STATE OF ALASKA
ALASKA OIL AND GAS CONSERVATION COMMISSION
333 West 7th Avenue
Anchorage, Alaska 99501

Re: THE APPLICATION OF EXXONMOBIL ALASKA PRODUCTON, INC. for an order authorizing underground injection of fluids for enhanced oil recovery in the Thomson Sand Undefined Oil Pool, Point Thomson Unit, North Slope Borough, Arctic Slope, Alaska	Area Injection Order No. 38 Docket No. AIO-15-017 Point Thomson Field Point Thomson Unit Thomson Sand Undefined Oil Pool August 25, 2015

IT APPEARING THAT:

1. By application received on May 1, 2015, Exxon Mobil Corporation, in its capacity as operator of the Point Thomson Unit, requested authorization to reinject produced gas to enhance oil recovery in the Thomson Sand Undefined Oil Pool of the Point Thomson Unit.

2. Pursuant to 20 AAAC 25.540, the Alaska Oil and Gas Conservation Commission (AOGCC) tentatively scheduled a public hearing for July 7, 2015. On May 5, 2015, the AOGCC published notice of the opportunity for that hearing on the State of Alaska's Online Public Notice website and on the AOGCC's website, electronically transmitted the notice to all persons on the AOGCC's email distribution list, and mailed printed copies of the notice to all persons on the AOGCC's mailing distribution list. On May 6, 2015, the AOGCC published the notice in the ALASKA DISPATCH NEWS.

3. On May 6, 2015, the AOGCC approved a Designation of Operator request to change the operator of the Point Thomson Unit from Exxon Mobil Corporation to ExxonMobil Alaska Production, Inc. (ExxonMobil)

4. On May 7, 2015, the AOGCC asked ExxonMobil to check the legal description of the proposed affected area in its application.

5. On May 14, 2015, ExxonMobil provided a corrected legal description.

6. No protest to the application or request for hearing was received.

7. The hearing commenced at 9:00AM on July 7, 2015, in the AOGCC's offices located at 333 West 7th Avenue, Anchorage, Alaska.

8. Testimony was received from representatives of ExxonMobil.

9. The record was held open until July 14, 2015, to allow the operator to respond to requests made during the hearing.

10. ExxonMobil provided the requested additional information on July 9, 2015.

FINDINGS:

1. Operator and Owners: ExxonMobil is the operator of the leases in the area proposed for development. ExxonMobil, BP Exploration (Alaska) Inc., ConocoPhillips Alaska, Inc., and 21 other partners are working interest owners, and the State of Alaska, Department of Natural Resources (DNR) is the landowner of the Affected Area, which is located within the North Slope Borough, approximately 60 miles east of Prudhoe Bay along Alaska's northern coastline.

2. Project Area Pool and Formations Authorized for Enhanced Recovery: ExxonMobil proposes to re-inject residual produced gas to enhance recovery from an accumulation of condensate and oil within the Thomson Sand of the Point Thomson Unit. In absence of a Conservation Order from the AOGCC formally defining a pool, this accumulation is properly termed the Thomson Sand Undefined Oil Pool and governed by the statewide rules of 20 AAC 25. ExxonMobil's target injection zone is correlative to the interval between 16,126 and 16,377 feet measured depth on the VISION/Scope Measured Depth Log recorded in reference well PTU No. 15 (PTU-15; see Figure 1, below).

3. Proposed Injection Area: ExxonMobil proposes to re-inject residual produced gas within the Affected Area shown on Figure 2, below. The Thomson Sand Undefined Oil Pool will be developed initially from the onshore, 55-acre Central Pad drill site (Central Pad), which is located in Section 34, Township 10N, Range 23E, Umiat Meridian (see Figure 2, below). ExxonMobil's development plans include a second, onshore, gravel drill site (termed the "West Pad") that will occupy about 17 acres within Section 36, Township 10N, Range 22E, Umiat Meridian.

   To date, 16 wells have penetrated the Thomson Sand Undefined Oil Pool in the Point Thomson Unit area.[1] Information from these wells and from seven overlapping, three-dimensional seismic surveys was used to determine the geologic structure, reservoir distribution, and the area that will be affected by re-injection of produced gas. Production test, drill-stem test, down-hole sampling, core, and well log data were used to establish reservoir properties, fluid properties, and the gas-oil and oil-water contacts for this pool.

4. Operators/Surface Owners Notification: All lands within the proposed Affected Area are leased. The only affected surface owner is DNR. The only affected operator is ExxonMobil. ExxonMobil provided the application for injection to all working interest owners and the DNR, the only affected parties within one-quarter-mile of the proposed affected area.

