Final Findings and Determination

For

Nikaitchuq Development
Royalty Modification
Application

Commissioner of the Department of Natural Resources

APPROVAL
OF MODIFICATION OF ROYALTY
FOR LEASES:
ADLs 388571, 388572, 388574, 388575, 388577, 388581, 388582, 388583, 390615, 390616 and 391283

January 11, 2008

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I. INTRODUCTION AND BACKGROUND

A. Introduction

On October 16, 2007, Eni US Operating Co. Inc. (Eni), as operator of the Nikaitchuq Unit (NU), on behalf of its affiliate Eni Petroleum US LLC, 100 percent working interest owner of the subject leases, submitted an application to the commissioner of the State of Alaska Department of Natural Resources (ADNR) for modification of royalty under AS 38.05.180(j)(1)(A) (Attachment 1). On November 30, 2007, ADNR issued a Preliminary Findings and Determination to respond to Eni's royalty modification application. The public was invited to comment on the preliminary decision for 30 days ending January 7, 2008. ADNR hereby issues its Final Findings and Determination as required under AS 38.05.

Eni has applied for royalty modification on 12 leases which overlie the Schrader Bluff and the Sag River reservoirs. However, the Sag River reservoir was withdrawn from the application at the request of Eni. Eni requests that the fixed royalty rates of

- 12.5 percent on the Net Profit Share (NPS) lease, ADL 391283, and
- 16.66667 percent on the 11 leases (ADLs 388571, 388572, 388574, 388575, 388577, 388580, 388581, 388582, 388583, 390615, and 390616)

be reduced to the minimum rate allowed, 5.0 percent, with an annual sliding-scale royalty percentage adjustment based on the level of Alaska North Slope West Coast (ANSWC) crude oil price. The 30 percent net profit share rate on ADL 391283 is to remain unchanged. Attachment 2 depicts the Nikaitchuq Unit boundaries and leases subject to this royalty modification application.

This Final Findings and Determination responds to the royalty modification application as required under AS 38.05.180(j)(8). Part I summarizes the royalty modification application and process. Part II reviews the history of the Nikaitchuq Unit formation and development, and Eni's royalty modification application. Part III reviews the state's authority to carry out royalty modification. Part IV reviews the requirements and terms of royalty modification pursuant to this application. Part V contains ADNR's analysis of the application under the royalty modification criteria. Part VI is the Final Findings and Determination.

B. Royalty Modification Procedure

This Final Findings and Determination is the first step in a process contemplated in AS 38.05.180(j) that could result in an authorization to modify the royalty terms for certain leases. The commissioner published the Preliminary Findings and Determination, gave public notice of a 30-day public comment period (Attachments 3 and 4), and offered to appear before the Legislative Budget and Audit Committee to provide a review of the

Findings and Determination and the administrative process. The commissioner will keep the submitted data confidential under AS 38.05.035(a)(9) at the request of the lessee or lessees making application for the royalty reduction. This Final Findings and Determination by ADNR regarding royalty modification is final and not appealable. With the Applicant's concurrence, ADNR will amend the subject leases to conform to the terms of this royalty modification Final Findings and Determination.

II. SUMMARY OF ENI'S APPLICATION FOR ROYALTY MODIFICATION

A. Unit and Lease Summary

ADNR approved the formation of the Nikaitchuq Unit effective April 29, 2004. At that time, Kerr-McGee Oil & Gas Corp. (KMG) held 70 percent of the working interest and Armstrong Oil & Gas Inc. (Armstrong) held 30 percent. The unit originally consisted of eight leases covering 12,968 offshore acres in the shallow waters of Harrison Bay in the Beaufort Sea, approximately three miles north of Oliktok Point. The Kuparuk River Unit (KRU) lies to the south, and the Milne Point Unit (MPU) lies to the east of the Nikaitchuq Unit. The Tuvaaq Unit, formed in August 2004, was adjacent to the western boundary of the original Nikaitchuq Unit. Effective October 5, 2007, ADNR approved the first expansion of the Nikaitchuq Unit, termination of the Tuvaaq Unit and the contraction of the Kuparuk River Unit. The Nikaitchuq Unit expanded to include all of the Tuvaaq Unit leases, the Kigun lease, formerly committed to the KRU, and two additional leases acquired by ENI at the 2004 Beaufort Sea Sale.

All 12 leases in the Eni royalty modification application are committed to the expanded Nikaitchuq Unit. (See lease map in Attachment 2.)

The ownership of the Nikaitchuq Unit has changed significantly since formation. Eni acquired Armstrong's 30 percent WIO of Nikaitchuq Unit in August 2005. In August 2006, Anadarko Petroleum Co. (Anadarko) acquired KMG, including KMG's 70 percent WIO in Nikaitchuq Unit, and became Nikaitchuq Unit operator. Eni subsequently acquired the remaining 70 percent Nikaitchuq Unit ownership from the operator, Anadarko, in March 2007, and became the 100 percent WIO and operator of Nikaitchuq Unit.

On January 11, 2006, KMG submitted an application for royalty modification under AS 38.05.180(j)(1)(A) for 14 leases of which 12 are the subject of this application.[1] KMG's application requested that the royalty rate for the 14 leases be modified from their respective existing fixed royalty rates of 16.67 percent and 12.5 percent to a fixed royalty rate of 5 percent. Effective October 31, 2006, the ADNR issued the Final Findings and Determination of the Commissioner of the Department of Natural Resources for the Nikaitchuq Development Royalty Modification Application denying KMG's application for royalty modification.

[1] The KMG application included ADLs 355021, 355024, 388571, 388572, 388574, 388575, 388577, 388578, 388580, 388581, 388582, 388583, 390615, and 390616.

B. Project Development History

In the 2003-2004 and 2004-2005 exploration/appraisal drilling programs KMG/Armstrong encountered accumulations of hydrocarbons in the area of the then-proposed Nikaitchuq Unit. A total of six wells were drilled in the Nikaitchuq area in the 2004 and 2005 winter drilling seasons; two additional wells were drilled in 2006.

