Preliminary Findings and Determination
Regarding
The Nicolai Creek Unit
Royalty Modification Application

Commissioner
of the Department of Natural Resources

Approval of Modification of Royalty
for Leases:
ADLs 17585, 17598, 63279, 391471, and 391472

August 5, 2025

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Executive Summary

On September 3, 2024, Amaroq Resources, LLC (Amaroq), as operator of the Nicolai Creek Unit (NCU) and working interest owner in the leases corresponding to the NCU, submitted an application (Application) to the Commissioner of the State of Alaska Department of Natural Resources (DNR) for modification of royalty under AS 38.05.180(j)(1)(B) and (C). This Preliminary Findings and Determination Regarding the NCU Royalty Modification Application (Preliminary Decision) constitutes DNR's analysis and decision on Amaroq's Application.

Royalty modification is sought for all five leases in the NCU. Amaroq asserted, under AS 38.05.180(j)(1)(B), that royalty modification is warranted to prolong the economic life of the NCU due to per-barrel operating costs being projected to increase due to declining production making future production no longer economically feasible. Royalty modification was also sought under AS 38.05.180(j)(1)(C), that royalty modification is warranted to reestablish production from two previously prolific wells. Amaroq proposed a royalty reduction to the statutory minimum of 3% until the unit shows an annual positive cashflow and profitability. The royalty modification would be applied as soon as practical and would extend the life of the NCU.

Amaroq provided sufficient technical and financial information to substantiate its Application as required under 11 AAC 88.105, 11 AAC 83.185, 11 AAC 05.110(d)(3)(I), and AS 38.05.180(j)(6). In accordance with AS 38.05.180(j)(2), the applicant clearly showed that the per-barrel operating cost increase was sufficient to make future production no longer economically feasible without royalty modification. According to AS 38.05.180(j)(1)(B), the applicant clearly showed that the modification of royalty would prolong the economic life of the NCU. The Application also showed that, with a royalty modification, Amaroq could economically restart production in two oil zones that had been previously targeted but are not currently producing under AS 38.05.180(j)(1)(C).

DNR finds that granting royalty modification for the NCU leases is in the best interest of the State. DNR authorizes a modification mechanism of three percent (3%) state royalty until the NCU's cumulative gross revenues, beginning September 1, 2024, total $25.3 million (MM), with royalty rates subsequently returning to original values. DNR analyses show that the modification of royalty would extend the life of the field for one year. This extension of operating life adds 80.0 million standard cubic feet (MMscf) of additional gas but reduces total revenues by $154,000.

The extension field life provides Amaroq with a crucial window to secure the necessary financing for drilling two new wells. These wells are set to re-establish production that has been offline since 2017 and 2019. This development is not only expected to contribute an additional four years of production to the NCU but also an extra 1.9 billion cubic feet (Bcf) of natural gas. Over this four-year timeframe, the state anticipates an increase of $523,000 in direct royalty revenues, contributing to a total of $890,000 in additional state revenues.

In addition to potential revenue gains, DNR also finds that there would be indirect benefits to the State from extending the operating life of the NCU. Specifically, DNR evaluated the indirect benefit of continuing Cook Inlet gas production for Southcentral Alaska utilities and their customers. DNR believes that ensuring additional gas from the Cook Inlet Basin is paramount. When considering this, in addition to the potential financial benefit to the State, Amaroq provides a compelling, clear and convincing case for granting royalty modification to the Nicolai Creek Unit.

I. Background

On September 3, 2024, Amaroq, as operator of the NCU and working interest owner in the NCU leases, submitted the Application to the Commissioner of the DNR for modification of royalty under Alaska Statute AS 38.05.180(j)(1)(B) and (C).

Prior to receiving an official application, Amaroq had begun engaging with DNR on the royalty modification process as early as October 2022 to learn the requirements of an application and expectations from DNR. In June 2024, Amaroq reengaged with DNR on the royalty modification process and followed with a draft application in July 2024. Based on DNR's feedback, Amaroq submitted the Application on September 3, 2024.

Amaroq, an Alaskan-registered company, is owned by Aurora Power Resources, Inc. (Aurora), which holds a 33.34% interest, and Trading Bay Oil & Gas, LLC (Trading Bay), which holds a 66.66% interest. Both Aurora and Trading Bay are also registered in Alaska, and all three companies, Amaroq, Aurora, and Trading Bay are currently in good standing within the state.

This Preliminary Decision responds to the Application as required under AS 38.05.180(j)(8).

A. NCU Development History

The NCU consists of 471 unitized acres and is located on the western shore of the Cook Inlet, approximately 60 miles west southwest of Anchorage, and 10 miles south of Tyonek. The NCU was originally formed by Texaco Inc. (Texaco) in 1968. Texaco operated the NCU until 1977 when production was shut in. Union Oil Company of California and Marathon Oil Company acquired the unit in 1988 but was unable to reestablish production. Aurora Gas, LLC (Aurora Gas) took over the leases in 2000 and restored production in 2001. Aurora Gas produced gas from the NCU until its bankruptcy in 2018. Amaroq acquired the NCU in 2018 and is the current operator of the NCU.

The NCU produces natural gas, which is used for providing energy and power in Southcentral Alaska. Current sustained production began in 2001. NCU production peaked in 2012 with an annual production of 1.2 Bcf. Average annual production, 2001 to 2024 has been only 0.4 Bcf. The NCU currently has three onshore pads with six active wells, one of which is a disposal injection well. Of the five production wells, only three are currently producing 380 thousand cubic feet per day (Mcf/d) (as of May 2025) for annual production of 0.1 Bcf.

B. Three Royalty Modification Scenarios Under Statute

Under Alaska statutes, royalty modification is allowed under three potential scenarios:

1. New production- AS 38.05.180(j)(1)(A) provides for modification of royalty, "to allow for production from an oil or gas field or pool…" that "… has not previously produced oil or gas for sale."
2. Existing production nearing the end of field life- AS 38.05.180(j)(1)(B) provides for modification of royalty, "to prolong the economic life of an oil or gas field or pool as per barrel or barrel equivalent costs increase or as the price of oil or gas decreases, and the

increase or decrease is sufficient to make future production no longer economically feasible."

3. Shut-in production- AS 38.05.180(j)(1)(C) provides for modification of royalty, "to reestablish production of shut-in oil or gas that would not otherwise be economically feasible."

Amaroq is seeking modification of royalty under AS 38.05.180(j)(1)(B), since the NCU is nearing the end of field life and AS 38.05.180(j)(1)(C) to reestablish production from the zones previously produced by now non-producing wells.

