ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 8672
1532 SCOMM 57: SENATE SPECIAL COMMITTEE ON OIL & GAS, 1987-1988 1329

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SCOMM 57: SENATE SPECIAL COMMITTEE ON OIL & GAS, 1987-88

MEMBERSHIP:

SENATOR BETTYE FAHRENKAMP, CHAIR
SENATOR JACK COGHILL
SENATOR PAUL FISCHER

Established by Senate Resolve No. 3, 1987 (SR 4)

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Tommy M. Butler
Signature of Camera Operator

3/17/92
Date

SB

49

ALASKA STATE LEGISLATURE

SENATE SPECIAL COMMITTEE
ON OIL AND GAS

Senator Bettye Fahrenkamp
Chairman
Senator Jack Coghill
Senator Paul Fischer

P.O. Box V, State Capitol
Juneau, Alaska 99811
(907) 465-3834

M E M O R A N D U M

TO: Members, Senate Special Committee on Oil and Gas

FROM: Committee Staff

RE: Committee Meeting, March 31, 1987

DATE: March 30, 1987

On Tuesday, March 31, at 3:30 pm in the Beltz Room, the Senate Special Committee on Oil and Gas will hear SB 49, Relating to the waste of oil and gas.

The Alaska Oil and Gas Conservation Commission is an independent agency whose mandate is to conserve and prohibit the waste of oil and gas. For field conservation purposes, the commission has the authority to regulate the quantity and rate of oil and gas production. DNR also has a similar authority under AS 38.05.180(q).

Current statute, under Title 31, defines "waste" only in terms of physical waste. Several oil producing states, including Texas, Oklahoma, Louisiana, Kansas, and New Mexico, define "waste" to include economic waste. This provision protects the financial interests of the states by ensuring that royalty oil will not be produced at a time when poor market demand would result in an unreasonably low price. For the state of Alaska, this may expand our options for dealing with an oil price collapse during which the wellhead price for oil approaches zero.

Two important considerations will be the impacts of this proposal on oil producers and carriers and the ability of the commission to execute the policy with existing resources.

Introduced: 1/19/87 5-0285A
Referred: Oil and Gas, Labor & Commerce
Resources and Finance

IN THE SENATE BY KERTTULA

SENATE BILL NO. 49

IN THE LEGISLATURE OF THE STATE OF ALASKA

FIFTEENTH LEGISLATURE - FIRST SESSION

A BILL

For an Act entitled: "An Act relating to the waste of oil and gas."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

* Section 1. AS 31.05.170(14) is amended to read:

(14) "waste" [MEANS, IN ADDITION TO ITS ORDINARY MEANING, "PHYSICAL WASTE" AND] includes

(A) the inefficient, excessive, or improper use of, or unnecessary dissipation of, reservoir energy; and the locating, spacing, drilling, equipping, operating or producing of any oil or gas well in a manner <u>that</u> [WHICH] results or tends to result in reducing the quantity of oil or gas to be recovered from a pool in <u>the</u> [THIS] state under operations conducted in accordance with good oil field engineering practices;

(B) the inefficient above-ground storage of oil; and the locating, spacing, drilling, equipping, operating or producing of an oil or gas well in a manner causing, or tending to cause, unnecessary or excessive surface loss or destruction of oil or gas;

(C) producing oil or gas in a manner causing unnecessary water channeling or coning;

(D) the operation of an oil well with an inefficient gas-oil ratio;

(E) the drowning with water of a pool or part of a pool capable of producing oil or gas, except insofar as and to the extent authorized by the commission;

(F) underground waste;

(G) the creation of unnecessary fire hazards;

(H) the release, burning, or escape into the open air of gas, from a well producing oil or gas, except to the extent authorized by the commission;

(I) the use of gas for the manufacture of carbon black, except as provided in this chapter;

(J) the drilling of wells unnecessary to carry out the purpose or intent of this chapter;

(K) the production of oil or gas in excess of transportation facilities, market facilities, or reasonable market demand.

MODEL STATUTE

A FORM
FOR AN OIL AND GAS CONSERVATION STATUTE
1981

RECEIVED
Department of Law
APR 16 1983
Office of the Attorney General
Anchorage Branch
Anchorage, Alaska

Published and Distributed by:
INTERSTATE OIL COMPACT COMMISSION
Box 53127
OKLAHOMA CITY, OKLAHOMA 73152

MODEL STATUTE

Oil or Gas which is a common source of supply, or several such accumulations which by rule or order of the Commission are allowed to be produced on a commingled basis and are treated by the Commission as a common source of supply.

1.1.18 "Waste" means and includes:

(1) the inefficient, excessive, or improper use, or the unnecessary dissipation, of reservoir energy;

(2) the inefficient storing of Oil or Gas;

(3) the locating, drilling, equipping, operating, or producing of any Oil or Gas well in a manner that causes or tends to cause reduction in the quantity of Oil or Gas ultimately recoverable from a Reservoir under prudent and proper operations, or that causes or tends to cause unnecessary wells to be drilled, or that causes or tends to cause the loss or destruction of Oil or Gas either at the surface or subsurface.

(4) the production of Oil or Gas in excess of (a) transportation, marketing, or storage facilities; (b) Reasonable Market Demand; or (c) the amount reasonably required to be produced in

FROM LAW ANCH CIVIL 03/30/87 10:33 P. 3

the proper drilling, completing, testing, or operating of a well or otherwise utilized on the lease from which it is produced; and

(5) underground or above ground waste in the production or storage of Oil or Gas, however caused, and whether or not defined in other subdivisions hereof.

SECTION 2. WASTE PROHIBITED.

2.1 The Waste of Oil and Gas is prohibited.

SECTION 3. AUTHORITY OF THE COMMISSION.

NOTE: Provisions for the creation and form of an oil and gas conservation commission or the delegation of authority to some existing commission, or with respect to such subjects as selection of commissioners, what constitutes a quorum, selection and training of trial examiners and other staff, salaries and financing are considered to be separate matters that will vary materially in different states and are not included in this form. Procedural matters, such as notice and hearing requirements, rules of evidence, and rulemaking procedures are also not included. Many of these matters are already covered by state administrative procedures acts.

3.1 This Act shall apply to all lands located in the State, how-

FROM LAW ANCH CIVIL 03/30/87 10:34 P. 4

OTHER STATES WITH "MARKET DEMAND WASTE"

underground waste and surface waste, but these terms are not always defined.[5] Some of the statutes define waste as including market demand waste [5.1] and the abuse of correlative rights of landowners in the common source of supply.[5.2] Most of the modern statutes give an administrative agency the jurisdiction and authority necessary for their effective enforcement [5.3] and in addition give the

rado, Florida, Georgia, Illinois, Indiana, Kansas, Louisiana, Maryland, Michigan, Mississippi, Montana, Nebraska, Nevada, North Carolina, North Dakota, Oklahoma, Oregon, South Dakota, Tennessee, Texas, Washington, Wyoming and Alberta cited in footnote 2, supra.

5. See the Alabama, Arkansas, Colorado, Florida, Georgia, Illinois, Kansas, Michigan, Nebraska, Nevada, New Mexico, North Carolina, Oklahoma, Oregon, South Dakota, Tennessee, Texas, Washington and Wyoming cited in footnote 2, supra.

5.1 Ala.—Code 1940, Tit. 26, § 179 (25) I (12).

Ariz.—A.C.A.1939, § 11-1702.

Kan.—G.S.1949, 55-602 and 55-702.

La.—LSA-R.S. 30:3(1) (b).

Mich.—Comp.Laws 1948, § 319.2, 1 (1) (2) (3) and § 319.54.

N.M.—1941 Comp. § 69-203.

N.D.—Laws 1953, ch. 227, § 3, 1, c.

Okl.—52 Okl.St.Ann. §§ 86.2, and 86.3.

Tex.—Vernon's Ann.Civ.St. art. 6008, § 3(b) and art. 6014(j).

Wash.—Laws 1951, Ch. 146, § 3, 1(j).

Alberta—Rev.St.1942, ch. 66, § 2(1) (iv).

In Kansas and Michigan market demand waste is limited to the production of oil.

Mississippi Code 1942, § 6132-01 negatives the intent and purpose of the conservation act "to require or permit the proration or distribution of the production of oil and gas among the fields and pools of Mississippi, on the basis of market demand."

5.2 Ark.—Stats. § 53-109 I (3) defines waste as including:

"Abuse of correlative rights and opportunities of each owner of oil and gas in a common reservoir due to nonuniform, disproportionate, and unratable withdrawals; causing undue drainage between tracts of land."

For similar provision see

Ala.—Code 1940, Tit. 26, § 179(25) I (3).

Fla.—F.S.A. § 377.19(10) (k).

Ga.—Code Ann. § 43-702 I (3).

N.C.—G.S. § 113-389(I) (3).

5.3 Ala.—Code 1940, Tit. 26, § 180-32.

Ariz.—A.C.A.1939, § 11-1704.

Ark.—Ark.Stats. § 53-111.

Cal.—Public Resources Code, §§ 3200 to 3236, gives commissioners authority to supervise drilling and production operations.

Colo.—Laws 1951, ch. 220, §§ 7a and 8.

Fla.—F.S.A. § 377.2[illegible]

AW ANCH CIVIL 03/30/87 10:35 P. 6

ALASKA OIL + GAS CONSERVATION COMMISSION

land. The authority of the commission further applies to all land included in a voluntary cooperative or unit plan of development or operation entered into in accordance with AS 38.05.180(p). (§ 1 ch 158 SLA 1978; am § 32 ch 94 SLA 1980)

Sec. 31.05.030. Powers and duties of commission. (a) The commission has jurisdiction and authority over all persons and property, public and private, necessary to carry out the purposes and intent of this chapter.

(b) The commission shall investigate to determine whether or not waste exists or is imminent, or whether or not other facts exist which justify or require action by it.

(c) The commission shall adopt regulations and orders and take other appropriate action to carry out the purposes of this chapter.

(d) The commission may require

(1) identification of ownership of wells, producing leases, tanks, plants and drilling structures;

(2) the making and filing of reports, well logs, drilling logs, electric logs, lithologic logs, directional surveys, and all other subsurface information on a well drilled for oil or gas, or for the discovery of oil or gas, or for geologic information, and the required reports and information shall be filed within 30 days after the completion, abandonment, or suspension of the well;

(3) the drilling, casing and plugging of wells in a manner that will prevent the escape of oil or gas out of one stratum into another, the intrusion of water into an oil or gas stratum, the pollution of fresh water supplies by oil, gas or salt water, and prevent blowouts, cavings, seepages and fires;

(4) the furnishing of a reasonable bond with sufficient surety conditions for the performance of the duty to plug each dry or abandoned well or the repair of wells causing waste;

(5) the operation of wells with efficient gas-oil and water-oil ratios, and may fix these ratios;

(6) the gauging or other measuring of oil and gas to determine the quality and quantity of oil and gas;

(7) every person who produces oil or gas in the state to keep and maintain for a period of five years in the state complete and accurate records of the quantities of oil and gas produced, which shall be available for examination by the Department of Natural Resources or its agents at all reasonable times;

(8) the measuring and monitoring of oil and gas pool pressures;

(9) the filing and approval of a plan of development and operation for a field or pool in order to prevent waste, insure a greater ultimate recovery of oil and gas, and protect the correlative rights of persons owning interests in the tracts of land affected.

(e) The commission may regulate, for conservation purposes

(1) the drilling, producing and plugging of wells;

(2) the shooting and chemical treatment of wells;

(3) the spacing of wells;

(4) the disposal of salt water, nonpotable water and oil field wastes;

(5) the contamination or waste of underground water;

(6) the quantity and rate of the production of oil and gas from a well or property; this authority shall also apply to a well or property in a voluntary cooperative or unit plan of development or operation entered into in accordance with AS 38.05.180(p).

(f) The commission may classify wells as oil or gas wells for purposes material to the interpretation or enforcement of this chapter.

(g) When the commission finds sufficient likelihood of an unexpected encounter of oil, gas, or other hazardous substance as a result of well drilling in an area of the state, the commission may, by regulation, designate the area and specify a depth in the area as one in which wells or any boring into the soil in excess of the specified depth but not otherwise subject to this chapter are subject to the regulations and requirements adopted under this section. The designation of an area or specification of a depth under this subsection does not constitute a certification that no hazardous substance will be encountered in another area or at a lesser depth, and the state is not liable for any damages arising from such an unexpected encounter of a hazardous substance.

(h) The commission may take all actions necessary to allow the state to acquire primary enforcement responsibility under 42 U.S.C. 300h-4 (Safe Drinking Water Act of 1974, as amended, 42 U.S.C. 300f-300j), for the control of underground injection related to the recovery and production of oil and natural gas. (§ 4 ch 40 SLA 1955; am § 2 ch 75 SLA 1960; am § 1 ch 209 SLA 1970; am § 1 ch 87 SLA 1977; am §§ 1, 2 ch 160 SLA 1978; am § 1 ch 91 SLA 1984)

Effect of amendments. — The 1984 amendment added subsection (h).

Sec. 31.05.035. Confidential reports. (a) For all wells for which a permit to drill has been issued by the commission since January 3, 1959, the commission may require:

(1) the making and filing of reports, well logs, drilling logs, electric logs, lithologic logs, directional surveys, and all other subsurface information on a well drilled for oil or gas, or for the discovery of oil or gas, or for geologic information; and

(2) the filing of flow test information and all logs, except experimental logs and velocity surveys run on a well and not required by (1) of this subsection;

DNR's authority

of the lessees, in connection with the institution and operation of a cooperative or unit plan as the commissioner determines necessary or proper to secure the proper protection of the public interest. The commissioner may require oil and gas leases issued under this section to contain a provision requiring the lessee to operate under a reasonable cooperative or unit plan, and may prescribe a plan under which the lessee must operate. The plan must adequately protect all parties in interest, including the state.

(q) A plan authorized by (p) of this section, which includes land owned by the state, may contain a provision vesting the commissioner, or a person, committee, or state agency, with authority to modify from time to time the rate of prospecting and development and the quantity and rate of production under the plan. All leases operated under a plan approved or prescribed by the commissioner are excepted in determining holdings or control under AS 38.05.140. The provisions of this section concerning cooperative or unit plans are in addition to and do not affect AS 31.05.

(r) Producing acreage on a known geologic structure of a producing oil or gas field is excluded from chargeability as against the acreage limitation provisions of AS 38.05.140.

(s) When separate tracts cannot be individually developed and operated in conformity with an established well-spacing or development program, a lease, or a portion of a lease, may be pooled with other land, whether or not owned by the state, under a communization or drilling agreement providing for an apportionment of production or royalties among the separate tracts of land comprising the drilling or spacing unit when determined by the commissioner to be in the public interest. Operations or production under the agreement are considered as operations or production as to each lease committed to the agreement.

(t) The commissioner may prescribe conditions and approve, on conditions, drilling, or development contracts made by one or more lessees of oil or gas leases, with one or more persons, when, in the discretion of the commissioner, the conservation of natural resources or the public convenience or necessity requires it or the interests of the state are best served. All leases operated under approved drilling or development contracts and interests under them, are excepted in determining holding or control under AS 38.05.140.

(u) To avoid waste or to promote conservation of natural resources, the commissioner may authorize the subsurface storage of oil or gas whether or not produced from state land, in land leased or subject to lease under this section. This authorization may provide for the payment of a storage fee or rental on the stored oil or gas, or, instead of the fee or rental, for a royalty other than that prescribed in the lease when the stored oil or gas is produced in conjunction with oil or gas not previously produced. A lease on which storage is so authorized

Senate Special Committee
On Oil and Gas

SB 49 3/31/87 -

If This comes up again...

1) get fiscal note

2) define "reasonable market demand"

consider the possibility that a producer's field costs might decrease over time. In 1986, for example, Arco lowered its operating expenses in the Kuparuk field by 40% in response to lower oil prices.[5] However, the Industrial Commodities Index component of the field cost allowance formula does not fully reflect this decrease in operating expenses. The index also fails to reflect the changing economics of the petroleum industry as accurately as other indices, such as the Fuels and Related Products and Power Index. For example, the August 1986 Industrial Commodities Index was at 95% of the 1985 annual level, the August 1986 Fuels and Related Products and Power Index was at 69% of the 1985 annual level, and Fall 1986 operating expenses in the Kuparuk field were at 60% of the 1985 annual level. A situation may therefore occur in which a producer's field cost allowance will continue to rise under the settlement agreement with the state, even though actual field costs have decreased.

The legislature may wish to investigate the possibility of revising the field cost agreements for Prudhoe Bay and Kuparuk at such time as the operators of these units may seek to have the state revise other terms of their unit agreements. In the event that such action is taken, consideration should be given to reviewing several different indices as possible alternatives to the Industrial Commodities Index.

Economic Waste

The waste of oil and gas from field production in Alaska is prohibited under AS 31.05.095. Although Title 31 defines "waste" strictly in terms of physical waste, it may be in the state's best interest to also have the authority to prohibit economic waste. In this context, economic waste refers to production in excess of market demand.

The Alaska Oil and Gas Conservation Commission (AOGCC) is an independent quasi-judicial agency that is charged, in part, with determining whether physical waste from oil or gas production exists or is imminent, and preventing such waste from occurring. The commission, for field conservation purposes, is also provided with the authority to regulate the quantity and rate of oil and gas production. DNR has a similar authority to regulate production under AS 38.05.180(q).

Related charges of the AOGCC are to regulate well drilling and well injections, authorize the establishment of drilling units, and protect the correlative rights of lessees. The language establishing the statutory framework of the AOGCC is similar to that which established the Interstate Oil Compact Commission and conservation commissions in other oil producing states. The commission is funded by revenues from the oil and gas regulation and conservation tax (AS 43.57), which is levied upon producers at the rate of one-eighth of one cent per barrel of production.

Several states, including Texas and Oklahoma, define "waste" to include oil production that is surplus to reasonable market demand. This provision protects the financial interests of the states and other royalty owners by ensuring that royalty oil or gas will not be produced at a time when poor market demand would result in an unreasonably low price for the commodities. By incorporating a similar provision into Alaska state law, it may be possible to mitigate some of the negative effects that result from a condition of market surplus. With such a law in place, the state's options would be expanded for dealing with the type of situation that occurred in 1986, in which Saudi Arabia glutted the world market to such an extent that the reported wellhead value of some of the oil produced from the Milne Point field was zero.

Consideration must also be given to the possible adverse effects of limiting production. Potential impacts include financial difficulties that may be faced by oil producers and carriers by the temporary reduction of production levels, and the possibility that reduced production could be an influencing factor in the shut-in of a marginal oil field.

The following statutory language would expand the

definition of "waste" to include economic waste:

1. AS 31.05.170(14) is amended, and a new subsection (K) is added, to read:

(14) "waste" [MEANS], in addition to its ordinary meaning, ["PHYSICAL WASTE" AND] includes

(K) the production of oil or gas in excess of transportation or market facilities or reasonable market demand.

<u>Production Rates</u>

The state's ability to influence the quantity and rate of oil production could be an important component of the state's revenue strategy. By decreasing production rates when oil approaches a zero wellhead value, the state would be able to retain its royalty oil until prices rise. Decreasing production rates might be preferable to storing the oil, since this alternative does not have the direct costs associated with storage. As with underlifting and other storage methods, consideration must be given to the degree of likelihood that the price of oil will rise in the future. Consideration should also be given to the possible negative impacts that reduced production levels may have upon oil producers and carriers.

AS 38.05.180(q) provides that a unit plan may contain a provision vesting the commissioner of DNR, or a person, committee, or state agency with the authority to modify from time to time the quantity and rate of production under the plan. Unfortunately, the state has effectively waived this authority for Prudhoe Bay and Kuparuk by including a provision in the unit agreements that severely limits the state's power to curtail production rates for these fields. In order to enhance the state's authority over the quantity and rate of oil production in other units, AS 38.05.180(q) could be amended to require that future leases and unit plans allow the state to modify these rates. Further protection could be provided by establishing a minimum production price or value, below which the state's share of oil would not be produced.

A statutory requirement could also be enacted to provide that lease forms and unit agreements establish a price level below which the state's royalty oil would not be produced. In this manner, the state would not be forced to either sell its oil at an excessively low price or pay for storage costs during times of unreasonable market conditions. The Alaska Oil and Gas Conservation Commission may regulate the quantity and rate of oil and gas production under AS 31.05.030(e)(6), although this authority is granted for field conservation purposes only.

The following statutory amendments would remedy the problems outlined above, especially with regard to new leases:

1. AS 38.05.180(q) is amended to read:

(q) A <u>lease or a unit</u> plan <u>issued or</u> authorized by (f) or (p) of this section, which includes land owned by the state, <u>shall</u> [MAY] contain a provision vesting the commissioner, or a person, committee, or state agency, with authority to modify from time to time the rate of prospecting and development and the quantity and rate of production under the plan. All leases operated under a plan approved or prescribed by the commissioner are excepted in determining holdings or control under AS 38.05.140. The provisions of this section concerning cooperative or unit plans are in addition to and do not affect AS 31.05.

2. AS 38.05.180 is amended by adding a new subsection (aa) to read:

(aa) In order to prevent economic waste, a lease or a unit plan issued or authorized by this section shall contain a provision vesting the commissioner with the authority to reduce or suspend oil production when the reported price or value for production from the land issued under the lease or authorized by the unit plan is less than $1.00 per barrel at the well, or when there is no reasonable market for the oil. For the purposes of this section, the price or value of oil at the well is in addition to the producers' field cost

...ance, if any, and the $1.00 value is the June 1987 value ... adjusted according to a price index determined by the ...ment of Revenue. Notwithstanding (m) of this section, a ... shall not terminate or be forfeited by such reason of ...nsion, provided that the lessee resumes operations with... reasonable time after removal of such cause. The provi... of this section concerning cooperative or unit plans are ...tion to and do not affect AS 31.05.

. AS 31.05.110(q) is repealed and reenacted to read:

(q) In order to prevent economic waste, a unit plan is... authorized by this section shall contain a provision ... the commission with the authority to suspend oil pro... when the price or value of oil from the land contained ... unit plan is less than $1.00 per barrel at the well, or ...here is no reasonable market for the oil. For the pur... of this section, the price or value of oil at the well ...addition to the producers' field cost allowance, if any, ... $1.00 value is the June 1987 value, to be adjusted to ... index determined by the Department of Revenue.

. AS 31.05.110 is amended by adding a new subsection (r) ...ad:

(r) This section applies to all involuntary units formed ... state. Subsections (a) and (g) - (q) of this section ... to all voluntary units formed in the state and to a ...ntary cooperative or unit plan of development or operation ...red into in accordance with AS 38.05.180(p).

Endnotes

. Atlantic Richfield Co., 1985 Third Quarter Report, p. 6 & 11.

. Department of Revenue internal memorandum from Roger Marks, August 6, 1986, p. 1.

. The information in this section is largely based on the following document:

STATE OF ALASKA
DEPARTMENT OF LAW
OFFICE OF THE ATTORNEY GENERAL

RECEIVED
FEB 17 1977
Division of Oil and Gas Conservation
Anchorage

February 14, 1977

Mr. Hoyle Hamilton
Director, Division of
Oil and Gas Conservation
Dept. of Natural Resources
3001 Porcupine Drive
Anchorage, Alaska 99501

RE: ECONOMIC WASTE UNDER AS 31

Dear Hoyle:

You have asked if AS 31.05 permits the Conservation Committee to consider "economic waste" as well as physical waste. It is my conclusion that the Conservation Committee is allowed to consider economic factors in its establishment of conservation practices but that the term "economic waste" must be defined and the question related to a specific regulatory decision before a more meaningful legal opinion is possible.

I.

Brief History of Conservation Regulation

It will be helpful to an understanding of AS 31.05 to review briefly the history of oil and gas conservation regulation by states.* This is appropriate and useful because Alaska's conservation statute contains many of the same clauses and provisions found in the IOCC model statute and/or other state conservation statutes.

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*/ This review is taken principally from S. McDonald, Petroleum Conservation in the United States: An Economic Analysis (1971); see also, Interstate Oil Compact Commission, A Study of Conservation of Oil and Gas in the United States (1964).

Initial conservation legislation was designed to prevent damage to other resources caused by oil and gas production and to eliminate certain obvious and easily preventable losses of natural gas. These initial conservation statutes usually established regulations applicable to individual wells (rather than whole reservoirs) and prohibittad specific practices or conversely required certain specific practices, such as for example, requiring the proper casing and plugging of wells to prevent interchange of fluids among reservoirs or the contamination of ground water supplies, or to prevent natural gas leaks. Later regulatory statutes usually retained the specific prohibitions of the earlier statutes but also included a general prohibition against waste which was defined in broad terms (or more often undefined). Thus, many state conservation statutes (including Alaska's) contain something of a collection of specific prohibitions and some rather broad, but undefined limitations.*

Conservation legislation, no doubt, was necessary because some operators in their haste to produce oil, employed poor production techniques and disregarded the impact of those practices on other resources (e.g. on ground water). However, another consideration was even more significant. Multiple ownership of the land overlying oil reservoirs combined with the rule of capture** to create an overpowering incentive for each owner of a lease to produce as

*/ AS 31.05.020 provides: "The waste of oil and gas in the state is prohibited." "Waste" is defined by AS 31.05.170(11) which because of its length is attached as appendix A hereto.

**/ The rule of capture says that whoever produces the oil owns it, regardless of where it is located underground. <u>Railroad Commission v. Rowan & Nichols Oil Co.</u>, 310 U.S. 573 (1939).

much oil as rapidly as possible. This resulted in a number of production practices which frequently caused unnecessary capital expenditures and/or the loss of large quantities of oil. For example, since each producer was competing with other producers in the same reservoir, he would usually drill as many wells as possible and operate each well as long as possible. This meant that more wells would be drilled than were actually required to produce all the oil which could be produced from a reservoir; and even more significantly, it usually meant reservoir pressure would be rapidly depleted resulting in less total oil being produced from the reservoir than could have been produced if production had been coordinated. Similarly, large quantities of oil were lost in above ground earthen storage reservoirs which were used because they were the fastest and cheapest way to store the rapidly produced oil. The more modern regulatory statutes (those enacted or amended after 1930) were intended to give state regulators more power to control production practices so as to prevent losses of oil and gas, resulting from the competitive race to produce oil as rapidly as possible from each reservoir.

The methods of production control employed by various state regulators have involved a number of overlapping and/or alternative approaches. One of the earliest approaches and also one of the simplest and most widely accepted regulatory methods has been to control the number and spacing of wells. Every state which has a conservation statute expressly authorizes the control of well spacing.* A second method of regulation has been to control directly the quantity of oil and/or gas produced. In practice, this type of regulation has

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*/ IOCC, A Study of Conservation of Oil and Gas in the United States, at 180 (1964).

taken two distinct forms, each of which will be discussed in greater detail below. A third method of regulation has been to authorize voluntary or compulsory unitization, and a fourth method of regulation has been to require the use of secondary recovery techniques. Many state statutes authorize one or more of these methods (several authorize all four methods), with individual states relying to varying degrees upon each method.

Direct Control of Production and "Economic Waste"

In the early years of the industry, the price of oil often was very low because producers, in their haste to capture as much oil as possible, frequently produced oil far in excess of market demand. Low prices, of course, meant little profit for the industry and also little revenue for those states which depended heavily on royalty payments and taxation of the oil industry for their income. Out of this situation emerged the concept of "economic waste", that is, the production of oil (or gas) in excess of market demand. In 1915 the Oklahoma conservation statute was amended to prohibit "economic waste" (which was not defined) and on the basis of that language, the Oklahoma regulatory agency adopted a regulatory scheme which allowed the agency to establish a statewide production limit and allocate production back to each well so that total production would not exceed that limit. Although this method of regulation effected prices (many persons charged it fixed prices), limiting production to market demand was found by the courts to be a valid method of preventing waste. Julian Oil and Royalties Co. v. Capshow, 292 P. 841 (1930); Champlin Refining Co. v. Oklahoma Corp. Commission, 286 U.S. 210 (1932). In Texas, a 1929 amendmendment to the conservation statute expressly stated that the prohibition against waste was not to be construed to mean "economic waste."

After the 1929 amendment, suits were filed challenging Texas's policy of limiting oil production to market demand. In one case, the court held Texas' regulatory approach valid despite the statutory reference to "economic waste." Danciger Oil and Refining Co. v. Railroad Commission, 49 S.W.2d 837 (1932). In a second case, however, the court held that the Railroad Commission's orders were intended to prevent "economic waste", and that this was in violation of the 1929 amendment. Alfred Macmillan v. Railroad Commission, 51 F.2d 400 (1931). In response to the MacMillan decision, the Texas legislature repealed the reference to "economic waste" and authorized the prohibition of "production of crude petroleum oil in excess of transportation or market facilities or reasonable market demand". Since the MacMillan case, the practice has been to avoid use of the term "economic waste" in conservation statutes.* Rather those states which employ a market demand method of production control have adopted such a regulatory policy through the use of language similar to that in the Texas statute.**

In the light of the above legal history, it is my conclusion that the term "economic waste", when used in reference to oil and gas conservation practices, is best understood to mean regulation which limits production to market demand.***

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*/ Only four state statutes use the term "economic waste." The Oklahoma and Kansas statutes each prohibit "economic waste", while the statutes of Illinois and Kentucky prohibit limitation of production to prevent or control "economic waste." IOCC, at 188-89.

**/ Ibid. at 176-79.

***/ One commentator has written: "Despite its apparent breadth, the term 'economic waste' is usually employed narrowly to mean the sale of oil or gas at a price below full cost or actual value and/or the use of oil or gas in ways which fail fully to exploit its intrinsic value". S. McDonald, Petroleum Conservation in the United States: An Economic Analysis 127 (1971).

II.

While the above discussion answers the question you have asked, I believe it might be helpful to discuss "economic waste" as the term might be defined or perceived by others. This discussion, because it is unrelated to any particular regulatory problem is general.

Direct Production Control and

the Maximum Efficient Rate of Production

In those states which do not employ a market demand method of production regulation, production is regulated on a reservoir-by-reservoir basis, with total production from a reservoir being limited to the maximum efficient rate (MER). Typically, the MER is determined with respect to engineering factors rather than economic considerations. Thus, the MER is that rate which will maximize the total output of oil (in an oil reservoir). A rate which causes total oil production to diminish (because, say reservoir pressure is dissipated too rapidly) will be in excess of the MER and will not be allowed. Once the MER is established, shares of production are allocated to each producer and/or well.

Although in practice, engineering considerations have dominated the determination of the MER, it is clearly possible that economic criteria could equally be used as the efficiency criteria. If this were done, the regulatory agency might establish rates designed to maximize total present value rather than total output. Thus, at a time of declining real prices for oil (or perhaps ever slowly rising prices) the regulator might well determine that the MER was at a rate which sacrificed future oil production for increased present production.*

There is certainly nothing express in AS 31.05 which would prevent the Conservation Committee from implementing production control using economic, rather than engineering criteria, to determine the MER. Indeed, words such as "unnecessary", "inefficient", and "excessive" might well connote economic criteria (at least to an economist) rather than engineering criteria. Nevertheless, I believe use of economic criteria, rather than engineering criteria, would represent a drastic change in regulatory practice in Alaska (and anywhere else for that matter) and thus, should only be undertaken in response to clear legislative directive in the form of amendments to the conservation statute.

Having noted that the regulatory practice in Alaska and elsewhere is to use engineering, rather than economic criteria to determine the MER, it should not go unstated that economic considerations are involved in many conservation decisions at least in a gross sense. For example, where the Conservation Committee is considering whether to require a water injection program, it certainly must compare the cost

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*/ The most striking difference between the use of engineering criteria and economic criteria may occur where a reservoir contains both oil and non-associated gas, and the production of one results in a diminshment of the other which can be produced. In that case, engineering criteria might call for maximization of total hydrocarbons (BTU's) while economic criteria would call for consideration of the present and probable future value (price) of each and maximization of the present value.

It should be noted that this is <u>not</u> the regulatory problem you face with the Prudhoe Bay field, since (based on my understanding) hydrocarbon production can be maximized provided gas production is held within reasonable bounds (which bounds may be zero if water flood is not employed; however, in that event, the field can be blown down once oil production ceases). Thus, if one is willing to indulge the assumption that gas prices will increase at a rate at least equal to the discount rate, the MER will be the same using either engineering or economic criteria.

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of such a program with the expected increase in recovered hydrocarbons. In doing so, the Conservation Committee need not adopt the economic criteria used by the producers, thus, a water injection program which the producer did not wish to undertake because the rate of return was too small (in their opinion) might still be required by the Conservation Committee. However, in the extreme case, where costs greatly exceeded any possible economic benefits to be derived, constitutional limitations likely would prevent the Committee from requiring an injection program.

Unitization of a Reservoir

One commentator has concluded that state conservation statutes "should require unitization of every oil reservoir within a reasonable time following discovery", and that such a statute "should supplant all present regulations (e.g. of well spacing and production rates) except those designed to protect other resources from damage by oil operations."* The conclusion is incorrect because it embodies a false assumption (which will be discussed below) but it nevertheless highlights an important consideration. That is, by eliminating the competition among producers of oil from a reservoir, one eliminates most of the incentive to engage in "wasteful" practices. In a unitized reservoir, all producers will be better off if production is maximized.

If a unitized reservoir was unregulated, production rates would be determined in accordance with procedures adopted by the unit participants. In such case, one would expect the unit participants acting as profit maximizing entities to produce the reservoir in a fashion which

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*/ S. McDonald, Unit Operation of Oil Reservoirs as an Instrument of Conservation, 49 Notre Dame Lawyer 305 (1973).

maximized the reservoir's present value.* Such rate of production likely would not correspond to the MER as determined by engineering principles. The public's interest ~~interest~~ in the production of nonrenewable oil and gas resources will correspond exactly with the producers' interest only in the hypothetical world of economists where competition is infinite and institutional constraints non-existent. In practice, the public's interest may be served by requiring the operators of a unitized reservoir to operate at a rate different from that which they would choose on their own. For example, the unit operators may decide against fluid injection because the anticipated rate of return is too low (in their view). The public's interest, however, might best be served by requiring an injection program. Or to give another example, where oil prices are controlled, maximization of present value by the producers likely will run counter to the public's interest.

Regulators of unitized fields have in the past required maximization of hydrocarbons while considering at least in gross terms economics factors. As before, regulators could well require maximization of other objective criteria. However, I would not advise such a course of action without clear Legislative direction in the form of amendments to the present conservation statute.

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*/ For various reasons in practice production rates may not be such as to maximize present value. For example, integrated producers may be facing crude shortages and willing to sacrifice future revenues while others may face a glut situation. The actual rate may represent a compromise. Some producers may want to hold back production to speculate on future market conditions, while others may prefer to follow less venturesome corporate policies. In short, producers may each have different discount rates.

Sincerely,

AVRUM M. GROSS
ATTORNEY GENERAL

Frederick H. Boness

By:
Frederick H. Boness
Assistant Attorney General

FHB:bvd

IV. REPRESENTING LANDOWNERS BEFORE OIL AND GAS CONSERVATION COMMISSIONS

A. Introduction

Oil and gas conservation commissions are charged with implementing and enforcing the public policy of preventing the waste of oil and gas, as expressed in legislative enactments, and protecting the correlative rights of persons owning interests in oil and gas, as required under the United States Constitution and the constitutions of many states.[338] The following is a primer of oil and gas conservation law and a brief discussion of the role of a lessor's attorney in oil and gas conservation proceedings.[339] Much more can and should be written to assist attorneys in effectively representing lessors before conservation commissions.

[338] For example, N.D. Cent. Code § 38-08-01(1980) provides:

> It is hereby declared to be in the public interest to foster, to encourage, and to promote the development, production, and utilization of natural resources of oil and gas in the state in such a manner as will prevent waste; to authorize and provide for the operation and development of oil and gas properties in such a manner that a greater ultimate recovery of oil and gas be had and that the correlative rights of all owners be fully protected. . . .

[339] For more information on this subject *see* Balkovatz, "Practice and Procedure Before Oil and Gas Commissions—Some Nuts and Bolts," 25 *Rocky Mt. Min. L. Inst.* 14-1 (1979) [hereinafter cited as Balkovatz]; McClintock, "Presenting a Case Before a State Conservation Commission," 15 *Rocky Mt. Min. L. Inst.* 243 (1969) [hereinafter cited as McClintock]; Robinson, "Procedures for Establishing a Drilling Unit", 2 *Rocky Mt. Min. L. Inst.* 353 (1956); Williams & Porter, "Practice Before the Wyoming Oil and Gas Conservation Commission," 10 *Land & Water L. Rev.* 353 (1975) [hereinafter cited as Williams & Porter] These articles are geared toward assisting the attorney who represents an operator, but they may be of help to the lessor's attorney as well.

B. A Primer on Oil and Gas Conservation

1. *Spacing and the Prevention of Waste (Market Demand Prorationing)*

The early belief about the nature of oil and gas was that it flowed beneath the surface in a sporadic and unpredictable manner. Early court cases treated oil and gas as if it were a wild animal[340] capable only of being "captured" and "reduced" to ownership by virtue of actual possession.[341] These views brought about a central principle of oil and gas law—the "rule of capture." Simply stated, the rule of capture allows a mineral owner the unqualified right to drill and capture as much oil and gas as he could reduce to possession, notwithstanding the fact that some of the oil and gas may have migrated from the lands of another. The remedy for neighboring landowners was to do likewise.[342]

As a result of these early beliefs and legal theories regarding the nature of oil and gas and the rule of capture, many early oil fields were developed by drilling wells as close together as physically possible. This rapid and unregulated development had several adverse effects. Produced oil was "wasted" at the surface due to a proliferation of wells, pipes, and tanks. More significantly, reservoir pressure (also called reservoir energy), which causes the natural flow of oil to the surface, quickly dissipated and field production rapidly declined. Finally, production of oil far exceeded the demand, causing rapid price declines. Fewer wells would have preserved field pressures, caused less physical waste of oil at the surface, supplied oil more in response to actual de-

[340] *See* State v. Ohio Oil Co., 150 Ind. 21, 49 N.E. 809 (1898).

[341] *See* Kelly v. Ohio Oil Co., 57 Ohio 317, 49 N.E. 399 (1897).

[342] *See* Stephens County v. Mid Kansas Oil & Gas Co., 113 Tex. 160, 254 S.W. 290 (1923).

mand, and returned more oil for each dollar invested in drilling.[343]

When the oil industry was on the verge of economic collapse in the 1930's due to excessive and wasteful production practices, states began to regulate production from oil fields. State legislatures established oil and gas "conservation" commissions or boards to regulate production.[344] The goal of these bodies was to limit oil production so that demand and supply would balance at a point that would prevent economic waste or, in other words, the collapse of the industry due to the inability to make a profit. This limiting of production was called "market demand prorationing." This regulatory policy was based, essentially, on the premise "more wells, more oil,"[345] but the number of wells and the production from the wells was limited so that the price of oil would not fall below the break-even point for well operators. "Well spacing units," which provided a minimum area for a well, typically ten acres, were created and production "allowables" were established as the benchmarks of market demand prorationing.[346]

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[343] *See generally* Interstate Oil Compact Commission, *A Study of Conservation of Oil and Gas* (I.O.C.C. 1964); Berger & Anderson, *Modern Petroleum, A Basic Primer of the Industry* (P.P.C. 1978); O'Neil, "A Mad Rush For Black Gold," *The End And the Myth* (Time-Life 1979).

[344] In order to assure a nation-wide conservation effort and to prevent federal preemption, producing states entered into a compact, the Interstate Oil Compact Commission, which has been approved by Congress.

[345] Williams, "Well Spacing—A Reappraisal," 1957-58 *ABA Mineral and Natural Resources Law Section* 44, 46 [hereinafter cited as Williams, "Well Spacing"]

[346] The need for market demand prorationing greatly declined after the Arab Oil Embargo in 1973 Some conservation commissions still prorate to control the flaring of gas and because of limited refinery capacities, limited pipeline capacities, excess supplies in some marketing areas, and other reasons. Prorationing hearings can be very controversial primarily because several methods for computing well "allowables" are possible.

In addition, conservation laws prohibit common purchasers of crude oil from discriminating against any producer or royalty owner. These laws were promulgated to stop large integrated oil companies from monopolizing the produc-

As the oil industry grew, so did scientific knowledge about the nature of oil and gas. Typically, oil and gas are found in reservoir "traps" and remain stagnant until disturbed by a sudden change in pressure such as a drill bit penetrating the "trap." Thus, oil does not flow sporadically and unpredictably, as once thought. Second, it was found that reservoir pressure and the strata's permeability and porosity greatly affect the ability to extract the oil. These factors are very significant in determining how many acres a single well can efficiently and effectively drain.

This increased scientific knowledge resulted in a change in regulatory policy. No longer were the size of well spacing units determined solely by how many wells a given field could economically support. Rather, well spacing units were established on the basis of how many wells would be needed to "efficiently and effectively drain" a field. Geologists and petroleum engineers found that one well, under the right conditions, could drain a large area. The old adage, "more wells, more oil," was discarded; instead, scientists recognized that more wells may mean less oil due to rapid declines in reservoir pressures.

Today, "waste" means more than producing oil and gas at an economic loss and losing oil and gas at the surface. Waste now includes the drilling of "unnecessary" wells and the waste of oil and gas in the ground. Drilling unnecessary wells is an economic waste of investment capital and actually decreases the ultimate recovery of oil and gas from a field due to resulting rapid declines in reservoir energy. As a result, wider spacing patterns are

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tion and marketing of oil. Under these laws, purchasers have to buy a fair share of production from each producer. This is commonly called "ratable taking."

THE LAW
OF
OIL AND GAS

A TREATISE COVERING
THE LAW RELATING TO THE PRODUCTION OF OIL AND GAS FROM PUBLIC AND PRIVATE LANDS AND THE TRANSPORTATION THEREOF

WITH

STATUTES AND REGULATIONS

FORMS

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Volume 1
Sections 1-86

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§ 85.049. Hearing.

(a) On verified complaint of any person interested in the subject matter that waste of oil or gas is taking place in this state or is reasonably imminent, or on its own initiative, the commission, after proper notice, may hold a hearing to determine whether or not waste is taking place or is reasonably imminent and if any rule or order should be adopted or if any other action should be taken to correct, prevent, or lessen the waste.

(b) The hearing shall be held at the time and place determined by the commission.

§ 85.050. Procedure at hearing.

(a) At the hearing, interested parties shall be entitled to be heard and to introduce evidence and require the attendance of witnesses.

(b) The production of evidence may be required as provided by law.

§ 85.051. Adoption of rule or order.

If the commission finds at the hearing that waste is taking place or is reasonably imminent, it shall adopt a rule or order in the manner provided by law as it considers reasonably required to correct, prevent, or lessen the waste.

§ 85.052. Compliance with rule or order.

From and after the promulgation of a rule or order of the commission, it is the duty of each person affected by the rule or order to comply with it.

§ 85.053. Distribution, proration, and apportionment of allowable production.

(a) If a rule or order of the commission limits or fixes in a pool or portion of a pool the production of oil, or the production of gas from wells producing gas only, the commission shall distribute, prorate, or otherwise apportion or allocate the allowable production among the various producers on a reasonable basis.

(b) When, as provided in Subsection (b) of Section 85.046 or Subsection (b) of Section 86.012 of this code, as amended, the commission has permitted production by commingling oil or gas or oil and gas from multiple stratigraphic or lenticular accumulations of oil or gas or oil and gas, the commission may distribute, prorate, apportion, or allocate the production of such comminowned properties in any pool be unitized under one management, control, or ownership;

(8) surface waste or surface loss, including the temporary or permanent storage of oil or the placing of any product of oil in open pits or earthen storage, and other forms of surface waste or surface loss including unnecessary or excessive surface losses, or destruction without beneficial use, either of oil or gas;

(9) escape of gas into the open air in excess of the amount necessary in the efficient drilling or operation of the well from a well producing both oil and gas;

(10) production of oil in excess of transportation or market facilities or reasonable market demand, and the commission may determine when excess production exists or is imminent and ascertain the reasonable market demand; and

(11) surface or subsurface waste of hydrocarbons, including the physical or economic waste or loss of hydrocarbons in the creation, operation, maintenance, or abandonment of an underground hydrocarbon storage facility.

(b) Notwithstanding the provisions contained in this section or elsewhere in this code or in other statutes or laws, the commission may permit production by commingling oil or gas or oil and gas from multiple stratigraphic or lenticular accumulations of oil or gas or oil and gas where the commission, after notice and hearing, has found that producing oil or gas or oil and gas in a commingled state will prevent waste, promote conservation, or protect correlative rights.

§ 85.047. Exclusion from definition of waste.

The use of gas produced from an oil well within the permitted gas-oil ratio for manufacture of natural gasoline shall not be included in the definition of waste.

§ 85.048. Authority to limit production.

(a) Under the provisions of Subsection (10), Section 85.046 of this code, the commission shall not restrict the production of oil from any new field brought into production by exploration until the total production from that field is 10,000 barrels of oil a day in the aggregate.

(b) The commission's authority to restrict production from a new field under other provisions of Section 85.046 of this code is not limited by this section.

trolling a condition in any local area or preventing a violation in any local area, then on the complaint of a person that the same or similar conditions exist in some other local area and the promulgation and enforcement of the rule could be beneficially applied to that additional area, the commission shall determine whether or not those conditions do exist, and if it is shown that they do, the rule or order shall be enlarged to include the additional area.

§ 85.044. Exempt purchases.

The provisions of Sections 85.041 through 85.043 of this code do not apply to the purchase of products of oil if made by the ultimate consumer from a retail distributor of the products.

§ 85.045. Waste illegal and prohibited.

The production, storage, or transportation of oil or gas in a manner, in an amount, or under conditions that constitute waste is unlawful and is prohibited.

§ 85.046. Waste.

(a) The term "waste," among other things, specifically includes:

(1) operation of any oil well or wells with an inefficient gas-oil ratio and the commission may determine and prescribe by order the permitted gas-oil ratio for the operation of oil wells;

(2) drowning with water a stratum or part of a stratum that is capable of producing oil or gas or both in paying quantities;

(3) underground waste or loss, however caused and whether or not the cause of the underground waste or loss is defined in this section;

(4) permitting any natural gas well to burn wastefully;

(5) creation of unnecessary fire hazards;

(6) physical waste or loss incident to or resulting from drilling, equipping, locating, spacing, or operating a well or wells in a manner that reduces or tends to reduce the total ultimate recovery of oil or gas from any pool;

(7) waste or loss incident to or resulting from the unnecessary, inefficient, excessive, or improper use of the reservoir energy, including the gas energy or water drive, in any well or pool; however, it is not the intent of this section or the provisions of this chapter that were formerly a part of Chapter 26, Acts of the 42nd Legislature, 1st Called Session, 1931, as amended, to require repressuring of an oil pool or to require that the separately

gled separate multiple stratigraphic or lenticular accumulations of oil or gas or oil and gas as if they were a single pool; provided, however, that:

(i) the commingling and distribution, proration, apportionment, or allocation of separate accumulations with commission established discovery dates after January 1, 1940, and prior to June 1, 1945, shall not serve to expand, add to, or extend the vertical or areal extent of any single pool;

(ii) such commingling shall not cause the allocation of allowable production from a well producing from any separate accumulation or accumulations to be less than that which would result from the commission applying the provisions of Section 86.095 of this code to such accumulation or accumulations;

(iii) the allocation of the allowable for such commingled production shall be based on not less than two factors which the Railroad Commission shall take into account as directed by Section 86.089 of this code; and

(iv) No gas well in any field falling within the classification under Subdivision (i) above where commingled separate accumulations of gas are being prorated under the authority granted by this Subsection (b) shall be assigned an allowable in excess of its production during the most recent production period reported to the commission and in the absence of any reported production the assigned allowable shall not exceed the open-flow potential of such well as reported to the commission; provided, however, that the commission may, if it finds special conditions require such, make a greater assignment.

§ 85.054. Allowable production of oil.

(a) To prevent unreasonable discrimination in favor of one pool as against another, and on written complaint and proof of such discrimination, the commission may allocate or apportion the allowable production of oil on a fair and reasonable basis among the various pools in the state.

(b) In allocating or ascertaining the reasonable market demand for the entire state, the reasonable market demand of one pool shall not be discriminated against in favor of another pool.

(c) The commission shall determine the reasonable market demand of the respective pool as the basis for determining the allotments to be assigned to the respective pool so that discrimination may be prevented.

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commissioner may also provide for credits to be earned by persons performing geophysical work on state land, if that work is performed during the two seasons immediately preceding an announced lease sale and on land included within the sale area and the geophysical information is made public following the sale. Credits may not exceed 50 percent of the cost of the drilling or geophysical work. Credits may be used during a limited period established by the commissioner and may be assigned during that period. Credits may be applied against (1) oil and gas royalty and rental payments payable to the state or (2) taxes payable under AS 43.55. A credit may not exceed 50 percent of the payment toward which it is being applied. Amounts due the Alaska permanent fund (AS 37.13.010) shall be calculated before the application of credits under this subsection.

(j) To prolong the economic life of an oil and gas field, the commissioner shall adopt regulations for all bidding methods to allow reduction of royalty on leases within the field to compensate for increasing costs in the later stages of production decline. The commissioner may not grant a reduction of royalty until two years' initial production from the field has occurred and each lessee requesting the reduction has made a clear showing that the revenue from all hydrocarbons produced from the field is insufficient to produce a reasonable rate of return with respect to that lessee's total investment in the field.

(k) The commissioner shall define all terms and adopt all regulations necessary for a reasonable understanding and evaluation of a particular bidding method before the public announcement of the terms of proposed sale employing that method.

(*l*) Subject to the provisions of AS 31.05, the commissioner has discretion to enter into an agreement whereby, with the consent of the lessee, the state's royalty share of oil and gas production may be stored or retained in storage by the lessee, or the commissioner may enter into an agreement with one or more of the affected field lease holders to trade current royalty production from a field for a like amount, kind, and quality of future production, on the condition that the state receives back its stored or traded royalty share during the first half of the estimated field life or no later than 15 years after start of production, whichever is sooner.

(m) An oil and gas lease must cover a reasonably compact area not exceeding 5,760 acres, and may be for a maximum period of 10 years, except that the commissioner may issue a lease for a period not less than five years upon a finding that it is in the best interests of the state. An oil and gas lease shall be automatically extended if and for so long thereafter as oil or gas is produced in paying quantities from the lease or if the lease is committed to a unit approved by the commissioner. A lease issued under this section covering land on which there is a well capable of producing oil or gas in paying quantities does not expire because the lessee fails to produce oil or gas unless the lessee is allowed

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(m) Operations carried on under and in accordance with the plan of unitization shall be regarded and considered as a fulfillment of a compliance with all of the provisions, covenants and conditions, express or implied, of the several oil and gas leases upon lands included within the unit area, or other contracts pertaining to the development of it insofar as the leases or other contracts may relate to the pool or portion of it included in the unit area. Wells drilled or operated on any part of the unit area no matter where located shall for all purposes be regarded as wells drilled on each separately owned tract within the unit area.

(n) Nothing in this section or in any plan of unitization shall be construed as increasing or decreasing the implied covenants of a lease in respect to a common source of supply or lands not included within the unit area of a unit.

(o) The unit area of a unit may be enlarged to include adjoining portions of the same pool, including the unit area of another unit, and a new unit created for the unitized management, operation and further development of the enlarged unit area, or the plan of unitization may be otherwise amended, or the unit area contracted, all in the same manner, upon the same conditions and subject to the same limitations as provided with respect to the creation of a unit in the first instance.

(p) An aliquot of unit production may be underlifted or overlifted from a unit established under this chapter or AS 38.05.180(p) only when it does not create waste, except the commissioner may permit underlifting or overlifting for temporary periods for the purpose of accommodating extraordinary disruptions to an interest owner's production disposal system. Underlifted oil may be recovered by an interest owner at a daily rate not to exceed 10 percent of the owner's working or royalty interest share of daily production at the time of underlift recovery. This subsection applies to all units created after June 30, 1978.

(q) This section applies to all involuntary units formed in the state. Subsections (a) and (g) — (p) of this section apply to all voluntary units formed in the state and to a voluntary cooperative or unit plan of development or operation entered into in accordance with AS 38.05.180(p). (§ 7 ch 40 SLA 1955; am §§ 8 — 13, 17 ch 160 SLA 1978; am § 33 ch 94 SLA 1980)

Cross references. — For provisions regarding oil and gas leasing, see AS 38.05.180.

Legislative history reports. — For conference committee letter of intent relating to the 1978 repeal of subsection (d) (sec. 17, ch. 160, SLA 1978 — HB 815), see 1978 House Journal, p. 1720.

Collateral references. — Operator's or lessee's responsibility for production of oil

A FORM

FOR AN OIL AND GAS

CONSERVATION STATUTE

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Oil or Gas which is a common source of supply, or several such accumulations which by rule or order of the Commission are allowed to be produced on a commingled basis and are treated by the Commission as a common source of supply.

1.1.18 "Waste" means and includes:

(1) the inefficient, excessive, or improper use, or the unnecessary dissipation, of reservoir energy;

(2) the inefficient storing of Oil or Gas;

(3) the locating, drilling, equipping, operating, or producing of any Oil or Gas well in a manner that causes or tends to cause reduction in the quantity of Oil or Gas ultimately recoverable from a Reservoir under prudent and proper operations, or that causes or tends to cause unnecessary wells to be drilled, or that causes or tends to cause the loss or destruction of Oil or Gas either at the surface or subsurface.

(4) the production of Oil or Gas in excess of (a) transportation, marketing, or storage facilities; (b) Reasonable Market Demand; or (c) the amount reasonably required to be produced in

trolling a condition in any local area or preventing a violation in any local area, then on the complaint of a person that the same or similar conditions exist in some other local area and the promulgation and enforcement of the rule could be beneficially applied to that additional area, the commission shall determine whether or not those conditions do exist, and if it is shown that they do, the rule or order shall be enlarged to include the additional area.

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(1) operation of any oil well or wells with an inefficient gas-oil ratio and the commission may determine and prescribe by order the permitted gas-oil ratio for the operation of oil wells;

(2) drowning with water a stratum or part of a stratum that is capable of producing oil or gas or both in paying quantities;

(3) underground waste or loss, however caused and whether or not the cause of the underground waste or loss is defined in this section;

(4) permitting any natural gas well to burn wastefully;

(5) creation of unnecessary fire hazards;

(6) physical waste or loss incident to or resulting from drilling, equipping, locating, spacing, or operating a well or wells in a manner that reduces or tends to reduce the total ultimate recovery of oil or gas from any pool;

(7) waste or loss incident to or resulting from the unnecessary, inefficient, excessive, or improper use of the reservoir energy, including the gas energy or water drive, in any well or pool; however, it is not the intent of this section or the provisions of this chapter that were formerly a part of Chapter 26, Acts of the 42nd Legislature, 1st Called Session, 1931, as amended, to require repressuring of an oil pool or to require that the separately

owned properties in any pool be unitized under one management, control, or ownership;

(8) surface waste or surface loss, including the temporary or permanent storage of oil or the placing of any product of oil in open pits or earthen storage, and other forms of surface waste or surface loss including unnecessary or excessive surface losses, or destruction without beneficial use, either of oil or gas;

(9) escape of gas into the open air in excess of the amount necessary in the efficient drilling or operation of the well from a well producing both oil and gas;

(10) production of oil in excess of transportation or market facilities or reasonable market demand, and the commission may determine when excess production exists or is imminent and ascertain the reasonable market demand; and

(11) surface or subsurface waste of hydrocarbons, including the physical or economic waste or loss of hydrocarbons in the creation, operation, maintenance, or abandonment of an underground hydrocarbon storage facility.

(b) Notwithstanding the provisions contained in this section or elsewhere in this code or in other statutes or laws, the commission may permit production by commingling oil or gas or oil and gas from multiple stratigraphic or lenticular accumulations of oil or gas or oil and gas where the commission, after notice and hearing, has found that producing oil or gas or oil and gas in a commingled state will prevent waste, promote conservation, or protect correlative rights.

§ 85.047. Exclusion from definition of waste.

The use of gas produced from an oil well within the permitted gas-oil ratio for manufacture of natural gasoline shall not be included in the definition of waste.

§ 85.048. Authority to limit production.

(a) Under the provisions of Subsection (10), Section 85.046 of this code, the commission shall not restrict the production of oil from any new field brought into production by exploration until the total production from that field is 10,000 barrels of oil a day in the aggregate.

(b) The commission's authority to restrict production from a new field under other provisions of Section 85.046 of this code is not limited by this section.

§ 86.2. Waste of oil—Defined—Prohibited—Prevention—Protection of fresh water strata and oil or gas bearing strata.

The term "waste", as applied to the production of oil, in addition to its ordinary meaning, shall include economic waste, under-ground waste, including water encroachment in the oil or gas bearing strata; the use of reservoir energy for oil producing purposes by means or methods that unreasonably interfere with obtaining from the common source of supply the largest ultimate recovery of oil; surface waste and waste incident to the production of oil in excess of transportation or marketing facilities or reasonable market demands. The production of oil in the State of Oklahoma in such manner and under such conditions as to constitute waste as in this Act defined is hereby prohibited, and the Commission shall have authority, and is charged with the duty, to make rules, regulations, and orders for the prevention of such waste, and for the protection of all fresh water strata and oil or gas bearing strata encountered in any well drilled for oil or gas.

tr. 52

(Text continued on page 30-815)

A FORM FOR AN OIL AND GAS CONSERVATION STATUTE

by

T. MURRAY ROBINSON, *Chairman*, E. J. COYLE,
ROBERT E. HARDWICKE, GEORGE W. HAZLETT,
ROSS L. MALONE JR., BLAKELY M. MURPHY,
E. LELAND RICHARDSON, AND S. L. DIGBY

a Drafting Subcommittee of the Legal Committee, The Interstate Oil Compact Commission

The Interstate Oil Compact Commission, Oklahoma City, Oklahoma.

1950

as cycling of gas, the maintenance of pressure, and the introduction of gas, water, or other substances into producing formations; and (e) disposal of salt water and oil field wastes.

(3) *To limit and to allocate the production of oil and gas from any field, pool, or area.*

(4) *To classify wells as oil or gas wells for purposes material to the interpretation or enforcement of this Act.*

(5) *To promulgate and to enforce rules, regulations, and orders to effectuate the purposes and the intent of this Act.*

SECTION 3. *It shall be unlawful to commence operations for the drilling of a well for oil or gas without first giving to the Commission notice of intention to drill, or without first obtaining a permit from the Commission, under such rules and regulatins as may be prescribed by the Commission.*

SECTION 4. *A. The Commission shall limit the production of oil and gas to that amount which can be produced without waste, and which does not exceed the reasonable market demand.*

"shall limit production to amt produced w/o waste & does not exceed market dem.

B. Whenever the Commission limits the total amount of oil or gas which may be produced in the state, the Commission shall allocate or distribute the allowable production among the pools therein on a reasonable basis, giving, where reasonable under the circumstances to each pool with small wells of settled production, an allowable production which prevents the general premature abandonment of the wells in the pool.

C. Whenever the Commission limits the total amount of oil or gas which may be produced in any pool in this state to an amount less than that amount which the pool could produce if no restriction was imposed (which limitation is imposed either incidental to, or without, a limitation of the total amount of oil or gas produced in the state), the Commis-

A FORM
FOR AN OIL AND GAS CONSERVATION STATUTE
1959

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A FORM FOR AN OIL AND GAS CONSERVATION STATUTE

(1959 Revision)

Preface

In approving this form, neither the Legal Committee nor the Compact Commission is committed to, or necessarily recommends, all of the provisions of the form. For example, some states may not choose to provide for compulsory unitization or the forced pooling of separate interests in spacing units. Other states may not choose to adopt other provisions of the form. Suitable provisions covering all such subjects are, however, included for the information and use as a guide to any state desiring to consider or adopt legislation to include any or all of such subjects.

Title of Act

NOTE: Since the requirements for a title or caption of a statute vary materially in the different states and cannot properly be written until the provisions of a statute are settled, no suggestions are given with respect to a proper title or caption.

Declaration of Purpose

The prevention of Waste of Oil and Gas and the Protection of Correlative Rights are declared to be in the public interest. The purpose of this Act is to prevent such Waste and to Protect Correlative Rights.

SECTION 1. DEFINITIONS.

1.1 Unless the context otherwise requires, the terms defined in this section shall have the following meaning when used in this Act:

1.1.1 "Waste" means and includes:

(1) physical waste, as that term is generally understood in the oil and gas industry;

(2) the inefficient, excessive, or improper use, or the unnecessary dissipation of, reservoir energy;

(3) the inefficient storing of Oil or Gas;

(4) the locating, drilling, equipping, operating, or producing of any Oil or Gas well in a manner that causes, or tends to cause, reduction in the quantity of Oil or Gas ultimately recoverable from a Pool under prudent and proper operations, or that causes or tends to cause unnecessary or excessive surface loss or destruction of Oil or Gas;

(5) the production of Oil or Gas in excess of (a) transportation or marketing facilities; (b) Reasonable Market Demand; (c) the amount reasonably required to be produced in the proper drilling, completing, or testing of the well from which it is produced; or (d) Oil or Gas otherwise usefully utilized; except Gas produced from an Oil well or Condensate well pending the time when with reasonable diligence the Gas can be sold or otherwise usefully utilized on terms and conditions that are just and reasonable; and

(6) underground or above ground waste in the production or storage of Oil, Gas, or Condensate, however caused, and whether or not defined in other subdivisions hereof.

tion in a gas field because some producers desired to deplete the gas at a very low rate regardless of the reason.

When waste, market demand, and correlative rights are in conflict the Commission must determine which is to be given preference. If the decision of the Commission is supported by evidence, the courts cannot interfere.

The orders of the Commission, under consideration, are not subject to the objection that they do not properly protect correlative rights under the facts disclosed by the record.

[17] The appellees contend that the orders of the Commission violate the commerce clause of the federal constitution and the Natural Gas Act.

Our attention is called to the fact that the subject of regulating interstate commerce is committed by the United States Constitution to the control of the federal government. (Oklahoma v. Kansas Nat. Gas Co., 221 U.S. 229, 31 S.Ct. 564, 55 L.Ed. 716; Pennsylvania v. West Virginia, 262 U.S. 553, 43 S.Ct. 658, 67 L.Ed. 1117; and Pennsylvania Gas Co. v. Public Service Comm., 252 U.S. 23, 40 S.Ct. 279, 64 L.Ed. 434.) Also, that the states have no authority, even in the absence of federal legislation, to regulate sales of gas for transportation and resale in interstate commerce. (Missouri ex rel. Barrett v. Kansas Natural Gas Co., 265 U.S. 298, 44 S.Ct. 544, 68 L.Ed. 1027. Public Util. Comm. of Rhode Island v. Attleboro Co., 273 U.S. 83, 47 S.Ct. 294, 71 L.Ed. 549; and State Corp. Comm'n of Kan. v. Wichita Gas Co., 290 U.S. 561, 54 S.Ct. 321, 78 L.Ed. 500.) We are further informed that the states cannot so regulate under its police power as to place an undue burden on interstate commerce. (Dahnke-Walker Milling Co. v. Bondurant, 257 U.S. 282, 42 S.Ct. 106, 66 L.Ed. 239; and Lemke v. Farmers Grain Co., 258 U.S. 50, 42 S.Ct. 244, 66 L.Ed. 458.)

No one appears to question these general propositions of law. However, they are not applicable here. The Commission's orders are not directed to the pipeline companies. The pipeline companies are not required to do anything, neither are they restricted in any way. None of the pipeline companies, except Panhandle, claim they are not able to take enough gas under the Commission's order to meet their present market demands. Panhandle is before this court in support of the Commission's action.

The facts in this case present a much different situation than those which existed in Northern Natural Gas Co. v. State Corp. Comm'n of Kansas, 372 U.S. 84, 83 S.Ct. 646, 9 L.Ed.2d 601. In the Northern Natural Gas case the Commission's order was directed to the pipeline company in an attempt to force it to take gas ratably from the wells to which it was connected in the Kansas-Hugoton Field.

The Commission's orders now before us are addressed only to the producers. The producers are not complaining and the royalty owners are supporting the Commission's action. The Commission's orders in no way attempt to regulate the sale or transportation of gas. The Supreme Court of the United States clearly stated the applicable law in Champlin Rfg. Co. v. Corporation Commission, 286 U.S. 210, 52 S.Ct. 559, 76 L.Ed. 1062:

> "Plaintiff contends that the act and proration orders operate to burden interstate commerce in crude oil and its products in violation of the commerce clause. Const.U.S. art 1, § 8, clause 3. It is clear that the regulations prescribed and authorized by the act and the proration established by the commission apply only to production and not to sales or transportation of crude oil or its products. Such production is essentially a mining operation, and therefore is not a part of interstate commerce, even though the product obtained is intended to be and in fact is immediately shipped in such commerce. Oliver Iron Co. v. Lord, 262 U.S. 172, 178, 43 S.Ct. 526, 67 L.Ed. 929; Hope Gas Co. v. Hall, 274 U.S. 284, 288, 47 S.Ct. 639, 71 L.Ed. 1049; Foster Foun-

tain Packing Co. v. Haydel, 278 U.S. 1, 10, 49 S.Ct. 1, 73 L.Ed. 147; Utah Power & Light Co. v. Pfost, supra [286 U.S. 165, 52 S.Ct. 548, 76 L.Ed. 1038]. No violation of the commerce clause is shown." (286 U.S. p. 235, 52 S.Ct. p. 565, 76 L.Ed. 1062.)

Appellees contend:

"It is abundantly clear * * * that the jurisdiction over sales of natural gas for resale in interstate commerce pursuant to the Natural Gas Act is exclusively in the Federal Power Commission. The Natural Gas Act was passed pursuant to the Commerce Clause contained in the United States Constitution and obviously was intended to occupy the entire area—the area involved in the instant appeals."

The Natural Gas Act and the decisions do not support the contention. Congress has not occupied the field in the area of state control of the production of natural gas. The Natural Gas Act specifically exempts from its coverage the production or gathering of natural gas. (15 U.S.C.A. § 717b.)

In Panhandle Eastern Pipe Line Co. v. Public Service Comm'n, 332 U.S. 507, 68 S.Ct. 190, 92 L.Ed. 128, the court reviewed the legislative history of the Natural Gas Act and said:

"* * * Three things and three only Congress drew within its own regulatory power, delegated by the Act to its agent, the Federal Power Commission. These were: (1) the transportation of natural gas in interstate commerce; (2) its sale in interstate commerce for resale; and (3) natural gas companies engaged in such transportation or sale." (332 U.S. p. 516, 68 S.Ct. p. 195, 92 L.Ed. 128.)

The court further said:

"Moreover, this unusual legislative precision was not employed with any view to relieving or exempting any segment of the industry from regulation. The Act, though extending federal regulation, had no purpose or effect to cut down state power. On the contrary, perhaps its primary purpose was to aid in making state regulation effective, by adding the weight of federal regulation to supplement and reinforce it in the gap created by the prior decisions." (332 U.S. p. 517, 68 S.Ct. p. 195, 92 L.Ed. 128.)

The regulation of the production of gas was clearly left within the jurisdiction of the states.

