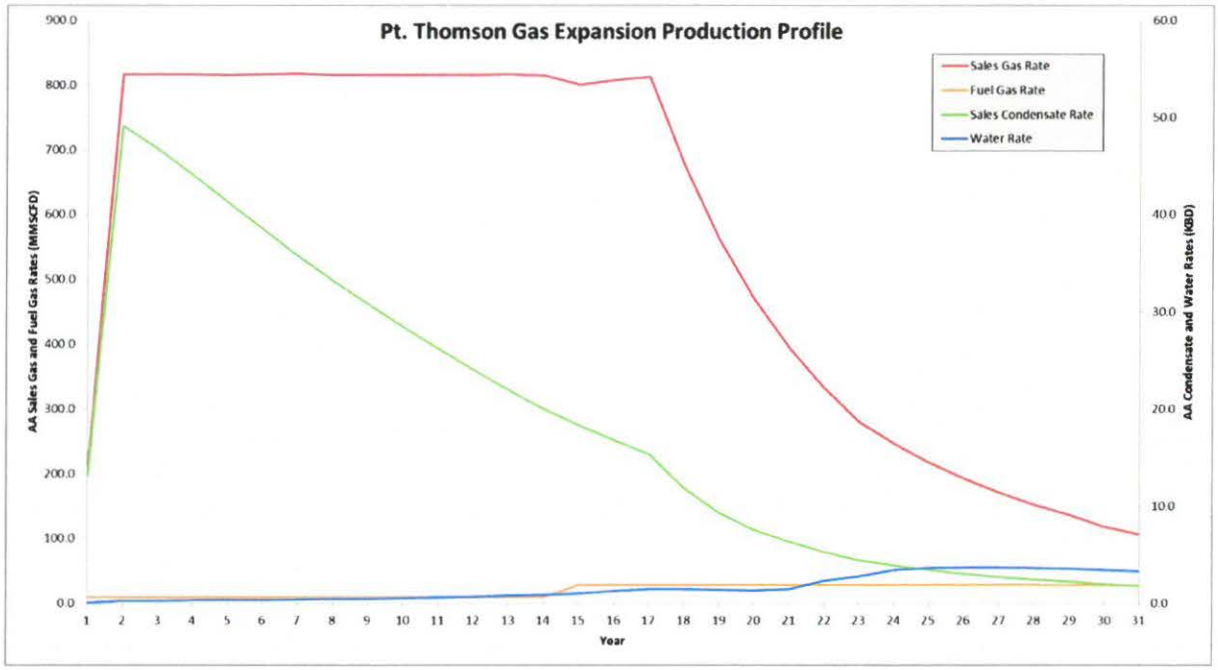


Figure 8.1-1 Point Thomson GE Project Reference Case Production Profile (includes booster compression)

The behavior of the Point Thomson reservoir during gas production is consistent with the description of a homogeneous gas reservoir. The pressure transient created by the displacement of gas moves through the reservoir, migrating more quickly through the high-permeability conglomerates and sandstones in the crest of the structure and slowing as it progresses through the poorer-quality sandstones and siltstones. While there are 15 mapped faults in the reservoir, none of them are expected to fully offset the Thomson reservoir and therefore gas is expected to be able to migrate through them. The simulation model predicts that reservoir pressure will decline by approximately 9,000 psi over 30 years of gas production, and this depletion of reservoir pressure - and therefore gas volumes - occurs relatively uniformly across the reservoir.

In a retrograde gas condensate field, as the reservoir pressure is decreased - via the removal of gas volumes – liquid hydrocarbon will begin to condense out of the gaseous phase in the reservoir. At Point Thomson, much of this condensate is thought to be immobile once it condenses onto the reservoir rock. This means that it will most likely not be produced back as a liquid phase, and condensate produced at the surface is attributed to the condensate remaining in the gas phase. This is directly predicted in the simulation model flow streams as a decrease in condensate rate over time, even with the gas rate remaining constant during the plateau period. When the gas rate begins to decline, the condensate rate is impacted by both the decreasing condensate yield from the gas and the overall declining gas rate.

In some fields, condensate remaining in the reservoir rock can impede gas flow through the reservoir. However, at Point Thomson the simulation model does not predict significant "condensate banking" due to the relatively high permeability of the reservoir and relatively low liquid dropout.