C. Procedure

The Commissioner will publish this Preliminary Decision and give public notice of a 30-day comment period per AS 38.05.180(j)(8), as well as appearing before the Legislative Budget and Audit Committee, if requested, to provide a review of the Preliminary Decision and administrative process per AS 38.05.180(j)(9). The Commissioner will keep the submitted data confidential under AS 38.05.035(a)(8) at the request of the lessee applying for the royalty reduction. Within 30 days of the close of the public comment period the Commissioner will prepare a summary of the public comments, make a Final Findings and Determination, and with the applicant's consent, amend the applicant's leases or unitization agreement consistent with the Final Findings and Determination per AS 38.05.180(j)(11). The Commissioner's Final Findings and Determination regarding a royalty reduction is final and not appealable to the court pursuant to AS 38.05.180(j)(11)(B).

II. Summary of Amaroq's Application for Royalty Modification

Amaroq applied for royalty modification of all five leases in the NCU. The State of Alaska royalty rate is 12.5 percent for each of these leases, and there are overriding royalty interests (ORRIs) between 1.5% and 6.5%. The average total burden for the NCU is 17.28% for these five leases[1].

The applicant asserted, under AS 38.05.180(j)(1)(B), that royalty modification was warranted to prolong the economic life of a gas field or pool due to the high operating cost of operating on the west side of the Cook Inlet and decreased production due to the unit's age. This has made future production no longer economically feasible. In fact, since purchasing the NCU in 2018, Amaroq has been operating the NCU each year at a negative cash flow as attempts to revitalize the field have not been successful. Per its Application, Amaroq contended that, given the expected production profile, cost structure, and with an updated contract gas price of $10 per Mcf, the field would continue to generate negative cash flows.

The applicant also asserted, under AS 38.05.180(j)(1)(C), that royalty modification was warranted to reestablish production from two currently shut in wells NCU 3 & 10. Without royalty modification, development of these wells would not be economically feasible. NCU 3 is an onshore well originally drilled in 1967, which ceased production in 1977. Aurora Gas was able to restart NCU 3 in 2001. NCU 3 produced consistently from 2001 to 2004, and intermittently at very low rates until 2014. NCU 10 was originally drilled in 2011 by Aurora Gas NCU 10 produced

[1] See Section II.C. for more details on the history of the ORRIs.

consistently until 2017 followed by a sharp decline and ending production in 2019. Since Amaroq took over the NCU in 2018 they have attempted to restart production from NCU 10 numerous times. Amaroq's application states that royalty modification would make future development opportunities to redrill these wells more economic and unlock currently identified proven reserves.

Amaroq requested an immediate royalty reduction to three (3%) percent until the NCU shows an annual positive cash flow and profitability.

A. Lease Summary

The following is a summary of all the NCU leases (Figure 1). The Division of Oil and Gas issued:

ADL 17585 effective February 1, 1962, on lease form DL-1 (Revised April 1961), with a primary term of five years. This lease has 5 segments based on area and depth and 4,264 total acres. A small portion, 37.58 acres of segment 3 is committed to the NCU. The remaining acreage is offshore.

ADL 17598 effective February 1, 1962, on lease form DL-1 (revised April 1961), with a primary term of five years. This lease has 2 segments based on area and depth and 3,241 total acres. A small portion, 43.8 acres of the combined segments are committed to the NCU. The remaining acreage is offshore.

ADL 63279 effective October 1, 1958, on BLM Form No. 4-1158 Fifth Edition (Sept. 1954), with a primary term of five years. This lease was granted by the BLM but later transferred to the State. This lease has 2 segments based on area and depth and 522 total acres. 320 acres of the combined segments are committed to the NCU.

ADL 391471 effective October 1, 1958, on BLM Form No. 4-1158 Fifth Edition (Sept. 1954), with a primary term of five years. This lease was granted by the BLM but later transferred to the State. This lease has 2 segments based on area and depth and 45.3 total acres. 44.51 acres of the combined segments are committed to the NCU.

ADL 391472 effective October 1, 1958, on BLM Form No. 4-1158 Fifth Edition (Sept. 1954), with a primary term of five years. This lease was granted by the BLM but later transferred to the State. This lease has 2 segments based on area and depth and 1,623 total acres. A small portion, 24.1 acres of the combined segments are committed to the NCU.

The total acreage of the NCU leases is 9,695, with 470 being unitized and the remaining acreage being held by production from the NCU. All leases have a fixed 12.5% royalty rate. These five leases were committed to the NCU effective December 15, 1967, extending the primary term in accordance with lease provisions so long as they remain committed to the unit agreement. Amaroq is the 100% Working Interest Owner and Operator of the NCU.