[18] The appellees last contend that the orders of the Commission violate the fourteenth amendment to the United States Constitution which provides, "* * * nor shall any State deprive any person of life, liberty, or property, without due process of law; * * *" and article 1, section 10 which provides, "No State shall * * * pass any * * * Law impairing the Obligation of Contracts. * * *"

Appellee's contention appears to be bottomed on the proposition that they have contracts to purchase the gas produced from certain leases in the field and they therefore have the right to determine the allowable production therefrom through their nominations, without interference by the Commission. Also, that their gas purchase contracts have various provisions which may be affected if their ability to determine the allowables is disturbed.

Individuals cannot by private contracts destroy the right of the state to exercise reasonable police power for the welfare of the public. It has been said, "* * * that an exercise of public policy cannot be resisted because of conduct or contracts done or made upon the faith of former exercises of it, upon the ground that its later exercises deprive of property or invalidate those contracts. Louisville & Nashville Railroad Co. v. Mottley, 219 U.S. 467, 31 Sup.Ct. 265, 55 L.Ed. 297, 34 L.R.A. (N.S.) 671." (Thornton v. Duffy, 254 U.S. 361, 369, 41 S.Ct. 137, 65 L.Ed. 304.) (See, also, 16 C.J.S. Constitutional Law § 180-182, 913 and 917; Phillips Petroleum Co.

prior to the entry of such plea." (175 Kan. p. 885, 267 P.2d p. 489.)

For other decisions of like import see Uhock v. Hand, 182 Kan. 419, 424, 320 P.2d 794, and McGee v. Crouse, 190 Kan. 615, 617, 376 P.2d 792.

[5] A further claim advanced by appellant is that he did not commit the offense of burglary in the nighttime even though he was specifically charged in the information with that crime and entered a plea of guilty thereto. This claim lacks merit and cannot be upheld. Under our decisions the guilt or innocence of one accused or convicted of crime is not justiciable in a habeas corpus proceeding. See Fisher v. Fraser, 171 Kan. 472, 233 P.2d 1066, 29 A.L.R.2d 699; Martin v. Edmondson, 176 Kan. 374, 270 P.2d 791; Hartman v. Edmondson, 178 Kan. 164, 283 P.2d 397.

Appellant devotes much time and space to a charge regarding the failure of his court appointed counsel to faithfully, conscientiously, intelligently and honestly perform his obligations as his attorney in the Elk County district court. Except to say it was all based upon his own uncorroborated statements in the court below, and completely refuted by other facts and circumstances of record, we are not disposed to burden our reports with a detailed statement of the evidence adduced by him in support of this position.

[6] A further short and simple answer to this claim is that under our decisions (See, e. g., McGee v. Crouse, supra.), it is presumed an attorney appointed to represent an accused in a criminal case discharged all duties imposed upon him by our statute (G.S.1949, 62-1304), and this presumption is not overcome by the uncorroborated statements of the petitioner in a habeas corpus proceeding.

[7] Another answer, equally decisive, is to be found in our numerous decisions holding that the unsupported and uncorroborated statements of the petitioner in a habeas corpus proceeding do not sustain the burden of proof or justify the granting of a writ where—as here—the judgment rendered is regular on its face and entitled to a presumption of regularity and validity. For just a few of our cases so holding see Johnson v. Crouse, 191 Kan. 694, 697, 383 P.2d 978; Uhock v. Hand, 182 Kan. 426, 320 P.2d 800, supra; Prater v. Hand, 185 Kan. 405, 407, 345 P.2d 634; Engling v. Edmondson, 175 Kan. 885, 267 P.2d 489, supra.

In conclusion it may be stated that, after careful examination of a confusing and unsatisfactory record, we find nothing in this appeal which warrants or permits a conclusion the trial court erred in denying the application for a writ of habeas corpus and remanding the petitioner to the custody of the respondent.

Therefore such judgment must be and it is affirmed.

192 Kan. 2

COLORADO INTERSTATE GAS COMPANY, Appellee,

v.

The STATE CORPORATION COMMISSION of the State of Kansas, Southwest Kansas Royalty Owners Association, and Panhandle Eastern Pipe Line Company, Appellants, Cross-Appellants, and Cross-Appellees (two cases).

NORTHERN NATURAL GAS COMPANY, a corporation, Appellee,

v.

The STATE CORPORATION COMMISSION of the State of Kansas, Southwest Kansas Royalty Owners Association, and Panhandle Eastern Pipe Line Company, Appellants, Cross-Appellants, and Cross-Appellees (two cases).

Nos. 41515, 41516, 41555, 41556.

Supreme Court of Kansas.

Nov. 2, 1963.

Rehearing Denied Jan. 3, 1964.

Review proceedings challenged orders of the State Corporation Commission estabunderground waste and surface waste, but these terms are not always defined.[5] Some of the statutes define waste as including market demand waste [5.1] and the abuse of correlative rights of landowners in the common source of supply.[5.2] Most of the modern statutes give an administrative agency the jurisdiction and authority necessary for their effective enforcement [5.3] and in addition give the

rado, Florida, Georgia, Illinois, Indiana, Kansas, Louisiana, Maryland, Michigan, Mississippi, Montana, Nebraska, Nevada, North Carolina, North Dakota, Oklahoma, Oregon, South Dakota, Tennessee, Texas, Washington, Wyoming and Alberta cited in footnote 2, supra.

5. See the Alabama, Arkansas, Colorado, Florida, Georgia, Illinois, Kansas, Michigan, Nebraska, Nevada, New Mexico, North Carolina, Oklahoma, Oregon, South Dakota, Tennessee, Texas, Washington and Wyoming cited in footnote 2, supra.

5.1 Ala.—Code 1940, Tit. 26, § 179 (25) I (12).

Ariz.—A.C.A.1939, § 11-1702.

Kan.—G.S.1949, 55-602 and 55-702.

La.—LSA-R.S. 30:3(1) (b).

Mich.—Comp.Laws 1948, § 319.2, 1 (1) (2) (3) and § 319.54.

N.M.—1941 Comp. § 69-203.

N.D.—Laws 1953, ch. 227, § 3, 1, c.

Okl.—52 Okl.St.Ann. §§ 86.2, and 86.3.

Tex.—Vernon's Ann.Civ.St. art. 6008, § 3(h) and art. 6014(j).

Wash.—Laws 1951, Ch. 146, § 3, 1(j).

Alberta—Rev.St.1942, ch. 66, § 2(1) (iv).

In Kansas and Michigan market demand waste is limited to the production of oil.

Mississippi Code 1942, § 6132-01 negatives the intent and purpose of the conservation act "to require or permit the proration or distribution of the production of oil and gas among the fields and pools of Mississippi, on the basis of market demand."

5.2 Ark.—Stats. § 53-109 I (3) defines waste as including:

"Abuse of correlative rights and opportunities of each owner of oil and gas in a common reservoir due to nonuniform, disproportionate, and unratable withdrawals causing undue drainage between tracts of land."

For similar provision see

Ala.—Code 1940, Tit. 26, § 179(25) I (3).

Fla.—F.S.A. § 377.19(10) (k).

Ga.—Code Ann. § 43-702 I (3).

N.C.—G.S. § 113-389(I) (3).

5.3 Ala.—Code 1940, Tit. 26, § 189-32.

Ariz.—A.C.A.1939, § 11-1704.

Ark.—Ark.Stats. § 53-111.

Cal.—Public Resources Code, §§ 3200 to 3236, gives commissioners authority to supervise drilling and production operations.

Colo.—Laws 1951, ch. 220, §§ 7a and 8.

Fla.—F.S.A. § 377.22.

THE LAW
OF
OIL AND GAS

A TREATISE COVERING
THE LAW RELATING TO THE PRODUCTION OF OIL AND GAS FROM PUBLIC AND PRIVATE LANDS AND THE TRANSPORTATION THEREOF

WITH

STATUTES AND REGULATIONS

FORMS

BY

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Volume 1
Sections 1–86

KANSAS CITY, MO.
VERNON LAW BOOK COMPANY

Alberta—St.1957, c. 63, § 2(u), sets out eight acts and practices which are designated as "wasteful operations".

Sask.—Rev.St.1953, c. 327, §§ 2(1), 16(a), (b), (c), (d) and (e).

Utah—U.C.A.1953, 40-6-4(k) and (l).

5. Alaska.

Manitoba—St.1959, c. 38, § 57(*l*).

Utah.

5.1 **Ariz.**—A.R.S. § 27-501(20)(e).

Manitoba—St.1958, c. 38, § 57(m)(vii).

Neb.—Laws 1959, ch. 262, § 3(1).

Sask.—Rev.St.1953, c. 327, §§ 2(1), 16(e).

Utah—U.C.A.1953, 40-6-4(l). . . .

5.2 **Colo.**—C.R.S. '53, 100-6-3(12)(c).

Neb.—Laws 1959, ch. 262, § 3(1)(c).

Sask.—Rev.St.1953, c. 327, § 3, states that one of the purposes of the act is the protection of correlative rights.

5.3 **Alaska**—Laws 1955, ch. 40, § 4, 1 and 2, 3 and 4.

Alberta—St.1957, c. 63, § 17.

Ariz.—A.R.S. § 27-503.

Colo.—C.R.S. '53, 100-6-7 and 100-6-8.

Ky.—KRS 353.530, 353.540, 353.550 and 353.560.

Manitoba—St.1955, c. 45, § 59, as amended by St.1959, c. 38.

Md.—The section of the Maryland statute here cited was repealed by Maryland Laws 1956, ch. 88.

Neb.—Laws 1959, ch. 262, § 5(1)(2). Section 57-215, R.S.1959, was repealed by the 1959 conservation act.

Or.—ORS 520.045, 520.055 and 520.095.

Sask.—Rev.St.1953, c. 327 §§ 5 to 8.

S.D.—SDC 1960 Supp. 42.0706.

Tex.—Delhi-Taylor Oil Corp. v. Gregg, Civ.App.1960, 337 S.W.2d 216, affirmed Gregg v. Delhi-Taylor Oil Corp., 1961, 344 S.W.2d 411, 162 Tex. 26.

Holmes v. Delhi-Taylor Oil Corp., Civ. App.1960, 337 S.W.2d 479.

Delhi-Taylor Oil Corp. v. Gregg, Civ. App.1960, 337 S.W.2d 222.

State v. Harrington, 1966, 407 S.W.2d 467, certiorari denied 87 S.Ct. 977, 386 U.S. 944, 17 L.Ed.2d 874.

Utah—U.C.A.1953, 40-6-3 and 40-6-5.

6. **Alberta**—St.1957, c. 63, § 34.

Ariz.—A.R.S. §§ 27-515 and 27-516.

Colo.—C.R.S. '53, 100-6-15.

Ky.—KRS 353.670.

Manitoba—St.1955, c. 45, § 59, as amended by St.1959, c. 38.

Md.—The cited section of the Maryland statute was repealed by Laws 1956, ch. 88, § 3.

Neb.—Laws 1959, ch. 262, § 5(3).

Ontario—The Ontario Fuel Board Act, 1954, c. 63, § 39, repealed all previous existing oil and gas legislation, consisting of The Fuel Supply Act, The Natural Gas Conservation Act, The Natural Gas Conservation Amendment Act, 1951, The Natural Gas Conservation Amendment Act, 1952 and The Well Drillers Act. The Fuel Board Act does not define and prohibit the waste of oil and gas but has the power, the drilling and operation of wells and the production, transmission, distribution, supply and use of natural gas. In the exercise of these powers it has authority to make and enforce regulations respecting these matters. The statute does not expressly define waste of oil and gas, it authorizes the board to make regulations for the conservation of oil and gas, § 35, and provides, § 32, that any person who is wasting or causing natural gas to be wasted is guilty of a criminal offence.

Or.—ORS 520.095.

Sask.—Rev.St.1953, c. 327, § 18, authorizes the Minister of Mineral Resources to make orders necessary to carry out the provisions of the statute, and § 19 authorizes the Lieutenant Governor to make orders and regulations for the same purpose. Many of the acts and practices authorized to be regulated by these two administrative agencies are the same. Chapter 328, § 3, of The Well Drillers Act, also authorizes the Minister

THE LAW

OF

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WITH FORMS

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W. L. SUMMERS

Volume 1

Sections 1 to 86

1986

Cumulative Pocket Parts

BY

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ing gas from the field, except in cases not here pertinent, shall take ratably from each owner in proportion to his interest and upon such terms as may be agreed upon; that if no agreement can be reached then the price and terms shall be such as may be fixed by the Corporation Commission after notice and hearing. 52 Okla.Stats. §§ 23-25, 231-233 (1941). These sections explicitly authorize the order requiring Cities to take gas ratably from Peerless and at a specific price. In 1915, Oklahoma strengthened its gas conservation laws by

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authorizing regulation of production of gas from a common source when production is in excess of market demand. 52 Okla.Stats. §§ 239-240 (1941). The Commission was authorized to limit the gas taken by any producer to "such proportion of the natural gas that may be marketed without waste" as the natural flow of gas at the wells of such producer bears to the total natural flow of the common source. In authorizing such regulation, the legislature declared that it acted "so as to prevent waste, protect the interest of the public, and of all those having a right to produce therefrom, and to prevent unreasonable discrimination in favor of any one such common source of supply as against another." The Oklahoma Supreme Court construed the 1915 Act to permit the general order setting a minimum price in the field. It further ruled that economic waste was within the contemplation of the statute. Finally, with regard to state questions, it held that the orders did not violate the Oklahoma Constitution.

The Oklahoma court also concluded that the statutes so construed and the orders made thereunder do not violate the Federal Constitution on the grounds relied on by Cities Service. We agree.

II.

[3] The Due Process and Equal Protection issues raised by appellant are virtually without substance. It is now undeniable that a state may adopt reasonable regulations to prevent economic and physical waste of natural gas. This Court has upheld numerous kinds of state legislation designed to curb waste of natural resources and to protect the correlative rights of owners through ratable taking, Champlin Refining Co. v. Corporation Commission, 1932, 286 U.S. 210, 52 S.Ct. 559, 76 L.Ed. 1062, or to protect the economy of the state. Railroad Commission of Texas v. Rowan & Nichols Oil Co., 1940, 310 U.S. 573, 60 S.Ct. 1021, 84 L.Ed. 1368. These ends have been held to justify

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control over production even though the uses to which property may profitably be put are restricted. Walls v. Midland Carbon Co., 1920, 254 U.S. 300, 41 S.Ct. 118, 65 L.Ed. 276.

[4, 5] Like any other regulation, a price-fixing order is lawful if substantially related to a legitimate end sought to be attained. Nebbia v. People of State of New York, 1934, 291 U.S. 502, 54 S.Ct. 505, 78 L.Ed. 940 and cases therein cited. In the proceedings before the Commission in this case, there was ample evidence to sustain its finding that existing low field prices were resulting in economic waste and conducive to physical waste. That is a sufficient basis for the orders issued. It is no concern of ours that other regulatory devices might be more appropriate, or that less extensive measures might suffice. Such matters are the province of the legislature and the Commission.

We have considered the other arguments raised by appellant concerning Due Process and Equal Protection and find them similarly lacking in merit.

III.

[6-9] The Commerce Clause gives to the Congress a power over interstate commerce which is both paramount and broad in scope. But due regard for state legislative functions has long required that this power be treated as not exclusive. Cooley v. Board of Wardens of Port of Philadelphia, 1851, 12 How. 299, 13 L.Ed. 996. It is now well settled that a state may regulate matters of local concern over which federal authority has not been exercised, even though the regulation has some impact on interstate commerce. Parker v. Brown, 1943,

317 U.S. 341, 63 S.Ct. 307, 87 L.Ed. 315; Milk Control Board of Pennsylvania v. Eisenberg Farm Products, 1939, 306 U.S. 346, 59 S.Ct. 528, 83 L.Ed. 752; South Carolina State Highway Dept. v. Barnwell Bros., 1938, 303 U.S. 177, 58 S.Ct. 510, 82 L.Ed. 734. The only requirements consistently recognized have been that the regulation not discriminate against or place an embargo on interstate commerce, that it safeguard an obvious state interest, and that the local interest at stake outweigh

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whatever national interest there might be in the prevention of state restrictions. Nor should we lightly translate the quiescence of federal power into an affirmation that the national interest lies in complete freedom from regulation. South Carolina State Highway Dept. v. Barnwell Bros., supra. Compare Leisy v. Hardin, 1890, 135 U.S. 100, 10 S.Ct. 681, 34 L.Ed. 128, decided prior to the Wilson Act, 26 Stat. 313, 27 U.S.C.A. § 121, with In re Rahrer, 1891, 140 U.S. 545, 11 S.Ct. 865, 35 L.Ed. 572, decided thereafter.

[10] That a legitimate local interest is at stake in this case is clear. A state is justifiably concerned with preventing rapid and uneconomic dissipation of one of its chief natural resources. The contention urged by appellant that a group of private producers and royalty owners derive substantial gain from the regulations does not contradict the established connection between the orders and a state-wide interest in conservation. Cf. Thompson v. Consolidated Gas Utilities Corp., 1937, 300 U.S. 55, 57 S.Ct. 364, 81 L.Ed. 510.

[11, 12] We recognize that there is also a strong national interest in natural gas problems. But it is far from clear that on balance such interest is harmed by the state regulations under attack here. Presumably all consumers, domestic and industrial alike, want to obtain natural gas as cheaply as possible. On the other hand, groups connected with the production and transportation of competing fuels complain of the competition of cheap gas. Moreover, the wellhead price of gas is but a fraction of the price paid by domestic consumers at the burner-tip, so that the field price as herein set may have little or no effect on the domestic delivered price. Some industrial consumers, who get bargain rates on gas for "inferior" uses, may suffer. But strong arguments have been made that the national interest lies in preserving this limited resource for domestic and industrial uses for which natural gas has no completely satisfactory substitute. See generally, F. P. C., Natural Gas Investigation (1948); F. P. C. v. Hope Natural Gas Co., 1944,

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320 U.S. 591, 657–660, 64 S.Ct. 281, 313, 315, 88 L.Ed. 333 (dissenting opinion). Insofar as conservation is concerned, the national interest and the interest of producing states may well tend to coincide. In any event, in a field of this complexity with such diverse interests involved, we cannot say that there is a clear national interest so harmed that the state price-fixing orders here employed fall within the ban of the Commerce Clause. Parker v. Brown, supra; Milk Control Board of Pennsylvania v. Eisenberg Farm Products, supra. Nor is it for us to consider whether Oklahoma's unilateral efforts to conserve gas will be fully effective. See South Carolina State Highway Dept. v. Barnwell Bros., supra, 303 U.S. at pages 190–191, 58 S.Ct. at pages 516, 517, 82 L. Ed. 734.

H. P. Hood & Sons v. Du Mond, 1949, 336 U.S. 525, 69 S.Ct. 657, 93 L.Ed. 865, is not inconsistent with this result. The Hood case specifically excepted from consideration the question here raised, whether price-fixing was forbidden as an undue burden on interstate commerce. Moreover, the Court carefully distinguished Eisenberg, which approved price regulations even though applied to a producer whose entire purchases of milk went directly, without processing, into interstate commerce. The vice in the regulation invalidated by Hood was solely that it denied facilities to a company in interstate commerce on the articulated ground that such facilities would divert milk supplies needed by local consumers; in other words, the regulation discriminated against interstate commerce. There is no such problem here.

stranger, Kelley was the United States official who held petitioners in custody. Any person held by the United States should be able to repose confidence in the Government official entrusted with his custody. There are obvious reasons why this should be true in the case of the foreign born, less familiar with our customs than are our native citizens.

205

The Court also relies on the fact that the motions to set aside the judgments contain "no allegations of privity or any fiduciary relations existing" between petitioners and Kelley. Surely the liberalizing provisions of 60(b) should not be emasculated by common-law ideas of "privity" or "fiduciary relations." If relevant, however, I should think that the phrase "fiduciary relations" given its best meaning encompasses the relationship between petitioners and the official who held them in custody.

Finally, since the Court holds that the allegations of petitioners' motions were insufficient to justify the hearing of evidence by the District Court, I think it inappropriate for the Court to consider what purports to be its judicial knowledge of the cost of transcripts and the ability of litigants to file typewritten records and briefs. The motions refute any such knowledge on the part of these petitioners and I am satisfied that no such knowledge would be established if the District Court were permitted to try these cases.

The result of the Court's illiberal construction of 60(b) is that these foreign-born people, dependent on our laws for their safety and protection, are denied the right to appeal to the very court that held (on the Government's admission) that the judgment against their co-defendant was unsupported by adequate evidence. It does no good to have liberalizing rules like 60(b) if, after they are written, their arteries are hardened by this Court's resort to ancient common-law concepts. I would reverse.

340 U.S. 179

CITIES SERVICE GAS CO. v. PEERLESS OIL & GAS CO. et al.

No. 153.

Argued Nov. 9-10, 1950.

Decided Dec. 11, 1950.

The Peerless Oil & Gas Company filed an application with the Oklahoma Corporation Commission to require Cities Service Gas Company to connect its pipeline to applicant's gas well and to take and receive the natural flow of gas from applicant's well ratably with its taking gas from other wells of the Guymon-Hugoton Field in Texas County, Oklahoma, and to have minimum prices fixed. The State, on relation of Commissioners of the Land Office, intervened. The Supreme Court of Oklahoma, Welch, J., 220 P.2d 279, entered a judgment affirming the Commission's orders granting the application and the Cities Service Gas Company appealed. The Supreme Court, Mr. Justice Clark, held that the Commission's order did not contravene either the Fourteenth Amendment or Commerce Clause of the Federal Constitution.

Judgment affirmed.

1. Courts ⟹394(10, 15)

Where Supreme Court of Oklahoma upheld orders of Oklahoma Corporation Commission as against contentions that they contravened the Fourteenth Amendment and Commerce Clause of federal Constitution, a substantial federal claim had been duly raised and necessarily denied by highest state court, so that United States Supreme Court had jurisdiction thereof. 28 U.S.C.A. § 1257(2); U.S.C.A.Const. art. 1, § 8, cl. 3; Amend. 14.

2. Commerce ⟹57
Constitutional law ⟹211, 278(1)
Mines and minerals ⟹92.4

The statutory grant of power to Oklahoma Corporation Commission to regulate the taking of natural gas from a common source of supply so as to prevent waste, protect interest of the public, and of those having a right to produce therefrom is not invalid as violative of either due process or equal protection provisions

MICHIGAN
COMPILED LAWS
Annotated

Under Arrangement of the Official
Compiled Laws of Michigan

Sections
311.1 to 322.End

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reservoir or reservoirs containing such oil or gas, or both. The words "field" and "pool" mean the same thing when only one underground reservoir is involved; however, "field," unlike "pool," may relate to 2 or more pools.

(f) "Product" means any commodity or thing made or manufactured from oil or gas, and all derivatives of oil or gas, including refined crude oil, crude tops, topped crude, processed crude petroleum, residue from crude petroleum, cracking stock, uncracked fuel oil, fuel oil, treated crude oil, residuum, gas oil, naphtha, distillate, gasoline, casing-head gasoline, natural gas gasoline, kerosene, benzine, wash oil, waste oil, lubricating oil, and blends or mixtures of oil or gas or any derivatives thereof whether enumerated or not.

(g) "Owner" means the person who has the right to drill into and produce from any pool, and to appropriate the production either for himself or for himself and another or others.

(h) "Producer" means the operator, whether owner or not, of a well or wells capable of producing oil or gas or both in paying quantities.

(i) "Commission" means the commission of natural resources for the state of Michigan.

(j) "Supervisor" means the supervisor of wells as provided by this act.

(k) "Board" means the advisory board appointed, as provided in this act, by the supervisor of wells.

(*l*) "Waste" in addition to its ordinary meaning includes:

(1) "Underground waste" as those words are generally understood in the oil business, and in any event to embrace (1) the inefficient, excessive, or improper use or dissipation of the reservoir energy, including gas energy and water drive, of any pool, and the locating, spacing, drilling, equipping, operating, or producing of any well or wells in a manner to reduce or tend to reduce the total quantity of oil or gas ultimately recoverable from any pool, and (2) unreasonable damage to underground fresh or mineral waters, natural brines, or other mineral deposits from operations for the discovery, development, and production and handling of oil or gas.

(2) "Surface waste," as those words are generally understood in the oil business, and in any event to embrace (1) the unnecessary or excessive surface loss or destruction without beneficial use, however caused, of gas, oil, or other product thereof, but including the loss or destruction, without beneficial use, resulting from evaporation, seepage, leakage or fire, especially such loss or destruction incident to or resulting from the manner of spacing, equipping, operating, or producing well or wells, or incident to or resulting from inefficient storage or handling of oil, (2) the unnecessary damage to or destruction of the surface, soils, animal, fish or aquatic life or property, or other environmental values from or by oil and gas operations; and (3) the drilling of unnecessary wells.

(3) "Market waste," which shall embrace the production of oil or gas in any field or pool in excess of the market demand as defined herein.

(m) The words "market demand" as used herein shall be construed to mean the actual demand for oil or gas from any particular pool or field for current requirements for current consumption and use within or outside the state, together with the demand for such amounts as are necessary for building up or maintaining reasonable storage reserves of oil or gas or the products thereof.

(n) "Illegal oil or gas" means oil or gas which has been produced by any owner or producer in violation of this act, rules promulgated pursuant to this act or orders of the supervisor.

(*o*) "Illegal product" means any product of oil or gas or any part of which was processed or derived in whole or part knowingly from illegal oil or gas.

(p) "Illegal conveyance" means any conveyance by or through which illegal oil or gas or illegal products are being transported.

(q) "Illegal container" means any receptacle which contains illegal oil or gas or illegal products.

(r) "Tender" means a permit or certificate of clearance for the transportation of oil or gas or products, approved and issued or registered under the authority of the supervisor.

Historical Note

Source:

P.A.1939, No. 61, § 2. Imd. Eff. May 3.
C.L.1948, § 319.2.
P.A.1966, No. 262, § 1. Imd. Eff. July 12.
C.L.1970, § 319.2.
P.A.1973, No. 61, § 1. Imd. Eff. July 19.

The 1966 amendment substituted "state geologist" for "director of conservation of Michigan".

The 1973 amendment substituted "a mixture of hydrocarbons and varying quantities of nonhydrocarbons in a gaseous state which may or may not be associated with oil, and including those liquids resulting from condensation" for "casing-head gas or gas produced incidental to the production of oil" in subd. (c); substituted "commission of natural resources" for "commission of conservation" in subd. (i); substituted "supervisor of wells" for "state geologists" in subd. (k); deleted "As used in this act, the term" preceding "waste" in the introductory language of subd. (*l*); deleted "casing-head" preceding "gas" in phrase "handling of oil or gas" in subd. (*l*)(1) and phrase "beneficial use, however caused, or gas, oil" in subd. (*l*)(2); inserted "or other environmental values" in subd. (*l*)(2); inserted phrase "or gas" in subds. (*l*)(3), (m), (n), (*o*), (p), (q), and (r); substituted "by any owner or producer in violation of this act, rules promulgated pursuant to this act or orders of the supervisor" for "within the state from any well or wells in excess of the amount allowed by any valid rule, regulation or order of the supervisor as distinguished from oil produced in the state not in excess of the amount so allowed, which is 'legal oil' " in subd. (n); deleted "as distinguished from 'legal product' which is a product processed or derived to no extent from illegal oil" at the end of subd. (*o*); and deleted "oil" preceding "products" in subds. (p) and (q).

Cross References

Commission of natural resources,
- Appointment and terms prior to executive organization act, see § 299.1.
- Appointments, membership and terms under executive organization act, see § 16.351.
- Establishment as head of department created under executive organization act, see § 16.351.

Oil defined for severance tax, see § 205.311

Person defined for severance tax, see § 205.312.

March 31, 1987

Senate Special Committee on Oil and Gas

SB 49, Relating to the waste of oil and gas.

TO TESTIFY:

SENATOR KERTTULA, Sponsor (or BETH)

STEVE PORTER, Assistant Attorney General, ANCHORAGE

Ask him to run through what options the state currently has for dealing with a situation where our wellhead value approaches zero value.

Would this proposed statutory change help to expand our options?

What other states have an "economic waste" statute?

How do they use it?

CHAT CHATTERTON, Commissioner, ALASKA OIL AND GAS CONSERVATION COMMISSION

What is the commission's position on this bill?

Are there other options for dealing with this low price problem?

What about underlifting?

How does the authority of the commission overlap with DNR's

a) for regulating production?

b) to shut in a field?

BILL VAN DYKE, Petroleum Manager, DEPARTMENT OF NATURAL RESOURCES

Does DNR have a position on the bill?

JIM PALMER, Standard Alaska Petroleum Company

BEV WARD, ARCO Director Public Relations

RICHARD BYRD, General Counsel to the INTERSTATE OIL COMPACT COMMISSION, (from KANSAS)

DEBRA VOGT, Assistant Attorney General

Are there potential constitutional questions raised here?

U.S. BRIEFS

Government

▶**Minerals Management Service** will conduct meetings Dec. 2 in Fort Bragg, Calif., and Dec. 4 in Eureka, Calif., on the draft environmental impact statement (DEIS) for Offshore Northern California OCS Sale 91, scheduled for February 1989 (OGJ, Aug. 25, Newsletter). Deadline for written comments in Los Angeles is Dec. 10. The DEIS is due in August 1987 and the final EIS in March 1988.

▶**Texas Railroad Commission** (TRC) received only 13 briefs from companies and associations about whether it should cut the state's monthly production allowable 10% in order to bolster oil prices. Two small independent producers and a Houston consultant filed briefs supporting the cut, while opposition came from Texas Mid-Continent Oil and Gas Association, Texas Independent Producers and Royalty Owners Association, and many of the major integrated petroleum companies. TRC indicated that the plan was unworkable and is expected to deny the application. The commission meets this week to decide Texas production allowables for December.

Processing

▶**Unocal Corp.** started operation of its new tail gas sulfur removal technology, intended to replace the Stretford process, at its Santa Maria refinery in Arroyo Grande, Calif. Unocal claims Unisulf doesn't need to continually replace chemicals used and the resulting solution needs to be changed only once every 7-10 years compared with perhaps twice a year with Stretford. Colicensor is Ralph M. Parsons Co.

▶**National Distillers & Chemical Corp.** (NDCC) completed its purchase of Enron Chemical Co. from Enron Corp. for about \$570 million cash and the assumption of about \$34 million of industrial revenue bond debt (OGJ, Sept. 29, p. 42). The acquisition makes NDCC the biggest U.S. polyethylene producer at 3.2 billion lb/year.

Drilling-production

▶**Seagull Energy Corp.** started up natural gas production of 20 MMcfd from adjoining Gulf of Mexico fields Mustang Island Block 828 and Mustang Island Block 831, about 35 miles southeast of Corpus Christi, Tex. Start-up of the two fields boosted Seagull's net gas output by about 80% to 17 MMcfd and its proved gas reserves by about half.

▶**ARCO Alaska Inc.** let contracts totaling about \$3 million for work in Alaska's giant Prudhoe Bay oil field. Brown & Root USA Inc. won a contract for \$850,000 to install gas injection modules for Prudhoe's new central gas facility and production expansion drillsite modules. A \$750,000 contract went to Brodero-Aber for field pipe insulation. Gino J.V. netted a contract for \$695,000 for unspecified work on the crude topping plant at Prudhoe. Contracts for \$500,000 and \$200,000 went to H.C. Price to repair or replace flowlines.

▶**Amoco Production Co.** produced nearly 11 bcf of carbon dioxide during October, a monthly record, at Bravo Dome CO_2 Gas Unit in Northeast New Mexico. The CO_2 is transported by pipeline to West Texas for enhanced oil recovery. Since completion of a 34 well expansion project in August, sales have exceeded 350 MMcfd of CO_2. The 258 wells connected to sales produce an average 1.38 MMcfd of CO_2. Cumulative production since April 1984 exceeds 200 bcf at Bravo Dome, at 1.036 million acres the world's largest mineral unit.

Transportation

▶**Exxon Shipping Co.** took delivery of the Exxon Valdez, the first of two 209,000 dwt, 987 ft long tankers being built for Exxon by National Steel & Shipbuilding Co., San Diego. The tankers will transport Alaskan North Slope crude from Valdez, Alaska, to Panama for further shipment to U.S. Gulf and East Coast markets.

▶**GATX Terminals Corp.** linked its Carteret, N.J., petroleum products terminal to Sun Pipe Line Co.'s Eastern U.S. pipeline network. The effort will improve flexibility for GATX customers wanting to move products from the Philadelphia area to New York Harbor by reducing delivery time to 24 hr from 3 days by barge.

Petrochemicals

▶**U.S. fertilizer** production was 8% lower in September 1986 than September 1985 and down 13% for July-September 1986, first 3 months of the fertilizer year. Fertilizer Institute says production of anhydrous ammonia, for which natural gas is a large feedstock, was down 7% in September and off 14% for July-September. Ammonia stocks grew by 22%.

Offshore

▶**Southwest Research Institute,** San Antonio, plans a cooperative industry research project to establish the first comprehensive engineering database on offshore flexible pipe installations and performance. Research will focus on installation type and configuration, performance/chemical environments, mechanical interfaces, hardware specifications, and field experience. Initial meetings are planned in London and Houston.

Marketing

▶**ARCO** hiked the price of leaded regular gasoline 1.8¢/gal to the same price for its unleaded regular, in order to reflect the added costs of lead phasedown under Environmental Protection Agency rules. ARCO is the first West Coast company to equalize leaded and unleaded prices, having cut the price difference to 1.8¢/gal from 4.8¢/gal in August. Its premium unleaded grade will stay separately priced.

Acquisitions

▶**PaineWebber/Geodyne Energy** Income Production Partnerships I-D and I-E acquired interests in 20 oil and gas producing wells mainly in Southwest Texas from Shell Western Exploration & Production Inc. for about \$11.7 million. The partnerships plans to spend about another \$30 million to acquire more properties, after spending about \$35.7 million for production to date.

▶**Wintershall Corp.,** Denver, completed the acquisition of the U.S oil and gas assets of International Minerals & Chemical Corp. (OGJ, Oct. 6, p. 42). The purchase gives the unit of Wintershall AG, Kassel, West Germany, a Louisiana gas pipeline and boosts its U.S. production by 2,000 b/d of oil and 29 MMcfd of gas, mostly in Louisiana.

Companies

▶**Diamond Shamrock Corp.,** which reduced its common stock dividend earlier this year, has no plans for another dividend cut as incorrectly stated in an earlier report (OGJ, Nov. 10, p. 60).

PF ✓
BF ✓

3:40

SB 49

Beth Kertula —
~~part of~~
management of oil

only "state" oil not private.

definition of how to avoid "economic waste"

underlifting.

define "market demand"

if price goes below —

other states do include.

OK in 1915 —

has been upheld in courts

Fischer

how resolve conflicts between state and producers —

what happens to long-term contracts?

Porter

negative royalty valuation

power to regulate production

does not have options -

does have option to put into unit plans.

Unit agreements have waived

in 1977 PB, 1981 + Kuparuk

1979 M. Ine does allow

38.05.180 (l) -

underlift - can defer production

but only w/ consent of producers)

Other states - OCC has powers

power is needed.

The commission is the appropriate agency.

Chatterton

commission deals w/ all lands

another approach.

Should require DNR comm to

put in lease ~~the~~ when

History of conservation statutes.

1) produce as you please.

2) collapsed in 1930's

3) regulation prohibited physical waste.

Texas uses economic waste

would proration work again?

U.S. controlled prices then regulating production.

Industry's in middle east were nationalized.

Demand increased. —

Unrestricted imports. —

→ Do not have resources to administer
no economists

→ Get fiscal note from AOGCE

Overlap — exists in TITLE 31 —

not more Than 10% in unit.

BILL VAN DYKE

existing statutes —

don't ~~allow~~ speak to "economic waste"

would take broader "police powers"

no position

Palmer could have devastating impact on industry.

Royalty oil is under contract —

how would affect contract.

Ward Glaser + Johnson.

Unreasonable burden on producers —

reduced investment.

increase risk

definitions — what are goals?

Fischer

→ fiscal note —

→ definition of "reasonable market demand"

SAPCO — John Rader
for more info.

adjourned 4:15

SENATE BILL 49

MADAM CHAIRMAN, MEMBERS OF THE OIL & GAS COMMITTEE. MY NAME IS BEVERLY WARD. I AM DIRECTOR OF GOVERNMENT & COMMUNITY RELATIONS FOR ARCO ALASKA, INC. WE APPRECIATE THE OPPORTUNITY TODAY TO COMMENT ON SB 49. ON THE TELECONFERENCE LINE IN ANCHORAGE IS JOHN GLAESER AND DOUG JOHNSON, FROM OUR ANCHORAGE OFFICE, WHO WILL BE AVAILABLE FOR QUESTIONS IF NECESSARY.

SENATE BILL 49 WOULD AMEND THE ALASKA OIL AND GAS CONSERVATION ACT BY EXPANDING THE DEFINITION OF "WASTE" TO INCLUDE:

> "(K) THE PRODUCTION OF OIL OR GAS IN EXCESS OF TRANSPORTATION FACILITIES, MARKET FACILITIES, OR REASONABLE MARKET DEMAND."

THE PASSAGE OF THIS BILL WOULD ALLOW THE COMMISSION INCREASED DISCRETIONARY AUTHORITY OVER OIL AND GAS OPERATIONS WITHIN THE STATE. THE LINKING OF PRODUCTION AND MARKET DEMAND IN THIS DEFINITION OF WASTEFUL PRACTICES WOULD CREATE THE BASIS FOR IMPLEMENTING PRODUCTION RESTRICTIONS WHENEVER THE COMMISSION DETERMINES THAT THE SUPPLY EXCEEDS "REASONABLE MARKET DEMAND." WHAT CONSTITUTES "REASONABLE MARKET DEMAND" IS NOT DEFINED AND THEREFORE LEFT TOTALLY TO THE DISCRETION OF THE COMMISSION. AS A RESULT, ONE COULD CONTEMPLATE A WIDE RANGE OF CIRCUMSTANCES THAT COULD TRIGGER PRODUCTION RESTRICTIONS, INCLUDING LOW OIL PRICES.

THE LONGER-TERM EFFECTS OF INTRODUCING THE CONCEPT OF ECONOMIC WASTE INTO ALASKA'S OIL AND GAS LAW WOULD LIKELY LEAD TO THE COMMISSION ESTABLISHING SOME TYPE OF PRORATIONING SYSTEM. THE EFFECT OF THIS TYPE OF ACTION WOULD PLACE AN UNREASONABLE BURDEN ON PRODUCERS. RECOGNIZING THAT THE LONG-TERM INTERESTS OF THE STATE AND THE PRODUCERS ARE GENERALLY THE SAME, THE STATE MUST BE WILLING TO STAND FAST IN THE BAD TIMES AS WELL AS SHARE IN THE GOOD TIMES, AND TO GIVE PRODUCERS CREDIT FOR MAKING PRUDENT DECISIONS REGARDING PRODUCTION FROM THEIR LEASES.

AN EXAMPLE OF THE EFFECTS OF PRORATIONING MIGHT BE A REQUIRED FIELD SHUT-DOWN BY THE STATE BECAUSE THERE IS NO "REASONABLE MARKET DEMAND" DUE TO LOW OIL PRICES. HOWEVER, IT MIGHT BE MORE REASONABLE AND ECONOMIC FOR THE PRODUCER TO CONTINUE TO PRODUCE DURING LOW OIL PRICES THAN TO SHUT DOWN AND RESTART WITH THE UPTURN IN OIL PRICES. AN ANALOGY MIGHT SUGGEST THAT THE STATE CLOSE ALL STATE OFFICES WHENEVER REVENUES DECLINE. THIS WOULD CLEARLY NOT BE IN THE BEST INTERESTS OF THE STATE DUE IN PART TO THE COSTS OF THE SHUTDOWN AND THE HIGH COST OF REHIRING AND RETRAINING STAFF WHEN REVENUES RETURN TO NORMAL.

IF PRORATIONING DUE TO ECONOMIC WASTE HAD BEEN IN EFFECT DURING 1986, PRODUCTION THEORETICALLY COULD HAVE BEEN MANDATORILY REDUCED (OR HALTED) WITH REDUCED OIL PRICES. THE RESULTS OF SUCH ACTIONS WOULD LIKELY HAVE BEEN AN INCREASE IN OIL SUPPLY TO THE MARKET BY OPEC AND A RESULTING LOSS OF MARKET SHARE BY ALASKAN PRODUCERS. THIS WOULD HAVE ONLY SERVED TO PROLONG AND INCREASE THE MAGNITUDE OF THE STATE'S REVENUE PROBLEMS. IT SHOULD ALSO BE NOTED THAT PRORATIONING DURING A PERIOD OF LOW OIL PRICES WOULD RESULT IN ADDITIONAL BUDGET CUTS AND PERSONNEL LAYOFFS BY THE PETROLEUM OPERATORS, FURTHER EXACERBATING A DIFFICULT SITUATION. ALASKA MUST PROTECT ITS MARKET SHARE FIRST AND THEN LEARN TO LIVE WITHIN THE PRICE RANGE DICTATED BY WORLD SUPPLY AND DEMAND.

PASSAGE OF SB 49 WOULD ALSO SIGNIFICANTLY AFFECT INDUSTRY ECONOMICS FOR CAPITAL PROJECTS. CAPITAL DOLLARS FOR MANY PROJECTS ARE SPENT YEARS IN ADVANCE OF PRODUCTION STARTUP. THE DEGREE OF PRE-PLANNING NECESSARY FOR LARGE SCALE PROJECTS IS ESPECIALLY GREAT ON THE NORTH SLOPE WHERE THERE ARE LONG LEAD TIMES FOR EQUIPMENT OR RESTRICTED CONSTRUCTION PERIODS. IT IS IMPORTANT THAT THE PRODUCTION ESTIMATES USED TO JUSTIFY THESE PROJECTS BE AS ACCURATE AS POSSIBLE. CURRENTLY, ESTIMATES OF PRODUCTION ARE BASED ON RESERVOIR PARAMETERS AND SOUND ENGINEERING PRINCIPLES, IN ACCORDANCE WITH THE COMMISSION'S REGULATIONS. INTRODUCING AN ADDITIONAL VARIABLE SUCH AS MANDATORY PRODUCTION RESTRICTIONS WOULD ADD CONSIDERABLE UNCERTAINTY AND MAKE PLANNING DIFFICULT, IF NOT IMPOSSIBLE. THIS WOULD TRANSLATE DIRECTLY INTO REDUCED OIL INVESTMENT IN THE STATE.

SINCE THE STATE ALSO NEEDS CONTINUING REVENUE, IT WOULD NORMALLY BE IN THE BEST INTEREST OF BOTH THE STATE AND THE INDUSTRY TO MAINTAIN PRODUCTION. ONLY UNDER THE MOST EXTREME (AND HOPEFULLY SHORT-TERM) CIRCUMSTANCES OF LOW TO NEGATIVE WELLHEAD PRICES, WOULD STATE AND INDUSTRY INTERESTS POSSIBLY DIVERGE. HOWEVER, THE VERY IMPORTANT CONSIDERATION OF THE LONG-TERM BEST INTERESTS OF THE STATE AND INDUSTRY WOULD STILL CLEARLY FAVOR CONTINUED PRODUCTION.

IN SUMMARY SB 49 WOULD PROVIDE NO DIRECT BENEFIT TO THE STATE OR INDUSTRY BUT COULD SIGNIFICANTLY INCREASE THE RISK INHERENT TO OPERATING IN THE HIGH COST ALASKA ENVIRONMENT. THIS WOULD BE DIRECTLY TRANSLATED INTO REDUCED OIL INVESTMENT IN THE STATE AND, THEREFORE, IS CLEARLY NOT IN THE LONG-TERM BEST INTERESTS OF EITHER THE STATE OR THE ALASKA OIL INDUSTRY.

Standard Alaska
Production Company
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 561-5111

STANDARD
ALASKA PRODUCTION

Testimony of Standard Alaska Production Company on SB49 before the Senate Oil and Gas Committee

Standard Alaska Production Company is very concerned with the potential effect of this amendment where temporary transportation of market conditions could be construed to preclude continued operation of fields in Alaska. If the Alaska Oil and Gas Conservation Commission is given the power to shut in production under standards as vaguely defined as are proposed in SB 49, the resulting uncertainty could have a devastating impact on oil and gas development in Alaska. Further, Standard fails to see any valid oil and gas conservation purpose which would be achieved through this legislation.

Senate Special Committee on Oil and Gas

Legislation Checklist

Bill number: SB 49 Sponsor: Kerttula

Date referred to committee: 1/19/87 Further referrals: L&C, Resources, Finance

Prior committee report:

Back up from sponsor:

Fiscal note(s):

Agency: Requested: Received:

Agency: Requested: Received:

Position paper(s):

Agency: Requested: Received:

Agency: Requested: Received:

Sectional Analysis:

Scheduled: 3/31 Heard: 3/31 Reported out:

Items for committee packet:

To Testify:

Chat Chatterton - 279-1433
333-8161 (h)

Bill Van Dyke - 561-2020

Other Contacts:

Richard Byrd (913) 242-1234
General counsel to IOCC

Steve Porter 276-3550

Bev Ward, ARCO

Jim Palmer SOHIO

John Radar BRIDGE 258-1808

SB

70

Senate Special Committee on Oil and Gas

Legislation Checklist

Bill number: SB 70 Sponsor: L B+A

Date referred to committee: 1/26 Further referrals: SA, Resources Finance

Prior committee report:

Back up from sponsor:

Fiscal note(s):

Agency: Revenue Requested: Received: 2/16

Agency: Requested: Received:

Position paper(s):

Agency: Requested: Received:

Agency: Requested: Received:

Sectional Analysis: (H) Jud - (HB 58)

Scheduled: 2/17 Heard: 2/17 Reported out:

Items for committee packet:

To Testify:

Revenue — Commissioner Malone
Law - Deborah Vogt

Other Contacts:

Barbara Herman - 277-8661
Jim Palmer
Bob Nelson
Mary Jensen

House Version HB 58

D

STATE OF ALASKA

POUCH V
JUNEAU, ALASKA 99811
(907) 465-4941

SENATE SPECIAL COMMITTEE ON OIL AND GAS

M E M O R A N D U M

TO: Members, Senate Special Committee on Oil and Gas

FROM: Committee Staff

RE: Committee Meeting, February 17, 1987

DATE: February 16, 1987

On Tuesday, February 17, at 3:30 pm in the Beltz Room, the Senate Special Committee on Oil and Gas will hear SB 70, Relating to the disclosure of certain tax assessment information by the Department of Revenue.

Current law prohibits the Department of Revenue from providing the Legislature with certain confidential tax information. Some of this information may be necessary to ensure proper legislative oversight over the department's tax collection function. In addition, the information may be useful in considering changes to the current tax structure.

A committee substitute has been prepared that adopts changes made this session to the house version of the bill, HB 58. The bill would allow only legislators and designated staff to review confidential information in executive session. Criminal penalties for disclosure would be a class A misdemeanor.

5-0321B

Offered: 2/2/87
Referred: Finance

P. 4
P. 5

Original sponsor: Rules/Legislative Budget and Audit

IN THE ~~HOUSE~~ SENATE BY THE ~~JUDICIARY~~ OIL + GAS COMMITTEE

CS FOR ~~HOUSE BILL NO. 58 (Judiciary)~~ SENATE BILL 70 (Oil and Gas)

IN THE LEGISLATURE OF THE STATE OF ALASKA

FIFTEENTH LEGISLATURE - FIRST SESSION

A BILL

For an Act entitled: "An Act relating to confidential tax information of the Department of Revenue; and providing for an effective date."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

* Section 1. LEGISLATIVE FINDINGS AND PURPOSE. (a) The legislature finds that

(1) the majority of the state's revenue is derived from taxation;

(2) tax revenue enables the state to provide essential services to the citizens of the state to ensure the public health and welfare;

(3) the elected representatives of the people of the state must be assured that the state is receiving all of the income to which it is entitled and that the tax laws are operating in the manner intended by the legislature;

(4) the legislature must exercise its oversight authority to ensure that tax revenue collection by the Department of Revenue is efficient, fair, prompt, and in the best interest of the state;

(5) there is a legitimate and compelling governmental interest in the legislature having adequate access to tax-related information to allow responsible oversight;

(6) without sufficient information, the legislature cannot adequately determine that the state's tax revenue collection functions are properly administered and that tax revenue due the state is promptly received;

information contained in a report or return filed under AS 43 with the Department of Revenue and furnished to the person under AS 43.05.-230(h) or (i).

* Sec. 3. AS 24.60.060 is amended by adding a new subsection to read:

(b) A person to whom this chapter applies may not disclose tax information contained within a report or a return filed under AS 43 with the Department of Revenue and furnished to the person under AS 43.05.230(h) or (i).

* Sec. 4. AS 24.60 is amended by adding a new section to read:

Sec. 24.60.172. SPECIAL PROCEEDINGS BEFORE THE COMMITTEE. Notwithstanding AS 24.60.170, if a complaint before the committee involves an allegation that a person to whom this chapter applies has disclosed tax information contained within a report or return filed under AS 43 with the Department of Revenue and furnished to the person under AS 43.05.230(h) or (i) and the taxpayer or a third party whose tax information is alleged to have been improperly disclosed does not agree to the public disclosure of the identity of the taxpayer, the third party, or the tax information,

(1) the hearing may not be held in open session;

(2) a transcript containing confidential tax information shall be edited to prevent the disclosure of the confidential information;

(3) a decision, if made public, shall be edited to prevent the disclosure of the tax information and to protect the identity of the taxpayer or the third party; and

(4) a public statement may not contain information identifying the taxpayer, a third party, or the tax information.

* Sec. 5. AS 43.05.230(f) is amended to read:

(f) <u>An intentional</u> [A WILFUL] violation of the provisions of

CORRECTION

THIS DOCUMENT
HAS BEEN REPHOTOGRAPHED
TO ASSURE LEGIBILITY

02-576(2/77)

Offered: 2/2/87
Referred: Finance

P. 4
P. 5

Original sponsor: Rules/Legislative
Budget and Audit

IN THE SENATE ~~HOUSE~~ BY THE OIL + GAS ~~JUDICIARY~~ COMMITTEE

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(5) there is a legitimate and compelling governmental interest in the legislature having adequate access to tax-related information to allow responsible oversight;

(6) without sufficient information, the legislature cannot adequately determine that the state's tax revenue collection functions are properly administered and that tax revenue due the state is promptly received;

(7) tax returns and return information contain confidential information, often regarding sensitive business information;

(8) taxpayers have protections against public disclosure of certain tax information;

(9) exchange agreements with the Internal Revenue Service require that certain tax information not be publicly disclosed;

(10) protection of confidentiality fosters full disclosure by taxpayers to taxing authorities and therefore promotes effective administration of tax programs; and

(11) legislators and legislative employees who improperly disclose confidential tax information should be subject to the same sanctions imposed against executive branch employees.

(b) The purpose of this Act is to ensure that

(1) the state is receiving all the tax revenue due the state;

(2) oversight of the tax revenue collection function is effectively provided;

(3) tax revenue due to the state is available to provide for the public health and welfare of the citizens of the state;

(4) taxpayers are protected from improper disclosure of tax information;

(5) the exchange agreements with the Internal Revenue Service regarding tax information are not jeopardized;

(6) tax programs are administered fairly; and

(7) the right of the people to privacy is recognized and may not be infringed.

* Sec. 2. AS 24.10 is amended by adding a new section to article 2 to read:

Sec. 24.10.070. CONFIDENTIALITY OF INFORMATION. A present or former employee or agent of the legislature may not disclose tax

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 8672
1533 SCOMM 57: SENATE SPECIAL COMMITTEE ON OIL & GAS, 1987-1988 1330

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(3) a decision, if made public, shall be edited to prevent the disclosure of the tax information and to protect the identity of the taxpayer or the third party; and

(4) a public statement may not contain information identifying the taxpayer, a third party, or the tax information.

* Sec. 5. AS 43.05.230(f) is amended to read:

(f) <u>An intentional</u> [A WILFUL] violation of the provisions of this section is <u>a class A misdemeanor</u> [PUNISHABLE BY A FINE OF NOT MORE THAN $5,000, OR BY IMPRISONMENT FOR NOT MORE THAN TWO YEARS, OR BY BOTH].

* Sec. 6. AS 43.05.230 is amended by adding new subsections to read:

(h) A legislative committee, after identifying the scope of an investigation or inquiry relating to matters of taxation [and the adoption by either house of a simple resolution giving the committee authority to receive confidential tax information,] may request the commissioner of revenue to provide confidential taxpayer returns or return information; the request by the committee shall be in writing and may identify, directly or indirectly, a particular taxpayer. On receipt of written request [~~adoption of the resolution~~], the commissioner of revenue shall provide the committee with the requested returns or return information. If specific returns or return information concerning a particular taxpayer are provided to a legislative committee under this subsection, the commissioner of revenue shall notify the particular taxpayer of the request and of the delivery to the committee of the information. The committee may designate legislative employees or agents to inspect returns and return information. The committee may consider information made available under this subsection only in executive session unless the taxpayer and any third party whose tax information is being considered consent in writing to a disclosure in open session.

(i) Notwithstanding (h) of this section, the commissioner may transfer information made confidential under this section to a legislative committee after a written finding by the commissioner that the transfer is in the best interest of the public. The transfer of the confidential information is in the best interest of the public if

(1) a taxpayer has testified before a legislative committee, either orally or in writing, or has otherwise provided

information to a committee concerning the administration of a tax under this title and the department has confidential information of the taxpayer that directly conflicts with the testimony or information offered by the taxpayer;

(2) a legislative committee is reviewing the administration of a tax imposed by this title and confidential information is needed to demonstrate the application of the tax to taxpayers;

(3) the legislature has under consideration a bill proposing to add an additional tax or to amend a tax administered by the department and confidential information is needed to demonstrate the fiscal effect of the proposed new tax or amendment; or

(4) after giving the taxpayer a hearing, the commissioner makes a written determination that the interest of the public in transferring the information to the legislative committee outweighs the interest of the taxpayer in avoiding the transfer of the information.

[(j) ~~If a return or information that is provided to a committee under (h) or (i) of this section identifies the taxpayer, the taxpayer may attend the portion of the committee meeting that considers the return or information.~~]

(k) The disclosure of information made confidential by this section by a member or former member of the legislature or by a present or former employee or agent of the legislature is a violation of this section. A member of the legislature and an employee or agent of the legislature, before receiving or reviewing information provided by the commissioner under (h) or (i) of this section, shall acknowledge, on a form prepared by the commissioner, that the information is confidential, and that a disclosure of the information is prohibited by law.

(l) The legislative committee and the commissioner of revenue shall adopt procedures governing the transmittal, receipt, safekeeping, and use of the confidential information provided by the commissioner under (h) or (i) of this section.

(m) This section does not permit the disclosure to the legislature of confidential information provided by the Internal Revenue Service under exchange agreements with the department.

* Sec. 7. This Act takes effect immediately under AS 01.10.070(c).

STATE OF ALASKA
THE LEGISLATURE

POUCH Y STATE CAPITOL
JUNEAU ALASKA 99811
907 465 3800

LEGISLATIVE AFFAIRS AGENCY

M E M O R A N D U M January 28, 1987

SUBJECT: Constitutional speech and debate issue in CSHB 58(Jud)

TO: Representative John Sund
Chair, House Judiciary Committee

FROM: Theresa L. Bannister
Legislative Counsel

This memorandum accompanies the draft of the committee substitute that you requested for HB 58. Please be aware that sec. 6 of the draft raises a constitutional question. Proposed subsection (i) added by sec. 6 could be challenged as violating the speech and debate immunity clause appearing in art. II, sec. 6 of the Alaska Constitution. Subsection (i) would subject legislators to liability enforceable by other branches of the government for acts occurring during the exercise of their legislative duties during the session or while going to or returning from the session.

It is not clear whether sec. 6 would be held to be constitutional. There does not appear to be any Alaska case law on this specific issue. In United States v. Helstoski, 442 U.S. 477, 490 (1979), the U.S. Supreme court suggested with regard to the speech and debate immunity provision of the U.S. Constitution that Congress could "enlist the aid of the Executive Branch and the courts" in disciplining its members by a "narrowly drawn statute passed by Congress in the exercise of its legislative power to regulate the conduct of its members". Id. at 492. Although the issue apparently has never arisen in court, the Internal Revenue Service appears to have taken the position that Congress has done just that in an Internal Revenue law, so that members of Congress are not immune from penalties for disclosure. However, since the Alaska Supreme Court has not addressed this specific issue, the outcome of a challenge to sec. 6 of the draft is unknown.

If I may be of further assistance, please advise.

TLB:mkr
m8/055

Enclosure

CHART 1

Summary of Outstanding Tax Liabilities Through 1982

Tax Type	Statute	Tax Assessed	Tax Amount Under Appeal
Oil and Gas Corporate Income	AS 43.21	$489,158,736	$489,158,736
Oil and Gas Production	AS 43.55	375,053,351	94,738,302
Corporation	AS 43.20	30,440,487	28,856,618
Individual	AS 43.20	6,090,639	1,669,340
Other		10,624,196	3,894,962
Total		$911,367,409	$618,317,958

Source: Department of Revenue Accounts Receivable Reports

MEMORANDUM

State of Alaska

TO: Royce Weller
Special Assistant
Department of Revenue

DATE: February 9, 1987

FILE NO:

TELEPHONE NO: 465-2366

FROM: Thomas C. Williams
Director
Enforcement Division

SUBJECT: Accounts Receivable Balances

Per your request, following is the breakdown of the tax, penalty, and interest balances due on the accounts receivable system as of February 2, 1987:

	Total	Tax	PFD
Principal	$ 939,097,727	$ 937,978,491	$1,119,236
Penalty	41,627,809	41,627,809	-0-
Interest	578,084,650	578,084,650	-0-
Total	$1,558,810,186	$1,557,690,950	$1,119,236

If you have any questions or need any further information, please call.

TCW:DLR:dlr

RECEIVED
ALASKA DEPARTMENT OF REVENUE
FEB 09 1987
OFFICE OF THE COMMISSIONER

3:45 BF
2/17/86 Fischer.

SB 70

Halford —

ARCO settlement —
good example.

→ spell out procedures for committees.

suggest Threshold value
in excess of 10 mil?

p. 9 l 13 — "returns or return info"

Fischer

Penalties —

→ what do other confidential statutes provide?

→ what do Texas + Louisiana do?

Malone

Oversight function — can't carry out w/o info. —
understand problems —

laws are adequate
administered fairly.
exec carry out law.

[illegible]

return not the right form a committee would need.

Stang

strengthen confidentiality.

Vogt

1) leg immunity —

never been prosecution —

U.S. Supreme never has ruled

2) Separation of powers — doesn't affect

removes bar of free flow of information -

3) exchange agreements w/ IRS —

sec (m)

→ check w/ IRS

4) "return on ret info" comes from statute. — let that info to be disclosed

→ Define "return & return info" from U.S law

Hal

could ARCO settlement kept this secret even w/ this bill?

Herman:

yes, couldn't take that right away. Does legislation supercede Atty-client privilege would it be retroactive?

Hance

1) "who + what info" — not broad enuf.

favor broader definition.

2) Threshold value of 10 million —
often critical info under the limit.
use 3rd party

Palmer

1) discourage honest reporting
2) separation of powers.

3) what point in audit process.

4) retroactivity — back taxes —

5) define tax info.

A) need for resolution — serious matter.
control which committee.
limit to specified committee.

B) prevent taxpayer from being there.

to get all information.

Hal provide that info to taxpayer.

Palmer 1) yes

Hal allow taxpayer at another time. —

Cog use Leg B+A

Hal evidence the California law has produced leaks?

Palmer no

Hal current audit process is —
couldn't be worse!

Jensen Exxon.
increase risk of disclosure —

1) LB+A isn has authority

2) Revenue can report to leg.

3) increase risk of disclosure -

4) Leg immunity

no problems in Califor.
AK has 3 major taxpayers.

Hal 29.22.71

Sec. 6

every

other states current.?

Ed California is current.
Louisiana audits go back 30 years
AK has unique valuation problems.

other states require prepayment?

no

Deane, Severance, Royalty.

property tax

Fed – require program
other states also require.

Look at LBNA
2422.71 (6)

does LBA have access to confidential tax info.?

Vogt
Leg Audit Division or
LBoNA

adjourned 5:22

~~Income tax has~~
~~withholding~~ !

- make more difficult to audit. -
violation of executive function -

run final bill pass IRS.

ck fed legislation as to return information

unintentional disclosure ???

At what point does the legislature become involved -

retroactivity -

what is tax payer information

which committees - (single resolution) specify committees -

legislatures only.

AB 22.71

Official Business

COMMITTEE:

SPEC. COMMITTEE ON OIL AND GAS

DATE: 2/17/87

SIGN-IN

Subject of meeting:

SB 70 - RELATING TO THE DISCLOSURE OF CERTAIN STATE TAX ASSESSMENT INFORMATION BY THE DEPT. OF REVENUE.

NAME	ADDRESS	PHONE	REPRESENTING	DO YOU WANT TO TESTIFY?
JIM PALMER	STANDARD OIL		STANDARD	yes
MARY JENSEN	EXXON CO. U.S.A. ANCHORAGE		EXXON	YES.

Halford

EXHIBIT A

CLOSING AGREEMENT

JOINT STATEMENT

Juneau, Alaska:

The Alaska Department of Revenue and ARCO Alaska, Inc. announced today that they have entered into an agreement which will substantially resolve a long standing dispute over tax liabilities owed under the Alaska Oil Production Tax for oil produced on Alaska's North Slope and from Cook Inlet. ARCO has agreed to pay a lump sum payment of $243 million on or before January 15, 1986. ARCO Alaska, Inc. is a subsidiary of Atlantic Richfield Company. An Atlantic Richfield spokesman stated that Atlantic Richfield's 1986 profits will not be affected by the payment because previously established financial reserves are sufficient to cover the cost of the settlement.

The agreement, which is the result of extensive negotiations between ARCO and the State, was executed this week by Commissioner of Revenue, Mary A. Nordale and Harold M. Brown, Attorney General for the State of Alaska. Harold C. Heinze, President of ARCO Alaska, Inc. and Senior Vice President of Atlantic Richfield Company, has signed it for ARCO.

Commissioner Nordale observed: "This Settlement Agreement marks the end of a long dispute and culminates years of intensive audit work done by several people in the Department of Revenue in close cooperation with the Department of Law. I believe it has resulted in a fair and equitable resolution of several very complex legal and audit problems."

Mr. Heinze of ARCO stated: "The agreement reached with the State of Alaska is a reasonable resolution of complex and difficult issues. The settlement ends continuing uncertainty and avoids costly and protracted litigation."

Attorney General Harold Brown commented: "Although the State was prepared to litigate this matter to its ultimate conclusion, I am convinced that this is an excellent settlement which in fact, serves the best interests of the people of the State of Alaska."

The Oil and Gas Properties Production tax is responsible for approximately 43% of the State's annual general fund revenues. In Fiscal Year 1985, the total production tax collected from the Alaska producers was $1,389,400,000. The payment of $243,000,000 relates primarily to tax periods 1980 through most of 1985 and is in addition to those taxes already paid by ARCO.

Under the terms and provisions of Alaska tax statutes, the terms and conditions of the agreement may not be disclosed.

TESTIMONY OF

MARY L. JENSEN
EXXON COMPANY, U.S.A.

BEFORE

SENATE SPECIAL OIL & GAS COMMITTEE
ON
COMMITTEE SUBSTITUTE SENATE BILL 70

JUNEAU, ALASKA
FEBRUARY 17, 1987

MY NAME IS MARY JENSEN. I AM THE ALASKA TAX ATTORNEY FOR EXXON COMPANY, U.S.A. WE APPRECIATE THE OPPORTUNITY TO PRESENT TESTIMONY IN OPPOSITION OF CSSB 70.

CSSB 70 WOULD PERMIT THE DEPARTMENT OF REVENUE TO PROVIDE CONFIDENTIAL TAXPAYER INFORMATION TO LEGISLATIVE COMMITTEES, THEIR EMPLOYEES AND AGENTS. WE OPPOSE THIS BILL FOR THE FOLLOWING REASONS:

- WE BELIEVE THIS BILL IS UNNECESSARY;

- IT WOULD INCREASE THE RISK OF UNAUTHORIZED DISCLOSURE OF CONFIDENTIAL TAXPAYER INFORMATION TO THE PUBLIC AND TO INDIVIDUALS;

- IT WOULD IMPEDE THE EFFECTIVE ADMINISTRATION OF THE STATE'S TAX LAWS.

WE WOULD LIKE TO DISCUSS EACH OF THESE POINTS IN MORE DETAIL.

CSSB 70 IS UNNECESSARY

THE LEGISLATURE CURRENTLY HAS SUFFICIENT STATUTORY AUTHORITY TO MONITOR THE OPERATIONS OF THE DEPARTMENT OF REVENUE. AS 24.20.271 PROVIDES THE LEGISLATURE OVERSIGHT AUTHORITY OVER THE TAX REVENUE COLLECTION FUNCTION OF THE DEPARTMENT OF REVENUE. IN ADDITION, AS 43.05.010 REQUIRES THE COMMISSIONER OF REVENUE ANNUALLY TO REPORT AND MAKE RECOMMENDATIONS TO THE GOVERNOR AND LEGISLATURE CONCERNING THE EFFICIENCY AND EFFECTIVENESS OF THE DEPARTMENT AND THE ADMINISTRATION OF THE TAX LAWS. THEREFORE, CSSB 70 IS UNNECESSARY AND, AS WRITTEN, WOULD BLUR THE CONSTITUTIONAL BOUNDARIES BETWEEN THE EXECUTIVE AND LEGISLATIVE BRANCHES OF GOVERNMENT.

UNWARRANTED RISK OF DISCLOSURE OF HIGHLY SENSITIVE TAXPAYER INFORMATION

DURING THE AUDIT PROCESS, THE DEPARTMENT OF REVENUE REVIEWS HIGHLY PROPRIETARY BUSINESS INFORMATION TO

DETERMINE THE ACCURACY OF A TAXPAYER'S REPORTED TAX LIABILITY. CSSB 70 WOULD PERMIT DISCLOSURE OF ALL THIS INFORMATION TO A LEGISLATIVE COMMITTEE, ITS EMPLOYEES AND AGENTS, INCLUDING TEMPORARY, CONTRACT EMPLOYEES. THIS GREATLY EXPANDED DISTRIBUTION OF HIGHLY PROPRIETARY INFORMATION INCREASES THE RISK OF UNAUTHORIZED DISCLOSURE TO THE PUBLIC AND TO COMPETITORS.

IN ADDITION, NO BILL CAN PROVIDE TAXPAYERS WITH COMPLETE PROTECTION FROM DISCLOSURE OF PROPRIETARY TAXPAYER INFORMATION. THE ALASKA CONSTITUTION PROVIDES TO LEGISLATORS IMMUNITY FROM CRIMINAL AND CIVIL SANCTIONS FOR UNAUTHORIZED DISCLOSURE OF CONFIDENTIAL INFORMATION IF MADE IN THE EXERCISE OF THEIR LEGISLATIVE DUTIES. ALSO, DISCLOSURE MAY OCCUR IN A MANNER THAT PRECLUDES IDENTIFICATION OF THE RESPONSIBLE PARTY. THE TAXPAYER'S ONLY REAL PROTECTION IS TO LIMIT THE INFORMATION PROVIDED.

