PRUDHOE BAY UNIT

APPLICATION FOR THE THIRD EXPANSION OF THE UNIT AREA AND FORMATION OF THE Pt. McINTYRE PARTICIPATING AREA

DECISION AND FINDINGS OF THE DIRECTOR OF THE DIVISION OF OIL AND GAS

AUGUST 18, 1993

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THIRD EXPANSION OF THE UNIT AREA AND
FORMATION OF THE PT. McINTYRE
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SUMMARY OF DECISION: On March 18, 1993, ARCO, BPX, and Exxon, the Pt. McIntyre Working Interest Owners (producers or lessees), applied to expand the Prudhoe Bay Unit (PBU) and to form the Pt. McIntyre Participating Area (PMPA) within the proposed expanded unit area. After a thirty day public comment period, the department extensively reviewed the statutes, both the former and current oil and gas unitization regulations, and the Prudhoe Bay Unit Agreement (PBUA). Based upon the producers' application, the producers' appeal of the recent PBU contraction decision, and this review, the application is denied. The producers have not demonstrated that expanding the PBU to encompass the Pt. McIntyre Reservoirs under the terms that they have proposed is necessary and advisable to protect the public interest.

I. BACKGROUND

The PBU is an oil and gas unit located on the Alaska North Slope (ANS). The state approved this unit effective April 1, 1977. The original PBU application proposed to unitize 111 state leases, all of which were executed on the Division of Lands DL-1 lease form. The original unit area consisted of approximately 245,767 acres. ARCO Alaska, Inc. (ARCO) and BP Exploration (Alaska) Inc. (BPX) jointly operate the PBU on behalf of all 14 working interest owners (WIOs). On February 29, 1984, the Department of Natural Resources (DNR) approved the first expansion of the PBU to include all or portions of an additional 7 state leases, comprising approximately 5760 acres. The expanded unit area comprised approximately 251,437 acres.

On November 9, 1984, the DNR received an application to simultaneously expand the Duck Island Unit (DIU) boundary and contract the then current PBU boundary. The application, submitted by ARCO, BPX and the Exxon Corporation (Exxon), sought to amend the boundaries of the two units so that those leases believed to be wholly or partially underlain by the Endicott Reservoir would thereafter be in a separate unit, the DIU. Lands overlying the Endicott Reservoir that were then within the PBU were proposed to be excluded from the PBU and included within the DIU. The area proposed for contraction from the PBU included three leases comprising approximately 7680 acres.

DNR approved the November 9, 1984 application effective February 22, 1985, on the condition that the WIOs of the two units file an application within one year to conform the boundary between the two units to follow the trend of the Mikkelsen Bay Fault. This condition was designed to ensure that the lands in the western boundary of the DIU were restricted to those overlying the Endicott Reservoir, and that those lands in the northeastern part of the PBU were restricted to those overlying the Lisburne Reservoir.

In response to the condition imposed by the DNR, the producers applied on November 21, 1985, to expand the PBU and simultaneously contract the DIU to effect the boundary adjustments. ARCO and BPX submitted this application on behalf of all the WIOs of the two units. The application was approved effective February 22, 1986. Thereafter, the PBU comprised approximately 248,007 acres.

On April 1, 1987, pursuant to the PBUA's provisions, the PBU automatically contracted. This contraction, on the 10th anniversary of the PBU, was intended to result in the unit area thereafter including only those leases within an approved participating area (PA). However, certain leases (the Tracts) not within an approved PA were granted a five year deferral of contraction to April 1, 1992. After this mandated contraction of the unit area, the PBU contained 104 leases encompassing approximately 233,419 acres.

In early 1992, the producers requested a second deferral of contraction for the Tracts for another year. On March 25, 1992, DNR responded that it would delay a decision on the second deferral application until after it had reviewed geologic data that the producers promised to provide by September 30, 1992. The producers failed to meet that date and requested that they be allowed until May of 1993 to provide the data. DNR informed the producers in no event would it delay the deferral decision beyond the first quarter of 1993.

On March 31,1993, the producers requested a third deferral for yet another year. On April 14, 1993, I issued my decision as director of the division of oil and gas (DO&G) refusing to delay further the contraction of the Tracts from the PBU. Thus, the Tracts consisting of Tract 5 (ADL 34626), certain parts of Tracts 6 (ADL 34627) and 7 (ADL 34624), and Tract 8 (ADL 28297), were eliminated from the PBU. I concluded that a deferral of more than five years past the agreed upon original contraction date had been sufficient to allow the producers to confirm whether those lands qualified to be in a PA <u>and</u> to request and secure a decision on the merits of their application. ARCO and Exxon have appealed my contraction decision to the commissioner and requested a decision on the appeal be deferred until a decision has been issued on the expansion application.

The Initial Participating Area (IPA), which includes two PAs, the Oil Rim and Gas Cap, consists of the leases and portions of leases within the PBU that have been determined to be capable of producing or contributing to production of hydrocarbons from the Prudhoe Bay Reservoir (Permo-Triassic) in paying quantities. Only leases that are either partially or wholly included within the IPA can have hydrocarbon production from the Prudhoe Bay Reservoir allocated to them. The IPA was approved simultaneously with the approval of the PBU Agreement on June 2, 1977. The IPA contains all or parts of 92 leases totaling approximately 213,546 acres.

A third PA within the PBU, the Lisburne Participating Area (LPA), was approved by the DNR effective December 1, 1986. Production commenced from the Lisburne Reservoir in the LPA on December 15, 1986. Currently, the LPA contains all or parts of 38 leases totaling approximately 80,039 acres.

A fourth PA within the PBU, the West Beach Participating Area (WBPA), was approved by the DNR effective February 22, 1993. The WBPA contains all or parts of five leases totaling approximately 2,347 acres. Production commenced from the Kuparuk Formation in the WBPA on April 8, 1993.

II. APPLICATION FOR THE THIRD EXPANSION OF PRUDHOE BAY UNIT AREA AND FOR THE FORMATION OF THE PT. McINTYRE PARTICIPATING AREA

On March 18, 1993, the producers applied to expand the PBU and to approve the formation of the PMPA within the expanded PBU area pursuant to 11 AAC 83.356 and Article 9.1 of the PBUA. The proposed third expansion would add all or portions of six state oil and gas leases, ADL 34627 (Tract 6), ADL 34624 (Tract 7), ADL 28297 (Tract 8), ADL 28298 (Tract 115), ADL 34622 (Tract 116), and ADL 365548 (Tract 117), totaling approximately 9696 acres, to the PBU for a total expanded PBU of approximately 243,115 acres.

Two of the leases were issued as a result of state Lease Sale No. 14 (Prudhoe West to Canning River), held on July 14, 1965. The leases, ADL 28297 and ADL 28298, were issued on state lease form DL-1 (Revised Oct. 1963) providing for a 12.5 percent royalty to the state. A reduction of the royalty rate from 12.5 percent to a discovery royalty rate of 5 percent for all production allocated to the lease ADL 28297 was granted on March 6, 1991. The reduced royalty rate is effective for the period April 1, 1988 through March 31, 1998. Royalty reduction was granted for ADL 28297 because the Pt. McIntyre accumulation was discovered by the drilling of the Pt. McIntyre State No. 3 well on that lease.

Three of the leases were issued as a result of state Lease Sale No. 18 (Prudhoe), held on January 24, 1967. These leases, ADL 34622, ADL 34624, and ADL 34627, were also issued on state lease form DL-1 (Revised Oct. 1963) providing for a 12.5 percent royalty to the state.

The last lease, ADL 365548, was issued as a result of state Lease Sale No. 45A (North Slope Exempt: Canning River to Colville River), held on September 24, 1985. This lease was issued on state lease form DO&G-24-84 (Royalty)(Rev. 8/84) which provides for a 16.667 percent royalty, and also stipulates that the state's royalty share of any oil or gas produced from the lease will be exempt from field costs.

Simultaneously with the application to expand the PBU, the producers applied to approve the formation of the PMPA within the expanded PBU. The unit expansion acreage and the acreage proposed for the PMPA encompass two reservoirs, the Pt. McIntyre Reservoir (consisting of the Kuparuk and Kalubik Formations) and the Stump Island Reservoir (Seabee Formation), which are purported to be capable of producing or contributing to the production of hydrocarbons in paying quantities. The PMPA application was submitted pursuant to 11 AAC 83.351 and Section 5.3 of the PBUA. The proposed PMPA would comprise all or parts of the six individual oil and gas leases proposed for the unit expansion, and would total approximately 10,828 acres.

The application also included a proposed plan of development and operations for the PMPA, interim PMPA Tract Participation Factors, confidential geological and geophysical data in support of the proposed PA, a proposed well test allocation methodology for allocating production from all the producing reservoirs that will share the Lisburne Production Center (LPC), a copy of the Third Amendment to the Lisburne Special Supplemental Provisions to the PBU Operating Agreement, and proposed methods for reporting the allocated production and gas reserve/gas debits from each PA sharing the LPC. Later, a copy of the Pt. McIntyre Special Provisions to the PBU Operating Agreement was provided to DNR. Also provided at a later date, June 24, 1993, were the final PMPA Tract Participation Factors. The application requested that DNR approve both the PBU expansion and the PMPA effective July 1, 1993.

Before the public notice required under 11 AAC 83.311 was issued, an opportunity was provided to the producers, without any prejudice to their appeal rights, to modify the proposed PBU expansion area to include the Tracts which were contracted out of the PBU by my April 14, 1993 decision. The producers intended that these lands be included within the expanded PBU and proposed PMPA. Noticing the entire proposed unit expansion and PA as originally contemplated by the producers before the contraction of the Tracts would have avoided the requirement of another public notice and thirty day public comment period if the producers did not prevail in their appeal to the commissioner of the contraction decision. The producers declined to modify the proposed PBU expansion area set forth in the March 18, 1993 application.