The planned development includes:

- Construction of a gravel pad with drilling, gathering and production facilities on Oliktok Point near the existing ConocoPhillips Alaska Inc. seawater treatment facility.
- Construction of a gravel drilling island near Spy Island tied back via a 3.8-mile subsea flow line and utility bundle to Oliktok Point for fluid processing.
- Construction of a +/-14-mile pipeline from Oliktok Point to a tie-in near KRU DS-1Y pad for connection to the Kuparuk Transportation common carrier pipeline.
- Consideration of future modifications required to adjust facility configuration to accommodate actual results of well performance.
- A total of 73 wells drilled between 2008 and 2011, of which 31 are expected to be producers.
- First oil expected in 2010.

Development studies indicate that extended reach horizontal producing and injection wells required for pressure maintenance are needed to economically recover the hydrocarbons in place. The planned development would permit a relatively small "footprint" for centralized facilities and minimal well pads, thereby reducing environmental impacts to the region. Initial drilling will be from a 313,000-square-foot pad to be constructed at Oliktok Point. Existing roads will be utilized for access. The production facilities will be located on the same pad. Later, a small gravel island is to be constructed within the barrier islands for future drilling. A subsea bundle containing a three-phase production line and multiple utility lines will be constructed to connect the gravel island to Oliktok Point to transport production and provide fuel, secondary recovery fluid, and power to the gravel island.

C. Eni Royalty Modification Request

On October 16, 2007, Eni submitted an application (Attachment 3) to the ADNR commissioner for modification of royalty on 12 leases, ADLs: 388571, 388572, 388574, 388575, 388577, 388580, 388581, 388582, 388583, 390615, and 390616 and ADL 391283 under AS 38.05.180(j)(1)(A). In accordance with 11 AAC 88.105, 11 AAC 83.185, and 11 AAC 05.010(a)(10)(H) Eni submitted a complete application with the required $250.00 filing fee.

The Eni application for royalty modification submitted on October 16, 2007, requests a 5.0 percent fixed royalty if the Alaska North Slope West Coast (ANSWC) crude oil price falls below an ANSWC price equivalent to the U.S. Department of Interior, Minerals Management Service (MMS) NYMEX West Texas Intermediate (WTI) oil price threshold for royalty modification for OCS August 2004-2006 deepwater oil leases in the Gulf of Mexico (GOM).[2] Eni proposes a sliding-scale royalty rate in any month after production start-up (expected in 2010) that would range between 5.0 and 16.6667 percent, depending on the average monthly price of ANSWC crude oil. An ANSWC monthly (nominal) price below the Alaska Department of Revenue (ADOR) *Spring 2007 Revenue Sources* forecast between 2010 (the year of first production) and 2017 shown in Figure II.1 (below) would trigger a reduced royalty rate from original fixed lease rates of 12.5 percent and 16.6667 percent, respectively. The amount of the reduction in royalty percentage would depend on (a) the original lease rate (either 12.5 percent or 16.6667 percent) and (b) the extent to which the actual future oil price falls below the ADOR forecast threshold.[3]

The original fixed royalty rate of 16.6667 percent for ADLs 388571, 388572, 388574, 388575, 388577, 388581, 388582, 388583, 390615, and 390616 and 12.5 percent with 30 percent net profit for ADL 391283 would be subject to the sliding scale modification in a low commodity price environment to a level at or above a floor of 5 percent. The 30 percent net profit share to the State attached to ADL 391283 would be unchanged under the Eni royalty modification proposal.

The Eni application also would provide full royalty relief at a reduced rate of 5 percent for all leases regardless of oil price if monthly production is below 4,000 barrels of oil per day for the first 10 years following the effective date of the royalty modification decision.

[2] ADNR estimates threshold to be $42.53 per barrel in 2010 based on a 2007 NYMEX WTI price of $42.64 assuming a 94 percent basis adjustment to ANSWC and 2 percent price escalation pursuant to the ENI proposal. See: MMS, *Price Thresholds and Annual Market Prices for MMS Deepwater and Deep Depth Oil and Gas Royalty Relief Programs*, Deep Water Oil, Economics Division at www.mms.gov/econ/DWRRAPrice1.htm.

[3] Under the Eni proposal, the royalty percentage rate adjustment would be approximately ¾ percentage point per $1 change in ANSWC price for leases with a 16.6667 percent base royalty rate and ½ percentage point per $1 change in ANSWC price for leases with a 12.5 percent base royalty rate. After 2017, the ADOR ANSWC price forecast is inflated by the monthly change in the Producer Price Index (PPI).

III. SUMMARY OF ROYALTY MODIFICATION AUTHORITY AS 38.05.180(j)(1)(A), (2), (3), (4)(A), (5)

A. General Royalty Modification Requirements

AS 38.05.180(j)(1)(A) authorizes the DNR commissioner to provide for royalty modification on individual leases, leases unitized as described in (p) of this section (AS 38.05.180), leases subject to an agreement described in (s) or (t) of this section (AS 38.05.180), or interests unitized under AS 31.05 to allow for production from an oil or gas field or pool if:

1. the oil or gas field or pool has been sufficiently delineated to the satisfaction of the commissioner;
2. the field or pool has not previously produced oil or gas for sale; and
3. oil or gas production from the field or pool would not otherwise be economically feasible.
4. Under AS 38.05.180(j)(2), the commissioner may not grant a royalty modification unless the lessee or lessees requesting the royalty modification make a clear and convincing showing that a royalty modification meets the three requirements set out above and is in the best interests of the state.

B. General Royalty Modification Terms

1. Under AS 38.05.180(j)(3) the royalty modification terms must provide for an increase or decrease or other modification of the state's royalty share by a sliding-scale royalty or other mechanism that shall be based on a change in the price of oil or gas and may also be based on other relevant factors such as a change in production rate, projected ultimate recovery, development costs, and operating costs.
2. Under AS 38.05.180(j)(4)(A) a modification to royalty may not be granted for the field or pool if the royalty modification would result in a royalty rate of less than 5 percent in amount or value of the production removed or sold from a lease or leases covering the field or pool.
3. Under AS 38.05.180(j)(5) a royalty reduction must include an explicit condition that the royalty reduction is not assignable without the prior written approval, which may not be unreasonably withheld, by the commissioner. The commissioner shall, in the preliminary and final findings and determinations, set out the conditions under which the royalty reduction may be assigned and may not grant a royalty reduction without an explicit condition that the royalty reduction is not transferable.