IMPEDE EFFECTIVE ADMINISTRATION OF TAX LAWS

THE DEPARTMENT OF REVENUE RECEIVES FROM TAXPAYERS A BROAD RANGE OF INFORMATION, SOME OF WHICH IS EXTREMELY CONFIDENTIAL. DISCLOSURE TO THE PUBLIC AND, POTENTIALLY, TO COMPETITORS COULD BE DAMAGING. CSSB 70 WOULD MAKE THE TAXPAYER MORE RELUCTANT TO PROVIDE SUCH CONFIDENTIAL INFORMATION.

FURTHERMORE, SINCE CSSB 70 DOES NOT LIMIT THE SCOPE AND PURPOSE OF THE LEGISLATIVE REVIEW OF TAX MATTERS, THE LEGISLATURE COULD INTRUDE IN THE AUDIT AND SETTLEMENT PROCESS WHICH IS THE RESPONSIBILITY OF THE DEPARTMENT OF REVENUE. SUCH AN INTRUSION WOULD INCREASE THE STATE'S ADMINISTRATIVE COSTS AND FURTHER DELAY THE RESOLUTION OF TAX DISPUTES.

CSSB 70 IS NOT IN THE BEST INTERESTS OF THE STATE OR THE TAXPAYER, AND WE URGE THE SENATE SPECIAL OIL AND GAS COMMITTEE TO REJECT THIS PROPOSAL.

TESTIMONY OF

STANDARD ALASKA PRODUCTION COMPANY

CONFIDENTIALITY OF CERTAIN TAX INFORMATION

The Standard Alaska Production Company recognizes Alaska's right to administer the audit, assessment and collection of tax revenues. However, we believe that the requirement of confidentiality imposed upon the State in matters relating to the audit and collection of taxes is essential in order to protect the sensitive and propriety business information of taxpayers.

THE BILL WOULD INHIBIT THE AUDIT PROCESS

ORIGINALLY, S.B. 70 would have simply allowed the disclosure of a taxpayer's name and the amount of an assessment. An objection could have been made to that proposal on the grounds that the only practical result would be to embarrass the taxpayer and that would serve no useful purpose. The proposed Committee Substitute however, is not designed to embarrass the taxpayer but is far more sweeping in scope. We believe it poses a very real economic threat to the taxpayer and does serious damage to the relationship between the taxpayer and the Department of Revenue during the audit process. There is a very real concern that the hearing process may be besieged by motions, discovery requests, delay tactics, objections and jurisdictional challenges, if information supplied by the taxpayer is subject to disclosure outside the Department of Revenue.

The duties of the Department of Revenue will be made more difficult by permitting a legislative panel to intervene, at any point in the audit process, and to question and challenge assumptions, calculations and compromises.

The audit procedure will be come far more formal and adversarial at a much earlier stage. Books and records that are now routinely submitted to the State to settle minor valuation or accounting problems will probably be produced only as a result of lengthy discovery motions. Audits will consume even more time delay even further the time when the State receives its tax revenues.

<u>THE BILL RISKS DISCLOSURE OF PROPRIETARY INFORMATION</u>

There is a significant risk inherent in the proposed legislation that a taxpayer's highly confidential information may be disclosed. Proprietary information would be available to legislators, legislative employees and their agents. Any number of copies of taxpayer information will inevitably be made and circulated. Certain pieces of this information, in the hands of an experienced analyst, would allow a competitor to anticipate our marketing and pricing strategies and thereby gain an unfair competitive advantage. Some of this information is so sensitive that it is currently subject to a protective court order. S.B. 70 would make it very difficult for SAPC to continue to protect this type of highly confidential information.

PENALTIES FOR DISCLOSURE ARE INADEQUATE

The penalties for disclosure are inadequate. For example, the penalties apply only to intentional disclosure of confidential information and not disclosure that is occassioned through inadvertence or carelessness.

Moreover, the penalties for disclosure apply only to those persons who would be specifically entitled to receive the tax information pursuant to the legislation. The sanctions do not apply to anyone who is not authorized to receive the information but simply sees a copy in the House or Senate chamber or in a Representative's office. Those persons may disclose any of this information with impunity. A newspaperman, for example, who publishes the information but refuses to reveal his sources, is effectively beyond any sanctions.

Obviously, a company always has the rish that a disgruntled employee may disclose some proprietary information. However, in the case of an employee, the Company has the recourse of terminating employment or possibly bringing a civil action for damages because of the breach of a fiduciary duty. The Company has no such remedies if its most confidential marketing information suddenly appears in the daily newspaper.

These fears are real. As noted in the January 17, 1986 letter from the Attorney General's office to the Legislative Budget and Audit Committee:

"The Department of Revenue has expressed concern that simple disclosure of the amount of an assessment might reveal sensitive information about taxpayers....
In the oil industry, it is possible that disclosure of assessments could allow one taxpayer to learn valuable information about the transportation costs or valuation practices of its competitors."

If the simple disclosure of an assessment can be that harmful, then the risk of damage occassioned by the distribution of entire tax returns and supporting information is obviously far, far greater.

SEPARATION OF POWERS

Under the Alaskan Constitution and general Separation of Power doctrine, we believe that tax law enforcement is a function of the Executive Branch -- through the Department of Revenue. Under the broad powers conferred by S.B. 70, a chosen legislative panel would appear capable of participating actively and perhaps controlling the tax audit process, including the negotiation of tax disputes. There is no limitation in S.B. 70 as to when, in the audit process, the tax returns and tax information may be requested by the designated legislative committee. The power could be invoked immediately at the onset of an audit with the taxpayer required to supply every record, invoice and strategy that is in its files, to the Legislative panel.

Additionally, S.B. 70 is conspicuously silent on what constitutes the exercise of legislative oversight. The Legislature has certain oversight functions. For example, the collection of information necessary for tax writing purposes or the review of charges of negligence or conflict or interest within the Department of Revenue. However, we believe that S.B. 70 is so broad, so all encompassing, that it could be used to raise new issues on audit and essentially perform a secondary review of proposed audit settlements. In so doing, S.B. 70 would allow a legislative panel to perform executive functions and second guess the tax professionals in the Department of Revenue.

S.B. 70 ignores the fact that the Department of Revenue has spent years familiarizing itself with the facts and law associated with the disputed issues. Tax settlements should be reached in an environment free from the pressures of the political arena and with professionals whose backgrounds and training have prepared them to deal with unbelievably complicated tax issues. Under S.B. 70, Standard would view negotiations with the Department of Revenue as merely preliminary, and not final. while the ultimate tax payment would probably be the same, the time period would be extended, manpower and costs unnecessarily increased, and the likelihood of litigation heightened.

CONCLUSION

In summary, we object to S.B. 70, because:

1. S.B. 70 empowers a legislative panel to perform functions

properly reserved to the Executive Branch and delegated to the Department of Revenue.

2. Despite sanctions against disclosure of confidential information, unauthorized disclosure of confidential material may result and such disclosure could cause Standard Alaska material competitive harm.

MEMORANDUM

TO: Louann Cutler, Committee Aide, House Finance Committee

FROM: J. Hartle, Committee Aide, House Judiciary committee

JH

RE: Sectional Analysis, CSHB 58(Judiciary)

CSHB 58(Jud) is very similar to CSHB 502(Jud)am which passed the House last year. Amendments were added at the request of the Department of Revenue, and the oil industry.

Sectional analysis:

Section 1: A findings and purpose section is included to assist the courts in interpreting the bill in balancing a taxpayer's right to privacy under Alaska Constitution Article 1, Section 22 with the legislature's need for information on how the state's tax laws are operating. Subsection (b) states the purpose of the Act. Page 2, line 24, item (7) was added at DOR's request.

Section 2: Adds a new section to Title 24, Article 2, on legislative employees, stating that a present or former employee or agent of the legislature may not disclose confidential tax information.

Section 3: Adds a new section to the Legislative Standards of Conduct Code, stating that no person covered by the Code may disclose confidential tax information.

Section 4: Also adds to the Legislative Standards of Conduct Code a section to protect confidential information that may have been a source of a complaint before the Legislative Ethics Committee.

Section 5: Changes the penalties for disclosing confidential tax information to a class A misdemeanor. (Maximum penalties: 1 year imprisonment and $5,000.) This is the criminal code classification that most closely approximates current law. Last year, CSHB 502 (Jud)am specified a Class C felony, The change was made at the request of the Department of Revenue.

Section 6: Subsection (h) lays out the procedures for the legislature to deal with confidential tax information. It requires: a simple resolution to be passed authorizing a committee to request the tax information, requests must be in writing, the taxpayer must be notified, and all consideration must be in executive session unless the taxpayer consents in writing to a public meeting.

Subsection (i) was added at the request of the Department of Revenue. The purpose of this section is to allow, under prescribed circumstances, the Commissioner of Revenue to initiate the process of disclosing confidential tax information to the legislature.

Subsection (j) was added at the request of the oil industry (Jim Palmer, Standard Alaska). It provides that if tax records to be examined by a legislative committee identify a specific taxpayer, that taxpayer may attend the portion of the meeting that considers their particular return.

Subsection (k) makes it a violation of the law for a legislative member, former member, or employee to disclose confidential tax information (see Section 5 for the penalties). This section raises constitutional questions under Alaska Constitution Article II, Section 6 (See memo from Theresa L. Bannister, Legislative Council.) The section is written under the constitutional theory enunciated in the U.S. Supreme Court decision in U.S. v. Helstoski 442 US 477 490. The theory is that the legislature has plenary powers to discipline itself and may enlist the aid of the administrative branch and courts to do so.

Section 6 also requires legislators or employees, before viewing confidential tax information, to sign a form acknowledging that they are aware that the information is confidential and disclosure is prohibited.

Subsection (k) ensures that the exchange of information agreement with the Internal Revenue Service will not be violated.

Section 7: The bill has an immediate effective date.

Items in the referral file include:
Proposed CSHB 58 (JUD)
Memo from Theresa Bannister
Sectional analysis
Februrary 21, 1986 memo from Deborah Vogt to Louann Cutler
Exerpt from U.S. v. Helstoski 442 US 477 490
January 16, 1986 Memo from Deborah Vogt to Mike Greany
Statutes from other states on disclosure of tax information
Zero fiscal note

STATE OF ALASKA 1987 LEGISLATIVE SESSION
FISCAL NOTE

Bill Version: SB 70
Publish Date:

REQUEST

Revision Date: 2/13/87
Title: An Act relating to the disclosure of certain state tax assessment info.
Sponsor: Rules Committee
Requestor: Legislative Budget & Audit

Agency Affected: Revenue
BRU: Audit
Components:

EXPENDITURES/REVENUES: (Thousands of Dollars)

	FY 87	FY 88	FY 89	FY 90	FY 91	FY 92
OPERATING						
PERSONAL SERVICES	-	-	-	-	-	-
TRAVEL	-	-	-	-	-	-
CONTRACTUAL	-	-	-	-	-	-
SUPPLIES	-	-	-	-	-	-
EQUIPMENT	-	-	-	-	-	-
LANDS & STRUCTURES	-	-	-	-	-	-
GRANTS, CLAIMS	-	-	-	-	-	-
MISCELLANEOUS	-	-	-	-	-	-
TOTAL OPERATING	-	-	-	-	-	-
CAPITAL	-	-	-	-	-	-
REVENUE	-	-	-	-	-	-

FUNDING: (Thousands of Dollars)

	FY 87	FY 88	FY 89	FY 90	FY 91	FY 92
GENERAL FUND	-	-	-	-	-	-
FEDERAL FUNDS	-	-	-	-	-	-
OTHER	-	-	-	-	-	-
TOTAL	-	-	-	-	-	-

POSITIONS:

	FY 87	FY 88	FY 89	FY 90	FY 91	FY 92
FULL-TIME	-	-	-	-	-	-
PART-TIME	-	-	-	-	-	-
TEMPORARY	-	-	-	-	-	-

ANALYSIS: Attach a separate page if necessary

Prepared By: Steven E. Kettel RW for
Division: Audit
Phone: 465-2320
Date: 2/13/87

Approved by Commissioner: Hugh Malone Royce [illegible] FOR
Agency: Department of Revenue
Date: 2/13/87

Distribution (by Agency preparing fiscal note):
- Legislative Finance
- Legislative Sponsor
- Requestor
- Office of Management and Budget
- Impacted Agency(ies)
- Senate Secretary

Louann Cutler
House Finance Committee

February 21, 1986

465-3600

Harold M. Brown
Attorney General

By: Deborah Vogt
Assistant Attorney General
Oil, Gas and Mining-Juneau

Disclosure of confidential tax information

HB 502, as currently drafted, would permit the Department of Revenue to disclose to the legislature the name of a taxpayer and the amount of an assessment levied against that taxpayer by the Department. You have asked me to look into what the United States and other states permit in the way of legislative oversight of tax matters, and to consider whether Alaska might follow those examples. You have further asked me to draft a proposed committee substitute for HB 502 permitting disclosure to the legislature, but prohibiting disclosure to the public.

26 U.S.C. 6103 is the Internal Revenue statute dealing with the confidentiality of tax information on the federal level. Like AS 43.05.230, it generally requires that information on a federal tax return be kept confidential. Section (f) of that statute permits the IRS to disclose otherwise confidential material to designated committees of Congress. Those committees are the "tax writing" committees -- House Ways and Means, Senate Finance and the Joint Committee on Taxation. Like Alaska's law, if the information does not identify particular taxpayers, it may simply be given to Congress. If, however, the information would disclose or identify a particular taxpayer, it may only be provided to those committees in executive session. Taxpayer-specific information may also be provided to the chief of staff of the joint committee, to other committees under more limited circumstances, and to the "agents" of the tax-writing committees (staff) that are designated by the chairman.

I have made a cursory survey of the laws of other states, and have located one (California) which permits disclosure to the legislature. Corporate income tax information is disclosable under California Statute § 26453, and personal income tax information under § 19285. I have attached copies of those statutes for your review. California provides that it is a misdemeanor for a member of a committee or its staff to disclose the particulars of tax information.

<u>Considerations</u>.

1. <u>Accountability</u>. The present confidentiality statute imposes criminal penalties for unauthorized disclosure of tax information. That criminal penalty is probably an effective deterrent to unintentional disclosure: I know it makes me take very seriously the confidentiality of taxpayer information. It may be that here in Alaska it is especially important to consider accountability since our major taxpayers are few in number, and as a result the contents of their tax returns may be more memorable than would be any particular return in a state like California or at the federal level. Although neither California nor the United States appear to have dealt with the question of legislative immunity, I believe it is appropriate to consider whether a criminal penalty would have any effect should a legislator disclose confidential tax information in the course of legislative debate. (I do not believe that any question of immunity arises in the event that a legislator were to disclose information in another context -- for example, to a friend or relative in a social context.)

The speech and debate immunity appearing in the Alaska Constitution, like that in the United States Constitution, was designed to "preserve the constitutional structure of separate, coequal, and independent branches of government. The English and American history of the privilege suggests that any lesser standard would risk intrusion by the Executive and the Judiciary into the sphere of protected legislative activities." <u>United States v. Helstoski</u>, 442 U.S. 477, 490. Thus, the immunity is more than an individual privilege protecting legislators; its purpose is to protect, as well, the constituents of those legislators, who have an interest in ensuring free debate by their legislature. As a result, since it is not a personal privilege, it is not clear whether the immunity may be waived by a legislative body.

In <u>Helstoski</u>, the Court suggested (but did not decide) that Congress could "enlist the aid of the Executive Branch and the courts" in disciplining its members by a "narrowly drawn statute passed by Congress in the exercise of its legislative power to regulate the conduct of its members." Id. at 492. Although the issue apparently has never arisen, the Internal Revenue Service takes the position that Congress has done just that in section 6103, so that members of Congress are not immune from penalties for disclosure. The attached draft bill, then, specifically provides that a legislator would not be immune from penalties for unauthorized disclosure of tax information.

The legislature may, of course, take any action it deems appropriate to regulate the conduct of its own members. The draft bill, then, provides that disclosure of tax information is a violation of the standards of conduct set out in AS 24.60. Thus, even if a legislator who disclosed confidential information were to successfully argue that he or she was immune from the penalties of AS 43.05.230, that legislator would nonetheless have violated the legislature's standards of conduct, and would be subject to the provisions of that chapter.

2. Information exchange with the Internal Revenue Service. The state is currently entitled to information from the IRS, so long as the state has certain confidentiality protections. In amending the confidentiality provisions, it is appropriate to consider whether the exchange of information with the IRS would be affected. There are two relevant provisions of federal law.

The first is 26 U.S.C. § 6103 (d), which authorizes the IRS to disclose information generated by the IRS directly to the states so long as the information is protected by the state. An example of this type of information would be the results of a federal a Windfall Profit Tax audit. The information is available only to the agency charged with administering the tax laws; it may not even be disclosed to the governor. Thus, information received by Alaska under this section would not be available to the legislature under the draft bill. However, the draft bill would not effect the receipt of this information by the state.

The second relevant provision is more indirect, and deals with federal tax information that is provided to the state by the taxpayer. For example, a state may require that the federal return be attached to the state return, or that certain information from the federal return be entered on the state return. Since this information comes directly from the taxpayer, the United States has no control over the use to which the information is put. However, § 6103(p)(8) provides that if the state does not protect the confidentiality of this information, the IRS will no longer provide the direct information under § 6103(d). I have checked with the IRS disclosure attorneys in Washington, and they tell me that disclosure to the legislature, but not to the public, should have no effect on the exchange of information. They have also said that the IRS will work with us to determine the potential effect of any legislation before it is passed. I also spoke with California, which discloses information to its legislature, and the attorney there told me that disclosure did not effect the exchange of information with the IRS.

3. Effect of proposed bill on legislative involvement in settlement of tax disputes. The confidential nature of the recent settlement of severance tax issues with Arco raises the question of what the the effect of the proposed bill would be on the settlement process. The bill would permit (subject to the restrictions against public disclosure) legislators to review settlements to the extent that they now may do so with respect to non-tax matters. In other words, the bill removes the bar of tax confidentiality, no more and no less. The bill would not expand the legislature's ability to participate in the settlement process beyond its present parameters in non-tax matters.

Summary of the Proposed Bill

The draft bill provides that confidential information will be provided to a committee designated by the speaker of the house or the senate president. For example, the speaker might request that information be provided to the house finance committee. The committee may review and consider confidential information only in a closed, executive session (unless the taxpayer consents to an open hearing). If the committee desires that legislative staff have access to materials, it must first define the scope of an inquiry or investigation and then designate specific staff members who are authorized to review otherwise confidential information. Legislative employees would include, for example, the house research agency, so long as the committee, acting as a whole, designated those employees. The proposed bill restates that disclosure of information received under the subsection is not permitted, and specifically notes that this is true notwithstanding the statute setting out legislative immunity. 1/ It further would require that any individual, before receiving or reviewing information, must sign a statement acknowledging that he or she knows the information is confidential and that disclosure is prohibited.

The bill would add a new subsection in the legislative standards of conduct chapter, prohibiting disclosure of information received under the amendments proposed in the bill. Thus, even if a legislator successfully argued immunity under the speech and debate clause, he or she would still be subject to the provisions of that chapter.

DV:jf

1/ The intent, here, is to waive the speech and debate immunity, not the protections from being subjected to court proceedings during the legislative session. A court would probably find that the latter protection was not waived by the draft bill, but it may be that this should be clarified.

Other states permitting disclosure to the legislature

LEGISLATURE

Alabama	§ 40-1-33
California	§ 19284
Idaho	§ 63-3077
[Minnesota	§ 290-61 -abstracted info only]
Oregon	§ 314.840 - name + amount of tax of corporations only
Washington	§ 8232.330
Wisconsin	§ 71.11 (44)

from Deborah Vogt, Assistant AG

EXXON COMPANY, U.S.A.
P.O. BOX 196601 • ANCHORAGE, ALASKA 99519-6601 • (907) 561-5331

DONALD E. CORNETT
ALASKA COORDINATOR

February 10, 1987

Representative Pat Pourchot
Alaska State Legislature
Pouch V (MS 3100)
Juneau, Alaska 99811

Dear Representative Pourchot:

We understand the House Finance Committee is reviewing HB 58 and wish to offer our comments. We believe that HB 58 is unnecessary because AS 24.20.271 already gives the legislature performance audit authority over the tax revenue collection function of the Department of Revenue. This bill would needlessly increase the risk of highly sensitive taxpayer information being disclosed to competitors.

If your committee still believes this bill is needed, we would like the opportunity to work with you to develop a bill which will keep the legislature informed but still protect taxpayers from unnecessary disclosure. We believe the following are the more important areas in HB 58 that would need to be addressed.

- Section 6(h) must provide limits on the scope and purpose of the legislative review. Otherwise, the legislature could interfere in the audit and settlement process which is the prerogative of the Department of Revenue.

- Section 6(i) is particularly unnecessary since AS 43.05.010 already requires the commissioner to annually report and make recommendations to the governor and legislature concerning the efficiency and effectiveness of the department and the administration of the tax laws. This section would needlessly encourage the commissioner to intrude in the legislative process.

- There must be a limit on the type of taxpayer information subject to legislative disclosure. This is particularly important given the legislative immunities clause in the Alaska Constitution which may not provide taxpayers with true protection from disclosure of proprietary taxpayer information.

We have other concerns with this bill, some of which were discussed in our testimony on HB 502 last year, and we would be pleased to discuss these with you.

Sincerely yours,

D.E. Cornett

DEC/MLJ:jlp

A DIVISION OF EXXON CORPORATION

SENATE SPECIAL COMMITTEE ON OIL AND GAS

FEBRUARY 17, 1987

SB 70, RELATING TO THE DISCLOSURE OF CERTAIN STATE TAX ASSESSMENT INFORMATION BY THE DEPARTMENT OF REVENUE.

A COMMITTEE SUBSTITUTE HAS BEEN PREPARED.

IT ADOPTS MOST OF THE LANGUAGE FROM THE HOUSE JUDICIARY SUBSTITUTE FOR HB 58, THE HOUSE VERSION.

THE TELECONFERENCE IS TO CONNECT BARBARA HERMAN, DEPARTMENT OF LAW ATTORNEY FOR BACK TAXES FROM ANCHORAGE.

TO TESTIFY:

COMMISSIONER MALONE, Department of Revenue.

SENATOR HALFORD, Vice Chairman, Legislative Budget and Audit Comm.

SENATOR STURGULEWSKI

DEBORAH VOGT, Assistant Attorney General

BARBARA HERMAN, Assistant Attorney General, Back Taxes (ANCHORAGE)

JIM PALMER, Standard Alaska Petroleum Company

MARY JENSEN, Exxon

QUESTIONS:

Ask Commissioner Malone what the effect would be of deleting Section 6(i).

This section allows the commissioner to transfer confidential information to the legislature <u>without</u> a legislative request.

More consideration needs to be taken on defining what kind of information a committee may receive.

Also the form in which a written request is made. How to insure that only needed information is requested?

Should the request require the agreement of the full committee? What committees could receive information? Finance? Oil and Gas?

ALASKA STATE LEGISLATURE

SENATE SPECIAL COMMITTEE ON OIL AND GAS

Senator Bettye Fahrenkamp
Chairman
Senator Jack Coghill
Senator Paul Fischer

P.O. Box V, State Capitol
Juneau, Alaska 99811
(907) 465-3834

M E M O R A N D U M

TO: Members, Senate Special Committee on Oil and Gas

FROM: Committee Staff

RE: Committee Meeting, March 10, 1987

DATE: March 9, 1987

On Tuesday, March 10, at 3:30 pm in the Beltz Room, the Senate Special Committee on Oil and Gas will hear SB 70, Relating to the disclosure of certain tax assessment information by the Department of Revenue.

Current law prohibits the Department of Revenue from providing the Legislature with certain confidential tax information. Some of this information may be necessary to ensure proper legislative oversight over the department's tax collection function. In addition, the information may be useful in considering changes to the current tax structure.

Testimony was heard by this committee on February 17. A committee substitute has been prepared that reflects the changes that were made to the House version of the bill (HB 58) in a House Finance subcommittee. The subcommittee's work sessions with industry representatives resulted in consensus being reached on several points but disagreement remained on three major points. Attached is a discussion of those outstanding issues.

5-0321L
Bannister
3/4/87

Original sponsor: Rules/Legislative
Budget and Audit

SENATE OIL + GAS
IN THE ~~HOUSE~~ BY THE ~~FINANCE~~ COMMITTEE

SENATE 70 (Oil + Gas)
CS FOR ~~HOUSE~~ BILL NO. ~~58 (Finance)~~

IN THE LEGISLATURE OF THE STATE OF ALASKA

FIFTEENTH LEGISLATURE - FIRST SESSION

A BILL

For an Act entitled: "An Act relating to confidential tax information; relating to the filing of tax returns; and providing for an effective date."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

* Section 1. LEGISLATIVE FINDINGS AND PURPOSE. (a) The legislature finds that

(1) the majority of the state's revenue is derived from taxation;

(2) tax revenue enables the state to provide essential services to the citizens of the state to ensure the public health and welfare;

(3) the elected representatives of the people of the state must be assured that the state is receiving all of the income to which it is entitled and that the tax laws are operating in the manner intended by the legislature;

(4) the legislature must exercise its oversight authority to ensure that tax revenue collection by the Department of Revenue is efficient, fair, prompt, and in the best interest of the state;

(5) there is a legitimate and compelling governmental interest in the legislature having adequate access to tax-related information to allow responsible oversight;

(6) without sufficient information, the legislature cannot adequately determine that the state's tax revenue collection functions are properly administered and that tax revenue due the state is promptly received;

(7) tax returns and return information contain confidential information, often regarding sensitive business information;

(8) taxpayers have protections against public disclosure of certain tax information;

(9) exchange agreements with the Internal Revenue Service require that certain tax information not be publicly disclosed;

(10) protection of confidentiality fosters full disclosure by taxpayers to taxing authorities and therefore promotes effective administration of tax programs; and

(11) legislators and legislative employees who improperly disclose confidential tax information should be subject to the same sanctions imposed against executive branch employees.

(b) The purpose of this Act is to ensure that

(1) the state is receiving all the tax revenue due the state;

(2) oversight of the tax revenue collection function is effectively provided;

(3) tax revenue due to the state is available to provide for the public health and welfare of the citizens of the state;

(4) taxpayers are protected from improper disclosure of tax information;

(5) the exchange agreements with the Internal Revenue Service regarding tax information are not jeopardized;

(6) tax programs are administered fairly; and

(7) the right of the people to privacy is recognized and may not be infringed.

* Sec. 2. AS 24.10 is amended by adding a new section to article 2 to read:

Sec. 24.10.070. CONFIDENTIALITY OF INFORMATION. A present or former employee or agent of the legislature may not disclose tax

information contained in a report or return filed under AS 43.05.230 and furnished to the person under AS 43.05.232.

* Sec. 3. AS 24.60.060 is amended by adding a new subsection to read:

(b) A person to whom this chapter applies may not disclose tax information contained in a report or a return filed under AS 43.05.230 and furnished to the person under AS 43.05.232.

* Sec. 4. AS 24.60 is amended by adding a new section to read:

Sec. 24.60.172. SPECIAL PROCEEDINGS BEFORE THE COMMITTEE. Notwithstanding AS 24.60.170, if a complaint before the committee involves an allegation that a person to whom this chapter applies has disclosed tax information contained in a report or return filed under AS 43 with the Department of Revenue and furnished to the person under AS 43.05.232, and if the taxpayer or a third party whose tax information is alleged to have been improperly disclosed does not agree to the public disclosure of the identity of the taxpayer, the third party, or the tax information,

(1) the hearing may not be held in open session;

(2) a transcript containing confidential tax information shall be edited to prevent the disclosure of the confidential information;

(3) a decision, if made public, shall be edited to prevent the disclosure of the tax information and to protect the identity of the taxpayer or the third party; and

(4) a public statement may not contain information identifying the taxpayer, a third party, or the tax information.

* Sec. 5. AS 43.05.230(a) is amended to read:

(a) It is unlawful for a current or former officer, employee, or agent of the state to divulge the amount of income or the particulars set out or disclosed in a report or return made under this title,

except

(1) in connection with official investigations or proceedings of the department, whether judicial or administrative, involving taxes due under this title;

(2) in connection with official investigations or proceedings of the child support enforcement agency, whether judicial or administrative, involving child support obligations imposed or imposable under AS 25 or AS 47;

(3) as provided in AS 38.05.036 pertaining to audit functions; and

(4) as otherwise provided in this section <u>or in AS 43.05.232</u>.

* Sec. 6. AS 43.05.230(f) is repealed and reenacted to read:

(f) A person who knowingly violates a provision of this section is guilty of a class A misdemeanor. A person whose gross negligence results in a violation of this section is subject to a civil penalty of $5,000.

* Sec. 7. AS 43.05 is amended by adding a new section to read:

Sec. 43.05.232. DISCLOSURE OF CONFIDENTIAL TAX RETURNS AND RETURN INFORMATION TO THE LEGISLATURE. (a) Confidential tax returns and return information may not be requested by a legislative committee under (b) of this section or transferred to a legislative committee under (c) of this section,

(1) unless the purpose of the committee's request under (b) of this section or of the transfer under (c) of this section is

(A) to assist the committee in carrying out its responsibilities to consider tax legislation;

(B) to oversee the effective and efficient administration of the state's tax laws, including the review of audits,

litigation, or settlements; or

(C) to estimate future state revenue;

(2) if the purpose of the request or transfer is to direct the executive branch in its audit, litigation, or settlement efforts, or to collect information to embarrass, harass, or discriminate against a taxpayer.

(b) After a legislative committee identifies the scope of an investigation or inquiry relating to matters of taxation, and after adoption by either house of the legislature of a simple resolution giving the committee authority to receive confidential tax information, the committee chair or co-chair may request confidential tax returns and return information and the commissioner of revenue shall provide the requested returns or return information. The request shall be in writing and may identify a particular taxpayer.

(c) When consistent with the purposes set out in (a) of this section, the commissioner may transfer unrequested confidential taxpayer returns or return information to a legislative committee after making a written determination that the transfer of the return or return information is in the best interest of the state. Before the return or return information is transferred, the commissioner shall provide a copy of the commissioner's determination to the taxpayer whose return or return information is to be transferred. In determining whether the transfer of the return or return information is in the best interest of the state, the commissioner shall consider

(1) if the legislative committee is reviewing the administration of a tax imposed by this title, whether the return or return information would demonstrate the application of a tax;

(2) if the legislative committee is considering adding a new tax or amending an existing tax, whether the return or return

information would demonstrate the effect on taxpayers of a change in tax law;

(3) whether the return or return information would assist the legislative committee in estimating future state revenue;

(4) whether the return or return information would clarify or rectify information provided by a taxpayer to a legislative committee;

(5) the potential harm the taxpayer may suffer by the possible subsequent disclosure of the return or return information illegally;

(6) any other interest of the taxpayer in avoiding the transfer of the return or return information.

(d) A legislative committee shall consider tax returns and return information transferred under (b) or (c) of this section in executive session only, unless the taxpayer and any third party whose tax return or return information is being considered in conjunction with the taxpayer's return or return information consent in writing to a disclosure in open session. The executive session must be open to all legislators. The committee chair or co-chair may designate legislative employees and agents to inspect the confidential tax returns and return information, but the chair or co-chair shall seek to minimize the number of employees and agents designated. The designated employees and agents may attend the executive session. The chair or co-chair may allow a taxpayer whose confidential tax return or return information is being considered to attend the portion of the executive session that considers that taxpayer's confidential tax return or return information.

(e) When confidential tax returns or return information concerning a specific taxpayer are provided to a legislative committee under this section, the commissioner shall notify the taxpayer of the content and delivery of the return and return information to the committee.

(f) Before providing confidential tax return or return information under (b) or (c) of this section, the commissioner shall review the purpose of the proposed transfer of the return or return information to determine what types of confidential tax return or return information will provide the needed information. If more than one type of confidential tax return or return information will provide the needed information, the commissioner shall choose the return or return information that, in the commissioner's discretion, is the least commercially sensitive.

(g) Disclosure contrary to the provisions of this section by a member or former member of the legislature or by a present or former employee or agent of the legislature of a return or return information that is confidential under AS 43.05.230 and transferred to the legislature under this section is a violation of AS 43.05.230. A member of the legislature and an employee or agent of the legislature, before receiving or reviewing a return or return information provided by the commissioner under (b) or (c) of this section, shall, on a form prepared by the commissioner,

(1) acknowledge that the return or return information is confidential and that a disclosure of the return or return information contrary to the provisions of this section is prohibited by law; and

(2) execute an agreement with the department to keep the return or return information confidential, to abide by regulations adopted by the department, and to return the documents to the department.

(h) The commissioner shall adopt regulations governing the transmittal, receipt, safekeeping, duplication, accounting for, and return of the confidential tax return and return information transferred under (b) and (c) of this section.

(i) This section does not permit the transfer to the legislature of confidential tax returns and return information provided by the Internal Revenue Service under exchange agreements with the department.

(j) In this section

(1) "return" has the meaning given in 26 U.S.C. 6103(b)(1), except that "secretary" is read as "department" and "this title" means AS 43;

(2) "return information" has the meaning given in 26 U.S.C. 6103(b)(2)(A), except that "secretary" is read as "department" and "this title" means AS 43.

* Sec. 8. AS 43.20.030 is amended by adding a new subsection to read:

(h) The department may grant an extension for filing a return required under this section. The extension may not exceed 30 days beyond the filing date or the extension granted to the taxpayer by the Internal Revenue Service for filing the taxpayer's federal income tax return, whichever is later. Granting the extension does not affect the due dates for payment of the tax.

* Sec. 9. AS 43.05.232, as enacted by sec. 7 of this Act, applies to all confidential tax returns and return information in the possession of the department on or after the effective date of this Act.

* Sec. 10. This Act takes effect immediately under AS 01.10.070(c).

ALASKA STATE LEGISLATURE

SENATE SPECIAL COMMITTEE ON OIL AND GAS

Senator Bettye Fahrenkamp
Chairman
Senator Jack Coghill
Senator Paul Fischer

P.O. Box V, State Capitol
Juneau, Alaska 99811
(907) 465-3834

March 10, 1987

SECTIONAL ANALYSIS OF PROPOSED CSSB 70 (Oil and Gas), RELATING TO CONFIDENTIAL TAX INFORMATION; RELATING TO THE FILING OF TAX RETURNS.

Title change: The original bill provided for public disclosure of certain tax information. The Oil and Gas Committee substitute allows only the transfer of information to the legislature under certain conditions. In addition, Section 8 codifies existing practice by allowing the commissioner to grant a 30 day extension on filing of corporate income tax returns.

Section 1: A finding and purpose section is included to assist the courts in interpreting the bill. A taxpayer's right to privacy under Alaska Constitution Article 1, Section 22 must be balanced with the legislature's need for information on how the state's tax laws are working.

Section 2: Adds a new section to Title 24, Article 2, on legislative employees. It would prohibit a present or former employee or agent of the legislature from disclosing confidential tax information.

Section 3: Adds a new section to the Legislative Standards of Conduct Code. Disclosure of confidential tax information by persons covered by the Code would be prohibited.

Section 4: Also adds to the Legislative Standards of Conduct Code a section to protect confidential information that may have been a source of a complaint before the Legislative Ethics Committee.

Section 5: Amends existing statute that prohibits disclosure of confidential tax information by state employees to allow the transfer of information to the legislature.

Section 6: Establishes penalties for violation of the confidentiality provisions. A "knowing" violation is a class A misdemeanor (Maximum penalties: 1 year imprisonment and $5,000); a "negligent" violation is subject to a civil penalty of $5,000. Current statute provides penalties only for an "intentional" violation.

Section 7: **Creates a new section of statute to deal specifically with the transfer of confidential tax information to the legislature.**

(a) Establishes purposes for which tax information may be transferred to the legislature (to assist in consideration of tax legislation, oversight of the administration of tax laws, including the review of settlements, litigation, and audits, or estimation of future state revenues), and purposes for which information may not be transferred (to direct the executive branch in its audit, litigation, or settlement efforts, or to embarrass, harass, or discriminate against a taxpayer).

(b) Establishes a procedure for requesting tax information. After adoption of a simple resolution that identifies the scope of the inquiry and allows a committee to receive information, a committee chair or co-chair may make a written request.

(c) Allows the commissioner to transfer unrequested information if a written finding is filed showing that the transfer is in the best interest of the state. Lists points the commissioner must consider (whether the information would demonstrate the application of a tax or the effect of a change in tax law, assist in estimating revenues, or clarify information provided by a taxpayer, and the potential harm a taxpayer may suffer by the possible subsequent illegal disclosure of the information). Requires the commissioner to provide affected taxpayers with a copy of the written finding.

(d) Requires that confidential information be considered only in executive session, and that all legislators may attend the session. Authorizes the chair or co-chair to designate employees and agents to review the tax information and attend the executive session, but to minimize the number of such employees. Authorizes the chair to allow the taxpayer whose returns are being considered to attend the executive session.

(e) Requires that the commissioner notify the taxpayer of the contents of the information transferred to the committee.

(f) Requires that, when more than one type of information will satisfy the legislature's request, the commissioner must choose the least commercially sensitive information.

(g) Specifies that anyone authorized to receive confidential information must sign a form acknowledging that disclosure of the information is prohibited by law, and agreeing to abide by procedures adopted by the department.

(h) Requires the commissioner to adopt regulations governing the transmittal, receipt, safekeeping, duplication, accounting for, and return of the information.

(i) Ensures that the exchange of information agreement with the Internal Revenue Service will not be violated.

(j) Defines "return" and "return information" as it is defined in federal law.

Section 8: Amends existing law to allow the department to grant taxpayers an extension for filing their returns.

Section 9: Specifies that the act applies to all returns and return information in the possession of the department on the effective date of the act.

Section 10: The bill has an immediate effective date.

Alaska State Legislature

REPRESENTATIVE
PAT POURCHOT

HOUSE FINANCE COMMITTEE
COMMITTEE ON OIL AND GAS

House of Representatives

March 5, 1987

CSHB 58 (Fin) Relating to confidential tax information of the Department of Revenue

The subcommittee's work sessions resulted in consensus being reached on several points. The following are points on which the subcommittee members agree, but on which the industry representatives who attended the work session do not:

1) Definition of "tax return" and "return information."

The subcommittee agreed to use the federal definition, which is very inclusive and would allow legislative access to a wide range of information filed with the Department of Revenue. Industry representatives expressed concern that this would include proprietary information such as specific transactional agreements with third parties. They argued that possible subsequent illegal disclosure of such information would be very damaging to a company's competitive position. Additionally, industry argued that such sensitive information was not of the type the Legislature needs to investigate tax laws and policies.

In an attempt to address this concern, the subcommittee added language to HB 58 which: a) Increases the penalties for disclosure (page 4, lines 14-17); b) Requires the commissioner to transfer the least commercially sensitive information that meets the legislature's request (page 7, lines 9-12); c) Requires the implementation of regulations that govern the transmittal and safekeeping of confidential documents (page 7, line 29 through page 8, line 3); and d) Minimizes the number of legislative employees and agents who would have access to the information (page 6, lines 21-22).

2) The commissioner's ability to initiate the transfer of information.

The subcommittee agreed to authorize the commissioner, under certain conditions, to come forward with confidential information (i.e., passage by the legislature of a simple resolution would not be required). The subcommittee felt this would provide a needed avenue when the legislature may not be aware of specific problems, as in the case of the Administration advancing its own tax legislation.

Industry representatives felt that the scrutiny associated with passage of a simple resolution provides a needed "control" over the scope and purposes of a request for information. They argued that no such parallel control would be placed on the commissioner, possibly resulting in abuses at some future time.

In an attempt to address this concern, the subcommittee strengthened language in HB 58 to require that the commissioner: a) Consider a number of criteria in a written finding that precedes the transfer (page 5, line 25 through page 6, line 12); b) Notify the taxpayer of the content of the information being transferred (page 7, lines 1-2); and c) Transfer information only when consistent with the purposes outlined in the act (page 4, line 24 through page 5, line 6). In addition, the safeguards discussed in #1 (definition) apply here also.

3) Access to information currently covered under "protective orders."

Industry representatives expressed concern that existing protective agreements (which generally provide an additional layer of protection beyond that currently provided in statute) were entered into with "one set of rules in mind," and the agreements should not change even if the rules do.

The Attorney General has advised that protective agreements ordered by the court (for example, due to ongoing litigation) will probably not be changed by passage of HB 58, but that administrative protective orders (for example, issued by Department of Revenue hearing officers during administrative hearings) could be affected. Should the legislature seek access to information currently covered by an administrative protective order, and should the taxpayer sue to block access, the court might decide that the protective agreement is of a contractual nature and thus unaffected by HB 58.

The subcommittee did not wish to explicitly prevent information from being transferred simply because it was covered by some type of protective order. The subcommittee recognized that some court orders might take precedence over a legislative request for information, but did not want to comment on, or prejudice any "separation of powers" argument, at this time.

Official Business

COMMITTEE:

SPECIAL COMMITTEE ON
OIL AND GAS

DATE: MARCH 10, 1987

SIGN - IN

Subject of meeting:

SB 70 "AN ACT RELATING TO THE DISCLOSURE OF CERTAIN STATE TAX ASSESSMENT INFORMATION BY THE DEPT. OF REVENUE."

NAME	ADDRESS	PHONE	REPRESENTING	DO YOU WANT TO TESTIFY?
Judy Elisen			Standard	YES

March 10, 1987

1) Exempt sales bill

WOULD LIKE TO INTRODUCE AS A COMMITTEE BILL.

EXEMPT OIL AND GAS SALES ARE SALES THAT ARE NOT PLANNED FOR IN THE 5 YEAR PLAN.

BILL WOULD STREAMLINE THE PROCESS.

ALLOW THE STATE TO HOLD EXEMPT SALES WITHOUT BEST INTEREST FINDINGS IF THE LEASES ARE IN OR NEXT TO AN AREA THAT HAS ALREADY HAD A FINDING PREPARED WITHIN THE PAST THREE YEARS.

2) MOVE SJR 8, Relating to a federal tax on imported oil

COPIES OF A HARVARD STUDY FOR COMMITTEE MEMBERS.

3) SB 70, Relating to the disclosure of certain state tax assessment information by the Department of Revenue.

A COMMITTEE SUBSTITUTE HAS BEEN PREPARED.

IT INCORPORATES THE LANGUAGE THAT WAS ADOPTED BY THE HOUSE FINANCE COMMITTEE LAST THURSDAY.

IS THE RESULT OF A SERIES OF WORK SESSIONS WITH INDUSTRY REPRESENTATIVES CONDUCTED BY A HOUSE FINANCE SUBCOMMITTEE.

CONSENSUS WAS REACHED ON MANY POINTS BUT THERE IS STILL DISAGREEMENT ON A FEW MAJOR POINTS.

TO TESTIFY: Danny 1st analysis of bill

last COMMISSIONER HUGH MALONE, Department of Revenue

JUDY ELLISON, Standard Alaska ~~Petroleum~~ Production Company

DEBRA VOGT
BARBARA HERMAN, Assistant Attorney General, Department of Law.

May propose amendment to clarify "negligent" violation.

3:40 BF ✓
Coghill

DC outlines —

→ executive session — need joint rules?
whose allowed in?

Debra Vogt

enforced by DOR.

Holford

sue for damages?

Judy Ellison SAPCO

protect proprietary information.

audit, delay

1) transactional documents —

2) protective orders

3) commissioners ability.

Malone

why aren't laws working?

failure of oversight function. of legislature

because of failure of ha

essential

info That leg needs -

legislature is responsible.

need access to all information:

Bill wouldn't change protective orders

no provision for interim requests?

dept. should be able to forward info to The legislature -

Leg will act responsibly.

adjourned 4:22

Standard Alaska
Production Company
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 561-5111

STANDARD
ALASKA PRODUCTION

MY NAME IS JIM PALMER. I AM THE MANAGER OF GOVERNMENTAL AFFAIRS FOR STANDARD ALASKA PRODUCTION COMPANY.

STANDARD APPRECIATES THE ATTENTION WHICH THIS COMMITTEE HAS PAID TO OUR CONCERNS ABOUT HOUSE BILL 58. CHANGES SUCH AS ALLOWING THE TAXPAYER AN OPPORTUNITY TO REVIEW THE CONTENTS OF THE INFORMATION TO BE TRANSFERRED AND TO COMMENT THEREON IS A VALUABLE PROTECTION TO ALL TAXPAYERS. THIS OPPORTUNITY BY THE TAXPAYER TO REVIEW AND COMMENT IS ALSO VALUABLE TO THE LEGISLATURE IN THAT THE LEGISLATURE IS MORE LIKELY TO RECEIVE A BALANCED PACKAGE OF INFORMATION. COMPARED TO EARLIER VERSIONS, THE CURRENT BILL STRIKES A FAR BETTER BALANCE OF THE TAXPAYER'S PRIVACY RIGHTS WITH THE LEGISLATURE'S NEED TO KNOW CERTAIN INFORMATION.

STANDARD DOES STOP SHORT OF ENDORSING THE BILL, HOWEVER, BECAUSE WITH 60 LEGISLATORS AND THEIR AIDES AND AGENTS HAVING ACCESS TO HIGHLY CONFIDENTIAL INFORMATION, THERE IS AN UNAVOIDABLE CONCERN ABOUT UNAUTHORIZED DISCLOSURE. ADDITIONALLY, THE BILL COULD ALLOW A FUTURE LEGISLATIVE BODY TO PERFORM EXECUTIVE FUNCTIONS. THIS COULD OCCUR WHERE THE LEGISLATURE UNDULY INFLUENCES THE DEPARTMENT IN THE EXECUTION OF AUDITS.

WHILE WE HAVE BASIC PROBLEMS WITH THE THRUST OF THE BILL, WE BELIEVE THIS COMMITTEE HAS INCORPORATED MANY SAFEGUARDS IN HB 58 WHICH ARE BENEFICIAL. IF THE LEGISLATURE BELIEVES THAT A BILL OF THIS TYPE IS NECESSARY, WE THINK THE OIL AND GAS COMMITTEE SUBSTITUTE CLOSES MANY OF THE LOOPHOLES THAT PREVIOUS VERSIONS HAD. STANDARD AGAIN THANKS THIS COMMITTEE FOR THE GOOD FAITH MANNER IN WHICH THE COMMITTEE LISTENED TO OUR CONCERNS AND FOR THE INCORPORATION OF CHANGES INTO THE BILL.

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

April 29, 1987

Senator Bettye Fahrenkamp
Chairman
Senate Oil & Gas Committee
Pouch V
Juneau, Alaska 99801

Dear Senator Fahrenkamp:

ARCO Alaska, Inc. greatly appreciated the opportunity to provide input during the shaping of what is now Senate CS for CS for HB 58. As a result of this process, the bill has, in our view, been substantially improved.

Unfortunately, we are still unable to endorse this bill because it permits unrequested information to be transferred out of the Department of Revenue and it subjects some of our most sensitive business documents to the risks of disclosure.

We do however, recognize the legislature's need for certain information and regret that we were unable to fully resolve our concerns during our extensive sessions.

Sincerely,

Hugh R Motley

Hugh R. Motley
Assistant Tax Officer

SB
182

Senate Special Committee on Oil and Gas

Legislation Checklist

Bill number: SB 182 Sponsor: O&G COMMITTEE

Date referred to committee: 3/12/87 Further referrals:
Resources
Finance

Prior committee report:

Back up from sponsor:

Fiscal note(s):

Agency: DNR Requested: Received:

Agency: Requested: Received:

Position paper(s):

Agency: Requested: Received:

Agency: Requested: Received:

Sectional Analysis:

Scheduled: 3/24 Heard: 3/24 Reported out:

Items for committee packet:

To Testify:

Jim Eason 762-4246 – Pam Rogers

Mike Abbott, RDC 276-0700

Eagy ADGA

Dan Smith, Exxon

Other Contacts:

RDC –

ADF&G –

DEC –

ALASKA STATE LEGISLATURE

SENATE SPECIAL COMMITTEE ON OIL AND GAS

Senator Bettye Fahrenkamp
Chairman
Senator Jack Coghill
Senator Paul Fischer

P.O. Box V, State Capitol
Juneau, Alaska 99811
(907) 465-3834

M E M O R A N D U M

TO: Senator Johne Binkley, Co-Chairman
Senate Finance Committee

FROM: Senator Bettye Fahrenkamp, BF Chairman
Senate Special Committee on Oil and Gas

RE: Committee Hearing on SB 182

DATE: April 30, 1987

I would appreciate your scheduling SB 182, An Act relating to the written findings required for certain state oil and gas lease sales, for a hearing before the Senate Finance Committee.

Current statute requires that all proposed state oil and gas lease sales be included in a yearly five year leasing program submitted to the legislature. However, under certain circumstances, sales that are not included in the five year plan, or "exempt sales", may be held. Exempt sales usually include previously offered leases, areas adjacent to those leases, or areas in which industry has shown high interest. Current statute requires that a written best interest finding be made for most exempt sales.

SB 182 would waive the best interest finding requirement for exempt sales if a previous finding has been made for that area within the preceding three years. This change may enable the department to add new areas to the leasing schedule with reduced administrative costs and delay.

ALASKA STATE LEGISLATURE

SENATE SPECIAL COMMITTEE ON OIL AND GAS

Senator Bettye Fahrenkamp
Chairman
Senator Jack Coghill
Senator Paul Fischer

P.O. Box V, State Capitol
Juneau, Alaska 99811
(907) 465-3834

M E M O R A N D U M

TO: Members, Senate Special Committee on Oil and Gas

FROM: Committee Staff

RE: Committee Meeting, March 24, 1987

DATE: March 23, 1987

On Tuesday, March 24, at 3:30 pm in the Beltz Room, the Senate Special Committee on Oil and Gas will hear SB 182, Relating to state oil and gas lease sales.

Current statute requires that all proposed state oil and gas lease sales be included in a yearly five year leasing program submitted to the legislature. However, under certain circumstances, sales that are not included in the five year plan, or "exempt sales", may be held. Exempt sales usually include previously offered leases, areas adjacent to those leases, or areas in which industry has shown high interest. Current statute requires that a written best interest finding be made for most exempt sales.

SB 182 would waive the best interest finding requirement for exempt sales if a previous finding has been made for that area within the preceding three years. This change may enable the department to add new areas to the leasing schedule with reduced administrative costs and delay.

Comments of
D. M. Smith
Exxon Company, U.S.A.
Senate Special Committee on Oil and Gas
SB-182
March 24, 1987

Good Afternoon. My name is Dan Smith and I am a Senior Government Affairs Representative with Exxon Company, U.S.A. I appear before you today to offer Exxon's support for Senate Bill 182.

Current law requires that land not included on the states five year lease program for two years can only be offered for leasing under specific conditions. Most of those conditions require that the Department of Natural Resources must, after a hearing, make a written finding in order to lease the lands in question. Such lands include land contigious to already leased properties, land adjacent to land owned or controlled by another party on which discoveries of commercial quantities have been made, or land adjacent to land included in the Federal OCS leasing program.

By streamlining the pre-leasing requirements to use existing findings for these well studied areas, this bill would simultaneously help the state avoid unnecessary costs and facilitate leasing in known areas of interest. In supporting this bill, we would hope that this accelerated timing would not be so rapid as to deprive potential bidders of time to adequately prepare to participate in a lease sale.

We appreciate the opportunity to comment.

JDH/4284:dag
3/23/87

MEMORANDUM
DEPARTMENT OF NATURAL RESOURCES

State of Alaska
DIVISION OF OIL AND GAS

TO: Carol Wilson, Special Assistant to the Commissioner

DATE: February 3, 1987

FILE NO:

TELEPHONE NO: 762-4241

FROM: James E. Eason, Director

SUBJECT: Proposals to Streamline Exempt Lease Sale Process

While I was in Juneau the week of January 26-30, I was asked by both Senator Bettye Fahrenkamp and Senator Jack Coghill for recommendations on how to promote early exploration of the state's lands; specifically, how to streamline the procedures for exempt oil and gas lease sales. On January 30, Ned Farquhar called me on behalf of Representative Sam Cotten and said that Rep. Cotten might be interested in possible changes to Title 38 that would make it easier to hold exempt acreage sales.

At present, exempt acreage sales must follow all of the procedural "hoops" required of scheduled sales. One way to streamline the process would be to apply previous best interest findings under AS 38.05.035 to the exempt sale area. This would greatly reduce administrative costs and delay. I am sending you a suggested change to AS 38.05.035 that would enable the state to hold exempt sales without having to write preliminary or final .035 best interest findings if the leases offered are in, contiguous with or adjacent to an area for which a written .035 finding has been prepared during the preceding 36 months. I would appreciate your discussing this proposal with the Commissioner, and if it meets with her approval, transmitting it on my behalf to Senators Fahrenkamp and Coghill and Representative Cotten.

AS 38.05.035(e). Amend by adding a new section (7), as follows: "(7) an exempt oil and gas lease sale under AS 38.05.180(d) for which a written finding has been issued, within a period of 36 months before the date of the sale, for the area of the proposed sale, or for contiguous or adjacent areas."

cc: Mark Worcester
Pam Rogers

0737R

DELIVER TO: Carol Wilson LOCATION: Juneau
FROM: Jim Eason LOCATION: Oil & Gas
TELEPHONE/TELECOPIER #: 586-2754 TOTAL NUMBER OF PAGES:
TRANSMITTING ON/SPEED: DATE: 2/3/87 TIME: 4:00
PHONE FOR PROBLEMS-NAME/NUMBER: Loletta 762-4244
COMMENTS:

Ned/DR
SR
SOL

5-0732A
Bannister
2/26/87

SENATE SPECIAL COMMITTEE ON OIL and GAS

IN THE SENATE BY ~~FAHRENKAMP~~

SENATE BILL NO.

IN THE LEGISLATURE OF THE STATE OF ALASKA

FIFTEENTH LEGISLATURE - FIRST SESSION

A BILL

For an Act entitled: "An Act relating to state oil and gas lease sales."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

* Section 1. AS 38.05.035(e) is amended to read:

(e) Upon a written finding that the interests of the state will be best served, the director may, with the consent of the commissioner, approve contracts for the sale, lease, or other disposal of available land, resources, property or interests in them, and, in addition to the conditions and limitations imposed by law, may impose additional conditions or limitations in the contracts as the director determines, with the consent of the commissioner, will best serve the interests of the state. A contract for the sale, lease, or other disposal of available land or an interest in land is not legally binding on the state until the commissioner approves the contract but if the appraised value is not greater than $50,000 in the case of the sale of land or an interest in land, or $5,000 in the case of the annual rental of land or interest in land, the director may execute the contract without the approval of the commissioner. Before a public hearing, if held, or in any case no less than 21 days before the sale, lease, or other disposal of available land, property, resources, or interests in them, the director shall make available to the public a written finding that sets out the facts and applicable law upon which the determination that the sale, lease, or other disposal will best serve the interests of the state was based. A written finding is not required before the approval of

(1) a contract for a negotiated sale authorized under AS 38.05.115;

(2) a lease of land for a shore fishery site under AS 38.05.082;

(3) a permit or other authorization revocable by the commissioner;

(4) a mineral claim located under AS 38.05.195;

(5) a mineral lease issued under AS 38.05.205; [OR]

(6) a production license issued under AS 38.05.207; or

(7) an oil or gas lease sale under AS 38.05.180(d), if within 36 months before the lease sale a written finding under this subsection has been made for the area of the proposed lease sale or for an area that is contiguous with or adjacent to the area of the proposed lease sale.

RESOURCE DEVELOPMENT COUNCIL
OIL AND GAS DIVISION
PROPOSED AMENDMENTS TO AS 38.05

Proposed Amendments to Implement Land Ownership and Management Strategies (page 6) to make it easier for the Commissioner of Natural Resources to add new areas to the leasing schedule.

AS 38.05.180 (b) is amended by adding a new sub-section to read:

(1) The leasing schedule should consider all prospective lands in the state and should provide that at least five percent of all state acreage be offered for ~~sale~~ lease each year.

AS 38.05.180 (c) is amended to read:

Oil and gas lease sales should be held as provided in the five year leasing program but due to changing circumstances the commissioner may add to the schedule during a year by giving notice to the public at least 180 days prior to a sale. A sale may be delayed by the commissioner if he determines it is in the best interest of the state. ok

Proposed Amendment to AS 38.05 to Implement Oil and Gas Strategy on "Incentives and Taxation to reinstate the "discovery royalty" (page 9).

AS 38.05.180 is amended by adding a new subsection to read:

(aa) the lessee of a state oil and gas lease on which a discovery well has been drilled shall be entitled to withhold a discovery royalty award of 60% of the oil and gas royalty otherwise payable to the state for that lease for a period of ten years provided that all of the following criteria are met:

1) the well must be drilled at a surface location at least 10 miles from the surface location of any other will which has been tested in commercial quantities or is presently capable of producing in commercial quantities; 2) a discovery test in commercial quantities has been witnessed by an agent of the state; 3) the discovery test interval is located entirely under the lease for which the award is given; 4) the discovery test is completed within one year from the date of first penetration of the producing zone in that well and 5) applications for the award is made within 180 days of the completion of the commercial test. The royalty award will be effective for 10 years from the date of first continuous production from the well.

Proposed Amendment to AS 38.05 to Implement Oil and Gas Strategy on "Incentives and Taxation" (pages 8 and 9).

AS 38.05.180(i) is amended as follows:

(i) The commissioner SHALL (may) provide for the establishment of an exploration incentive credit system under which a lessee of state land drilling an exploratory well on that land may earn credits based upon the footage drilled and the region in which the well is situated. The commissioner SHALL (may) also provide for credits to be earned by persons performing geophysical work on state land, if that work is performed during the two seasons immediately preceding an announced lease sale and on land included within the sale area and the geophysical information is made public following the sale. Credits may not exceed 50 percent of the cost of the drilling or geophysical work. Credits may be used during a limited period established by the commissioner and may be assigned during that period. Credits may be applied against (1) oil and gas royalty and rental payments payable to the state or (2) taxes payable under AS 43.55. A credit may not exceed 50 percent of the payment toward which it is being applied. Amounts due the Alaska permanent fund (AS 37.13.010) shall be calculated before the application of credits under this subsection.

RDC amendments

(1) what is "all prospective land"?

balance between flooding

exempt sales - not on 5-year schedule

use almost yearly —
adjacent

owned by state —

offered all the good acreage the state has!

in Pr.

makes sum

market

(2) Allow brand new areas to be leased w/o sufficient notice -
what is "changing circumstances"

(3) Discovery royalty — incentive -
repealed —
value of incentive not clear.

Senator John B. (Jack) Coghill
Alaska State Legislature

Pouch V
Juneau, Alaska 99811
(907) 465-4921

Box 55028
North Pole, Alaska 99705
(907) 488-0862

MEMORANDUM

TO: Senator Fahrenkamp, Chairwoman, Oil and Gas Committee

FROM: Senator Coghill Jack

RE: Proposed Amendments to AS 38.05

DATE: February 4, 1987

My office recently received from the Resource Development Council, a draft of proposed changes to statute, which would "make it easier for the Commissioner of Natural Resources to add new areas to the leasing schedule."

It is my feeling that this is a good idea.

I am forwarding a copy of the language they supplied my office.

Please read it over and let me know if you are either already working on this legislation or want to take it up in your committee.

RESOURCE DEVELOPMENT COUNCIL
OIL AND GAS DIVISION
PROPOSED AMENDMENTS TO AS 38.05

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1) the well must be drilled at a surface location at least 10 miles from the surface location of any other will which has been tested in commercial quantities or is presently capable of producing in commercial quantities; 2) a discovery test in commercial quantities has been witnessed by an agent of the state; 3) the discovery test interval is located entirely under the lease for which the award is given; 4) the discovery test is completed within one year from the date of first penetration of the producing zone in that well and 5) applications for the award is made within 180 days of the completion of the commercial test. The royalty award will be effective for 10 years from the date of first continuous production from the well.

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Senator John B. (Jack) Coghill
Alaska State Legislature

Box V
Juneau, Alaska 99811
(907) 465-4797

Box 55028
North Pole, Alaska 99705
(907) 488-0862

May 13, 1987

MEMORANDUM

To: All Members of the Senate

From: Senator John B. Coghill

Re: CSSB 196 (Rules)

The passage of CSSB 196 (Rules) is essential because a recent Supreme Court decision (Alaska Survival v. State of Alaska) requires the department of Natural Resources to do regional land plans before disposals of state land or resources can take place.

The Alaska Survivial case addressed a land disposal at Chase. Howevers its implications go much further than programmatic land disposals. Since August 29, 1986, the department has stopped all new classification actions that are not based on comprehensive plans.

DNR has been making prudent decisions on a site specific basis in areas without regional plans for many years. The result of the court decision is that conveyances and disposals in areas without regional plans are now held up.

Examples of the impact of this court decision include:

1. State timber near Cooper Landing is infested with beetles. Despite a U.S. Forest Service plan to cut timber adjacent to state land, the state's Division of Forestry cannot sell our affected timber because the land is unclassified. There is no area plan for state lands on the Kenai, so the land cannot be classified.

2. Several residents of the Hope area hold U.S. Forest Service permits for land now owned by the state. The state cannot sell the permitted land to the occupants as required under the

preference rights statute because it is not appropriately classified. The land cannot be reclassified.

3. The City of Nome has not been able to acquire a tidelands lease to protect the rock loading jetty it built because there is no comprehensive plan on which to base a classification action required for lease issuance.

In short, while the subject of Alaska Survival v. State of Alaska was programmatic land disposals, the decision stymied other land management actions such as leasing unclassified lands, particularly tide and submerged lands; conducting timber sales over 10MBF; selling land to U.S. Forest Service permittees and resolving municipal claims.

In addition to authorizing the department to adopt site-specific plans land use plans of the department or a municipality with planning and zoning powers, CSSB 196 also makes changes to Title 38, that reflect the needs of the department.

A sectional analysis is attached.

Sectional Analysis

CSSB 196 (Rules)

Sec.1: The section amends existing law to require plans be adopted instead of developed by the Commissioner.

Sec. 2: This section removed the word "region" in existing law, to remove any impled or inferred distinction between an "area" and a "regional" plan. It also given priority to renewable and non-renewable resource development.

Sec. 3: Same improvement as Sec. 2.

Sec. 4: This new language allows the department to use plans adopted by other entities and local governments as a basis for classification actions when the Commissioner, after public and agency review, determines those plans are in the best interest of the state. This is a dollars and sense provision that lets us take advantage of other plans when we haven't done our own.

Sec. 5: Technical change.

Sec. 6: The changes are intended to reinforce the consistency of state plans with municipal plans.

Sec. 7: The section makes clear that a regional plan must be adopted before the department may proceed with a programmatic land disposal (homesite, homestead, lottery) as a new commercial ag project. It also makes clear that oil and gas lease sales are subject to the five year sale process in existing law.

Sec. 8: This technical amendment brings the definition of short term lease current with changes adopted in AS 38.05.060(b) in 1984.

Sec. 9: This amendment allows the department to sell land at fair market value to folks who acquired improvements on the land from another state agency when that land is excess to existing state programs.

Sec. 10: This section amends existing law on best interest findings, required prior to disposal of state interests, to allow the Commissioner to reoffer oil and gas interests within 3 years after a prior best interest finding. Under existing law, when leases are rescinded or are not sold at a lease sale, the Commissioner may be required to go through the best interest finding process a second time.

Sec. 11: This amendment makes clear that the department shall retain a reversionary interest in land which it conveys at less than fiar market value to a local government or charitable institution. It further requires a written best interest finding if the reversionary interest retention is not in the best interest of the state and should be waived.

Sec. 12: This amendment conforms the definition of vereran in this section to that which is the standard in all other definitions of veteran for the purpose of land discounts.

Sec. 13: This amendment allows homesteaders to trade entry permits upon the commissioner approval. It allows family members and friends to receive adjacent parcels when everyone is willing.

Sec. 14: This amendment give a little breathing room to homesteaders who currently have only 1 years to survey their parcels. Funding cuts to the department have slowed the issuance of survey instructions. It also clarifies the cleaing requirements made necessary by massive soil reclassifications by SCS.

Sec. 15: This section deletes the lot line brushing requirements for a homesteader when a parcel is described by aliquot parts. It also conforms the soil classification language improved in Sec. 14.

Sec. 16: This section validates land classification made prior to the supreme court decision in <u>Alaska Survival</u> pending the completion of plans.

Sec. 17: This section validates land management and disposal decisions made by the commissioner on the basis of AS 38.05.300 (site specific plans) prior to the effective date of this bill, whether or not area plans underlay the classification orders leading to disposal.

Sec. 18: This section makes clear that mineral management decisions made pursuant to existing law before this Act are valid whether or not the land as classified.

Sec. 19: This section reinforces the decision of the Supreme Court that DNR must reconsider its Chase decision.

Sec. 20: This section repeals th esection that was amended in Sec. 15. It makes survey of homesteads uniformly 5 years instead of 2 and up to 5 on a case by case basis.

Sec. 21: Provides for an effective date.

STATE OF ALASKA

DEPARTMENT OF LAW

OFFICE OF THE ATTORNEY GENERAL

STEVE COWPER, GOVERNOR

REPLY TO:

☐ *1031 W 4th AVENUE SUITE 200 ANCHORAGE, ALASKA 99501 PHONE: (907) 276-3550*

☐ *1st NATIONAL CENTER 100 CUSHMAN ST. SUITE 400 FAIRBANKS, ALASKA 99701 PHONE: (907) 452-1568*

☐ *P.O. BOX K-STATE CAPITOL JUNEAU, ALASKA 99811 PHONE: (907) 465-3600*

May 6, 1987

The Honorable Sam Cotten
Co-Chairman
House Resources Committee
P. O. Box V
Juneau, Ak 99811

Dear Representative Cotten:

This letter responds to your request for an opinion concerning the potential implications of Alaska Survival v. State, 723 P.2d 1281 (Alaska 1986), in the absence of legislation amending AS 38.04.065.

Before the Alaska Survival decision, the Department of Natural Resources (DNR), in accordance with its regulations, routinely classified land on the basis of site-specific land use plans if the land was located in an area of the state which was not yet included in a comprehensive regional land use plan. The court held that this procedure violated AS 38.04.065, stating:

> In our view, both the organization of the statutory scheme and the particular language of AS 38.04.065(c) and (d) express an unambiguous intent that regional planning precede land classifications and disposals.

Alaska Survival v. State, 723 P.2d at 1289.

The court's ruling has created considerable uncertainty with respect to the authority of DNR to manage and develop state land and resources because less than half of the land owned by the state is now covered by regional land use plans. In addition, there are a number of unresolved questions concerning the scope of the supreme court's ruling.

DNR, with the advice of this office, has interpreted the Alaska Survival decision narrowly as having only prospective effect and as prohibiting only new classification actions, but not necessarily disposals, before regional plans are complete.

There is a significant risk, however, that the decision will be construed by the courts to prohibit all disposals of land and resources before regional plans are completed. Under a broad interpretation of the decision, DNR could be precluded from granting rights of way, selling gravel, leasing commercial property or holding oil and gas lease sales. The validity of classifications and disposals made before the court's decision may also be questioned.

The scope of the court's ruling has already been the subject of question and controversy. For example, in an October 2, 1986, letter commenting on the proposed five year oil and gas leasing program, Trustees for Alaska questioned the effect of Alaska Survival on the oil and gas leasing system. A copy of this letter is attached. As the letter points out, many of DNR's proposed oil and gas lease sales are in areas with no regional land use plans. Significantly, no regional planning process has been initiated for the North Slope. The lack of a regional land plan has also been raised in litigation, now dismissed, challenging the validity of an agreement to settle Anchorage's municipal entitlement. Pending litigation challenges the mandatory renewal of an offshore mining lease, initially issued in 1964, because no regional plan or classification covers the leased submerged land.