On May 14, 1993, the DO&G determined that the expansion application was complete under 11 AAC 83.306. On May 19, 1993, public notice was published in the Anchorage Daily News and in the Tundra Times, as required by 11 AAC 83.311. Copies of the public notice were provided to interested parties in compliance with 11 AAC 83.311, as well as to the City of Barrow, the North Slope Borough, the Arctic Slope Regional Corporation, the Alaska Department of Environmental Conservation, the Alaska Department of Fish and

Game, the Alaska Department of Natural Resources, Division of Land and Water Management, and the Alaska Oil and Gas Conservation Commission (AOGCC).

During the 30 day public notice period allowed under 11 AAC 83.311, no comments were received from the public, interested parties, or state or local agencies.

III. DISCUSSION OF DECISION CRITERIA

Pursuant to AS 38.05.180(p) and 11 AAC 83.303(c), the DNR commissioner or his designee may approve expansion of a unit area if it is determined that expansion is "necessary or advisable to protect the public interest." Approval must be based on the criteria in 11 AAC 83.303(a) and the factors enumerated in 11 AAC 83.303(b). If the expansion would not protect the public interest, the proposed unit expansion must be disapproved.

Article 9.1 of the PBU Agreement (PBUA), which permits expansion of the PBU if approved by the director,[1] restates the commissioner's discretionary power under AS 38.05.180(p) and 11 AAC 83.303. Article 5.3 of the PBUA reflects the commissioner's discretionary power under AS 38.05.180(p) and 11 AAC 83.351 to approve or disapprove formation of a participating area. Article 5.3 requires the lessees to apply for expansion of participating areas using specified criteria and procedures but does not change the commissioner's discretion to approve establishment, enlargement, or contraction of lands reasonably proven to be within the reservoir limits.

The producers have argued that because a portion (slivers) of certain of the Tracts which they originally proposed to include within the PMPA were within the PBU before contraction, the commissioner lacks discretionary power to disapprove expansion to include all acreage adjacent to those slivers which may overlie PMPA. The slivers contain less than 5 percent of the recoverable reserves currently attributed to the Pt. McIntyre reservoirs. My April 14, 1993 decision contracted the slivers out of the PBU. Because the producers have appealed that decision, the effect of the contraction decision has been stayed pending the commissioner's decision on appeal under DNR's appeal regulations, 11 AAC 02.060. If the commissioner affirms my decision, the producers admit that their argument, that they have a contractual right to expand the PBUA to encompass the proposed expansion area, fails.

However, even if the commissioner reverses the contraction decision and determines that the slivers should still be within the PBU, the commissioner's discretionary authority to deny expansion or to condition expansion remains unchanged. The producers argue that because the slivers, which overlay a portion of the Kuparuk Formation within the proposed PMPA,

[1]When the PBU was executed, the state director of the division of minerals and energy management, the predecessor agency of the DO&G, was responsible for contraction and expansion decisions.

are within the PBU (because of the stay of the contraction decision), all of the Pt. McIntyre leases which overlie the Kuparuk Formation must be included in the PBU. The producers contend that once that additional area is included, the Kalubik Formation which overlies the Kuparuk Formation within the proposed PMPA, must also be included in the PBU.[2] (Because the slivers contain less than five percent of the recoverable reserves projected for Pt. McIntyre production, the producers' argument is like the dog's tail wagging the dog.) Their position rests on two arguments. I reject both.

The first relies on 11 AAC 83.356(a) which provides that a "unit must encompass the minimum area required to include <u>all or part of one or more oil or gas reservoirs.</u>" That regulation does not mandate that where two reservoirs are side by side or where one reservoir partially overlies another, both must be in the same unit; by its very terms, the regulation provides that a unit must encompass, at a minimum, only part of a reservoir.[3] The producers read the regulations to provide that the minimum area that must be included is <u>all reservoirs</u>. This reading ignores the "part of one" language in the regulation. A unit area may include part of one reservoir, one complete reservoir, one complete reservoir and part of another reservoir, or any one of a number of combinations. At a minimum, it must include, part of a Reservoir. In other words, a unit cannot be formed without at least a portion of a reservoir, but it can be formed with only that minimum area. Over time as more geologic data become available the unit area must be contracted to exclude areas that do not contain any reservoir. 11 AAC 83.356(b).

11 AAC 83.356(a) is consistent with AS 38.05.180(p) which gives the commissioner discretion to approve or disapprove a unit consisting of "all or <u>a part of an oil or gas pool</u>, field, or like area" when it is "necessary or advisable in the public interest." Even if the slivers are within the PBU, neither 11 AAC 83.356(a) nor AS 38.05.180(p) take away the commissioner's discretion in this regard. Any other interpretation renders 11 AAC 83.303 and the remaining provisions in 11 AAC 83.356 meaningless.

The producers also argue that Article 9.1 of the PBUA mandates that the entire Pt. McIntyre reservoir must be within the PBU because the slivers were within the PBU area. Article 9.1 provides:

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[2] The producers further contend that if the PMPA is included in the PBU, then they may deduct "field costs" from the state's royalty share of the PMPA production under the 1980 Settlement Agreement. <u>See</u> <u>infra</u> § 111.4.6.

[3] In the case of an exploratory unit, the minimum area is "part of one...potential hydrocarbon accumulation...." The West McArthur River Unit is an exploratory unit that includes only a part of a potential hydrocarbon accumulation. The Kuparuk River Unit is a producing unit that initially included only a part of the oil or gas accumulation from which it produces.

> The Unit Area may be enlarged from time to time so as to include any additional lands reasonably determined to be within any Reservoir any portion of which is within the Unit Area. The lands to be included shall be based on such subdivisions of the public land survey as may be approved by the Director, but not less than the area approved by the well-spacing order affecting such lands for such Reservoir.
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> After due consideration of all pertinent information, the Director shall render his decision, separate as to each lease or lands therein submitted for commitment.

I reject the lessees' argument that Article 9.1 of the PBUA mandates expansion and, thus, limits the commissioner's discretion. The "may" and "may be approved" language in Article 9.1 makes it clear that an approval by the director is necessary for expansion of the unit area and that his approval is discretionary. Further, if expansion was mandated and automatic, the language requiring the director to issue a decision would be meaningless. Again, the criteria in 11 AAC 83.303 would be applicable to the director's consideration.[4]

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[4]Exxon representatives argued in an August 12, 1993 meeting with state representatives that the unitization regulations in effect in 1974 do not permit the commissioner to consider the economic consequences to the state of unit expansion. The unitization statute gives the commissioner authority to approve unitization when it is "necessary or advisable in the public interest." AS 38.05.180(p). Current 11 AAC 83.303 list the criteria to be used in determining whether unitization is necessary or advisable to protect the public interest. Included in the criteria are the "economic costs and the benefits to the state." 11 AAC 83.303(b)(5). Although the former 1974 unitization regulation did not list specific factors to be considered in determining whether unitization was in the public interest, it still required that the commissioner decide the same ultimate question. Moreover, the 1974 version, like the current one, specifically requires the commissioner to protect the interest of the state. It is inconceivable that in determining whether unitization is in the public interest, the commissioner could not consider the economic costs and benefits to the state.

The "public interest" standard, as it existed in 1974, is one of broad discretion which permits the commissioner to consider a multitude of criteria and factors. See Hammond v. North Slope Borough, 645 P. 2d 750, 758 (Alaska 1982) (in describing the DNR commissioner's finding that a lease sale will best serve the interests of the state, the court said that a "best interests determination is almost entirely a policy decision, involving complex issues that are beyond this court's ability to decide"); Alaska Survival v. State, 723 P. 2d 1281, 1287 (Alaska 1986) (a best interest determination a decision is arbitrary if the commissioner fails to consider an important factor).

Further, the director's decision approving the PBUA makes clear that Article 9.1 was never intended to provide for expansions to include reservoirs or pools that had not even been discovered when the state approved the PBUA in 1977. See Decision and Findings Re Application for Approval of Unit Agreement, Prudhoe Bay dated May 25, 1977 (1977 Findings). When the PBUA was approved, several reservoirs were known. Id. at 3. The size of these reservoirs was subject to dispute and some lessees felt the proposed unit area was too small. Article 9.1 was the vehicle to handle this problem. If the lessees had geological data which showed that acreage outside the unit boundaries was "productive in the same [then known] pool as acreage in the Unit, it [could] be brought into the unit under the provisions of Article 9."[5] The state never contemplated that Article 9 would be used to expand the PBU to include reservoirs or pools that would be discovered more than ten years after the formation of the PBU. Thus, under the statutes, the unitization regulations, and the terms of the PBUA, the commissioner retains the discretion, after consideration of the criteria in 11 AAC 83.303, to approve or deny expansion of the PBU to include the PMPA.[6]

In accordance with AS 38.05.180(p) and 11 AAC 83.303, the commissioner will approve a proposed expansion of a unit area, a proposed PA, or a proposed production or cost allocation formula if the commissioner finds that each requested approval is necessary or advisable to protect the public interest. To find that any or all of the requested approvals are necessary or advisable to protect the public interest, the commissioner must find that the requested approval will: (1) promote the conservation of all natural resources; (2) promote the prevention of economic and physical waste; and (3) provide for the protection of all parties of interest, including the state.

In evaluating the above criteria, the commissioner will consider: (1) the environmental costs and benefits; (2) the geological and engineering characteristics of the potential hydrocarbon accumulation or reservoir(s) proposed for inclusion in the participating area; (3) prior

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[5]The director's decision also makes clear that if existing pools were expanded, he could "condition" the expansion on the producers' agreement to various stipulations. 1977 Findings at 3 & 5.