5. Description of Operations: ExxonMobil's planned operations, termed the Initial Production System Project, will initially develop the Thomson Sand Undefined Oil Pool from the Central Pad using two wells: PTU-15, the initial gas producer, and PTU No. 16 (PTU-16), a gas injector. ExxonMobil plans to drill one additional well, PTU No. 17 (PTU-17), from the

[1] Records for several exploratory wells located in the eastern portion of the Point Thomson area are held confidential indefinitely because of their close proximity to unleased acreage in the Arctic National Wildlife Refuge.

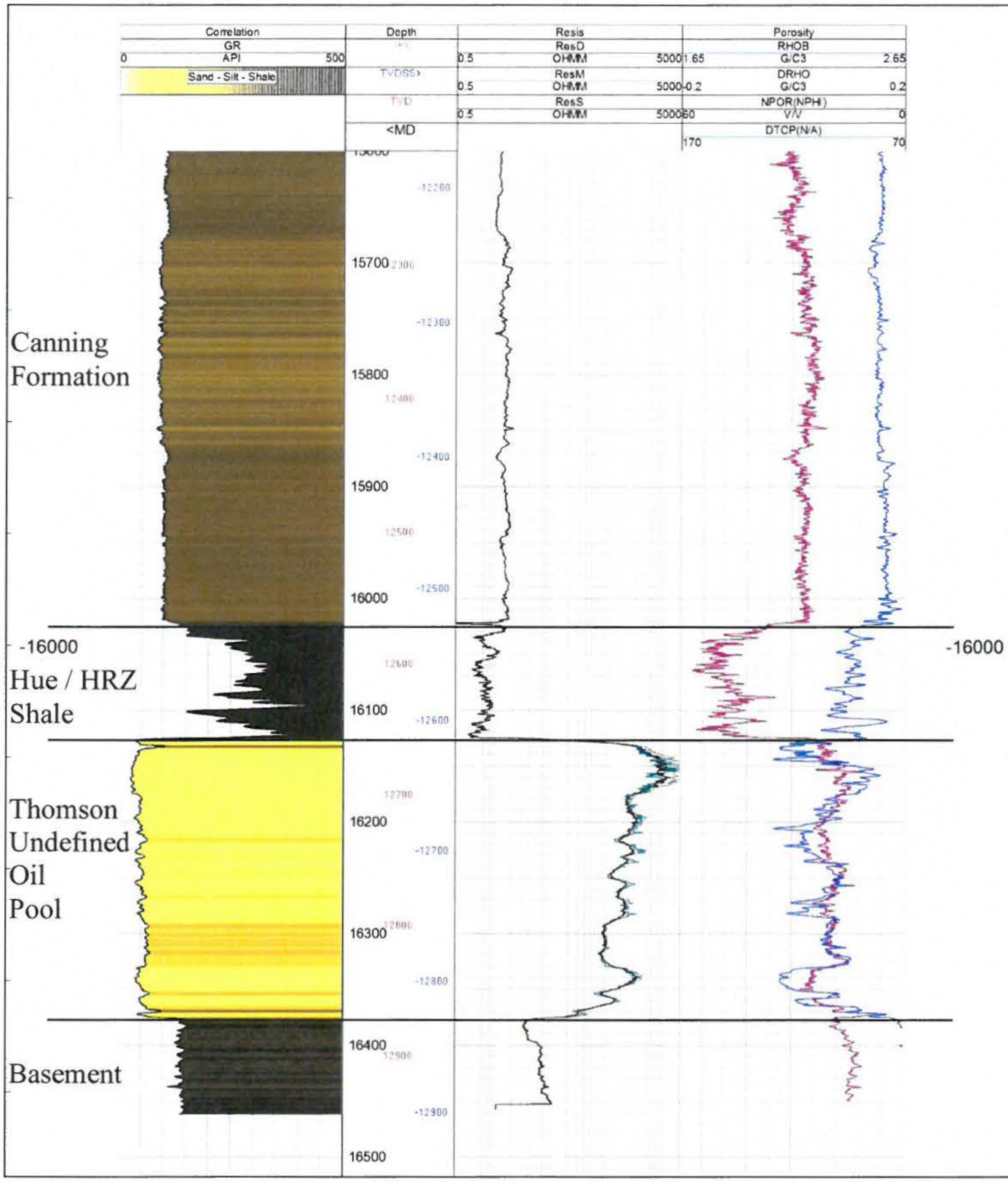

Figure 1. PTU-15 – Reference Well Log for the Proposed Injection Interval, Thomson Sand Undefined Oil Pool[2]

West Pad and complete it as a gas producer. Upon completion of PTU-17, well PTU-15 will be re-completed as a gas injector.