It appears likely that the scope of the Alaska Survival decision will continue to be the subject of controversy and litigation in the absence of legislation amending AS 38.04.065. DNR's efforts to effectively manage and develop state land and resources may therefore be substantially hindered. Legislation which clarifies DNR's land planning responsibilities will resolve these issues without litigation. An immediate effective date would insure that previous disposals and disposals occurring within the first ninety days after enactment will be free from the risks and costs of litigation.

Yours sincerely,

GRACE BERG SCHAIBLE
ATTORNEY GENERAL

By: M. Francis Neville
M. Francis Neville
Assistant Attorney General

MFN/jmo
Encl:

Trustees for ALASKA

October 2, 1986

OCT 27 1986
Office of the Attorney General
Anchorage Branch
Anchorage, Alaska

RECEIVED
OCT 08 1986
DIVISION OF OIL & GAS
ANCHORAGE, ALASKA

James Eason, Director
Division of Oil and Gas
Department of Natural Resources
P.O. Box 7034
Anchorage, Alaska 99510-7034

re: Proposed Five-Year Oil and Gas Leasing Program

Dear Mr. Eason:

Trustees for Alaska appreciates this opportunity to comment on the State's proposed 5-year oil and gas leasing program. Most of our comments relate to the general approach to the State's oil and gas leasing program, rather than comments on specific sales. We will submit more detailed specific comments on individual sales as appropriate.

We strongly support the State's suggestion to use increasingly limited resources to focus on fewer lease sales (Schedule B). Any attempt to continue the existing ambitious program in the face of personnel cutbacks would be counterproductive, and would result in less careful attention to each sale. As a result, we believe that environmental protection would receive relatively less focus, i.e. DOG would have less ability to limit or to prohibit leasing in particularly sensitive areas, and to develop conditions and stipulations necessary to protect important environmental resources.

The proposed cutback in the 5-year lease schedule also makes sense from an economic perspective. While the call for comments correctly notes that cutting back the 5-year program will result in less areas being explored and developed quickly, it is not DOG's role to maximize short-term development potential. Rather, as the manager of the State's oil and gas resources, DOG must consider ways to maximize the State's long-term return from its resources in a balanced fashion, while ensuring that development is conducted consistent with the protection of other resources, such as renewable fish and wildlife resources. Given the current oil market, it would appear to make sense to limit production at this time, in order to maximize long-term returns. By slowing down development, more attention can be paid to protecting environmental resources for leases that are issued, and additional areas can be added as oil prices increase. Moreover, future development in sensitive areas can proceed with the benefit of technological advances that may minimize overall environmental impacts. Therefore, we believe that the proposed reduction in the 5-year program is in the long-range interests of the State of Alaska.

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 8672
1534 SCOMM 57: SENATE SPECIAL COMMITTEE ON OIL & GAS, 1987-1988 1331

Despite our agreement with the overall approach, we do object to the creation in the 5-year plan of a firm expectation that a prescribed minimum number of lease sales will be held each year. The call for comments does note that no final decisions have been made with respect to any given sale. Nevertheless, the general statements establishing minimum numbers of sales result in considerable institutional pressure to proceed with the identified sales, for fear of not meeting the identified "quota". State law requires the Department to make an independent, objective determination, based on all available information and public input at the time of the sale, of whether each individual sale is in the best interests of the State. Therefore, the 5-year plan should state simply that the Department plans to "consider" the listed lease sales within the deadlines set out in the schedule.

We also are interested in the Department's views on the effect of the State Supreme Court's recent ruling in Alaska Survival v. DNR on the oil and gas leasing system. The Court ruled that no classification or disposition of state land may occur prior to the development of comprehensive, regional land use plans. Presumably, this ruling extends to state land classifications and dispositions that involve less than fee simple land conveyance, particularly since the Chase land disposal involved only surface rights for agricultural use. Many of the Department's proposed lease sales, however, are in areas with no regional land use plans. While we have made no decision regarding how we believe the Court's decision applies to oil and gas lease sales, we believe that the issue deserves serious consideration. We would appreciate your views on this issue. It would also be useful if you could provide an explanation of how and when state land is "classified" for purposes of oil and gas lease sales, and how best interests findings for lease sales relate to the land use planning process.

Finally, we have only a few comments at this time regarding specific sales identified in the call for comments. We previously submitted comments on the Prudhoe Bay Uplands Sale, which has now been split into two separate lease sales. We simply wish to reiterate our concern that these sales consider carefully the effect of these sales on the adjacent Arctic National Wildlife Refuge, which is currently being considered for either inclusion in the National Wilderness Preservation System or for oil and gas development. Considerable wildlife migration occurs accoss the Canning River, and some Central Arctic Caribou Herd calving may occur in this area.

We are also concerned about the size of proposed lease sale 65, which stretches across the arctic coastline from the Canning delta to the region north of Teshekpuk Lake. While we have no general opposition to additional sales in the Prudhoe Bay region, assuming adequate environmental safeguards, we object to the proposed inclusion at this time of coastal areas adjacent to the ANWR and the Teshekpuk Lake Special Area. Our concerns about the arctic coastline near the ANWR were specified in our comments on the proposed Camden Bay and Demarcation Point Sales. In addition, we question the wisdom of planning a sale along the coastline of the Teshekpuk Lake Special Area, before the Bureau of Land Management decides what the appropriate oil and gas development policy for this area should be. Oil development in the State's coastal region will entail the use of onshore facilities for support and transportation, including pipelines, in order for development to be economically feasible. In addition, the State is undoubtedly aware of the tremendous importance of the Teshekpuk Lake region for waterfowl and other important wildlife populations. Therefore, the State should withhold its plans for development of this area pending a decision by BLM.

Thank you again for this opportunity to comment on the State's proposed 5-year oil and gas leasing plan.

Very Truly yours,

Bob Adler

Bob Adler
Executive Director

SB 196

STATE OF ALASKA

OFFICE OF THE GOVERNOR

BILL ANALYSIS

DEPARTMENT	DIVISION	BILL NUMBER	SPONSOR
Fish and Game	Habitat	HB 289	(H) Resources

DEPARTMENT POSITION

Support with amendment

PREPARED BY	DATE	COMMISSIONER'S SIGNATURE	DATE
Habitat Division	4/27/87	Don W. Collinsworth	4-30-87

SUMMARY

OTHER AGENCIES AFFECTED BY BILL	CONSTITUENT GROUP(S) AFFECTED BY BILL
Department of Natural Resources	All Users of State Land

ORGANIZATIONAL SUPPORT FOR BILL	ORGANIZATIONAL OPPOSITION TO BILL
Unknown	Unknown

FISCAL IMPACT: ☒ NONE ☐ FISCAL NOTE ATTACHED

BACKGROUND/LEGISLATIVE INTENT

Sections 1 through 7 amend AS 38.04.065 to allow the Department of Natural Resources to classify land for disposal or other purposes on the basis of site-specific land-use plans, excepting land disposals under the lottery, homesite, and homestead programs. Sections 10, 11, and 12 amend procedural aspects of the Homestead Act, AS 38.09. Section 9 provides certain exemptions for state-exempt oil/gas lease sales from the best interest finding requirement of AS 38.05.035(e).

ANALYSIS OF BILL/PROGRAM EFFECTS

Sections 13 and 14 of this measure will validate all previous land classifications, including public recreation and wildlife habitat designations, that might be subject to legal challenge as a result of the Alaska Supreme Court ruling in Alaska Survival v. State, 723 P.2d. 1281 (August 29, 1986). Sections 1 through 7 will restore limited flexibility to the Department of Natural Resources to classify land based on a site-specific land-use plan, rather than a regional plan. Major land disposals under the lottery, homesite and homestead programs will continue to be based on a regional land use plan, as required by the Alaska Survival v. State decision.

Section 9 of this measure will exempt AS 38.05.180(d) oil and gas lease sales from an AS 38.05.035(e) best interest finding if an .035(e) finding has been completed for the area or an adjacent or contiguous area within the last three years. The Department of Fish and Game does not support this exemption. In our opinion, it is inappropriate to make potentially

(continued)

AMENDMENTS PROPOSED

Section 9 - Reword AS 38.05.035(e)(7) as follows:

"(7) an exempt oil and gas sale under AS 38.05.180(d) for which a written best interest finding has been issued for the area of sale [OR FOR A CONTIGUOUS OR ADJACENT AREA] within the 36 months before the date of the sale." It is not in the public interest to extend an AS 38.05.035(e) best interest finding to adjacent and contiguous areas that may be very different economically, socially, and environmentally from the area of the original .035 best interest finding.

PLEASE ATTACH A SEPARATE SHEET FOR ADDITIONAL COMMENTS OR ANALYSIS.

ANALYSIS OF BILL/PROGRAM EFFECTS (Continued)

major, long term (e.g., 10 to 20 year) commitments of public resources without first providing the public an opportunity to review and comment on the proposed action. Written best interest findings are the only public review documents that evaluate the cumulative and the potential socioeconomic and environmental consequences of proposed state exempt oil/gas lease sales. Written findings further constitute the formal decision document describing how and why a proposed sale is or is not in the public interest. Written findings describe what information was considered in evaluating the cost/benefits of a proposed lease sale, the key issues associated with the sale, and provides a summary of public and agency comments and concerns regarding a proposed sale. The Department of Fish and Game believes that it is essential to maintain such an administrative record in a single document, so that the state's justification for holding, postponing, or cancelling a lease sale is readily available.

If Section 9 is enacted, many future sales on the North Slope and in the Cook Inlet/Bristol Bay Region could potentially be exempted from any formal leasing process, public hearing, or best interest finding requirement.

STATE OF ALASKA 1987 LEGISLATIVE SESSION
FISCAL NOTE

REQUEST:

Bill Version: HB 289
Publish Date: 4/27/87

Revision Date:
Title: An Act relating to management of state land
Sponsor: Resource Committee
Requestor:

Agency Affected:
BRU:

Components:

EXPENDITURES/REVENUES: (Thousands of Dollars)

OPERATING	FY 87	FY 88	FY 89	FY 90	FY 91	FY 92
PERSONAL SERVICES						
TRAVEL						
CONTRACTUAL						
SUPPLIES						
EQUIPMENT						
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING	0	0	0	0	0	0
CAPITAL	0	0	0	0	0	0
REVENUE	0	0	0	0	0	0

FUNDING: (Thousands of Dollars)

GENERAL FUND	0	0	0	0	0	0
FEDERAL FUNDS						
OTHER						
TOTAL	0	0	0	0	0	0

POSITIONS:

FULL-TIME						
PART-TIME						
TEMPORARY						

ANALYSIS: (Attach a separate page if necessary)

Bruce H. Baker

Prepared by: Bruce H. Baker
Division: Habitat
Phone: 465-4105
Date: 4/27/87

Approved by Commissioner: Don W. Collinsworth
Date: 4.30.87
Agency: Department of Fish and Game

Distribution (by preparer):
- Legislative Finance
- Legislative Sponsor
- Requestor
- Office of Management and Budget
- Impacted Agency(ies)
- Senate Secretary

page ___ of ___

ALASKA STATE LEGISLATURE

SENATE SPECIAL COMMITTEE
ON OIL AND GAS

Senator Bettye Fahrenkamp
Chairman
Senator Jack Coghill
Senator Paul Fischer

P.O. Box V, State Capitol
Juneau, Alaska 99811
(907) 465-3834

M E M O R A N D U M

TO: All Members of the Senate

FROM: Senator Bettye Fahrenkamp, Chairman
Senate Special Committee on Oil and Gas

RE: SB 182, An Act relating to the written findings required for certain state oil and gas lease sales.

DATE: May 7, 1987

Current statute requires that all proposed state oil and gas lease sales be included in a five year leasing program submitted to the legislature annually. However, under certain circumstances, sales that are not included in the five year plan, or "exempt sales", may be held. Exempt sales usually include previously offered leases, areas adjacent to those leases, or areas in which industry has shown high interest. Current statute requires that a written best interest finding be made for most exempt sales.

SB 182 would waive the best interest finding requirement for exempt sales if a previous finding has been made for that area within the preceding three years. It would also apply to an area that is contiguous with or adjacent to the area of the proposed exempt lease sale.

This change should promote early exploration of state lands and enable the department to add new areas to the leasing schedule with reduced administrative costs and delay.

ALASKA STATE LEGISLATURE

SENATE SPECIAL COMMITTEE
ON OIL AND GAS

Senator Bettye Fahrenkamp
Chairman
Senator Jack Coghill
Senator Paul Fischer

P.O. Box V, State Capitol
Juneau, Alaska 99811
(907) 465-3834

M E M O R A N D U M

TO: Senator Dick Eliason, Chairman
Senate Rules Committee

FROM: Senator Bettye Fahrenkamp, Chairman BF
Senate Special Committee on Oil and Gas

RE: SB 182

DATE: May 6, 1987

I would appreciate your scheduling SB 182, An Act relating to the written findings required for certain state oil and gas lease sales, on the Senate calendar.

Current statute requires that all proposed state oil and gas lease sales be included in a yearly five year leasing program submitted to the legislature. However, under certain circumstances, sales that are not included in the five year plan, or "exempt sales", may be held. Exempt sales usually include previously offered leases, areas adjacent to those leases, or areas in which industry has shown high interest. Current statute requires that a written best interest finding be made for most exempt sales.

SB 182 would waive the best interest finding requirement for exempt sales if a previous finding has been made for that area within the preceding three years. This change may enable the department to add new areas to the leasing schedule with reduced administrative costs and delay.

Thank you for your consideration.

5-0732B
Bannister
3/23/87

Original sponsor: The Senate Special Committee on Oil and Gas

See p. 2

IN THE SENATE

BY THE SENATE SPECIAL COMMITTEE ON OIL AND GAS

CS FOR SENATE BILL NO. 182 (O&G)

IN THE LEGISLATURE OF THE STATE OF ALASKA

FIFTEENTH LEGISLATURE - FIRST SESSION

A BILL

For an Act entitled: "An Act relating to the written findings required for certain state oil and gas lease sales."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

* Section 1. AS 38.05.035(e) is amended to read:

(e) Upon a written finding that the interests of the state will be best served, the director may, with the consent of the commissioner, approve contracts for the sale, lease, or other disposal of available land, resources, property or interests in them, and, in addition to the conditions and limitations imposed by law, may impose additional conditions or limitations in the contracts as the director determines, with the consent of the commissioner, will best serve the interests of the state. A contract for the sale, lease, or other disposal of available land or an interest in land is not legally binding on the state until the commissioner approves the contract but if the appraised value is not greater than $50,000 in the case of the sale of land or an interest in land, or $5,000 in the case of the annual rental of land or interest in land, the director may execute the contract without the approval of the commissioner. Before a public hearing, if held, or in any case no less than 21 days before the sale, lease, or other disposal of available land, property, resources, or interests in them, the director shall make available to the public a written finding that sets out the facts and applicable law upon which the determination that the sale, lease, or other disposal will best serve the interests of the state was based. A written finding is not required before the approval of

(1) a contract for a negotiated sale authorized under AS 38.05.115;

(2) a lease of land for a shore fishery site under AS 38.-05.082;

(3) a permit or other authorization revocable by the commissioner;

(4) a mineral claim located under AS 38.05.195;

(5) a mineral lease issued under AS 38.05.205; [OR]

(6) a production license issued under AS 38.05.207; or

(7) an oil or gas lease sale under AS 38.05.180(d), if within 36 months before the lease sale a written finding under this subsection has been made for the area of the proposed lease sale, ~~or~~ for an area that ~~is contiguous with or adjacent to the area of the proposed lease sale~~.

3/24/87

BF ✓
PF ✓
Cog ✓

SB 182

State O+G lease sales

BF —

Carol Wilson, DNR —

support bill.

streamline exempt sales —

industry requests —

still do public notice —

Pam Rogers —

7 exempt sales since 1980.

other sales have included exempt acreage

when leases expire near already held acreage

2 north slope sales

1) 42,000 acres - $12.13 /acre
all sold

2) other sales 9.00 /acre

Phil Holdsworth. former com of DNR

support –

in the case of "drainage".

Don Smith Esson Co., USA.

support.

Ron 12–18 months w/ full funding

10–12.

6 months for noticing

plus land check.

Mike Abbott projects coordinator –

RDC – supports

Guy move to adopt CS

on p. 2 13 after sale part.

& delete rest.

moved w/

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

STEVE COWPER, GOVERNOR

400 WILLOUGHBY AVE.
JUNEAU, ALASKA 99801-1796
PHONE: (907) 465-2400

March 24, 1987

The Honorable Bettye Fahrenkamp, Chair
Senate Special Committee on Oil and Gas
Alaska State Legislature
P.O. Box V
Juneau, AK 99811

Dear Senator Fahrenkamp:

Subject: Senate Bill 182, which would allow the Department of Natural Resources to streamline procedures for exempt acreage oil and gas lease sales.

Position: The Department of Natural Resources supports this bill, with a slight change in wording, because it would promote early exploration of state lands previously leased or adjacent to existing oil and gas leases or discoveries. Early exploration of exempt acreage will result in earlier receipt of lease bonus and rental payments and, in the event of a discovery, earlier receipt of royalties and taxes.

Background: Exempt acreage oil and gas lease sales are allowed under AS 38.05.180(d). To qualify, acreage must have previously been subject to an oil and gas lease, contiguous to land under an oil and gas lease, or adjacent to land where a commercial oil or gas discovery has been made.

Exempt sales need not be listed on the formal five-year leasing schedule presented to the Legislature each January. Exempt sales are requested by the oil and gas industry when a genuine interest in leasing and exploring the area exists.

The department receives at least two or more requests for exempt sales each year. Before an exempt acreage sale can be held, just as for all other state oil and gas lease sales, Division of Oil and Gas staff are required by AS 38.05.035(e) to prepare a written finding that the proposed sale is in the state's best interest.

Since exempt sales are for previously leased acreage or for areas adjacent to leased acreage, written findings for the already leased areas are revised slightly to serve as the exempt acreage sale finding. However, since exempt acreage written findings are prepared by existing staff, they can only be completed as time is available.

This bill would allow the findings previously prepared for the general sale area, if completed within 36 months of the exempt sale, to meet the best interest finding requirement for the proposed exempt sale.

Recommendation: Delete lines 13 and 14, page 2 and the word "or" at the end of line 12, page 2. This will clarify the intent of the bill.

Conclusion: By streamlining the exempt sale process, additional exempt sales could be offered each year and less time would elapse between the sale request and the sale. Early exploration of exempt acreage land would be encouraged. Public notice requirements would still be in effect, as would all other oil and gas lease sale requirements.

Please let me know if you would like additional information about our oil and gas lease sale process.

Sincerely,

Judith M. Brady
Commissioner

cc: Committee Members
George Sullivan
Rod Swope
Commissioner Collinsworth, DF&G
Commissioner Kelso, DEC

STATE OF ALASKA 1987 LEGISLATIVE SESSION
FISCAL NOTE

REQUEST:

Bill Version: SB 182
Publish Date:

Revision Date: March 23, 1987
Title: State Oil and Gas Lease Sales
Sponsor: Senate Oil & Gas Special Committee
Requestor: Senate Oil & Gas Committee

Agency Affected: Natural Resources
BRU: Petroleum Management
Components:

EXPENDITURES/REVENUES: (Thousands of Dollars)

OPERATING	FY 87	FY 88	FY 89	FY 90	FY 91	FY 92
PERSONAL SERVICES						
TRAVEL	**	**	**	**	**	**
CONTRACTUAL	**	**	**	**	**	**
SUPPLIES						
EQUIPMENT						
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING	-0-	-0-	-0-	-0-	-0-	-0-

CAPITAL	-0-	-0-	-0-	-0-	-0-	-0-

REVENUE	*	*	*	*	*	*

FUNDING: (Thousands of Dollars)

GENERAL FUND						
FEDERAL FUNDS						
OTHER						
TOTAL	-0-	-0-	-0-	-0-	-0-	-0-

POSITIONS:

FULL-TIME						
PART-TIME						
TEMPORARY						

ANALYSIS: (Attach a separate page if necessary)

* Earlier offering of exempt acreage sales resulting from this bill will result in earlier receipt of bonus and rental payments and, in the event of a discovery, earlier receipt of royalties and taxes.

** Some savings in contractual and travel costs related to public meetings could occur, depending on the location of the exempt sale and the public's interest.

Prepared by: Carol Wilson
Phone: 465-2400
Division: Commissioner's Office
Date: 3/23/87

Approved by Commissioner:
Date:
Agency: Natural Resources

Distribution (by preparer):

- Legislative Finance
- Legislative Sponsor
- Requestor
- Office of Management and Budget
- Impacted Agency(ies)
- Senate Secretary

ALASKA STATE LEGISLATURE

SENATE SPECIAL COMMITTEE ON OIL AND GAS

Senator Bettye Fahrenkamp
Chairman
Senator Jack Coghill
Senator Paul Fischer

P.O. Box V, State Capitol
Juneau, Alaska 99811
(907) 465-3834

M E M O R A N D U M

TO: Members, Senate Special Committee on Oil and Gas

FROM: Committee Staff

RE: Committee Meeting, March 24, 1987

DATE: March 23, 1987

On Tuesday, March 24, at 3:30 pm in the Beltz Room, the Senate Special Committee on Oil and Gas will hear SB 182, Relating to state oil and gas lease sales.

Current statute requires that all proposed state oil and gas lease sales be included in a yearly five year leasing program submitted to the legislature. However, under certain circumstances, sales that are not included in the five year plan, or "exempt sales", may be held. Exempt sales usually include previously offered leases, areas adjacent to those leases, or areas in which industry has shown high interest. Current statute requires that a written best interest finding be made for most exempt sales.

SB 182 would waive the best interest finding requirement for exempt sales if a previous finding has been made for that area within the preceding three years. This change may enable the department to add new areas to the leasing schedule with reduced administrative costs and delay.

March 24, 1987

Senate Special Committee on Oil and Gas

SB 182, Relating to state oil and gas lease sales.

TELECONFERENCED TO ANCHORAGE

A Committee Substitute has been prepared that narrows the title to be more specific.

The proposed title now reads: " An Act relating to the written findings required for certain state oil and gas lease sales."

The Department of Natural Resources also has a proposed amendment that would limit this provision to only the area of the proposed lease sale.

TO TESTIFY:

CAROL WILSON, Special Assistant to the Commissioner of Natural Resources.

PAM ROGERS, Leasing Manager, Division of Oil and Gas, DNR
Standing by → FROM ANCHORAGE

PHIL HOLDSWORTH, Resource Development Council

DAN SMITH, Exxon Corporation - 8 to 12 month -

MIKE ABOTT, RDC

example of FINDINGS.
J. 43015

STATE OF ALASKA

BILL SHEFFIELD, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

P.O. BOX 7034
ANCHORAGE, ALASKA 99510-7034

November 20, 1986

Phone: 762-4277

-NOTICE-
OF
FINAL DECISION AND FINDING UNDER AS 38.05.035(e)
REGARDING PROPOSED OIL AND GAS LEASE SALE 50 (Camden Bay)

The Department of Natural Resources, Division of Oil and Gas (DO&G), gives formal notice under AS 38.05.945(a)(3) of its intention to make a final finding and decision under AS 38.05.035(e) regarding the sale of oil and gas leases in proposed Oil and Gas Lease Sale 50 (Camden Bay). Before this sale may be held, the Director of the Division of Oil and Gas must make a written final decision that the sale serves the best interests of the state. This decision will set out the facts and applicable law upon which the director bases his determination that the sale of oil and gas leases in proposed Sale 50 will or will not best serve the interests of the state. This final decision is expected to be available to the public in April, 1987.

Proposed Oil and Gas Lease Sale 50 includes 36 tracts with a total area of approximately 122,745 acres. The proposed sale area consists of state owned tide and submerged lands in the Beaufort Sea, lying between Flaxman Island and the mouth of the Hulahula River. The Arctic National Wildlife Refuge (ANWR) lies immediately south of the proposed Sale 50 area. The entire sale area is within the North Slope Borough. The North Slope communities of Deadhorse/Prudhoe Bay, Nuiqsut, Barrow, and Kaktovik may be affected by the proposed sale.

The location of Alaska's Territorial Sea Boundary and the seaward boundary of ANWR are the subjects of a dispute between the United States of America and the State of Alaska. This dispute is pending before by the U.S. Supreme Court. At issue is the ownership of a significant amount of tide and submerged land along these borders. Currently, the State of Alaska is negotiating agreements with the U.S. Minerals Management Service and the U.S. Fish and Wildlife Service that will define these boundaries for purposes of Oil and Gas Leasing in Sale 50. These agreements may require adjustments to the boundaries which may result in the deletion of some acreage between now and the date of the final notice.

A preliminary analysis of the potential effects of proposed Sale 50 and the means by which they may be mitigated is now available at DO&G, 3601 "C" Street, Room 1398, Anchorage, Alaska. Included in the preliminary analysis is the preliminary Alaska Coastal Management Program (ACMP) consistency determination. The public is invited to comment on any aspect of this sale including any proposed term or condition.

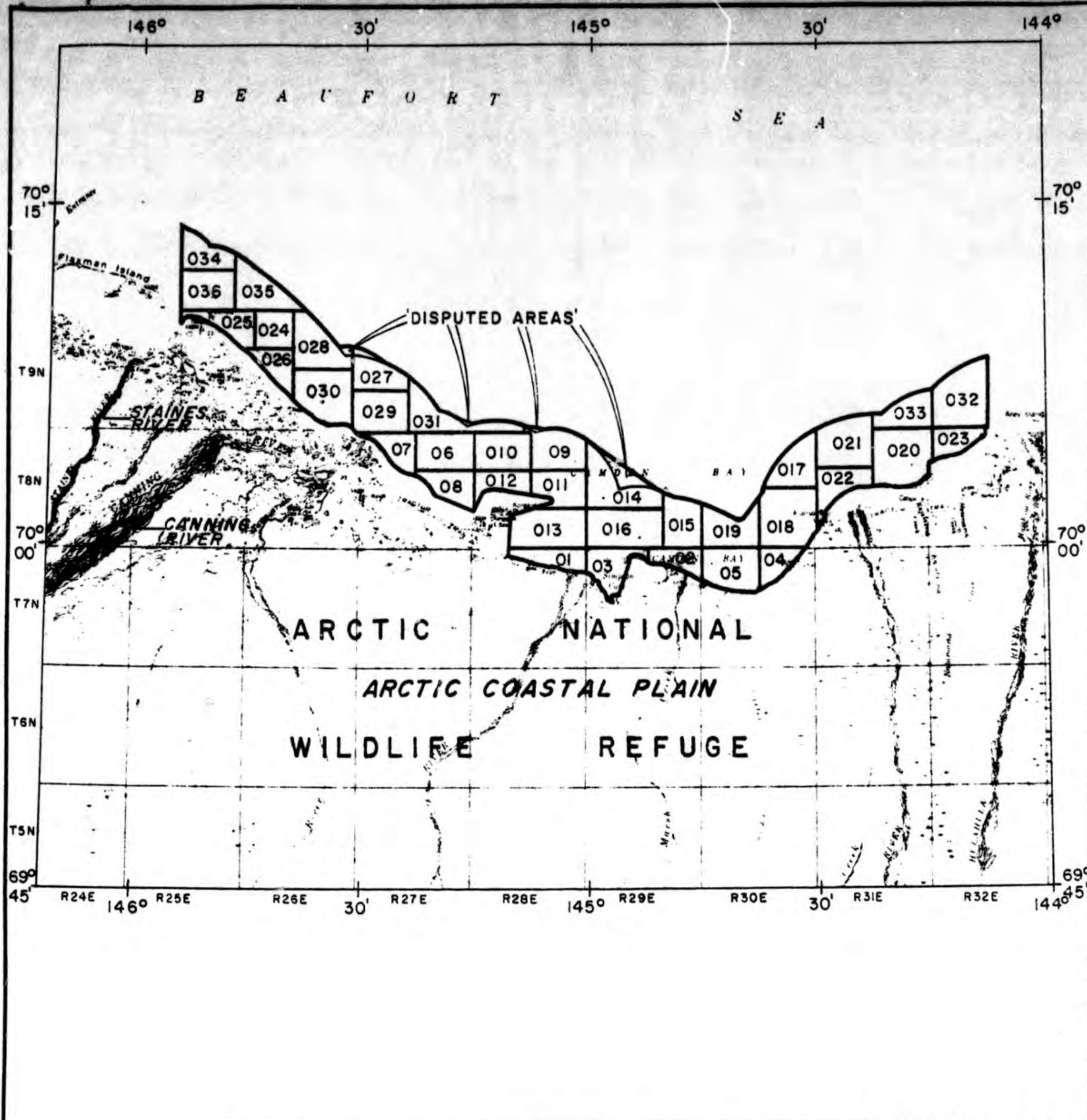
Comments should be mailed to DO&G, P.O. Box 7034, Anchorage, Alaska 99510, Attention: Pam Rogers. Comments should be received at DO&G by December 30, 1986 in order to be considered in the final decision of whether or not this sale is to be held. The final ACMP consistency determination will be included in the Final Decision of the Director. Preliminary legal descriptions for Sale 50 are available upon request to potential bidders and the public at DO&G. Preliminary Tract Maps are also available at a cost of $50 per set.

If a decision is made that the proposed sale best serves the interest of the state, an "Information to Bidders" packet will be made available in April, 1987. If a decision is made to hold the sale, it is tentatively scheduled to occur at the Clarion Hotel, in Anchorage, on June 30, 1987 in accordance with AS 38.05.180. This date represents a postponement of 28 days from the originally scheduled date of sale as published in the State of Alaska's 1986 Five Year Oil and Gas Leasing Program. This change is a result of adjustments made for the 1987 Oil and Gas Leasing Program.

James E. Eason
Director

Date

0748b



STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL & GAS

PROPOSED OIL AND GAS LEASE SALE 50

CAMDEN BAY PRELIMINARY TRACT MAP

SCALE 1:456,200 1 inch = 7.2 Miles Approx.

6 0 6 12 18 Miles

DIRECTOR, DIV. OF OIL & GAS JIM EASON	DRAWN BY O.D.S.	DATE APPROVED 11/12/86
LEASING MANAGER PAMELA ROGERS	CHECKED BY: JM	BASE MAP: REDUCED FROM, UNIVERSAL TRANSVERSE MERCATOR PROJECTION BY U.S.G.S., "ORIGINAL SCALE" 1:250,000 1 INCH = 4 MILES

NOTE: THIS MAP IS NOT TO BE CONSTRUED AS AN OFFICIAL TRACT MAP. A SET OF 1:63,360 SCALE TRACT MAPS ARE AVAILABLE AT THE DEPT. OF NATURAL RESOURCES, DIVISION OF OIL AND GAS, 3601 C. ST., P.O. BOX 7034, ANCHORAGE, ALASKA 99510 -7034 PHONE (907)561-2020

NOTE: NO DECISION HAS YET BEEN MADE ON WHETHER THE STATE WILL HOLD THIS LEASE SALE. THE STATE IS GATHERING SOCIAL, ENVIRONMENTAL & ECONOMIC INFORMATION ON WHICH TO BASE A DECISION.

PROPOSED SALE AREA

PRELIMINARY ANALYSIS OF THE DIRECTOR
AND PRELIMINARY ACMP CONSISTENCY DETERMINATION
REGARDING OIL AND GAS LEASE SALE 50,
CAMDEN BAY

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL AND GAS
ANCHORAGE, ALASKA

NOVEMBER 20, 1986

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REQUEST FOR COMMENTS

This document is a preliminary analysis for proposed Competitive Oil and Gas Lease Sale 50, Camden Bay, tentatively scheduled for June 30, 1987 (Figure 1). A detailed description of the proposed sale area and a discussion of issues pertaining to oil and gas development in the area are presented in this analysis. No conclusions regarding the proposed sale have been made at this time. A final decision on whether or not to hold the sale will be issued following public and agency review of this document.

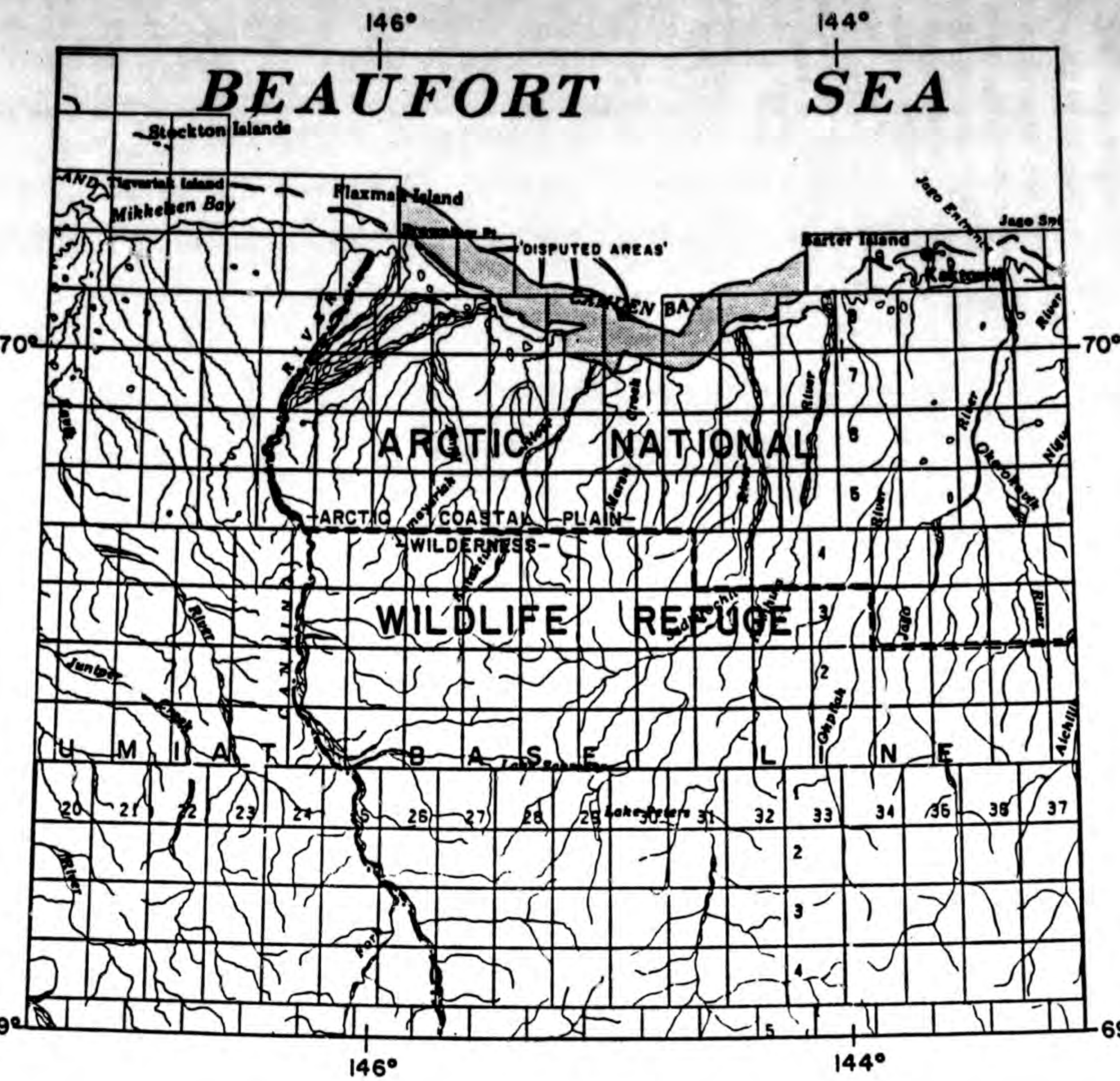
After receiving public and agency comments, the Director of the Division of Oil and Gas will determine if the proposed sale is in the state's best interests, and issue a final finding and decision. If a positive finding is made, the final decision document will list mitigating measures to be imposed on the lessees and describe the leasing method, minimum bid, and term of the leases to be offered. It will also contain the Alaska Coastal Management Program consistency determination.

The public is invited to comment on any part of this document, including the preliminary consistency determination. Comments must be received by January 6, 1987 in order to be considered, and should be sent to: Division of Oil and Gas, P.O. Box 7034, Anchorage, Alaska 99510-7034, ATTN: Pam Rogers, Leasing Manager, (907) 762-4277.

The final finding and decision for proposed Sale 50 will be available on or about April 30, 1987, and will be based on the information and analysis presented here and comments generated by this document.

November 19, 1986
Date

James E. Eason
James E. Eason
Director



STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL & GAS
PROPOSED OIL AND GAS LEASE SALE 50
CAMDEN BAY

SCALE 1:1,000,000 1 Inch = 16 Miles

10 0 10 20 30 40 50 Miles

DIRECTOR, DIV. OF OIL & GAS, JIM EASON	DRAWN BY O.D.S.	DATE APPROVED 10/24/86
LEASING MANAGER, PAMELA ROGERS	CHECKED BY:	BASE MAP: © COPYRIGHT ARCTIC ENVIRONMENTAL INFORMATION AND DATA CENTER, 1978 ALL RIGHTS RESERVED, INCLUDING REPRODUCTION IN WHOLE OR IN PART IN ANY FORM. UNIVERSAL TRANSVERSE MERCATOR PROJECTION ON SIX DEGREE BANDS

NOTE: NO DECISION HAS YET BEEN MADE ON WHETHER THE STATE WILL HOLD THIS LEASE SALE. THE STATE IS GATHERING SOCIAL, ENVIRONMENTAL, AND ECONOMIC INFORMATION ON WHICH TO BASE A DECISION.

PROPOSED SALE AREA

FIGURE 1.

Introduction

On June 30, 1987, the State of Alaska proposes to offer for lease state tide and submerged lands adjacent to the Arctic National Wildlife Refuge (ANWR) for petroleum exploration and development in Competitive Oil and Gas Lease Sale 50, Camden Bay. The proposed sale area is situated in the Beaufort Sea offshore of the arctic coastal plain between Flaxman Island and the Hulahula River in Camden Bay. It consists of approximately 122,745 acres in 36 tracts (Figure 2) None of these lands have been leased previously for petroleum exploration or development.

The proposed sale area is entirely contained within the boundaries of the North Slope Borough. The North Slope Borough is a home rule borough with a population of approximately 8308 (DCRA 1986). The borough's headquarters are located in Barrow, the largest North Slope community. The borough has powers of taxation, education, planning, platting, and zoning. Additionally, the North Slope Borough has adopted a comprehensive plan and land management regulations that may impose restrictions on oil and gas activity in the proposed sale area.

The North Slope community located closest to the proposed sale area is Kaktovik which is sited on Barter island about 12 miles east of the proposed sale area, and has a population of 206 (DCRA 1986). Kaktovik is a second class city with a mayor and a city council. Nuiqsut, an Inupiat village of 337 people (DCRA 1986), is located approximately 120 miles west of the sale area. Nuiqsut was repopulated in 1973, and is now a second class city with a mayor and a city council. Residents of these Arctic villages are primarily dependant upon a traditional subsistence hunting and fishing lifestyle. Camden Bay and the adjacent ANWR coastal plain host fish and wildlife resources important to the subsistence activities of these people, with residents of Kaktovik being the most impacted by exploration and development which may follow the issuance of leases as a result of proposed Sale 50.

A variety of marine mammals, migratory waterbirds, and marine and anadromous fish occur in the proposed sale area. Bowhead whales, polar bears, and ringed seals are mammals of primary concern. Waterfowl and shorebirds are abundant, the most numerous of these are the oldsquaws. The most abundant marine and anadromous fish species are the fourhorn sculpin, Arctic cod, and Arctic char. The coastal plain adjacent to Camden Bay is an important habitat for a diverse assemblage of fish and wildlife species. It is the calving grounds for the Porcupine caribou herd and the nesting area for a great number of migratory waterfowl. Additionally, the coastal plain and riparian habitats of ANWR host the second largest herd of muskox in North America.

The proposed sale area was added to the state's five-year oil and gas leasing schedule in 1982. Originally, the sale was scheduled for September 1986; but, in 1983, the sale was postponed to May 1987 pending a decision by the U.S. Congress on future oil and gas exploration and development in ANWR. The proposed sale date has since been delayed another 30 days, until June 1987, to accommodate adjustments to the state's five-year oil and gas leasing schedule for the period 1987 to 1991. The June 1987 sale date is thought to be optimum considering the timing of the decline of known producible reserves on the North Slope and the possibility that leasing in Camden Bay may favorably influence the Congressional decision to lease in ANWR.

The State of Alaska is in favor of Congress opening the ANWR coastal plain to oil and gas leasing and development. The Congressional decision, however, will be based primarily on a Department of the Interior (DOI) report, required by Section 1002(h) of the Alaska National Interest Lands Conservation Act (ANILCA), covering resource management in the refuge. The DOI report was to be considered by the U.S. Congress in September 1986, but has been delayed pending litigation regarding the necessity of preparing an Environmental Impact Statement (EIS) prior to the ANWR decision. The result of the Congressional decision may effect the economic viability of any potential discoveries in the proposed Sale 50 area.

The Department of Natural Resources has determined that the Camden Bay area has a moderate to high petroleum potential. The proposed sale area is near known accumulations of oil and gas. Geophysical exploration has occurred in and around the proposed sale area, and some exploratory wells have been drilled nearby. The close proximity of the ANWR coastal plain also argues favorably for the high petroleum potential of the proposed Sale 50 area. In recent statements (Anchorage Times, 9/9/86; DGC, 1986), analysts and industry officials have commented that the ANWR coastal plain may have the highest oil and gas potential of any unleased area on the North American continent.

The Exxon Corporation has made a significant discovery of oil and gas immediately to the west of Camden Bay at Point Thomson. The company has estimated oil and gas reserves at Point Thomson to be 350 million barrels and 5 trillion cubic feet, respectively. Exploratory drilling has also occurred both south and north of the proposed sale area. In 1986, Chevron, Standard Alaska Production Company, BP Alaska and the Arctic Slope Regional Corporation (ASRC) completed an onshore well 14 miles southeast of Barter Island on land owned by ASRC. Shell Western Exploration & Production Company has recently completed drilling a well on its "Corona" prospect 20 miles north of the proposed sale area and Union Oil Company of California has just completed drilling a second exploration well at it's "Hammerhead" prospect 15 miles northwest of the proposed sale area. Additionally, Amoco has received approval to drill it's "Erik" prospect 10 miles northeast of the proposed sale area.

An unresolved ownership dispute between the federal government and the State of Alaska has changed the original boundaries of the proposed sale area. This dispute is pending resolution by the U.S. Supreme Court. At issue is the ownership of a significant amount of tide and submerged land along Alaska's territorial sea boundary and the seaward boundary of ANWR.

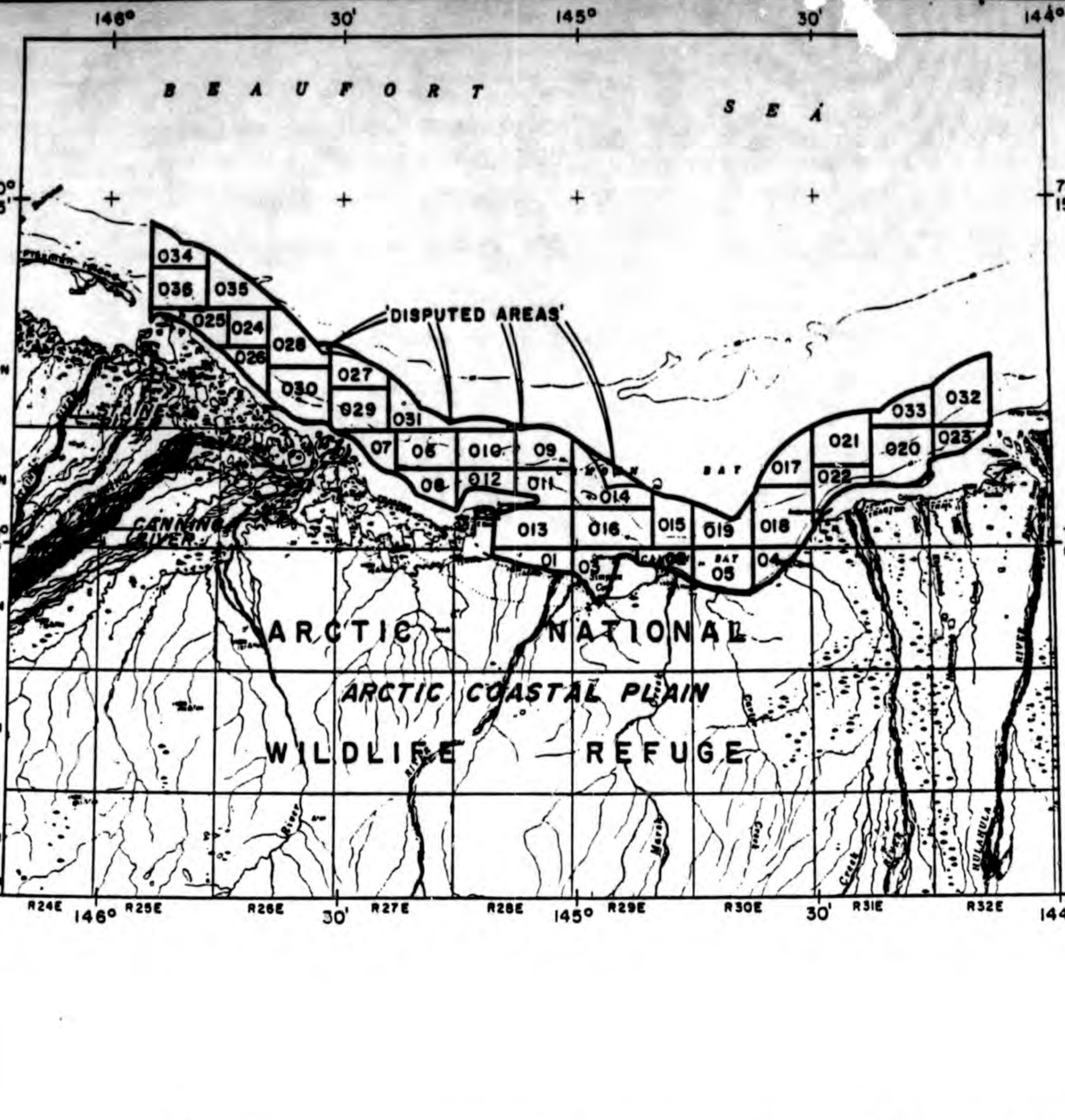
The dispute concerning acreage along Alaska's territorial sea boundary has resulted from employing two different methods of establishing that boundary. The state and federal governments, however, are pursuing an agreement under Section 7 of the Outer Continental Shelf (OCS) Act to allow the sale of disputed acreage along the territorial sea boundary to proceed as part of proposed Sale 50. Failure to reach an agreement may affect the amount of acreage available for leasing in proposed Sale 50, and may result in deletion of some acreage between the date of this document and the date of the final notice.

The principle dispute affecting the ANWR boundary involves the ownership of tide and submerged lands between the barrier islands and the mainland. At issue, is whether these lands are actually a part of ANWR. The barrier islands in Camden Bay, however, are contained within ANWR and are not part of the proposed sale area. The state claims the tide and submerged lands between the mainland and the island under the Statehood Entitlement Act whereas the federal government claims ownership under its interpretation of the legislation establishing ANWR. In this case, the federal agency managing ANWR, the U.S. Fish and Wildlife Service, lacks the authority to negotiate a leasing agreement which would allow the disputed lands to be offered in proposed Sale 50. Before such an agreement could be negotiated, the Congress must first determine whether oil and gas activities will be allowed in ANWR. Consequently, because the state lacks clear title to this disputed land, the tide and submerged lands between the barrier islands and the coastal plain are not being considered for leasing in proposed Sale 50. However, the decision not to offer the disputed acreage in Sale 50 does not imply any recognition of the federal government's ownership of this land.

Although the ANWR disputed acreage is not being offered in proposed Sale 50, the state remains concerned that future lease boundary problems may arise because of the ambulatory nature of barrier islands which are used to delineate the seaward ANWR boundary. For this reason, the State of Alaska is pursuing an agreement with the U.S. Fish and Wildlife Service which will recognize the integrity of lease boundaries established for this sale throughout the life of the lease. Failure to reach an acceptable agreement before the deadline for providing final notice may result in deletion of additional acreage along the southern boundary of the proposed Sale 50 area.

Prior to this analysis, the Division of Oil and Gas issued a call for comments (DNR/DO&G undated) and a request for socioeconomic and environmental information for proposed Sale 50 (DNR/DO&G 1/27/86). State and federal agencies, the North Slope Borough, representatives of the petroleum industry, and environmental organizations each commented on the proposed sale. Information submitted by agencies and organizations is reflected in this analysis. A summary of these comments is included in Appendix 1.

Representatives of the petroleum industry supported proposed Sale 50 and asked that the sale terms reflect the high cost of exploration and development in this region (Gibson-Smith 1986; Morrison 1985; Hughes 1985; Eke 1986). Environmental groups, along with the North Slope Borough, recommended cancellation of proposed Sale 50. The North Slope Borough, however, in it's comments on the proposed Five-Year Oil and Gas Leasing Program for the period 1987 to 1991, indicated the need for an aggressive leasing program on the North Slope and endorsed all sales in the state's five-year leasing schedule (Ahmaogak 1986). Environmental groups expressed concern that oil and gas exploration and development in Camden Bay would have a negative impact on the unique fish and wildlife resources of the region. These groups also considered oil and gas activities in this area to be contrary to the intent behind the creation of ANWR (see appendix 1). The Alaska Department of Fish and Game and the U.S. Fish and Wildlife Service recommended delay of the proposed sale until the U.S. Congress issues its decision regarding oil and gas leasing in ANWR, and litigation over contested jurisdiction of the coastal lagoons is complete (Stroebele 1982/1983/1985; Cohen 1986; Nolke 1986).



STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL & GAS

PROPOSED OIL AND GAS LEASE SALE 50
CAMDEN BAY PRELIMINARY TRACT MAP

SCALE 1:456,200 1 Inch = 7.2 Miles Approx.

6 0 6 12 18 Miles

DIRECTOR, DIV. OF OIL & GAS JIM EASON *Jim Eason*	DRAWN BY O.D.S.	DATE APPROVED 11/12/86
LEASING MANAGER PAMELA ROGERS *Pamela Rogers*	CHECKED BY: JMJ	BASE MAP: REDUCED FROM, UNIVERSAL TRANSVERSE MERCATOR PROJECTION BY U.S.G.S., "ORIGINAL SCALE" 1:250,000 1 INCH = 4 MILES

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NOTE: NO DECISION HAS YET BEEN MADE ON WHETHER THE STATE WILL HOLD THIS LEASE SALE. THE STATE IS GATHERING SOCIAL, ENVIRONMENTAL & ECONOMIC INFORMATION ON WHICH TO BASE A DECISION.

PROPOSED SALE AREA

FIGURE 2.

In accordance with AS 38.05.035(e) and under a delegation of authority from the Commissioner of Natural Resources, the Director of the Division of Oil and Gas must determine whether the disposal will serve the state's best interests before the sale may be held. This preliminary analysis describes the proposed sale area, analyzes the potential effects of the sale, lists proposed mitigating measures and also serves as a preliminary consistency determination regarding the Alaska Coastal Management Program (ACMP). This discussion will precede a final finding and decision by the director which will determine whether the sale will or will not be held, and under what conditions any potential lessee may operate. In preparing these findings, a primary concern of the state is that none of the oil and gas activities which may occur as a result of the proposed sale adversely affect the environment or interfere with the traditional subsistence activities of North Slope residents.

Generally, the Department of Natural Resources believes that adequate environmental protection can be achieved by imposing specific measures to reduce or eliminate any potential adverse effects of oil and gas exploration and development. Accordingly, while the Department recognizes the intent behind the creation of ANWR, it does not believe it is necessary to establish an undeveloped area, or buffer zone, around the refuge to achieve an acceptable level of protection for fish and wildlife within ANWR. Proposed mitigating measures are described elsewhere in this analysis.

In addition to agency and public comments, other data sources considered in this analysis include the North Slope Borough's coastal management plan (Maynard and Partch, Woodward-Clyde Consultants 1984) and Final Findings (DNR/DO&G 1984, 1986a-d; DNR/DMEM 1982a, 1983) and Social, Economic, and Environmental Analyses (SEEA) (GAACL 1982a, 1983) prepared for other North Slope oil and gas lease sales. Additionally, the final Environmental Impact Statement for the federal government's Diapir Field Oil and Gas Lease Sale (June 1984) (USDOI 1984) provided information about coastal resources and communities.

POTENTIAL EFFECTS

Before a state oil and gas lease sale can take place, the Director of the Division of Oil and Gas must consider whether the sale serves the state's best interests. This decision is contingent upon an analysis of the potential effects of the sale, both adverse and beneficial. Many of the potential adverse effects are avoidable, and the state imposes stipulations and terms of sale to mitigate these effects. Some adverse effects are unavoidable, and these must be anticipated and balanced against the beneficial effects. This section outlines the activities which will probably occur as a result of this proposed sale, discusses how these activities will affect fish and wildlife populations, human use of fish and wildlife, and the local economy and well-being of the community, and describes proposed mitigating measures. The terms and stipulations referenced below are set out fully in the Proposed Mitigating Measures section.

The magnitude of effects from the proposed sale will depend on whether commercial quantities of oil and gas are discovered and produced, the location of such deposits, the type and extent of facilities necessary for development, and the effectiveness of mitigating measures in negating impacts. Until oil and gas are actually discovered, it is impossible to predict precisely what activities may occur as a result of this sale. This discussion of potential effects assumes that petroleum production will occur.

Effects on Fish and Wildlife

Impacts on fish and wildlife will be directly dependent on the amount of habitat degradation caused by petroleum-related activity. Generally, impacts can be grouped into three broad categories: (1) pollution from discharge of oil, drilling muds and cuttings, formation and cooling waters, or other wastes directly to the environment; (2) habitat loss or alteration from facilities construction; and (3) disturbance from noise and human presence. This section describes general environmental protections proposed as stipulations and terms of sale which should benefit fish and wildlife by reducing or eliminating habitat degradation. Specific fish and wildlife concerns and the measures designed to lessen foreseeable impacts are then described in more detail in the following discussion. Important habitats in the proposed sale area and vicinity, which have been identified by the Department of Fish and Game, are shown in Figures 3 and 4.

Pollution from offshore oil discharges associated with exploration, development and production, generally originates in the following ways: well accidents (blowouts), pipeline spills, tanker spills, and chronic operational spills of low volumes involving fuels and other petroleum products associated with the normal operation of drilling rigs and other facilities. Adherence to several proposed terms will aid in preventing accidental discharges of oil or dealing with an accident if one should occur. Of primary concern are measures to help prevent and mitigate the effects of a major oil spill caused by loss of well control due to an oil blowout or other accident.

The probability of a blowout is extremely low. Over 2700 oil wells have been drilled in Alaska in recent years, and no oil blowouts have occurred (Sadek 1986). Gas blowouts, on the other hand, have occurred in Alaska, most recently in May 1985 in Cook Inlet. Gas blowouts, however, pose less serious environmental hazards than oil blowouts since gas readily disperses into the atmosphere. While the probability of an oil or gas blowout or oil spill is low, the probability is not zero. In recognition of this fact, the state will require that lessees develop an Oil Discharge Contingency Plan, as specified under AS 46.04.030 and 18 AAC 75, for all offshore operations (proposed Term 7). In addition, approval to drill a well must be received from the Alaska Oil and Gas Conservation Commission (AOGCC). The technical review provided by AOGCC ensures that proper well control devices, casing design, and cement programs are used in each exploratory and development well drilled for oil and gas, and further reduces the chance that a blowout will occur. The likelihood of accidents will be reduced further by adherence to proposed Stipulation 2 which imposes seasonal drilling restrictions and expands the requirements imposed on lessees before drilling in broken ice conditions. Additionally, proposed Term 12 requires that pipelines be located so as to facilitate the containment and clean up of oil spills. Finally, the transport of oil and gas by pipeline is environmentally preferable to transport by tanker and, where technically feasible, will be required by proposed Term 14.

Pollution from other sources can be avoided by requiring proper care and disposal of offending substances. To prevent and mitigate the effects of improper discharges and disposals, the state will prohibit disposal of solid waste on natural or artificial islands or into marine waters, and will require a permit approved by the Commissioner, Department of Environmental Conservation for disposal in other areas (proposed Term 23). The state also will require that all garbage and refuse be incinerated and that residue and nonburnables be disposed of at an approved upland site (proposed Term 24).

The state will prohibit disposal of oil contaminated drilling muds and cuttings to offshore waters or sea ice (proposed Term 25b) and discharge of produced waters into marine waters of less than 10 meters in depth (proposed Term 25a). The state, however, will allow disposal of uncontaminated drilling muds and cuttings onto the sea ice (proposed Term 25e) and into open water (proposed Term 25d) during exploratory drilling operations. Discharge of muds and cuttings under sea ice will be allowed only if ice conditions make surface disposal methods impractical (proposed Term 25d). When under ice discharges are allowed, each part of drilling fluid must be prediluted with at least nine parts seawater. During development and production, disposal of drilling muds and cuttings will be subject to the conditions of National Pollution Discharge and Elimination System (NPDES) permits issued by the U.S. Environmental Protection Agency (proposed Term 25g). The provisions of proposed Term 25 should help prevent drilling effluent pollution of marine waters overlying submerged tracts in the proposed Sale 50 area.

In addition to land and water pollution, air quality in the proposed sale area will be a significant concern if new production facilities are developed (Wheeler 1986). Monitoring of air pollutant emissions from existing facilities is required at the Prudhoe Bay and Kuparuk River fields. Similar monitoring will occur at future major development sites. Significant deterioration of air quality will be prevented through compliance with the terms of permits issued and monitored by the Department of Environmental Conservation.

Air pollution monitoring, and conformance with the proposed terms regarding oil discharge and wastewater and solid waste disposal, (proposed Stipulation 2 and Terms 7, 12, 14, 23, 24, and 25) should reduce the likelihood of damage from pollutants in the proposed sale area.

Habitat loss or alteration will be minimized by requiring that (a) lessees secure water rights from the Department of Natural Resources (proposed Term 4); (b) facilities be set back from the mouths of fish-bearing streams and rivers (proposed Term 8); (c) activities and structures be designed to maintain natural oceanographic circulation patterns and nearshore water quality and allow safe passage of fish and mammals (proposed Term 9); (d) facilities and transportation routes be located to avoid sensitive fish and wildlife habitat (proposed Term 10); (e) permanent facilities not be built during exploration (proposed Term 11); and (f) facilities sites be rehabilitated after abandonment (proposed Term 13). Additionally, the Department of Environmental Conservation has prepared a Manual of Recommended Practices for Transportation Corridor Development, Roads, Railroads, Pipelines, and Subdivisions (DEC 1980). The manual includes recommendations to minimize habitat degradation by controlling erosion and sedimentation through appropriate facility design, construction, and maintenance.

Disturbance from noise and human presence will be reduced by (a) restricting low altitude operation of air craft (proposed Term 5); (b) requiring lessees' employees to undergo environmental training (proposed Term 17); and (c) restricting exploration activities in specified areas at certain times of the year (proposed Stipulation 2, proposed Terms 30 and 31).

The proposed stipulation and proposed terms of sale described above should prevent and mitigate many of the potential negative effects of petroleum exploration and development on fish and wildlife. Some of the fish and wildlife concerns specific to the proposed sale area, however, deserve additional consideration.

1. Bowhead Whales -- Considerable debate exists regarding the risks posed to bowhead whales if oil and gas exploration, development and production activities were to occur in the Camden Bay area. Both an endangered species and a vital subsistence resource to the Inupiat people, the bowhead whale has become a concern of the North Slope Borough (NSB); the Alaska Eskimo Whaling Commission (AEWC); local residents; state and federal agencies; the environmental community; and members of the petroleum industry.

   Of primary concern is the effect of seismic exploration and drilling activities on the migratory patterns of the bowhead whale. It has been suggested that noise disturbances or a major oil spill along the bowhead's migratory path, or in feeding areas, could jeopardize survival of the species. It is thought by some that disturbances of this nature could cause the bowhead whale to migrate too far from shore, thereby spending less time in important feeding areas or, perhaps, bypassing them altogether and thus risking nutritional deficiencies from inadequate food supply. The approximate path of fall migration for bowhead whales is illustrated in Figure 3.

   Another concern is the potential danger posed to bowhead whales from contact with an oil spill. It is conceivable that contact with oil might adversely effect whales by irritating their eyes, harming their skin, damaging their respiratory system from inhalation of vapors, and clogging their baleen. Studies conducted on the effects of oil on cetaceans (Geraci and St. Albans, University of Guelph, Canada, 1982) however,

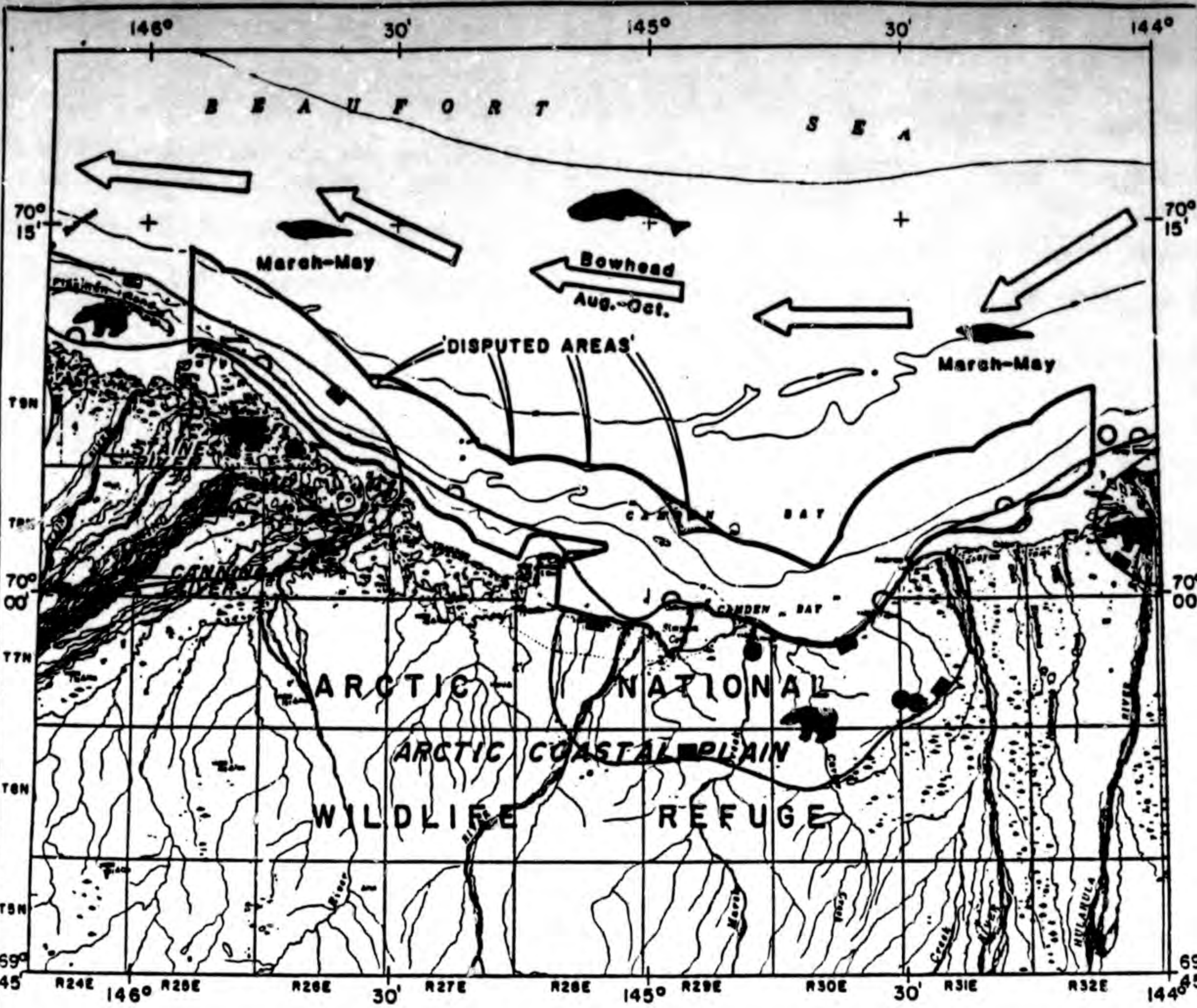


FIGURE 3. KEY MARINE MAMMAL HABITATS IN THE SALE 50 VICINITY

Polar Bear Confirmed Coastal Denning Areas

Polar Bear Possible Den Sites

Polar Bear Den Sites (Documented)

Ringed Seal Breeding and Pupping Habitat — March-May

Bowhead Whale Fall Migration Route — Bowhead Aug.-Oct.

Sources:

ADF&G 1986 — Habitat Division June 1986

USFWS 1982

PROPOSED SALE AREA

indicate that exposure of the bowhead whale to an oil spill would be of such short duration (as when surfacing) and that longterm ill effects would be unlikely.

Inupiat whalers from Nuiqsut and Kaktovik historically hunt the bowhead whale during its fall migration from the Canadian Beaufort, westward through the Alaska Beaufort, to its winter range in the Central Bering Sea. This hunt, central to the Inupiat lifestyle, provides not only meat and muktuk, but holds tremendous social and cultural importance to the villagers along the Beaufort Sea Coast.

Subsistence whalers believe that increased vessel traffic in the Beaufort Sea is forcing the whales further offshore, making them inaccessible to whaling crews. While studies have shown (Fraker, M.A., W.J. Richardson and B. Wursig. 1982) that bowhead whales do respond to vessels by moving away, or altering their surfacing and diving patterns, it has not been established that permanent changes to feeding or migratory patterns have occurred.

A step toward addressing many of the whaler's concerns was taken in early 1986 by representatives from the oil industry, North Slope Borough (NSB), Alaska Eskimo Whaling Commission (AEWC), and whaling captains from Kaktovik and Nuiqsut. The representatives met to discuss individual interests and ways these groups might work together to allow for seismic surveying and exploratory drilling by oil companies without detriment to Inupiat whaling, or the well-being of the bowhead whale.

As a result of these meetings, an agreement governing industry exploration activities in the Beaufort Sea was negotiated between industry, the NSB and whaling captains. Under the terms of the agreement, the NSB provided a communications tower, and the oil industry provided communication equipment, thereby enabling all whalers and industry vessel operators to talk with one another during their respective activities. Additionally, industry also agreed to employ an Inupiat "communicator" to operate the communication equipment on each vessel and to serve as a liaison between industry and whaling crews.

Industry also provided three satellite navigational devices (Satnavs) to the whaling fleet. Using the satnavs, the exact positions of whaling vessels can be determined and, using the established communication system, reported to industry vessels. In this manner, industry vessels are informed about the location of whaling boats, and can avoid areas of whaling activities, or in the event of an emergency, can render assistance.

This communication and navigational system is not used for scouting or reporting whale locations to whaling crews. The agreement, however, does allow industry to provide indirect assistance during the hunt. Contingent on vessel availability, assistance can include help with towing the whale to a butchering site, help in caching supplies, providing emergency assistance when required, and help with the transport of meat and muktuk to villages to prevent spoilage (Oil/Whalers Working Group, 1986).