IV. DISCUSSION OF ROYALTY MODIFICATION CRITERIA

A. Leases Are Eligible For Consideration

The leases meet the requirements for consideration and all eleven subject leases proposed for royalty modification are committed in entirety to the Nikaitchuq Unit. AS 38.05.180(j)(1) allows modification of royalty for individual leases and unitized leases.

B. Reservoir Delineation: Discussion of Reservoir Geology and Engineering

1. Introduction to reservoir delineation.

The commissioner may grant royalty modification to allow for production from an oil or gas field or pool if the oil or gas field or pool has been sufficiently delineated to the satisfaction of the commissioner.

The area within the Nikaitchuq Unit for which royalty relief is sought lies offshore in the Beaufort Sea in the vicinity of Spy Island, approximately three miles north of Oliktok Point. The Nikaitchuq Unit is north of and contiguous with the northern edge of the KRU and the Milne Point Unit (MPU). The KRU is operated by ConocoPhillips and produces from the Cretaceous Kuparuk River Formation and shallower Schrader Bluff Formation. The BP-operated MPU field lies to the south-southeast of the Nikaitchuq Unit and produces oil from the Schrader Bluff, Kuparuk, and Triassic Sag River formations. The western edge of the proposed Nikaitchuq Unit is adjacent to the recently expanded Oooguruk Unit (OU) operated by Pioneer. Production from the OU is expected from the Kuparuk and Jurassic Nuiqsut sandstones.

Within the Nikaitchuq Unit, potential commercially recoverable reserves have been tested in both the Cretaceous Schrader Bluff and the Triassic Sag River formations.

Based upon the submitted application and the planned initial development, the request for royalty modification at Nikaitchuq is limited to the OA sand of the Schrader Bluff Formation. For the purpose of this application, the OA sand is defined in Kerr McGee Nikaitchuq #1 (API No. 50629231930000), completed in 2004, as the interval between 5034 feet measured depth (4127 feet subsea true vertical depth) and 5090 feet measured depth (4170 feet subsea true vertical depth).

ENI has adequately delineated the OA sand of the Schrader Bluff Formation in the Nikaitchuq area. Their drilling, testing, and evaluation programs appear to have highlighted the obvious risks inherent to developing viscous oil and identified the possible upside potential available through use of extended reach drilling and advanced completion technologies.

Although upside potential may also exist within the shallower Schrader Bluff N sand interval, the current lack of core, well test, or fluid data from this interval increases the risk and precludes it from being deemed delineated and included as part of this application. ENI plans to gather more data to thoroughly evaluate the N sand during the course of developing the deeper OA sand.

The Sag River Formation contains lighter oil than the Schrader; however, it is plagued with poor quality reservoir rock. The development potential is marginal at best unless there are significant advances in stimulation or enhanced oil recovery technology. Delineation of the Sag River Formation at Nikaitchuq to date has revealed limited reserves and similar test results to the analog at MPU where wells within the Sag River Formation consistently show initial flush production followed by steep decline within the first year. ENI is still evaluating the development potential of this interval and, as such, it has been excluded from this application.

2. Exploration History of the Area

Two key early exploration wells lie within several miles of the Nikaitchuq development area. The Unocal East Harrison Bay State #1 well lies near the northwest corner of the KRU, to the southwest of the Nikaitchuq Unit. The well was drilled in February 1977 to a measured depth of 9,809 feet, bottoming in argillite basement. The East Harrison Bay State #1 well logs appear to contain about 15 feet of oil-bearing Kuparuk Formation that appears cemented in the upper half. The Jurassic section looks silty on logs. The ARCO Kalubik #3 well, drilled in February 1998, lies to the south-southwest of the Nikaitchuq area. The well bottomed in the Jurassic at a measured depth of 7,000 feet. The well encountered a 40-foot-thick measured depth (MD) interval of Kuparuk C sandstone that appears on electric logs as oil-bearing, but siderite cemented in the upper 10 feet of the interval. On well logs the Jurassic interval contains silt with a 12-foot silty sand developed around 6,565 feet MD. The well was plugged and abandoned on March 6, 1998.

3. Drilling History

The first major exploration activity in the area in the early 1970s targeted the Ivishak Formation following the discovery of the prolific Ivishak Formation in Prudhoe Bay State #1 in 1967. The Hamilton Brothers Milne Point #18-1 was one of the early wells drilled on the Milne Point structure in 1970 in search of Ivishak and Lisburne objectives. This well encountered about 50 feet of tight oil-saturated sandstone that was not tested and a section of Kuparuk sandstone that tested at a rate of 875 BOPD. This discovery led to increased industry interest in the Milne Point area and led to exploration and delineation drilling for Kuparuk reserves. In the early 1980s the Sag River was cored in the Conoco Milne Point Unit #C-1 well and contained bleeding oil and gas. The Sag River Sandstone was also cored in the MPU #L-1 well and contained no visible porosity or staining and appeared tight on wire line logs.

In the early 1990s about a dozen wells were drilled to the west-southwest of the Nikaitchuq area with Jurassic sandstones and Kuparuk C sandstones as targets. The ARCO Kalubik #1 well encountered approximately 160 feet of productive Nuiqsut and Nechelik sandstone that tested approximately 336 BOPD (un-stimulated). In addition, the well penetrated an 85-foot section of Sag River Sandstone with calculated log porosities in the range of 15 to 22 percent. The Thetis Island #1 well also encountered an 80-foot section of porous Sag River sandstone with log-calculated porosities in the range of 16-24 percent. A pay section of Nuiqsut sandstone was also encountered that tested at an average rate of 120 BOPD with a high rate of 650 BOPD. Both the Kalubik #1 well and Thetis Island #1 well drilled through Brookian sandstones that contained mud log hydrocarbon shows.