[2] Figure 1 is presented for illustration purposes only. Refer to the well log measurements on the VISION/Scope Measured Depth Log recorded in reference well PTU-15 for a more precise representation of the Thomson Sand Undefined Oil Pool. The horizontal grid lines in this figure represent increments of ten feet true vertical depth subsea. The acronym TVD refers to true vertical depth, and the acronym TVDSS refers to true vertical depth subsea (true vertical depth below sea level).

ExxonMobil's project will produce and sell condensate liquids associated with gas from the reservoir and then re-inject the residue gas as the enhanced recovery mechanism (informally termed "gas-cycling"). This process will preserve gas for reservoir pressure maintenance and for future development. This project will also provide information about gas condensate production and reservoir connectivity.

Condensate production and gas re-injection are scheduled to begin during the first quarter of 2016. The IPS is designed to produce approximately 200 million standard cubic feet per day (MMSCFPD) of gas and transport it via surface flow line to the Point Thomson Unit production processing facility located at Central Pad. Approximately 10,000 barrels of condensate per day will be extracted and transported by above-ground pipeline from the Central Pad for delivery to the Badami, Endicott, and Trans-Alaska Pipeline System common carrier pipelines. Approximately 194 MMSCFPD will be reinjected into the Thomson Sand Undefined Oil Pool.

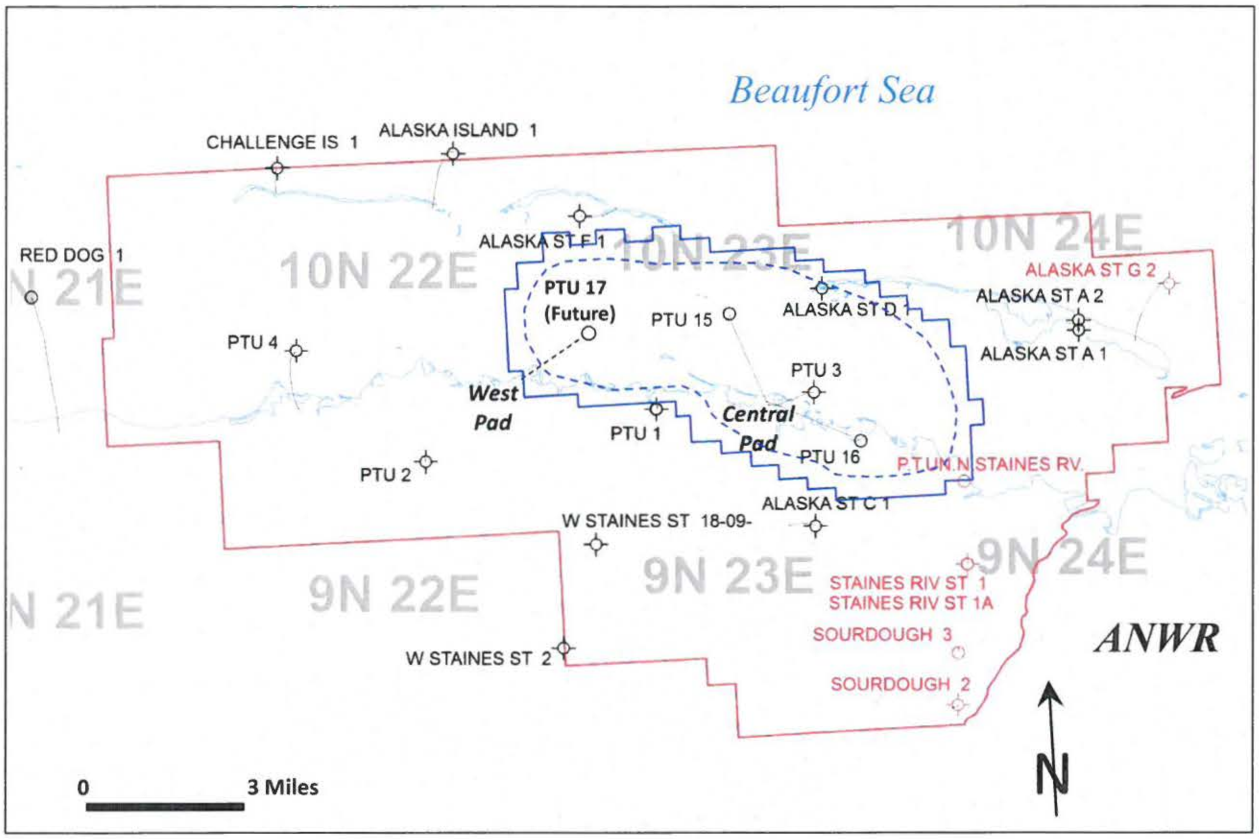

Figure 2. Affected Area of Injected Gas, Thomson Sand Undefined Oil Pool – Solid red line indicates of the Pt. Thomson Unit. Solid blue line indicates approximate outline of the Affected Area. Dashed blue line indicates approximate Initial Production System Area. [3] **Confidential wells are shown in red.**