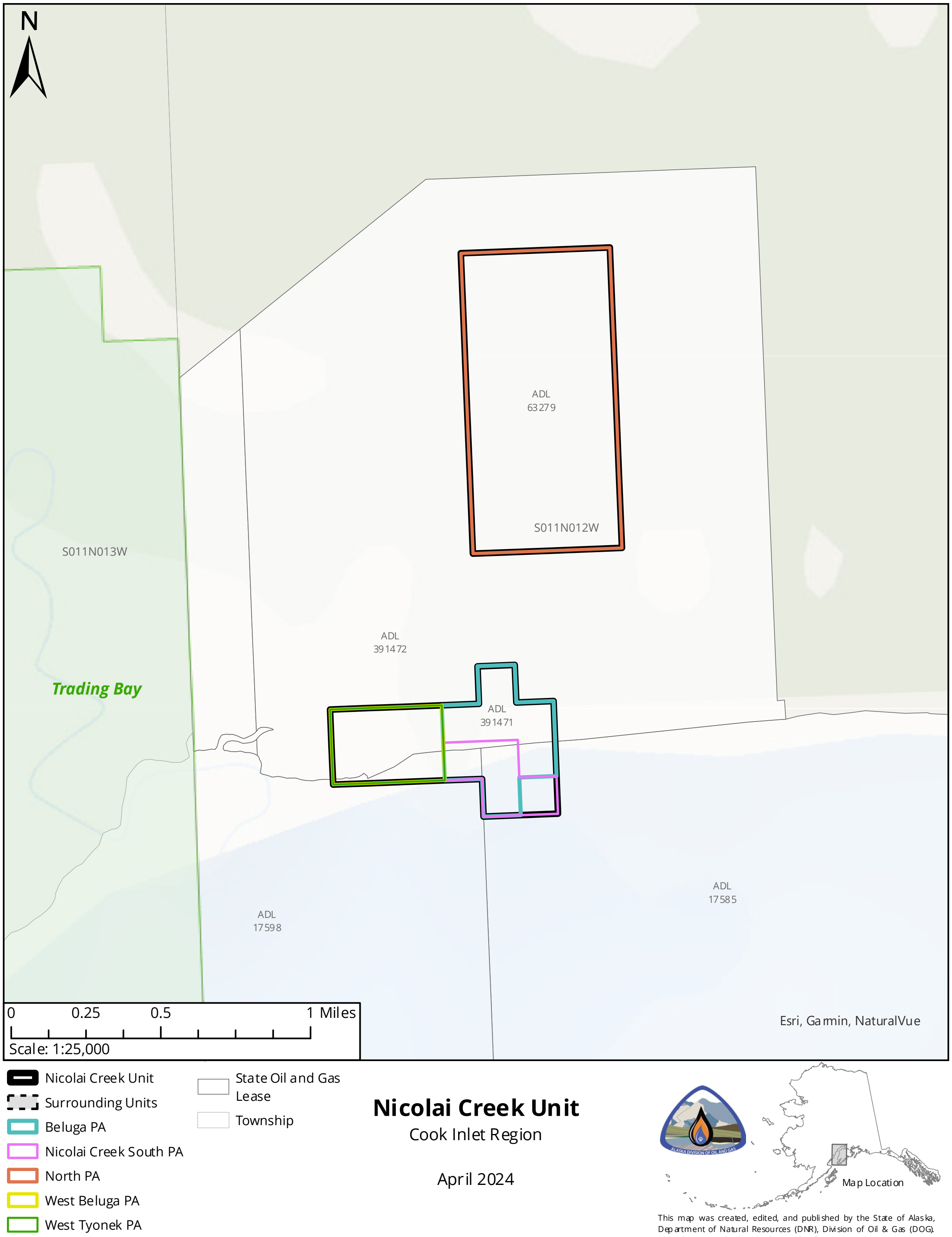

Figure 1: NCU Boundary with Tract Designations, Leases, and PA Boundaries[2]

[2] Source: DNR – Division of Oil and Gas https://dog.dnr.alaska.gov/Information/MapsAndGis

B. Production History

The NCU encompasses 470 acres. Production at NCU averaged 275 Mcf/d in 2024 and comes from two Participating Areas (PAs) (Figure 1), the Beluga PA and the West Tyonek PA. There are currently two wells in the NCU that penetrate the West Tyonek and Beluga pools (Figure 2):

- NCU 09 (producing from the Beluga Pool)
- NCU 11 (producing from Beluga and West Tyonek Pool)

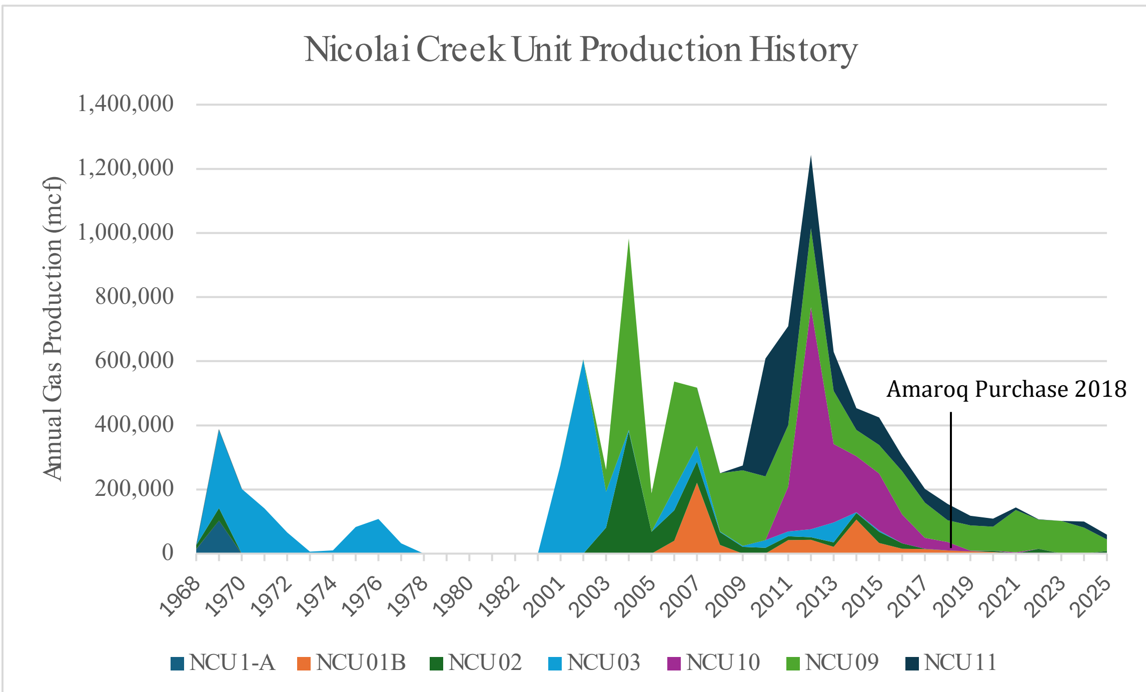

Figure 2: NCU Lifetime Well Production History through May 2025

C. Overriding Royalty Interests at the NCU

An Overriding Royalty Interest (ORRI) is an interest in oil and gas produced at the surface, free of the expense of production. This interest is nonpossessory. An ORRI is carved from the lessee's interest. The ORRIs at NCU are between 1.5 and 6.8 percent based on the individual lease and segmented depth. The State's royalty is from its interest as lessor. The State's royalty interest is 12.5 percent for all leases.

Most of the NCU ORRIs were established or reserved by various working interest owners prior to Amaroq's acquisition of the NCU leases.

Historically, a group of lease investors received ORRIs when Texaco operated the Unit. Aurora Gas honored these overrides upon acquiring the Unit. During Aurora Gas's operations, a 1% ORRI was assigned to David Boelens in exchange for his investment. Additionally, Cook Inlet Region Incorporated and the Mental Health Trust Land Office were assigned ORRIs by Aurora Gas in exchange for specific concessions.

In 2018, Amaroq acquired all rights, title, and interest in Aurora Gas. Before that acquisition, Aurora Gas had retained an override on certain deep rights conveyed to Apache in 2012. This 1.5% ORRI was transferred to Amaroq with this acquisition. Subsequently, in 2022, Amaroq acquired these deeper segments from Apache Alaska Corporation (Apache), Apache, in turn, retained its own 1% override.

DNR only reviews the initial creation of an ORRI and does not take action to approve or post records of any subsequent assignments of ORRIs.[3] DNR may have information on such transfers of interest in its records, but there is no obligation for DNR to track or approve subsequent transfers. A full list of the ORRIs and to whom they were granted or reserved is listed in Exhibit B.