While the industry/whaler agreement does much to alleviate conflicts between industry and subsistence whalers, the state must still take steps to protect the bowhead whale from potential impacts caused by oil and gas development. The State of Alaska, in consultation with the National Marine Fisheries Service (NMFS) and in consideration of the Endangered Species and Marine Mammal Protection Acts, has adopted a seasonal drilling restriction and whale monitoring program to decrease the likelihood that bowhead whales may be negatively impacted by oil and gas activities. Proposed Stipulation 2 outlines the current seasonal drilling restriction. As review of ongoing agency and industry whale studies occurs, the seasonal drilling restriction may be amended accordingly to protect the whales and the interests of affected parties.

In addition to the seasonal drilling restriction, several other measures have been developed that could decrease the potential impact that oil and gas exploration and development may have on bowhead whales.

Proposed Term 6 prohibits the use of explosives in open waters.

Proposed Term 7 requires an Oil Discharge Contingency Plan for all offshore operations as specified under the Alaska Statutes.

Proposed Term 9 requires lease activities and structures to be designed and sited to maintain natural oceanographic circulation patterns and to provide for free movement of fish and mammals.

Proposed Term 10 requires that facilities and transportation routes be consolidated, to the extent feasible and prudent, to avoid sensitive fish and wildlife habitat.

Proposed Term 15 prohibits continuous fill causeways unless it is determined that no other feasible and prudent alternative exists.

Proposed Terms 23-29 are designed to lessen any adverse effects to fish, wildlife and the environment by restricting the disposal of solid waste and drilling byproducts, and the mining of gravel for facilities construction.

2. Seals -- Ringed seals are protected under the Marine Mammal Protection Act of 1972; however, the incidental taking of small numbers of ringed seals may be allowed under a 1981 amendment to the Act. Ringed seals are the most abundant seal in the Beaufort, Sea and probably the most abundant marine mammal in Camden Bay. These seals live on the ice year-round. The seasonal ice cycle has an important effect on their distribution and abundance in the proposed sale area.

   Ringed seals are common in the nearshore waters when the Beaufort Sea ice is present. During winter and spring, most of the breeding adults are found on stable land-fast ice. Later, from March through May during the spring breeding and pupping season, high densities of adults remain on the land-fast ice while subadults are most numerous in adjacent flaw zones. During the majority of the year, land-fast ice commonly occurs in Camden Bay (LaBelle et al. 1983). As a result, Camden Bay provides ringed seal breeding and pupping habitat and may also be an important winter and spring feeding area (Figure 3).

During the late spring and early summer, ringed seals use the ice as a solid surface on which to haul out and complete their annual molt. They are usually found near cracks, open leads or holes where they have rapid access to water. Feeding is greatly reduced during the molt and the amount of time spent on the ice increases as the molt season progresses.

In summer, most of the adult ringed seals are found along the edge of the pack ice, well seaward of the proposed sale area. Subadults may remain in the ice free areas. Ringed seals spend much of the summer and early fall in the water feeding.

Open leads and cracks in the ice are used by ringed seals to surface and breathe. During the fall as freeze-up begins, seals will actively keep breathing holes open. In areas where drifted snow covers breathing holes, the holes are often enlarged and used to haulout and excavate lairs. The lairs are used by all seals for resting as well as for pupping by the adult females. Ringed seals build their lairs on the lee side of pressure ridges and hummocks in 20cm of snow or more. Flat areas on the ice with little or no snow accumulation will contain mostly breathing holes and few lairs.

A proposed stipulation and several proposed measures will reduce the likelihood that oil and gas exploration will adversely effect marine mammals. The seasonal drilling restriction (stipulation 2) is designed to protect the bowhead whale but may also asist in the protection of other marine mammals by limiting oil and gas activities in certain areas during the spring or fall whale migration periods.

In addition, the following proposed terms extend protection to the ringed seal:

Proposed Term 6 prohibits the use of explosives in open waters.

Proposed Term 7 requires an Oil Discharge Contingency Plan for all offshore operations as specified under the Alaska statutes.

Proposed Term 8 prohibits the location of permanent facilities near the mouths of fish-bearing streams.

Proposed Term 9 will reduce the likelihood that oil and gas will adversely impact marine mammals by requiring lease activities and structures to be designed and sited to maintain natural oceanographic circulation patterns and free movement of fish and mammals.

Proposed Term 10 suggests that facilities and transportation routes be consolidated to avoid sensitive fish and wildlife habitat.

Proposed Term 15 prohibits continuous fill causeways unless it is determined that no other feasible and prudent alternative exists.

Proposed Terms 23-29 are designed to reduce any adverse effects to fish, wildlife and the environment by restricting the disposal of solid waste and drilling byproducts as well as the mining of gravel for facilities construction.

3. Polar bears -- Polar bears in the proposed sale vicinity belong to the northern Alaska subpopulation which totals about one-third of the entire population of polar bears in Alaska, or approximately 1900 bears (Cohen 1986). Since polar bears reside on floating pack ice, except while denning, they are considered marine mammals. Polar bears are generally found in the proposed sale area from fall until spring. Some pregnant female bears travel to nearshore areas in September and October to den in snowdrifts on land or shorefast ice. Cubs are born inside the dens during mid-winter. Female bears and cubs emerge from dens in March or April, and may remain near their dens for up to 15 days. Bears and cubs move onto the sea ice during summer.

   All of Camden Bay is within the known denning range of polar bears (Figure 3). Six active dens have been identified onshore in the vicinity of Camden Bay, and one site was observed offshore near the Hulahula River. Dens are located where snow accumulates in sufficient quantities for their construction. Most dens are found within ten miles (16 km) of the coast, but dens have been observed up to 30 miles (48 km) inland. Regionally significant numbers of polar bears den between the Colville and Canning Rivers; more dens and newborn cubs have been found in this area than elsewhere on the Alaska Beaufort Sea coast.

   Polar bears are protected by an international treaty and by the Marine Mammal Protection Act. In addition, proposed Term 30 will help prevent disturbance of denning polar bears by requiring that winter travel routes and exploration programs avoid denning habitat. Exploration activities within one mile of documented, active polar bear dens may be prohibited. The use of explosives will be prohibited within 1/4 mile of cutbanks identified by the Department of Fish and Game.

   Additionally, several other proposed terms will help reduce the likelihood that polar bear may be adversely impacted by oil and gas development.

   Proposed Term 5 will restrict low aircraft flights over sensitive areas.

   Proposed Term 7 requires an Oil Discharge Contingency Plan for all offshore operations as specified under the Alaska Statutes.

   Proposed Term 10 will consolidate facilities and surface transportation routes to avoid sensitive fish and wildlife habitat.

   Proposed Term 24 requires that all garbage and refuse be incinerated and disposed of at an approved upland site.

4. Fish -- Species found in proposed sale area waters are listed in Table 1. Arctic cod and fourhorn sculpin are the most common marine fish inhabiting the waters of Camden Bay. Arctic cod are common all along the Beaufort Sea coast, and are considered a key species in the ecosystems of the Arctic Ocean because of their abundance and their importance in the diets of marine mammals, birds, and other fish. They spawn under the ice in nearshore waters during January and February. Fourhorn sculpin also are abundant and widespread along the Beaufort Sea coast. Other marine fish likely to occur in the sale area include saffron cod, arctic flounder, capelin, pacific herring, snailfish and the pacific sand lance.

Anadromous fish-bearing streams flowing into the proposed Sale 50 area are the Canning River, including the Staines River channel, and the Hulahula River. Anadromous fish found in these rivers and in nearby lakes and streams include arctic char, broad whitefish, and humpback whitefish. Chum, pink and red salmon are found in the Canning River (DF&G 1986a). Arctic char and arctic cisco were the most frequently captured in 1970 inventories of Camden Bay (Rogusky and Komarek 1971). Broad whitefish, humpback whitefish, least cisco, and boreal smelt also occur in the region but are not abundant in the sale area.

Anadromous arctic char and broad and humpback whitefish remain in freshwater for several months or years, depending on species, before migrating to coastal waters. After the initial migration, these anadromous species summer in coastal waters, returning to inland waters to spawn and overwinter. Char remain in the river systems from approximately mid-August until May or June. During summer months they feed in coastal waters of the Beaufort Sea, returning in the fall to spawn and overwinter in rivers adjacent to the sale area. Seasonal migrations of the arctic cisco in the Beaufort Sea are poorly understood; however, these fish are known to occur in Camden Bay during the summer. Whitefish spend much of their life cycle in fresh water. They feed in salt water during the summer, but generally remain in freshwater plumes extending out from river mouths and in marine waters of lower salinity. As with arctic char, these species move up river around mid-August and spawn in late September or October (Roguski and Komarek 1971).

Freshwater fish listed on Table 1 spawn and overwinter in rivers or lakes. These nonanadromous fish inhabit freshwater year-round, although arctic grayling move into river deltas and nearshore coastal waters after spring break-up.

Title 16 of the Alaska Statutes protects documented anadromous streams from disturbances associated with development. Proposed terms listed below are imposed by the Division of Oil and Gas to prevent oil and gas exploration and development from adversely affecting anadromous streams in the proposed sale area. The habitats of the Canning, Hulahula and other anadromous rivers and streams as well as offshore fish habitats will be protected by proposed Terms 7, 8, 9, 10, 15, 25, 27, 28, and 29.

Proposed Term 7 requires an Oil Discharge Contingency Plan for all offshore operations as specified under the Alaska Statutes.

Proposed Term 8 prohibits facilities within 500 feet of the active floodplains of the Canning River and within 100 feet of all other fish-bearing streams and lakes.

TABLE 1

Documented Anadromous, Marine and Freshwater Fish Within and Adjacent to the Proposed Sale 50 Area

Common name	Scientific name
Anadromous	
Arctic char*	Salvelinus alphinus
Arctic cisco*	Coregonus autumnalis
Least cisco*	Coregonus sardinella
Bering cisco	Coregonus laurettae
Broad whitefish	Coregonus nasus
Humpback whitefish	Coregonus pidschian
Pink salmon	Onchorynchus gorbuscha
Chum salmon*	Onchorynchus keta
Arctic lamprey	Lampetra japonica
Boreal smelt	Osmerus eperlanus
Ninespine stickleback *	Pungitius pungitius
Three spine stickleback	Gasterosteus aculeatus
Marine	
Fourhorn (deepwater) Sculpin	Myoxocephalus quadricornis
Arctic flounder	Liopsetta glacialis
Starry flounder	Platichthys stellatus
Arctic cod	Boreogadus saida
Saffron cod	Eleginus gracilis
Capelin	Mallotus villosus
Pacific herring	Clupa harengus
Snailfish	Liparus sp
Pacific sand lance	Ammodytes hexapterus
Freshwater	
Arctic Grayling*	Thymallus arcticus

* Species reported from lakes and drainages of the Arctic National Wildlife Refuge.

Source: USFWS 1982 (Adapted from Wilson et al. 1977 and Craig and Halderson 1980)

Proposed Term 9 requires that all activities and structures be designed, sited, and constructed to maintain normal water flow and drainage patterns and to allow for free movement and safe passage of fish.

Proposed Term 10 requires that, where feasible and prudent, facilities and surface transportation routes should be sited and consolidated to avoid sensitive fish and wildlife habitat.

Proposed Term 15 prohibits construction of continuous fill causeways, however, noncontinuous fill causeways may be permitted when the Director, Division of Oil and Gas, after consultation with the Department of Fish and Game and the Department of Environmental Conservation, determines that a causeway is necessary for field development, and that no other feasible and prudent alternative exists. Approved causeways must be sited and constructed to prevent significant changes to oceanographic circulation.

Proposed Term 23 prohibits the disposal of solid waste into marine waters.

Proposed Term 25 regulates the disposal of produced waters, drilling muds, and cuttings into water bodies and onto the ice.

Gravel removal from fish-bearing streams, river deltas, coastal lagoons, nearshore areas, and barrier islands to support oil and gas activities could adversely impact marine and anadromous fish. Gravel removal could increase sediment loads, change the streambed courses and water circulation patterns, destroy spawning habitat, and create obstacles to fish migration. Several proposed terms will protect fish and their habitat by restricting gravel mining operations.

Proposed Term 26 requires that, if gravel is needed for exploration, development, and production, gravel from abandoned drill pads and existing material sites be used first.

Proposed Term 27 prohibits gravel removal from floodplains of active watercourses for exploration activities.

Proposed term 28 prohibits gravel extraction from barrier islands, coastal lagoons and nearshore areas.

Proposed Term 29 restricts the number of gravel sites to the minimum number of approved upland or offshore sites required for development activities and prohibits gravel mining from active floodplains during development and production.

Adverse effects to proposed sale area fish from oil and gas exploration and development should be minimized by the proposed mitigating measures described above.

5. Birds -- Wetlands near the proposed sale area provide important nesting, feeding, molting, and staging habitat for numerous migratory waterfowl and shorebirds (Figure 4). Waterfowl, seabirds, and shorebirds commonly found here include ducks, geese, swans, loons, gulls, terns, plovers, and

longspurs. Terrestrial species include peregrine falcons, owls, ptarmigan, and hawks. Bird species listed in Table 2 have been observed on the Canning River delta and may occur in the proposed Sale 50 nearshore waters (Martin 1983).

Most of the region's birds are present seasonally, arriving during late April to mid-June. Spring staging usually occurs in wetlands near the coast. The birds later move onto the tundra to nest. Nesting generally extends from mid-June to mid-July. After breeding, tundra-nesting birds gather along the coast to feed before their fall migration, which begins in late August and ends by mid-September. These birds may migrate long distances, and changes to North Slope populations or habitat may affect bird populations and associated human uses in faraway locations.

Different bird habitats are important to different species at different times of the year (Martin and Moitoret 1981). For instance, nesting waterfowl and shorebirds typically prefer wet tundra habitat; this preference is reflected in lower nesting densities as elevations increase away from the coast. Generally, staging and nesting concentrations of these birds are high in the Sagavanirktok River and the Canning River deltas. Wetlands and tideflats in and near the Sagavanirktok and Canning-Tamayariak River deltas also provide important resting and feeding habitat for migratory birds in the early spring (Cohen 1986). These waters become ice-free, and available for birds to feed and rest in them before lakes and other coastal areas.

Coastal wetlands are aquatic habitats bordering the Beaufort Sea within a zone directly influenced by sea water. These areas of salt or brackish water attract large numbers of migrating shorebirds and waterfowl (Martin and Moitoret 1981:II-1). Black brant commonly rest and feed in coastal wetlands.

Like waterfowl and shorebirds, peregrine falcons are seasonal residents of the region, and are generally found near the area between mid-April and early September. Peregrine falcons nest on high cliffs or bluffs along rivers, and return to the same areas year after year. Nests have been located on bluffs along the Canning River south of the proposed sale area.

Peregrine falcons are listed as threatened on the federal endangered species list, and lessees are advised that disturbing a peregrine falcon nest violates federal law. Proposed Term 31 will regulate activities in the vicinity of nest sites. If a lessee discovers an active peregrine falcon nesting site, proposed Term 31 requires that the nest location be reported to the Director, Division of Oil and Gas. Because peregrine falcons generally hunt within 5 to 15 miles of their nests, proposed Term 31 regulates the use of pesticides within this range.

Gyrfalcons, rough-legged hawks, ptarmigan, snowy owls, and ravens also are common near the proposed sale area. Except for rough-legged hawks, these terrestrial species are year-round residents.

Nesting birds are sensitive to human activities associated with industrial development. Activities which require the use of heavy equipment and repeated aircraft flights near the nests could disrupt nesting and resting birds. The effects of such disturbances could include loss of eggs,

TABLE 2

Bird Species Observed in the Canning River Delta, 1979-1980.
(Asterisk denotes confirmed breeding species in the study area.)

Common Name	Scientific Name
* Red-throated Loon	Gavia stellata
* Arctic Loon	Gavia Arctica
Yellow-billed Loon	Gavia adamsii
* Tundra Swan	Cygnus columbianus
Greater White-fronted Goose	Anser albifrons
Snow Goose	Chen caerulescens
Ross' Goose	Chen rossii
* Brant	Branta bernicla
* Canada Goose	Branta canadensis
Green-winged Teal	Anas crecca
Mallard	Anas platyrhynchos
* Northern Pintail	Anas acuta
Northern Shoveler	Anas clypeata
Gadwall	Anas strepera
American Wigeon	Anas americana
Greater Scaup	Aythya marila
* Common Eider	Somateria mollissima
* King Eider	Somateria spectabilis
* Spectacled Eider	Somateria fishcheri
* Oldsquaw	Clangula hyemalis
Black Scoter	Melanitta nigra
Surf Scoter	Melanitta perspicillata
White-winged Scoter	Melanitta fusca
Red-breasted Merganser	Mergus serrator
Northern Harrier	Circus cyaneus
Rough-legged Hawk	Buteo lagopus
American Kestrel	Falco sparverius
Peregrine Falcon	Falco peregrinus
Gyrfalcon	Falco rusticolus
Willow Ptarmigan	Lagopus lagopus
* Rock Ptarmigan	Lagopus mutus
Sandhill Crane	Grus canadensis
* Black-bellied Plover	Pluvialis squatarola
* Lesser Golden-Plover	Pluvialis dominica
Whimbrel	Numenius phaeopus
Hudsonian Godwit	Limosa haemastica
Bar-tailed Godwit	Limosa lapponica
* Ruddy Turnstone	Arenaria interpres
Red Knot	Calidris canutus
Sanderling	Calidris alba
* Semipalmated Sandpiper	Calidris pusilla
Western Sandpiper	Calidris mauri
White-rumped Sandpiper	Calidris fuscicollis

TABLE 2. (cont.)

* Baird's Sandpiper	Calidris bairdii
* Pectoral Sandpiper	Calidris melanotos
* Dunlin	Calidris alpina
* Stilt Sandpiper	Calidris himantopus
* Buff-breasted Sandpiper	Tryngites subruficollis
* Long-billed Dowitcher	Limnodromus scolopaceus
Common Snipe	Gallinago gallinago
* Red-necked Phalarope	Phalaropus lobatus
* Red Phalarope	Phalaropus fulicaria
Pomarine Jaeger	Stercorarius pomarinus
* Parasitic Jaeger	Stercorarius parasiticus
Long-tailed Jaeger	Stercorarius longicaudus
Herring/Thayer's Gull	Larus argentatus/thayeri
* Glaucous Gull	Larus hyperboreus
Black-legged Kittiwake	Rissa tridactyla
* Sabine's Gull	Xema sabini
* Arctic Tern	Sterna paradisaea
(Thick-billed?) Murre	Uria sp.
* Black Guillemot	Cepphus grylle
Horned Puffin	Fratercula corniculata
Snowy Owl	Nyctea scandiaca
Short-eared Owl	Asio flammeus
unid. flycatcher	Empidonax sp.
Horned Lark	Eremophila alpestris
Cliff Swallow	Hirundo pyrrhonota
Common Raven	Corvus corax
Gray-cheeked Thrush	Catharus minimus
Varied Thrush	Ixoreus naevius
Yellow Wagtail	Motacilla flava
Water Pipit	Anthus spinoletta
Orange-crowned Warbler	Vermivora celata
Yellow Warbler	Dendroica petechia
American Tree Sparrow	Spizella arborea
Savannah Sparrow	Passerculus sandwichensis
White-throated Sparrow	Zonotrichia albicollis
White-crowned Sparrow	Zonotrichia leucophrys
Dark-eyed Junco	Junco hyemalis
* Lapland Longspur	Calcarius lapponicus
* Snow Bunting	Plectrophenax nivalis
Rusty Blackbird	Euphagus carolinus
* Common/Hoary Redpoll	Carduelis flammea/horneamannii

Source: Martin 1983.

inability to feed and develop sufficient fat reserves, and abandonment of molting areas (Collinsworth 1983).

Disturbance of tundra-nesting birds may be reduced by proposed Term 5. This proposed term of sale requires that aircraft fly at altitudes of greater than 1,500 feet or at a lateral distance of one mile around barrier islands, river deltas, and wetlands within one mile of the Beaufort Sea coast from May 15 through September 30.

Tundra-nesting birds will also be protected by several general provisions listed below:

Proposed Term 7 requires an Oil Discharge Contingency Plan for all offshore operations as specified under the Alaska Statutes.

Proposed Term 8 requires that permanent facilities be sited away from river mouths unless the Director, Division of Oil and Gas, after consultation with the Department of Fish and Game, determines that such facilities placement will not significantly disturb critical wildlife habitats or that such a requirement is not feasible or prudent.

Proposed Term 9 requires that all activities and structures be designed, sited, and constructed to maintain normal water flow and drainage patterns.

Proposed Term 23 regulates the disposal of solid waste.

Proposed Term 24 regulates disposal of all garbage and refuse.

Proposed Term 25 regulates disposal of produced waters, drilling muds, and cuttings.

Collectively, these proposed terms should help protect the physical and chemical integrity of bird habitat proximal to the sale area from potential degradation by oil and gas exploration and development.

Effects on Human Use of the Proposed Sale Area

The proposed sale area and adjacent vicinity receives considerable human use. This is due to the proximity of the area to Kaktovik, a traditional community located immediately to the east of the proposed sale area. Primary human uses consist of subsistence hunting and fishing by residents of Kaktovik, and occasionally Nuiqsut. Caribou, moose, seals, whales, polar bear, furbearers, fish, and birds are important Inupiat subsistence resources; of these, whales, bears, seals, fish, and birds are commonly available in the proposed sale area. The proposed sale area and vicinity may also attract some sport hunters and fishermen, as well as recreational boaters, and hikers.

Subsistence is an important part of the Inupiat culture, encompassing cultural, social, nutritional, and economic values (Maynard and Partch, Woodward-Clyde Consultants 1984:2-17). Certain animals, such as bowhead whale, bear, and seals, are more important culturally to Inupiat subsistence than other animals; their cultural value cannot be quantified. For example, whaling is considered the single most valued activity in the North Slope subsistence economy (USDOI 1984:III-54). However, in terms of effort spent

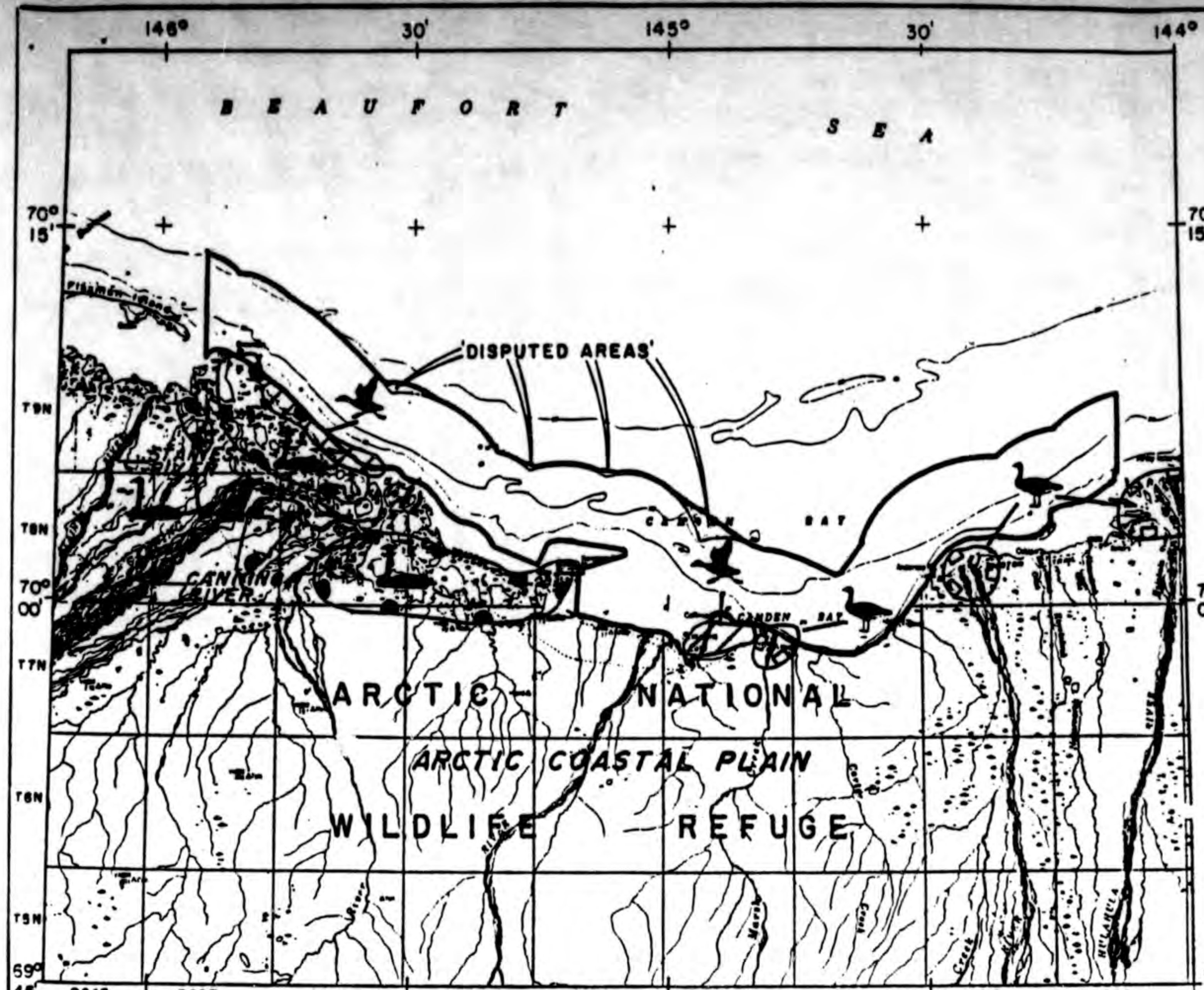


FIGURE 4. KEY BIRD HABITATS IN THE SALE 50 VICINITY

Tundra Swan High Density Nesting Areas

Black Brant Fall Staging Concentration Areas

Oldsquaw High Density Molting Concentration Areas

Sources:

ADF&G 1986

USFWS 1984

Habitat Division June 1986

PROPOSED SALE AREA

hunting and quantity of meat hunted and eaten, caribou is the most important species harvested (USDOI 1984:III-54). Traditional land use inventory sites are depicted in Figure 5.

Because the availability of animals varies from year to year, harvest patterns must change accordingly. An example of an annual subsistence harvest cycle for Kaktovik is depicted on Figure 6. Jacobson and Wentworth (1982:29-68) have documented that Kaktovik residents use the proposed sale area primarily for fishing, whaling, and access to caribou hunting grounds. Summer fishing occurs along the coast as far west as the Shaviovik River, but especially near Bullen Point and in the Canning River. The Canning River and its delta are also important for winter fishing, as are the Sagavanirktok, Sadlerochit, and Hulahula Rivers. Typically, caribou are hunted each summer along the coast and on the Canning River Delta; winter hunting may occur here as well.

Several other factors affect subsistence activities; specifically, the availability of fish and wildlife populations, weather, methods of harvest, availability of transportation, state and federal hunting and fishing regulations, local economic conditions, and availability of cash to purchase gasoline and equipment. In the proposed sale area, terrain also affects harvests (Pedersen and Coffing 1984:15; Jacobson and Wentworth 1982:33). Soggy tundra and shallow rivers restrict most summertime activities to coastal areas, but ice, frozen ground and snow cover allow the use of snow machines to expand harvest areas each winter.

Current subsistence activities are heavily dependent on cash (Alaska Consultants, Inc. et al 1984:80-81). The cost of each subsistence activity largely depends on the equipment and amount of gasoline needed to reach hunting and fishing areas. Most harvest activities are conducted from snow machines and outboard motor boats, which are expensive to purchase and maintain. Consequently, each individual's harvest activities reflect that individual's access to cash. Thus, each hunter exhibits a different pattern of harvest depending on how much gasoline and equipment he or she can afford.

Oil and gas exploration and development of the proposed sale area could adversely affect subsistence activities if fish and wildlife populations are reduced or their habitats damaged, if access to hunting and fishing areas is restricted, or if development in the proposed sale area results in improved outside access and increased competition for the area's resources. However, if proposed Sale 50 development contributes to the availability of jobs, opportunities to pursue a subsistence lifestyle could be enhanced. Local employment may limit subsistence activities to evenings, weekends, or a few longer periods for some family members, but it is not viewed as interfering with the practice of subsistence itself (Alaska Consultants et al 1984:96). Proposed Term 16, which encourages lessees to hire local and Alaska residents, could promote hiring of qualified residents for work in the proposed Sale 50 area.

Continued use of proposed sale area fish and wildlife will depend on the maintenance of fish and wildlife populations. As discussed in Effects on Fish and Wildlife, exploration, development, and production activities will be regulated to prevent significant disruption of subsistence species and to minimize disturbance to wildlife habitat. Petroleum activities, therefore, are not likely to substantially affect proposed Sale 50 fish and wildlife resources.

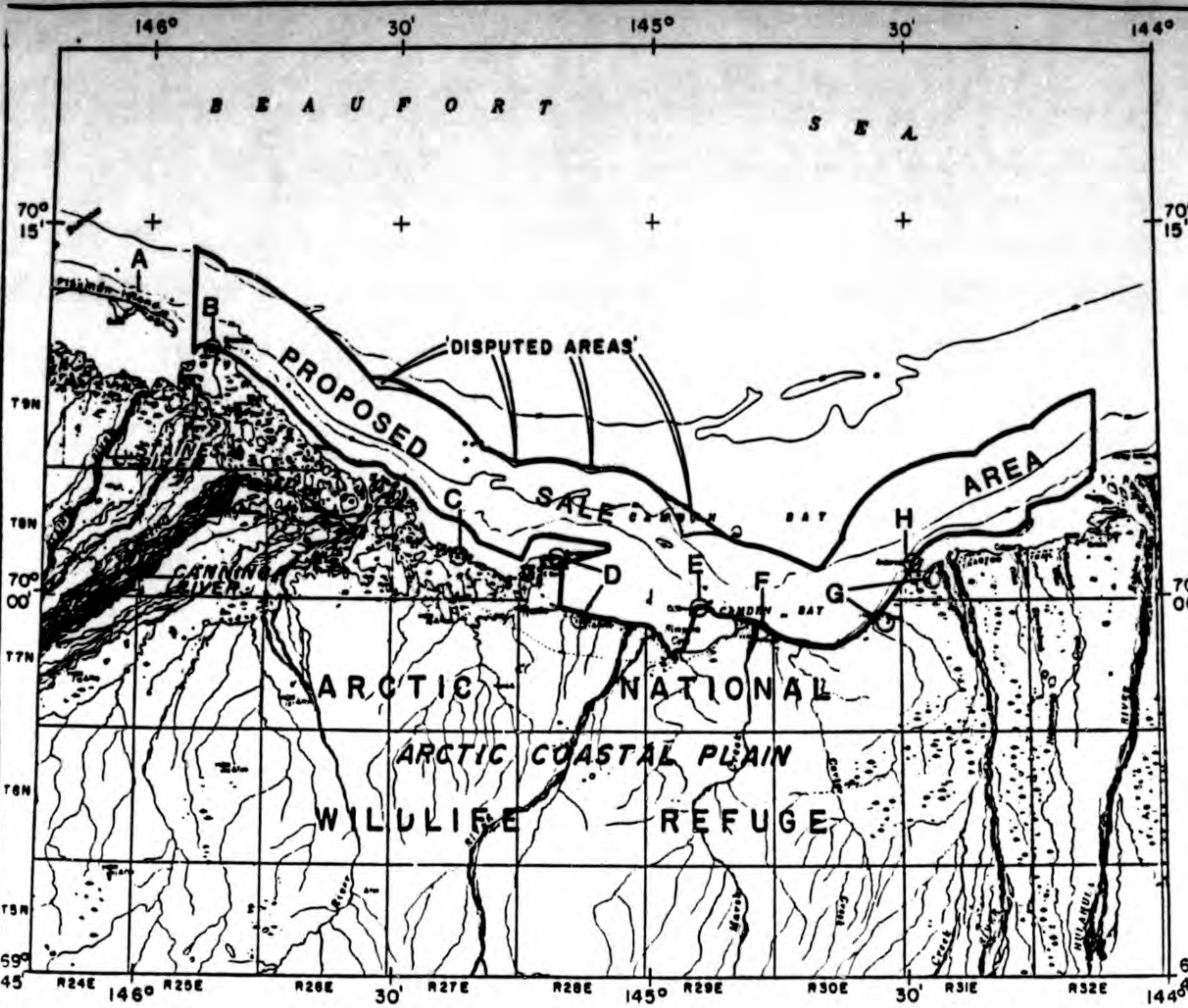


FIGURE 5. TRADITIONAL LAND USE INVENTORY SITES II

A. FLAXMAN ISLAND QIKIQTAO
B. (BROWNLOW PT.) Agliguagruk
C. Kayutak
D. (KONGANEVIK PT.) Kaninniivik
E. Nuvugaq (PT. COLLISION)
F. Kunagrak
G. Aanalaaq
H. ANDERSON PT.

PROPOSED SALE AREA

Source: Jacobson and Wentworth 1982.

wo terms are proposed to prevent disturbance of subsistence activities as a result of access conflicts or interference. Proposed Term 18 requires that public access to and use of leased areas be unrestricted except in the immediate vicinity of facilities, and proposed Term 19 requires that surface uses be restricted, as necessary, to prevent unreasonable conflicts with subsistence harvests.

Development of the proposed Sale 50 area could facilitate public access to the area for subsistence users and for sport hunters and fishermen and other recreationists, consequently increasing pressure on fish and wildlife populations and increasing competition among resource users. However, the Dalton Highway, which lies about 85 miles west of the proposed sale area, is closed by statute to unauthorized traffic. Additionally, it is likely that, as is the case at the Prudhoe Bay and Kuparuk River oil fields, oil companies will restrict public use of roads that they construct and maintain to support oil field operations in or near the sale area. This restriction applies only to use of the road, not to use of the sale area. During the exploratory phase, lessees are restricted to existing roads and to ice and winter roads and trails (proposed Term 11). Although newly constructed ice roads available to the public could temporarily facilitate wintertime access to the proposed sale area, given the extreme winter weather conditions, significant increases in wintertime sport harvests are unlikely. Consequently, the proposed sale should not affect harvest levels or opportunities to harvest.

Recreational use of the region is not well documented. Some kayaking may occur along the coast. The area is less frequently used than other regions of Alaska (Maynard and Partch, Woodward-Clyde Consultants 1984:3-27 & 31). No specific sport harvest data are available for hunting and fishing in the proposed sale area, but some hunting and fishing does occur in the region.

Effects on Local Economy and Well-being

In general, changes in the well-being of North Slope Borough communities will depend on the degree of change in local values or lifestyles caused by the proposed sale. Proposed Sale 50 acreage is located about 12 miles west of Kaktovik and 120 miles east of Nuiqsut, the nearest villages.

In these communities, subsistence is both culturally and economically significant; community well-being depends on the continued use of subsistence resources. Significant adverse effects to sale area fish and game species should be prevented by provisions discussed under Effects on Fish and Wildlife. Continued opportunities to pursue a subsistence lifestyle are discussed in Effects on Human Use of the Proposed Sale Area. In addition, proposed Term 17 should make oil field workers more sensitive to local concerns. This proposed term requires lessees' employees to be informed of the environmental, social, and cultural concerns which relate to the employee's job.

Direct benefits to the North Slope Borough's economy will depend on the discovery and subsequent production of commercial quantities of petroleum. Borough revenues are primarily raised by taxing oil and gas properties, and are used to fund capital improvement projects and to provide community services such as education, public safety, planning, and health care.

CORRECTION

THIS DOCUMENT
HAS BEEN REPHOTOGRAPHED
TO ASSURE LEGIBILITY

02-576(2/77)

Two terms are proposed to prevent disturbance of subsistence activities as a result of access conflicts or interference. Proposed Term 18 requires that public access to and use of leased areas be unrestricted except in the immediate vicinity of facilities, and proposed Term 19 requires that surface uses be restricted, as necessary, to prevent unreasonable conflicts with subsistence harvests.

Development of the proposed Sale 50 area could facilitate public access to the area for subsistence users and for sport hunters and fishermen and other recreationists, consequently increasing pressure on fish and wildlife populations and increasing competition among resource users. However, the Dalton Highway, which lies about 85 miles west of the proposed sale area, is closed by statute to unauthorized traffic. Additionally, it is likely that, as is the case at the Prudhoe Bay and Kuparuk River oil fields, oil companies will restrict public use of roads that they construct and maintain to support oil field operations in or near the sale area. This restriction applies only to use of the road, not to use of the sale area. During the exploratory phase, lessees are restricted to existing roads and to ice and winter roads and trails (proposed Term 11). Although newly constructed ice roads available to the public could temporarily facilitate wintertime access to the proposed sale area, given the extreme winter weather conditions, significant increases in wintertime sport harvests are unlikely. Consequently, the proposed sale should not affect harvest levels or opportunities to harvest.

Recreational use of the region is not well documented. Some kayaking may occur along the coast. The area is less frequently used than other regions of Alaska (Maynard and Partch, Woodward-Clyde Consultants 1984:3-27 & 31). No specific sport harvest data are available for hunting and fishing in the proposed sale area, but some hunting and fishing does occur in the region.

Effects on Local Economy and Well-being

In general, changes in the well-being of North Slope Borough communities will depend on the degree of change in local values or lifestyles caused by the proposed sale. Proposed Sale 50 acreage is located about 12 miles west of Kaktovik and 120 miles east of Nuiqsut, the nearest villages.

In these communities, subsistence is both culturally and economically significant; community well-being depends on the continued use of subsistence resources. Significant adverse effects to sale area fish and game species should be prevented by provisions discussed under Effects on Fish and Wildlife. Continued opportunities to pursue a subsistence lifestyle are discussed in Effects on Human Use of the Proposed Sale Area. In addition, proposed Term 17 should make oil field workers more sensitive to local concerns. This proposed term requires lessees' employees to be informed of the environmental, social, and cultural concerns which relate to the employee's job.

Direct benefits to the North Slope Borough's economy will depend on the discovery and subsequent production of commercial quantities of petroleum. Borough revenues are primarily raised by taxing oil and gas properties, and are used to fund capital improvement projects and to provide community services such as education, public safety, planning, and health care.

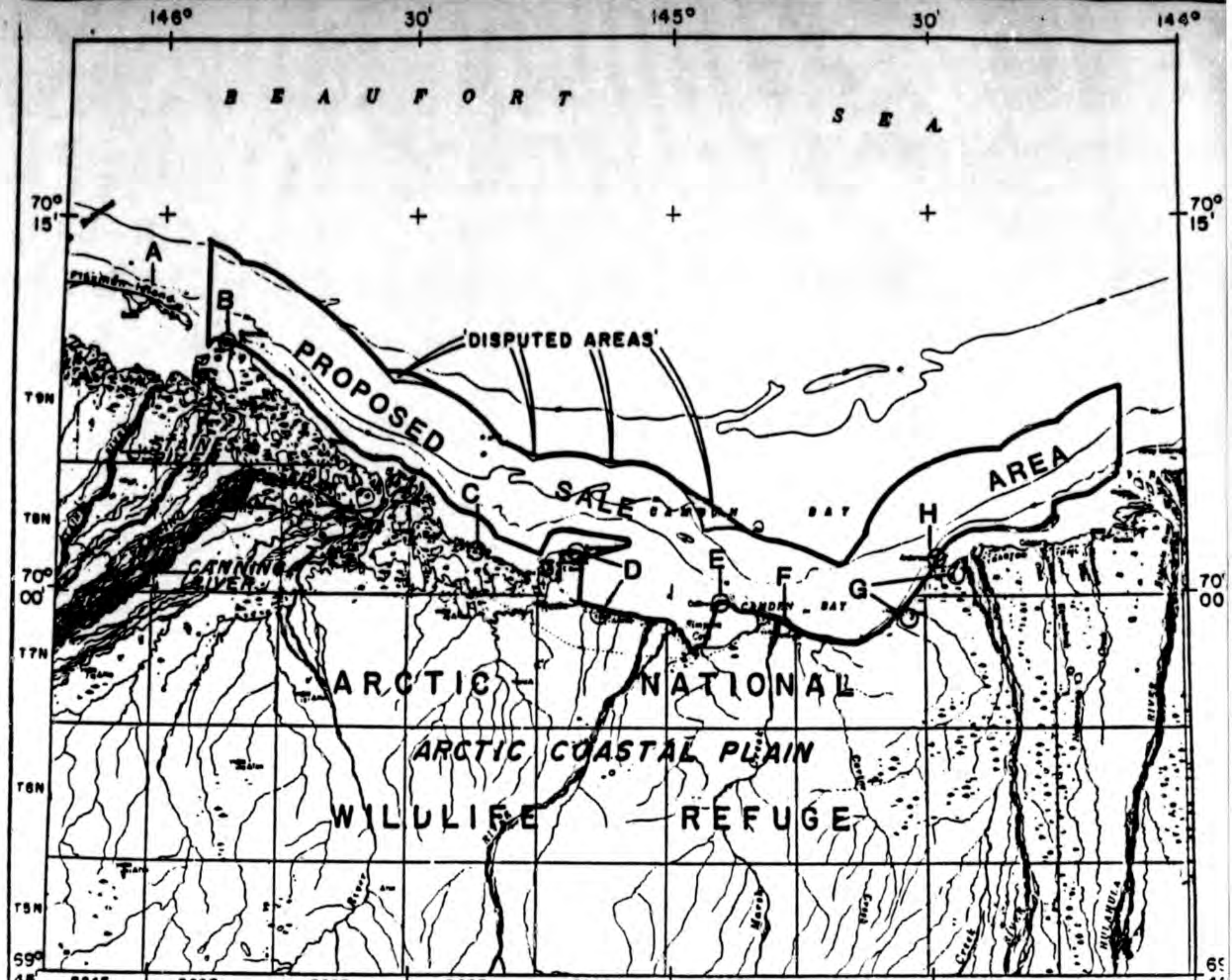


FIGURE 5. TRADITIONAL LAND USE INVENTORY SITES II

A. FLAXMAN ISLAND QIKIQTAO
B. (BROWNLOW PT.) Agliguagruk
C. Kayutak
D. (KONGANEVIK PT.) Kaninniivik
E. Nuvugaq (PT. COLLISiON)
F. Kunagrak
G. Aanalaaq
H. ANDERSON PT.

PROPOSED SALE AREA

Source: Jacobson and Wentworth 1982.

Direct benefits to borough residents will depend upon their ability to obtain oil industry jobs or jobs related to borough financed projects. Unemployment continues to be a problem in Alaska. The Sale 50 comments from North Slope Mayor George N. Ahmaogak (1985) recommended that Kaktovik residents receive hiring preference for development-related jobs, and Nuiqsut residents have expressed their wish to receive jobs and contracts related to local oil and gas activities (Nukapigak 1985; Ahmakak 1985). In response to these expressions of interest, the Department of Natural Resources continues to encourage oil companies to hire local and Alaska residents to perform work done on state oil and gas leases (proposed Term 16).

The borough is the region's principal employer (excluding the oil industry), especially of Inupiat workers (Kruse et al 1983:112-113). Over half of the workers in Kaktovik in 1982 were employed by local government (Kruse et al 1983:E-19), and half of the workers in Nuiqsut in 1983 were employed by the North Slope Borough (Research Foundation 1984:112). Reductions in capital improvement projects may have changed these statistics, but more recent figures are unavailable. North Slope Borough employment policies should help ensure that local residents are hired for borough funded community projects.

The recent dramatic drop in the price of oil could potentially affect the amount of property tax dollars available to the borough, and thus reduce the number of jobs available to borough residents. However, the possibility of new discoveries of commercial quantities of oil and gas that may result from proposed Sale 50 could add to or help maintain the borough's tax base, and thus contribute to the stability of the local economy.

The borough feels that a subsistence lifestyle should be available to local residents when oil and gas activities in the area cease. The North Slope Borough land management regulations, comprehensive plan, and proposed coastal management plan, combined with the mitigating measures developed for the proposed sale, should help to control the detrimental impacts of oil field development on the environment and the Inupiat culture.

Other Effects

1. Public access to navigable and public waters -- Restriction of public access to navigable and public waters within the proposed sale area as a consequence of petroleum development activities is prohibited, except in the immediate vicinity of drill sites and related structures (AS 38.05.127) (proposed Term 18). If a facility would impair public access, the state can require that the facility be placed elsewhere, if feasible, or that easements for public access be provided (11 AAC 53.310 and .330). Public access will not be restricted unless the facility cannot be located elsewhere, and continued public access becomes hazardous or poses a security threat.

2. Cultural resource sites -- It is not likely that any cultural resource sites would be identified within the proposed sale area. However, no cultural resource surveys have been conducted in the area, and the discovery of sites should not be ruled out.

Any sites documented, as well as any artifacts discovered will be protected by proposed Term 22. This term requires lessees to inventory archeological and historical sites within areas affected by their activities prior to construction or placement of any structure, road, or facility. Inventories must be submitted to the Division of Oil and Gas for review by the Alaska Division of Parks and Outdoor Recreation and the North Slope Borough. If a cultural resource site could be adversely affected by an activity, the Division of Oil and Gas will direct lessees as to what course of action is necessary to mitigate the adverse effect.

Lessees may discover cultural resources as a result of activities related to proposed Sale 50. Proposed Stipulation 1 will provide newly discovered sites with the same protection proposed Term 22 affords previously documented sites.

3. Native allotments and other third-party interests -- Activities proposed under a plan of operations must not unreasonably diminish the use and enjoyment of lands encompassed within a native allotment. Before entering a pending or approved native allotment, lessees must contact the Bureau of Indian Affairs and the Bureau of Land Management, and obtain approval to enter. Lessees must also comply with applicable federal law on native allotments (proposed Term 21). The North Slope Borough advises that there are native allotments near the proposed Sale 50 area (Ahmaogak 1985).

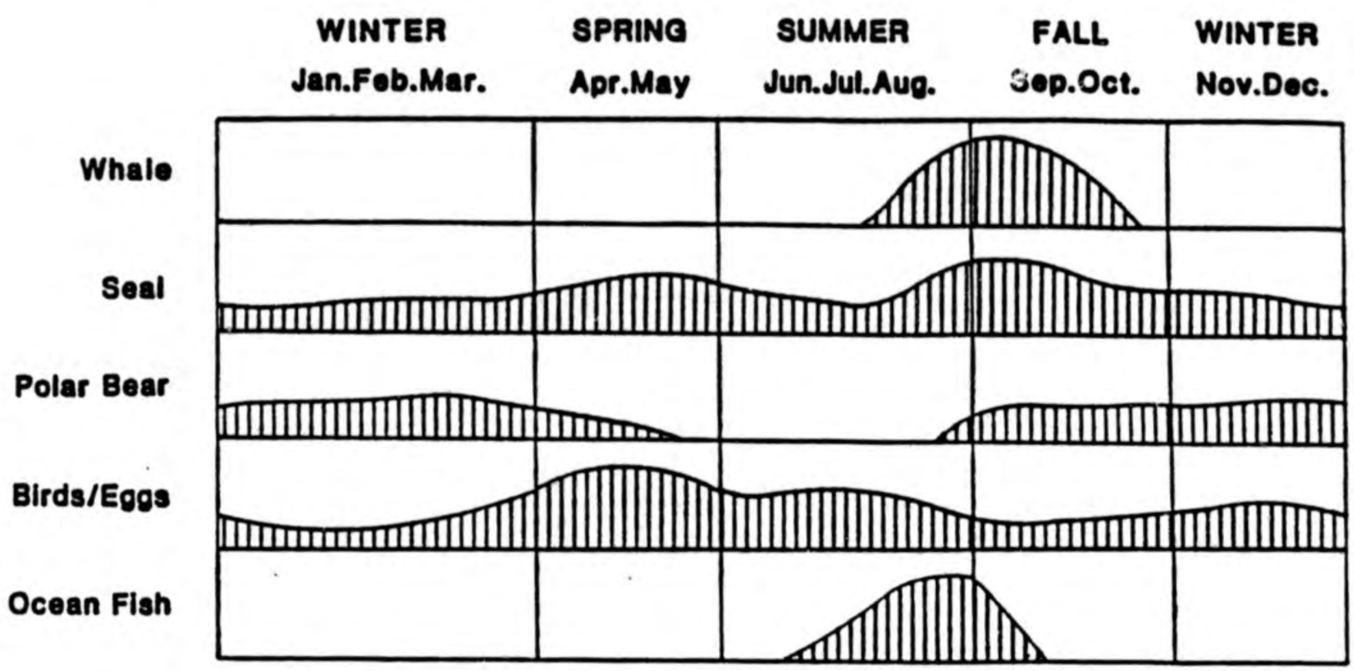
   If the surface estate is owned by a third-party, or if the surface is owned by the state but subject to third-party interests, the lessee must not enter upon such land until the lessee makes a good faith effort to agree with the surface interest holder on settlement of damages that may be caused by lease activities. If an agreement cannot be reached, the Director, Division of Oil and Gas, has the authority to approve the activity, provided adequate provisions have been made with the state to pay for any damages the surface interest holder may suffer (proposed Term 20).

Cumulative Effects

Considered independently of other activities on Alaska's North Slope, proposed Sale 50 will have negligible impacts on terrestrial fish and wildlife and their various habitats. With proper planning, the likelihood of permanent negative effects on marine fish and wildlife will also be minimal. However, the proposed sale must be evaluated in the context of current and future projects. Current human activities on the North Slope focus on oil and gas exploration, development, and production and associated support functions. In the context of on-going petroleum development, proposed Sale 50 could influence subsequent North Slope petroleum activity and contribute to the cumulative effects of petroleum development on the environment.

More than 3.6 million acres of state land have been leased on the North Slope since 1964 (Table 3). Some of this acreage has been leased more than once as leases have expired or have been relinquished. Proposed North Slope sales listed in the state's revised five-year oil and gas leasing program (1987 to 1991) could result in the leasing of over 3.9 million more acres in the next five years. Figure 7 shows the location of state, federal, and native corporation acreage currently under lease and state land proposed for leasing through 1991. Much of the state land between the Colville and Canning Rivers has been leased, as have offshore state submerged lands between the Canning

FIGURE 6 KAKTOVIK YEARLY CYCLE



Only includes key species harvested in nearshore waters of the Sale 50 area and immediately adjacent coastline. For caribou, moose and other species, refer to original source.

Patterns indicate desired periods for pursuit of each species based upon the relationship of abundance, hunter access, seasonal needs, and desirability.

Source: Jacobson and Wentworth 1982

River and Pitt Point. Native corporation and federal leases extend oil and gas activity east to Kaktovik and west to within the National Petroleum Reserve-Alaska (NPRA). Additional federal lands in NPRA may be offered, and federal leasing within the Arctic National Wildlife Refuge (ANWR) may be authorized by Congress following its review next year of the Secretary of the Interior's recommendations regarding possible development of ANWR. Federal offshore lands have been leased in the Beaufort Sea Outer Continental Shelf (OCS). Both the state and federal governments plan other lease sales in the Beaufort Sea during the next five years. In addition, the Arctic Slope Regional Corporation (ASRC) has initiated exploration and development agreements for some of its subsurface resources within the ANWR coastal plain.

Much of the land west of the sale area is under lease. The federal government has leased submerged lands north of the proposed sale area and lands to the east are also under lease. Leasing Sale 50 acreage will mean that some of Alaska's most prospective unexplored lands will be available for exploration and development. Subsequent discoveries of commercial quantities of oil and gas could extend segments of the North Slope's petroleum infrastructure east from Prudhoe Bay. A Congressional decision to make the Arctic National Wildlife Refuge's coastal plain available for leasing could extend exploration activities throughout the coastal plain of ANWR.

Subsistence use of the proposed sale area is important. Consequently, the cumulative impacts on subsistence and on subsistence resources must be considered. The effects of proposed Sale 50 combined with other current and proposed oil and gas activities will probably be similar to those considered in Effects on Human Use of the Proposed Sale Area and in Effects on Fish and Wildlife. The cumulative impacts of oil and gas-related activities could possibly affect subsistence opportunities by reducing fish and wildlife populations or by restricting access to hunting and fishing areas as a result of facilities construction. However, any development within the proposed sale area would be very localized. Therefore, the cumulative effects would be quite limited and site specific. As described elsewhere, several proposed terms are designed to retain opportunities for subsistence activities by maintaining access to leased areas (proposed Term 18) and by restricting surface uses to avoid conflicts with subsistence (proposed Term 19). Furthermore, almost all of the mitigating measures proposed are designed to maintain fish and wildlife populations and their habitat (see Effects on Fish and Wildlife).

Recent comments received by the Division of Oil and Gas, indicated that the North Slope Borough is supportive of an aggressive leasing program to assure the continued economic well-being of the borough. The results of development on the North Slope and the environmental safeguards imposed have proven to borough residents that oil and gas exploration and development can occur without permanent negative impacts to the environment or subsistence resources (George N. Ahmaogak, Sr. 1986). With continued planning, research and imposition of proper controls, the cumulative impact of industry activities on the North Slope fish and wildlife resources and human uses of those resources should be minimal.

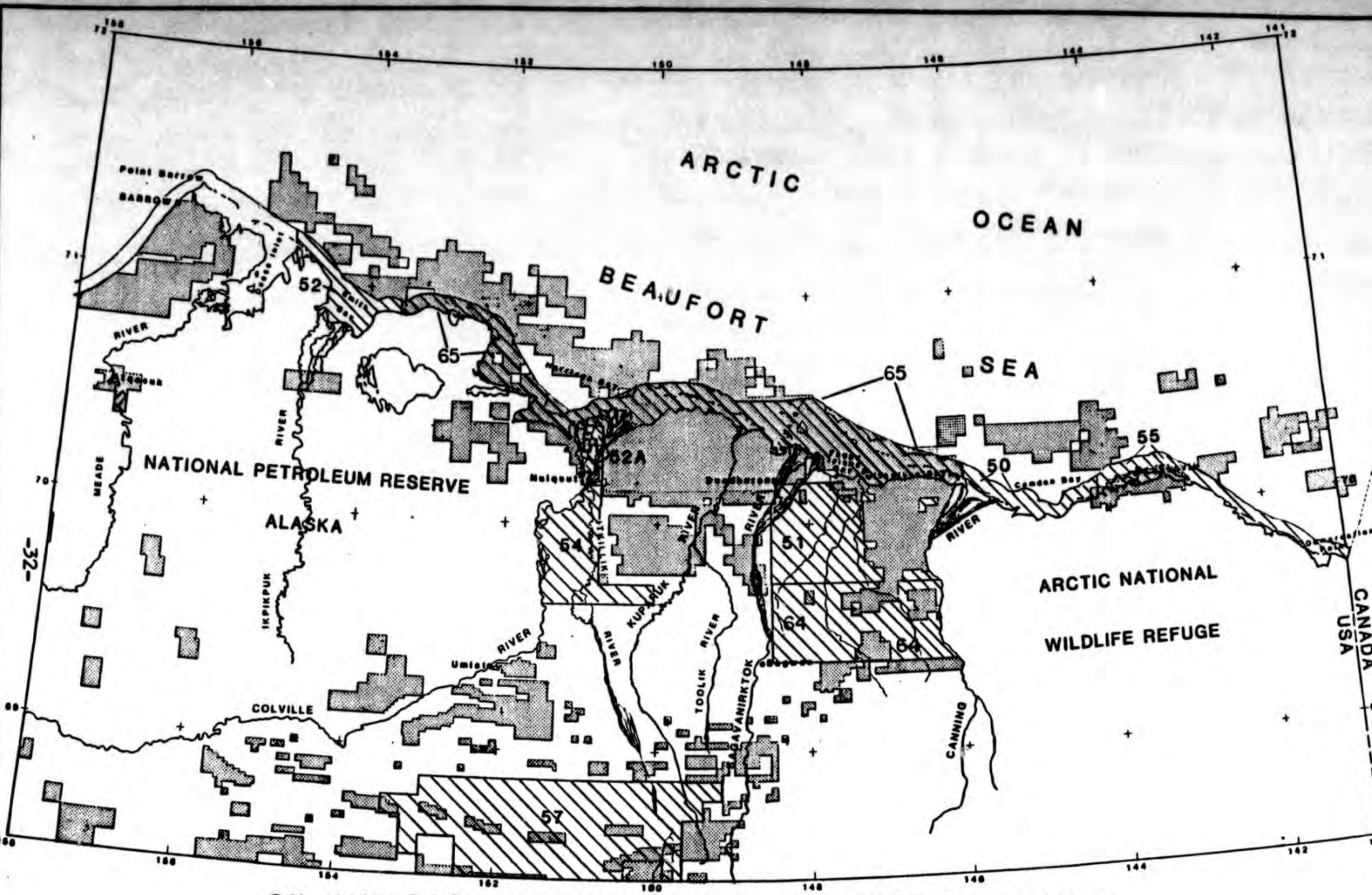
TABLE 3

North Slope Acreage, Leased and Proposed for Leasing

Number of North Slope acres (including submerged Beaufort Sea lands) leased by the State of Alaska between 1964 and 1986, and the number of North Slope acres currently proposed to be offered in state oil and gas lease sales between 1987 and 1991.

Sale	Year	# of acres leased	Proposed Sale	Year	# of acres proposed
13	1964	573,570	51	1987	592,142
14	1965	403,000	50	1987	122,745
18	1967	42,397	54	1988	455,000
23	1969	412,548	52A	1988	53,185
30	1979	296,307	55	1988	299,520
31	1980	196,268	52	1989	176,870
34	1982	571,954	57	1990	1,500,000
36	1982	60,000	64	1991	771,840
39	1983	211,988	65	1991	*
43/43A	1984	357,863			
47	1985	182,560			
48/48A	1986	308,789			
		3,617,244 Total			3,971,302 Total

*Proposed Sale 65 will consist of state lands available for reoffering; no acreage estimates may be made at this time.



OIL AND GAS LEASING IN THE ALASKAN BEAUFORT SEA AND ON THE ALASKAN NORTH SLOPE

Currently Under State, Federal, or Native Corp. Lease = 8/86

Proposed State Oil And Gas Lease Sales = SALE 65 WILL CONSIST OF PREVIOUSLY LEASED, BUT EXPIRED, ACREAGE.

FIGURE 7

This map is for information only and is not an official proposed sale area map.

Effects on National and State Economy and State Revenue

The long range goal of the state's oil and gas leasing program is to provide the basis for a stable, prosperous economy. Oil and gas leasing, and its related development, provide employment for the private sector and funding for state government services.

Since December 1985, oil prices have declined by approximately 50 to 60%, and could fall even further under current market conditions. Declining oil prices have profound implications for the domestic oil industry and for Alaska's role in that industry. About 15% of U.S. production is from stripper wells that produce 10 barrels of oil a day or less (Oil and Gas Journal 1986a). At prices less than $10 per barrel, most of these wells are unprofitable, and many are unprofitable even at $15 per barrel. In the long run, most of this production could be lost if oil prices remain at current levels. Unless domestic exploration and development costs can be dramatically reduced, the likely replacement for this lost output is from the import of foreign production. Consequently, a continuation of lower oil prices will most likely reduce domestic production, increase domestic consumption, and increase imports from approximately 30% of domestic consumption to 70% or more by the 1990's (Oil and Gas Journal 1986b).

Recent estimates indicate that about 83% of the state government's total income in fiscal year 1986 was petroleum-related (Department of Revenue 1986). North Slope fields were responsible for about 97% of this income.

Unfortunately, even with current and planned secondary and enhanced recovery efforts, Prudhoe Bay Unit production will begin declining in the late 1980's. Unless this production is replaced by new discoveries, this decline will affect state government spending as well as the state's potential for long-term economic growth.

However, uncertainty in the world oil market will adversely affect oil industry activity in Alaska in the near term, and the financial implications for the state are significant. As previously stated, the state government receives approximately 83% of its revenue from the oil industry. This figure could decline to less than 70% if oil prices remain in the $10 to $15 per barrel range.

Given North Slope exploration and development costs, oil prices in the $15 to $20 per barrel range, could render uneconomic all but huge prospects comparable to the Prudhoe Bay field. The probability of future discoveries of this magnitude is extremely low. In the near term, North Slope exploration activities will be based on the likelihood that real oil prices will begin rising sometime in the future. The uncertainty associated with the current price outlook will likely be reflected in bids submitted in proposed Sale 50.

In the absence of any discoveries or before commercial production of new discoveries, revenue will be earned by the state through the collection of bonuses and rents. If production occurs, the state will earn additional revenue from royalties, production taxes, corporate income taxes, and property taxes.

Alaska remains a prospective source of new crude oil supplies. A continuing program of state oil and gas lease sales which result in discoveries and production of new oil and gas fields will help reduce the nation's dependence on imported oil. Proposed Sale 50 will result in exploration near areas of known petroleum reserves, and production from these areas could be a source of domestic oil in the late 1990's. In addition it will extend exploration activities eastward from Pt. Thomson, and if discoveries occur in the sale area, the incremental cost of producing and transporting oil, condensate and gas from that field will be lessened. Thus, proposed Sale 50 could have positive effects both on the state's and the nation's economy by contributing to future domestic oil production.

PRELIMINARY ALASKA COASTAL MANAGEMENT
PROGRAM CONSISTENCY DETERMINATION

The proposed sale area is within the North Slope Borough (NSB) and entirely within Alaska's interim coastal zone. Consequently, the disposal of leases within the coastal zone and subsequent activities on those leases are subject to the Alaska Coastal Management Program (ACMP). As required by the ACMP, the Division of Oil and Gas must review the proposed stipulations and terms of sale proposed for Sale 50 and determine whether the sale is consistent with ACMP provisions. All activities on leases in the coastal zone will be bound by the standards of the ACMP.

Additional consistency determinations will be made on individual plans of operations submitted prior to development of leases, and on land use permits requested in conjunction with exploration activities on the leases. Future consistency determinations will address specifically the actual activities resulting from the sale.

This determination reviews the proposed stipulations and terms of sale developed to mitigate possible adverse social, economic, and environmental impacts of proposed Sale 50 in terms of their consistency with ACMP standards and in terms of their potential consistency with the NSB coastal management plan. In addition, this determination reviews whether the state will have the flexibility to implement ACMP policies and standards when approving plans of operations and land use permits. The proposed stipulations and terms of sale referenced below are set forth in the Proposed Mitigating Measures section.

North Slope Borough Coastal Management Program

The North Slope Borough has prepared a coastal management plan, which was approved by the Coastal Policy Council in April 1985 and submitted to the U.S. Department of Commerce in June 1985 as a routine program implementation change to the ACMP. The Department of Commerce determined that the North Slope Borough Coastal Management Program (NSBCMP) was a significant amendment to the ACMP, and initiated preparation of an environmental assessment. Since then, the Department of Commerce has advised the state that the NSBCMP does not meet all the requirements of the federal Coastal Zone Management Act, and that additional changes to the NSBCMP will be necessary before the environmental assessment will be completed (Tweedt 1986).

When the North Slope Borough's coastal management plan is incorporated into the ACMP, all lease-related activities in the borough's coastal zone will then be required to comply with the borough's plan. The Division of Oil and Gas has reviewed the borough's coastal development policies. No apparent conflicts exist between these policies and the proposed stipulations and terms of sale developed for proposed Sale 50. Borough requirements, once the plan is implemented, will be specifically addressed in permits and plans of operations issued for lease-related activities. Proposed Term 3 informs bidders that leases will be subject to the provisions of all approved coastal district plans and ordinances.

Standards of the ACMP

This section describes the standards of the ACMP which are applicable to the proposed sale and to resulting lease activities. All ACMP standards were considered, but only those which are applicable are discussed. The proposed stipulations and terms of sale that will ensure consistency with the standards are then summarized.

1. 6 AAC 80.040 Coastal Development -- This standard requires that in planning for and approving development in the coastal area, state agencies shall give, in the following order, priority to: water-dependent uses and activities; water-related uses and activities; and uses and activities that are neither water-dependent nor water-related for which there is no feasible and prudent inland alternative to meet the public need for the use or activity. This standard also provides that the placement of structures and the discharge of dredge or fill material into coastal water must, at a minimum, comply with the standards contained in Parts 320-323, Title 33, Code of Federal Regulations.

   Granting oil and gas leases in the proposed sale area will not preempt other uses of the area. The state reserves the right to establish or grant easements or rights-of-way on the leased property, as well as the right to manage and dispose of the surface of the leased area or interests therein by grant, lease, or permit to third parties. Proposed Term 18 prohibits the restriction of public access to and use of the lease area as a consequence of oil and gas activities, except in the immediate vicinity of facilities. In addition, proposed Term 8 requires that permanent facilities, except for road and pipeline crossings, be setback from the mouths of fish-bearing streams. These proposed terms will prevent significant interference with other water-dependent and water-related activities. Proposed Term 3 requires consistency with the ACMP.

   Leases are subject to all applicable local, state, and federal laws, rules, and regulations, including 33 CFR 320-323.

   Proposed Sale/50 is consistent with the Coastal Development Standard.

2. 6 AAC 80.050 Geophysical Hazard Areas -- This standard requires that state decision-makers not approve development in known geophysical hazard areas until siting, design, and construction measures for minimizing property damage and protecting against loss of life have been provided. Geophysical hazard areas are defined in the coastal management standards as those areas which present a threat to life or property from geophysical or geological hazards, including flooding, tsunami run-up, landslides, snowslides, faults, ice hazards, erosion, and littoral beach processes. Geophysical hazards will be considered on a site-specific basis when plans of operations are reviewed. Proposed Term 3 requires consistency with the ACMP.

   Proposed Sale 50 is consistent with the Geophysical Hazard Areas Standard.

3. 6 AAC 80.060 Recreation -- Section (a) of this standard was written primarily for coastal districts, but section (b) requires that state agencies place a high priority on maintaining and, where appropriate, increasing public access to coastal waters. As mentioned earlier, proposed Term 18 prohibits restriction of public access to and use of the area as a consequence of oil and gas activities except in the immediate vicinity of facilities. Proposed Term 8 requires that facilities be set back from the mouths of fish-bearing rivers. Proposed Term 3 requires consistency with the ACMP.

   Proposed Sale 50 is consistent with the Recreation Standard.

4. 6 AAC 80.070 Energy Facilities -- These standards regulate the siting of energy facilities. Specific standards include measures to protect the environment while meeting industrial needs. These standards will be addressed during approval of plans of operations when specific information is available on the location and design of facilities. Proposed measures that will affect the siting of facilities include the following proposed terms.

   Proposed Term 1 requires simultaneous review of plans of operations and permit applications.

   Proposed Term 3 requires consistency with the ACMP.

   Proposed Term 8 requires that facilities be setback from the mouths of fish-bearing rivers.

   Proposed Term 9 requires that facility design maintain water flow and drainage patterns and provide for movement and passage of fish and mammals.

   Proposed Term 10 requires that facilities be sited and consolidated to avoid sensitive fish and wildlife habitat.

   Proposed Term 11 requires that exploration facilities be temporary.

   Proposed Term 12 defines criteria for locating pipelines.

   Proposed Term 13 requires that facilities be removed and sites be rehabilitated.

   Proposed Term 18 disallows restriction of public access except in the immediate vicinity of facilities.

   Proposed Term 19 protects subsistence uses.

   Proposed Term 22 requires an archeological survey.

   Proposed Term 31 protects peregrine falcons.

   While each of the above terms are designed to protect the environment when siting facilities, sufficient flexibility based on feasible and prudent considerations are built into these terms to recognize and provide for industrial needs.