[6]Interestingly, although the producers now maintain that expansion is mandated and the commissioner has no discretion, they filed their application to expand the PBU pursuant to the very regulations that give the commissioner discretion. Furthermore, their current position that the PBUA mandates that the PBU be expanded whenever a portion of a new reservoir underlies the PBU area is inconsistent with their past practices. Portions of both the Kekiktuk Formation in the Duck Island Unit and the Kuparuk Formation in Kuparuk River Unit underlie the PBU. Nevertheless, the producers applied to form separate units (the Duck Island and Kuparuk River Units, respectively) rather than expand the PBU to include these new formations, and the various commissioners, acting within their discretion, approved the separate units.

exploration activities in the proposed participating area; (4) the applicant's plans for exploration or development of the proposed participating area; (5) the economic costs and benefits to the state; and (6) any other relevant factors (including mitigation measures) the commissioner determines necessary or advisable to protect the public interest.

Further, 11 AAC 83.351(a) provides that, upon formation, a PA may include only land reasonably known to be underlain by hydrocarbons and known or reasonably estimated through use of geological, geophysical, or engineering data to be capable of producing or contributing to the production of hydrocarbons in paying quantities. "Paying quantities" is defined by 11 AAC 83.395(4) to mean:

> quantities sufficient to yield a return in excess of operating costs, even if drilling and equipment costs may never be repaid and the undertaking as a whole may ultimately result in a loss; quantities are insufficient to yield a return in excess of operating costs unless those quantities, not considering the costs of transportation and marketing, will produce sufficient revenue to induce a prudent operator to produce those quantities.

An application for approval of a PA must be evaluated under these standards, as well as those of 11 AAC 83.303. The following evaluates this application under these criteria and considerations.

(A) <u>Promote the Conservation of All Natural Resources.</u>

The unitization of oil and gas reservoirs and the formation of PAs within unit areas to develop hydrocarbon-bearing reservoirs is a well accepted means of hydrocarbon conservation. Without unitization, the unregulated development of reservoirs tends to be a race for possession by competitive operators. The results can be: (1) overly dense drilling, especially along property lines; (2) rapid dissipation of reservoir pressure; and (3) irregular advance of displacing fluids. These all contribute to the loss of ultimate recovery or economic waste. The proliferation of surface activity; duplication of production, gathering, and processing facilities; and haste to get oil to the surface also increase the likelihood of environmental damage (such as spills and other surface impacts). Requiring lessees to comply with conservation orders and field rules issued by the AOGCC would mitigate some of these impacts without an agreement to unitize operations. Unitization, however, provides a practical and efficient method for maximizing oil and gas recovery, and minimizes negative impacts on other resources.

The formation of a PA to encompass the area overlying the two Pt McIntyre Reservoirs will allow them to be efficiently developed. Adoption of a comprehensive operating agreement and plan of development governing that production will help avoid unnecessary duplication of development efforts on and beneath the surface.

The Pt. McIntyre producers are also the same owners of the existing LPC which will process the Pt. McIntyre production. These producers have negotiated agreements among themselves to share the existing excess production capacity of the Lisburne facilities, and they have a separate plan of development that will optimize the recovery of the hydrocarbon reserves from the Pt. McIntyre Reservoirs. The state has participated in the producers' attempts to reduce the need for additional major processing facilities and thus to minimize any additional surface impacts and costs. The state has agreed to allow commingled production through the existing LPC and has worked with the producers to provide for a well test-based production allocation methodology for any current and future reservoir sharing the LPC.

Furthermore, producing hydrocarbon liquids from the two Reservoirs through the existing LPC reduces the environmental impacts. Using the existing facilities, gravel pads, and infrastructure eliminates the need to construct additional processing facilities. Although expanding the PBU to encompass the two Pt. McIntyre Reservoirs and the leases overlying those reservoirs would promote resource conservation, creating a separate unit, under terms and conditions more favorable to the public interest, would accomplish the same goal. In fact, in numerous meetings with the producers after the application was received, they presented no substantive reasons which lead me to believe that the conservation goals could not be accomplished by a separate unit agreement with terms and conditions more favorable to the public interest compared to those the producers seek to impose on the state by this application.

(B) The Prevention of Economic and Physical Waste.

Traditionally, under unitized operations, the assignment of undivided equity interests in the oil and gas reservoirs to each lease largely resolves the tension between lessees to compete for their share of production. Economic and physical waste, however, could still occur without an equitable cost sharing formula, and a well designed and coordinated development plan. Consequently, unitization must equitably divide costs as well as production, and plan to maximize physical and economic recovery from any reservoir. It must also treat the royalty owner fairly.

An equitable allocation of hydrocarbon shares among the WIOs discourages hasty or unnecessary surface development. Similarly, an equitable cost-sharing agreement promotes efficient development of reservoirs and common surface facilities and encompasses rational operating strategies. Such an agreement further allows the WIOs to decide well spacing requirements; scheduling, reinjection and reservoir management strategies; and the proper common, joint-use surface facilities.

Unitized operations greatly improve development of reservoirs beneath leases which may have variable productivity. Marginally economic reserves, which otherwise would not be produced on a lease by lease basis, often can be produced through unitized operations in combination with more productive leases. Facility consolidation saves capital and promotes better reservoir management by all WIOs. Pressure maintenance and secondary recovery procedures are much more predictable and attainable through joint, unitized efforts than would otherwise be possible. In combination, these factors allow less profitable areas of a reservoir to be developed and produced in the interest of all parties, including the state.

Although expanding the PBU to unitize the leases encompassing the Pt. McIntyre Reservoirs prevents economic and physical waste, creating a separate unit, under terms and conditions more favorable to the public interest, would accomplish these same goals.

(C) The Protection of All Parties in Interest, Including the State.

Expansion of the PBU will not be approved unless all parties of interest, including the state, can be protected. 11 AAC 83.303(a)(3). There has been no showing that the state's interests, particularly its economic interests, are protected by expansion of the PBU to include the proposed PMPA area, as opposed to forming a new unit area under the terms of a separate unit agreement. Some of the specific negative consequences to the state of approving the expansion of the PBU to include the proposed PMPA will be discussed in the section discussing the economic costs and benefits to the state (Section III.4.a.-g. below). The state does not seek an unfair advantage, rather it seeks to prevent an unmitigated loss. The producers' proposal to expand the PBU under their terms gives them many economic benefits, but does not share the benefits with the state.

(D) Consideration of Factors

In reviewing the above criteria, the following factors were considered:

(1) The Environmental Costs and Benefits of Unitized Development

This factor has been previously addressed in section III.A.

(2) Geological and Engineering Characteristics, and Previous Exploration of the Proposed Expansion Area and Proposed Participating Area

In March 1988, the Pt. McIntyre No. 3 well discovered the Pt. McIntyre Reservoir. Since the discovery well was drilled, approximately twenty-four wells have penetrated the Pt. McIntyre Reservoir within the proposed PMPA. Of these twenty-four wells, four (Pt. McIntyre No. 3, No. 4, No. 5, and No. 7) have been certified by DNR as capable of producing in paying quantities. Development drilling continues within the proposed PA from two permanent drill site locations, DS PM-1 and DS PM-2.

The producers supported their application with geological, geophysical, and engineering information. These include Kuparuk Formation structure maps, total oil pore foot and total hydrocarbon pore foot maps, individual geologic zone net-to-gross maps, porosity and water saturation maps by geologic zone, individual well logs for the available Pt. McIntyre wells, and tract volumetrics for the tracts within the proposed PA. This information supports the determination that the proposed tracts are appropriate for inclusion into a PA or a separate unit.

(3) The producers' plans for development for the proposed unitized area

The planned development program for the proposed PMPA reservoirs includes the directional drilling of 75 to 90 total wells on an average well spacing of 80-acres from the two Pt. McIntyre drill site locations, DS PM-1 and DS PM-2. The initial development combines patterned waterflood operations in portions of the Kuparuk Formation after field start-up, and produced gas reinjection into the gas cap. The possibility of using enhanced recovery techniques to increase recovery will be evaluated in the future.

Pt. McIntyre, Lisburne, and West Beach production will be commingled at the LPC. Pt. McIntyre will also share existing PBU infrastructure to minimize duplicating facilities. Commingling procedures and the methodology for allocating production to the appropriate fields sharing the LPC will be conducted in accordance with conditions approved by various state agencies, including DNR, DOR and AOGCC.

(4) The economic costs and benefits to the state.

a) Maximization of Production/Facility Sharing

The producers claim that expansion protects the interests of all parties, including the state, because it maximizes hydrocarbon recovery and will increase revenues from the Pt. McIntyre leases. They say that the state's direct economic benefit from expansion will be approximately $800 million over the life of the Pt. McIntyre field.

These same benefits, however, may be accomplished at less economic cost to the state by forming a new unit separate from the PBU, like the Duck Island and the Kuparuk River Units. Although the producers claim that the existing and underused LPC cannot be used to process Pt. McIntyre oil if Pt. McIntyre is not brought within the PBU, there is no good reason why a new unit may not share this same excess capacity. In fact, use of the LPC by a third party through the payment of a fee would benefit all parties by reducing capital investments in stand-alone production facility and by extending the economic lives of both the shared processing facilities and all the associated fields by spreading operating costs over a larger number of produced barrels.

Using the capacity of existing facilities will encourage greater production and ANS resource development by reducing capital investments and per barrel operating costs. Thus, the state agreed to allow commingled production through the LPC and worked with the lessees to get a facility sharing allocation methodology. The state understood that the lessees from other areas outside the PBU, including areas of known discoveries which are currently uneconomic to development using stand-alone facilities, possibly could share PBU facilities. The lessees have apparently changed their position on the potential availability of PBU facilities to process hydrocarbons from non-unit properties. This is inconsistent with the representations they made on several earlier occasions when requesting the state to allow commingling and facility sharing allocation. They have offered no explanation why sharing the LPC with production originating outside the PBU is now impossible.