III. Summary of Royalty Modification Authorities AS 38.05.180(J)

A. Authority on Royalty Modification Criteria

AS 38.05.180(j)(1)(B) provides the DNR Commissioner the authority to grant modification of royalty to unitized or individual leases for existing production to extend the life of the field as mentioned in Section (1)(B). AS 38.05.180(j)(2) provides that the Commissioner may not grant a royalty modification unless the lessee or lessees requesting the royalty modification make a clear and convincing showing that:

1. Royalty modification is necessary to prolong the economic life of an oil or gas field or pool as per barrel or barrel equivalent costs increase or as the price of oil or gas decreases, and the increase or decrease is sufficient to make future production no longer economically feasible; or

2. AS 38.05.180(j)(1)(C) provides the DNR Commissioner the authority to grant modification of royalty to unitized or individual leases to reestablish production of shut-in oil or gas that would not otherwise be economically feasible; and

3. Royalty modification is in the best interests of the State. When evaluating whether royalty modification is in the best interests of the State, DNR looks to the objectives and criteria listed in statutes such as AS 38.05.180(a) and (j).

B. Additional Statutory Requirements for Royalty Modification

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)(B) a modification to royalty may not be granted for the field or pool to extend the life of the field if the royalty modification would result in a royalty rate of

[3] 11 AAC 82.605(b).

less than three 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 of the Commissioner, which may not be unreasonably withheld. The Commissioner shall, in the Preliminary and Final Findings and Determinations, set out the conditions under which the royalty reduction may be assigned.

IV. Applicant's Clear and Convincing Showing for Royalty Modification

DNR determined that Amaroq provided sufficient technical and financial information to substantiate its Application as required under AS 38.05.180(j)(6), 11 AAC 83.185, and 11 AAC 88.105.

Per AS 38.05.180(j)(2), the applicant clearly showed that the current operating costs and declining production are sufficient to make future production no longer economically feasible from the NCU without royalty modification. Operating expenditures do not significantly change with lower production volumes. Likewise, there is a minimum general and administrative costs that does not change with production. Therefore, as production decreases the impact of those fixed expenditures become more significant.

The applicant also states that royalty modification would allow them to reestablish production from two currently shut in wells NCU 3 and 10 meeting the requirements of AS 8.05.180(j)(1)(C). Amaroq had a third party independently review the potential reserves remaining under these wells. In June 2024, Petrotechnical Resources of Alaska prepared a report of the estimated proven reserves in the NCU. That report confirmed there were proven and probable reserves that could be economically recovered with more favorable economic conditions.

In accordance with, AS 38.05.180(j)(1)(B), the applicant clearly showed that the modification of royalty would prolong the economic life of the NCU. Amaroq's application stated that with royalty modification the life of the field would be extended "at least 12 months" and with additional development up to 10 additional years. Granting royalty modification would provide Amaroq the ability to sustain operations while planning additional well work to maintain and restore any production from existing wells and implement additional development of the NCU acreage.

Additionally, per AS 38.05.180(j)(2), the applicant showed that the reduction of the royalty rate is in the best interests of the State based on extension of field life and the potential indirect benefits of Amaroq's continued operation of the NCU.

The applicant proposed a royalty rate of 3% until "the NCU shows annual positive cash flow and profitability." However, this mechanism for the reduction of the royalty rate was not optimal according to DNR's analysis. In light of the statutory authority of the Department, the royalty modification approved by DNR is based on cumulative gross revenues – which are driven by the price and volume of gas sold – which are expected to occur over the extended field life period to conform to the requirements of AS 38.05.180(j)(3).

V. Summary of State's Royalty Modification Decision, Terms and Conditions

A. Royalty Modification Decision

Amaroq has paid the filing fee and submitted a complete application for royalty modification, including meeting the financial and technical data requirements of AS 38.05.180(j)(6), 11 AAC 83.185, and 11 AAC 88.105. Amaroq qualifies for royalty modification on ADLs 17585, 17598, 63279, 391471, and 391472 under AS 38.05.180(j)(1)(B) and (C) as there are reserves under the leases that can be developed to extend field life and two wells that have stopped production that can be reworked for additional production. DNR will grant royalty modification based on a sliding scale incorporating both oil price, production and conditions for the best interest of the State. DNR's granting of royalty modification is effective as of September 1, 2024, until the gross revenue target is reached, as described in Section V.B.1. below.

B. Royalty Modification Terms

1. The royalty rate will be three percent (3%) per month until the gross revenue generated from the NCU beginning from September 1, 2024, reaches a cumulative amount of $25,300,000.00 (Gross Revenue Target). After this Gross Revenue Target is reached, the royalty rate will return to 12.5 percent on all leases, and royalty modification will expire.

2. The Gross Revenue Target was generated from the total monthly cost and expense estimates, general operating expenses, and accessing the reserves under the NCU 3 and NCU 10 wells, with adjustments that DNR deemed reasonable.

3. Monthly gross revenues will be assessed against the Gross Revenue Target in determining monthly royalty rates.

4. For the month in which the Gross Revenue Target is reached, the royalty rate will be 12.5 percent for the entire month. The 3 percent royalty rate will not be prorated in that month.

5. The procedure for determining royalty modification, and the resulting calculation, are as follows:

    a) For every production month, DNR will calculate the monthly gross revenue as the product of the monthly production of natural gas[4] and the royalty value of such natural gas at the NCU.

    b) If the cumulative gross revenue from September 1, 2024, to the current production month is less than or equal to the Gross Revenue Target, then the royalty rate will be three percent for that month.

[4]Oil & Gas producers report their monthly gas production to DNR using the operator O1 report under disposition code 0008.

c) Once the monthly gross revenue has reached a cumulative amount greater than or equal to the Gross Revenue Target, then the royalty rate will be 12.5 percent for that month.

d) Royalty reduction shall not result in a royalty rate less than three percent.

e) These royalty calculations are subject to routine DNR royalty audits.

6. Royalty modification will apply to the five leases in the NCU, ADLs 17585, 17598, 63279, 391471, and 391472 all tracts and segments.

7. DNR shall have the right to obtain invoices and financial and accounting records from Amaroq annually after granting royalty modification.

8. DNR shall have the right, upon notice to Amaroq, to terminate the royalty modification in whole or in part if DNR determines that the criteria of AS 38.05.180(j)(1)(B) and (C) or AS 38.05.180(j)(2) are no longer met. Furthermore, if DNR finds the NCU operator to be in default per 11 AAC 83.374[5], and the default is not cured, then this royalty modification will terminate effective at the end of the month of when the cure period[6] ends.