In the late 1990s BP drilled several dedicated Sag River Sandstone test wells, including MPU #C-23, #K-33, #E-13A, 3F-33, #F-33A, and #F-73A. Alaska Oil and Gas Conservation Commission (AOGCC) production data indicate that several Milne Point wells have produced oil out of the Sag River Sandstone and two oil producing wells MPU F-33A and K-33, are currently shut-in. MPU #C-23 produced 378,012 barrels of oil between 1996 and 2001. MPU #F-33 produced 314,276 barrels of oil between September 1996 and May 1999 and was subsequently plugged and abandoned. MPU #K-33 has produced approximately 93,241 barrels of oil since 1997. MPU #E-13A produced 366,665 barrels of oil between 1995 and April 2001. MPU #F-33A produced approximately 661,099 barrels of oil since April of 2001. MPU #F-73A produced 13,430 and is now a water-alternating-gas injection (WAGIN) well. BP estimated the original oil-in-place (OOIP) at 62 MM STB oil and the reservoir area about 8500 acres based upon seismic and log data during an AOGCC Conservation Order hearing in May 1998. AOGCC reservoir data indicate that the oil commonly recovered from the Sag River sandstone has an API oil gravity of about 37 degrees. Total production from the MPU Sag River Sandstone has been 1,834,131 barrels of oil and 1,875,668 MSCF gas through October 2007. MPU Sag River recovery is less than 3 percent to date based on OOIP. The original GOR ranged from 784 – 974 SCF/STB. Production from the Sag River pool at MPU has been intermittent with extended shut-in periods since June 1999.

Between 2004 and 2005, Kerr McGee (KMG) drilled six wells in the Nikaitchuq and Tuvaaq Units. Initially, the primary exploration target was the Sag River Formation; the Kuparuk Formation was a secondary target. Although the wells did not encounter reservoir quality sand in the Kuparuk, the well logs indicated that sands in the shallower Schrader Bluff Formation were prospective. KMG then adjusted the exploration program to thoroughly evaluate the Schrader Bluff Formation. Three of the six wells tested oil from the viscous Schrader Bluff or Sag River formations. In 2006/2007 KMG drilled two additional pre-development wells from Oliktok Point to further delineate and test the Schrader Bluff sandstone. The two wells are currently suspended.

4. Schrader Bluff Formation Tests

KMG Nikaitchuq #4

Approximately 3,000 feet of gross horizontal Schrader Bluff OA sand was drilled in this well, with approximately 2,270 feet of horizontal or lateral net pay, from a 30-foot true-vertical-depth net pay thickness. A two-week production test was performed on the well using an electric submersible pump (ESP) to aid in producing the 16–17 API crude. The well tested at rates up to 1,200 barrels of oil per day during periods of the initial test. Permeability estimated from the test was greater than 350 millidarcies and was confirmed from the analysis of the flow tests conducted on a whole core obtained from the well.

KMG Tuvaaq #1

The well was not tested. It penetrated 30 feet net pay Schrader Bluff OA Sand and 12 feet net Schrader Bluff N sand. There were no cores taken at Tuvaaq. Schrader Bluff N sand was interpreted to be oil-filled here and at Kigun #1 appeared unconsolidated with permeability estimated from 100-1000 millidarcies and porosity 25-35 percent.

KMG Kigun #1

The well was not tested. It penetrated 29 feet net pay Schrader Bluff OA sand and 30 feet net N sand. An MDT tool run sampled the Schrader Bluff OA fluids which were 18 degree API, GOR 59 SCF/STB and viscosity of 82 cp at 87 degree reservoir temperature. (Contamination of the samples with oil-based mud caused concern about the reliability of the sample estimates and properties.) Schrader Bluff OA sand core data indicated 25 percent to 38 percent porosity and up to 1,000 millidarcies permeability in the sandstone intervals.

KMG Oliktok Point I-1 KMG Oliktok Point I-2

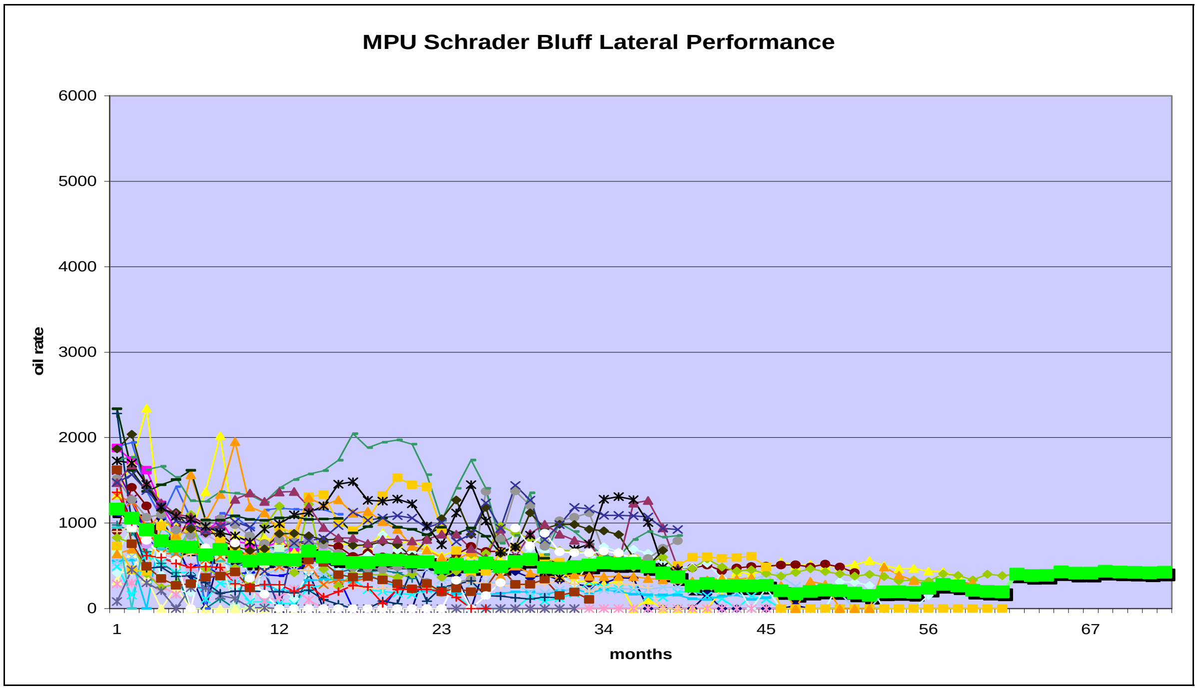
These two wells were drilled by KMG during the 2006/2007 drilling season as pre-development wells to further test and delineate the Schrader Bluff reservoir. These wells have been suspended. Results from these wells are currently held confidential under AS 38.05.035(a)(9).