Proposed Sale 50 is consistent with the Energy Facilities Standard.

5. 6 AAC 80.080 Transportation and Utilities — This standard requires that transportation and utility routes and facilities in the coastal area be sited, designed, and constructed so as to be compatible with district programs, and that transportation and utility routes and facilities be sited inland from beaches and shorelines unless the route or facility is water-dependent or no feasible and prudent inland alternative exists to meet the public need for the route or facility. Transportation and utility routes will be specifically defined at the time the lessee submits its plan of operation to the state for approval. At that time, a determination will be made to ensure that proposed transportation and utility routes are consistent with approved district programs and 6 AAC 80.080(b). Proposed mitigating measures that allow the Division of Oil and Gas the flexibility to ensure that this standard is met include the following proposed terms of sale.

   Proposed Term 3 requires consistency with the ACMP.

   Proposed Term 8 requires that facilities be setback from the mouths of fish-bearing rivers.

   Proposed Term 10 requires that facilities and transportation routes be sited and consolidated to avoid sensitive fish and wildlife habitat.

   Proposed Term 12 requires pipelines to be located to facilitate the containment and clean up of spilled hydrocarbons.

   Proposed Term 14 defines criteria for locating pipelines.

   Proposed Term 13 requires that facilities be removed and sites be rehabilitated.

   Proposed Term 18 disallows restriction of public access except in the immediate vicinity of facilities.

   Proposed Sale 50 is consistent with the Transportation and Utilities Standard.

6. 6 AAC 80.110 Mining and Mineral Processing -- Paragraph (a) of this standard says that mining and mineral processing must be regulated, designed, and conducted so as to be compatible with the standards contained in the chapter, adjacent uses and activities, statewide and national needs, and district programs. Paragraph (b) of this standard provides that sand and gravel may be extracted from coastal waters, intertidal areas, barrier islands, and spits when there is no feasible and prudent alternative to coastal extraction which will meet the public need for the sand or gravel.

   Gravel extraction that accompanies oil and gas development will comply with this standard. The specifics of each proposal will be addressed when considering plans of operations and material sales contracts. Proposed terms of sale that allow the Division of Oil and Gas the flexibility to ensure that this standard is met are listed below.

Proposed Term 3 requires consistency with the ACMP.

Proposed Term 11 requires that exploration facilities not be constructed of gravel.

Proposed Term 26 requires that gravel be reused.

Proposed Term 27 restricts gravel mining in floodplains during exploration.

Proposed Term 28 prohibits gravel mining from barrier islands.

Proposed Term 29 restricts gravel mining for development activities.

Proposed Sale 50 is consistent with the Mining and Mineral Processing Standard.

7. 6 AAC 80.120 Subsistence -- This standard requires districts and state agencies to recognize and assure opportunities for subsistence usage of coastal areas and resources. As discussed in Effects on Human Use of Fish and Wildlife, the protection of subsistence uses and resources has been addressed throughout the proposed stipulations and terms of sale developed for this sale. Proposed mitigating measures include the following proposed terms of sale.

Proposed Stipulation 2 protects bowhead whales from drilling operations.

Proposed Term 3 requires consistency with the ACMP.

Proposed Term 5 protects migratory waterfowl and calving caribou from aircraft overflights.

Proposed Term 8 requires that facilities be setback from the mouths of fish-bearing rivers.

Proposed Term 10 requires that facilities be sited and consolidated to avoid sensitive fish and wildlife habitat.

Proposed Term 11 requires that exploration facilities be temporary.

Proposed Term 13 requires that facilities be removed and sites be rehabilitated.

Proposed Term 16 encourages the lessee to hire local and Alaska residents for work performed on the leased area.

Proposed Term 17 requires environmental training of personnel.

Proposed Term 18 disallows restriction of public access except in the immediate vicinity of facilities.

Proposed Term 19 protects subsistence uses.

Proposed Term 21 protects native allotments.

Proposed Term 23 controls solid waste disposal.

Proposed Term 24 requires that garbage be burned, or otherwise disposed of at an approved upland site.

Proposed Term 25 controls the discharge of produced waters, drilling muds, and cuttings.

Proposed Term 30 protects denning polar bears.

Proposed Sale 50 is consistent with the Subsistence Standard.

8. 6 AAC 80.130 Habitats — This standard contains requirements for the management of eight habitats in the coastal area which are subject to the Alaska Coastal Management Program: (1) offshore areas; (2) estuaries; (3) wetlands and tideflats; (4) rocky islands and seacliffs; (5) barrier islands and lagoons; (6) exposed high energy coasts; (7) rivers, streams, and lakes; and (8) important upland habitat. Habitats within the proposed sale area includes tideflats, lagoons and offshore areas and are immediately adjacent to 5 7, and 8. The proposed terms of sale and stipulation that have been developed in recognition of the habitats standards include the following.

Proposed Stipulation 2 imposes a seasonal drilling restriction and a high standard for drilling in broken ice conditions.

Proposed Term 3 requires consistency with the ACMP.

Proposed Term 4 requires that lessees apply for water rights and ensure that an adequate supply of water exists for winter use.

Proposed Term 6 prohibits the use of explosives in open water areas.

Proposed Term 7 requires an Oil Discharge Consistency Plan for offshore operations.

Proposed Term 8 requires that facilities be setback from the mouths of fish-bearing rivers.

Proposed Term 9 requires lease activities and structures to be designed and sited to maintain natural oceanographic circulation patterns and free movement of fish and mammals.

Proposed Term 10 requires that facilities be sited and consolidated to avoid sensitive fish and wildlife habitat.

Proposed Term 11 requires that exploration facilities be temporary.

Proposed Term 12 requires pipelines to be located so as to facilitate containment and clean up of spilled hydrocarbons.

Proposed Term 13 requires that facilities be removed and sites be rehabilitated.

Proposed Term 14 defines criteria for locating pipelines.

Proposed Term 15 prohibits continuous fill causeways.

Proposed Term 17 requires environmental training of personnel.

Proposed Term 23 controls solid waste disposal.

Proposed Term 24 requires that garbage be burned, or otherwise disposed of at an approved upland site.

Proposed Term 25 controls the discharge of produced waters, drilling muds, and cuttings.

Proposed Term 26 requires that gravel be reused.

Proposed Term 27 restricts gravel mining in floodplains during exploration.

Proposed Term 28 restricts gravel extraction from barrier islands, lagoons, and nearshore areas.

Proposed Term 29 restricts gravel mining for development activities.

Proposed Term 31 limits the use of pesticides to protect peregrine falcons.

These measures have been developed to minimize the impact of oil and gas activity on the environment and to conform to 6 AAC 80.130(b) and 6 AAC 80.130(c). Yet, there will be activities that will result from this proposed sale which will not "maintain or enhance the biological, physical, and chemical characteristics" of the coastal habitat in which they are located. In these cases, under 6 AAC 80.130(d), when approving the activity it must be shown that:

1. there is a significant public need for the proposed use or activity;

2. there is no feasible or prudent alternative to meet the public need for the proposed use or activity which would conform to the standards contained in (b) and (c) of this section; and

3. all feasible and prudent steps to maximize conformance with the standards contained in (b) and (c) of this section will be taken.

There is a significant public need to conduct the proposed sale. As discussed in the section on Effect on National and State Economy and State Revenue, the majority of the state's current income is generated by revenues from oil and gas development. Prudhoe Bay Unit production is projected to begin declining soon. If the accompanying revenue decline is to be minimized, the state must adhere to its leasing schedule and make these prospective lands available for exploration and development at the earliest possible time.

A specific need for this proposed oil and gas lease sale has been demonstrated. Offering acreage located outside the coastal zone is the only feasible alternative to leasing in the coastal zone. However, leasing of tracts in other areas may not be a prudent alternative. For example, it would not be prudent to sell leases in interior areas that had a low probability of containing oil or gas only because they were not located in the coastal zone.

The area encompassed by proposed Sale 50 lies adjacent to known oil fields. Because a portion of the infrastructure necessary to support oil and gas activity is in place as a result of petroleum industry activity on the North Slope over the last 15 years, development can occur more quickly and with less disruption of habitat than in other remote areas.

As discussed earlier, the proposed terms and stipulations listed above have been designed to minimize the proposed sale's impact on the environment and to comply with ACMP standards. They represent all feasible and prudent steps designed to maximize conformance with 6 AAC 80.130(b) and (c).

Proposed Sale 50 is consistent with the Habitats Standard.

9. 6 AAC 80.140 Air, Land, and Water Quality -- This standard incorporates into the ACMP the Department of Environmental Conservation's statutes, regulations, and procedures that pertain to the protection of air, land, and water quality. Proposed stipulations and conditions to address this standard were developed after consultation with the Department of Environmental Conservation, and reflect the concerns of that department. The proposed stipulations and conditions that have been developed in recognition of this standard are listed below.

   Proposed Stipulation 2 restricts drilling during certain seasons and requires and imposes additional criteria under the oil spill contingency plan for drilling in broken ice conditions.

   Proposed Term 3 requires consistency with the ACMP.

   Proposed Term 7 requires an Oil Discharge Contingency Plan for offshore operations.

   Proposed Term 8 requires that facilities be setback from the mouths of fish-bearing rivers.

   Proposed Term 9 requires that facility design maintain natural oceanographic circulation and drainage patterns and allow movement and passage of fish and mammals.

   Proposed Term 11 requires that exploration facilities be temporary.

   Proposed Term 12 requires pipelines to be located so as to facilitate containment and clean up of spilled hydrocarbons.

   Proposed Term 13 requires that facilities be removed and sites be rehabilitated.

   Proposed Term 14 defines criteria for locating pipelines.

   Proposed Term 15 prohibits continuous fill causeways.

   Proposed Term 17 requires environmental training of personnel.

Proposed Term 23 controls solid waste disposal.

Proposed Term 24 requires that garbage be burned, or otherwise disposed of at an approved upland site.

Proposed Term 25 controls the discharge of produced waters, drilling muds, and cuttings.

Proposed Term 26 requires that gravel be reused.

Proposed Term 27 restricts gravel mining in floodplains during exploration.

Proposed Term 28 restricts gravel mining for development activities.

Proposed Sale 50 is consistent with the Air, Land, and Water Quality Standard.

10. 6 AAC 80.150 Historic, Prehistoric, and Archeological Resources -- This standard requires that districts and appropriate state agencies shall identify areas of the coast which are important to the study, understanding, or illustration of national, state, or local history or prehistory. In recognition that future oil and gas related activity may result in the identification of currently unknown resource sites, proposed Stipulation 1 requires the lessee to report the discovery of any site, structure, or object of historical or archaeologic significance and to make every reasonable effort to preserve and protect the site, structure, or object until direction is given by DNR regarding its protection. Proposed Term 22 requires that an archaeological survey be completed before an area is affected by oil and gas activity. Proposed Term 3 requires consistency with the ACMP.

    Proposed Sale 50 is consistent with the Historic, Prehistoric, and Archeological Resources Standard.

11. 6 AAC 80.160 Areas Which Merit Special Attention (AMSA) -- This standard requires districts to designate within their district boundaries areas which merit special attention. Areas not within district boundaries are to be designated by the Coastal Policy Council. At this time there are no AMSAs in the proposed sale area.

Conclusion

Under the Alaska Coastal Management Program, the Division of Oil and Gas is obligated to review the proposed sale against the coastal management standards contained in 6 AAC 80, and to ensure that the Division's actions in the coastal area are consistent with these standards and plans, as applicable. In consultation with other resource agencies and local authorities, the Division of Oil and Gas has designed an array of proposed mitigating measures to preserve values of public concern in the coastal area. These proposed measures are imposed as lease stipulations or legally binding terms of sale. Additionally, the Division of Oil and Gas possesses statutory and regulatory authority governing other activities associated with oil and gas exploration and development in the coastal area.

The offering of competitive oil and gas leases in Sale 50 which are conditioned upon the proposed terms of sale and stipulations referenced above and by other statutory and regulatory authorities, is consistent with the Alaska Coastal Management Program.

PROPOSED MITIGATING MEASURES

AS 38.05.035(e) and the departmental delegation of authority provide the Director, Division of Oil and Gas, with the authority to impose conditions or limitations, in addition to those imposed by statute, to ensure that a resource disposal is in the state's best interests. Lease stipulations will be enforced throughout the term of the lease. Measures listed under "Plans of Operations and Other Terms of Sale" will be imposed through plans of operations and other permits to mitigate the social and environmental effects of lease activities. These measures have been developed after considering best interest findings for previous North Slope and Beaufort Sea oil and gas lease sales, fish and wildlife resources and harvest activities in the proposed Sale 50 vicinity submitted by Alaska Department of Fish and Game (ADF&G), environmental information relative to air and water quality, solid waste disposal and oil spill contingencies for proposed Sale 50 submitted by the Department of Environmental Conservation (DEC), and public comment submitted in response to the January 27, 1986, Request for Socioeconomic and Environmental Information Regarding Proposed Oil and Gas Lease Sale 50 Camden Bay.

Lease Stipulations

1. Discovery of historic or archaeologic objects:

   In the event any site, structure, or object of historic or archaeologic significance is discovered during operations on the leased area, the lessee must report immediately such findings to the Director, Division of Oil and Gas, and make every reasonable effort to preserve and protect such site, structure, or object from damage until the Director, Division of Oil and Gas, after consultation with the State Historic Preservation Officer, has given directions as to its preservation.

2. Seasonal drilling restriction:

   All tracts in proposed Sale 50 will be subject to a seasonal drilling restriction. The seasonal drilling restriction in effect in the Beaufort Sea during 1986 is set out below. This stipulation will be reevaluated periodically on the basis of experience and new information. Information gathered from research conducted in 1986 will be evaluated and a current policy will be issued prior to the 1987 drilling season.

   a. Exploratory Drilling from Bottom-founded Drilling Structures and Natural and Gravel Islands

      Subject to conditions c and d below, exploratory drilling operations and other downhole operations are allowed year-round from bottom-founded drilling structures and from natural and gravel islands.

   b. Exploratory Drilling Operations from Floating Drilling Structures

      Subject to conditions c and d below, exploratory drilling and other downhole operations above a predetermined threshold depth and testing through casing is allowed year-round from floating structures.

Exploratory drilling below the threshold is prohibited upon commencement of the fall bowhead whale migration until half of the whale population has passed the drillsite, as determined by the National Marine Fisheries Service (in consultation with the Alaska Eskimo Whaling Commission), or until October 1st, whichever occurs first.

c. Exploratory Drilling During the Fall Bowhead Whale Migration

When exploratory drilling activity is authorized and conducted at a location in the main migratory path of the bowhead whale during the whale migration, the operator must conduct a bowhead whale research program to determine the effects of noise from drilling activity and related support activities on bowhead whales and on the subsistence bowhead whale hunt. For exploratory locations between the barrier islands and the main migratory path, a decision on whether a research program is needed will be made on a case-by-case basis.

The general objectives of the research program shall be to determine if the following occurs as a result of noise and disturbance generated from drilling and support activities:

i. disruption of bowhead whales, or bowhead whale hunters, that makes subsistence hunting more difficult;

ii. short-term displacement of bowhead whales from their migratory path, from subsistence hunting areas, or from feeding areas (Information must be collected on distribution, behavior and movement of bowhead whales in the vicinity of the drillsite and of support operations. This information will later be used to determine whether long-term displacement is occurring.); and

iii. separation of cows and calves.

To ensure that the research program will adequately address these objectives, the operator shall begin consultation with the State of Alaska by April 15. The state will coordinate with the North Slope Borough and appropriate federal agencies to assist the operator in the development and approval of a research program. Unless it is determined by the state that it is not feasible or necessary, the operator shall consult with the state before: (1) the objectives of the research proposal are finalized and sent out to the contractor for bid, (2) the contractor for the project is selected, and (3) the program is finalized. The applicant will retain the authority for final approval and selection of the contractor. The state must approve the research program after consultation is completed.

A draft of the report that summarizes the results of each year's research effort shall be submitted to the state for peer review and an opportunity to provide comments at least 60 days before the results are printed as final. The results of each year's study effort must be submitted not later than six months after the field season.

All nonessential boat and barge traffic associated with the drilling activity shall be prohibited during the migration. Essential traffic shall avoid subsistence hunting areas during whaling activities. Nonessential boat traffic is defined as traffic that could reasonably occur prior to or after the migration.

If it is determined by the State of Alaska that the drilling and related support activity is interfering with the subsistence hunt, the state shall require that the activity causing the disturbance be suspended until after the hunt.

d. Exploratory Drilling in Broken Ice

Consistent with the May 1, 1984, "Tier 2" decision, lessees conducting drilling operations during periods of broken ice must: (1) participate in the Oil Spill Research an Development Program; (2) be trained and qualified in accordance with Minerals Management Service standards pertaining to well-control equipment and techniques; and (3) have an oil spill contingency plan approved by the state which meets the requirements of the "Tier 2" decision, including requirements for in situ igniters, fire resistant boom, relief well plans, and the decision process for igniting an uncontrolled release of oil.

Plans of Operations and Other Terms of Sale

Lessees must submit a detailed plan of operations to the Division of Oil and Gas for approval before conducting any exploratory or development operations. Plans of operations must identify the specific measures, design criteria and construction methods and standards that will be employed to meet the restrictions listed below. The lessee shall concurrently submit an informational copy of its plan of operations to the North Slope Borough.

Except as indicated, the restrictions listed below do not apply to seismic exploration on state lands. Seismic activities are governed by 11 AAC 96. The following restrictions will be imposed on lands leased in this sale as a condition of the approval of plans of operation:

General:

1. Plans of operations for lease activities and specific permit applications which are subject to approval by the U.S. Corps of Engineers; which require a Certificate of Reasonable Assurance from the Department of Environmental Conservation; or which require other state agency authorizations must be submitted simultaneously for state agency review and approval at least 60 days prior to the conduct of such activities. Such reviews will conform to consistency review procedures in 6 AAC 50.

2. Lessees are advised that the North Slope Borough (NSB) Assembly has adopted a Comprehensive Plan and Land Management Regulations under Title 29 of the Alaska Statutes. The regulations require NSB approval for certain activities necessary for exploration and development of the lease. The state may not in all instances accept this assertion of jurisdiction.

3. During the conduct of all activities related to this lease, the lessee will be subject to the provisions of all valid coastal zone plans and ordinances. The Division of Oil and Gas will require, as a condition for consistency approval of lease operations, such modification or stipulations as may be necessary to ensure consistency with the Alaska Coastal Management Program, and with sound planning and management of coastal zone resources.

4. An application for water rights must be submitted to the Department of Natural Resources prior to diverting, impounding, or withdrawing water from any ground or surface source. The lessee will be responsible for ensuring that an adequate supply of water is available for winter use through development of such means as storage reservoirs and snow melting.

5. The following provisions will govern aircraft operations in and near the sale area:

   a. Aircraft must fly at altitudes of greater than 1,500 feet (457 m) or at a lateral distance of one mile around barrier islands, lagoons, river deltas, and wetlands within one mile of the Beaufort Sea coast (excluding take-offs and landings) from May 15 through September 30.

   b. Human safety will take precedence over aircraft restrictions.

6. In conducting offshore geophysical surveys, neither lessees nor their agents will use explosives in open water areas. Offshore geophysical surveys will be restricted as necessary to comply with the provisions of the Marine Mammal Protection Act and with the provisions of the Endangered Species Act as they relate to the bowhead whale.

7. An Oil Discharge Contingency Plan will be required for offshore operations as specified under AS 46.04.030 and 18 AAC 75.

Facilities and Structures:

8. Permanent facilities will be prohibited within 500 feet (152 m) of the Canning River. Permanent facilities will be prohibited within 100 feet (30 m) of the mouths of all other fish-bearing streams unless the Director, Division of Oil and Gas, after consultation with the Department of Fish and Game, determines that such facilities placement will not significantly disturb critical wildlife habitats or that such a requirement is not feasible or prudent.

9. To the extent feasible and prudent, all lease activities and structures must be designed, sited and constructed to maintain natural oceanographic circulation patterns and nearshore water quality and to allow free movement and safe passage of fish and mammals.

10. Facilities and surface transportation routes will, to the extent feasible and prudent, be sited and consolidated to avoid sensitive fish and wildlife habitat.

11. Exploration facilities, with the exception of artificial gravel islands, must be temporary and must not be constructed of gravel. Use of existing abandoned gravel structures may be permitted on an individual basis by the Director, Division of Oil and Gas, after consultation with the Director of the Division of Land and Water Management and the Department of Fish and Game. Approval for use of abandoned structures will depend on the extent and method of restoration needed to return these structures to a usable condition.

12. Pipelines must be located so as to facilitate the containment and clean up of spilled hydrocarbons.

13. Upon abandonment of offshore drilling sites, all buildings, erosion armament, production platforms, pipelines, or other facilities must be removed. Upon abandonment of onshore support facilities, such facilities must be removed and the site rehabilitated unless the Director, Division of Oil and Gas, after consultation with the Departments of Fish and Game and Environmental Conservation, determine that such removal and rehabilitation is not in the state's best interest.

14. Oil and gas transportation pipelines will be encouraged if the Director, Division of Oil and Gas, determines that the laying of such pipelines is technically feasible and environmentally preferable to transport by oil tanker. Pipelines, including flow and gathering lines, must be designed and constructed to provide adequate protection from water currents, storm and ice scouring, subfreezing conditions, and other hazards as determined on a case-by-case basis. Following the installation of a pipeline of sufficient capacity, no crude oil will be transported by surface vessel from offshore production sites, except in an emergency. The Director, Division of Oil and Gas, will evaluate the emergency and determine an appropriate response to the condition. If the use of a pipeline is not feasible and preferable and surface transportation must be employed, all vessels used for carrying hydrocarbons to shore will conform with all standards established for such vessels, pursuant to the Ports and Waterways Safety Act of 1972 (46 U.S.C. 391(a)) and the Port and Tanker Safety Act of 1978 (33 U.S.C. 1221).

15. Continuous fill causeways are prohibited. Noncontinuous fill causeways may be permitted when the Director, Division of Oil and Gas, after consultation with the Department of Fish and Game and the Department of Environmental Conservation, determines that a causeway is necessary for field development and that no other feasible and prudent alternative exists. Approved causeways must be designed, sited and constructed to prevent significant changes to oceanographic circulation.

Local Hire:

16. The lessee is encouraged to hire and employ local and Alaska residents and companies, to the extent they are available and qualified, for work performed on the leased area.

Environmental Training:

17. The lessee must include in any exploration and/or development plans a proposed environmental training program for all personnel involved in exploration or development activities (including personnel of the lessee's contractors and subcontractors) for review and approval by the Director, Division of Oil and Gas. The program must be designed to inform each person working on the project of specific types of environmental, social, and cultural concerns which relate to the individual's job. The program must be formulated and implemented by qualified instructors experienced in each pertinent field of study and must employ effective methods to ensure that personnel understand and use techniques necessary to preserve archeological, geological, and biological resources. The program must also be designed to increase the sensitivity and understanding of personnel to community values, customs, and life styles in areas in which such personnel will be operating. The lessee must also submit for review and approval a continuing technical environmental briefing program for supervisory and managerial personnel of the lessee and its agents, contractors, and subcontractors.

Access:

18. No restriction of public access to, or use of, the leased area will be permitted as a consequence of oil and gas activities except in the immediate vicinity of drill sites, buildings and other related structures. Such areas where access is to be restricted must be identified in the plan of operations. No lease facilities or operations may be located where they would block public access to or along navigable and public waters as defined in AS 38.05.965(12) and (16). If lease facilities will be located in the vicinity of these public waters, an easement will be reserved under AS 38.05.127 and 11 AAC 53.330 to ensure the right of public access.

19. Surface use will be restricted, as necessary, to prevent unreasonable conflicts with local subsistence harvests.

Third Party Interests:

20. If only the subsurface estate is owned by the state, or if the surface is owned by the state but subject to third party interests, the lessee must not enter upon such land until the lessee makes a good faith effort to agree with the surface interest holder on settlement of damages that may be caused by lease activities. If an agreement cannot be reached, the Director, Division of Oil and Gas has the authority to approve the activity, provided adequate provisions have been made by the lessee with the state to pay for any damages the surface interest holder may suffer.

21. The activities proposed under the plan of operations must not unreasonably diminish the use and enjoyment of lands within a native allotment. Before entering a pending or approved native allotment, lessees must contact the Bureau of Indian Affairs and the Bureau of Land Management and obtain permission to enter, if required. Lessees must also comply with applicable federal law regarding native allotments.

Archeological and Historical Sites:

22. Prior to the construction or placement of any facility resulting from exploration, development, or production activities, the lessee must conduct an inventory of archeological and historical sites within the area affected by a proposed activity. Such inventory must consider literature provided by the North Slope Borough and local residents, documentation of oral history regarding historic and prehistoric uses of such sites, evidence of consultation with the Alaska Heritage Resources Survey and the National Register of Historic Places, and site surveys. The inventory must also include a detailed analysis of the potential effects estimated to result from the proposed activity. The inventory must be submitted to the Director, Division of Oil and Gas, for distribution to the Director of the Division of Parks and Outdoor Recreation and the Mayor of North Slope Borough for purposes of review and comment. In the event that an archeological or historical site or area may be adversely affected by an activity, the Director, Division of Oil and Gas, after consultation with the Director of the Division of Parks and Outdoor Recreation and the North Slope Borough, will direct the lessee as to what course of action will be necessary to mitigate the adverse effect.

Disposal of Wastes, Produced Waters, Drilling Muds and Cuttings:

23. Solid waste disposal on natural or artificial islands and into marine waters is prohibited. Before the lessees dispose of solid waste in other areas, the disposal must be approved through permits by the Commissioner, Department of Environmental Conservation.

24. All garbage and refuse must be incinerated. Residue and nonburnables must be disposed of at an approved upland site. No new solid fill disposal sites, except possibly for the disposal of drilling muds and cuttings, will be approved during the exploratory phase.

25. Discharge of produced water, drilling muds, and cuttings:

    a. Discharge of produced waters into open or ice-covered marine waters of less than 10 meters in depth is prohibited. The Commissioner of the Department of Environmental Conservation may approve discharges into waters greater than 10 meters in depth based on a case-by-case review of environmental factors and consistency with the conditions of a state certified development and production phase NPDES permit issued for the sale area.

    b. Disposal of oil-based or oil-contaminated drilling muds and cuttings in offshore waters and on sea ice is prohibited.

c. Offshore discharge of drilling muds and cuttings is prohibited within 1000 m of river mouths or deltas during unstable or broken ice or open water conditions.

d. During exploratory drilling, the disposal of drilling muds and cuttings within the two-meter isobath is prohibited during open water conditions. Drilling muds and cuttings free of hydrocarbon contamination may be discharged to open water outside of the two-meter isobath. However, the discharge must be diluted at a ratio of at least nine parts seawater to one part drilling fluid.

e. When exploratory drilling operations occur during periods of stable ice, uncontaminated drilling muds and cuttings may be disposed of on the sea ice surface in areas free of cracking or major stress fractures. Predilution is not required.

f. When exploratory drilling operations occur during periods of broken or unstable ice, uncontaminated drilling muds and cuttings may not be discharged unless it is not practicable to store them for disposal on stable sea ice or in open water; to dispose of them on land; to create an on-ice disposal site by pumping and artificial thickening of sea ice; or to handle the muds and cuttings in a manner that prevents below-ice discharge. If it is not practicable to meet these conditions, discharge is subject to approval by the Department of Environmental Conservation.

g. Offshore disposal of drilling muds and cuttings during development and production will be subject to the conditions of NPDES permits issued by the Environmental Protection Agency and those Alaska Coastal Management Program consistency requirements incorporated in or accompanying the NPDES permit.

Gravel Mining:

26. In meeting gravel needs for exploration, development and production, gravel from nearby abandoned drilling sites and existing material sites must be used first unless the Director, Division of Land and Water Management, after consultation with the Director, Division of Oil and Gas, and the Department of Fish and Game, determines that the reuse of such sources is not feasible and prudent.

27. Gravel mining sites required for exploration activities must not be located within an active floodplain of watercourses, unless the Director, Division of Land and Water Management, after consultation with the Department of Fish and Game, determines that a floodplain source will cause the least adverse environmental impact. Mining site development and rehabilitation within floodplains must follow the procedures outlined in Gravel Removal Guidelines For Arctic and Subarctic Floodplains, 1980, U.S. Fish and Wildlife Service-Woodward Clyde Consultants. Under AS 16, Department of Fish and Game approval is required if the mining site is located within an anadromous stream or could block fish passage.

28. Gravel extraction from barrier islands is prohibited. Gravel extraction from lagoons and nearshore areas is prohibited unless the Director, Division of Land and Water Management, finds, in consultation with the Department of Fish and Game and the Department of Environmental Conservation, that, on the basis of scientific evidence, gravel extraction in these areas will not adversely affect the environment or that no alternative feasible and prudent source exists.

29. Gravel mining sites required for development activities will be restricted to the minimum number of upland or approved offshore sites needed to develop the field efficiently and with minimal environmental damage. Where feasible and when large quantities of water will be needed for domestic or industrial use, upland gravel sites must be designed and constructed to function as reservoirs for winter water supplies. Gravel mining will not be allowed from active floodplains during development and production activities, unless the Director, Division of Land and Water Management, after consultation with the Department of Fish and Game, determines that there is no other feasible and prudent alternative and, if applicable, AS 16 requirements are met.

Special Areas:

30. Prior to the initiation of any field activities which could impact denning polar bears, lessees shall consult with the appropriate state and federal agencies to acquire the most recent information on possible locations of den sites and the location of any radio-tagged bears. Exploratory activities within one mile of documented, active polar bear dens may be restricted or prohibited during plan of operations approval. When polar bear dens are encountered in the field, they should be immediately reported to the Director, Division of Oil and Gas, and subsequently avoided.

31. Peregrine falcon nesting sites do not occur within the proposed sale area. However, the proposed sale area is within range of the arctic peregrine falcon. Lessees are advised that disturbing a peregrine falcon nest violates federal law. If the lessee discovers active peregrine falcon nest sites, the lessee must immediately report the nest locations to the Director, Division of Oil and Gas. To comply with state and federal endangered species acts, the following restrictions will apply in the vicinity of peregrine falcon nests sites, except as approved by the Department of Fish and Game, after consultation with the U.S. Fish and Wildlife Service. All known nest sites will be considered active between April 15 and June 1. Known nest sites that have not been surveyed will be considered active throughout the summer season. Nest sites not having a peregrine falcon present by June 1 will be considered inactive, and oil and gas activities near inactive nests will not be subject to the restrictions listed under b, c and d. Activities at existing development sites within two miles of newly established nests will not be subject to these restrictions.

   a. Within one mile (1.6 km) of all nest sites -- Facilities, including but not limited to roads, pipelines, disposal sites, gravel mines, storage facilities and camps will be prohibited.

b. Within one mile (1.6 km) of active nest sites -- Between April 15 and August 31, surface entry will be prohibited and aircraft overflights must avoid nest sites by an altitude of 1500 feet (457 m) above nest level.

c. Within two miles (3.2 km) of active nest sites -- Noisy activities, including blasting and gravel washing, will be prohibited between April 15 and August 31. Airfields, construction camps, disposal sites, compressor stations, and other permanent facilities that occupy large areas, are noisy or require sustained human occupancy will be prohibited.

d. Within 15 miles (24 km) of active nest sites -- Except for limited non-aerial applications of approved non-persistent insecticides, pesticide use will be prohibited.

SUMMARY AND CONCLUSIONS

The decision to hold proposed Sale 50 will undoubtedly be controversial. The proposed sale area is host to unique varieties of fish and wildlife which inhabit a sensitive and relatively undisturbed region in Alaska's Beaufort Sea. The proposed sale area also is proximal to the Arctic National Wildlife Refuge, which holds its own unique assemblage of fish and wildlife resources that could be affected by offshore oil and gas development. Native Alaskans in this region are especially dependant upon the fish and wildlife found in and around the sale area for their subsistence lifestyle.

On the other hand, the results of geologic studies in this region suggest that there may be large volumes of oil and gas contained within similar geologic settings as those identified at Prudhoe Bay and Point Thomson to the west and in discoveries in the Canadian Beaufort Sea to the east. Consequently, the proposed Sale 50 area holds promise for future oil and gas discoveries. Development of Alaska's oil resources is essential for the future economic stability of the state.

Concern has been expressed that any oil and gas development in this region would be detrimental to the Arctic National Wildlife Refuge (ANWR) and it's fish and wildlife resources. ANWR was established by Public Land Order 2214 in 1960 to preserve the wildlife, their habitats and the wilderness character of a unique region on Alaska's North Slope. The possibility of oil and gas development and the associated impact on the coastal plain of ANWR will be dealt with by Congress when it decides whether or not to open ANWR to oil and gas leasing. Such a discussion is beyond the scope of this document. At this time it is assumed that any exploration or development in Camden Bay would be supported by offshore facilities or facilities located at approved onshore sites.

The State of Alaska derives between 75 and 85 percent of it's revenues from oil and gas royalties, taxes, bonus and rental payments. Alaska's largest oil field, Prudhoe Bay, is approaching it's decline and other fields must be discovered and developed to take it's place. Once a discovery is made, it usually takes about 15 years to develop facilities and begin production. In the case of Alaska's North Slope, development of an oil and gas field may require new production methods and technologies which could add considerably to the time and money necessary to bring these resources to market. Consequently, in order to offset declining production and ensure a stable source of future revenues, the state must maintain a dependable leasing schedule that includes lands with real potential for the discovery of oil and gas. A dependable leasing program is not only in the best interest of the state, but it also contributes to meeting the nation's energy requirements and providing future national security.

Oil companies have been operating and producing oil from Alaska's sedimentary basins for 84 years. Over the years oil companies have successfully met the increasing demands for environmental safeguards. Cooperative studies between government, industry and interested groups have produced a wealth of information concerning the effects of oil and gas activities on the environment and fish and wildlife habitats. Lease stipulations and mitigating measures have been developed and imposed upon leases issued to the oil industry so that lessees may develop Alaska's petroleum resources while at the same time preserving Alaska's wildlife and environmental resources. Industry has been cooperative, and as a result, fish and wildlife continue to abound in Alaska. The success of these programs has indicated that industry has the skill and ability to operate in sensitive areas such as Camden Bay without creating irreparable negative impacts. Ongoing research as required by some of the terms of sale will allow us to adjust these stipulations and measures as needed to maximize their effectiveness.

The subsistence activities of the north slope communities and protection of the endangered bowhead whales are important issues in the proposed Sale 50 area. As has been discussed elsewhere in this document, measures have been designed to allow continued access to the proposed sale area, and to restrict oil and gas activities during the bowhead whale migration season. These and other measures presented in the preceding discussion are proposed to allow oil and gas activities to occur with minimal limitations on the activities of local residents and without imposing an unnecessary or unreasonable negative impact on fish and wildlife resources in the region.

Many of the comments received to date have recommended the postponement of proposed Sale 50 until the settlement of pending jurisdictional disputes and the issuance of a Congressional decision regarding allowable oil and gas activities in ANWR. The State of Alaska is in favor of oil and gas leasing in ANWR. The Division of Oil and Gas believes that its is possible to develop the petroleum resources of the region without creating permanent degradation in the refuge or surrounding area. Holding proposed Sale 50 as scheduled is consistent with the state's support for oil and gas development in general, and is consistent in particular with the state's recommendation to allow environmentally sound exploration and development in ANWR. If there is a positive response by industry to leasing in Camden Bay, the pending Congressional decision concerning oil and gas leasing in ANWR may be favorably influenced.

The possibility of leasing on the coastal plain of ANWR would greatly increase the economic potential of proposed Sale 50 as well as the surrounding region. Combined transport of oil from several discoveries, the prospect of linking several pools together and the larger area for potential discoveries could reduce development and transportation costs significantly. With discovery of a large volume of oil, it may be possible for production from this remote region to offset, at least partially, the decline of Prudhoe Bay. Development and production of the existing nearby discoveries and the construction of proposed gas pipelines from Pt. Thomson to Prudhoe Bay and from Prudhoe Bay south may also become economically feasible.

Proceeding with the proposed sale as scheduled may allow lands adjacent to ANWR to be evaluated prior to any possible land trade within the refuge. The U.S. Fish and Wildlife Service (USFWS) has been discussing with several Native corporations the possibility exchanging subsurface rights to lands contained within ANWR for title to other lands with unique fish and wildlife habitats around the state. The state also has expressed interest in exchanging land in various Alaskan parks and refuges for ANWR acreage. The USFWS has identified lands owned or selected by Native corporations and the state for consideration of a possible trade. The USFWS has indicated that it would be willing to discuss any land exchange proposal that would help to consolidate refuge lands in ANWR or other refuges. The USFWS also has stated that no proposed land exchange will occur prior to the submission to Congress of the report required by Section 1002(h) of Alaska National Interest Lands Conservation Act unless authorized by Congress.

With the exception of the National Petroleum Reserve-Alaska (NPRA) where it is entitled to 50 percent, the state of Alaska receives 90 percent of the revenues derived from oil and gas production on federal land within the state's boundaries. Unless specifically provided for in a land trade agreement between the federal government and third parties, the state's 90 percent revenue share of production could be jeopardized by the exchanges being considered by USFWS. The state will presumably continue its attempt to ensure that the benefits which it would receive if exploration in ANWR is authorized by Congress are not jeopardized by any land exchange agreement.

In holding proposed Sale 50 as scheduled, there will be some variables involved that could negatively affect the interest in the sale or possibly the level of bonus bids to be received for lease tracts sold. These concerns include the effect of offering disputed acreage in Camden Bay, the status of leasing in ANWR, the current and projected price and demand for oil, and present industry cutbacks, as well as transportation and development uncertainties. Oil companies that have responded to the state's call for comments, recommended that the proposed sale be held as scheduled. Their interest in this region appears to be high, as indicated by the amount of federal and native lands already under lease in the vicinity. The State of Alaska derives the vast majority of it's petroleum revenues from oil and gas royalties and taxation. Therefore, bonus bids are a minor overall concern. Holding proposed Sale 50 as scheduled would be an important step toward maintaining prosperity for the people and industries in Alaska. The development of our petroleum resources in this region of high petroleum potential, as part of a long term plan, is in the best interest of the state and is consistent with the state's leasing program.

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APPENDIX 1
SUMMARY OF COMMENTS

1) National Audubon Society: (D.R. Cline/3-17-1986)

Recommends cancelling both Sale 50 and Sale 55.

a) The title to the submerged lands between the mainland and the barrier islands as well as the boundary between the United States and Canadian waters is in dispute.
b) The Congressional decision on inclusion of the arctic coastal plain in the National Wilderness Preservation System will not be made until after September 1986.
c) The barrier island/lagoon ecosystem along the coast of the Arctic National Wildlife Refuge is a critical habitat for fish and wildlife which could suffer a negative impact from oil and gas exploration and associated development.
d) Oil and gas development along the coast of the Arctic National Wildlife Refuge could threaten the subsistence resources and lifestyles of the residents of Kaktovik.
e) Development of submerged lands along the coast of ANWR would aesthetically degrade the wilderness character of the refuge.

2) Trustees for Alaska: (R.W. Adler/9-24-1985 & 3-13-1986)

Recommends cancelling Sale 50.

a) Development in the Sale 50 area would likely require onshore support, transportation and other facilities, sale of oil and gas leases here would be inconsistent with the intent in creating ANWR.
b) Development in the sale area would jeopardize the wilderness and important habitats that Congress sought to protect with the creation of ANWR. This coastal plain and shallow coastal water environment represents a critical habitat that supports numerous species of birds, fish, as well as marine and terrestrial mammals.
c) Development in this area would threaten a region heavily used by Alaskans for subsistence and sport hunting and would not be in the best interest of the state.
d) Until title disputes are resolved on the coastal plain, it would be inappropriate to continue planning for this sale.
e) Considering recent depressed world oil markets and industry cutbacks, the bonus potential of lease tracts would be extremely low. With Alaska's current fiscal crisis, Sale 50 would not be in the state's best interest.

3) Northern Alaska Environmental Center: (M. Matz/9-26-1985, R. Rogers/4-15-1986)

Recommends postponement or cancellation of Sale 50.

a) Considering the dispute over title to portions of the Sale 50 area and a pending Congressional decision concerning exploration and development in ANWR it would seem premature to hold this sale.

Northern Alaska Environmental Center continued:

b) Exploration activities in the sale area would have a serious impact on the wildlife resources of the refuge.
c) Oil and gas activities along the Arctic coast could detrimentally impact subsistence lifestyles and recreational resources.

4) The North Slope Borough: (G. Ahmaogak/9-26-1985, L. Ahvakana/9-23-1983)

Recommends cancelling Sale 50.

a) Oil and gas activities may alter traditional feeding and migratory patterns of the bowhead whales and effect subsistence whale hunting.
b) Oil and gas activities could impact the access to or quality of the subsistence fishery on the Canning River.
c) Oil and gas activities on native allotments must be authorized.
d) Residents of the North Slope Borough must be given job preference.

5) City of Nuiqsut: (M. Kovalsky/9-10-1985)

a) Nuiqsut wants no seismic activities during fall whaling and is concerned about whale migration and fish and wildlife habitat.
b) The Nuiqsut City Council supports the City of Kaktovik.
c) Nuiqsut City Council requests that public hearings be held prior to any lease sales affecting their community.

6) The Wilderness Society: (S. Alexander/3-17-1986)

Recommends cancelling Sales 50, 51 and 55.

a) The sales violate national interest. Their proximity to ANWR conflicts with the purpose and intent in the creation of the refuge.
b) State offering of oil and gas leases in this region may influence the Congressional decision over leasing on the arctic coastal plain.
c) Subsequent development of proposed sale areas could threaten fish and wildlife populations of the Arctic Refuge.
d) The subsistence lifestyles of people in Kaktovik and other rural areas dependant on fish and wildlife could be placed in jeopardy.

7) Sierra Club: ([illegible] Matz/3-31-1986)

Recommends cancelling Sales 50, 51 and 55.

a) The low value of oil and economically inviable development and production would net poor returns for Alaska's natural resources.
b) Uncertain status of adjacent areas in ANWR.
c) Development is incompatible with this type of wilderness from which all Americans benefit. Development may cause damage to fish and wildlife on which local residents depend for subsistence.

8) BP Alaska Exploration Inc.: (C.S. Gibson-Smith/3-10-1986)

Recommendation is to hold Sale 50 as scheduled.

a) With no existing transportation facilities, development costs in this area will be high, the terms of the lease should reflect these economic constraints.

9) Chevron U.S.A. Inc.: (W.C. Morrison/8-22-1985)

Recommendation is to hold Sale 50 as scheduled.

a) Chevron wants this area to be offered with a 10 year lease term using cash bonus as the bid variable and royalty fixed at 12 1/2%.

10) Shell Western E&P Inc.: (K.E. Hughes/9-16-1985)

Recommendation is to hold Sale 50 as scheduled.

a) Shell has a moderate interest in this sale.
b) Shell would like this area to be offered with a 10 year lease term using cash bonus as the bid variable and a fixed royalty.
c) Tract size should be three miles by three miles (5,700 acres) or larger, where possible, given the irregular coastline.

11) Texaco U.S.A.: (J.N. Eke/3-10-1986)

Recommendation is to hold Sale 50 as scheduled.

a) Industry has proven it's ability to operate in the region without adversely impacting local fish and wildlife populations or the economy, lifestyles and well-being of local communities.

12) U.S. Dept. of the Interior, Fish and Wildlife Service Northern Alaska Ecological Services: (J. Nolke/4-10-1986, J. Stroebele/9-21-1983 & 9-25-1985)

Recommends postponement of Sale 50.

a) A Congressional decision regarding development within ANWR is pending and the State of Alaska is contesting jurisdiction of the coastal lagoon environments in the sale area.
b) The impact of exploration activities on refuge resources and subsistence lifestyles must be evaluated and stipulations should specifically address the migration of bowhead whales.

Recommended Measures:

1. No gravel removal, fill, or other exploration activities or structures permitted on barrier islands, spits, shorelines, or within the lagoon and nearshore areas.

Northern Alaska Ecological Services continued:

2. Minimum flight altitudes should be established over critical waterfowl nesting and staging areas during nesting and migration seasons.
3. Offshore disposal of any drilling muds in shallow or low energy, nearshore areas should be prohibited.
4. Delineation and protection of the offshore benthic macrophyte community identified in the sale area should be required.
5. Seasonal drilling restrictions are necessary to protect migrating bowhead whales.
6. Identification and protection of denning polar bears should be required.
7. The overwintering arctic char and grayling in the mouth of the Canning River should be protected.
8. Provisions should be made to avoid conflicts between oil and gas activities and subsistence activities along the coastline of Camden Bay and vicinity.
9. Camden Bay has been the epicenter of many shallow earthquakes, stipulations should address blowout prevention and relief well construction consistent for areas with high gas potential (MMS 1984).

13) State of Alaska, Dept. of Labor: (J. Robinson/9-10-1985)

a) The Department of Labor supports hiring of Alaska companies and residents for operations on oil and gas leases.

14) State of Alaska, Dept. of Environmental Conservation: (M.E. Wheeler/ 8-8-1985)

a) The Department of Environmental Conservation has begun collecting information pertinent to the air and water quality issues and solid waste management in the sale area. Impact on bowhead whales is a concern.

15) State of Alaska, Office of Archaeology: (J.E. Bittner/8-9-1985, 1-31-1986)

a) Alaska's cultural resources must be protected by the appropriate stipulations, sites are common on the barrier islands and the coastal plain but no known sites occur on submerged lands.

16) State of Alaska, Department of Fish and Game: (N.A. Cohen/7-14-86)

Recommends Postponement of Sale 50

a) Close proximity of the sale area to the ANWR may create possible adverse impacts on fish and wildlife resources in the refuge.
b) There may be conflicts between oil and gas operations and Kaktovik subsistence activities.
c) Bowhead whales and Inupiat whaling activities must be protected.

State of Alaska, Department of Fish and Game continued:

d) To ensure that Sale 50 is in the State's best interest, the potential benefits and disadvantages of the sale should be evaluated in the preliminary analysis.

Recommended Measures:

1. Measures should be implemented to ensure continued access to subsistence resources and harvest areas.
2. Unitization plans for land within the sale area should include surface management plans for the unit that provide for fish and wildlife resources and habitats.
3. Habitat alteration and disturbances of fish and wildlife should be avoided to the maximum extent possible.
4. Gravel extraction from barrier islands and nearshore areas should be regulated.
5. Solid fill causeways should be prohibited. Noncontinuous causeways should be designed in such a way that no disruptions or alterations of nearshore water circulation patterns will occur.
6. The State's prevailing policy on seasonal drilling shall be adopted.
7. The use of non-explosive energy sources such as air guns and gas exploders should be adopted as permit requirements.
8. All refuse should be incinerated and disposed of at an upland site.
9. No restriction of public access to, or use of, the proposed sale area should be permitted as a result of oil and gas activities except for the immediate vicinity of drill sites and related structures.
10. Surface use by lessee's should be restricted to avoid conflicts with the subsistence harvests.
11. Lessee's should include in all exploration and development plans an environmental training program for all personnel.
12. A permitting and review system should be established so that adverse impacts on fish and wildlife are avoided or mitigated.
13. Activities except for mandatory maintenance should be prohibited within one mile of documented polar bear denning sites, lessees should consult with the appropriate state and federal agencies.
14. Surface entry within one-half mile of the Canning-Tamayariak delta complex should be prohibited with the exception of approved winter seismic surveys.
15. To protect birdlife aircraft should be prohibited from flight below 1500 feet and within 1 mile horizontal distance of river deltas, barrier islands, lagoons and wetlands, and within 2.5 miles of the Beaufort Sea coast.

SJR
7

Senate Special Committee on Oil and Gas

Legislation Checklist

Bill number: SJR 7

Sponsor: STURGULEWSKI

Date referred to committee:

Further referrals: Resources

Prior committee report:

Back up from sponsor:

Fiscal note(s):

Agency: Requested: Received:

Agency: Requested: Received:

Position paper(s):

Agency: Requested: Received:

Agency: Requested: Received:

Sectional Analysis:

Scheduled: 2/12 Heard: Reported out:

Items for committee packet:

To Testify:

Other Contacts:

Debbie Miller, Fbks.

See page 2

5-0180B
Bannister/
Bradley
2/12/87

Original sponsors: Sturgulewski, Fischer, Abood, et al.

IN THE SENATE

BY THE SENATE SPECIAL COMMITTEE ON OIL AND GAS

CS FOR SENATE JOINT RESOLUTION NO. 7 (Oil & Gas)

IN THE LEGISLATURE OF THE STATE OF ALASKA

FIFTEENTH LEGISLATURE - FIRST SESSION

Relating to oil and gas exploration, development, and production within the Arctic National Wildlife Refuge, Alaska.

BE IT RESOLVED BY THE LEGISLATURE OF THE STATE OF ALASKA:

WHEREAS the United States Congress has reserved the right to permit further oil and gas exploration, development, and production within the coastal plain of the Arctic National Wildlife Refuge, Alaska; and

WHEREAS the oil industry, the state, and the U.S. Department of the Interior consider the coastal plain to have the highest potential for discovery of very large oil and gas accumulations on the continent of North America; and

WHEREAS a decision to permit oil and gas exploration, development, and production on the coastal plain of the refuge would increase the value and facilitate the development of highly promising state-owned tideland and federally-owned outer-continental-shelf land offshore of the refuge; and

WHEREAS the facilities that are developed to transport petroleum resources discovered on the coastal plain of the refuge to the Trans-Alaska Pipeline System may allow marginal discoveries located between the refuge and the pipeline to be developed and produced, and may prolong the economic life of the pipeline; and

WHEREAS oil and gas exploration and development of the coastal plain of the refuge and adjacent land could result in major discoveries that would reduce our nation's future needs for imported oil, help balance the nation's trade deficit, and significantly increase the nation's security; and

WHEREAS the oil and gas industry and related Alaska employment have been severely affected by reduced oil and gas activity, and the reduction in industry investment and employment has broad implications for the Alaska work force and the entire state economy; and

WHEREAS the development of coastal plain oil and gas resources can and should be conducted by the corporations and workers of the state, who have the expertise to bring the resources to market; and

WHEREAS 8,000,000 of the 19,000,000 acres of the refuge have already been set aside as wilderness; and

WHEREAS the 1,500,000-acre coastal plain of the refuge comprises only eight percent of the refuge, and the development of the oil and gas reserves in the refuge's coastal plain would affect an even smaller percentage of the refuge; and

WHEREAS the oil industry has shown at Prudhoe Bay, as well as at other locations along the Arctic coastal plain, that it can safely conduct oil and gas activity without adversely affecting the environment or wildlife populations;

BE IT RESOLVED by the Alaska State Legislature that the Congress of the United States is urged to open the coastal plain of the Arctic National Wildlife Refuge, Alaska, to oil and gas exploration, development, and production; and be it

FURTHER RESOLVED that that activity be conducted in a manner that protects the environment and utilizes the state's work force to the maximum extent possible.

COPIES of this resolution shall be sent to the Honorable Donald Hodel, Secretary of the Department of the Interior; to the Honorable J. Bennett Johnston, Chairman of the Senate Committee on Energy and Natural Resources; to the Honorable Morris K. Udall, Chairman of the House Committee on Interior and Insular Affairs; and to the Honorable Ted Stevens and the

Honorable Frank Murkowski, U.S. Senators, and the Honorable Don Young, U.S. Representative, members of the Alaska delegation in Congress.

Offered: 2/13/87
Referred: Resources

5-0180B

Original sponsors: Sturgulewski, Fischer, Abood, et al.

IN THE SENATE

BY THE SENATE SPECIAL COMMITTEE ON OIL AND GAS

CS FOR SENATE JOINT RESOLUTION NO. 7 (Oil & Gas)

IN THE LEGISLATURE OF THE STATE OF ALASKA

FIFTEENTH LEGISLATURE - FIRST SESSION

Relating to oil and gas exploration, development, and production within the Arctic National Wildlife Refuge, Alaska.

BE IT RESOLVED BY THE LEGISLATURE OF THE STATE OF ALASKA:

WHEREAS the United States Congress has reserved the right to permit further oil and gas exploration, development, and production within the coastal plain of the Arctic National Wildlife Refuge, Alaska; and

WHEREAS the oil industry, the state, and the U.S. Department of the Interior consider the coastal plain to have the highest potential for discovery of very large oil and gas accumulations on the continent of North America; and

WHEREAS a decision to permit oil and gas exploration, development, and production on the coastal plain of the refuge would increase the value and facilitate the development of highly promising state-owned tideland and federally-owned outer-continental-shelf land offshore of the refuge; and

WHEREAS the facilities that are developed to transport petroleum resources discovered on the coastal plain of the refuge to the Trans-Alaska Pipeline System may allow marginal discoveries located between the refuge and the pipeline to be developed and produced, and may prolong the economic life of the pipeline; and

WHEREAS oil and gas exploration and development of the coastal plain of the refuge and adjacent land could result in major discoveries that would reduce our nation's future needs for imported oil, help balance the nation's trade deficit, and significantly increase the nation's security; and

WHEREAS the oil and gas industry and related Alaska employment have been severely affected by reduced oil and gas activity, and the reduction in industry investment and employment has broad implications for the Alaska work force and the entire state economy; and

WHEREAS the development of coastal plain oil and gas resources can and should be conducted by the corporations and workers of the state, who have the expertise to bring the resources to market; and

WHEREAS 8,000,000 of the 19,000,000 acres of the refuge have already been set aside as wilderness; and

WHEREAS the 1,500,000-acre coastal plain of the refuge comprises only eight percent of the refuge, and the development of the oil and gas reserves in the refuge's coastal plain would affect an even smaller percentage of the refuge; and

WHEREAS the oil industry has shown at Prudhoe Bay, as well as at other locations along the Arctic coastal plain, that it can safely conduct oil and gas activity without adversely affecting the environment or wildlife populations;

BE IT RESOLVED by the Alaska State Legislature that the Congress of the United States is urged to open the coastal plain of the Arctic National Wildlife Refuge, Alaska, to oil and gas exploration, development, and production; and be it

FURTHER RESOLVED that that activity be conducted in a manner that protects the environment and utilizes the state's work force to the maximum extent possible.

COPIES of this resolution shall be sent to the Honorable Donald Hodel, Secretary of the Department of the Interior; to the Honorable J. Bennett Johnston, Chairman of the Senate Committee on Energy and Natural Resources; to the Honorable Morris K. Udall, Chairman of the House Committee on Interior and Insular Affairs; and to the Honorable Ted Stevens and the

Honorable Frank Murkowski, U.S. Senators, and the Honorable Don Young, U.S. Representative, members of the Alaska delegation in Congress.

Introduced: 1/28/87
Referred: Resources

IN THE HOUSE BY THE RESOURCES COMMITTEE

HOUSE JOINT RESOLUTION NO. 9

IN THE LEGISLATURE OF THE STATE OF ALASKA

FIFTEENTH LEGISLATURE - FIRST SESSION

Relating to the Arctic National Wildlife Refuge, Alaska.

BE IT RESOLVED BY THE LEGISLATURE OF THE STATE OF ALASKA:

WHEREAS the United States Congress has reserved the right to permit further exploration for, and development of, oil and gas within the coastal plain of the Arctic National Wildlife Refuge, Alaska; and

WHEREAS the U.S. Department of the Interior, the state, and the oil industry consider the coastal plain to have the highest potential for discovery of very large oil and gas accumulations on the continent of North America; and

WHEREAS a decision to permit oil and gas exploration, development, and production on the coastal plain would facilitate the development of highly promising state and federal tideland and submerged land; and

WHEREAS the facilities that are developed to transport oil and gas from the coastal plain to the Trans-Alaska Pipeline System (TAPS) may allow the development of marginal fields between the refuge and TAPS, extending the economic life of the pipeline and reducing tariffs that are expected to balloon in approximately 20 years; and

WHEREAS development of oil and gas in the refuge should and will be subject to strict environmental safeguards, including those protecting water, land, air, and important wildlife habitat that supports the subsistence resources used by Natives of the state and of the Yukon Territory in Canada; and

WHEREAS the permanent protection of large areas in the state's arctic region is assured by park, reserve, and refuge designations encompassing over 35,000,000 acres of federal land in the region; and

WHEREAS the biological and recreational resources of the refuge are very valuable, and the protection of these resources with adequate development safeguards is in the interest of the nation and the state; and

WHEREAS the land trades proposed by the U.S. Department of the Interior with private corporations would reduce or eliminate the state's existing entitlement to oil and gas revenue from the refuge; and

WHEREAS the state is a vast and under-served state with basic education, capital improvement, and public service needs, and a reduction in state revenue is a serious matter for the state's residents; and

WHEREAS the U.S. Congress could consider reducing the state's existing entitlement to oil and gas revenue within the refuge, even though the reduction might violate solemn agreements between the federal government and the state, discriminate against the state as compared to other states, and reverse decades-long policies of the federal government regarding the management of public domain lands within the states; and

WHEREAS development of coastal plain oil and gas resources can and should be conducted by the corporations and workers of the state, who have the expertise to bring the resources to market; and

WHEREAS the oil and gas industry and employment of the state have been severely affected by reduced oil and gas activity in recent years, and the reduction has broad implications for the entire state economy;

BE IT RESOLVED that the Alaska State Legislature adopts the following consensus points regarding management of the coastal plain of the Arctic National Wildlife Refuge, Alaska:

(1) the U.S. Congress should promptly open the coastal plain of the Arctic National Wildlife Refuge, Alaska, to oil and gas exploration, production, and transportation under conditions that are in the interest of the nation and the state, reserving the leasing of land in the core caribou

calving grounds until a later time;

(2) the U.S. Department of the Interior should desist from discussing land trades that would eliminate the state's revenue share from oil and gas activity in the refuge and that could reduce the ownership influence of the state and federal governments on oil and gas leasing in the refuge;

(3) unless the state concurs, the U.S. Congress should not allow measures or actions that reduce the state's entitlement to oil and gas revenue from the refuge;

(4) the U.S. Congress should require the protection of the environmental and subsistence resources of the refuge, including wildlife habitat, air, and water, in the event of oil and gas development on the coastal plain of the refuge; and

(5) the U.S. Congress, in recognition of the state's economic situation and the need for long-term economic development in the state, should require that the exploration and development activity in the refuge be conducted by the work forces of the state; and be it

FURTHER RESOLVED that the state's delegation in Congress and the Governor of the state should support opening the coastal plain of the Arctic National Wildlife Refuge, Alaska, to oil and gas exploration, production, and transportation under conditions that would advance the interests of the people of the state, and work with the U.S. Department of the Interior to forestall proposed refuge land trades that would be inimical to the interests of the state.

COPIES of this resolution shall be sent to the Honorable Ronald Reagan, President of the United States; to the Honorable Donald Hodel, Secretary of the Department of the Interior; to the Honorable Steve Cowper, Governor of Alaska; to the Honorable Ted Stevens and the Honorable Frank Murkowski, U.S. Senators, and the Honorable Don Young, U.S. Representative, members of the Alaska delegation in Congress; and to each of the other members of the U.S. Congress.

Introduced: 1/22/87
Referred: Resources and Finance

BY MARTIN, BARNES, COLLINS, FRANK, FURNACE, HANLEY, HUDSON, MENARD, PEARCE, PETTYJOHN, RIEGER, SHULTZ, TAYLOR, ZAWACKI AND MILLER

IN THE HOUSE

HOUSE JOINT RESOLUTION NO. 7

IN THE LEGISLATURE OF THE STATE OF ALASKA

FIFTEENTH LEGISLATURE - FIRST SESSION

Relating to oil and gas exploration, development, and production within the Arctic National Wildlife Refuge, Alaska.

BE IT RESOLVED BY THE LEGISLATURE OF THE STATE OF ALASKA:

WHEREAS the Arctic National Wildlife Refuge, Alaska, includes more than 19,000,000 acres of land, which amounts to approximately five percent of the size of the entire state; and

WHEREAS the coastal plain of the Arctic National Wildlife Refuge, Alaska, covers approximately eight percent of the refuge and is considered to have high potential for the discovery of large quantities of oil and gas; and

WHEREAS the U.S. Congress has reserved the right to decide if the coastal plain will be opened to further oil and gas exploration, development, and production; and

WHEREAS the petroleum industry has consistently demonstrated its ability to operate under conditions similar to those found on the coastal plain in a safe and responsible manner without significant adverse environmental effects; and

WHEREAS the United States must develop domestic petroleum resources if the United States is to prevent itself from becoming overwhelmingly dependent on foreign petroleum sources in the 21st century; and

WHEREAS the value and development potential of state-owned tideland and federally-owned outer continental shelf land offshore of the coastal plain would be enhanced by a decision by the U.S. Congress to open the coastal plain to further oil and gas exploration, development, and production; and

WHEREAS the facilities that would be developed to transport petroleum resources discovered on the coastal plain to the Trans-Alaska Pipeline System might allow marginal discoveries located between the refuge and Prudhoe Bay to be developed; and

WHEREAS the energy security of the nation depends on the development of domestic oil and gas resources to replace depleted United States reserves; and

WHEREAS the nation will derive revenue, including portions of bonuses, royalties, and rents, from oil and gas development of the coastal plain; and

WHEREAS opening the coastal plain to further oil and gas exploration, development, and production will generate increased employment and business opportunities for all citizens of the state and the nation;

BE IT RESOLVED by the Alaska State Legislature that the Congress of the United States is urged to open the coastal plain of the Arctic National Wildlife Refuge, Alaska, to environmentally responsible oil and gas exploration, development, and production.

COPIES of this resolution shall be sent to the Honorable George Bush, Vice-President of the United States and President of the U.S. Senate; the Honorable Donald P. Hodel, Secretary of the Department of the Interior; the Honorable Jim Wright, Speaker of the U.S. House of Representatives; the Honorable Ted Stevens and the Honorable Frank Murkowski, U.S. Senators, and the Honorable Don Young, U.S. Representative, members of the Alaska delegation in Congress; and to the presiding officer of each legislative house of the other states in the United States.

STATE OF ALASKA 1987 LEGISLATIVE SESSION
FISCAL NOTE

REQUEST:

Bill Version: CSSJR 7 (Oil & Gas)
Publish Date:

Revision Date:
Agency Affected: Dept. of Natural Resources
Title: Relating to oil & gas exploration, development, etc.
BRU: Oil and Gas
Sponsor Sturgulewski, Fischer, Abood, et al.
Components: Oil and Gas
Requestor:

EXPENDITURES/REVENUES: (Thousands of Dollars)

OPERATING	FY 87	FY 88	FY 89	FY 90	FY 91	FY 92
PERSONAL SERVICES						
TRAVEL						
CONTRACTUAL						
SUPPLIES						
EQUIPMENT						
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING	-0-	-0-	-0-	-0-	-0-	-0-
CAPITAL						
REVENUE						

FUNDING: (Thousands of Dollars)

GENERAL FUND						
FEDERAL FUNDS						
OTHER						
TOTAL						

POSITIONS:

FULL-TIME						
PART-TIME						
TEMPORARY						

ANALYSIS: (Attach a separate page if necessary)

Prepared by: Sharon L. Barton
Phone: 465-2406
Division: Management
Date: 02-12-87

Approved by Commissioner: Arms D Gmoll, Deputy
Date: 2/12/87
Agency: Department of Natural Resources

Distribution (by preparer):
- Legislative Finance
- Legislative Sponsor
- Requestor
- Office of Management and Budget
- Impacted Agency(ies)
- Senate Secretary

SENATE COMMITTEE REPORT

FIRST COMMITTEE OF REFERRAL

Date of Waived 2/10/87 5-DAY NOTICE
IN ACCORDANCE WITH UNIFORM RULE 23

FURTHER: RESOURCES

**FISCAL NOTE(S) ATTACHED ______ **
IN ACCORDANCE WITH AS 24.08.035
(see below)

1/20/87

DATE TURNED INTO OFFICE ____________

Mr. President:

OIL AND GAS Committee considered SJR 7

relating to oil and gas exploration, development, and production within the Arctic Natinal Wildlife Refuge, Alaska.

and recommended:

[X] replace with CS SJR 7 (O+G) [X] same title [] new title

[ ] attached amendment(s) and

[X] do pass

[ ] do not pass

[ ] no recommendation

[ ] individual recommendations

[ ] further referral to ____________

[ ] letter of intent adopted and attached

** Committee [ ] attached or [ ] adopted fiscal note(s)
[ ] zero [ ] fiscal impact

MEMBERS SIGNING DO PASS	OTHER RECOMMENDATIONS
Paul Fischer	

Bettye Fahrenkamp (do pass)
Chairman signature and recommendation

[ ] Committee Backup Attached

5-0180B
Bannister/
Bradley
2/12/87

Original sponsors: Sturgulewski, Fischer,
Abood, et al.

IN THE SENATE BY THE SENATE SPECIAL COMMITTEE ON OIL AND GAS

CS FOR SENATE JOINT RESOLUTION NO. 7 (Oil & Gas)

IN THE LEGISLATURE OF THE STATE OF ALASKA

FIFTEENTH LEGISLATURE - FIRST SESSION

Relating to oil and gas exploration, development, and production within the Arctic National Wildlife Refuge, Alaska.

BE IT RESOLVED BY THE LEGISLATURE OF THE STATE OF ALASKA:

WHEREAS the United States Congress has reserved the right to permit further oil and gas exploration, development, and production within the coastal plain of the Arctic National Wildlife Refuge, Alaska; and

WHEREAS the oil industry, the state, and the U.S. Department of the Interior consider the coastal plain to have the highest potential for discovery of very large oil and gas accumulations on the continent of North America; and

WHEREAS a decision to permit oil and gas exploration, development, and production on the coastal plain of the refuge would increase the value and facilitate the development of highly promising state-owned tideland and federally-owned outer-continental-shelf land offshore of the refuge; and

WHEREAS the facilities that are developed to transport petroleum resources discovered on the coastal plain of the refuge to the Trans-Alaska Pipeline System may allow marginal discoveries located between the refuge and the pipeline to be developed and produced, and may prolong the economic life of the pipeline; and

WHEREAS oil and gas exploration and development of the coastal plain of the refuge and adjacent land could result in major discoveries that would reduce our nation's future needs for imported oil, help balance the nation's trade deficit, and significantly increase the nation's security; and

WHEREAS the oil and gas industry and related Alaska employment have been severely affected by reduced oil and gas activity, and the reduction in industry investment and employment has broad implications for the Alaska work force and the entire state economy; and

WHEREAS the development of coastal plain oil and gas resources can and should be conducted by the corporations and workers of the state, who have the expertise to bring the resources to market; and

WHEREAS 8,000,000 of the 19,000,000 acres of the refuge have already been set aside as wilderness; and

WHEREAS the 1,500,000-acre coastal plain of the refuge comprises only eight percent of the refuge, and the development of the oil and gas reserves in the refuge's coastal plain would affect an even smaller percentage of the refuge; and

WHEREAS the oil industry has shown at Prudhoe Bay, as well as at other locations along the Arctic coastal plain, that it can safely conduct oil and gas activity without adversely affecting the environment or wildlife populations;

BE IT RESOLVED by the Alaska State Legislature that the Congress of the United States is urged to open the coastal plain of the Arctic National Wildlife Refuge, Alaska, to oil and gas exploration, development, and production; and be it

FURTHER RESOLVED that that activity be conducted in a manner that protects the environment and utilizes the state's work force to the maximum extent possible.