Finally, additional recovery of hydrocarbons, in and of itself, is not determinative of the state's best interest. The terms and conditions of production must also protect the state's interests.

b) Field Costs

One major economic disadvantage to expansion of the PBU is that it would subject the Pt. McIntyre leases to a field cost allowance for the royalty share of oil and for any gas that may be produced after commencement of a major gas sale on the North Slope. Under the terms of the PBUA and the 1980 Field Cost Settlement Agreement, the state currently pays field costs of $0.79 per barrel for every barrel of in kind and in value royalty oil taken from the PBU and any expanded area of the PBU. If the PBUA and 1980 Settlement Agreement is made applicable to the PMPA or the state otherwise agreed to pay field costs, the state would bear a major cost (in excess of $25 million in nominal terms). Furthermore, allowing field costs conflicts with the present policy of the state, as well as the legislature's directive enunciated in AS 38.05.180(f), that the state not pay field costs for royalty oil. A detailed review of the field cost issue follows.

i) Introduction

The legislature, which is constitutionally charged with development of the state's natural resources for the maximum benefit of all the people of Alaska, has had as its longstanding policy that the producers/lessees may not deduct field costs from the state's royalty share. Alaska Const. art. VIII, §§ 2 & 12; AS 38.05.180(f); AS 31.05.110(h).[7] Under its

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[7] Judge, now Justice, Compton has noted the importance of these constitutional provisions.

constitutional charge, the legislature authorized the DNR commissioner to establish an oil and gas leasing program including the authority to issue leases under specific conditions and to approve units when it is in the public interest to do so. AS 38.05.180(f) & (p).

The legislature has declared state policy with respect to the creation and operation of units both in the Alaska Land Act (AS 38.05) and in the Alaska Oil and Gas Conservation Act (AS 31.05). The legislative policy prohibiting the deduction of unit expenses (which incorporates all the expenses included in the term "field costs") has existed since the passage of the Alaska Oil and Gas Conservation Act in 1955 and the Alaska Land Act. Nevertheless in 1978, the legislature amended both statutes to eliminate any uncertainty about this longstanding policy. Specifically, in 1978, the legislature amended AS 38.05.180 to make explicitly clear that the state's royalty share is "free and clear of all lease or unit expenses." Similarly, in 1978, the legislature amended AS 31.05.110 to make it clear that regardless of whether a voluntary or involuntary unit is formed, the "landowners' royalty...shall be paid to...the landowners...free and clear of all unit expense."[8]

> These constitutional provisions require that the legislature set the terms of oil and gas leases in such a manner as to provide the maximum benefit for its people. No "term" could be more critical to its people than the monetary return realized on the depletion of their natural resources. If "production" under AS 38.05.180(a) does not mean what the State claims it means, then the legislature has impermissibly delegated a constitutional duty to an administrative agency. The legislature did not do so.

ANS Royalty Litigation, No. 1JU-77-847 Civil at 18 (Alaska Super., April 6, 1979)(emphasis in original) ("1979 Decision").

[8]Producers that hold leases located over the same oil field commonly share exploration and development expenses through some relationship which divides the production and costs relative to ownership interests in the leases. "Unitization" is a method used to accomplish this purpose. When state leases are involved, producers may apply to the commissioner to form a unit with the state as a party to the unit agreement. This is referred to as a "voluntary" unit. If the producers cannot agree to the terms and conditions for a voluntary unit, either by petition by the producers or the state, or by motion by the Alaska Oil and Gas Conservation Commission (AOGCC) itself, the AOGCC can compel unitization. Additionally, under the DL-1 lease form, paragraph 32, and AS 38.05.180(p), the commissioner can force the producers to unitize by "prescrib[ing] a [unit] plan under which the lessee must operate." This is referred to as "involuntary" unitization. If, however, the producers petition the AOGCC to form an involuntary unit, the AOGCC's authorizing statute mandates that the state's royalty share be "free and clear of all unit expense." AS 31.05.110(h).

Given the mandates contained in these two statutory provisions, I believe that, because the Commissioner, or I, as his designee, have the responsibility to administer the leasing program according to the legislature's explicit policy, I should not approve an application to form a voluntary unit or to expand an existing unit to which the state is a party if the applicant proposes to burden the state's royalty share with field costs unless I am legally compelled to do so.[9] As mentioned earlier in this Decision and Findings, I have concluded that, except for the "slivers," I am not legally obligated to allow a field cost deduction for any of the area proposed to be included in an expanded PBU area.

ii) State's consistent position

The state has consistently taken the position that its royalty share is free of field costs under the state's "DL-1 leases."[10] Regarding the ANS, the dispute over field cost deductions

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[9] The state has taken the position that under AS 38.05.180(a), as enacted in 1959, the legislature did not give the commissioner discretion to enter into leases which provide for a royalty of less than 12-1/2 percent. See ANS Royalty Litigation State's Reply dated 5/31/78 at 44-47. Although in approving units under AS 38.05.180 the commissioner has the discretion to change the royalty requirements of a lease, this discretion should not be exercised when it would contravene the legislature's explicit intent except in a highly unusual situation.

[10] The first oil and gas leases issued by the state are commonly called "DL-1 Leases." It is fair to say that many of the provisions in the final DL-1 Lease were initially drafted and recommended by the Western Oil and Gas Association ("WOGA"). For example, WOGA recommended inserting the phrase "at the well" after the word "value" in the basic royalty provision in the proposed state lease form. WOGA also recommended adding a provision for an allowance for cleaning and dehydrating the state's royalty oil. Both of these recommended language changes became part of the final version of the DL-1 Lease and both were relied on by the producers as support for their claim to field cost deductions during the 1977-1979 summary judgment proceeding.

There have been several revisions to the original DL-1 form, but until 1979, the state competitive leases all bore the DL-1 designation and they all contained similar language regarding the lessees' royalty obligation. In 1979, the state lease form was substantially revised. Included in the revisions was an explicit provision that royaLty share is free of any field costs. That language continues in the lease form used in current state competitive lease sales.

Like the original DL-1, industry was primarily, if not entirely, responsible for drafting the PBUA. Indeed, industry drafted the PBUA after first refusing to sign the state's model unit crystalized during the summer of 1977, shortly after the giant Prudhoe Bay field came into production. During this period, then Commissioner LeResche notified the producers that "[r]oyalty payments made on the basis of a . . . price or value at the flow stations or gathering centers or at the pads from which the wells have been drilled . . . will not be regarded as fulfilling the royalty obligations owed the State." In essence, Commissioner LeResche was informing the producers that any costs incurred by them in producing the oil before its delivery to the Lease Automatic Transfer Point (LACT) meter, i.e., field costs, could not be deducted from the state's royalty share.

On September 2, 1977, the state began the litigation now referred to as the "ANS Royalty Litigation." The state sued the producers, seeking a declaratory judgment that under the DL-1 leases the producers were not allowed to deduct field costs. On April 6, 1979, the superior court granted the state's motion for summary judgment holding that AS 38.05.180(a) prohibited the producers from deducting field costs from the state's royalty when the state takes its royalty "in value" (RIV). 1979 Decision at 5.

The court stated that "[f]ield costs are costs of production" and since royalty is to be paid free of production costs, the state's royalty share does not bear these costs. 1979 Decision at 20.[11] The court also held, however, that cleaning and dehydration costs, a portion of field costs, are deductible when the state takes its royalty "in kind" (RIK), noting that when the state takes its royalty share in kind it "competes" in the selling of oil with the producers. 1979 Decision at 5 & 20. Further, the court held that the commissioner is prohibited from taking the state's royalty in kind if the amount realized would be less than if taken in value. 1979 Decision at 5. This meant that when the state acted as a competitor with the producers by taking its royalty in kind, the state was required to obtain a premium over the in value price from its in kind purchasers sufficient to pay for cleaning and dehydration costs. In sum, the court affirmed the state's policy position that its royalty share was free of field costs.

The state continues to maintain its right to a royalty free of field costs. Although the field costs issue pertaining to any oil production and to gas production after a major gas sale from the PBU was settled in part (see discussion below), the state continues to assert in the ANS Royalty Litigation that the state's royalty share for gas production before a major gas sale is free of field costs. Additionally, as discussed below, the state has required as a condition

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agreement. Accordingly, I believe that any ambiguity in the PBUA should be construed against industry and not the state. See Royalty Litigation State's Memorandum in Support of Motion for Summary Judgment re Field Gas Supply Option dated July 2, 1993, at 51.

[11] The court also accepted the state's argument that since the leases had been issued pursuant to the legislature's authorization in AS 38.05.180 and since that statute provided for a minimum royalty of 12-1/2 percent, deducting field costs would violate the statute because it would reduce the royalty below the 12-1/2 percent minimum.

of its approval of every unit application submitted after 1979 except one, that the producers waive any claimed right to field costs under the DL-1 leases.

The commissioner has the discretion to require, as a condition of approving unit formation or unit expansion, the waiver of the right to deduct field costs from the royalty share even if the DL-1 leases explicitly provided that the producers were entitled to deduct field costs. The right to renegotiate royalty terms of leases as part of unitization has been recognized for years. Both the DL-1 leases and the voluntary unitization statute expressly contemplate that upon unitization lease provisions may be renegotiated. Paragraph 32 of the DL-1 lease form provides: "Lessor may with the consent of Lessee establish, alter, change, or revoke drilling, producing, rental, minimum royalty, and royalty requirements of this lease if committed to any such. . . unit agreement." (emphasis added). AS 38.05.180(p) is substantially similar and provides: "The commissioner may with the consent of the holders of the leases involved, establish, change; or revoke drilling, producing and royalty requirements of the leases . . . in connection with the institution and operation of a unit plan." (emphasis added).

Under this authority, the ANS producers, including Arco, BPX, and Exxon, in the past have agreed to renegotiate various lease terms including DL-1 lease terms. See Commissioner's Decision and Findings re Hemi Springs Unit Agreement dated January 15, 1984 at 3-4. Even the royalty rate itself has been renegotiated under this authority. For example, as a condition of approval of the Milne Point Unit, the commissioner required those producers to agree that the royalty rate on certain leases within that unit be raised from a 12½% royalty rate stated in the leases to a 20% rate. (In other unit applications, DNR has considered adjusting the royalty rates in the DL-1 leases proposed to be committed to a unit, but determined that under the specific circumstances of each unit, raising the rates was not in the state's best interest. Id. at 8.)