5. Analog Schrader Bluff Formation Performance

Milne Point Unit (MPU) Schrader Bluff Pool (Figure 1), Kuparuk River Unit (KRU) West Sak Pool (Figure 2) and Prudhoe Bay Unit (PBU) Polaris and Orion pools – Figure 3, represent analog Schrader Bluff Formation horizontal well performance. Each of the pools was developed initially with vertical or slanted completions. More recently a number of horizontal lateral and multi-lateral wells have been completed in each of these pools. MPU and KRU Schrader Bluff wells show a distinct, lower rate performance than the newer developed Polaris and Orion Pool wells. A significant portion of the performance difference is likely due to differences in fluid quality. Within the Schrader Bluff Formation / West Sak, developments oil gravities can vary between 15-24 degrees API and viscosity can vary between 5-130 centipoise. To date, development has been limited to those areas with higher API Gravity and lower viscosity. Later Schrader Bluff Formation developments are building on earlier techniques by going from vertical to horizontal and multilaterals wells. The horizontal and multilaterals should consistently outperform the older wells because more formation is exposed and the completions are more efficient.

The wells in each Schrader Bluff Formation pool exhibit early flush production for six to 12 months. The PBU Schrader Bluff completions show slightly higher initial rate profiles followed by relatively steep decline. The average MPU Schrader Bluff completion (heavy bright green points and line) declined from 1200 bopd to 500 bopd at 12 to 40 months. KRU West Sak lateral completions have performed similar to MPU Schrader Bluff.

Figure 1. MPU Schrader Bluff Formation lateral performance and average performance (heavy green).



6. Reservoir delineation determination.

ENI has adequately delineated the OA sand of the Schrader Bluff Formation in the Nikaitchuq area. Their drilling, testing, and evaluation programs appear to have highlighted the obvious risks inherent to developing viscous oil and identified the possible upside potential available through use of extended reach drilling and advanced completion technologies.

Figure 2. KRU West Sak sands lateral performance and average performance (heavy orange).

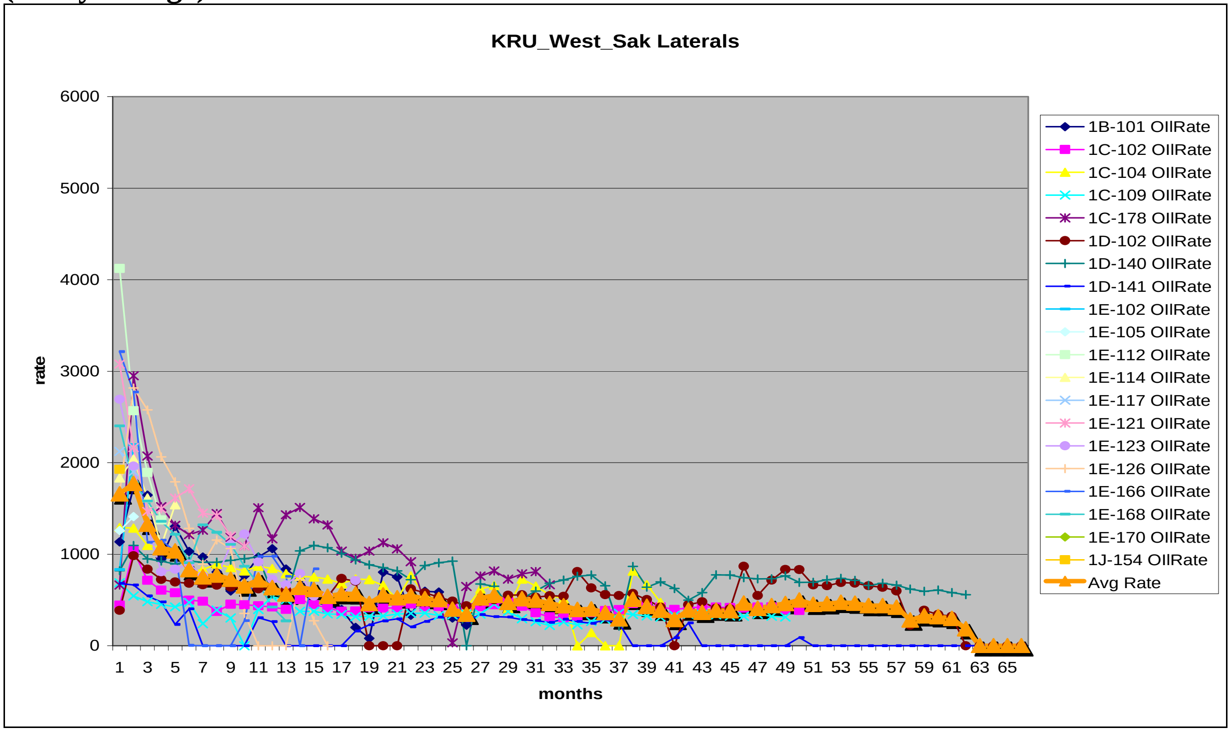
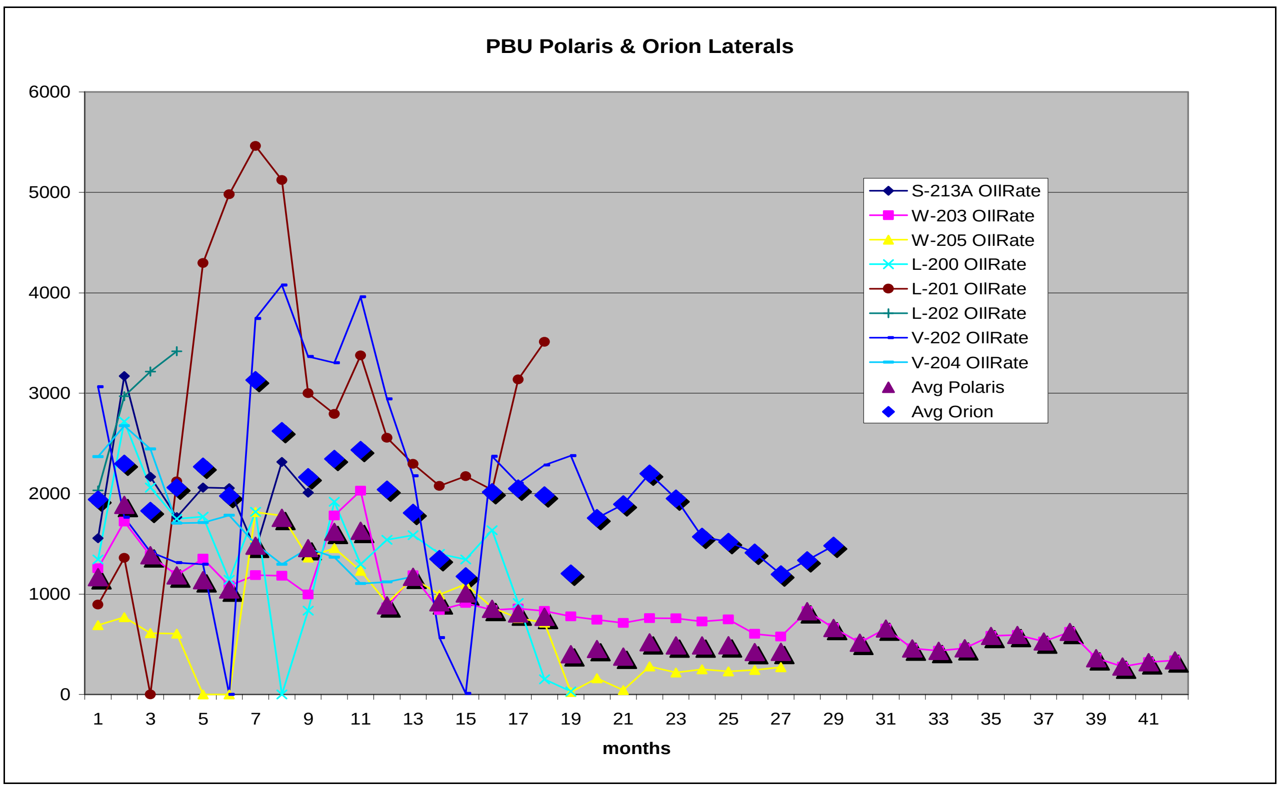