8.2 Offtake Rate Sensitivities

A sensitivity study was performed using the simulation model to test the impact of different offtake rates on condensate and gas recovery from Point Thomson. Production rates ranging from 400 MMSCFD to 1200 MMSCFD were tested. In every case, it was observed that the gas offtake rate had no measurable impact on gas or condensate recovery so long as the field was allowed to produce to the same abandonment pressure in the reservoir – beyond the 30 year design life in lower offtake rate cases. In other words, if the Point Thomson field were produced at lower rates, the same amount of recoverable gas and condensate would be produced as at higher rates, but over a considerably longer period of time. At an offtake rate of 400 MMSCFD, it could take over 40 years to produce the same amount of gas and condensate the field could produce at 1100 MMSCFD in 30 years. This validates the current planned offtake rate request of 1100 MMSCFD as it balances facility design considerations, well count, and overall plateau duration and recoverable volumes within a reasonable field and facilities life.

9.0 Production Measurement and Production Allocation

9.1 PTU Export Condensate Measurement

The existing PTU IPS condensate custody transfer meter will be expanded to accommodate the increased condensate volume from the GE Project. This is expected to use a Coriolis meter similar to the currently approved IPS meter.

9.2 PTU Export Gas Measurement

A gas export custody transfer meter will be installed at the Central Pad. The export gas will contain CO2 and other byproducts that will be removed at the AKLNG Project GTP at Prudhoe Bay. Inlet and outlet flow will also be metered at the GTP.

9.3 PTU Well Allocation

The current plan for allocating production to the PTU producing wells includes in-line multiphase meters on each well. In addition to providing a basis for well allocations, these meters will also provide for continuous measurement on a well by well basis.

9.4 AOGCC Approval of Custody Transfer Measurement and Well Allocation

All custody transfer measurement and production allocation equipment and procedures will comply with applicable AOGCC regulations. GTP gas specifications have not been developed and other aspects of GE Project metering and production allocation have not been determined or finalized. Future requests will be made to the Commission for review and approval of custody transfer measurement and production allocation equipment and procedures in accordance with 20 AAC 25.228 and 20 AAC 25.230.

10.0 Gas Oil Ratio

As inferred by Section 8.0 and **Figure 8.0-1**, gas oil ratios (GORs) will increase over time due to condensate rates declining faster than gas rates. This is inherent in the development plan for the Thomson gas condensate reservoir and does not indicate any inefficiency in the production mechanism. Since it is impractical to maintain GORs at or close to the original GOR, ExxonMobil requests a waiver from the requirements of 20 AAC 25.240 (a), as provided in 20 AAC 25.240 (c), which would limit production if the GOR increased by 100% of the original GOR).

11.0 Reservoir Surveillance and Monitoring

ExxonMobil understands the need for reservoir surveillance and monitoring and will develop an appropriate program. Prior to startup of the PTU GE Project, ExxonMobil will provide its proposed reservoir surveillance and monitoring plan to the Commission.

12.0 Other Development Considerations

In seeking to identify a viable development path, the PTU WIOs have evaluated or considered other potential development scenarios for the Thomson reservoir. Some of these have been reviewed with the Commission previously. A brief discussion is provided here for reference.

12.1 Oil Rim

The oil rim (containing approximately 160 million barrels original oil in place as characterized by the geologic model discussed previously) is located between the gas cap and the underlying aquifer. The thickness of the oil rim, at about 37 feet, was established from MDT fluid identifications in the PTU_16 (described in Section 2.4). Most of its thickness is in the oil-water transition zone, in which both oil and water are partially mobile. The reservoir fluid is heavy oil,

approximately 10° to 18° API gravity, and the viscosity is approximately 2 centipoise (cP) at reservoir conditions.

For a thin oil rim, horizontal wells are usually drilled to develop the resource. However, study results for a Thomson reservoir oil rim horizontal well development indicate that initially heavy oil from the oil rim would be recovered, followed by high rates of gas and water within weeks or months of initial production. After the onset of gas and water production, heavy oil production from the oil rim would be minimal and overall recovery very low. The oil rim wells would produce at high water cuts and high gas oil ratios.

Other challenges affecting the viability of oil rim development are drilling long reach horizontal wells into the high and abnormally pressured Thomson reservoir and installation of separate facilities required to process heavy oil and separate large amounts of produced water.

Consequently, due to these challenges and low anticipated production, production from the oil rim is not considered viable.