[3] This map is presented for illustration purposes only. For more precise depictions, refer to Figures 1 and 2 of ExxonMobil's Application for Area Injection Order, Point Thomson Unit, received May 1, 2015, and to the legal description included on pages 9 and 10 of this order.

6. Hydrocarbon Recovery: The Thomson Sand Undefined Oil Pool contains an estimated original gas in place volume of 8 trillion standard cubic feet. Short-term flow tests on wells PTU-15 and PTU-16 suggest a condensate yield of approximately 65 barrels of condensate liquids per one million standard cubic feet of gas under gas sales separation conditions. However, with the higher outlet pressure of a gas cycling separation system anticipated condensate yield for the IPS is approximately 50 barrels of condensate liquids per one million standard cubic feet.

7. Geology:

   a. Stratigraphy: The Thomson Sand Undefined Oil Pool comprises the early Cretaceous-aged Thomson Sand, which lies between 16,126 and 16,377 feet measured depth in reference well PTU-15 (equivalent to -12,614 and -12,828 feet true vertical depth below sea level, which is also termed "true vertical depth subsea" and shortened to TVDSS[4]).

      The Thomson Sand lies unconformably atop pre-Mississippian-aged basement rocks comprising phyllite, argillite, quartzite, and dolomite. Fractured and/or karsted dolomite appears restricted to the northern part of the field, and this rock may serve as a secondary reservoir in communication with the Thomson Sand. The rocks that underlay the Affected Area are expected to be phyllite and quartzite.

   b. The Thomson Sand consists of conglomerate, sandstone, and siltstone derived from an area of Pre-Mississippian-aged basement rock that was exposed, during the early Cretaceous, in the northern and northeastern portion of the Point Thomson Field.[5] At that time, these exposed basement rocks were bordered to the southwest by a sea. Sediments eroded from this exposed source area were transported down-gradient to the southwest and deposited in alluvial fan, fan-delta, and shallow marine shoreface environments. Accordingly, the grain size of the sediments comprising the Thomson Sand diminishes progressively toward the southwest.

      ExxonMobil has identified and mapped a flooding surface that informally divides the Thomson Sand into an upper member and a lower member. The lower member is dominantly progradational, whereas the upper member is dominantly retrogradational.

      ExxonMobil also informally separates the Thomson Sand into six petrofacies based on grain size, sorting, cementation, and ductile grain content. These petrofacies are: cemented conglomerate and breccia, open-framework conglomerate, bimodal conglomerate, clean sandstone, silty sandstone, and siltstone. Each of these petrofacies occupies a well-defined area on a plot of core porosity versus core permeability.

      The Thomson Sand is unconformably overlain by siltstone, mudstone, and shale assigned to the Canning Formation, Hue Shale, and HRZ, in descending stratigraphic order. Erosion has thinned the Hue and HRZ shale intervals toward the northeast, and these intervals are not present in the northern and northeastern parts of the Point

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[4] To avoid confusion, when depths presented in the text represent true vertical depth subsea (*i.e.*, true vertical depth below mean sea level), the footage will be preceded by a minus sign and followed by the acronym TVDSS (*e.g.*, 13,300 feet below mean sea level is depicted by the phrase -13,300 feet TVDSS).

[5] ExxonMobil, 2015, see Figure 14 in ExxonMobil's Application for Area Injection Order, Point Thomson Unit, received May 1, 2015.

Thomson Field. Where the Hue and HRZ intervals are absent or very thin, mudstone and siltstone comprising the lower portion of the Canning Formation will arrest fractures and provide upper confinement for injected fluids.[6]

c. Structure: The structure of the Thomson Sand Undefined Oil Pool is a gently dipping, four-way anticlinal closure. Based on well- and 3D-seismic control, the top of the pool lies about -12,500 feet TVDSS.[7] The anticlinal closure is cut by several, north- and north-northeast-trending, normal faults, but none of these faults appear to completely offset the Thomson Sand or create isolated compartments within it.

d. Trap Configuration: Well log and seismic information indicate that the condensate and oil accumulation within the Thomson Sand Undefined Oil Pool is influenced by both structural and stratigraphic elements. The broad, east-southeast-trending, shale-capped anticlinal closure provides primary control for the accumulation. Facies changes within the Thomson Sand strongly influence reservoir quality, especially in the southwestern portions of the Point Thomson Unit.

e. Confining Intervals: Preliminary modeling for well PTU-16 indicates planned hydraulic fracturing operations will be confined to the Thomson Sand, and will yield an effective fracture half-length of about 50 feet. Figure 1, above, depicts the confining intervals above and below the reservoir.