Figure 3. PBU Polaris and Orion Schrader Bluff Formation initial performance.



ENI stated that their plan is to develop Nikaitchuq Schrader Bluff Formation with horizontal wells. Their prognosis of performance can be compared to the analogs by evaluating average Schrader Bluff well performance from initial completion to date. There are up to seven years of production history for the various Schrader Bluff Formation horizontal and lateral wells. Orion appears to be more productive so far but the long term performance has yet to be defined. ENI appears to estimate their development will improve on the previous KRU and MPU Schrader Bluff completions by using the latest technology, namely very long horizontal and or multi-lateral completions. ENI's cases align reasonably with the MPU Schrader Bluff and KRU West Sak and PBU Polaris average performance. PBU Orion performance is notably better than ENI's high case average rates. Analyses of oil samples taken within the OA sand in the Nikaitchuq area demonstrate measured oil viscosities of 95–188 centipoise. This is heavier than the average viscosity of production from existing KRU, MPU and PBU Schrader Bluff developments. In addition, the Nikaitchuq development will include construction of a new standalone facility. The KRU, MPU, and PBU Schrader Bluff pools had existing infrastructure and production from other formations to support the additional development. Both of these factors increase the risk and make this project more economically challenged compared to existing heavy oil developments.

C. No Previous Sale of Produced Oil or Gas

The pools underlying the leases have not previously produced oil or gas for sale.

D. Economic Analysis

ADNR used its own in-house probabilistic economic model (ADNR Model) for the Nikaitchuq development to independently assess the financial performance and ultimate economic effects of a royalty modification for both Eni and for the State of Alaska. Eni shared with the state portions of its proprietary economic model, but the state chose to use its own model that incorporated many input assumptions provided by Eni.[4]

ADNR closely examined the assumptions and methods currently in use by the U.S. Minerals Management Service (MMS) for the Deep Water Royalty Relief Program. The MMS has developed an in-house proprietary probabilistic economic model for Royalty Suspension Viability Program. ADNR adopted an approach similar to that of the MMS by applying the quantitative results from the ADNR model to a prudent-investor decision framework. The ADNR decision framework is confidential. It is designed to replicate the kind of analytical framework used by industry for making prudent oil and gas investment decisions under uncertain conditions involving significant capital outlays and lengthy project life cycles.

[4] Eni has submitted financial and technical data and analyses and requested that they be held confidential in accordance with AS 38.05.035(a)(9). Thus this section does not discuss any confidential information concerning Eni's geologic, engineering and cost data. These documents are included and discussed in detail in the confidential *Economic Analysis and Internal Decision Process*, (Attachment 6).

The prudent investor standard is maintained throughout the project evaluation process. Under this standard, ADNR incorporates a collection of project performance benchmarks that are consistent with industry norms.

To obtain royalty relief the applicant must show by clear and convincing evidence that without royalty modification the project is not economically feasible. Nikaitchuq is an offshore, heavy oil prospect with relatively high expected exploration and development costs and low expected production possibilities. The final analysis of Nikaitchuq project development conducted by ADNR pursuant to the Eni royalty modification application suggests that, under reasonable assumptions about future oil prices and without some form of royalty relief, this project would not be sanctioned for funding and development.

In its simplest form, the ADNR Model describes project cash-flows for the Nikaitchuq development over a 50-year time horizon. The ADNR Model incorporates expected investment, production, price, revenue, and cost. It incorporates fiscal system attributes, including state and federal tax, state production tax (including the recent ACES legislation)[5], and royalty obligations, as well as other important commercial relationships, such as facility sharing and pipeline transportation charges.

The ADNR in-house model is flexible enough to allow ADNR to evaluate the effects of changes to the fiscal system. The model provides a platform for systematic evaluation of the effect of a change to the royalty rate. The model calculates the changes to the various financial metrics that result from a change in the royalty rate. These metrics include annual and cumulative discounted and undiscounted cash flow, years to payout, net present value (NPV), expected monetary value (EMV), and internal rate of return (IRR) on investment, as well as state revenues. Also, ADNR used its model to carry out sensitivity analysis of key driver assumptions and to characterize certain price, production, and cost variables in terms of probability distributions to evaluate how uncertainty among these drivers affects key project metrics and state revenues.

Eni furnished ADNR with 200 realizations of project production that depict the range of values and probabilities for the many reservoir factors that that determine ultimate reservoir recovery (e.g., aerial and vertical extent, rock characteristics, fluid composition and properties). These 200 Eni realizations represent the universe of possible resource recovery outcomes for ADNR's Monte Carlo analysis that fit the well-test data. The ADNR model samples repeatedly from this universe of production realizations, as well as from volatility inherent in price formation, as characterized in the mean reversion price model (see below), to generate a distribution of net present value (NPV) outcomes for the Nikaitchuq project. The central tendency (mean and median) and dispersion (variance) of the NPV outcomes depict project performance uncertainty and speak to the dimensions of ADNR's prudent-investor decision framework mentioned above.