9. The royalty modification shall expire once the Gross Revenue Target is reached, unless terminated previously pursuant to condition 8 above.

10. The royalty modification may only be assigned by Amaroq to another lessee, pursuant to AS 38.05.180(j)(5), upon the written approval of the Commissioner. The Commissioner will approve a transfer of the royalty modification unless the Commissioner makes a written finding that the transfer would adversely affect the best interests of the State or does not comply with applicable statutes or regulations.

11. The royalty modification shall be applied retroactively to September 1, 2024. Royalties paid at the full 12.5% rate shall be totaled and any over payment of royalties shall be prorated and credited for future production. When refiling royalty reports from September to the current period, no interest shall be paid by the state for any over payment of royalties.

[5] 11 AAC 83.374. Default. (a) Failure to comply with any of the terms of an approved unit agreement, including any plans of exploration, development, or operations which are a part of the unit agreement, is a default under the unit agreement.

[6] 11 AAC 83.374. Default. (b) The commissioner will give notice to the unit operator and defaulting party (if other than the unit operator) of the default. The notice will state the nature of the default and include a demand to cure the default by a specific date, which in the case of failure to pay rentals or royalties will be a date determined by the commissioner and in the case of any other default will be a date not less than 90 days after the date of the commissioner's notice of default.

VI. Discussion of Royalty Modification Decision

A. Leases Eligible for Consideration

Amaroq applied for royalty modification for the five leases committed to the NCU. Pursuant to AS 38.05.180(j)(1), DNR may grant royalty modification to individual leases, and leases unitized and so approves royalty modification to the five unitized NCU leases described in Section V.B.6.

B. Applicant Data Submission Review

Amaroq was required to provide detailed information allowing DNR to comprehensively evaluate the economics of operating the NCU, per AS 38.05.180(j)(6). Amaroq completed this requirement with its Application, and provided updated information as requested throughout DNR's evaluation process as additional questions arose or follow up materials were needed.

Amaroq also provided detailed information supporting the basis for its cost and production assumptions. DNR checked model inputs against cost and production assumptions reflected in these documents. DNR reviewed the formulas used to capture the costs and benefits of the project and was able to create a dynamic scenario-based cash flow model to analyze the Application.

C. DNR Financial Modeling Review

DNR carefully reviewed and modified the Amaroq model for the NCU in several important ways, after evaluating the model assumptions. These modifications made the model dynamic; extended the period under consideration; modeled possible NCU field shutdown scenarios; and created a simulation environment where price, production, and different royalty modification mechanisms could be tested. In all, 46 different scenarios (with both fixed and random stochastic assumptions) were considered before deciding upon the royalty modification mechanism proposed in this Preliminary Decision based on Amaroq's submissions.

Amaroq's application and subsequent plan of development for 2025 indicated their plans to drill up to three new wells and that royalty modification would help reduce costs and extend field life while they obtained funding for the drilling program. Initial modeling determined that royalty modification could extend the life of the NCU pursuant to AS 38.05.180(j)(1)(B). It was anticipated that field life could be extended by one year. Royalty modification would also make it more economic to reestablish production from two zones that have not successfully produced in years as considered by AS 38.05.180(j)(1)(C). The net present value for the State's royalty share and for Amaroq were better under royalty modification such that Amaroq would likely be able to meet its POD commitments.

DNR further analyzed Amaroq's economic model to better understand how far into the future the NCU field life could be extended with and without additional drilling. DNR then expanded the period under consideration and added sensitivity to price and production to get broader understanding of the NCU's expected field life. Under these assumptions, DNR modeled a royalty modification mechanism different than what Amaroq had requested that extended the life of the field by up to four and a half years while increasing State revenues more than four times compared to not granting royalty modification.

In the last stage of modeling, DNR compared the estimated direct impacts to State revenues (royalties, production tax, property tax, and corporate income tax[7]) and estimated the extensions to the life of the field from granting royalty modification as opposed to not doing so. This enabled DNR to determine a royalty modification mechanism that both brought meaningful extension to the life of the NCU while being statutorily compliant.

DNR estimated direct impacts to State revenues following guidelines given by DOR's Revenue Sources Book for Fall 2024, and references therein. Production tax and related authorities are found under AS 43.55, corporate income tax authorities are found under AS 43.20, while property tax authorities are found under AS 43.56.

D. Stochastic Modeling Approach

i. Modeling Framework

The DNR model was dynamic compared to the static model Amaroq presented. DNR designed a model that used a simulation framework where the user could specify scenarios that they would be interested in running and could compare outcomes from multiple price and production expectation scenarios by toggling between options. This framework was utilized in all stages of scenario evaluation. The modeling time horizon was between 2024 to 2036. Amaroq provided its initial forecast on an annual basis, but upon review and discussion DNR used a month-to-month basis for its final analysis and recommendations. Every stochastic scenario was simulated 5 times, with 10,000 iterations in each simulation run, using Palisade's @Risk software.

ii. Price Scenarios

The applicant provided a fixed price path based on their current short-term gas sales contract with Marathon Petroleum. Their price forecast started at $10 per Mcf and escalated $1 each subsequent year. DNR used this price path and developed a second price path based on current sales contracts and increasing with inflation rather than set amounts annually. This second price path has a more conservative view beginning in 2029.

DNR used only these two fixed price paths because gas prices in the Cook Inlet are generally consistent and are almost entirely done under contracted prices that are reviewed by the Regulatory Commission of Alaska. There is not a regular, liquid spot market for Cook Inlet gas so the Department did not evaluate scenarios where gas prices would be volatile from one month to the next.

iii. Production Scenarios

DNR initially evaluated the submitted decline profile of risking production at 50 percent and determined that it was reasonable, based on historical reservoir performance, downtime activities, and expected decline. DNR also modeled risking production at 25 percent to capture scenarios where well performance is less than expected, and 75 percent where well performance is better than expected.

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[7] DNR estimated that corporate income tax was not a consideration for the period under examination. As a limited liability company, Amaroq does not pay corporate income tax.

iv. NCU Field Shutdown Scenarios

DNR used the monthly forecast to determine when Amaroq’s cash flow would go negative and would indicate a field shutdown is likely. DNR modeled this strategic consideration with the assumption that Amaroq would shut down the once cash flows went negative and there was no prospect of annual positive cash flows in the future. This gave DNR the ability to evaluate various Amaroq shut down time horizons to see how royalty modification would help field economics and incentivize field life extension.

This evaluation further enabled a review of how the modification mechanism would interact with price and production variation, and on average, how State revenues would change accordingly.