The Milne Point producers did not have to consent to this condition, but the approval of a voluntary unit, as they had requested, would have been denied. Similarly, the producers, including Arco, BPX, and Exxon, have agreed on various occasions to renegotiate the DL-1 leases as part of unitization to make clear that field costs would not be deducted from the royalty share in exchange for the substantial benefits of unitization and lease extensions that they were seeking. See Gwydyr Bay, Milne Point, Hemi Springs, and Becharof unit agreements. Again, the producers did not have to renegotiate, but the proposed voluntary unit would have been denied. There is plenty of precedent for requiring the producers to waive any claimed right to field costs as a condition of approval of a unitization request.

Similarly here, the producers do not have to agree to waive field costs; but if they do not, neither I nor the commissioner must approve a voluntary expansion of the PBU as they have requested. A remedy for the producers if they find this condition unacceptable is to petition the AOGCC to form a separate involuntary unit.[12] The state has consistently maintained that the DL-1 leases do not bear field costs, and that even if they arguably do, the producers must give up any such claim before the state will approve an application for a voluntary unit or for expansion of the PBU. The reason for this is obvious -- the alternative whether arrived at through an AOGCC proceeding or under a plan prescribed by the commissioner would produce the same and, obviously, preferable result from the state's perspective -- production of the state's royalty share free of field costs.

iii. The legislature's policy

The legislature's view on whether field costs should be allowed against the state's royalty share has been made crystal clear. In 1978, the oil and gas leasing statutes were extensively amended by the legislature. AGO 1092955. Part of the reason for the comprehensive amendments was to confront the problems which were by then recognized in determining the state's royalty share resulting from the several disputes in the ANS Royalty Litigation. AGO 1092955; ANS Royalty Litigation, Findings of Fact and Conclusions of Law, dated August 13, 1980, at 4 (Findings). The then director of research for the legislative affairs agency noted that the bill contained language to "insure that future leases are not subject to the sort of dispute over [field] costs as the state is now litigating with the . . . producers." AGO 1093219.

In passing the comprehensive revision, the legislature clearly and expressly stated that the state's royalty share shall be free of field costs.

> A royalty share is reserved to the State, it shall be delivered in pipeline quality and free of all lease and unit expenses, including but not limited to separation, cleaning, dehydration, gathering, saltwater disposal, and preparation for transportation off the lease or unit area.

AS 38.05.180(f) (emphasis added).

Also in 1978, the legislature amended the Oil and Gas Conservation Act (Title 31) to clarify that if an oil and gas field is unitized, regardless of whether the unit is formed voluntarily or involuntarily, the royalty share was free of field costs. The Act provides:

> A one-eighth part of the unit production allocated to each separately owned tract shall be regarded as royalty to be distributed to and among, or the proceeds of it paid to, the royalty owners free and clear of all unit expense and free of any lien therefore.

[12]Additionally, as previously discussed, the DNR commissioner has authority to compel an involuntary unit.

AS 31.05.110(h) (emphasis added). As part of the ANS Royalty Litigation in 1977-78, the state argued that subsection (h) expressly forbade the producers' taking of field costs against the state's royalty share. The producers disagreed, claiming that the subsection did not apply to the PBU because it was a voluntary unit.

In 1978, the legislature amended AS 31.05.110 by adding subsection (q), which explicitly stated that subsection (h) was applicable to voluntary units. The state has recently argued that this 1978 amendment, which immediately followed the controversy over subsection (h)'s application to voluntary units, evidences the legislature's intent that even before 1978 it intended subsection (h) to apply to voluntary units. ANS Royalty Litigation, State's Memorandum in Support of Motion for Summary Judgment on Counts I-V, dated July 2, 1993, at 76-79. Regardless of whether subsection (h) applied to voluntary unitization before 1978, it undoubtedly applies now, and I must consider it in analyzing whether it is in the state's best interest to form a new unit or expand an existing unit areas under the specific facts and circumstances surrounding each application.[13]

In short, the Alaska legislature has explicitly stated that it intends that the state's (or any landowner's) royalty share as part of unitization shall be free and clear of all unit expense.

iv) DNR's implementation of the legislature's policy

Shortly after the amendments to the oil and gas leasing statutes, DNR amended its model form lease and unit agreement to conform with the legislature's policy. The first lease sale to be held after 1978 offered leases that reflected the amended statutes. Regarding field costs, the new lease form provided:

> Royalty paid in value shall be free and clear of all lease expenses (and any portion of such expenses which has occurred away from the leased area), including but not limited to expenses for separation, cleaning, dehydration, gathering, saltwater disposal, and preparing the oil, gas or associated substances for transportation off the leased area. . . .
>
> Royalty delivered in kind shall be free and clear of all lease expenses (and any portion of such lease expenses which is incurred away from the leased area), including, but not limited to expenses for separation, cleaning, dehydration, gathering, saltwater disposal, and preparing the oil, gas or associated substance for transportation off the leased area.

[13] The same criteria that apply to unit decisions apply to unit expansion decisions. See 11 AAC 83.303, .311, .316 & .356.

Form No.DMEM-A (revised August 27, 1979), ¶¶ 2 & 3 (emphasis added). The concept of a royalty share free of field costs has been carried forward to the current date. See Form No. DOG9208 (created August, 1992), ¶¶ 37 & 37. Indeed, BPX's lease in the proposed PMPA, which was issued in 1985, is a Form DO&G 24-84 (royalty) (rev. 8/84) lease providing that neither RIV nor RIK bears field costs.

In addition, after the 1978 amendments, DNR's consistent position has been to require that any claimed right to field costs be waived by a producer seeking to voluntarily unitize a field. Of the twelve voluntary units formed since the effective date of the 1978 amendments, all but one have explicitly provided for no field costs.[14] The state's model unit agreement form provides that the royalty share "shall be free and clear of all lease expenses". DNR Form No. 10-1128 (Unit Agreement) (Revised April 1990) at Art. 10.9.

Four of the twelve units approved since 1979 have contained DL-1 leases. In order to gain the DNR's approval of the proposed units, the producers were required, consistent with the legislature's policy, to waive any argument that they were entitled under the DL-1 leases to deduct field costs.[15] The producers who have so waived field costs under DL-1 leases include Arco, BPX, and Exxon. See Gwyder Bay and Hemi Springs unit agreements. As discussed above, these precedents undercut any argument by them that the commissioner cannot require the waiving of field costs as a condition of his approval of an application to unitize or expand a unit area.

v) The 1980 Settlement Agreement

In 1980 the state and the producers settled the field cost issues in the ANS Royalty Litigation for oil production and for gas production after a major gas sale from the PBU. Despite the court's favorable summary judgment decision that the state did not have to bear field costs, the state agreed to pay the producers an equal fee for oil produced from the PBU whether the state's royalty share was taken in value or in kind.

Admittedly, the 1980 Settlement Agreement was at odds with the policy adopted by the legislature in 1978 that the state's royalty share shall be free of field costs. Nevertheless, the state entered into the 1980 Settlement Agreement to obtain an early cash payment, to avoid both litigation risk and significant legal expense, to facilitate the state's right to take its royalty share in kind, and to allow the state to plan for the long-term disposition of its natural resources. Findings at 4-5. As a result of that settlement, however, the state has

[14] The only exception to DNR's implementation of the legislative policy was in approving the formation of the KRU. This exception is discussed later in this Decision and Findings.

[15] I have previously discussed the commissioner's authority to require a waiver of field costs.

paid the PBU producers in excess of 650 million dollars to date -- none of which the state would have had to pay under the 1979 Decision if the royalty was taken in value.

In entering into the 1980 Settlement Agreement, the state and the producers were desirous that the Agreement would help to settle disputes. Unfortunately, the Agreement has actually fostered other misunderstandings and disputes which continue to the present day.

First, I believe that it has paid more under the 1980 Settlement Agreement than it ever intended to pay. The producers dispute this. At the time of the 1980 Settlement Agreement, the producers estimated the recoverable reserves for the PBU at 9.6 billion barrels of oil. Thus, the state contemplated that its payment would be approximately the per barrel fee times the royalty share (one-eighth) of 9.6 billion barrels. The number of recoverable reserves has since been shown to be as much as 12 billion barrels of oil. As a result, the state will ultimately pay considerably more than it contemplated in 1980 based upon the expected production volume. In fact, BPX has recently stated publicly that it now believes the reserves may be raised by another billion barrels as the result of drilling additional development wells. Under anyone's interpretation of the DL-1 lease, however, the costs of drilling development wells is a cost to be borne solely by the producer. These new reserves are not reserves that the state contemplated that it would be responsible for sharing the costs to produce. Nevertheless, as a result of the 1980 Settlement Agreement, the state will continue to pay field costs for an additional billion barrels of production.

Pt. McIntyre production, whether from a new unit or a new PA in the PBU, will be processed through already existing facilities which the state shares the costs of under the 1980 Settlement Agreement. Yet, the producers wish to impose the same per barrel fee on Pt. McIntyre reserves as the state currently pays for each PBU royalty barrel. As WIOs of the Lisburne facilities within the PBU, ARCO, BPX and Exxon have negotiated agreements with themselves as Pt. McIntyre Owners in which they will recover a processing fee of $2.00 per barrel for their earlier investments in those facilities. However, they have made no provision for repaying the state for its proportionate share of those costs. Moreover, they insist that the state must pay again for those same facilities to process the royalty share of Pt. McIntyre reserves through them!