ADNR incorporated the applicant's input data into its model along with its own assumptions about the path of uncertain future prices to derive independent results for the

[5] See HB2001 (11/15/2007).

economic feasibility of the Nikaitchuq project. The ADNR Model examines a range of possible inputs to derive a P50, or median, outcome from a Monte Carlo simulation. The P50 result is the value where 50 percent of the outcomes lay below this point and 50 percent of the outcomes lay above the P50 outcome. The ADNR Model uses Palisades Software's "@Risk" Monte Carlo software application to run the simulations and determine risk-weighted outcomes reported in the confidential supplement to this *Final Findings and Determination* (Attachment 7).

Calculating risk weighted outcomes is critical to a full analysis of a project. The probabilistic rate profile, determined based on the applicant's reservoir simulation results, is combined with pricing to determine the project revenue stream. Annual Alaska North Slope West Coast (ANSWC) crude oil prices were generated from an Ornstein-Uhlenbech type Mean-Reversion price model[6] with parameters estimated as described by Schwartz, (1997)[7] using annual price data for ANSWC crude as reported by Platt's. The starting ANSWC delivered price used in the model is $67 per barrel, the average price for 2007. The risk weighted cost profiles are then matched to the revenue stream generated by the probabilistic price and production models. This yields an NPV distribution. The mean of the NPV distribution is the EMV for the entire project that incorporates uncertainty and can be compared "apples-to-apples" with other versions of the project.

ADNR analyzed various senarios to explore Nikaitchuq project performance with and without royalty modification. DNR approves royalty modification only when it believes a project will not go forward without it. This means that the impact to royalty revenues to the state is the difference between the royalty revenues with royalty modification as was prescribed in the DNR decision and zero. Even under low price scenarios, ADNR determined that the state can expect to receive an additional $100 million over the life of the project.

If it is assumed that the project could have gone forward without royalty modification (again, not what ADNR assumes) the impact would be as indicated in Table 1. This table presents several possible price scenarios and the indicated change to the state royalty cash flow stream.

In Table 1 the scenarios labeled "$43 and Above (Sustained)" and "$40 Sustained" simply use a flat price deck for "Alaska North Slope West Coast" (ANSWC) crude oil (before inflation) for the life of the project, the price does not vary from year-to-year. An oil price of $40 is always just below the $42.64 royalty modification threshold and thus results in 5 percent royalty rates for every barrel of oil produced from the reservoir for the life of the project and the greatest negative impact to overall state royalty revenues.

[6] Dixit & Pindyck, 1994, http://www.puc-rio.br/marco.ind/sim_stoc_proc.html#mc-mrd.

[7] The Stochastic Behavior of Commodity Prices: Implications for Valuation and Hedging", Schwartz, E., Journal of Finance, 1997, Volume 52, issue 3, 923-973

Table 1. Change in Alaska royalty revenues if royalty modification were not necessary and project produced oil without royalty modification.

Price Scenario	Impact on State of Alaska Royalty Revenue ("With Royalty Modification Per Decision" Minus "Without Royalty Modification", 5% discount rate)
$43 and Above (Sustained)	$0 million
DNR Price Model	($39 million)
$40 Sustained	($160 million)

The "DNR Price Model" scenario does not use a constant or "sustained" price for the life of the project (i.e. flat price deck) as is the case with the other two scenarios in Table 1. We use a forward-looking, Monte Carlo-based "mean-reversion" model, as discussed above. This price model creates a price forecast where oil price fluctuates over time, simulating real-life price variability similar to what history has shown. The price for 2007, $67 per barrel ANSWC, was taken from U.S. Energy Information Agency's most recent price projection for West Texas Intermediate (WTI) crude, and adjusted for ANS-WTI basis by taking the previous 12-month average difference between these two prices. The model reverts to DNR's expected mean value of $53 per barrel, over time.

The ADNR has determined that under ADNR's price and discounting assumptions, the project attributes furnished by Eni, and the existing lease royalty rates in effect prior to this *Final Finding and Determination* (16.6667 percent fixed royalty rate and the 12.5 percent fixed royalty with 30 percent NPS for ADL 391283), the Nikaitchuq project does not meet prudent-investor standards for economic feasibility. ADNR concludes further that the royalty modification terms and conditions stipulated in Section IV.B would improve project economics. Eni represents that royalty modification would make project sanction more likely.

V. PUBLIC COMMENTS

On November 30, 2007, ADNR issued a Preliminary Findings and Determination to respond to Eni's royalty modification application. The public was invited to comment on the preliminary decision for thirty days, ending January 7, 2008 (Attachments 3 and 4).

No comments were received from the public.

VI. STATE'S PROPOSED ROYALTY MODIFICATION

A. Royalty Modification Requirements for the Nikaitchuq Project

1. Eni's application for royalty modification on ADLs 388571, 388572, 388574, 388575, 388577, 388580, 388581, 388582, 388583, 390615, and 390616, and ADL 391283 meets the requirements for consideration under AS 38.05.180(j)(1). Eni has paid the filing fee and submitted a complete application for the royalty modification including financial and technical data that meet the requirements of 11 AAC 88.105, 11 AAC 83.185, 11 AAC 05.010(a)(10)(H), and AS 38.05.180(j)(6).

2. The Schrader Bluff pool has been sufficiently delineated to the satisfaction of the commissioner for the purpose of considering royalty modification; this pool has not previously produced oil or gas for sale.

3. Eni has shown that oil or gas production from the Schrader Bluff pool would not otherwise be economically feasible.

4. Eni has made a clear and convincing showing that a modification of royalty meets the requirements of 38.05.180(j)(1)(A), and is in the best interests of the state.

B. Royalty Modification Terms for the Nikaitchuq Project

1. Royalty modification pursuant to the terms herein is granted to Eni US Operating Co. Inc. (Eni), as operator and 100 percent working interest owner of the Nikaitchuq project (Project), on ADLs 388571, 388572, 388575, 388574, 388577, 388581, 388582, 388583, 390615, 390616, and 391283. Royalty modification is denied for ADL 388580 because there was no apparent resource allocated to this lease.