   The Thomson Sand is overlain by thick, laterally extensive accumulations of siltstone, mudstone, and shale that are assigned to the Canning Formation, Hue Shale, and HRZ Shale, in descending stratigraphic order. These intervals will provide the top seal that will keep injected fluids within the approved interval and arrest any fractures caused by injection operations.

   Pre-Mississippian-aged phyllite and quartzite basement rocks will arrest fractures and provide lower confinement for injected fluids.

f. Reservoir Compartmentalization: Facies distribution, flow tests, and reservoir pressure measurements suggest that the Thomson Sand Undefined Oil Pool is not separated into isolated compartments within the Affected Area.

g. Permafrost: Permafrost base lies at about -1,800 feet TVDSS within the Affected Area.

8. Reservoir Properties: Within the Affected Area, reservoir porosity for the Thomson Sand ranges from about 5% to 34%, and averages about 14%. Permeability ranges from 0.01 millidarcies in some samples of cemented conglomerate and breccia to 50 darcies in some samples of open-framework conglomerate.

9. Reservoir Fluid Contacts: The gas-oil contact is -12,975 feet TVDSS from Modular Dynamic Tester (MDT) pressure measurements and fluid samples obtained in PTU-16. The oil-water contact is -13,012 feet TVDSS based on well tests and well log data from a well granted extended confidentiality by the DNR. The elevations of these contacts are believed

[6] ExxonMobil, 2015, see Figures 11 and 19 in ExxonMobil's Application for Area Injection Order, Point Thomson Unit, received May 1, 2015.

[7] ExxonMobil, 2015, Top Thomson Sand Structure Map in the Participating Area, Figure 5 in ExxonMobil's Application for Area Injection Order, Point Thomson Unit, received May 1, 2015.

to be constant throughout the Affected Area.

10. Reservoir Fluid Properties: Within the Point Thomson Field, the hydrocarbon accumulation trapped in the Thomson Sand comprises a nearly 500-foot thick, high-pressure, condensate "gas cap" and an underlying, 37-foot thick rim of viscous oil. Public-domain well test results for wells Alaska State No. A-1 and Pt. Thomson Unit No. 1 yield gas-oil ratios of 864 and 5,830 standard cubic feet of gas per stock tank barrel (scf/stb) of oil,[8] which requires classification of the Thomson Sand accumulation as an oil pool.[9]

    Flow tests of PTU-15 and PTU-16 indicate the API gravity of the condensate liquid is 38°. The API gravity of the black oil in the oil rim is reported to be 12-14°. Hydrogen sulfide (H_2S) and carbon dioxide (CO_2) are present within the Thomson Sand reservoir.[10]

11. Reservoir Pressure and Temperature: Average reservoir pressure is about 10,100 psi at the datum of -12,700 feet TVDSS. Reservoir temperature ranges from about 220° to 230° F.

12. Well Logs: Logs of the injection wells, PTU-15 and PTU-16, have been filed with the AOGCC according to the requirements of 20 AAC 25.

13. Mechanical Integrity and Design of Injection Wells: The casing and cementing programs for all injection wells will comply with 20 AAC 25.030. Cement-bond logs will be run to demonstrate the isolation of injected fluids to the Point Thomson reservoir as required by 20 AAC 25.412(d). Mechanical integrity tests will be performed in accordance with 20 AAC 25.412(c). To facilitate installation of gravel pack completions, ExxonMobil has applied for and obtained waivers from AOGCC to 20 AAC 25.412(b) to allow packers in injection wells to be located more than 200 feet measured depth above the top of the injection zone but below the top of the upper confining zone.

14. Type of Fluid / Source: The only fluid requested for injection is gas produced from the Thomson Sand Undefined Oil Pool.

15. Compatibility with Formation: Evidence of water compatibility is not required unless ExxonMobil seeks approval from the AOGCC to inject produced water or non-native fluids into the Thomson Sand reservoir.