12.2 Gas Cycling

Since discovery of the Thomson reservoir, it has been recognized that the reservoir could best be developed through a North Slope gas sales project, but that it would require a number of years to develop the transportation and other infrastructure needed to bring the gas to market. In the meantime, the WIOs pursued studies to identify a viable development option.

A full field gas cycling project was intensively evaluated in the early 2000s. After considerable analysis, including significant subsurface technical evaluation, facilities and well engineering design and cost estimating, and regulatory permitting, the WIOs determined such a cycling project was not viable. Major impediments were the limited amount of condensate that could be recovered, the high cost of the facilities and wells, and the significant risks associated with a gas cycling development. Key among these risks included separating gas and condensate at approximately 3,000 psi, injecting gas at greater than 10,000 psi, and reservoir connectivity or gas channeling leading to poor sweep, gas breakthrough, and lower condensate recovery. While some of these considerations might also exist for a gas sales development scenario, they are more easily addressed for a gas sales development than a gas cycling development.

As part of efforts to understand how the Thomson reservoir might be developed, ExxonMobil conducted an extensive study of 230 other gas condensate reservoirs. The results of that study did not find any reservoir with similar producing characteristics to PTU that was developed through a gas cycling approach. Reservoir injection pressures were one of the key differentiating factors. No other gas cycling project operated at pressures as high as those

required for Point Thomson. Other gas cycling projects were at lower pressures and typically had higher gas condensate yields.