The Preliminary Decision previously highlighted that Amaroq has consistently operated the NCU at a negative cash flow. Despite the NCU's proven reserves, Amaroq's past development efforts have not been successful, resulting in these recurring annual losses. It's important to note that when the DNR conducts end-of-field-life analyses, it does so under the assumption that all potential economic development activities have concluded. In such a scenario, the unit's production would solely rely on existing wells, declining at its natural rate as the underlying reservoirs are depleted.

v. The Royalty Modification Mechanism Considered

DNR settled on modification mechanisms that explicitly addressed the NCU monthly gross cash flows. DNR wanted to ensure that the proposed mechanism would grant royalty relief now when it is most needed for continued gas production in the Cook Inlet, and enabling a meaningful extension of field life. Moreover, the DNR modification mechanism would result in sliding scale royalty relief if revenues were to increase due to new drilling resulting in additional production or if prices significantly increase, so that the royalty rate would commensurately go back to original levels as field economics allow.

The model used the cumulative gross revenue mechanism to determine which months would be eligible for royalty relief. If a given month’s cumulative gross revenue is less than the Gross Revenue Target, then there will be a reduction of the royalty rate to three percent. The model estimated whether royalty relief was sufficient or not to delay shutdown of the field and calculated the corresponding State revenues, gas production, and Amaroq’s cash flows in all cases.

E. Results of Scenario Modeling

The results shown in the three tables below (Tables 1, 2, and 3) show a range of results for granting royalty modification for the extension of field life, and to reestablish production from previously developed zones. The scenario results assume that DNR would grant royalty modification commencing September 1, 2024.

To understand the effects of royalty modification, a baseline end of field life was established. According to Amaroq’s model without royalty modification and no development drilling, end of field life would likely occur in September 2026 when costs to continue operating the NCU become more than the revenue generated. This is because continued development of the field is uneconomic under the current royalty rate. In this baseline, Amaroq could be expected to produce about 0.2 Bcf of gas between September 1, 2024, to September 2026. The State would get approximately $0.25MM (NPV12.5) in royalties at the 12.5 percent royalty rate and a total of $0.33MM when including estimated production and property taxes.

With royalty modification, DNR expects the life of the field to be extended an additional 12 months to September 2027 based on the scenarios modeled. With this extension of field life, the amount of gas produced for the benefit of Alaskans increases to 0.30 Bcf. The State's total revenue would be reduced to $0.18MM. Based on the modeling the Gross Revenue Target would not be met before the field became uneconomic.

The effects of reestablishing production from the two zones in the NCU were also reviewed and modeled using the same dynamic model used for the end of field life analysis. Six scenarios were evaluated using a high, medium and low case for production under two different price paths. In its application Amaroq provided a forecasted price of $10.00/Mcf for 2025, escalating by $1.00 annually for the future. This scenario was modeled along with a separate price path developed by DNR with a step increase in 2026 followed by inflation related increases of 4% annually thereafter. While consideration for extending the field life is not paramount under AS 38.05.180(j)(1)(C) the impact to field life from additional gas production is shown in Tables 2 and 3.

In addition to the significant benefit of continued Cook Inlet gas production in the near term, DNR found that this development would lead to additional gas production leading to increases in direct revenues to the State in royalties, production tax, and property taxes. These expected royalty gains would not occur otherwise. Additionally, production and property taxes continue to be collected as the field continues to produce.

In terms of royalty revenue to the State, Scenarios 2 and 3 show royalty revenues of $0.36MM – $1.23MM (NPV 12.5). Production and property taxes are expected to generate $0.28MM – $0.47MM, for a total projected revenue to the State of $0.64MM – $1.70MM. Cook Inlet production would be increased by a total of 1.2 Bcf to 2.7 Bcf with the successful reestablishment of production from these zones.

Table 1: DNR Final Modeling Results

Results of Economic Modelling End of Field Life Scenario 1								
	End of Field Life	Royalty Modification Ends	Cumulative Production (MMSCF)	Royalty Income ($'000)	Production Tax ($'000)	Property Tax (50%) ($'000)	Total State Revenue ($'000)	Additional Gas (beyond Sept 2026) (MMSCF)
Scenario 1: No Royalty Modification (baseline)	Sep 2026	No RM	224.60	$257	$38	$36	$331	
Scenario 1a: Royalty Modification - no Development Drilling	Sep 2027	End of Field Life	304.32	$82	$49	$46	$177	79.7

Table 2: Results of Economic Modeling – Amaroq Price Path

Results of Economic Modelling Reestablish Production Amaroq Price Path - Scenario 2:								
	End of Field Life	Royalty Modification Ends	Cumulative Production (MMSCF)	Royalty Income ($'000)	Production Tax ($'000)	Property Tax (50%) ($'000)	Total State Revenue ($'000)	Additional Gas (beyond Sept 2026) (MMSCF)
Scenario 2a: Royalty Modification - Development Drilling (High Case)	Jul 2031	Jun 2029	2,997.65	$1,231	$362	$103	$1,696	2,773.1
Scenario 2b: Royalty Modification - Development Drilling (Medium Case)	Sep 2030	End of Field Life	2,078.59	$511	$260	$104	$875	1,854.0
Scenario 2c: Royalty Modification - Development Drilling (Expected Case)	Nov 2030	End of Field Life	2,187.47	$536	$272	$104	$912	1,962.9
Scenario 2d: Royalty Modification - Development Drilling (Low Case)	Jul 2030	End of Field Life	1,501.83	$372	$192	$87	$651	1,277.2

Table 3: Results of Economic Modeling – DNR Price Path

Results of Economic Modelling Reestablish Production DNR Utility Price Path - Scenario 3:								
	End of Field Life	Royalty Modification Ends	Cumulative Production (MMSCF)	Royalty Income ($'000)	Production Tax ($'000)	Property Tax (50%) ($'000)	Total State Revenue ($'000)	Additional Gas (beyond Sept 2026) (MMSCF)
Scenario 3a: Royalty Modification - Development Drilling (High Case)	Feb 2031	May 2029	2,888.36	$1,166	$353	$103	$1,622	2,663.8
Scenario 3b: Royalty Modification - Development Drilling (Medium Case)	Jul 2030	End of Field Life	2,037.99	$502	$256	$96	$855	1,813.4
Scenario 3c: Royalty Modification - Development Drilling (Expected Case)	Aug 2030	End of Field Life	2,126.64	$523	$267	$104	$894	1,902.0
Scenario 3d: Royalty Modification - Development Drilling (Low Case)	Apr 2030	End of Field Life	1,454.38	$361	$187	$87	$636	1,229.8

VII. Royalty Modification is in the Best Interest of the State

This Preliminary Decision concludes that granting royalty modification on the five leases described in Section V.B.6 is in the best interest of the State based on the direct benefits presented above (Tables 1-3) in terms of expected field life extension, increase in gas production, and increases in direct revenues to the State. Beyond the quantifiable advantages, two additional indirect benefits to the State, while not quantifiable, are significant. DNR is of the opinion that incorporating both these unquantified benefits and the quantifiable benefits underscores their collective potential to advance the State's best interests concerning the NCU royalty modification.