16. Injection Rates, Pressures and Pressure Monitoring: ExxonMobil proposes to develop this pool as a gas-only injection, enhanced condensate liquid recovery project. Expected maximum gas injection will be approximately 194 million standard cubic feet per day, which represents 200 million standard cubic feet per day of production minus liquids sold and fuel gas consumed. Re-injection of residual produced gas will maintain reservoir voidage at a ratio of about 0.97:1.

    Injection pressures are expected to average approximately 9,800 to 10,000 psi at the wellhead, and they will be limited to a maximum of injection pressure of 11,025 psi at which time the injection process will be shutdown. Mechanical Integrity Tests (MITs) will be conducted on injection wells as required by the AOGCC.

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[8] AOGCC, 1984, Statistical Report: Reservoir Data for Wells Alaska State A-1 and Pt. Thomson Unit No. 1, p. 103.

[9] Regulation 20 AAC 25.990(45):"oil well" means a well that produces predominantly oil at a gas-oil ratio of 100,000 scf/stb or lower, unless on a pool-by-pool basis the commission establishes another ratio.

[10] An H_2S concentration of 30 PPM was measured in PTU-16. ExxonMobil's estimated composition of the injected gas stream includes 4.5 mole percent CO_2 (see Table 1 in ExxonMobil's Application for Area Injection Order).

17. Fracture Information: The fracture gradient for the confining interval is estimated to be 0.91 psi per foot. Maximum planned gas injection pressure is 10,400 psi at reservoir level, so injection operations will not initiate or propagate fractures through the confining intervals.

18. Absence of Underground Sources of Drinking Water: In September 2009, the U.S. Environmental Protection Agency (U.S. EPA) confirmed that there are no underground sources of drinking water within the Affected Area.[11]

19. Mechanical Condition of Adjacent Wells: Twenty-two wells have been drilled within the Point Thomson Field area. Of these, four are currently suspended and 18 wells have been plugged and abandoned. All of these wells have sufficient mechanical isolation to confine fluids and prevent cross-flow.

20. Hydraulic Fracturing of Wells: Small-scale, cased-hole, frac-pack operations will be conducted in PTU-15, PTU-16, and PTU-17. Short (about 40-foot), lateral fractures will be hydraulically induced and then filled with sized-sand that will act as a filter to prevent the flow of formation sand into the wellbores.

CONCLUSIONS:

1. The requirements of 20 AAC 25.402 have been met.
2. The accumulation of condensate and oil within Thomson Sand is properly classified as an oil pool properly termed the Thomson Sand Undefined Oil Pool.
3. ExxonMobil's IPS Project will not cause waste, and it will provide reservoir, fluid, and production information that is critical to determining future development of the Thomson Sand Undefined Oil Pool.
4. There are no underground sources of drinking water beneath the proposed Affected Area.
5. Only residual, produced gas is authorized for re-injection into the Thomson Sand Undefined Oil Pool. A separate approval is required before injecting any other fluids into the pool.
6. The proposed injection operations will be conducted in permeable strata, which can reasonably be expected to accept injected fluids at pressures less than the fracture pressure of the confining strata.
7. Injected fluids will be confined within the appropriate receiving intervals by impermeable lithology, cement isolation of the wellbores, and appropriate operating conditions.
8. Daily to continuous well surveillance and reservoir monitoring coupled with regularly scheduled MITs will demonstrate appropriate performance of the enhanced oil recovery project and disclose possible abnormalities. An annual report of injection performance is warranted, and it must include an assessment of fracture propagation into adjacent confining intervals.
9. Setting the packers in the injection wells more than 200 feet measured depth above the

[11] U.S. EPA, 2009: letter from E.J. Kowalski, Director of the Office of Compliance and Enforcement, to D. Pittman, ExxonMobil Production Company, date stamped Sep 25 2009; included as Exhibit 4 in ExxonMobil's Application for Area Injection Order, Point Thomson Unit, received May 1, 2015.

injection interval to facilitate installation of the gravel pack completion will not increase the risk of an injection fluid confinement failure, provided that the packer is set at least 300 feet measured depth below the top of the production casing cement and is not above the confining zone. The location of production casing cement will be established through cement bond logging or alternate methods deemed acceptable by the AOGCC. Any alternative methods must be approved in advance by the AOGCC. MITs regularly scheduled by the AOGCC will ensure integrity of injection wells.

10. Reservoir voidage will be maintained at a replacement ratio of about 0.97:1.

11. Sufficient information has been provided to authorize injection of gas into the Thomson Sand Undefined Oil Pool for the purposes of pressure maintenance and enhanced condensate recovery, subject to monitoring as described in the rules below.