2. Only production from Nikaitchuq Unit's Schrader Bluff OA reservoir, as delineated under this Findings and Determination, shall be eligible for royalty modification. To receive royalty modification on production, the lease must be committed to an approved participating area within six years of the date of Project sanction. After six years, any subject lease or portion of a subject lease not committed to an approved participating area for the Nikaitchuq Schrader Bluff OA reservoir shall revert to the respective individual lease royalty rates that were in effect immediately prior to this Findings and Determination.

3. If the Project, not materially changed from that set out in the October 16, 2007, royalty modification application, is not sanctioned by all working interest owners by February 28, 2008, this royalty modification decision is rescinded.

4. Within 30 days following the date of Project sanction, the working interest owners shall provide ADNR with the Project sanction documents, approvals for expenditure, and other documents supporting the technical and financial data submitted with Project sanction documents excluding any proprietary data. ADNR agrees to keep all such data confidential.

5. If six years following the date of Project sanction total actual Project spending starting December 1, 2007, does not meet $822 million in nominal dollars, then this royalty modification is rescinded. If 11 years following the date of Project sanction total actual Project spending does not meet $1.398 billion in nominal dollars, then this royalty modification is rescinded. The ADNR may audit the working interest owners' spending on this Project to determine compliance any time between the sixth and the 13^{th} year following Project sanction. If at either cost threshold juncture this royalty modification is rescinded, then Eni will refund to the State of Alaska the difference between the royalty which would have been due at the royalty rates that were in effect immediately prior to the effective date of this Findings and Determination and the royalty due at the modified royalty rate, with interest as set forth in AS 38.05.135(d).

6. The NPS lease regulations set out in 11 AAC 83.201 – 11 AAC 83.295 remain in full force and effect for ADL 391283, except that the cost to the applicant for the application for royalty modification will not be included in any NPS lease Development Account balance.

7. (a) Nikaitchuq royalty modification mechanism implemented as follows:

i. Original lease rates are 12.5 percent for ADL 391283 and 16.67 percent for ADLs 388571, 388572, 388575, 388574, 388577, 388581, 388582, 388583, 390615, and 390616.

ii. For the first 25 years following the date of first sustained production, when Alaska North Slope West Coast ("ANS WC") delivered crude prices are below the threshold price per barrel as adjusted by inflation, then production from the Nikaitchuq Schrader Bluff OA reservoir on the subject lease will pay a 5 percent royalty. The ANS WC crude price for the month of production is the average assessment by Platt's Oilgram Price Report and Reuters online data providing service, of the spot price for ANS delivered on the West Coast. The average assessment of the spot price for ANS by each reporting service is the average of the midpoints of the high and low closing assessments for the spot price for ANS for all days during the month of production for which closing assessments are reported. The threshold price shall start at $42.64 per barrel. This threshold price will be adjusted annually for inflation starting on May 1, 2008, and shall be adjusted on each May 1 thereafter. The inflation adjustment shall be (1 + inflation rate) multiplied by the previous year's inflation-adjusted threshold price. The inflation rate shall be determined by taking the previous year's annual implicit price deflator for GDP (initially, for the year 2007) as reported by the end of April of each year, dividing that deflator by the two-years-previous annual implicit price deflator (initially, for the year 2006), and then subtracting 1. The source of the inflation data shall be the Department of Commerce Bureau of Analysis (BEA) U.S. Economic Accounts-GDP. National Income and Productions Account (NIPA) Table 1.1.9. When the monthly ANS WC oil price is above the threshold, royalty rates for production attributable to such month(s) shall return to the original lease royalty rates.

iii. This royalty modification shall be terminated 25 years following the date of first sustained production and at that time royalty rates shall revert to the respective individual lease royalty rates that were in effect immediately prior to this Findings and Determination.

(b) For the 18th through the 120th months after first commercial production from the Nikaitchuq Schrader Bluff OA reservoir, if production from all of the subject leases averages below 4,000 barrels of oil per day for any previous twelve month period, full royalty modification rates of 5 percent shall be in effect for all production from the Nikaitchuq Schrader Bluff OA reservoir, regardless of oil price. Provided, however, nothing in this provision shall prevent Eni from applying for royalty modification under AS 38.05.180 (j)(1)(B)or (C).

8. In the determination of royalty value of oil or gas from any of its properties, Eni shall waive any rights to a transportation deduction for the pipeline constructed pursuant to the Easement granted on ADL 417493. This waiver shall remain in effect even if such pipeline is converted to a common carrier.

9. If any working interest owner should contract to use any processing facilities at any time for production from the reservoirs delineated and leases covered in this Findings and Determination, that working interest owner shall furnish ADNR the facilities contract, including information regarding the fee structure and volumes processed unless such contract prevents disclosure of such information. This information will be kept confidential by ADNR. The working interest owner shall also furnish produced oil, water, and gas volumes on a monthly basis broken down by individual working interest owner.

10. Should any third party petition the Nikaitchuq Unit facility owners to contract for use of any unit facilities, the cost of use shall be based on market rates. Any resulting contract covering facilities access or use shall be shared with the ADNR. ADNR agrees to keep all such information confidential.

11. This royalty modification is not assignable without prior written approval of the ADNR commissioner, which shall not be unreasonably withheld. The assignee must be fit, willing, and able to satisfy all of the duties and obligations attached to this royalty modification and all other lease terms.

12. If at any time royalty modification is rescinded, the terms and conditions of this Findings and Determination shall terminate, with two exceptions. First, the provisions of Term 8 shall survive the termination of royalty modification. Second, all obligations to keep information confidential that was submitted pursuant to this Findings and Determination shall survive the termination of royalty modification.

VI. PROPOSED FINDINGS AND DETERMINATION

After detailed consideration where all the materials presented by the applicant were reviewed and incorporated into our analysis, the ADNR has determined that Eni meets the necessary requirements and that royalty modification for the Nikaitchuq development project is warranted under the terms established in Section IV of this finding and determination.

1/11/08

Thomas E. Irwin
Commissioner

Date

cc: Kevin Banks, Director, Division of Oil and Gas
Antony Scott, Senior Commercial Analyst, Division of Oil and Gas
Jeff Landry, Department of Law