A. Quantified Total Direct Benefits to the State

In terms of direct revenue benefits to the State for the most likely scenario (Scenario 3c) over the baseline at NPV 12.5, they include 2.13 BCF of Cook Inlet gas production, $0.52MM in royalty revenues, $0.27MM in production tax revenue, and $0.10MM in property tax revenue for a grand total of $0.89MM in direct benefits to the State. This is an incremental increase in State revenue of $0.56MM. In terms of extension to the life of the field, per AS 38.05.180(j)(1)(B), the proposed royalty modification would extend field life by at least one year and make reestablishing production from the previously producing zones in the Beluga and Tyonek pools economic, resulting in an even greater extension of field life.

B. Unquantified Indirect Benefits to the State

DNR's decision to grant royalty modification is also based on two different possible sources of indirect benefits to the State.

i. Continued Local Gas Production

Cook Inlet is facing a potential natural gas shortfall to local utilities and could easily experience shortfalls. In 2022, Hilcorp Alaska, LLC, the largest producer of natural gas in the Cook Inlet, announced it would not have enough reserves to sign new gas contracts beyond its current contract commitments. These contracts have already begun to expire. Buyers of Cook Inlet gas are considering potentially costly alternatives, including LNG imports, or other sources of energy. Maintaining a stable Cook Inlet gas supply is in the State of Alaska's best interest. DNR has a mandate to assure local gas can continue to be produced. By granting royalty relief on the five leases described in Section V.B.6., it will help the NCU be more economic to maintain production, develop and increase local gas production.

Displacing local gas with imported gas has several impacts, including zero royalty income to the State on gas imports. The number of high-paying local jobs in the oil and gas industry will decline as demand for their services decreases, assuming imported gas facilities would not create an equivalent number of new jobs. The Cook Inlet region will suffer from reduced exploration activities and diminished interest as a viable energy production basin. The State and Kenai Peninsula Borough would expect fewer property taxes with declining development. Ultimately, replacing local Cook Inlet gas with another energy source will likely cost more, which will likely increase energy costs to utility rate payers as well.

ii. Environmental, Social, and Cultural Impacts

The best interests of the State also need to consider the environmental, social, and cultural impacts of Amaroq's continued operations at the NCU that this royalty modification decision would facilitate. DNR develops lease stipulations through the Areawide Lease Sales process to mitigate potential environmental, social, and cultural impacts from oil and gas activity.

In terms of environmental impacts, the leases that are included in the royalty modification contain many stipulations designed to protect the environment and address any outstanding concerns regarding impacts to the area's fish and wildlife species and to habitat and subsistence activities. They address the protection of primary waterfowl areas, site restoration, construction of pipelines, seasonal restrictions on operations, public access to, or use of the leased lands, and avoidance of seismic hazards. The granting of royalty modification will not result in additional restrictions or limitations on access to surface lands or to public and navigable waters.

The Commissioner's approval of the royalty modification is an administrative action, which by itself does not convey any authority to conduct operations on the leases, within the development area, unit or participating area. Amaroq must still obtain approval of a Unit Plan of Operations and various permits from state agencies before initiating activities. In addition, Amaroq has in place a Dismantlement Removal & Restoration Financial Assurances Agreement with DNR, as well as meeting bonding requirements with the Alaska Oil and Gas Conservation Commission for plugging and abandoning NCU wells.

In terms of social and cultural impacts, the leases comprising the NCU have provisions requiring the lessee to undertake a program to encourage the employment of Alaskans. Amaroq employs two full-time operators, one part-time administrative employee and two seasonal full-time operators. Drilling additional wells would add over 70 people for the season, including barging operators, heavy equipment operators and a drilling crew.

VIII. Proposed Findings and Determination

After detailed consideration where all the materials presented by the applicant were reviewed and incorporated into our analysis, DNR has determined that Amaroq meets the necessary requirements and that royalty modification for the five leases described in Section V.B.6 is warranted under the terms established in Section V of this Final Decision.

8.5.25

John Boyle — Date
Commissioner

cc: Derek Nottingham, Director, Division of Oil and Gas
Ryan Fitzpatrick, Commercial Section Manager, Division of Oil and Gas
Mary Gramling, Department of Law

Exhibit A – Calculation of Royalty Relief – Three Examples

	Month 12	Month 51	Month 52
Royalty Value of Gas	$10.00	$13.50	$13.50
Gross Production (Mcf)	7,500	41,200	40,200
Gross Revenue	$75,000	$556,200	$542,700
Cumulative Gross Revenue - Prior Month	**$1,825,000**	**$24,317,000**	**$24,873,200**
Cumulative Gross Revenue	**$1,900,000**	**$24,873,200**	**$25,415,900**
Cumulative Gross Revenue – Target	**$25,300,000**	**$25,300,000**	**$25,300,000**
Gross Revenue Target Met	NO	NO	YES
Royalty Rate Reduced	YES	YES	NO
Royalty Rate	3.0%	3.0%	12.5%
Royalty Revenue	$2,250	$16,686	$67,838

The table above shows how the royalty modification mechanism works given three hypothetical months. A step-by-step general description of the mechanism is provided below. This is followed by a description of three possible cases corresponding to: the case where royalty relief is applied and royalty relief is not applied.

General Description

- Royalty Value of Gas- This is the price Amaroq sells its gas per Mcf, which is used in the calculation of revenue and royalty.
- Gross Production – Gas production in Mcf for each month.
- Gross Revenue - The product of the royalty value and the gross production for each month.
- Cumulative Gross Revenue – Prior Month
- Cumulative Gross Revenue – The cumulative revenue from September 1, 2024, to the production month in question.
- Cumulative Gross Revenue Target - $25.3MM used in this Preliminary Decision.
- Gross Revenue Target Met - States whether the condition of the Gross Revenue Target has been met or not.
- Royalty Rate Reduced - States whether royalty rates will be reduced or not, based on whether the Gross Revenue Target has been reached.

- Royalty Rate - The royalty rate as a percentage for that particular month (3 percent if Gross Revenue Target has not been reached, and 12.5 percent otherwise).
- Royalty Revenue - Calculates the State's royalty amount for the corresponding month.