NOW, THEREFORE, IT IS ORDERED that:

The underground injection of fluids for pressure maintenance and enhanced oil recovery is authorized in the following area, subject to the following rules and, to the extent not superseded by these rules, 20 AAC 25:

Affected Area: Umiat Meridian

Township, Range	Sections	Portions
10 North, 24 East	29	W-1/2 SW-1/4
10 North, 24 East	30	S-1/2, NW-1/4, and SW-1/4 NE-1/4
10 North, 24 East	31	All
10 North, 24 East	32	W-1/2
10 North, 23 East	16	SW-1/4, and S-1/2 SE-1/4
10 North, 23 East	17	SW-1/4, and S-1/2 SE-1/4
10 North, 23 East	18	SW-1/4, and S-1/2 SE-1/4
10 North, 23 East	19-22 & 25-30 & 34-36	All
10 North, 23 East	23	S-1/2,S-1/2 NE-1/4, and NW-1/4
10 North, 23 East	24	SW-1/4, S-1/2 SE-1/4, and NW-1/4 SE 1/4
10 North, 23 East	31	N-1/2, and N-1/2 SE-1/4
10 North,23 East	32	N-1/2, N-1/2 SW-1/4, and N-1/2 SE- 1/4
10 North, 23 East	33	N-1/2, SE-1/4, N-1/2 SW-1/4, and SE-1/4 SW-1/4
10 North, 22 East	24	E-1/2, and E-1/2 SW-1/4
10 North, 22 East	25	E-1/2, E-1/2 NW-1/4, and E-1/2 SW-1/4
10 North, 22 East	36	NE-1/4
9 North, 24 East	5	W-1/2, and W- 1/2 NE-1/4
9 North, 24 East	6	All
9 North, 24 East	7	N-1/2, N-1/2 SW-1/4, and N-1/2 SE-1/4
9 North, 24 East	8	NW-1/4

Township, Range	Sections	Portions
9 North, 23 East	1& 2	All
9 North, 23 East	3	N-1/2, SE-1/4, N-1/2 SW-1/4
9 North, 23 East	4	NE-1/4
9 North, 23 East	11	N-1/2 NW-1/4, NE-1/4
9 North, 23 East	12	N-1/2, N-1/2 SW-1/4,and N-1/2 SE-1/4

Rule 1 Authorized Injection Strata for Enhanced Recovery

Fluids authorized under Rule 3, below, may be injected for purposes of pressure maintenance and enhanced oil recovery within the Affected Area into strata that are common to, and correlate with, the interval between 16,126 and 16,377 feet measured depth on the VISION/Scope Measured Depth Log recorded in reference well PTU-15.

Rule 2 Well Construction

Packers in injection wells may be located more than 200 feet measured depth above the top of the Thomson Sand Undefined Oil Pool; however, packers shall not be located above the confining zone. The production casing cement volume must be sufficient to place cement a minimum of 300 feet measured depth above the planned packer depth. Cement placement must be confirmed by cement bond log or another method approved in advance by the AOGCC.

Rule 3 Authorized Fluids for Enhanced Recovery

The only fluid authorized for injection is natural gas produced from the Thomson Sand Undefined Oil Pool. Any other fluids shall be approved in advance by separate administrative action based upon proof of compatibility with the reservoir and formation fluids.

Rule 4 Authorized Injection Pressure for Enhanced Oil Recovery

Injection pressures must be maintained at or below 11,500 psi at the reservoir sand-face so that injected fluids do not fracture the confining intervals or migrate out of the approved injection strata.

Rule 5 Monitoring Tubing-Casing Annulus Pressure

Inner and outer annulus pressure shall be monitored each day for all injection and production wells. Inner annulus, outer annulus, and tubing pressure shall be constantly monitored and recorded for all injection and production wells. The outer annulus pressures of all wells that are not cemented across the Thomson Sand Undefined Oil Pool and are located within a ¼-mile radius of a Point Thomson injector shall be monitored daily. All monitoring results shall be documented and available for AOGCC inspection.

Rule 6 Demonstration of Tubing/Casing Annulus Mechanical Integrity

The mechanical integrity of each injection well must be demonstrated before injection begins and before returning a well to service following any workover affecting mechanical integrity. An AOGCC-witnessed MIT must be performed after injection is commenced for the first time in a well, to be scheduled when injection conditions (temperature, pressure, rate, etc.) have stabilized. Subsequent tests must be performed at least once every four years thereafter. The AOGCC must be notified at least 24 hours in advance to enable a representative to witness an MIT.

Unless an alternate means is approved by the AOGCC, mechanical integrity must be demonstrated by a tubing/casing annulus pressure test using a surface pressure of 1,500 psi or 0.25 psi/ft multiplied by the vertical depth of the packer, whichever is greater, that shows stabilizing pressure and does not change more than 10 percent during a 30-minute period. Results of MITs must be readily available for AOGCC inspection.