Second, the 1980 Settlement Agreement led to additional disputes between the producers and the state regarding the deduction of field costs for the state's royalty share as part of the Kuparuk River Unit (KRU) formation. Ultimately, the dispute was settled by a renegotiation of the leases' field cost terms as part of the unit formation, with the state again agreeing to pay a portion of the field costs. Importantly, for the state's economic protection, the producers significantly compromised their claimed field cost deductions from $0.882 per barrel to $0.395 per barrel as part of the settlement. The KRU Decision and Findings noted that the KRU settlement did not resolve the dispute for future units. Since numerous other units would come before the state, it was likely that future litigation would ensue.[16]

Third, that prophesy has been borne out as reflected by the current disputes surrounding whether the producers have an absolute right to expand the PBU and, thus, the ability to force the state to pay field costs by operation of the 1980 Settlement Agreement. The parties continue to argue about the acreage to which the 1980 Settlement Agreement applies. The Agreement's effect was limited by its terms to certain leases within the then existing PBU and to such other leases as the unit area may be expanded to include. The producers argue that the 1980 Settlement Agreement, in combination with the PBUA, deprive the commissioner of the discretion to deny an expansion request if any portion of a newly discovered reservoir underlies the PBU. They also argue that he has no authority to condition a proposed expansion on the waiving of field costs. As discussed earlier, this position is contrary to the statutory and regulatory best interest findings regarding unit expansions.

Fourth, the producers have recently contended in the gas related portion of the ANS Royalty Litigation that the effect of the 1980 Settlement Agreement, which settled only PBU field cost issues for oil and for gas after a major gas sale, bars the state from asserting the same position that it asserted in its 1977 motion for summary judgment. They assert the state can no longer contend that AS 38.05.180 precludes a field cost deduction for gas before a major gas sale.

Given that the PBU producers are likely to continue to attempt to expand the PBU to take advantage of the 1980 field cost allowance (and other economic benefits that accrue to them as a result of operating within the PBU), I believe that it is in the state's best interest to resolve the issue once and for all, not just for the current situation.

vi) Conclusion

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[16] As previously discussed, this is the only time since the 1978 amendments that the DNR Commissioner, acting within his discretion, has approved a unit which allowed field costs to be deducted from the royalty share. Field costs were allowed, however, as part of the formation of the Endicott Participating Area (Endicott PA) in the Duck Island Unit. Although the Duck Island Unit was formed before the effective date of the 1978 amendments, the Endicott PA within that unit was formed after the effective date. The field cost deduction of only \$0.42 per barrel allowed for the Endicott PA is significantly less than the \$0.80 per barrel requested by the producers here, although the fields are of similar size and, unlike the Endicott PA, the PMPA has the benefits of facility sharing. Given the significantly lower fields costs agreed to by the producers than those proposed here, I can understand how those commissioners, acting within the scope of their discretion, approved the respective unit and PA. This situation is distinguishable.

In summary, I do not believe that it is in the state's best interest to approve the expansion of the PBU to include the proposed PMPA if it means that the state's royalty share from the Pt. McIntyre leases, other than the slivers, would be burdened with field costs. First, as mentioned above, the state's longstanding position is that the royalty share should not bear field costs. Second, the legislature has made that position its explicit policy. Third, allowing field costs is not consistent with DNR's approval of other unitization requests. Fourth, allowing field costs would not resolve disputes between the state and the producers over this issue. Fifth, by providing for commingling, the state has provided the producers with benefits which should allow production of the field even if field costs cannot be deducted or even if production takes place from a separate unit. Sixth, allowing field costs would not be in the state's economic interest because it would deprive the state of in excess of $25 million dollars over the life of the Pt. McIntyre production, and potential other revenues if field costs were later allowed for other future units because of established precedent.

The producers have stated that certain economic benefits will accrue to them aside from deducting field costs if the proposed PMPA is within the PBU. The producers have not proposed to share those benefits with the state in any form. Although it has been done several times before, they have adamantly refused to waive their claimed right to field costs so that the state can, at least, share in some of the additional economic benefits of unitization. I simply do not believe that the producers have presented any compelling reason why the legislature's policy that the royalty share is to be free of field costs should not be followed.

c) Tract Allocation

As required by 11 AAC 83.371, the producers submitted an allocation of production and costs characterized by them as a "value-based" allocation. The producers claim that expansion protects the interests of all parties, including the state, by equitably allocating production to lease tracts. But the producers agreed only among themselves how to allocate production to tracts and how to share facilities; their agreements were designed to protect only their equity interests. The state was not consulted by the producers, nor is there any evidence that its royalty interest was considered by them. Therefore, the producers' agreements do not necessarily protect the state's interests. The producers have argued that approval should be granted because disapproval will delay production of Pt. McIntyre while the lessees renegotiate their agreements. However, protection of the state's interest with the formation of a separate unit agreement outweighs whatever benefits are derived from early production of Pt. McIntyre under the PBUA.

The proposed allocation essentially distributes working interest equity among the several leases by recognizing differing development costs and recoverable reserves among the leases. The basis for the calculation of value-based equity and allocations, as opposed to an allocation based on original oil in place (OOIP or black oil reserves) or some other technically based standard, was arrived at, as discussed above, through confidential negotiations among the producers with no advance notice or approval by the state.

Although redistributing the equity owners' share of production may be warranted to promote unitized development, undoubtedly the royalty owner does not bear responsibility to underwrite such cost sharing arrangements—particularly where the royalty share is bartered without the royalty owners' assent. Where the royalty rates of all leases are the same within a unit or a proposed expansion area, negotiations among the equity owners to reallocate costs are irrelevant to the royalty owner. Regardless of which costs are borne by which lessee, the royalty owner's share of production is not reduced.

But the royalty rates are not the same here. The proposed expansion area encompasses six leases. One lease provides for a royalty rate of 16 2/3 percent. Another lease was awarded a discovery royalty certification, and thus has a five percent royalty for a ten year term commencing the first day of the month following discovery. The other four leases have a 12 1/2 percent royalty rate. The producers' value-based tract allocation would reduce the state's royalty share by imputing a larger equity (tract allocation) to the five percent discovery royalty tract.

Under the regulations, the commissioner must approve the production allocation before it takes effect. I cannot approve an allocation which reduces the state's royalty revenues simply to accommodate a negotiated settlement of the WIOs' cost and revenue disputes. Exxon, however, in meetings with DNR representatives on August 12, 1993, opined that this is precisely what the state is bound to do if it approves the proposed expansion. Exxon reads the PBUA, the terms of the 1980 Settlement Agreement and the May 25, 1977 "Decision and Findings of the Director, Division of Minerals and Energy Management With Respect to Application for Approval of Unit Agreement, Prudhoe Bay", in combination, to constitute a waiver of the commissioner's discretion to deny a specific allocation or to require amendment of a proposed tract allocation. Obviously, the commissioner's discretion in this regard cannot be questioned in the context of forming a new unit. I believe it is equally obvious that if the approval of the expansion is discretionary, it would not be in the state's interest to incur the additional risk of litigation to establish its authority to reject a disadvantageous tract allocation within an expanded area of the PBU.

Although the state has not completed its review of the producers' proposed tract allocations, I would accept an allocation, for royalty purposes, based on black oil reserves.

d) Royalty in Kind (RIK) Issue

In evaluating the state's economic interests under the alternatives of either expanding the PBU under the terms proposed by the producers or creating a separate unit, it is also proper to consider the effects of both alternatives on the state's existing royalty in kind contract relationships. Under the terms of the PBUA, the state must nominate its volumes of RIK oil as a specific percentage of daily production from the unit area; it cannot nominate either a specific volume or from a selected PA in the PBU. Both the state and its purchasers are constantly faced with the need to adjust volumes to accommodate variances in production rates. In addition, there are strict limitations on the notice which the state must provide to the PBU WIOs of adjustments that it wishes to make to balance its RIK deliveries with changing production rates.

Under the producers' interpretation of the PBUA, however, they are not obliged to consider the states's RIK contract relationships or the effects of their unilateral production decisions on those relationships. Although the state must give several months' notice of its intent to increase or decrease its in kind taking, the producers maintain that they are free to tender new production from expansion areas such as that proposed for Pt. McIntyre, with virtually no advance notice and at the same percentage rate as the state's then current in kind unit wide nominations for its RIK sales. This would create additional hardships for the state's purchasers, as they would find themselves in the difficult position of having to arrange for additional pipeline space and marine transportation to accommodate the producers' scheduling and planning over which the purchasers have no control and for which they may have inadequate notice.

The effects of this unbalanced relationship would fall particularly hard on Tesoro, one of the state's in kind purchasers. In an attempt to improve its financial footing, Tesoro has announced a major recapitalization program and has taken steps to implement what it terms a "market-driven strategy" to reduce costs and improve refining margins. Crucial to that strategy is the reduction and fine-tuning of the volumes of RIK oil which Tesoro purchases from the state to more closely match product demand. Tesoro has pursued this reduction over the past several months through reductions in its nomination in conformance with the terms of its RIK contract and the terms of the PBUA. As a consequence of the proposed expansion, Tesoro's efforts would be disrupted, potentially increasing the state's litigation risk. In discussions between the state and the producers, they have evidenced a complete disregard of this complication and an unwillingness to mitigate its effects as evidenced by the correspondence attached as Exhibits 1 - 6.

Production of the Pt. McIntyre reserves from a new unit would enable the state to elect its in kind and in value nominations to avoid complications such as these. Moreover, either formation of a new unit or the applicants' willingness to amend the existing PBUA to allow nomination by participating area would avoid these problems. Either would also reduce the state's litigation risk. However, the applicants have rejected either alternative.

e) <u>Miscellaneous Economic Issues</u>

There are other economic costs to expansion of the PBU. Recently, it has become apparent that the state's and producers' interpretations of the PBUA and 1980 Settlement Agreement are radically different. As litigation over the agreements has proceeded in the pending gas related portion of the ANS Royalty Litigation, the producers have adopted an interpretation of these agreements that is very unfavorable to the state.