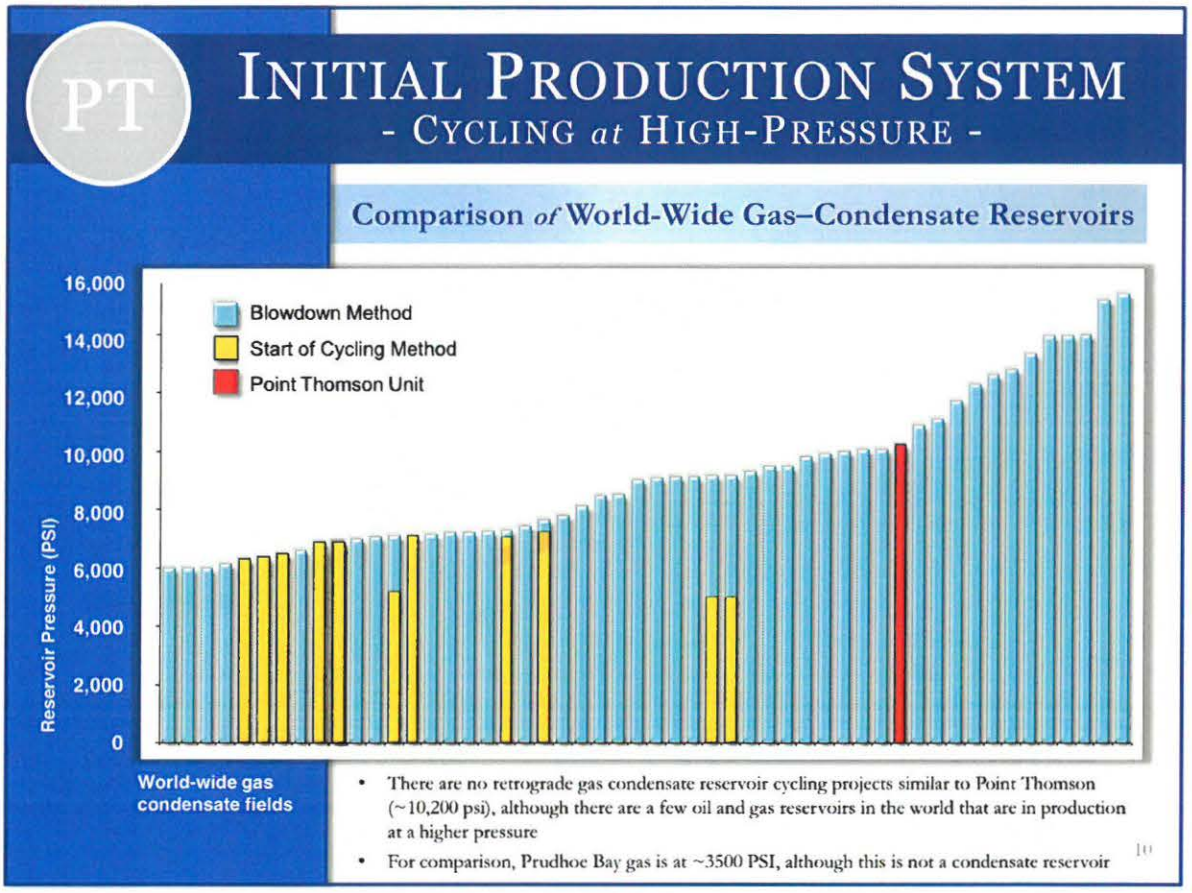


Figure 12.1-1 Comparison of Cycling in World-Wide Gas Condensate Reservoirs

The work to evaluate a full field gas cycling project for the Thomson reservoir that was previously undertaken by the PTU WIOs and resulting conclusions regarding viability was thorough. However, the WIOs also have assessed whether an expanded gas cycling project that utilizes wells and facilities designed for a gas sales project to the maximum extent practical, thereby minimizing incremental capital required for gas cycling, might provide sufficient additional recovery to improve potential viability. The results of this assessment are consistent with earlier work and have led the PTU WIOs to conclude that MGS is a preferable development plan to expanded cycling. Moreover, the PTU WIOs do not consider it prudent to pursue work that could adversely impact timing and viability of the AKLNG Project.

For this assessment, it was assumed that expanded cycling would occur for 10 to 20 years, followed by gas sales, which would result in gas volumes and revenues not starting for a corresponding period of 10 to 20 years. Hydrocarbon recovery, on an oil equivalent barrel

basis, would essentially be the same for gas cycling followed by gas sales as for a gas sales project, e.g., incremental condensate volumes are largely offset by additional fuel gas consumption contributing to reduced gas recoveries.

While the IPS production operations will provide useful information about the reservoir, no scenarios have been identified in which this information would materially improve the current outlook for viability of expanded gas cycling. For instance, IPS operations could reveal high permeability streaks that lead to channeling/premature breakthrough of injected gas, or compartmentalization; either finding would impact cycling efficiency and reduce cycling recovery. The only potential factor that might appear to improve benefits from cycling would be if the condensate to gas ratio was higher than expected. However, the condensate to gas ratio has remained consistent in the gas samples collected from the numerous wells drilled at PTU. Significant deviation in the condensate-gas ratio discovered in new development wells may indicate that the reservoir is compartmentalized, which would be detrimental to an expanded gas cycling project.

12.3 PTU Gas to Prudhoe Bay Unit

Another potential PTU development option would be to produce and deliver PTU gas to the Prudhoe Bay Unit (PBU) for injection into its primary reservoir. The current PTU GE Project subsurface and facilities engineering and regulatory/permitting work would largely be applicable to this option. This would reduce the duplication of manpower and costs if two distinct projects were pursued and potentially could allow such a project to progress on a similar time line.

Based upon the current AKLNG Project and PTU GE Project schedules, however, the maximum acceleration in PTU startup under this option would be approximately one to two years. The gas transmission line between PTU and PBU, which is currently part of the AKLNG Project scope, would need to be accelerated (and potentially moved to PTU GE Project scope) to be used for a PTU to PBU option.

Given the additional commercial, engineering and regulatory effort that would be required by the PTU WIOs, PBU WIOs, the AKLNG Project participants and the State of Alaska to pursue a PTU gas to PBU option, it is unlikely that the additional costs and diversion of resources could be justified for only a one or two year acceleration in PTU startup, which might not be achievable in any event. Any further consideration of this option would depend upon progress on the AKLNG Project.

13.0 Conclusion

The most prudent development plan for Point Thomson is to simultaneously produce gas for delivery to an Alaska LNG project and condensate for export to the existing oil export pipeline system.

The PTU WIOs request an allowable gas offtake rate of 1,100 MMSCFD. This will provide flexibility in design and operations of the PTU GE Project facilities and wells that will be used to deliver gas to an Alaska LNG project GTP, and account for seasonal variations. During normal operations, it is envisioned that the gas offtake rate from PTU will be approximately 920 MMSCFD during winter conditions, and approximately 820 MMSCFD on an annual average basis. Modeling shows ultimate recovery to have little to no sensitivity to the gas offtake rate at Point Thomson.