Rule 7 Well Integrity and Confinement

Whenever any pressure communication, leakage or lack of injection zone isolation is indicated by an injection rate, operating pressure observation, test, survey, log, or any other evidence (including outer annulus pressure monitoring of all wells within a ¼-mile radius of where the Point Thomson is not cemented), the Operator shall notify the AOGCC by the next business day and submit a plan of corrective action on a Form 10-403 for AOGCC approval. The Operator shall immediately shut in the well if continued operation would be unsafe or would threaten contamination of freshwater, or if so directed by the AOGCC. A monthly report of daily tubing and casing annuli pressures and injection rates must be provided to the AOGCC for all injection wells for which well integrity failure or lack of injection zone isolation is indicated.

Rule 8 Annual Performance Reporting

An annual surveillance report will be required by April 1st of each year subsequent to commencement of enhanced oil recovery operations. In addition to such other information as the AOGCC may require the report shall include the following:

a. progress of the enhanced recovery project and reservoir management summary including engineering and geological parameters;
b. reservoir voidage balance by month of produced and injected fluids;
c. analysis of reservoir pressure surveys within the pool;
d. results and, where appropriate, analysis of production and injection log surveys, tracer surveys and observation well data or surveys;
e. assessment of fracture propagation into adjacent confining intervals;
f. summary of MIT results;
g. summary of results of inner and outer annulus monitoring for all production wells, injection wells, and any wells that are not cemented across the Thomson Sand Undefined Oil Pool and are located within a ¼-mile radius of a Point Thomson injector;
h. results of any special monitoring;
i. reservoir surveillance plans for the next year; and
j. future development plans.

Rule 9 Notification of Improper Class II Injection

Injection of fluids other than those listed in Rule 3 without prior authorization is considered improper Class II injection. Upon discovery of such an event, the operator must immediately notify the AOGCC, provide details of the operation, and propose actions to prevent recurrence. Additional notification requirements of any other State or Federal agency remain the operator's responsibility.

Rule 10 Other Conditions

If fluids are found to be fracturing the confining zone or migrating out of the approved injection stratum, the Operator must immediately shut in the injection wells and immediately notify the AOGCC. Injection may not be restarted unless approved by the AOGCC.

Rule 11 Administrative Action

Upon proper application, or its own motion, and unless notice and public hearing are otherwise required, the AOGCC 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.

This order shall expire if ExxonMobil ceases to be the Designated Operator for the Point Thomson Unit or five years after the effective date shown below, whichever occurs first.

DONE at Anchorage, Alaska, and dated August 25, 2015.

Cathy P. Foerster
Chair, Commissioner

Daniel T. Seamount, Jr.
Commissioner

ALASKA OIL AND GAS CONSERVATION COMMISSION

RECONSIDERATION AND APPEAL NOTICE

As provided in AS 31.05.080(a), within **20** days after written notice of the entry of this order or decision, or such further time as the Commission grants for good cause shown, a person affected by it may file with the Commission an application for reconsideration of the matter determined by it. If the notice was mailed, then the period of time shall be **23** days. An application for reconsideration must set out the respect in which the order or decision is believed to be erroneous.

The Commission shall grant or refuse the application for reconsideration in whole or in part within 10 days after it is filed. Failure to act on it within 10-days is a denial of reconsideration. If the Commission denies reconsideration, upon denial, this order or decision and the denial of reconsideration are **FINAL** and may be appealed to superior court. The appeal **MUST** be filed within **33** days after the date on which the Commission mails, **OR 30** days if the Commission otherwise distributes, the order or decision denying reconsideration, **UNLESS** the denial is by inaction, in which case the appeal **MUST** be filed within **40** days after the date on which the application for reconsideration was filed.

If the Commission grants an application for reconsideration, this order or decision does not become final. Rather, the order or decision on reconsideration will be the **FINAL** order or decision of the Commission, and it may be appealed to superior court. That appeal **MUST** be filed within **33** days after the date on which the Commission mails, **OR 30** days if the Commission otherwise distributes, the order or decision on reconsideration. As provided in AS 31.05.080(b), "[t]he questions reviewed on appeal are limited to the questions presented to the Commission by the application for reconsideration."

In computing a period of time above, the date of the event or default after which the designated period begins to run is not included in the period; the last day of the period is included, unless it falls on a weekend or state holiday, in which event the period runs until 5:00 p.m. on the next day that does not fall on a weekend or state holiday.