Three Cases Considered

Month 12: This is an example where the Cumulative Gross Revenue is less than the $25.3MM Cumulative Gross Revenue Target. Thus, there is a reduction to the royalty rate for this month to 3 percent. The State receives the statutory minimum 3 percent royalty, which is $2,250.

Month 51: This is an example final month with royalty relief. Cumulative Gross Revenue remains less than the $25.3MM Cumulative Gross Revenue Target. Thus, there is still a reduction to the royalty rate for this month to 3 percent. The State receives the statutory minimum 3 percent royalty, which is $16,686.

Month 52: This is an example of no royalty relief given in the month the Gross Revenue Target is reached. Since the Cumulative Gross Revenue surpassed the Cumulative Gross Revenue Target, royalty relief has expired. Therefore, the original royalty rate of 12.5 percent would be the final effective royalty rate for revenue calculations. Amaroq would not see any royalty relief for this, or subsequent months and State royalties would be $67,838 for that month.

End of Exhibit A

Exhibit B – NCU Leases, ORRI Owners

Lease Number	Segment	Tract #	Acreage	Depth	Depths	Alaska State Royalty	ORRI Holder	ORRI
63279	2	1	320	<5053'	Shallow	12.5%	Alice F. & J. Bailey Hinkle, et al	0.25794%
							Mitsue & Robert K. Masuda	0.28571%
							Keiso & Marcella T. Masuda	0.28571%
							Donald L. Stroble	0.25794%
							Alice Coulthard	0.25794%
							Jayne Y. & Fred S. Hokama	0.25794%
							Katie & Satashi Kaku, et al	0.25794%
							Rose & Bernard Maresh, et al	0.25794%
							Ruth S. & Mobley Pharis	0.25794%
							Patricia & Jack B Conway	0.25794%
							Laverna I. Traxinger, et al	0.25794%
							John R. Roderick	0.12500%
							David Bolens	1.00000%
							TOTAL	4.01788%

Lease Number	Segment	Tract #	Acreage	Depth	Depths	Alaska State Royalty	ORRI Holder	ORRI
391471	A	2	44.513	>4911'	Deep	12.5%	Alice F. & J. Bailey Hinkle, et al	0.25794%
							Mitsue & Robert K. Masuda	0.28571%
							Keiso & Marcella T. Masuda	0.28571%
							Donald L. Stroble	0.25794%
							Alice Coulthard	0.25794%
							Jayne Y. & Fred S. Hokama	0.25794%
							Katie & Satashi Kaku, et al	0.25794%
							Rose & Bernard Maresh, et al	0.25794%
							Ruth S. & Mobley Pharis	0.25794%
							Patricia & Jack B Conway	0.25794%
							Laverna I. Traxinger, et al	0.25794%
							John R. Roderick	0.12500%
							David Bolens	1.00000%
							Apache Alaska Corporation	1.00000%
							Amaroq Resources, LLC	1.50000%
							TOTAL	6.51788%

Lease Number	Segment	Tract #	Acreage	Depth	Depths	Alaska State Royalty	ORRI Holder	ORRI
17585	1	3	37.584	<6620'	Shallow	12.5%	David Bolens	1.00000%
							Mental Health Trust Land Office	0.50000%
							TOTAL	1.50000%
17585	A	3	37.584	>6620'	Deep	12.5%	David Bolens	1.00000%
							Mental Health Trust Land Office	0.50000%
							Amaroq Resources, LLC	1.50000%
							TOTAL	3.00000%

Lease Number	Segment	Tract #	Acreage	Depth	Depths	Alaska State Royalty	ORRI Holder	ORRI
17598	1	4	7.903	<4558'	Shallow	12.5%	David Bolens	1.00000%
							Mental Health Trust Land Office	0.50000%
							TOTAL	1.50000%
17598	A	4	7.903	>4558'	Deep	12.5%	David Bolens	1.00000%
							Mental Health Trust Land Office	0.50000%
							Amaroq Resources, LLC	1.50000%
							TOTAL	3.00000%
17598	2	6	35.9	<4558'	Shallow	12.5%	David Bolens	1.00000%
							Mental Health Trust Land Office	0.50000%
							Cook Inlet Region Incorporated	0.25000%
							TOTAL	1.75000%
17598	B	6	35.9	>4558'	Deep	12.5%	David Bolens	1.00000%
							Mental Health Trust Land Office	0.50000%
							Cook Inlet Region Incorporated	0.25000%
							Amaroq Resources, LLC	1.50000%
							TOTAL	3.25000%

Lease Number	Segment	Tract #	Acreage	Depth	Depths	Alaska State Royalty	ORRI Holder	ORRI
391472	2	5	24.1	<4911'	Shallow	12.5%	Alice F. & J. Bailey Hinkle, et al	0.25794%
							Mitsue & Robert K. Masuda	0.28571%
							Keiso & Marcella T. Masuda	0.28571%
							Donald L. Stroble	0.25794%
							Alice Coulthard	0.25794%
							Jayne Y. & Fred S. Hokama	0.25794%
							Katie & Satashi Kaku, et al	0.25794%
							Rose & Bernard Maresh, et al	0.25794%
							Ruth S. & Mobley Pharis	0.25794%
							Patricia & Jack B Conway	0.25794%
							Laverna I. Traxinger, et al	0.25794%
							John R. Roderick	0.12500%
							David Bolens	1.00000%
							Cook Inlet Region Incorporated	0.25000%
							TOTAL	4.26788%

Lease Number	Segment	Tract #	Acreage	Depth	Depths	Alaska State Royalty	ORRI Holder	ORRI
391472	B	5	24.1	>4911'	Deep	12.5%	Alice F. & J. Bailey Hinkle, et al	0.25794%
							Mitsue & Robert K. Masuda	0.28571%
							Keiso & Marcella T. Masuda	0.28571%
							Donald L. Stroble	0.25794%
							Alice Coulthard	0.25794%
							Jayne Y. & Fred S. Hokama	0.25794%
							Katie & Satashi Kaku, et al	0.25794%
							Rose & Bernard Maresh, et al	0.25794%
							Ruth S. & Mobley Pharis	0.25794%
							Patricia & Jack B Conway	0.25794%
							Laverna I. Traxinger, et al	0.25794%
							John R. Roderick	0.12500%
							David Bolens	1.00000%
							Cook Inlet Region Incorporated	0.25000%
							Apache Alaska Corporation	1.00000%
							Amaroq Resources, LLC	1.50000%
							TOTAL	6.76788%

Total Unitized Acreage **470**

End of Exhibit B