Consistent with simultaneous gas and condensate production, ExxonMobil requests the Commission grant an exception to the requirements of 20 AAC 25.240(a) as provided in 20 AAC 25.240(c) which would otherwise limit gas offtake from the Thomson Pool.

14.0 Proposed Pool Rules

ExxonMobil as operator on behalf of the PTU WIOs respectfully requests the Commission adopt the following Pool Rules for the Thomson Pool.

Rule 1: Field and Pool Name

The field is the Point Thomson Field and the Pool is defined as the Thomson Pool.

Rule 2: Definition of Pool

The Thomson Pool is defined as the accumulation of hydrocarbons corresponding to depths 16,126' to 16,377' measured depth (MD) (-12,614' to -12,828 True Vertical Depth Subsea or TVDSS) on the PTU_15 type log and contained within the area described Table 14.0-1.

Rule 3: Gas Oil Ratio Exemption

Wells producing from the Thomson Pool are exempt from the gas-oil ratio limits of 20 AAC 25.240 (a).

Rule 4: Allowable Gas Offtake Rate

The maximum allowable annual average gas offtake rate from the Thomson Pool is 1,100 million standard cubic feet per day (MMSCFD).

Rule 5: Administrative Action

Upon proper application, or its own motion, and unless notice and public hearing are otherwise required, the Commission may administratively waive the requirements of any rule stated herein or administratively amend this order as long as the change does not promote waste or jeopardize correlative rights, is based on sound engineering and geoscience principles and will not result in an increased risk of fluid movement into freshwater.

Table 14.0-1
Point Thomson Unit - Proposed Thomson Pool

ADL No.	Description
47557	**T10N-R24E, UM** Secs. 29, 30, 31, and 32
47558	**T10N-R23E, UM** Secs. 25, 26, 35, and 36
47559	**T10N-R23E, UM** Secs. 27, 28, 33, and 34
47560	**T10N-R23E, UM** Sec. 32
47561	**T10N-R22E, UM** Secs. 25, 26, 35, and 36
47562	**T10N-R22E, UM** Secs. 27, 28, 33, and 34
47563	**T10N-R22E, UM** Secs. 29, 30, 31, and 32
47564	**T10N-R21E, UM** Secs. 25, 26, 35, and 36
47566	**T9N-R22E, UM** Secs. 5, 6, 7, and 8
47567	**T9N-R22E, UM** Secs. 3, 4, 9, and 10
47568	**T9N-R22E, UM** Secs. 1, 2, 11, and 12
47569	**T9N-R23E, UM** Secs. 5, 6, 7, and 8
47570	**T9N-R23E, UM** Secs. 3, 4, 9, and 10
47571	**T9N-R23E, UM** Secs. 1, 2, 11, and 12
47572	**T9N-R24E, UM** Secs. 5, 6, 7, and 8
50983	**T10N-R23E, UM** Sec. 29
51667	**T10N-R23E, UM** Secs. 30 and 31
28380	**T9N-R23E, UM** Secs. 17 and 18
28381	**T9N-R23E, UM** Secs. 15 and 16 Sec. 21: N/2 Sec. 22: N/2
28382	**T9N-R23E, UM** Secs. 13 and 14 Sec. 23: N/2 Sec. 24: N/2
47556	**T10N-R24E, UM** Secs. 27, 28, 33, and 34

ADL No.	Description
47573	**T9N-R24E, UM** Secs. 17 and 18 Sec. 19: N/2 Sec. 20: NW1/4
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 1152.00HECTARES, 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.
312866	**T10N-R23&24E, UM** TRACT C30-114 (BF-114): A PORTION OF BLOCKS 799 AND 800 AS SHOWN ONTHE "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.
343109	**T10N-R24E, UM** Sec. 25: S/2 Sec. 26
343110	**T10N-R24E, UM** Secs. 35 and 36
	T9N-R24E, UM Sec. 2
343111	**T9N-R24E, UM** Secs. 3, 4, and 9 Sec. 10: N/2 and SW/4
343112	**T9N-R24E, UM** Sec. 15: All, excluding ANWR Sec. 16: N/2
377020	**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.

ADL No.	Description
377016	**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.
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).
389728	**T10N-R21E, 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. 21 E., U.M., Alaska, excluding the E1/2E1/2 of Sections 1, 12, 13 and 24.
389730	**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 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.
390310	**T9N-R24E, UM** 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