For example, the producers have argued that under the Fuel Gas Supply Option (FGSO) in the PBU Operating Agreement, they are not obligated to pay royalties on gas sold among themselves. Before implementation of the FGSO, some PBU producers set ANS prices at an artificially low level apparently to influence their obligation to one another under the FGSO. Another issue currently being litigated is whether the liquid hydrocarbons recovered at the Central Gas Facility (CGF) and subsequently marketed as ANS crude oil are subject to field costs. These issues involve the potential loss of hundreds of millions of dollars to the state. Expanding the PBU to include the Pt. McIntyre leases would subject the leases to the same litigation risks burdening the PBU and would increase the costs of an unfavorable decision to the state.

For all of the above reasons, the economic costs of expanding the PBU to include the Pt. McIntyre far outweighs the benefits to be derived from expansion.

IV. FINDINGS AND DECISION

Based on the foregoing, I find:

1. The decision of whether or not to expand the PBU under the conditions proposed by the producers is discretionary.

2. In evaluating whether to exercise my discretion to approve the proposed expansion, I must determine that it is in the state's best interest to do so considering the specific facts and circumstances surrounding the application.

3. In making a determination that the proposed expansion is in the state's best interest, it is necessary to evaluate the proposal in light of the statutes, the regulations and the contractual obligations to which the state is party.

As set forth in the body of this decision, I have determined that it is not in the state's best interest to approve the proposed expansion of the PBU and to form the PMPA within an expanded PBU. Therefore, the application to do so is denied. This decision, however, does not prejudice any rights which the applicants may have to amend their proposal to mitigate the negative effects on the state's interest which have been described in this Decision and Findings. See 11 AAC 83.316(b). If they decide to do so or apply to form a separate unit, this decision will be reconsidered.

Under 11 AAC 02.010-.080, the producers have thirty calendar days after the date of delivery of the decision to appeal the decision to commissioner. To be timely filed, the appeal must be received by the Department of Natural Resources, at 5th Floor, 400 Willoughby Avenue, Juneau, Alaska, 99801-1724, within the thirty calendar days.

James E. Eason
James E. Eason, Director
Division of Oil and Gas

August 18, 1993
Date

cc: Harry A. Noah, Commissioner
Alaska Department of Natural Resources

David Johnston, Chairman
AOGCC

Attachments:

Delegation of Authority from Commissioner to
Director, Division of Oil and Gas

Exhibits 1 through 6

PBU.EXP.PMPA.D&F.txt

DELEGATIONS OF AUTHORITY FOR THE DIVISION OF OIL AND GAS

Regulatory Citation	Purpose or Action	Authority Vested in	Authority Delegated to
11 AAC 82.400	Parcels Offered for Competitive Lease	Commissioner	No Delegation
11 AAC 82.405	Method of Bidding	Commissioner	No Delegation
11 AAC 82.410	Minimum Bid	Commissioner	No Delegation
11 AAC 82.445	Incomplete Bids	Commissioner	No Delegation
11 AAC 82.450	Rejection of Bids	Commissioner	No Delegation
11 AAC 82.455	Tie Bids	Commissioner	No Delegation
11 AAC 82.460	Additional Information	Commissioner	No Delegation
11 AAC82.465	Award Leases	Commissioner	Director, Div. of Oil Gas (DOG)
11 AAC 82.470	Issue Leases	Commissioner	Director, DOG
11 AAC 82.475	Bid Deposit Return	Commissioner	Director, DOG
11 AAC 82.600	Required Bonds	Commissioner	Director, DOG
11 AAC 82.605	Approve/Deny Assignments of Oil and Gas Leases	Commissioner	Director, DOG
11 AAC 82.610	Segregate Leases	Commissioner	Director, DOG
11 AAC 82.620	Transfer of a Lease, Permit or Interest as a Result of Death	Commissioner	Director, DOG
11 AAC 82.625	Eff. Date of Assignments	Commissioner	Director, DOG
11 AAC 82.635	Surrenders	Commissioner	Director, DOG
11 AAC 82.640	Survey Requirement	Commissioner	No Delegation
11 AAC 82.645	Conforming Protracted Description to Official Surveys	Commissioner	No Delegation

Regulatory Citation	Purpose or Action	Authority Vested in	Authority Delegated to
11 AAC 82.650	Control of Lease Boundaries	Commissioner	No Delegation
11 AAC 82.660	Excess Area; Partial Termination	Commissioner	No Delegation
11 AAC 82.665	Rental and Royalty Relief	Commissioner	No Delegation
11 AAC 82.700	Taking Royalty in Kind	Commissioner	No Delegation
11 AAC 82.705	Bidding Method	Commissioner	No Delegation
11 AAC 82.710	Notice of Sale	Commissioner	No Delegation
11 AAC 82.800	Production Records	Commissioner	Director, DOG
11 AAC 82.805	Test Results	Commissioner	Director, DOG
11 AAC 83.153	Well Confidentiality	Commissioner	Director, DOG
11 AAC 83.158	Approve/Deny Lease Plan of Operations	Commissioner	Director, DOG
11 AAC 83.303	Unit Agreement Approval	Commissioner	Director, DOG
11 AAC 83.306	Accept Application for Unit Agreement Approval	Commissioner	Director, DOG
11 AAC 83.311	Publish Public Notice of Unit Agreement Application	Commissioner	Director, DOG
11 AAC 83.316	Approve/Deny Unit Agreement	Commissioner	Director, DOG
11 AAC 83.326	Require or Accept Nonstandard Unit Agreement Language	Commissioner	Director, DOG
11 AAC 83.328	Mandate Unitization (Involuntary Unitization)	Commissioner	No Delegation
11 AAC 83.331	Approve/Deny Change in	Commissioner	Director, DOG Unit Operator
11 AAC 83.336	Grant Extension of Unit Term; Grant Suspension of Operations (Force Majeure); Terminate Unit	Commissioner	No Delegation

Regulatory Citation	Purpose of Action	Authority Vested in	Authority Delegated to
11 AAC 83.341	Approve/Deny Plan of Exploration	Commissioner	Director, DOG
11 AAC 83.343	Approve/Deny Plan of Development	Commissioner	Director, DOG
11 AAC 83.346	Approve/Deny Plan of Operations	Commissioner	Director, DOG
11 AAC 83.351	Approve/Deny Participating Area	Commissioner	Director, DOG
11 AAC 83.356	Expand/Contract Unit Area	Commissioner	Director, DOG
11 AAC 83.361	Certify Wells as Capable of Production in Paying Quantities	Commissioner	Director, DOG
11 AAC 83.371	Approve/Deny Allocation of Cost and Production Formulas	Commissioner	Director, DOG
11 AAC 83.373	Sever Leases	Commissioner	Director, DOG
11 AAC 83.374	Declare Unit in Default	Commissioner	No Delegation
11 AAC 83.383	Notation of Approval on Joinder	Commissioner	Director, DOG
11 AAC 83.385	Modification of Unit Agreement	Commissioner	Director, DOG
11 AAC 83.393	Approval of Federal or Private Party Unit Agreements	Commissioner	No Delegation

I hereby delegate the authority vested in me through AS 38.05.180 to the Director of the Division of Oil and Gas as noted above. This delegation of authority is effective until revoked by me.

Harry A. Noah, Commissioner
Alaska Department of Natural Resources

7/21/93
Date

WALTER J. HICKEL, GOVERNOR

DEPT. OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

P.O. BOX 107034
ANCHORAGE, ALASKA 99510-7034
PHONE: (907) 762-2553

April 30, 1993

Von Hutchins
Sr. Operations Engineer
ARCO AK Inc.
PO Box 100360
Anchorage, AK 99510-0360

Dear Mr. Hutchins,

The State of Alaska (State) is requesting that ARCO remove the Point McIntyre and North Prudhoe Bay State RIK allocations from the July 1993 nomination. These two areas are not part of the Prudhoe Bay Unit and the State does not wish to make additional nominations from these two areas at this time.

If you have any questions regarding this letter, please call Linda Reem at 762-2556.

Sincerely,

Nancy L. Cress

Nancy L. Cress
Royalty Accounting Manager

d:rik;lr;4/30/93

Exhibit 1

ARCO Alaska
Post Office Box 100360
Anchorage, Alaska 99510 0360
Telephone 907 276 1215

May 5, 1993

Ms. Nancy L. Cress
Royalty Accounting Manager
Department of Natural Resources
Division of Oil and Gas
P. O. Box 107034
Anchorage, Alaska 99510-7034

Re: **July 1993 Royalty Nominations for Point McIntyre and North Prudhoe Bay State**

Dear Ms. Cress:

This letter responds to your letter of April 30, 1993, to V. L. Hutchins. ARCO recognizes that the State of Alaska must approve the production of hydrocarbon resources from the Point McIntyre and North Prudhoe Bay Areas and that there are a number of issues that are not yet resolved.

If those issues can be resolved, there will be no ability to tender the expected Point McIntyre and/or North Prudhoe Bay State production to TAPS in July 1993, unless the recently submitted nominations are made now by all of the Owners of the expected production, including the State.

If those issues cannot be timely resolved, it is likely that a July 1993 start-up will be impossible. For example, if the State requires a separate unit for Point McIntyre, quality bank issues between Point McIntyre and Lisburne which will affect State RIK purchasers will have to be resolved. Under those circumstances, there would not be any penalty for having over-nominated July 1993 production to TAPS.

For the foregoing reasons, ARCO requests that the State apply its RIK percentage from the PBU to the entire projected commingled July 1993 LPC production as set forth in ARCO's Production Forecast letter of April 30, 1993.

Exhibit 2

Ms. Nancy L. Cress
May 5, 1993
Page 2

Please call me at 265-6538 or Rosy Jacobsen at 265-6549 if you have any questions concerning this matter.