COPIES of this resolution shall be sent to the Honorable Donald Hodel, Secretary of the Department of the Interior; to the Honorable J. Bennett Johnston, Chairman of the Senate Committee on Energy and Natural Resources; to the Honorable Morris K. Udall, Chairman of the House Committee on Interior and Insular Affairs; and to the Honorable Ted Stevens and the

Honorable Frank Murkowski, U.S. Senators, and the Honorable Don Young, U.S. Representative, members of the Alaska delegation in Congress.

STATE OF ALASKA 1987 LEGISLATIVE SESSION
FISCAL NOTE

FEB 12 1987

Bill Version:
Publish Date:

REQUEST:

Revision Date: February 12, 1987
Title: Arctic Nat'l Wildlife Refuge/oil and gas
Sponsor: Sturgulewski
Requestor: Fahrenkamp

Agency Affected: Fish and Game
BRU:

Components:

EXPENDITURES/REVENUES: (Thousands of Dollars)

OPERATING	FY 87	FY 88	FY 89	FY 90	FY 91	FY 92
PERSONAL SERVICES	0					
TRAVEL	0					
CONTRACTUAL	0					
SUPPLIES	0					
EQUIPMENT	0					
LAND & STRUCTURES	0					
GRANTS, CLAIMS	0					
MISCELLANEOUS	0					
TOTAL OPERATING	0					

CAPITAL	0					

REVENUE	0					

FUNDING: (Thousands of Dollars)

GENERAL FUND	0					
FEDERAL FUNDS	0					
OTHER	0					
TOTAL	0					

POSITIONS:

FULL-TIME						
PART-TIME						
TEMPORARY						

ANALYSIS: (Attach a separate page if necessary)

Prepared by: Roland Shanks
Phone: 465-4100
Division: Commissioner's Office
Date: 2/12/87

Approved by Commissioner:
Date:
Agency: Fish and Game

Distribution (by preparer):
- Legislative Finance
- Legislative Sponsor
- Requestor
- Office of Management and Budget
- Impacted Agency(ies)
- Senate Secretary

STATE OF ALASKA 1987 LEGISLATIVE SESSION
FISCAL NOTE

Bill Version : CSSJR 7 (Oil & Gas)
Publish Date :

REQUEST:

Revision Date:
Title : Relating to oil & gas exploration, development, etc.
Sponsor Sturgulewski, Fischer, Abood, et al.
Requestor :

Agency Affected : Dept. of Natural Resources
BRU : Oil and Gas
Components : Oil and Gas

EXPENDITURES/REVENUES: (Thousands of Dollars)

OPERATING	FY 87	FY 88	FY 89	FY 90	FY 91	FY 92
PERSONAL SERVICES						
TRAVEL						
CONTRACTUAL						
SUPPLIES						
EQUIPMENT						
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING	-0-	-0-	-0-	-0-	-0-	-0-
CAPITAL						
REVENUE						

FUNDING: (Thousands of Dollars)

GENERAL FUND						
FEDERAL FUNDS						
OTHER						
TOTAL						

POSITIONS:

FULL-TIME						
PART-TIME						
TEMPORARY						

ANALYSIS : (Attach a separate page if necessary)

Prepared by : Sharon L. Barton
Division : Manageme[illegible]
Phone : 465-2406
Date : 02-12-37

Approved by Commissioner : Arms D [illegible], Deputy
Date : 2/12/87
Agency : Department of Natural Resources

Distribution (by preparer) :
- Legislative Finance
- Legislative Sponsor
- Requestor
- Office of Management and Budget
- Impacted Agency(ies)
- Senate Secretary

page 1 of 1

IN THE SENATE

BY STURGULEWSKI, FISCHER, ABOOD UEHLING AND KELLY

SENATE JOINT RESOLUTION NO. 7

IN THE LEGISLATURE OF THE STATE OF ALASKA

FIFTEENTH LEGISLATURE - FIRST SESSION

Relating to oil and gas exploration, development, and production within the Arctic National Wildlife Refuge, Alaska.

BE IT RESOLVED BY THE LEGISLATURE OF THE STATE OF ALASKA:

WHEREAS the United States Congress has reserved the right to permit further oil and gas exploration, development, and production within the coastal plain of the Arctic National Wildlife Refuge, Alaska; and

WHEREAS the oil industry, the state, and the U.S. Department of the Interior consider the coastal plain to have the highest potential for discovery of very large oil and gas accumulations on the continent of North America; and

WHEREAS a decision to permit oil and gas exploration, development, and production on the coastal plain of the refuge would increase the value and facilitate the development of highly promising state-owned tideland and federally-owned outer-continental-shelf land offshore of the refuge; and

WHEREAS the facilities that are developed to transport petroleum resources discovered on the coastal plain of the refuge to the Trans-Alaska Pipeline System may allow marginal discoveries located between the refuge and the pipeline to be developed and produced, and may prolong the economic life of the pipeline; and

WHEREAS oil and gas exploration and development of the coastal plain of the refuge and adjacent land could result in major discoveries that would reduce our nation's future needs for imported oil, help balance the nation's trade deficit, and significantly increase the nation's security; and

WHEREAS 8,000,000 of the 19,000,000 acres of the refuge have already been set aside as wilderness; and

WHEREAS the 1,500,000-acre coastal plain of the refuge comprises only eight percent of the refuge, and the development of the oil and gas reserves in the refuge's coastal plain would affect an even smaller percentage of the refuge; and

WHEREAS the oil industry has shown at Prudhoe Bay, as well as at other locations along the Arctic coastal plain, that it can safely conduct oil and gas activity without adversely affecting the environment or wildlife populations;

BE IT RESOLVED by the Alaska State Legislature that the Congress of the United States is urged to open the coastal plain of the Arctic National Wildlife Refuge, Alaska, to environmentally responsible oil and gas exploration, development, and production.

COPIES of this resolution shall be sent to the Honorable Donald Hodel, Secretary of the Department of the Interior; to the Honorable J. Bennett Johnston, Chairman of the Senate Committee on Energy and Natural Resources; to the Honorable Morris K. Udall, Chairman of the House Committee on Interior and Insular Affairs; and to the Honorable Ted Stevens and the Honorable Frank Murkowski, U.S. Senators, and the Honorable Don Young, U.S. Representative, members of the Alaska delegation in Congress.

Proposed amendment to SJR 7

Page 2, line 1, insert:

WHEREAS the oil and gas industry and related Alaskan employment have been severely affected by reduced oil and gas activity, and the reduction in industry investment and employment has broad implications for the Alaskan work force and the entire state economy; and

WHEREAS the development of coastal plain oil and gas resources can and should be conducted by the corporations and workers of the state, who have the expertise to bring the resource to market; and

Page 2, line 13, delete:
environmentally responsible

Page 2, line 14, add:
and that activity be conducted in a manner that protects our environment and utilizes the Alaskan workforce to the maximum extent possible.

Introduced: 1/28/87
Referred: Resources

IN THE HOUSE BY THE RESOURCES COMMITTEE

HOUSE JOINT RESOLUTION NO. 9

IN THE LEGISLATURE OF THE STATE OF ALASKA

FIFTEENTH LEGISLATURE - FIRST SESSION

Relating to the Arctic National Wildlife Refuge, Alaska.

BE IT RESOLVED BY THE LEGISLATURE OF THE STATE OF ALASKA:

WHEREAS the United States Congress has reserved the right to permit further exploration for, and development of, oil and gas within the coastal plain of the Arctic National Wildlife Refuge, Alaska; and

WHEREAS the U.S. Department of the Interior, the state, and the oil industry consider the coastal plain to have the highest potential for discovery of very large oil and gas accumulations on the continent of North America; and

WHEREAS a decision to permit oil and gas exploration, development, and production on the coastal plain would facilitate the development of highly promising state and federal tideland and submerged land; and

WHEREAS the facilities that are developed to transport oil and gas from the coastal plain to the Trans-Alaska Pipeline System (TAPS) may allow the development of marginal fields between the refuge and TAPS, extending the economic life of the pipeline and reducing tariffs that are expected to balloon in approximately 20 years; and

WHEREAS development of oil and gas in the refuge should and will be subject to strict environmental safeguards, including those protecting water, land, air, and important wildlife habitat that supports the subsistence resources used by Natives of the state and of the Yukon Territory in Canada; and

WHEREAS the permanent protection of large areas in the state's arctic region is assured by park, reserve, and refuge designations encompassing over 35,000,000 acres of federal land in the region; and

WHEREAS the biological and recreational resources of the refuge are very valuable, and the protection of these resources with adequate development safeguards is in the interest of the nation and the state; and

WHEREAS the land trades proposed by the U.S. Department of the Interior with private corporations would reduce or eliminate the state's existing entitlement to oil and gas revenue from the refuge; and

WHEREAS the state is a vast and under-served state with basic education, capital improvement, and public service needs, and a reduction in state revenue is a serious matter for the state's residents; and

WHEREAS the U.S. Congress could consider reducing the state's existing entitlement to oil and gas revenue within the refuge, even though the reduction might violate solemn agreements between the federal government and the state, discriminate against the state as compared to other states, and reverse decades-long policies of the federal government regarding the management of public domain lands within the states; and

WHEREAS development of coastal plain oil and gas resources can and should be conducted by the corporations and workers of the state, who have the expertise to bring the resources to market; and

WHEREAS the oil and gas industry and related Alaskan employment ~~of the state~~ have been severely affected by reduced oil and gas activity ~~in recent years~~, and the reduction in industry investments, employment has broad implications for the Alaskan workforce and the entire state economy;

BE IT RESOLVED that the Alaska State Legislature adopts the following consensus points regarding management of the coastal plain of the Arctic National Wildlife Refuge, Alaska:

(1) the U.S. Congress should promptly open the coastal plain of the Arctic National Wildlife Refuge, Alaska, to oil and gas exploration, production, and transportation under conditions that are in the interest of the nation and the state, reserving the leasing of land in the core caribou

calving grounds until a later time;

and Congress consider the State of Alaska & Nation's best interests in ~~the proposed~~ land exchange proposals

(2) the U.S. Department of the Interior should desist ~~from~~ discussing land trades that would eliminate the state's revenue share from oil and gas activity in the refuge and that could reduce the ownership influence of the state and federal governments on oil and gas leasing in the refuge;

(3) unless the state concurs, the U.S. Congress should not allow measures or actions that reduce the state's entitlement to oil and gas revenue from the refuge;

(4) the U.S. Congress should require the protection of the environmental and subsistence resources of the refuge, including wildlife habitat, air, and water, in the event of oil and gas development on the coastal plain of the refuge; and

(5) the U.S. Congress, in recognition of the state's economic situation and the need for long-term economic development in the state, should require that the exploration and development activity in the refuge be conducted by the work forces of the state; and be it

FURTHER RESOLVED that the state's delegation in Congress and the Governor of the state should support opening the coastal plain of the Arctic National Wildlife Refuge, Alaska, to oil and gas exploration, production, and transportation under conditions that would advance the interests of the people of the state, and work with the U.S. Department of the Interior to forestall proposed refuge land trades that would be inimical to the interests of the state.

COPIES of this resolution shall be sent to the Honorable Ronald Reagan, President of the United States; to the Honorable Donald Hodel, Secretary of the Department of the Interior; to the Honorable Steve Cowper, Governor of Alaska; to the Honorable Ted Stevens and the Honorable Frank Murkowski, U.S. Senators, and the Honorable Don Young, U.S. Representative, members of the Alaska delegation in Congress; and to each of the other members of the U.S. Congress.

Alaska State Legislature

FEB 10 1987

PRESIDENT

907-465-3755

JAN FAIKS
POST OFFICE BOX V
JUNEAU, ALASKA 99811

Senate

February 7, 1987

MEMORANDUM

TO: Senator Bettye Fahrenkamp
Chairman, Special Committee on Oil and Gas

FROM: Senator Jan Faiks
President of the Senate

SUBJECT: ANWR Resolutions

In talking with the oil industry during the last few days I have found that they feel it is important for the Legislature to pass a resolution in full support of oil and gas exploration and development in the Coastal Plain as soon as possible. Their impression based on discussions with the Department of the Interior and the Fish and Wildlife Service is that a resolution passed within the next 30 days will have a significant impact, even though it will not be included in the public comments on the 1002(h) report.

It is also extremely important that the House and Senate pass identical resolutions to show the unity of the Alaska Legislature on this issue. Hopefully your meetings with the sponsors of the House and Senate resolutions will iron out the differences between SJR 7, HJR 7 and HJR 9.

If I can be of any assistance in this effort please let me know.

OUT OF SESSION

6060 YUKON DRIVE ANCHORAGE, ALASKA 99516 907-274-6611

Alaska State Legislature

PRESIDENT
907-465-3755

JAN FAIKS
POST OFFICE BOX V
JUNEAU, ALASKA 99811

Senate

January 31, 1987

MEMORANDUM

TO: Senator Bettye Fahrenkamp, Chairman
Senate Special Committee on Oil and Gas

FROM: Senator Jan Faiks
President of the Senate

SUBJECT: Senate Joint Resolution 7
Relating to oil and gas exploration, development, and production within the Arctic National Wildlife Refuge

SJR 7 was referred to the Special Committee on Oil and Gas on January 26th. Since then, Governor Cowper has joined with the resolution's many sponsors and expressed the importance of Alaska's combined effort to open up ANWR for development of the coastal plain's oil and gas potential.

Because of the issue's importance, I am certain you will agree that the Senate's efforts reflect its timeliness and urgency. As a result, I would greatly appreciate your committee's consideration of SJR 7 prior to Friday, February 6th so that the resolution can be calendared to come before the full Senate as soon as is possible.

Thank you.

cc: Senator Arliss Sturgulewski

OUT OF SESSION
6060 YUKON DRIVE ANCHORAGE, ALASKA 99516 907-274-6611

SJR

8

Senate Special Committee on Oil and Gas

Legislation Checklist

Bill number: SJR 8 Sponsor: Josephson

Date referred to committee: Further referrals: Resources, Finance

Prior committee report:

Back up from sponsor:

Fiscal note(s):

Agency: DNR Requested: Received:

Agency: DOR Requested: Received:

Position paper(s):

Agency: DNR Requested: Received:

Agency: Requested: Received:

Sectional Analysis:

Scheduled: 2/26 Heard: Reported out:

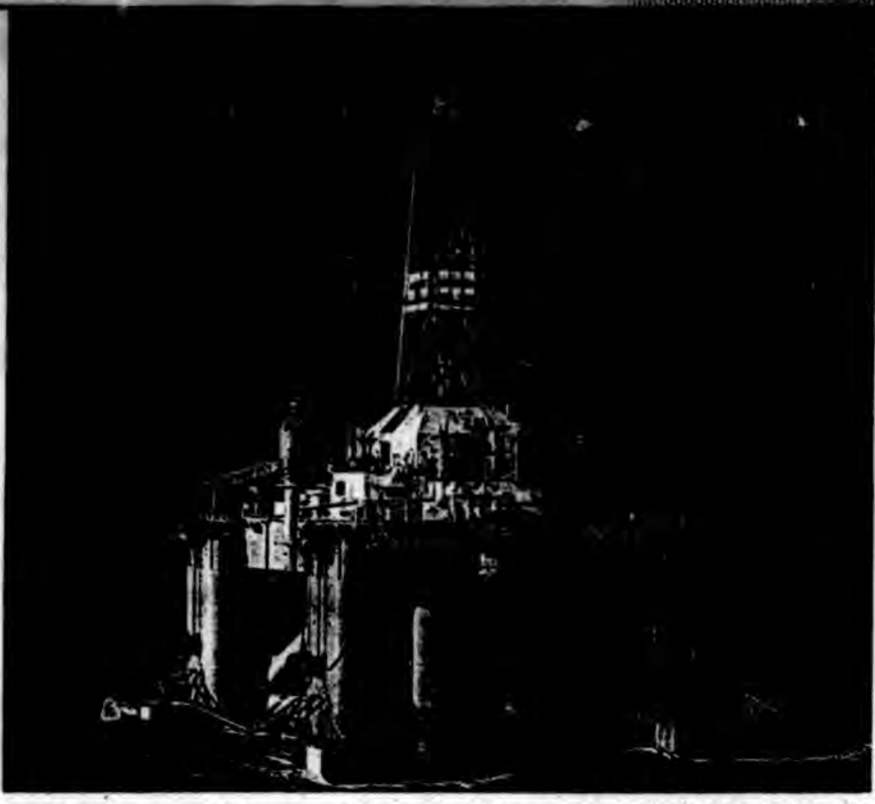
Items for committee packet:

To Testify:

Jim Eason, DNR
Ed Phillips
Scott Goldsmith, ISER 786-7710
Bob Anderson, Union Oil 263-7600
Cliff Groh. 272-6474

Other Contacts:

Senator Boren, OK, S302 Oil Import Tax
Murkowski. S460 - Murkowski [illegible]
(Tom Roberts)
Gov. Clements, Texas
Dillard Hamett
Tim Dowd, Chair IOCC
from OK
Bev Ward
Palmer
Dixon



Zane Barnes severe environment semisubmersible will go to work for Shell Oil Co. in the Gulf of Mexico in March under a multiyear contract. It is 370 ft long, 225 ft wide, and 170 ft high to the drilling floor. Derrick height adds 205 ft.

f. SJR 8

New generation rig to drill in gulf

Reading & Bates Corp. plans to place in service in March one of the world's largest semisubmersibles.

The Zane Barnes, a Trendsetter class rig, is capable of drilling to 30,000 ft in as much as 6,000 ft of water under normal weather conditions. It is designed to operate safely in such areas as the North Sea and off Alaska in severe weather.

The rig's mooring system makes it 35% more stable than earlier semisubmersibles, Reading & Bates said. A combined wire rope and chain system allows the rig to be anchored in as much as 4,921 ft of water.

A fully computerized rig management system checks and controls ballast, bilge, fuel, materials/equipment, water and electricity supply, fire, engine, and drilling equipment, and hull positioning. Variable deck load is 6,000 long tons, and the rig can accommodate a crew up to 122 persons.

Ishikawajima-Harima Heavy Industries Co. Ltd., Tokyo, constructed the semisubmersible in 19 months at its Aichi works. Designer is Friede & Goldman Ltd., New Orleans.

The rig is under tow by tugboat around the Cape of Good Hope. It is scheduled to arrive in the Gulf of Mexico next month.

The rig, with a gross weight of 19,928 long tons, consists of the main deck, two lower hulls, and five columns. A large diameter center caisson with buoyancy enables safe drilling work without being affected by floe.

The center caisson, 72 ft in diameter, also contains storage for riser pipes between its inner and outer shells. A moonpool within the inner shell facilitates handling of the riser and drill pipe. The unique shape of the lower hull improves hull oscillation characteristics against high waves. ▪

NPC outlines policy options to curb oil imports

The recent increase in oil prices is not enough to reduce the likelihood that U.S. dependence on imports will continue to rise at alarming rates, says a draft report approved last week by the National Petroleum Council's committee on U.S. oil and gas outlook.

To boost drilling, says the report, industry needs more economic incentives, including oil prices above the current level of about $18/bbl.

"Positive government energy policies that encourage, rather than discourage, domestic petroleum exploration and production will lead to a more stable, secure energy future for the U.S.," it reads.

"Tax incentives, decontrol of natural gas prices and markets, and opening unexplored federal lands are a few examples of such policies."

The draft final report, subject to considerable change before its submission to Energy Sec. John S. Herrington, is to be ready for presentation to the full NPC next month. An interim report to Herrington was prepared by the committee last year (OGJ, Sept. 29, 1986, p. 36).

A dozen options. The committee report outlines advantages and disadvantages of 12 government policy options to reduce U.S. dependence on oil imports.

The policy options are:

- Greater access to federal lands and improve the lease terms.
- Removal of tax disincentives and use of positive incentives to maintain existing production and stimulate exploration/development.
- Stabilization of wellhead prices through the use of import fees at a level that will reduce consumption and stimulate production.
- Promotion of research and development in secondary and tertiary recovery methods and alternate fuels production technologies.
- Decontrol of gas prices and markets through repeal of Natural Gas Policy Act price controls and the Fuel Use Act.
- Reduction of demand by increasing oil prices through consumption and excise taxes.
- Creation of incentives and mandates to continue energy conservation efforts.
- Greater use of alternate fuels.
- Diversification of supply sources to reduce the likelihood that a disruption of a single source could precipitate a crisis.
- Implementation of diplomatic actions that could increase the interdependence of U.S. and Middle East exporting countries to make oil supply continuity beneficial to all parties.
- Increasing the strategic petroleum reserves to enhance the ability to limit the effects of supply shortages and price increases.
- Implementation of fiscal and monetary policies that could be developed to mitigate the effects of price shocks.

Although not specifically developed, another option is to guarantee a minimum oil price to producers. ▪

NSC head to seek energy policy

By ANDREW MANGAN
The Associated Press

WASHINGTON — National security adviser Frank Carlucci views the rising level of imported oil as a threat to national security and will urge President Reagan to create a national energy policy to deal with the problem, a congressman said Wednesday.

Rep. Beau Boulter, R-Texas, said Carlucci told him and two other congressmen last week that he will recommend the president issue a national security decision directive to examine ways to deal with the problem, including the imposition of an oil import fee.

"What we were told by Carlucci is that he would see to it that there is a formal order signed by the president directing the NSC (National Security Council) to develop proposals and a national energy policy to deal with the national security threat posed by the high levels of imported oil," Boulter said.

Such an action would be the first formal recognition that the White House views rising imports as a serious threat to the nation's security.

Last week, Energy Secretary John Herrington told Boulter and Texas Gov. Bill Clements he was reviewing an 800-page Department of Energy draft report outlining options available to stem the flow of low-cost foreign oil into the United States.

"The indication is that Carlucci will start to work on the issue right after the DOE study is completed," Boulter said. The study is 95 percent complete, he said.

In his meeting with Carlucci, which was also attended by Reps. Mickey Edwards, R-Okla., and Dick Cheney, R-Wyo., Boulter said the national security adviser did not say whether he favored an oil import fee, tax credits or any other specific solution.

"We all pushed for an import fee by executive order. What he did say is that he is awash with studies and that now is the time to take action."

The level of Persian Gulf oil being imported into the United States grew from 6 percent of total consumption in 1985 to 15 percent last year, the highest percentage since 1981.

SJR 8

Anchorage Daily News Tł

3/5/87

Anchorage Daily News

United Press International

ıairman Frank Carlucci

CUR
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☐ Lynne Curry is
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THIS
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E TAX MAN
LL.

TESORO

Tesoro Petroleum Corporation

Low-Priced Oil or National Security? An Import-Fee Alternative

Presented to Senator Richard G. Lugar, Chairman
Foreign Relations Committee
of the United States Senate
Washington, D.C.

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Robert V. West, Jr.
Chairman,
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Senator Lugar:

Thank you for affording me the opportunity to present my views to you and the Senate Foreign Relations Committee on the threat to U.S. national security of low-priced oil conditions now prevailing globally and to suggest a new approach to deal with that threat.

The only approach heretofore suggested has been one of a sliding-scale oil-import fee, whose purpose would be to protect economically the domestic oil industry and to bring U.S. crude oil prices back to a general level of $20 per barrel or slightly more. It is perceived that a domestic crude oil price of this level could currently support an ongoing, although just barely viable, domestic petroleum industry.

The concept of an oil-import fee is so controversial that, regardless of its merits, it is unlikely that it would ever be adopted. The U.S. Administration has taken a strong stance against it. Certain U.S. industries who export their products into world markets and depend upon competitive petroleum prices for their survival oppose it. Even the petroleum industry itself has a divided attitude toward it. I believe that, because of the opposition of so many groups toward it and without extensive loopholes in it, the concept of an import fee won't be accepted, and that a different approach must be followed.

To have the national-security benefits inherent in a truly viable domestic petroleum industry, U.S. consumers must be willing to pay the slightly higher costs for petroleum products that higher crude oil prices would bring. Admittedly, educating consumers to the relationship between higher petroleum-product prices and U.S. national security will be difficult. Persuading the U.S. government that present low oil prices represent a threat to U.S. national security may be equally difficult.

Average consumers are gratified with low gasoline prices that have prevailed during the recent free-fall in world crude oil prices. They are comfortable with the fact that the gasoline they are buying costs only 70¢ to 80¢ per gallon, compared with prices double that during the last several years. Not long ago the President made a statement to the effect that it was good, for a change, to see the number of gallons on a gasoline pump meter go up faster than the number of dollars as a consumer's tank was being filled. This emphasis on low petroleum prices represents an unrealistic, short-sighted attitude toward the future security of America.

Recently it has become popular in the press, in Wall Street and in economic circles to refer to crude oil and petroleum products as "just other commodities" and to think of them in that manner. The thrust of my views is to point out that this thinking is erroneous. Petroleum differs significantly from conventional commodities. It should not be compared in thinking or in treatment to soybeans, sugar or other pure commodities.

If petroleum has some commodity characteristics, it should be differentiated as a strategic substance vitally important to America's national security. Since the free-fall began in world oil prices 10 months ago, this fact has largely been ignored by the U.S. government. The Administration's emphasis has been on "freeing up the markets" - whatever that may mean - and letting the chips fall where they may with respect to the viability or demise of the U.S. petroleum industry.

The domestic availability of petroleum products in times of crisis is vital to America's security. In times of embargoes or other arbitrary petroleum cutoffs by foreign producers, the availability of a reasonable level of domestic supplies will be imperative. Our relatively small Strategic Petroleum Reserve will not begin to satisfy our potential needs.

Petroleum is not just another commodity, whose price should be permitted to seek its own level in competition with the global glut and the vast supply/demand imbalances now existing. Instead it is a substance with vital strategic importance to America. It must be recognized as such.

This recognition should not be partisan. Neither should it be regional. Instead it must be objective and far-reaching.

During the 130-year history of the petroleum industry in the U.S., the industry has been characterized by sharp swings in supply/demand balances. Unfortunately, this circumstance is inherent to the industry.

In the past, because petroleum was always recognized as a strategic substance, the U.S. government or state governments within our country were unwilling for very long to leave petroleum to the mercies of free commodity markets. Invariably during the history of the domestic industry there has been intervention to smooth out the peaks and valleys in supplies and prices of U.S. oil production. If government intervention in domestic petroleum pricing and the defense of the viability of the U.S. petroleum industry do not recur again now, this lack of involvement will represent a wide departure from past U.S. practices.

In the early 1930's, with the discovery of the giant East Texas oilfield, the state of Texas utilized the oil and gas division of its then-existent Texas Railroad Commission to prorate the supply of Texas crude oil and to keep it in balance with state, national and international demands. In the process crude oil prices maintained a level that would permit ongoing exploration, development and production.

Before the imposition of Texas state proration rules for the East Texas oilfield, the price of crude oil in Texas dropped to as low as 10¢ per barrel. Even with the then-temporary glut of petroleum associated with that vast new field, that price level would not have permitted the maintenance of a viable domestic petroleum industry. At that time there was no threat to the U.S.'s being flooded with low-priced foreign oil or to our national security's being jeopardized by that flood - both as there are today.

Even so, the state of Texas took a bold step and instituted the concept of statewide oil proration. Supply was put back in balance with demand. Oil prices stabilized at a reasonable level.

Most other U.S. oil-producing states instituted their own regulatory and proration practices, generally following the pattern of Texas. As a result, for approximately 40 years, ending with the nationalization waves of Mid-East and South American countries in the 1960's and early 1970's, crude oil supply/demand balancing was achieved by proration of U.S. oil-producing states, by production restraints of international oil companies operating abroad or, later, by import controls in the U.S. and Canada.

In the process crude oil prices stabilized. These actions were not perceived as price-fixing or cartel-like by government officials and economists of those days. Rather they were perceived as necessary steps to preserve the viability of the U.S. domestic petroleum industry.

In the early 1980's the OPEC oil-producing nations attempted to restore supply/demand balances and price stability, which were largely destroyed by pricing and production practices - at unrealistically high price levels - by OPEC and non-OPEC nations alike during the past decade. However, petroleum consumers of the world came to expect that OPEC nations in general, and Saudi Arabia in particular, would absorb all the excesses of global over-supply, and that these nations alone would subject themselves to self-imposed proration, while other oil-producing nations of the world produced in wide-open fashion, taking all of the global markets, internal and external, that their production capacities would permit.

Largely this attitude of "let OPEC prorate" is the result of consumer hostility toward OPEC nations. This hostility has its origin in the nationalization by OPEC countries of non-OPEC petroleum interests, including those of U.S. companies. Further it has its origins in the Arab oil embargo of 1973 and 1974 and in the sharp crude-oil price increases associated with that embargo. Also, it has its origin in the now seemingly false oil shortage resulting from the Iranian revolution in 1979 and the further sharp rises in petroleum prices associated with that revolution.

Thus world consumers in general, and those in the U.S. in particular, have little or no sympathy for OPEC and expect OPEC nations to bear the brunt of all proration necessary to maintain petroleum supply/demand balances under today's global-glut circumstances. Unfortunately this thinking is more emotional than practical. Actions of key OPEC producers since December 1985 and January 1986 prove that point.

The U.S. should put aside its emotional attitude toward OPEC and view realistically the situation as it is today. The U.S. is faced with the likelihood of losing the viability of its domestic petroleum industry and the paralyzing national-security threat which that loss would represent.

I am not speaking as an advocate of OPEC, of any of its individual member states or of its production/pricing strategies. Instead I am trying to view the current global oil glut, and the solution to that glut, dispassionately and objectively.

I am an American, and I am vitally concerned about America's national security. I am speaking out because I am keenly aware of the devastating threat to that security, and I am trying to communicate my urgent concerns to you and other responsible U.S. government officials.

I look back to the early 1930's and to the imposition by the state of Texas of bold, far-reaching proration controls resulting from the oil surpluses of that day. Texas stepped forward, creatively and dispassionately, and mandated proration for all oil producers in the state. There was no expectation that one producer would bear the brunt of bringing supply and demand back into balance. Instead the requirement was that all producers would be subjected to mandatory proration, on a predetermined objective basis.

I believe that a global proration approach similar to this is the only realistic solution to today's ominous oil supply/demand imbalances, and I believe that some system of worldwide proration must be adopted to deal with that imbalance. It is not realistic to expect that OPEC nations are for long going to permit non-OPEC producers to flow their wells at capacity, while some OPEC members prorate themselves to only 30% or 40% of their capacities.

Circumstances have shown that this condition is not acceptable to OPEC, and that the strategy of OPEC to continue it has changed completely. Whether countries such as the U.S. and the U.K. like it or not, OPEC nations feel that certain shares of global oil markets should be available to them, and they intend to take those shares by whatever means necessary.

The stark reality is that there has been only a temporary arrest in the worldwide price erosion of crude oil. This arrest may be short-lived, and global prices may free-fall again. OPEC nations in the aggregate will not be content for long with the nominal total production of 16 million barrels per day existing today.

Unfortunately for the U.S., most of its crude oil production is in the high-cost category, and its potential additional reserves - as yet undiscovered and unproven - will require huge sums for exploration and development. At today's levels, even with the small recent price recoveries, crude oil prices in the U.S. are far too low to encourage meaningful exploration and development.

This fact is borne out vividly by the decline in U.S. drilling rig activity, which reached an all-time low of 663 rigs during July of this year, and which is only about 750 now. By comparison, the rig count exceeded 4,500 just a few years ago. It should be at least 3,000 to sustain the viability of the U.S. domestic petroleum industry.

The U.S. is the most vulnerable major oil producer in the world. It has been producing oil for more than a century. It is the world's oldest oil-producing nation and has been highly explored. It is the home of the world's most costly oil production and the nation with the world's lowest reserve/life production ratio. It is vital for the U.S. to do something about this situation to protect itself and its own self-interest.

Right now many small U.S. oil explorers and producers are facing bankruptcy. Oil company employees are being terminated in droves. Oil-service companies have curtailed their activities dramatically, and the personnel and business infrastructures of that industry segment are being lost. Major companies have sharply curtailed U.S. exploration budgets, mothballed most of their exploration and development rigs on the North Slope of Alaska and nearly ceased exploration in the Gulf of Mexico and elsewhere offshore.

The U.S. banking industry, with large loans to U.S. oil producers and to Latin American oil-producing nations, faces a difficult future. Current low oil prices are a serious threat to the Mexican economy, to Mexico's ability to repay debts to the U.S. banking system and to its internal political stability. The threat to the U.S. of social unrest in Mexico, attributable to low oil prices, is present and real.

The time is here - in fact, it is long overdue - for all of us to recognize that a truly viable U.S. petroleum industry is vital to America's national security. The time is here also for the U.S. and the world at large to face up to the fact that OPEC nations are not forever going to absorb all the world's proration disciplines necessary to maintain crude oil supply/demand balances and to permit other oil-producing countries, including the U.S., to retain viable domestic petroleum industries.

This brings me to my recommendation. Operating in conjunction with OPEC, the U.S. and other non-OPEC oil-producing countries of the world should create a modern-day, worldwide proration mechanism for crude oil production. Production should be shared in some equitable manner to maintain crude oil supply/demand balances and to permit prices to stabilize at levels acceptable both to oil-producing nations and to consumers, taking their contrasting desires into account.

Admittedly implementation of this recommendation would be a vast undertaking, surrounded by significant political and organizational problems. In spite of those difficulties, I believe the concept has fundamental merit, and that its implementation should be attempted. The U.S. must take the lead in such an effort. Doing so would put the global prestige of the United States behind the concept and give it substance and credibility.

Under a worldwide crude-oil proration mechanism, a price figure of at least $22 per barrel should represent a target level now, gradually increasing over time, based on future conditions. OPEC has given indications that in the near term this level would be acceptable to it. Its more responsible producers recognize that earlier prices of $30 per barrel or more are unrealistic in today's environment.

With respect to non-OPEC producers, and to the U.S. in particular, a crude oil price of $22 per barrel is one that the industry could live with now and remain barely viable. That level would not represent a bonanza for U.S. producers and would not stimulate the necessary exploration and development drilling that the country desperately needs for long-term national-security purposes.

However, at present it should be high enough to provide temporary viability, and hopefully still low enough to be politically acceptable to consumers and the U.S. Administration. At a price of $22 per barrel, gasoline in the U.S. would cost approximately $1.05 to $1.15 per gallon, compared to the prevailing level of 70¢ to 80¢ per gallon, and to the level 10 months or so ago of $1.40 to $1.50 per gallon.

With respect to degrees of non-OPEC proration, I would recommend levels substantially less severe than those that I mentioned earlier which certain OPEC producers are experiencing - i.e., 30% to 40% of capacity. The situations of those producers are different from those of the U.S. They do not have large internal consumption of their own, and in general their national-security requirements are minimal - in many cases because the U.S. provides security umbrellas over them.

Accordingly, I would not suggest that the U.S. - or the U.K., Norway, Egypt, Canada or Mexico - enter into worldwide proration arrangements which would prorate all countries evenly in relation to their potential producing capacities. Instead I would suggest that the U.S. and other non-OPEC producers agree to a proration of their individual producing amounts of approximately 10% each or to a level of 90% of recent production capacities. It is worthwhile to note that on September 10, 1986 Norway voluntarily stated its intention to cut its production 10% to help alleviate world supply/demand imbalances.

If the necessary calculations are made, it can be shown that if all non-OPEC producers cut their production by 10%, OPEC in the aggregate could be allocated 18 to 19 million barrels per day of crude oil production now, compared to the 16 million barrels per day to which it recently agreed to cut back during September/October 1986. In the process of these 10% proration initiatives, hopefully the global price of crude oil would rise to about $22 per barrel. With an aggregate production of 18 to 19 million barrels per day, and with a current price of $22 per barrel, again hopefully OPEC nations individually and collectively would be satisfied with their petroleum-export revenues and would honor the supply/demand agreements.

If the U.S. were voluntarily to cut its production by 10%, that cut would represent an aggregate decrease of about 900,000 barrels per day from the 9.0 million barrels per day level which the U.S. was producing 9 or 10 months ago. However, associated with that decrease would be a price increase, a degree of restored viability to the domestic petroleum industry and a much greater level of national-security comfort.

Numerous forecasts indicate that, without some solution for the problems of the U.S. domestic petroleum industry, America's producing level will erode to 6.0 million barrels per day or so in the next few years. This erosion will occur as a result of the shut-in of stripper and other marginal wells, normal production declines of non-marginal wells and the lack of economic incentive for additional exploration and drilling. Accordingly, the U.S. as a nation would be far better off under the suggested global proration program than under the continuation of existing circumstances.

Many of the necessary agencies to implement a global proration program now exist. In this regard I refer to the International Energy Agency, the U.S. Department of Energy, the state regulatory bodies in the individual producing states of the U.S. and to OPEC. Even though the state regulatory bodies no longer have influence on global supplies, they still exist and function. They could be utilized by the U.S. government to implement a global proration mechanism, on an individual state-by-state basis or in conjunction with the U.S. Department of Energy.

Economists might say that this recommended global proration approach just represents an extension of cartel-like conditions to the petroleum industry worldwide, and that it contradicts free-market principles. I suggest that if this is the perception, it would not be unique to the petroleum industry. What this approach would recognize is that petroleum markets are truly international, not regional or national.

The mandatory limited access of Japanese automobiles to the U.S. represents an indirectly comparable situation. Under this mandatory limit the U.S. recognizes that the automobile market is an international one. With the limit, the U.S. is forcing proration of Japanese automobile manufacture and at the same time imposing proration on U.S. automobile manufacturers by permitting the importation of Japanese and other foreign automobiles in the first place.

With the weight of its worldwide prestige, the U.S. must be the leader for a global crude-oil-proration mechanism to succeed. By leading, it would demonstrate to the world that the U.S. recognizes its own national-security needs for a viable domestic petroleum industry but at the same time recognizes the imbalances and inequities that OPEC nations feel with respect to their global market shares.

If the U.S. takes the lead with sufficient resolve, demonstrating its understanding, objectivity and fairness, there is reasonable hope that in addition to Norway, the U.K. and other non-OPEC producers would adopt similar attitudes. Too there is hope that major OPEC producers would welcome those leads and work conscientiously on a global basis to alleviate supply/demand imbalances.

High-level conversations on global proration should begin immediately in order that an early determination may be made whether or not the approach has a chance of political success. The U.S. government must emerge from its role of doing nothing to protect the viability of the domestic petroleum industry. It needs to understand the future national-security implications of that do-nothing policy. It needs to step forward into a role of pro-active leadership and do something to stabilize volatile, chaotic world oil markets.

The moment for action is here, and the time is short. With this thought in mind I strongly recommend the approach I have outlined for your consideration and that of your colleagues. Thank you again for affording me the opportunity to present my views to you and to the U.S. Senate Foreign Relations Committee.

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HIGHLIGHTS

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IEA ENERGY USE WAS ALMOST UNCHANGED IN 1986

The International Energy Agency's 1986 review of the energy policies and programs of its 21 member countries reports that their total primary energy requirements (TPER) rose only 0.4% to 3531.5 million tons of oil equivalent (about 140 quadrillion Btu) in 1986.

In Europe, TPER went up 1.3% to 41 quads while in the Pacific region requirements grew 1.2% to 19 quads. However, North American energy demand declined 0.3% to 71 quads. Oil demand increased 2.7% in the entire IEA to about 60 quads, including a 3.3% increase in the U.S. Oil imports jumped 11.8% to 31 quads, including a 23.1% rise to 11 quads in the U.S.

The IEA forecasts that its members' total primary energy requirements will increase from 3881.2 million tons of oil equivalent in 1985 (151 quadrillion Btu) to 4652-5083 million toe (185-202 quads) by the year 2000. The lower projections assume that world oil prices stay at the $28-$30/bbl level of 1985; the higher forecast assumes prices fluctuate between $15 and $20/bbl ($17.50 average) for the rest of the century. The economic growth rate is assumed to average 3%/year through 1990 and 2.5%/year from 1990 to 2000.

As the table shows, oil's share of TPER would remain around 42% in the $17.50/bbl scenario and would be lower if prices were higher. The share of gas is also inversely linked to the price of oil, though not to the same extent. Solid fuels, nuclear, and renewable resources would have higher shares when oil prices are high and vice versa.

Oil consumption in the 24 countries of the Organization for Economic Cooperation and Development is projected to grow from 34 million bbl/day in 1985 to 37-39 million bbl/day in 1990 and then remain at this level until the end of the century. Domestic production is expected to decline from 16.9 million bbl/day in 1985 to 15.5-16.5 million bbl in 1990 and 13.5-14.5 million bbl/day by 2000. Total world petroleum consumption, excluding the centrally planned economies, is estimated to rise from 45.6 million to 50.4-52.6 million bbl/day in 1990 and 53.2-56.8 million bbl/day by the year 2000. OPEC's production, 17.2 million bbl/day in 1987, will rise to 21.7-24.2 million bbl in 1990 and to 25.5-29.5 million bbl/day by 2000, according to the IEA.

The IEA report recommends that, given the prospects for tightening energy markets in the 1990s, attention should be given to: the development of alternatives to oil, especially for electricity generation; a review and possible abolition of remaining price controls; the application of new technologies for energy production and use; government review of incentives for conservation; a removal of barriers to international trade in energy; and resistance against such protectionist barriers as import fees.

Long-Term OECD Energy and Oil Demand Growth

CASE:	$30 Reference		$17.50 in 1989 to $30 in 1999		$17.5 Constant	
	1985-90	90-2000	1985-90	90-2000	1985-90	90-2000
Demand Growth (per cent per annum)						
TPER	1.4	1.3	2.5	0.8	2.6	1.6
Oil	0.6	0.3	3	-	3.2	1.1
	1985	2000		2000		2000
TPER (Mtoe)	3 811.2[1]	4 652		4 685		5 083
Market Share (per cent of TPER)						
Oil	42.5	36		38		42
Gas	19	17		18		17
Solid Fuels	24.5	28		27		25
Nuclear	7	10		9		8.5
Hydro/Renewables	7	9		8		7.5

1. Note that this figure includes bunker oil demand as well as TPER for OECD Member countries who are not also members of the IEA (Finland, France, Iceland). It therefore differs from the figure for TPER in 1985 shown in Appendix D.

Source: IEA Secretariat

J- STR8 - imported oil tariff

JAPAN PASSES U.S. IN GOVERNMENT SPENDING ON ENERGY RD&D

According to the International Energy Agency's 1986 review of the energy policies and programs of its 21 member countries, for the first time Japan surpassed the United States in total government expenditures on energy research, development, and demonstration. As the table shows, last year Japan spent $2.31 billion on energy RD&D, up 2.4% from 1985, compared with $2.26 billion for the U.S., a 7.0% decline. (All figures are in 1986 U.S. dollars.) U.S. RD&D funding peaked at $5.30 billion in 1979. Overall, IEA RD&D expenditures fell 6.3% to $7.13 billion — down from the $10.21 billion peak in 1979.

Italy came third with $761 million, a 1.2% rise, followed by West Germany $566 million (a 30% drop), the United Kingdom $378 million (-13%), Canada $336 million (-7.4%), and The Netherlands $161 million (up 3.6%).

The area with the largest budget remained conventional nuclear, where overall IEA spending totaled $2.69 billion in 1986, down 3.3% from 1985. Japan was the leader with $1.11 billion, followed by the U.S., $753 million and Italy, $324 million. Advanced nuclear RD&D received $1.82 billion in funding, with Japan spending $661 million, the U.S. $381 million and Italy $334 million.

IEA Government Energy RD+D Budgets in 1986 United States Dollars[1]
(Millions)

	1975	1977	1979	1980	1981	1982	1983	1984	1985	1986	Average 1986 Exchange Rates Units per $
Canada	221.9	246.8	302.0	282.2	332.4	343.5	393.7	447.1	363.6	336.3	1.389
United States	2 317.0	4 187.0	5 302.8	5 229.2	4 023.7	3 106.3	2 916.2	2 433.0	2 432.0	2 261.3	1.000
Australia	n.a.	30.4	49.3	63.4	72.1	n.a.	83.6	n.a.	n.a.	n.a.	1.496
Japan	820.8	1 018.9	1 376.7	1 987.2	2 114.5	2 116.9	2 127.9	2 146.6	2 256.7	2 310.9	168.500
New Zealand	4.5	4.5	7.6	12.9	11.0	9.9	9.3	11.1	10.3	3.9	1.917
Austria	8.4	26.7	28.2	30.5	28.4	31.0	29.3	32.0	29.4	n.a.	15.270
Belgium	144.0	116.3	97.5	121.6	105.6	97.2	87.6	93.3	85.8	74.1	44.690
Denmark	13.8	22.8	36.8	27.0	17.7	17.0	16.6	15.1	14.1	14.4	8.089
Germany	817.5	878.3	1 032.1	1 049.9	1 130.8	1 442.4	848.4	847.3	804.4	565.8	2.172
Greece	n.a.	1.1	5.3	37.3	31.3	7.2	6.6	8.4	11.1	15.3	139.480
Ireland	2.0	3.3	6.7	8.1	9.5	8.0	5.1	2.0	2.9	n.a.	.747
Italy	n.a.	277.9	383.7	397.7	677.1	520.5	609.5	805.2	751.8	761.0	1 491.000
Netherlands	96.4	141.3	153.2	155.6	160.7	132.8	132.5	114.0	155.4	161.1	2.450
Norway	22.9	31.8	44.7	41.0	35.0	31.1	25.8	24.6	24.5	28.9	7.392
Portugal	n.a.	n.a.	n.a.	5.0	3.9	3.9	4.9	7.8	7.3	n.a.	148.170
Spain	82.4	52.3	74.5	87.1	82.1	75.1	171.2	176.4	53.0	70.3	139.970
Sweden	70.7	80.3	133.1	127.5	177.1	141.8	127.0	112.9	104.1	79.4	7.124
Switzerland	20.0	43.3	67.6	71.9	67.5	63.8	65.7	64.5	69.2	69.6	1.798
Turkey	n.a.	n.a.	n.a.	2.8	1.2	1.9	2.8	2.4	2.3	2.5	669.000
United Kingdom	457.8	393.1	476.0	474.6	507.6	461.5	492.2	456.9	435.1	378.4	.682
IEA Total	5 080.2	7 555.7	9 577.6	10 212.4	9 589.2	8 611.8	8 155.7	7 800.6	7 513.4	7 133.3	
EC	n.a.	161.2	218.4	335.7	235.9	426.2	458.2	389.3	492.0	468.7	1.025

1 Values in Table 3 have been derived from those presented in Table C2 (government energy RD&D budgets expressed in 1986 national currencies), by using 1986 average exchange rates to the United States dollar calculated from those provided by the OECD Secretariat. Caution should be used when assessing trends in United States dollars, due to considerable recent exchange rate fluctuations.

Source: Country submissions

1986 Government Expenditure on Energy RD&D Per Unit of Gross Domestic Product

(including nuclear)	
Country	RD&D/GDP (per mille) 1986(1981)
Italy	1.99(1.52)
Japan	1.73(1.39)
Netherlands	1.29(1.00)
Canada	0.98(1.05)
Belgium	0.94(1.02)
Germany	0.91(1.43)
United Kingdom	0.85(1.05)
Sweden	0.79(1.28)
Switzerland	0.75(0.54)
USA	0.59(1.31)
Norway	0.51(0.60)
Greece	0.46(0.79)
Spain	0.41(0.37)
Denmark	0.25(0.48)
New Zealand	0.16(0.70)
Turkey	0.05(0.03)
Australia	n.a.(0.52)
Austria	n.a.(0.38)
Ireland	n.a.(0.43)
Portugal	n.a.(0.22)

The IEA research budget for electricity RD&D totaled $692 million in 1986, down 4.5%. Coal RD&D spending amounted to $677 million, down 2.3% and less than half the 1981 peak of $1.46 billion. U.S. spending on coal fell from $980 million in 1980 to $256 million in 1986, though it remained in first place. Expenditures on conservation RD&D in the IEA declined 4.3% to $466 million and renewables research 13.1% to $484 million. The only area where an increase occurred was oil and gas RD&D, which rose 26.9% to $312.7 million, mainly due to increases in Canada and Japan. In the U.S., however, government spending dropped 15.4% to $38 million.

The IEA notes that, along with a continued decline in government funding of energy RD&D, private sector support, particularly in the oil industry, is being severely cut as a result of lower oil prices. "Future government RD&D funding will need to be assessed in light of the implications of this situation for medium- and long-term energy security."

For the second year in a row, the U.S. ranked tenth in government spending on research, development, and demonstration as a percentage of gross domestic product. As the second table indicates, U.S. government RD&D expenditures accounted for 0.059% of its 1986 GDP — the same as in 1985 (*IGT Highlights*, December 29, 1986). However, other IEA countries showed significant increases: Italy devoted 0.199% of its GDP to government energy RD&D spending, up from 0.160% in 1985; Japan 0.173% (0.134%); The Netherlands 0.129% (0.093%), and Belgium 0.094% (0.078%).

HARVARD STUDY REITERATES NEED FOR TARIFF ON IMPORTED OIL

A new study by Harvard University calls for a $5/bbl tariff on oil imports that would reduce our rapidly rising dependence on imported oil, help maintain downward pressure on world oil prices, and encourage conservation and domestic production. The $10 billion in revenues from such a tariff could be used to increase the size of the Strategic Petroleum Reserve and to build up stockpiles of products.

Nearly a year ago, another Harvard study recommended the immediate imposition of a $10-$11/bbl import fee to reduce levels to the point where the costs to society of importing an incremental barrel of oil would just balance the benefits (*IGT Highlights*, December 1, 1986).

In the new 99-page report, *Energy Security Revisited*, authors William Hogan and Bijan Mossavar-Rahmani of Harvard's Energy and Environmental Policy Center write that "the flare-up in the Iran-Iraq tanker war and the escalating U.S. involvement — both political and military — serve as stark reminders of the fragility of Persian Gulf oil supply flow." They concede that the Administration's laissez-faire approach to energy markets is 'difficult to attack when oil prices are low and supplies are plentiful and also given the problems created by previous government intervention. But just because consumers feel comfortable is no reason to squander opportunities to launch policies that will bear fruit later. "The forces are in motion to shift the balance and time is short."

The authors charge that energy security policies based exclusively on the SPR are "myopic," since the SPR does not solve the problems created by rising dependence on imports. A tariff, on the other hand, forces the market to "recognize and internalize the true cost of imported oil." In estimating the size of a tariff, the researchers take into account two sets of market imperfections that comprise the oil import premium: 1) the economic component, which reflects the fact that the price the U.S. pays for oil is affected by its own level of demand and the effect of oil price changes on U.S. macroeconomic performance, and 2) the security component which reflects external costs that stem from sudden, unexpected, and large changes in the world price of oil.

They estimate that, if the price is $27/bbl, the optimal tariff would be $11.03/bbl; with oil at $15/bbl, it would be $12.55/bbl. However, they concede that a figure of $5/bbl is politically more realistic and almost as beneficial, since it would compel the market to internalize the true cost of imported oil. Additionally, it would help maintain downward pressure on world oil prices, foster investment in capital equipment with flexibility in fuel usage, and would counteract negative effects on the nation's trade balance.

Hogan and Mossavar-Rahmani said that the Dept. of Energy's *Energy Security* report (*IGT Highlights*, April 6, 1987) overestimated the costs of a tariff to the nation's economy, which it put at $200 billion over the next decade. But DOE assumed that the economy is perpetually shocked by a tariff and never adjusts. "If these assumptions are replaced with a view of a more flexible economy and of government policies designed to avoid recession, the quantifiable benefits of a tariff indeed exceed the costs," says the Harvard study.

MIDCON WANTS TO CHARGE CUSTOMERS FOR MAINTAINING FIRM SUPPLIES

Natural Gas Pipeline Co. of America, a subsidiary of MidCon Corp., asked the Federal Energy Regulatory Commission for authorization to levy a 55¢/1000 CF Inventory Holding Charge on its utility customers to recover the cost of maintaining firm gas supplies to meet their service requirements. The charge would go into effect November 1 and be recalculated annually. On a monthly basis, customers would be assessed the costs associated with reserving the gas they do not actually purchase, minus volumes they purchase directly from producers for which NGPL receives take-or-pay credit.

NGPL said the charge would reflect future costs charged by producers for gas that is ordered but not purchased. The pipeline noted that, because of increasing spot-market purchases by utilities and other large gas users, its sales have declined from about 1 trillion CF/year to 200 billion CF/year, while average sales have fallen from historic levels of 3 BCF/day to 100 million CF/day in March and April and to 300 million CF/day at the present time.

NGPL's filing with FERC noted that, although its customers are buying small amounts of gas, they continue to nominate large volumes of gas as "insurance" against spot market shortages. ". . . If interstate pipelines are to be called upon to 'backstop' distributor requirements with firm supply, they must be permitted to assess charges which adequately reflect the costs of maintaining such a supply," said the filing. "Customers should not have to pay a charge for the pipeline to maintain a gas inventory they do not want. Conversely, however, pipelines cannot reasonably be expected to maintain a supply adequate to meet maximum daily and annual obligations if their customers are unwilling to pay the costs."

Last month, NGPL asked FERC for permission to convert 20% of its service obligations from sales to firm transportation (*IGT Highlights*, August 10, 1987). The pipeline said it will soon file with FERC a plan to recover other gas-supply-related costs.

DOE CHOOSES 4 TEAMS FOR "MILD GASIFICATION" RESEARCH

The Dept. of Energy has chosen 4 private-sector teams to negotiate contracts to investigate "mild gasification" processes — coal conversion processes that operate at relatively low temperatures (1100-1500°F) and at near-atmospheric pressures to produce liquid and solid coproducts in addition to gases. The contracts could be worth as much as $13.5 million over three years.

DOE notes that, while mild gasification techniques have been known since the early 1800s, recent advances in coal chemistry have resulted in processes that could increase production of liquid fuels and improve their quality. The capital cost of a mild gasification plant is expected to be relatively low compared with conventional gasification technology, because the number of processing steps is reduced and lower-cost alloys could be used in the reactor vessel.

The teams are headed by IGT, working with Peabody Holding Co., Bechtel National Inc., and Caterpillar, Inc.; the Western Research Institute, whose team comprises AMAX Inc. and Riley Stoker Corp.; the University of North Dakota Energy and Mineral Center, heading a team that includes Foster Wheeler Development Corp., Solar Turbines, Inc., and Southwest Research Institute; and the University of North Dakota Energy and Mineral Center, with a team consisting of AMAX, Inc., and J.C. Sinor Consultants.

In an initial 5-month phase, each of the 4 teams will examine the technical feasibility of various mild gasification processes and assess the industrial markets that could use the products. Based on the data, DOE will then select one or more of the concepts for the second-phase construction of small-scale experimental systems. If the processes selected prove technically feasible, DOE would fund a third phase, in which a larger development unit integrating all the process steps would be designed and built and a 1000 ton/day demonstration plant designed and economically evaluated.

To explore one application of a "mild gasification" product, DOE also awarded a $100,000 grant to United Coal Company Research Corp., the Commonwealth of Virginia, and CSX Railroad Corp. to determine whether a liquid fuel produced from "mild gasification" can be burned in a diesel locomotive engine.

REPORT URGES CANADA TO BECOME WORLD LEADER IN HYDROGEN TECHNOLOGY

A report by the Advisory Group on Hydrogen Opportunities prepared for the Canadian government recommends that Canada adopt a national mission to be "first into the hydrogen age" and develop and own technologies for hydrogen production, distribution, and use, especially the use of neat hydrogen as a transportation fuel.

The report begins by noting that the world is steadily evolving toward the increased use of hydrogen and in the long term will see electricity and hydrogen dominate as energy *currencies* derived from a number of *sustainable* sources. Canada has an opportunity for leadership because of its high demand for hydrogen to upgrade products from heavy crudes and bitumen, its large reserves of natural gas, and its large electricity generating capacity which, coupled with a water electrolysis industry, will allow the production of non-fossil-derived hydrogen.

The report recommends that Canada develop and own the best technologies for the economic production of hydrogen from fossil and sustainable sources and for hydrogen purification, distribution, and storage. Suggested development areas include improving the energy efficiency of steam reforming; improving the reliability of partial oxidation; reducing the capital cost of water electrolysis, beginning with construction of a 100-MW demonstration plant; and achieving efficient hydrogen liquefaction, distribution, and storage.

The report also says that Canada must aggressively develop improved technologies for using hydrogen in the production of conventional fuels and chemicals from heavy crudes, bitumen, coal, and possibly biomass. This is the first step towards the more comprehensive integration of multiple energy sources; for example, coprocessing coal and oil, incorporating electrolytic hydrogen and oxygen into heavy oil upgrading, and mobilizing Canada's electricity generating capacity for the production of fuels and chemicals.

Canada must also develop technologies and products that use neat hydrogen. As a first step, the report recommends developing, demonstrating, and evaluating hydrogen fuel-cell locomotives, hydrogen-fueled urban road vehicles, and patrol aircrafts.

The group suggests that program be coordinated by a Canadian Hydrogen Authority that offers guidance and enlists the nation's scientific, engineering, business, labor, and entrepreneurial talents, but is not a "performer." The panel recommends that $50 million in funding be allocated for an initial 5 years to the Authority which would report at the Ministerial level.

As for costs, the report notes that over the next 20 years, hydrogen will be more expensive than conventional fuels: probably 1.6 times the price of natural gas based on current methane steam reforming (SMR) technologies and about 1.2 times the price of crude oil. However, with improved MSR technologies and favorable site-specific circumstances for hydrogen derived from sustainable resources, its cost would be about the same as gasoline and other petroleum-derived fuels. Technologies must be specially developed to exploit the unique properties of neat hydrogen, which would improve its competitiveness.

In the U.S., the House Science, Space, and Technology Committee's Subcommittee on Energy Research and Development heard testimony on legislation to promote a hydrogen R&D program. T. Nejat Veziroglu, president, International Assn. for Hydrogen Energy, called for a national policy to convert from the present fossil fuel system to a hydrogen energy system over the next 50-60 years. In the U.S., the cheapest hydrogen can be produced from coal near mines and then transported by pipeline, he said.

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oil import fee

Harvard study another important reminder of U.S. energy dilemma

The U.S. last week received another important reminder that its energy situation is serious and getting more so with each new barrel of imported crude oil. The reminder came in a study, "Energy Security Revisited," by William W. Hogan and Bijan Mossavar-Rahmani of Harvard University's Energy and Environmental Policy Center.

The study will receive as much attention as supporters of its centerpiece proposal can muster. It calls for a $5/bbl fee on imported crude oil and products. And the more attention, the better.

Opponents of an oil tariff—including the Reagan administration and a majority in Congress—should not dismiss the new Harvard study because of what it prescribes for a serious problem. It is, in fact, a clear statement of that problem, a statement that must be repeated until someone in government hears and acts.

The study happens also to be a strong argument for an oil tariff, which it says would "force the market to recognize and internalize the true cost of imported oil." This touches the heart of the issue. Something is cockeyed about a policy that funnels billions of dollars to protection of Middle Eastern oil and even risks war, yet spends nothing for domestic petroleum development. The U.S. may have better alternatives than an oil tariff. But before it rejects any option it must acknowledge all costs of the foreign oil it is consuming at rapidly rising rates.

For the moment, political arithmetic rules. Most voters and their representatives, blind to the costs of import addiction, see a tariff as a way to make oil consumers bail out the oil industry. They want no part of it. This the Harvard researchers understand. They prefer the $10/bbl tariff proposed earlier by a colleague but figure their $5/bbl alternative stands a better chance.

That the Harvard study gives life to the otherwise fading oil tariff discussion is one of two reasons for the oil industry to welcome it. The tariff discussion deserves more than the Reagan administration's free market cold shoulder. Perhaps more important, the Harvard study stokes the fire under a simmering national dilemma that has been studied beyond the point of meaningful analysis and officially ignored.

Given political realities, the industry might do well to pin its hopes for help at least as much on the Harvard study's premise as on its proposal for an import fee. Other recent studies disagree on the proposal but agree on the general view of the problem: that the U.S. has a growing energy problem and that the government must do something about it.

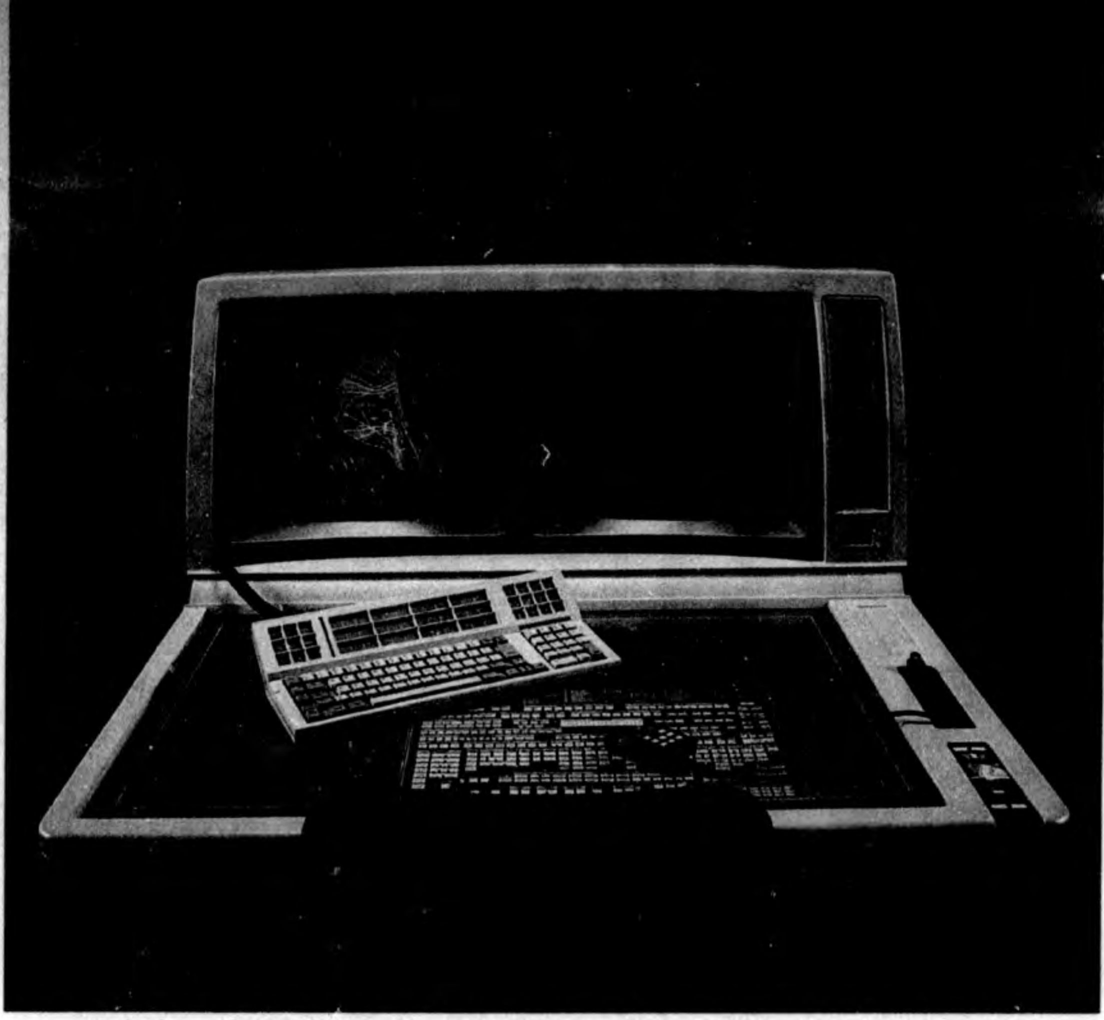
If not an oil tariff, however, what?

The government can take great strides toward solving the nation's energy problem by quit being such a big part of it. More specifically, it can make energy policy a consideration of some priority when it deals with taxes and the environment. Against the scenario depicted by the Harvard study—steadily rising U.S. oil imports and demand, flagging domestic production—the continued existence of an excise tax on oil production seems absurd. So does legislated erosion of the producing industry's ability to recover capital and virtual elimination, by way of the alternative minimum tax, of current year expensing of intangible drilling costs.

Even more preposterous is what government does to national energy health in the name of environmentalism. Federal land management has made most remaining exploration frontiers off limits to drilling. The Environmental Protection Agency wants to stiffen regulation of drilling wastes. Air and water quality proposals would multiply costs of refining in pursuit of marginal environmental gains.

Energy policy, meanwhile, concentrates on what to do in an emergency and ignores what should be done to prevent one. Its solo achievement: a strategic crude oil stockpile. So the government fills its emergency reserve and blithely proceeds with tax and environmental actions that make the U.S. more vulnerable to the emergency that's certain to come.

That's why the U.S. is in the energy predicament to which the Harvard researchers and others point with such legitimate alarm. And that's what must change if the U.S. is to avert another oil supply disaster. If the U.S. can't encourage energy development, it should at least quit discouraging it. The government must quit ignoring what the Harvard study calls "the true cost of imported oil" and start doing something about its energy policy equivalent, the true benefit of domestic supply.



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Senate Rejects Plan to Keep Oil Imports From Exceeding 50% of Domestic Use

By MONICA LANGLEY
Staff Reporter of THE WALL STREET JOURNAL

WASHINGTON—The Senate, continuing work on trade legislation, rejected a measure designed to prevent oil imports from exceeding 50% of U.S. consumption.

The senators voted 55-41 to delete from the trade package the so-called "energy security" provision. Lawmakers will continue voting next week on amendments to the trade bill—including a provision to require companies to give advance notice of plant closings and one to provide relief to domestic industries battered by imports.

Lawmakers opposing the measure said it was an attempt to help domestic oil companies. "It is special interest legislation at its worst," said Sen. Howard Metzenbaum (D., Ohio). "It seeks to prop up the domestic oil industry at the expense of every one else."

The oil-import measure had been cleared by the Senate Finance Committee in May. Sponsored by Finance Chairman Lloyd Bentsen (D., Texas), it would have required the president each year to submit to Congress a three-year projection of U.S. oil production, demand and imports. For any year in which oil imports would be projected to exceed 50% of demand, the president would have been required to propose a corrective plan that could include tax incentives to increase domestic drilling or a fee on oil imports.

Sen. Bob Packwood (R., Ore.) attacked the measure, calling it "an effort to impose an oil import fee." He noted that the Senate had twice rejected such a fee.

After the Senate rejected the provision, Sen. Bentsen said the vote nevertheless represented "quite a dramatic change" in sentiment concerning an oil import fee. Last year, he said, only 15 senators voted for such a fee. He said he was considering offering a weaker version of the measure.

In arguing for the provision, Sen. Bentsen said the growing U.S. dependence on oil imports threatens national security. "There has probably never been a time in our history when the dangers of dependence on oil from the Persian Gulf are more apparent," the Texas Democrat said. "There is a war in the gulf and ships are being attacked."

The Reagan administration opposed the

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The Better Way to Tax Oil

Virtually all fiscal analysts agree that more venue is needed to reduce the Federal budget ficit. Now Richard Gephardt joins Gary Hart in oposing to raise the money with a tariff on imrted oil. Could this be the beginning of a trend nong Democratic Presidential candidates, and ners?

As taxes go, an oil tariff would engender the st political resistance. Oil states like the idea because their producers would profit behind the tariff. any economists approve because it would slow the ift toward dependence on oil from the Persian ilf. Labeled a "energy security fee" rather than a x, it could even offer President Reagan a faceving way of raising revenue.

If the choice were between an oil import tax and tax at all, then tax it should be. But there are less stly ways of raising revenue that offer as much otection against OPEC. The most sensible would to tax *all* oil, domestic and foreign.