Sincerely yours,

J. L. Harris
Engineering Supervisor
Lisburne/Point McIntyre Engineering

/pfm

WALTER J. HICKEL, GOVERNOR

DEPT. OF NATURAL RESOURCES

PO BOX 107034
ANCHORAGE, ALASKA 99510-7034
PHONE: (907) 762-2553

DIVISION OF OIL AND GAS

May 6, 1993

J. L. Harris, Engineering Supervisor
Lisburne/Point McIntyre Engineering
ARCO Alaska, Inc.
P. O. Box 100360
Anchorage, Alaska 99510-0360

Dear Mr. Harris:

I am in receipt of your May 5, 1993 letter to Ms. Nancy Cress regarding July 1993 royalty nominations for Pt McIntyre and North Prudhoe Bay State. I have carefully reviewed the rationale provided in your letter for ARCO's belief that it is appropriate to apportion royalty production from Pt. McIntyre and North Prudhoe Bay State No. 3 according to the state's current royalty nominations for Prudhoe Bay production. Nevertheless, I am unpersuaded by any of the arguments which you have made that there is a rational basis for determining that it is in the state's interest to accept your proposed nominations.

I would like to reiterate, as Ms. Cress has before, that the state has not nominated, and we do not desire to nominate, any in-kind deliveries from either Pt. McIntyre or North Prudhoe Bay State at this time. As you are no doubt aware, we have royalty in-kind contracts with Tesoro and Mapco which limit the oil they are entitled to take to either a percentage or a fixed volume of royalty oil from Prudhoe Bay Unit production. However, as neither Pt. McIntyre nor Prudhoe Bay leases are part of the Prudhoe Bay Unit, it is inappropriate that you should unilaterally nominate on behalf of the state oil for in-kind taking to the benefit (or detriment) of our in-kind purchasers.

Accordingly, please revise your nominations to reflect the state's wishes <u>immediately</u>.

Sincerely,

James E. Eason
Director

cc: Glenn A. Olds, Commissioner
Bruce Botelho, Deputy Attorney General
Jim Baldwin, Assistant Attorney General
Patrick Coughlin, Assistant Attorney General
Bill Van Dyke, Lease Administration/Royalty Accounting Manager
Nancy Cress, Accountant
Mike Welch, Mapco Alaska Petroleum
Don Reep, Tesoro Alaska Petroleum Company

Exhibit 3

WALTER J. HICKEL, GOVERNOR

DEPT. OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

P.O. BOX 107034
ANCHORAGE, ALASKA 99510-7034
PHONE: (907) 762-2553

(907)762-2547

June 3, 1993

Colin Howard, Vice President
& Chief Counsel
ARCO Alaska, Inc.
P. O. Box 100360
Anchorage, Alaska 99510-0360

Dear Colin:

This is a followup to the telephone conversation which you, Patrick Coughlin and I had earlier on June 3, 1993. Patrick and I called you to discuss the implications of the August 1993 LPC production forecast dated May 28, 1993 which arrived with a cover letter from Mr. V. L. Hutchins. I expressed my concern about the continuing nomination of Pt. McIntyre production as if it was production from the Prudhoe Bay Unit and allocation of that production to RIK and RIV components, notwithstanding my earlier letters to ARCO requesting that you revise those nominations to reflect that the Pt. McIntyre production is not part of the Prudhoe Bay Unit and that the state has made no RIK nominations affecting that anticipated production.

Based upon our conversation, I understand that ARCO intends to reply to my earlier letters, but that it has not yet coordinated that reply with its partners at Pt. McIntyre. In the meantime, I wanted to confirm my understanding of one specific portion of our conversation. You stated that, should the application to form the Pt. McIntyre Participating Area within an expanded Prudhoe Bay Unit Area not be approved, these nominations really will not be an issue because the Pt. McIntyre owners do not intend to tender any Pt. McIntyre oil to TAPS absent approval by the state of the application. As we discussed further in our conversation, I believe it is important to confirm this understanding because otherwise the state would need to notify Alyeska of a potential dispute over ownership of oil being tendered to TAPS.

Exhibit 4

I believe that I have accurately stated the substance of this portion of our conversation. If I have it wrong, please let me know so that, if necessary, I can promptly notify TAPS.

Sincerely,

Jim

James E. Eason
Director

cc: Glenn A. Olds, Commissioner, Department of Natural Resources
Harry Noah, Commissioner Designee, Department of Natural Resources
Bruce Botelho, Deputy Attorney General, Department of Law
Patrick Coughlin, Assistant Attorney General, Department of Law
Gayle Simmons, Vice President in Refining, Tesoro Alaska, San Antonio, Texas
Mike Welch, Senior Accounting Supervisor, Mapco Alaska, North Pole, Alaska

060393ch.je

ARCO Alaska, Inc.
Legal Department
Post Office Box 100360
Anchorage, Alaska 99510
Telephone 907 265 6541

Colin C. Howard
Vice President and
Chief Counsel

RECEIVED

June 17, 1993

Mr. James E. Eason
Director
Division of Oil and Gas
Alaska Department of Natural Resources
P.O. Box 107034
Anchorage, AK 99510

RE: Point McIntyre Production Allocation/Offtake Schedule

Dear Mr. Eason:

This confirms our earlier conversation concerning the commingled production forecast for the Lisburne Production Center. As Operator, ARCO believes that it has no alternative but to continue to issue such forecasts, including projections of Point McIntyre production. Such forecasts allow all owners, including the State of Alaska and its RIK purchasers, to be able to protect their rights to have access to TAPS.

Such access to TAPS will be desirable in the event the State approves the Application to expand the Prudhoe Bay Unit and create a Point McIntyre Participating Area.

As an Point McIntyre Working Interest Owner, ARCO believes that it has no alternative but to pursue expansion of the Prudhoe Bay Unit and creation of a Point McIntyre Participating Area. As we have discussed, the sharing agreements required to utilize Prudhoe Bay Unit facilities would be greatly complicated, if not make impossible, if such agreements were for a non-unit operation.

Additionally, dividing commingled production into different nominations to TAPS will create perpetual imbalances between the Working Interest Owners and the State and its RIK purchasers due to the nomination procedures imposed by the tariffs approved by FERC and the APUC. Separate nominations would also greatly complicate quality bank payments with respect to RIK purchasers which will only be made worse if any changes are made to the quality bank in the current proceedings.

Exhibit 5

With respect to the effect TAPS tariffs nomination procedures have on divided commingled production, we do not believe that a State challenge to those procedures would result in any change simply for the lack of any practical solution. The potential for such problems is created by the approval of commingling upstream of TAPS, not the tariffs.

With respect to Point McIntyre field start-up and actual delivery of its production to TAPS, ARCO believes that the State can prevent such start-up and related deliveries by withholding final or temporary approvals. We do not believe that any such withholding of approvals and resulting delay of Point McIntyre start-up would be in the best interests of any party, including the State.

As I mentioned to you, ARCO hopes that the State will preserve the option for a Point McIntyre start-up as part of an expanded Prudhoe Bay Unit. The State can preserve such an option by advising its Prudhoe RIK purchasers as follows: First, that the Prudhoe RIK purchasers may or may not receive an allocation of Point McIntyre production. And second, that they should take whatever steps they deem desirable to protect their ability to receive such production in their TAPS nominations under those circumstances.

Please call if you have any questions or would like additional information.

Sincerely,

Colin C. Howard

Colin C. Howard

ARCO Alaska,
Post Office Box 100360
Anchorage Alaska 99510-0360
Telephone 907 265 6375

James D. Weeks
Senior Vice President

RECEIVED
JUL 9 1993
DIV. OF OIL & GAS

July 9, 1993

Mr. Harry Noah
Commissioner
Department of Natural Resources
P.O. Box 107034
Anchorage, Alaska 99510

Subject: Point McIntyre

Dear Commissioner Noah:

This letter is in response to the State's counterproposal relating to Point McIntyre interim approvals and project start-up which was faxed to us at the close of business on Friday, July 2. Although we are encouraged that the State shares the desire to "advance the project and to protect all parties interests... while preserving the State's and the Producers' administrative and legal rights and remedies," we are extremely disappointed with both the general approach and the specific substance of the State's counterproposal. Attached is a specific list of comments and questions which more fully addresses our concerns.

Because a delay in start-up is neither in the State's nor the owners' best interest, we would hope that the expansion of the Prudhoe Bay Unit (PBU) can be finalized with the State. If the State would explain its concerns regarding the start-up of Pt. McIntyre within the PBU along the concepts proposed in my fax of June 30, 1993, it would help us understand why the State believes that its rights and positions would not be preserved by our proposal, and why a counterproposal was deemed necessary.

In addition, the counterproposal suggests that we produce hydrocarbons as a "tract-by-tract operation" during the interim period. However, a "tract-by-tract operation," which is apparently neither a unit operation nor a lease operation, is not addressed or defined by State statute or regulation. Therefore, an entire "set of rules" or agreements would first need to be developed for the interim period. Defining new rules would not only be a complex and time-consuming process, but it would most likely add a new subset of legal disputes. In our proposal, the interim period is well defined by existing statutes, regulations, agreements and contracts which already govern the PBU.

Exhibit 6

Finally, the State's counterproposal does not meet the requirements specified by the Alaska Oil and Gas Conservation Commission Conservation Order 317, dated July 2, 1993, which requires the subject leases be in a unit prior to production. Our proposal satisfies this condition. The Division of Oil and Gas counterproposal does not. Under our proposal, Point McIntyre would be a unitized operation both during the interim period and after final resolution of the outstanding issues. Thus, we believe all State agencies' requirements for start-up will be met.

Harry, you said you would not deal with these issues under the time pressure of start-up. I respect and agree with that. It is unreasonable to expect us to behave any differently. Negotiating a new, separate unit agreement prior to start-up puts us in the same position you refuse to be in. The same issues in contention now will be in contention whether Pt. McIntyre is in an expanded PBU or a new unit. Not expanding the PBU now resolves nothing and only creates further delay. Something like my June 30, 1993 proposal is the only practical way to enable early production from Pt. McIntyre and preserve all parties' rights and obligations, and I urge you to accept it.

We look forward to discussing these issues with you in person.

Sincerely,

J. D. Weeks
Senior Vice President

Attachments

cc: J. E. Eason
J. E. Golden
J. W. Kiker
A. D. Simon