•

According to a new study by the Energy Dertment, a $10-a-barrel import fee would funnel out $30 billion a year to the Treasury by 1995. It ould stimulate domestic production by 400,000 rrels a day, while imports would be cut by 1.6 miln. The annual oil import bill would fall by $24 biln. But there are catches.

The Energy Department argues the big inease in oil prices would push up inflation by two to ree percentage points. That, in turn, would reduce e gross national product by tens of billions, more an offsetting the benefits of greater self-sufficiency and lower import bills. Perhaps. But the dertment's analysis ignores the cost of *not* raising xes. Without some credible deficit reduction, the llar will almost certainly fall further, raising import prices and disrupting world trading patterns.

More questionably, the tariff wouldn't deliver much production bang for the buck. Much of the extra $22 billion a year going to domestic oil producers would amount to a windfall on oil that would have been pumped at lower prices. Consumers would, in effect, pay an extra $22 billion for just 146 million barrels — nearly $150 for each additional barrel produced.

There are diplomatic concerns, too. If Mexico, Venezuela and Canada were exempted from an oil tariff, both the revenue and efficiency gains would be halved. If they weren't, hemispheric alliances would be sorely tested.

A better way would be to increase the tax on gasoline. A 25 cent-a-gallon tax would yield about $25 billion a year and cut the import bill by as much as $9 billion — and with roughly half the inflationary impact of the $10-a-barrel import fee. Unfortunately, the burden of a gasoline tax varies enormously among families and regions. Rural and suburban residents would take the biggest hit.

The arguably fairer approach would be to tax all oil products. A 10 cent-a-gallon tax spread over all oil consumers would raise the same revenue as a 25-cent gasoline tax on drivers. The oil tax would also be more efficient than an oil import fee, offering incentives for conservation without diverting billions into the production of high-cost domestic oil. Some poor people would feel the sting of higher heating costs; they could be compensated at relatively minor cost to the Treasury.

Oil and gasoline conservation taxes are unlikely to find favor along the oil belt, or among consumers. But good policy rarely coincides with political ease. The test of leaders — and those who would like to lead — is their capacity to sell unpopular ideas that make sense.

ALASKA STATE LEGISLATURE

SENATE SPECIAL COMMITTEE ON OIL AND GAS

Senator Bettye Fahrenkamp
Chairman
Senator Jack Coghill
Senator Paul Fischer

P.O. Box V, State Capitol
Juneau, Alaska 99811
(907) 465-3834

M E M O R A N D U M

TO: Members, Senate Special Committee on Oil and Gas

FROM: Committee Staff

RE: Committee Meeting, February 26, 1987

DATE: February 25, 1987

On Thursday, February 26, at 3:30 pm in the Beltz Room, the Senate Special Committee on Oil and Gas will hear SJR 8, Relating to a federal tax on imported oil.

SJR 8 urges the U.S Congress to impose a federal tax on imported oil. There are currently at least two oil import fee proposals before the U.S Congress (S 302 and S 460).

Supporters of the legislation claim that by imposing a tariff on imported oil we could reduce the national budget deficit, protect our national security, and maintain the viablility of our domestic oil industry. The resulting rise in domestic oil prices would likely result in a windfall to our state treasury. Economists from the Division of Oil and Gas predict that an oil import tariff would increase state revenues by at least $450 million a year. A flat fee of $10 per barrel on imported oil would increase state revenues by as much as $1.5 billion a year.

Any oil import tariff would result in increased costs to consumers. Representatives from consuming states are generally opposed to the concept. The fee is also opposed by some members of the oil industry. Certain U.S. industries such as steel, aluminum and petrochemicals would also be hard hit by increased oil prices.

Testimony will be heard via teleconference from national figures such as: U.S Senator David Boren, Tim Dowd, Chairman of the Interstate Oil Compact Committee, Ray Plank, Chairman of Apache Corporation and the Energy Security Policy Group, Dr. Robert West, Chairman of Tesoro Petroleum Corporation, and a representative of Governor Clements, Texas.

Introduced: 1/20/87 5-0309A
Referred: Oil & Gas, Resources and Finance

IN THE SENATE BY JOSEPHSON, KELLY, HALFORD AND STURGULEWSKI

SENATE JOINT RESOLUTION NO. 8

IN THE LEGISLATURE OF THE STATE OF ALASKA

FIFTEENTH LEGISLATURE - FIRST SESSION

Relating to a federal tax on imported oil.

BE IT RESOLVED BY THE LEGISLATURE OF THE STATE OF ALASKA:

WHEREAS rapidly fluctuating oil prices create an unstable environment in Alaska and the United States for business planning and investment and threaten the stability of the domestic petroleum exploration and development industry, the stability of which is vital to the national security; and

WHEREAS the continuation of energy conservation measures and further development of alternative energy technologies could be jeopardized by sharp declines in oil prices; and

WHEREAS the federal government needs additional revenue to reduce the federal deficit and the threat of another period of high inflation; and

WHEREAS Americans face the prospect of significant budget reductions in federal programs that are vital to the health, education, and welfare of many Americans, but the imposition of an oil import tax would moderate the severity of these reductions; and

WHEREAS a precipitous decline in oil prices results in major reductions in revenue to oil-producing states, subjecting them to undue hardships in providing the governmental services and infrastructure support needed to continue the production of domestic oil at the same time that these states are being given expanded responsibility as a result of diminishing federal participation through revenue-sharing and similar programs;

BE IT RESOLVED that the Alaska State Legislature encourages the United States Congress to impose a federal tax on imported oil, the revenue to be

Federal study indicates energy crisis likely

Juneau Empire 2/28/87

By LEE A. DANIELS
THE NEW YORK TIMES

NEW YORK – Declining domestic crude oil production and the growing dependence of the United States on petroleum imports could lead to an energy crisis in the 1990s far worse than those experienced in the 1970s, according to the draft report of a federal advisory committee.

The study, conducted by the National Petroleum Council at the request of Energy Secretary John S. Herrington, warns that current conditions pose a serious threat to the viability of the American oil and gas industry – and to national security and economic stability.

The council, made up of experts from outside the government, is an official advisory body to the energy secretary. The draft report reaches conclusions similar to those of several other recent studies that warn that a severe oil shock could be just a few years away.

The final version of the council report is to be delivered to Herrington on Tuesday after a meeting of the council in Washington. A copy of the draft report was obtained by The New York Times. Several members of the council said that the final report was not likely to substantially differ from the draft report.

The council study, begun last spring when crude oil prices had plummeted $19 in six months and were still falling, found that by 1995 as much as 60 percent of the nation's oil needs would have to be supplied from foreign sources, up from 27 percent in 1985.

The study states that even under a "best case" outlook, the level of imports was likely to reach 48 percent by 1995, about 10 percentage points higher than during the 1979 oil shock. Using the "best case" scenario, the import level in 1990 was predicted to be the same as it was just before the 1979 oil shortage.

The study contends that by the early 1990s the members of the Organization of Petroleum Exporting Countries, particularly those in the Persian Gulf, will probably be exerting greater control over the world oil market than they did in the 1970s.

"It makes it very clear that we've entered into that cycle that led to the oil shocks of 1973 and 1979," said George P. Mitchell, a member of the committee that prepared the report.

"The country could have very serious problems within a short period of time," said Mitchell, who is chairman, chief executive and president of the Mitchell Energy and Development Corporation of Houston.

John H. Lichtblau, president of the Petroleum Industry Research Foundation and a member of the committee, said that the report's message is that "the period of declining oil prices and declining U.S. dependence on foreign oil has come to an end."

He continued: "We are going to be much more dependent on foreign oil, and our national energy policy has to take that into account."

The study found that each of the 1970s oil shocks pushed the economy into a recession, causing the value of goods and services produced to fall as much as 3.5 percent, unemployment to rise by up to 2 percentage points and inflation to rise by 3 percentage points. It said that the potential of an equal or greater impact increases in tandem with the country's dependence on imports.

Committee members said the study is the most comprehensive to date on the domestic ramifications of the crash in world crude oil prices that began in November 1985. At that time, West Texas Intermediate, the major American crude oil, was priced near $32 a barrel. In late summer of 1986, the price bottomed out at $9.75 and has since risen to around $17 or $18.

The council's report lists 13 general options that it says the government and the public should consider. The options include opening more federal lands to exploration for oil and natural gas; revising tax policies to encourage exploration and production; imposing a tariff on imported oil; de-controlling natural gas prices, and adding crude oil to the nation's strategic petroleum reserves as a supply buffer.

The report also lists methods of encouraging energy conservation, including increased taxes on fuels, particularly gasoline and heating oil, and greater use of alternative fuels.

"The Congress, the administration, and the public must realize something has to be done," said Michel T. Halbouty, another committee member, and the chairman and chief executive of the Michel T. Halbouty Energy Co.

"Sure, some of these options are controversial," Halbouty said.

The draft report was called disappointing by one outside expert, Christopher Flavin, senior researcher of Worldwatch Institute, an environmental research organization.

After the report's list of options was read to him, Flavin said: "It sounds like a fairly tired old laundry list of options. Among all those things, I don't see a single one that strikes me as being new and innovative."

OIL IMPORT TARIFF

The case for a tax on imported oil

In Washington

by
Robert
Walters

WASHINGTON — A new federal tax on all imported crude oil and petroleum products — a concept often debated but never adopted by Congress in recent years — may be an idea whose time has come.

Within the petroleum industry, support for an import tax generally has been limited to independent producers in the Southwest. They would reap a financial bonanza from such a levy because they could increase the price of their domestic oil to match the post-tax price of imports.

When the American Petroleum Institute recently held its annual meeting in Houston, however, API Chairman George M. Keller called for an oil import fee or a similar mechanism to establish a "minimum floor price" that would provide "disaster insurance."

In addition to heading the industry's main trade association, Keller is chairman of Chevron, the nation's third largest oil company.

Like other integrated, multinational firms with domestic and offshore crude oil reserves, Chevron long has adamantly opposed any government intervention in petroleum pricing.

Keller, speaking for his company but not API, suggested that an oil import tax of $2 to $4 per barrel could revive the financially devastated domestic oil industry.

Sen. Gary Hart, D-Colo., has proposed an import tax of $10 per barrel. He would also provide rebates to the low-income consumers who would be most adversely affected by price increases.

(Each $1 increase in the price of a 42-gallon barrel of crude oil is equivalent to 2.3 cents in the cost of a gallon of gasoline.)

After global oil prices collapsed late last year, a barrel of crude oil plunged from $32 to less than $10 before recovering to the current price of about $15.

That has led to what George P. Mitchell, one of the country's leading independent producers, has described as "a severely reduced U.S. production capacity and greater dependence upon foreign producers."

Indeed, petroleum imports during the first nine months of this year averaged 5.94 million barrels per day compared with 4.85 million barrels daily during the same period last year — an increase of 22.5 percent.

Hart is among those who argue convincingly that the higher post-tax price would encourage conservation. Mitchell, head of the Mitchell Energy & Development Corp., notes that the proposed levy would provide a needed stimulant to "our country's faltering energy productivity."

President Reagan is firmly opposed to the tax because of his antipathy to both increased taxes and government intervention in the free market.

But when the Senate convenes next year under Democratic leadership, two key committees wil be chaired by legislators from leading oil-producing states who enthusiastically support an oil import tax.

Sen. Lloyd Bentsen of Texas will head the Finance Committee, while Sen. J. Bennett Johnston Jr. of Louisiana will lead the Energy and Natural Resources Committee.

Thus, industry and political pressure could surmount White House opposition to an idea that is eminently sensible, especially if domestic producers are willing to make a sacrifice in return for the financial windfall they will receive.

Specifically, they should relinquish unjustified tax benefits from accelerated depreciation allowances and immediate write-offs of intangible drilling costs.

BUSINESS

Economists See Faults in Oil Import Fee

By John M. Berry and Anne Swardson
Washington Post Staff Writers

Imposition of an oil import fee—which is actively under consideration by some Reagan administration officials and members of the Senate Finance Committee—would reverse some or all of the economic growth and lower inflation and interest rates generated by the current decline in oil prices, many economists say.

These economists, who range from conservative to liberal, question whether it would be worth paying that price to boost federal revenue—particularly if the purpose of the fee is to replace the revenue lost from lowering personal income tax rates by a greater amount and increasing corporate taxes by a smaller amount than proposed in the House-passed tax revision bill pending before the committee.

Moreover, such a fee does not seem to be the first choice of many economists because it would raise business costs and make American products less competitive on world markets.

Many economists also see falling oil prices as a special boon this year when the inflationary impact of the declining value of the U.S. dollar on foreign exchange markets is expected to be felt. Some analysts fear that the Federal Reserve Board could decide to tighten credit conditions and slow economic growth if inflation begins to accelerate. The oil price decline is seen as reducing that possibility.

Perhaps surprisingly, most segments of the oil industry oppose such a fee. Not only are major companies such as Exxon Corp., Mobil Corp. and Chevron Corp. against it, but so is the Independent Petroleum Association of America, whose members are small drilling and producing companies. "... Taxes, tariffs, fees or quotas on imported crude oil or petroleum products would be counterproductive to the national interest at this time," a recent IPAA policy statement said.

A $5-a-barrel fee, the most commonly mentioned figure, would be equal to about 12 cents a gallon and raise about $8 billion a year if imports of crude oil and refined products remained at last year's levels.

Imports account for less than 30 percent of U.S. petroleum use. If their cost were raised by a fee, the price of domestically produced crude oil and natural gas liquids also would go up, and the U.S. oil industry's revenue would increase by about $20 billion.

A portion of that increase would be taxed away through the federal crude oil windfall profits tax as the price of oil rose, and through the corporate and personal income taxes as well. How much additional federal revenue those taxes might yield would depend on a number of things, including how higher oil prices affected the overall economy, economists say.

There also could be some increase in natural gas and coal prices—or at least less of a decline than otherwise would occur—if oil prices are propped up by an import fee.

Altogether, the direct increase in the cost of petroleum products, if passed through entirely to users, would approach $30 billion and be equal to about 0.7 percent of this year's gross national product, which is expected to be about $4.2 trillion.

It probably would take about two years for the higher prices to work their way through the economy, according to economists who have studied the situation.

At the moment, oil prices are falling while the import fee is still only a proposal, albeit apparently a serious possibility, according to Senate Finance Committee Chairman Bob Packwood (R-Ore.). That timing difference led economist Alan Greenspan of Townsend-Greenspan & C[illegible] to caution the committee last week. "Ther[illegible] is somehow an assumption it is politicall[illegible] easy" to impose a fee, Greenspan sai[illegible] "There is almost never a way to time such [illegible] tax so that prices don't fall and then ris[illegible] again when it is put on."

Greenspan's point was that whatever re[illegible]straining influence falling oil prices ma[illegible] have on various price indexes will have oc[illegible]curred already by the time an import fe[illegible] could be imposed. Then, when the higher o[illegible] prices begin to show up in the indexes, th[illegible] additional inflation will be highly visible, h[illegible] predicted.

The Finance Committee is considerin[illegible] the fee for several reasons, including pro[illegible]viding some price support for the saggin[illegible] domestic oil industry and for bankers wh[illegible] have risky loans to it. But the principal co[illegible]cern is to find added revenue to offset oth[illegible]

See OIL TAX, F8, Col. 1

Oil Import Fee Questioned

OIL TAX, From F1

tax cuts that President Reagan and members of the committee want to make as part of the massive tax revision bill passed late last year by the House of Representatives.

Several committee members are backing legislation to enact a fee. Sen. Malcolm Wallop (R-Wyo.) wants a sliding fee to capture any decline in crude prices below $22 a barrel. Sen. David L. Boren (D-Okla.) is pushing a $5-a-barrel fee that would begin to phase out if the price rose above $25 a barrel and would disappear after the price reached $30 a barrel.

Both proposals include a higher fee on imported refined products to provide additional protection for U.S. refiners. Wallop would add $3 a barrel; Boren, $10 a barrel. Sen. Lloyd Bentsen (D-Tex.) is a cosponsor of both bills. Senate Majority Leader Robert J. Dole (R-Kan.) also favors an import fee, as does ranking committee Democrat Russell B. Long (D-La.).

All the sponsors are from oil-producing states. Committee members from other parts of the country generally oppose the idea. For example, Sen. George Mitchell (D-Maine) said, "It's an incredible windfall for the domestic oil producers. I don't see what benefit there is to the nation in that. And it would be extremely inflationary."

This split mirrors the different economic impact a fee would have in various regions. Areas such as New England that are heavy users of oil products would pay higher prices but get little of the benefits flowing to the domestic oil industry. Oil-producing areas in the Southwest also are heavy oil consumers, but they would share in the gains of the domestic producers.

Greenspan, a former chairman of the Council of Economic Advisers, noted that a fee on oil imports would raise the cost of chemical products made from oil, of which the United States is a substantial exporter. Higher oil prices could have a significant impact on many lower-cost products, he said.

Nevertheless, Greenspan believes that the fee ought to be looked at as a possible revenue source. "It is the least worst of the available political decisions," he declared. "Whether it's desirable is another question."

Another former CEA chairman, Murray L. Weidenbaum of Washington University, who also testified before the Finance Committee last week, said he would not impose an oil import fee because it would worsen the U.S. competitive position.

John Makin, a tax economist at the American Enterprise Institute, opposes the proposal. "I really think the energy tax is just a habit of thought," he said. "There was a lot of talk about it in the late 1970s. People have reports and studies, and they dust them off. I don't think that's a good way to go."

Charles L. Schultze of the Brookings Institution, Weidenbaum's predecessor at the CEA, flatly opposes an oil import fee. Falling oil prices "will take some or all of the sting out of the falling dollar," he said. Putting on a fee "would undo some of the good things" that lower prices will produce.

A $5-a-barrel fee would generate about $10 billion in additional revenue, Schultze estimated. "If that was the last $10 billion needed for a decent budget package [to reduce the deficit], I'd hold my nose and buy it, but I would not advocate it," he said.

However, the Senate Finance Committee is looking at a fee primarily as a way of making Reagan-backed changes such as reducing the top personal income tax rate from a proposed 38 percent to 35 percent—it is now 50 percent—and increasing the current $1,080 personal exemption to $2,000 for all but the highest-income taxpayers.

Other changes Reagan is seeking include a corporate income tax rate of 33 percent instead of the 36 percent

members also want to reduce depreciation allowances on business investments in new plants and equipment significantly less than did the House.

Harvard University economist Martin Feldstein, another former CEA chairman, strongly advocates reducing investment incentives by less than what the House has proposed. In order to do that, while still keeping the tax revision measure from generally neither raising more or less revenue than current law, Feldstein would use the fee. "It's a good tradeoff," he said, adding, "It would be better still to have a combination of an oil import fee and a gasoline tax, with heavier weight on the gasoline tax." Feldstein is much less enthusiastic about using part of the revenue from an import fee to offset revenue lost by reducing the top marginal rate for individuals from 38 percent to 35 percent.

Most of the discussion in recent months about an oil import fee has been in the context of raising revenue to reduce the large continuing federal budget deficits. It was in that vein that President Reagan included a $5-a-barrel fee on both imported and domestic oil in a contingency tax package he proposed in early 1983. That package—which he later let be known he did not want to have passed—would have gone into effect only if several conditions were met, including prior enactment of major spending cuts.

Recent public statements by some of the major oil companies, including a Mobil Corp. advertisement in today's Washington Post, generally oppose the fee as a way of cutting deficits. Mobil calls the fee "a dud" because of its inflationary and competitive consequences for the American economy.

An Exxon Corp. statement declares, "These additional fees, which are in effect taxes, would increase consumer prices, increase inflation and reduce real gross national product. In addition, they would distort competition among fuels, place energy-intensive U.S. manufacturing industries at a competitive disadvantage against foreign competition and fall inequitably on different regions of the country . . .

"If it is determined that tax increases are necessary, however, they should be as broad-based as possible."

Former Treasury tax economist Harvey Galper has been invited by the Finance Committee to testify this week on the impact of taxes on international competition and capital formation. Galper said he plans to tell the committee that the most solid way to improve America's competitive position and to increase capital formation is not by providing larger investment incentives through the tax code—especially if the price is imposition of an oil import fee—but rather to increase national saving. And he said that the best way to increase the amount of savings available for investment is to reduce federal bud-

New York Times - 2/23/86

Tax Oil to Save Oil

As surely as rising oil prices taught Americans to conserve energy, lower prices will lead them to forget. That would be a national tragedy, and a foolish security risk. Prices are falling because we conserved. Now that the price is not incentive enough to save, add a tax.

No new oil price shock is in sight. But the world's affordable supplies are still being depleted, and the risk of upheaval in the Middle East is ever present. As long as they last, lower prices mean greater consumption the world over.

Homeowners won't tear out insulation bought when heating costs soared; new energy-efficient buildings won't be razed. But the pressure to spend money for more conservation is being lost.

Just think about automobiles, which burn more than half the oil we consume. At less than $1 a gallon, drivers lose their incentive to slow down and tune up, and they stop caring about mileage ratings on new cars. They drift back into larger models, and Government can't resist relaxing the regulations that made the biggest '86 cars more efficient than the smallest in 1973.

America consumed 17.5 million barrels of oil a day in 1973. Today, in an economy one-third larger, consumption has fallen below 16 million. Dependence on foreign oil has also declined, from 36 percent of consumption in 1973 to 30 percent, and, significantly, the decline is much sharper for Persian Gulf oil.

The Reagan Administration wants only to reap the disinflation benefits. It favors more off-shore domestic drilling and, rightly, more deregulation of natural gas. But it is blindly rushing past this chance to build up the Strategic Petroleum Reserve at bargain prices. For transient budget benefit, it would even sell off three naval reserve fields. And it has unwisely relaxed the pressure on Detroit's car designers.

Federal fuel standards and other regulation would be less necessary if we turned to a tax to encourage more conservation. With prices falling, we could conserve by paying ourselves instead of Middle East potentates.

What's the best form of tax? On alternate days, President Reagan offers to consider a tax on oil imports — provided it's called a "fee" and is used to finance tax-law revisions. Congress, too, seems to prefer an import fee to a tax on gasoline or all energy. An all-energy tax, in any case, would have no special impact on oil consumption. The choice comes down to taxing imported oil and refined products or taxing gasoline at the pump.

An import fee would reduce dependence on foreign sources and encourage domestic production. The oil patch likes the idea because raising the price of foreign oil would let American producers charge more for domestic oil. The consuming states of the Northeast and West Coast and Florida balk at the idea and would, at the least, insist on taxing away the domestic producers' windfall. So taxing imports would lead to taxing all oil.

That would raise the cost of living, retard growth and damage friendly suppliers, like Mexico and Canada, which might need exemptions. The petrochemical industry, too, would want exemption, and who knows who else. The administrative complexity is offset by the political attraction: the public wouldn't much notice an import fee.

A gasoline tax would be highly visible even if it only held prices at prior levels. But it would be simple to administer atop the existing Federal tax of 9 cents a gallon. And it would not discriminate against any region.

Either tax could be shaped to yield as much as $100 billion over five years — $8 a barrel on imports combined with a 50 percent "windfall" profits tax, or 20 to 25 cents a gallon on gasoline. The revenue could help balance the Federal budget and thus improve the economy.

The main and lasting benefit of either tax would be in conservation and national security. An oil conservation tax is good policy any time. It is more easily achieved now that prices are down.

International Gas Technology
HIGHLIGHTS

Volume XVI | December 1, 1986 | No. 24

HARVARD STUDY URGES OIL IMPORT FEE

A study by Harvard Univ. economists Harry Broadman and William Hogan, both with the Energy and Environmental Policy Center, calls for the immediate imposition of a \$10-\$11/bbl fee on imports of crude oil and products in order to halt the nation's rising dependence on imports. They argue that such a tariff could reduce U.S. import levels to the point where the costs to society of importing an incremental barrel of oil just balance the benefits.

The market price paid for imported oil does not reflect its true cost, which includes what the economists call an "economic component" and a "security component." The greater the volume of oil imported into the U.S., the higher the price, which means that, as demand rises, *all* importers must pay a higher price. Rising oil prices also have an adverse effect on the U.S. economy and the trade balance.

As for the security component, the U.S. is vulnerable in the event of a price run-up to an increased transfer of wealth abroad with all the attendant costs, and this vulnerability is a direct function of the volume of imports. Also, the larger the value share of oil in the economy at the time of a disruption, the greater the macroeconomic costs from the price shock.

In order to calculate the optimal premium, Broadman and Hogan developed a model that maximizes the expected net social benefits of oil imports for normal and disrupted periods and allows for the simultaneous estimation of the premium's individual components. The table shows their estimates of the optimal tariff and the costs of continuing a free-market policy.

The authors consider 3 optional forms of tariff: a simple fixed fee, a variable fee, and a fee defined in proportion to the price of oil. They prefer the first on the grounds that it provides approximately the right incentives at the margin and the closest approximation to the optimal tariff calculations revealed by their analyses, and avoids the difficulties of managing the macroeconomic costs during an interruption.

The authors note that while the redistribution of resources throughout the economy will have both "winners" and "losers," the winners' gains are likely to be larger than the losers' costs.

Copies of the study are available from Nancy Kingston, Energy and Environmental Policy Center, Harvard Univ., 79 John F. Kennedy St., Cambridge, MA 02138. Price: \$10

OPTIMAL TARIFF AND COST OF FREE MARKET POLICY PROBABILITY DISTRIBUTIONS

High price case (\$27)

	\$/bbl			
	Lower 25%	Median	Upper 25%	Expected Value
Economic Tariff	\$ 1.95	\$ 2.85	\$ 3.90	\$ 3.14
Security Tariff	3.63	5.64	8.52	6.44
Combined Tariff (\$ per barrel)	7.00	8.96	11.26	9.58
Cost of Free Market Policy (\$billion/year)	4.64	8.24	13.18	10.60

Low price case (\$15)

	\$/bbl			
	Lower 25%	Median	Upper 25%	Expected Value
Economic Tariff	\$ 4.03	\$ 5.68	\$ 6.87	\$ 5.86
Security Tariff	2.80	4.20	6.65	5.23
Combined Tariff (\$ per barrel)	8.71	0.81	1.89	11.09
Cost of Free Market Policy (\$billion/year)	11.72	7.90	27.93	22.44

Coghill
BF:

3:38
SJR 3. Oil Import Fee

Joe/ supporting statement.

Cody
Problems in domestic industry 7/85
1985 ~~[illegible]~~ 25%
1987 40% foreign
1500% increase

70% of world's production is controlled by Governments

Sen Bentsen - peril point.

Pres report to Cong on level of import
12 + 24 months

if rise above 50% — propose to

Congress how to reduce level

Resolution helps

Texas Railroad Commission says 46% imports

Sen Chafee - R.I. - willing to work

TOM BURNS

no industry wide consenses.

Chevron - raise public awareness.

feller point out to public that a problem exists -

Studies - API
NPC
DOE
Harvard

Security premium.

Establish minimum price - floor.

1) what level necessary for survival
2) consensus what kind of program.
3) put program into place.

Import - easiest to administer -
no need for exemptions

dereg nat'l gas
ANWR
eliminate windfall tax
OCS development

if wait to 50% — too late.
Oil affects
GNP 3 times the effect of auto indust

Minimum floor price —
gives confidence to lenders, etc.
eliminate economic risk.

Bob Anderson AK district land manager for
UNOCAL

3/20/86

down 700,000/day from 1986

highest 36%
1977 47%?

2.1

Lost stripper oil, enhanced recovery

Swanson River - terminated.

Airport fee - Milne Point.
Cook Inlet.

~~OPEC~~

$24 floor?

Fin. Board

29 states

yo-yo effect from OPEC

6/86 mtg in Anch.

2 resolutions - 1 support tariff
1 support ANWR

Consumer states - energy
help plan costs

Ray Plank

National security issue

1) stable price
2) at adequate level — to help secondary
tertiary recovery

$18 ~~not~~ enuf.
$24

dropped 830,000/day.
by 1990 reach 50%

finding cost 1/3 price of product,

24 = 8/barrel finding cost

18 wouldn't do much good.

reserves = 27 billion

long lead times —

Harvard Study. Kennedy school dept Energy + Environment

U.S. has costs that other nations don't.

U.S Navy escorting foreign flags -
Costs of "
Taxpayers pay this cost.

Unemployed lost trades, = Social costs
as revenue base declines
+ loan losses to banks = 70 billion

foreign oil doesn't pay these costs -

Harvard est estimates those cost = $10/barrel
forgotten OPEC

OPEC wants to keep at allow our "starvation level"

other social cost

120 billion Trade deficit

Cut message to D.C. -

~~Joe~~
Industry division?

Plank

Personal - Exxon, Royal Dutch, Shell, Mobil
gain

if majors for it — Public against it —

free market does not exist

industry coming together.

Minnesota — support higher prices —

to encourage alternative energy.

Arco — neutral to positive —

Ed Phillips

→ * letter from West Gov's Assoc.

Support temp tariff —

benefits to AK —

1) higher price — more drilling —
higher rate of transport.
more total recovery from reservoirs —

2) further explorations in AK.
timelines + costs are higher
reduce risks

3) at $18 ANWR + West Sak Sands
not viable.

Joe ANWR - w/o price floor

BF/ $1 = 2.3¢ / gallon. to consumer.

Dillard Hammett - State Energy Advisor for Gov. Clements.

Clements met w/ Reagan yesterday —
#1 was tariff —

1) no free market
80% controlled by gov'ts
2) Sec of Int Hodel - long lines

3) Sec Herrington - supports tariff.

26 states = 30 million people in IOCC - support Energy policy

Present 18/Annual at Texas 1/2 production

$21 to survive
29 to investin new projects

Get the countries to join

2) conference of nations

3) repeal windfall profit tax.

4) 1 billion for enhanced recovery research

losing 60% in ground -
technology not there.

DOE only 2% oil
7.% on coal } on R+D

Introduced: 1/20/87 5-0309A
Referred: Oil & Gas, Resources and Finance

IN THE SENATE BY JOSEPHSON, KELLY, HALFORD AND STURGULEWSKI

SENATE JOINT RESOLUTION NO. 8

IN THE LEGISLATURE OF THE STATE OF ALASKA

FIFTEENTH LEGISLATURE - FIRST SESSION

Relating to a federal tax on imported oil.

BE IT RESOLVED BY THE LEGISLATURE OF THE STATE OF ALASKA:

WHEREAS rapidly fluctuating oil prices create an unstable environment in Alaska and the United States for business planning and investment and threaten the stability of the domestic petroleum exploration and development industry, the stability of which is vital to the national security; and

WHEREAS the continuation of energy conservation measures and further development of alternative energy technologies could be jeopardized by sharp declines in oil prices; and

WHEREAS the federal government needs additional revenue to reduce the federal deficit and the threat of another period of high inflation; and

WHEREAS Americans face the prospect of significant budget reductions in federal programs that are vital to the health, education, and welfare of many Americans, but the imposition of an oil import tax would moderate the severity of these reductions; and

WHEREAS a precipitous decline in oil prices results in major reductions in revenue to oil-producing states, subjecting them to undue hardships in providing the governmental services and infrastructure support needed to continue the production of domestic oil at the same time that these states are being given expanded responsibility as a result of diminishing federal participation through revenue-sharing and similar programs;

BE IT RESOLVED that the Alaska State Legislature encourages the United States Congress to impose a federal tax on imported oil, the revenue to be used to reduce the federal deficit.

COPIES of this resolution shall be sent to the Honorable Ronald Reagan, President of the United States; the Honorable George Bush, Vice-President of the United States and President of the U.S. Senate; the Honorable Jim Wright, Speaker of the U.S. House of Representatives; the Honorable Robert Byrd, Majority Leader of the U.S. Senate; and to the Honorable Ted Stevens and the Honorable Frank Murkowski, U.S. Senators, and the Honorable Don Young, U.S. Representative, members of the Alaska delegation in Congress.

down
703,000 bbls
from last year.

FEBRUARY 26, 1987

Senate Special Committee on Oil and Gas

SJR 8, Relating to a federal tax on imported oil

TELECONFERENCED TO FAIRBANKS AND ANCHORAGE

TO TESTIFY:

Senator Josephson, Sponsor

Cody Graves, Legislative Assistant fro Energy and Environmental Affairs, for:
U.S. Senator David Boren, Sponsor of S 302, Oil Import Tariff

Mr. Tim Dowd, Chairman of the Interstate Oil Compact Committee, Alaska is a member

Mr. Raymond Plank, Chairman and CEO of Apache Corporation, Founder and Chairman of the Energy Security Policy Group.

Mr. Dillard Hammett, Representing Governor Clements, Texas.
TOM BURNS, Manager, Economic Dept. CHEVRON - San Francisco
Dr. Robert West, Chairman of Tesoro Petroleum Corporation
HE JUST CANCELLED, BUT WRITTEN TESTIMONY HAS BEEN DISTRIBUTED.
Mr. Robert Anderson, representing UNOCAL Union Oil - if unchecked would be alarming

and Ed Phillips, Petroleum Economist, Division of Oil and Gas, DNR

QUESTIONS:

Why is there so much disagreement among oil companies on this concept?

What would the effect on consumers be? (Each one dollar increase in the price of a barrel equates to roughly 2.3 cents per gallon of gasoline) (rule of thumb)

Dr ~~Joseph Stanislay~~ from Cambridge Energy Research Associates ~~indicated~~ yesterday that he was unsure whether even $24 oil would stimulate domestic production. Comments?

He also indicated that support for a fee might change in Congress if the level of imported oil rises above 50%.

8 21 to survive
24 to prosper —
other consumers to join with other nations

Secretary Harrington — agrees but does not stand up
+ push for what is right for the US.

26 states endorsed tariff on oil import
30 million people have stood up + said we should
support a tariff —
* 18 oil will cut Texas production in half.

Just met with President Regan —
there is no free market for oil
Never will be as long as 80% is produced
in 1 area

****
*
* DELIVER TO: LTCCGTG
*
*
* ORIGINAL
* SENT: 02/26/87 TIME: 16:39
* FROM: LIOCANC
* SUBJECT: NEW SITE
* PRINT DATE: 02/26/87 TIME: 16:39
*
****

Immediate
consequence of
consumer
nations

Repeal windfall tax
stop leaving 60%
of oil in the ground

GLENN FROM DAVID:

MR. HAMMETT HAS JOINED US FROM TEXAS.

DJ State Energy Advisor — Texas

$ 70 billion dollar losses in loans alone
Taxpayer in future generations

130 ships attacked
last year
Social cost rise as revenue is
declining

Energy
Security
Policy group

National Security
issue here

Harvard Study
Kennedy School
Energy + Environment
$~~[illegible]~~$10 barrel
import fee

Variable import fee
stable
+ adequate levels + continue
US Production

agree with $24 -
objectives of OPEC is
to get the US market

830,000 per day drop

US reserves 27 billion barrels
Prices would quickly rise
1800 - is US starvation line
170 billion trade deficit

Gramm Rudman

Reymond Plank Denver –

Tim Dowd Oklahoma

29 oil + gas
producing
states

- continue to
impact production
- only way to counter
attack from your competition
is something like SR 8

supports development
of Dowd - not
feasible below
$24 level for
price of oil
even $18 would
give some
stability -

Chevron - econ survival - most are too cumbersome to be workable
what type of gov effort - investors + producers lead time

continuing deregulation
Anwar
elim - windfall profits -
50% land to state. -

1974 - 36%
1977 - 42%

On Line
Ed Phillips Anchorage
Tom Burns San Francisco
Sen Boren's Office - Codie Graves
Bob Anderson - Anchorage
Floor level

Anchorage 40
Fairbanks 40

Cut
File

STATE OF ALASKA 1987 LEGISLATIVE SESSION
FISCAL NOTE

Bill Version: SJR 8
Publish Date:

REQUEST:

Revision Date: February 24, 1987
Title: Federal tax on imported oil

Agency Affected: Natural Resources
BRU: Petroleum Management

Sponsor: Josephson,Kelly,Halford,Sturgelewski
Requestor:

Components: Petroleum Management

EXPENDITURES/REVENUES: (Thousands of Dollars)

OPERATING	FY 87	FY 88	FY 89	FY 90	FY 91	FY 92
PERSONAL SERVICES						
TRAVEL						
CONTRACTUAL						
SUPPLIES						
EQUIPMENT						
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING	-0-	-0-	-0-	-0-	-0-	-0-
CAPITAL						
REVENUE		*	*	*	*	*

FUNDING: (Thousands of Dollars)

GENERAL FUND						
FEDERAL FUNDS						
OTHER						
TOTAL						

POSITIONS:

FULL-TIME						
PART-TIME						
TEMPORARY						

ANALYSIS: (Attach a separate page if necessary)

* SEE ATTACHED

Prepared by: James E. Eason
Phone: 762-4241
NS Division: Oil and Gas
Date: February 24, 1987

Approved by Commissioner: Robert D. Arnold, Deputy
Date: 2/25/86
Agency: Natural Resources

Distribution (by preparer):

- Legislative Finance
- Legislative Sponsor
- Requestor
- Office of Management and Budget
- Impacted Agency(ies)
- Senate Secretary

It is not anticipated that a federal import tax on imported oil would generate increased expenditures from either the operating or capital budgets. The tax would increase income to the state treasury by increasing the wellhead price of Alaska oil. Actual monetary benefits will depend upon the actual amount of the proposed tariff and the projected wellhead price. At this time it is not known if the wellhead price of Alaskan crude could adjust to match the tariff increase. Thus, all that can be said is that for every one dollar increase in wellhead price, between $135 million and $150 million would annually accrue to the state treasury as a result of increased royalties and severance taxes. Assuming a ten dollar per barrel tariff and a full corresponding adjustment to wellhead prices, at current production levels, the state would receive about $1.35 to $1.50 billion dollars annually.

By raising the wellhead price of domestic oil, and in effect, creating a floor price for domestic oil, the federal tariff would also encourage (1) more intensive drilling and production in existing reservoirs; (2) development of marginal fields near Prudhoe Bay, such as offshore Lisburne, Pt. Thompson, and Gwyder Bay; and (3) exploration in more remote, wildcat areas.

Low-Priced Oil or National Security? An Import-Fee Alternative

Presented to Senator Richard G. Lugar, Chairman
Foreign Relations Committee
of the United States Senate
Washington, D.C.

by
Robert V. West, Jr.
Chairman,
Tesoro Petroleum Corporation

October 2, 1986

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 8672
1536 SCOMM 57: SENATE SPECIAL COMMITTEE ON OIL & GAS, 1987-1988 1333

Low-Priced Oil or National Security? An Import-Fee Alternative

Remarks by Robert V. West, Jr.

Senator Lugar:

Thank you for affording me the opportunity to present my views to you and the Senate Foreign Relations Committee on the threat to U.S. national security of low-priced oil conditions now prevailing globally and to suggest a new approach to deal with that threat.

The only approach heretofore suggested has been one of a sliding-scale oil-import fee, whose purpose would be to protect economically the domestic oil industry and to bring U.S. crude oil prices back to a general level of $20 per barrel or slightly more. It is perceived that a domestic crude oil price of this level could currently support an ongoing, although just barely viable, domestic petroleum industry.

The concept of an oil-import fee is so controversial that, regardless of its merits, it is unlikely that it would ever be adopted. The U.S. Administration has taken a strong stance against it. Certain U.S. industries who export their products into world markets and depend upon competitive petroleum prices for their survival oppose it. Even the petroleum industry itself has a divided attitude toward it. I believe that, because of the opposition of so many groups toward it and without extensive loopholes in it, the concept of an import fee won't be accepted, and that a different approach must be followed.

To have the national-security benefits inherent in a truly viable domestic petroleum industry, U.S. consumers must be willing to pay the slightly higher costs for petroleum products that higher crude oil prices would bring. Admittedly, educating consumers to the relationship between higher petroleum-product prices and U.S. national security will be difficult. Persuading the U.S. government that present low oil prices represent a threat to U.S. national security may be equally difficult.

Average consumers are gratified with low gasoline prices that have prevailed during the recent free-fall in world crude oil prices. They are comfortable with the fact that the gasoline they are buying costs only 70¢ to 80¢ per gallon, compared with prices double that during the last several years. Not long ago the President made a statement to the effect that it was good, for a change, to see the number of gallons on a gasoline pump meter go up faster than the number of

dollars as a consumer's tank was being filled. This emphasis on low petroleum prices represents an unrealistic, short-sighted attitude toward the future security of America.

Recently it has become popular in the press, in Wall Street and in economic circles to refer to crude oil and petroleum products as "just other commodities" and to think of them in that manner. The thrust of my views is to point out that this thinking is erroneous. Petroleum differs significantly from conventional commodities. It should not be compared in thinking or in treatment to soybeans, sugar or other pure commodities.

If petroleum has some commodity characteristics, it should be differentiated as a strategic substance vitally important to America's national security. Since the free-fall began in world oil prices 10 months ago, this fact has largely been ignored by the U.S. government. The Administration's emphasis has been on "freeing up the markets" - whatever that may mean - and letting the chips fall where they may with respect to the viability or demise of the U.S. petroleum industry.

The domestic availability of petroleum products in times of crisis is vital to America's security. In times of embargoes or other arbitrary petroleum cutoffs by foreign producers, the availability of a reasonable level of domestic supplies will be imperative. Our relatively small Strategic Petroleum Reserve will not begin to satisfy our potential needs.

Petroleum is not just another commodity, whose price should be permitted to seek its own level in competition with the global glut and the vast supply/demand imbalances now existing. Instead it is a substance with vital strategic importance to America. It must be recognized as such.

This recognition should not be partisan. Neither should it be regional. Instead it must be objective and far-reaching.

During the 130-year history of the petroleum industry in the U.S., the industry has been characterized by sharp swings in supply/demand balances. Unfortunately, this circumstance is inherent to the industry.

In the past, because petroleum was always recognized as a strategic substance, the U.S. government or state governments within our country were unwilling for very long to leave petroleum to the mercies of free commodity markets. Invariably during the history of the domestic industry there has been intervention to smooth out the peaks and valleys in supplies and prices of U.S. oil production. If government intervention in domestic petroleum pricing and the defense of the viability of the U.S. petroleum industry do not recur again now, this lack of involvement will represent a wide departure from past U.S. practices.

In the early 1930's, with the discovery of the giant East Texas oilfield, the state of Texas utilized the oil and gas division of its then-existent Texas Railroad Commission to prorate the supply of Texas crude oil and to keep it in balance with state, national and international demands. In the process crude oil prices maintained a level that would permit ongoing exploration, development and production.

Before the imposition of Texas state proration rules for the East Texas oilfield, the price of crude oil in Texas dropped to as low as 10¢ per barrel. Even with the then-temporary glut of petroleum associated with that vast new field, that price level would not have permitted the maintenance of a viable domestic petroleum industry. At that time there was no threat to the U.S.'s being flooded with low-priced foreign oil or to our national security's being jeopardized by that flood - both as there are today.

Even so, the state of Texas took a bold step and instituted the concept of statewide oil proration. Supply was put back in balance with demand. Oil prices stabilized at a reasonable level.

Most other U.S. oil-producing states instituted their own regulatory and proration practices, generally following the pattern of Texas. As a result, for approximately 40 years, ending with the nationalization waves of Mid-East and South American countries in the 1960's and early 1970's, crude oil supply/demand balancing was achieved by proration of U.S. oil-producing states, by production restraints of international oil companies operating abroad or, later, by import controls in the U.S. and Canada.

In the process crude oil prices stabilized. These actions were not perceived as price-fixing or cartel-like by government officials and economists of those days. Rather they were perceived as necessary steps to preserve the viability of the U.S. domestic petroleum industry.

In the early 1980's the OPEC oil-producing nations attempted to restore supply/demand balances and price stability, which were largely destroyed by pricing and production practices - at unrealistically high price levels - by OPEC and non-OPEC nations alike during the past decade. However, petroleum consumers of the world came to expect that OPEC nations in general, and Saudi Arabia

in particular, would absorb all the excesses of global over-supply, and that these nations alone would subject themselves to self-imposed proration, while other oil-producing nations of the world produced in wide-open fashion, taking all of the global markets, internal and external, that their production capacities would permit.

Largely this attitude of "let OPEC prorate" is the result of consumer hostility toward OPEC nations. This hostility has its origin in the nationalization by OPEC countries of non-OPEC petroleum interests, including those of U.S. companies. Further it has its origins in the Arab oil embargo of 1973 and 1974 and in the sharp crude-oil price increases associated with that embargo. Also, it has its origin in the now seemingly false oil shortage resulting from the Iranian revolution in 1979 and the further sharp rises in petroleum prices associated with that revolution.

Thus world consumers in general, and those in the U.S. in particular, have little or no sympathy for OPEC and expect OPEC nations to bear the brunt of all proration necessary to maintain petroleum supply/demand balances under today's global-glut circumstances. Unfortunately this thinking is more emotional than practical. Actions of key OPEC producers since December 1985 and January 1986 prove that point.

The U.S. should put aside its emotional attitude toward OPEC and view realistically the situation as it is today. The U.S. is faced with the likelihood of losing the viability of its domestic petroleum industry and the paralyzing national-security threat which that loss would represent.

I am not speaking as an advocate of OPEC, of any of its individual member states or of its production/pricing strategies. Instead I am trying to view the current global oil glut, and the solution to that glut, dispassionately and objectively.

I am an American, and I am vitally concerned about America's national security. I am speaking out because I am keenly aware of the devastating threat to that security, and I am trying to communicate my urgent concerns to you and other responsible U.S. government officials.

I look back to the early 1930's and to the imposition by the state of Texas of bold, far-reaching proration controls resulting from the oil surpluses of that day. Texas stepped forward, creatively and dispassionately, and mandated proration for all oil producers in the state. There was no expectation that one producer would bear the brunt of bringing supply and demand back into balance. Instead the requirement was that all producers would be subjected to mandatory proration, on a predetermined objective basis.

I believe that a global proration approach similar to this is the only realistic solution to today's ominous oil supply/demand imbalances, and I believe that some system of worldwide proration must be adopted to deal with that imbalance. It is not realistic to expect that OPEC nations are for long going to permit non-OPEC producers to flow their wells at capacity, while some OPEC members prorate themselves to only 30% or 40% of their capacities.

Circumstances have shown that this condition is not acceptable to OPEC, and that the strategy of OPEC to continue it has changed completely. Whether countries such as the U.S. and the U.K. like it or not, OPEC nations feel that certain shares of global oil markets should be available to them, and they intend to take those shares by whatever means necessary.

The stark reality is that there has been only a temporary arrest in the worldwide price erosion of crude oil. This arrest may be short-lived, and global prices may free-fall again. OPEC nations in the aggregate will not be content for long with the nominal total production of 16 million barrels per day existing today.

Unfortunately for the U.S., most of its crude oil production is in the high-cost category, and its potential additional reserves - as yet undiscovered and unproven - will require huge sums for exploration and development. At today's levels, even with the small recent price recoveries, crude oil prices in the U.S. are far too low to encourage meaningful exploration and development.

This fact is borne out vividly by the decline in U.S. drilling rig activity, which reached an all-time low of 663 rigs during July of this year, and which is only about 750 now. By comparison, the rig count exceeded 4,500 just a few years ago. It should be at least 3,000 to sustain the viability of the U.S. domestic petroleum industry.

The U.S. is the most vulnerable major oil producer in the world. It has been producing oil for more than a century. It is the world's oldest oil producing nation and has been highly explored. It is the home of the world's most costly oil production and the nation with the world's lowest reserve/life production ratio. It is vital for the U.S. to do something about this situation to protect itself and its own self interest.

Right now many small U.S. oil explorers and producers are facing bankruptcy. Oil company employees are being terminated in droves. Oil service companies have curtailed their activities dramatically, and the personnel and business infrastructures of that industry segment are being lost. Major companies have sharply curtailed U.S. exploration budgets, mothballed most of their exploration and development rigs on the North Slope of Alaska and nearly ceased exploration in the Gulf of Mexico and elsewhere offshore.

The U.S. banking industry, with large loans to U.S. oil producers and to Latin American oil-producing nations, faces a difficult future. Current low oil prices are a serious threat to the Mexican economy, to Mexico's ability to repay debts to the U.S. banking system and to its internal political stability. The threat to the U.S. of social unrest in Mexico, attributable to low oil prices, is present and real.

The time is here - in fact, it is long overdue - for all of us to recognize that a truly viable U.S. petroleum industry is vital to America's national security. The time is here also for the U.S. and the world at large to face up to the fact that OPEC nations are not forever going to absorb all the world's proration disciplines necessary to maintain crude oil supply/demand balances and to permit other oil-producing countries, including the U.S., to retain viable domestic petroleum industries.

This brings me to my recommendation. Operating in conjunction with OPEC, the U.S. and other non-OPEC oil-producing countries of the world should create a modern-day, worldwide proration mechanism for crude oil production. Production should be shared in some equitable manner to maintain crude oil supply/demand balances and to permit prices to stabilize at levels acceptable both to oil-producing nations and to consumers, taking their contrasting desires into account.

Admittedly implementation of this recommendation would be a vast undertaking, surrounded by significant political and organizational problems. In spite of those difficulties, I believe the concept has fundamental merit, and that its implementation should be attempted. The U.S. must take the lead in such an effort. Doing so would put the global prestige of the United States behind the concept and give it substance and credibility.

Under a worldwide crude-oil proration mechanism, a price figure of at least $22 per barrel should represent a target level now, gradually increasing over time, based on future conditions. OPEC has given indications that in the near term this level would be acceptable to it. Its more responsible producers recognize that earlier prices of $30 per barrel or more are unrealistic in today's environment.

With respect to non-OPEC producers, and to the U.S. in particular, a crude oil price of $22 per barrel is one that the industry could live with now and remain barely viable. That level would not represent a bonanza for U.S. producers and would not stimulate the necessary exploration and development drilling that the country desperately needs for long-term national-security purposes.

However, at present it should be high enough to provide temporary viability, and hopefully still low enough to be politically acceptable to consumers and the U.S. Administration. At a price of $22 per barrel, gasoline in the U.S. would cost approximately $1.05 to $1.15 per gallon, compared to the prevailing level of 70¢ to 80¢ per gallon, and to the level 10 months or so ago of $1.40 to $1.50 per gallon.

With respect to degrees of non-OPEC proration, I would recommend levels substantially less severe than those that I mentioned earlier which certain OPEC producers are experiencing - i.e., 30% to 40% of capacity. The situations of those producers are different from those of the U.S. They do not have large internal consumption of their own, and in general their national-security requirements are minimal - in many cases because the U.S. provides security umbrellas over them.

Accordingly, I would not suggest that the U.S. - or the U.K., Norway, Egypt, Canada or Mexico - enter into worldwide proration arrangements which would prorate all countries evenly in relation to their potential producing capacities. Instead I would suggest that the U.S. and other non-OPEC producers agree to a proration of their individual producing amounts of approximately 10% each or to a level of 90% of recent production capacities. It is worthwhile to note that on September 10, 1986 Norway voluntarily stated its intention to cut its production 10% to help alleviate world supply/demand imbalances.

If the necessary calculations are made, it can be shown that if all non-OPEC producers cut their production by 10%, OPEC in the aggregate could be allocated 18 to 19 million barrels per day of crude oil production now, compared to the 16 million barrels per day to which it recently agreed to cut back during September/October 1986. In the process of these 10% proration initiatives, hopefully the global price of crude oil would rise to about $22 per barrel. With an aggregate production of 18 to 19 million barrels per day, and with a current price of $22 per barrel, again hopefully OPEC nations individually and collectively would be satisfied with their petroleum-export revenues and would honor the supply/demand agreements.

If the U.S. were voluntarily to cut its production by 10%, that cut would represent an aggregate decrease of about 900,000 barrels per day from the 9.0 million barrels per day level which the U.S. was producing 9 or 10 months ago. However, associated with that decrease would be a price increase, a degree of restored viability to the domestic petroleum industry and a much greater level of national-security comfort.

Numerous forecasts indicate that, without some solution for the problems of the U.S. domestic petroleum industry, America's producing level will erode to 6.0 million barrels per day or so in the next few years. This erosion will occur as a result of the shut-in of stripper and other marginal wells, normal production declines of non-marginal wells and the lack of economic incentive for additional exploration and drilling. Accordingly, the U.S. as a nation would be far better off under the suggested global proration program than under the continuation of existing circumstances.

Many of the necessary agencies to implement a global proration program now exist. In this regard I refer to the International Energy Agency, the U.S. Department of Energy, the state regulatory bodies in the individual producing states of the U.S. and to OPEC. Even though the state regulatory bodies no longer have influence on global supplies, they still exist and function. They could be utilized by the U.S. government to implement a global proration mechanism, on an individual state-by-state basis or in conjunction with the U.S. Department of Energy.

Economists might say that this recommended global proration approach just represents an extension of cartel-like conditions to the petroleum industry worldwide, and that it contradicts free-market principles. I suggest that if this is the perception, it would not be unique to the petroleum industry. What this approach would recognize is that petroleum markets are truly international, not regional or national.

The mandatory limited access of Japanese automobiles to the U.S. represents an indirectly comparable situation. Under this mandatory limit the U.S. recognizes that the automobile market is an international one. With the limit, the U.S. is forcing proration of Japanese automobile manufacture and at the same time imposing proration on U.S. automobile manufacturers by permitting the importation of Japanese and other foreign automobiles in the first place.

With the weight of its worldwide prestige, the U.S. must be the leader for a global crude-oil-proration mechanism to succeed. By leading, it would demonstrate to the world that the U.S. recognizes its own national-security needs for a viable domestic petroleum industry but at the same time recognizes the imbalances and inequities that OPEC nations feel with respect to their global market shares.

If the U.S. takes the lead with sufficient resolve, demonstrating its understanding, objectivity and fairness, there is reasonable hope that in addition to Norway, the U.K. and other non-OPEC producers would adopt similar attitudes. Too there is hope that major OPEC producers would welcome those leads and work conscientiously on a global basis to alleviate supply/demand imbalances.

High level conversations on global proration should begin immediately in order that an early determination may be made whether or not the approach has a chance of political success. The U.S. government must emerge from its role of doing nothing to protect the viability of the domestic petroleum industry. It needs to understand the future national-security implications of that do-nothing policy. It needs to step forward into a role of pro-active leadership and do something to stabilize volatile, chaotic world oil markets.

The moment for action is here, and the time is short. With this thought in mind I strongly recommend the approach I have outlined for your consideration and that of your colleagues. Thank you again for affording me the opportunity to present my views to you and to the U.S. Senate Foreign Relations Committee.

October 2, 1986

Council at odds over tariff

By GUY DARST
The Associated Press

WASHINGTON — A tariff to raise prices of imported oil remains a controversial question in the oil industry, and a report from the National Petroleum Council suggests one reason why: Low oil prices are good for the economy.

A council report Tuesday said the United States would become increasingly vulnerable to supply interruptions as long as domestic production is falling and imports are taking a larger share of the market.

But the council, an advisory group, made no recommendations because it could not get

See Page E-6, TARIFF

TARIFF: Controversy spreads

Continued from Page E-1

agreement on all its ideas, said Ralphy Bailey, the council chairman and chairman of Conoco Inc., the DuPont Co.'s petroleum subsidiary.

In particular, tariffs leave the industry "badly divided," he said.

Domestic producers, who saw 150,000 jobs evaporate in the oil price collapse of 1986, favor tariffs. Many major companies with overseas operations do not. Refining and marketing companies generally do not.

The council approved the report without dissent, but discussion of the cover letter to Energy Secretary John Herrington led Bailey to seek and get authority to redraft it to reflect "some of the urgency I think I detect."

Several speakers said the letter should make specific recommendations, and some called for action to guarantee the industry a price of around $25 a barrel.

The council asked the forecasting firm of Data Resources Inc. to predict the economy under low oil prices — $12 in 1986 and increasing 4 percent a year faster than general inflation — and high prices, starting at $18 and increasing 5 percent faster than inflation. The low-price scenario puts oil at $21, in terms of 1986 buying power, in the year 2000; the high-price case carries it to $36.

The lower price:

• Adds 0.1 percentage point to the average growth rate in the economy, making it 2.6 percent instead of 2.5 percent per year.

• Adds 0.3 percentage point to average annual growth in industrial production, 2.8 percent instead of 2.5 percent

• Cuts average annual inflation by half a percentage point, making the change in the Consumer Price Index average 4.5 percent instead of 5.0 percent.

• Cuts the annual federal budget deficit from $140 billion to $120 billion and the trade deficit from $42 billion to $15 billion.

A tariff would raise inflation, cut growth and cause a decline in tax collections from non-energy companies and their employees, the report said.

"This could ultimately offset the increase in taxes collected from the oil industry," it added.

Additional arguments against a tariff include:

It would lead to a "politically troublesome" dependence on imported heating oil in some parts of the country.

It would violate the General Agreement on Tariffs and Trade.

J. Leaing 2/26/87

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DANNY CONSTANTINE:

ATTACHED IS A LIST OF OBSERVERS IN FAIRBANKS FOR TODAY'S OIL AND GAS TELECONFERENCE. ALSO ON LINE WERE:

1. BOB ANDERSON - ANCHORAGE
2. TOM BURNS - SANFRANCISCO
3. ED PHILLIPS - ANCHORAGE
4. CODY GRAVES - WASHINGTON D.C.
5. TIM DOWD - OKLAHOMA
6. RAYMOND PLANK - DENVER
7. 21 OBSERVERS - JUNEAU
8. NOONE ATTENDED IN THE ANCHORAGE LIO
9. DILLARD HAMMETT - AUSTIN

GLENN GRAY
JUNEAU LIO

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FINAL STATS

DATE: FEBRUARY 26, 1987
SITE: FAIRBANKS
SPONSOR: SENATE SPECIAL COMMITTEE ON OIL & GAS
SUBJECT: PUBLIC HEARING: SJR 8, TAX ON OIL
MODERATOR: MELBA J. OESTER

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TESTIFY:

NAME\REPRESENTING	ADDRESS	PHONE:#
1.) -0-		

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OBSERVE:

NAME\REPRESENTING	ADDRESS	PHONE #
1.) FRED PRATT, PO BOX 72981, FBKS., 99707		452-3061
2.) SALLY WELLS, 1012 SUMMER ROSE DR., FBKS., 99709		457-2730
3.) JO SWARNER, 515 7TH AVE., #130, FBKS., 99701		452-4882

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TESTIFIED: __0__ TIME START: __3:30 PM__
OBSERVED: __3__ TIME END: __4:47 PM__
TOTAL: __3__

ALASKA STATE LEGISLATURE

SENATE SPECIAL COMMITTEE ON OIL AND GAS

Senator Bettye Fahrenkamp
Chairman
Senator Jack Coghill
Senator Paul Fischer

P.O. Box V, State Capitol
Juneau, Alaska 99811
(907) 465-3834

For further information contact:
Daniel Consenstein
(907) 465-3834

MEDIA ADVISORY
February 25, 1987

OIL IMPORT TAX MEETING TO BE HELD

On Thursday, February 26, the Senate Special Committee on Oil & Gas will conduct a teleconference to hear testimony on Senate Joint Resolution 8 and the oil import tax in the Beltz Room.

In addition to having Anchorage and Fairbanks Legislative Information Offices open for the teleconference, the following individuals will provide testimony on this state and national issue:

Senator Joe Josephson - Prime sponsor of SJR 8

U.S. Senator David Boren (Oklahoma) - Sponsor of S.302, advocating for a oil import tax.

Mr. Tim Dowd - Chairman of Interstate Oil Compact Committee, of which Alaska is a member.

Mr. Raymond Plank - Chairman & CEO of Apache Corporation and Founder & Chairman of the Energy Security Policy Group. (The Energy Security Policy Group commissioned Harvard University to do a study regarding the oil import tax. The results have been publicized nationwide recently.)

Mr. Dillard Hammett - Representing Governor Clements, Texas.

~~Mr. Robert V. West,~~ Jr. - Chairman of Tesoro Petroleum Corporation

TOM BURNS (MORE)

Mr. Robert Anderson - Representative for Unocal Corporation

Mr. Ed Phillips, Petroleum Economist, Division of Oil & Gas

Still unconfirmed for testimony are the following:

U.S. Senator Frank Murkowski
U.S. Congressman Richard Gephardt
Mr. James Eason, Director, Division of Oil & Gas

TESTIMONY RE: TAX ON IMPORTED OIL

State Senator Joe Josephson to give introduction to SJR 8.

U.S. Senator David Boren (D-Oklahoma) or legislative assistant, Cody Graves, to testify following State Senator Josephson's introduction of SJR 8 before the committee. Will be calling from Washington, D.C. (Must testify before 4:00 pm, has another appointment.)

Mr. Tim Dowd, Chairman of Interstate Oil Compact Committee (IOCC), of which Alaska is a member. He is located in Oklahoma City, Oklahoma. (Must testify before 4:15 pm, has another appointment.)

Mr. Raymond Plank, Chairman and CEO of Apache Corporation, an independent oil company headquartered in Denver, and founder and Chairman of the Energy Security Policy Group, who commissioned Harvard University to conduct a just completed study on the tax of imported oil. (Must testify following Mr. Dowd, due to an appointment he has within the next 30 minutes.)

Mr. Dillard Hammett, Special Assistant to Governor Clements of Austin, Texas. Governor Clements has come out strongly in favor of the oil import tax and has made it a priority. (He will testify following Mr. Plank.)

Unknowns:

U.S. Senator Frank Murkowski, R-Alaska
U.S. Senator Bennett Johnston, D-Louisiana
U.S. Congressman Richard Gephardt, D-Missouri

International Gas Technology
HIGHLIGHTS

Volume XVI December 1, 1986 No. 24

HARVARD STUDY URGES OIL IMPORT FEE

A study by Harvard Univ. economists Harry Broadman and William Hogan, both with the Energy and Environmental Policy Center, calls for the immediate imposition of a $10-$11/bbl fee on imports of crude oil and products in order to halt the nation's rising dependence on imports. They argue that such a tariff could reduce U.S. import levels to the point where the costs to society of importing an incremental barrel of oil just balance the benefits.

The market price paid for imported oil does not reflect its true cost, which includes what the economists call an "economic component" and a "security component." The greater the volume of oil imported into the U.S., the higher the price, which means that, as demand rises, *all* importers must pay a higher price. Rising oil prices also have an adverse effect on the U.S. economy and the trade balance.

As for the security component, the U.S. is vulnerable in the event of a price run-up to an increased transfer of wealth abroad with all the attendant costs, and this vulnerability is a direct function of the volume of imports. Also, the larger the value share of oil in the economy at the time of a disruption, the greater the macroeconomic costs from the price shock.

In order to calculate the optimal premium, Broadman and Hogan developed a model that maximizes the expected net social benefits of oil imports for normal and disrupted periods and allows for the simultaneous estimation of the premium's individual components. The table shows their estimates of the optimal tariff and the costs of continuing a free-market policy.

The authors consider 3 optional forms of tariff: a simple fixed fee, a variable fee, and a fee defined in proportion to the price of oil. They prefer the first on the grounds that it provides approximately the right incentives at the margin and the closest approximation to the optimal tariff calculations revealed by their analyses, and avoids the difficulties of managing the macroeconomic costs during an interruption.

The authors note that while the redistribution of resources throughout the economy will have both "winners" and "losers," the winners' gains are likely to be larger than the losers' costs.

Copies of the study are available from Nancy Kingston, Energy and Environmental Policy Center, Harvard Univ., 79 John F. Kennedy St., Cambridge, MA 02138. Price: $10.

OPTIMAL TARIFF AND COST OF FREE MARKET POLICY PROBABILITY DISTRIBUTIONS

High price case ($27)

	$/bbl			
	Lower 25%	Median	Upper 25%	Expected Value
Economic Tariff	$ 1.95	$ 2.85	$ 3.90	$ 3.14
Security Tariff	3.63	5.64	8.52	6.44
Combined Tariff ($ per barrel)	7.00	8.96	11.26	9.58
Cost of Free Market Policy ($billion/year)	4.64	8.24	13.18	10.60

Low price case ($15)

	$/bbl			
	Lower 25%	Median	Upper 25%	Expected Value
Economic Tariff	$ 4.03	$ 5.68	$ 6.87	$ 5.86
Security Tariff	2.80	4.20	6.65	5.23
Combined Tariff ($ per barrel)	8.71	0.81	1.89	11.09
Cost of Free Market Policy ($billion/year)	11.72	7.90	27.93	22.44

FEB 23 1987

International Gas Technology HIGHLIGHTS

Volume XVII | February 9, 1987 | No. 3

IPAA IS CONCERNED OVER LARGEST DROP IN U.S. OIL OUTPUT IN HISTORY

According to the Independent Petroleum Assn. of America, average U.S. crude oil production last year fell from a high of 9.18 million bbl/day in February to 8.35 million bbl/day in December — the largest and most rapid fall in production ever recorded. As the figure shows, the decline offset 4 years of production gains.

This decline was more serious than expected, notes the IPAA. Earlier, the Energy Information Administration had estimated production would decrease 231,000 bbl/day from January to December. The EIA's revised estimate puts the decline at 773,000 bbl/day through September.

"In less than one year, manipulation of crude oil prices by the dominant Arab OPEC producing countries has offset all of the production gains realized between 1982 and 1985," commented IPAA chairman Raymond Hefner. "We are optimistic that EIA's revisions will send a message to the Reagan Adminstration and the U.S. Congress that the situation is more serious than originally thought."

OIL IMPORTS ROSE 26.5% IN 1986, BUT THEIR VALUE DECLINED 28%

The Commerce Dept. reports that U.S. imports of crude oil and products averaged 6.58 million bbl/day in 1986 — up 26.5% from the 1985 average of 5.20 million bbl/day. The value of these imports, however, declined 28.1% from \$52.36 billion to \$37.64 billion, reflecting a drop in oil prices from \$27.55/bbl to \$15.66/bbl in 1986. This prevented the record trade deficit of \$169.8 billion from being even higher.

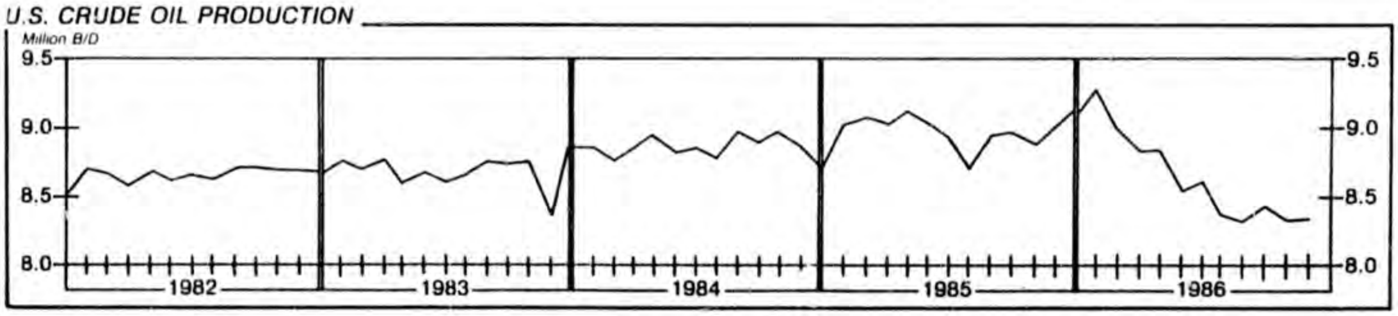
Imports peaked at 8.03 million bbl/day in September, and for three months last year were higher than 7 million bbl/day. In December, however, they fell to 6.2 million bbl/day. Crude oil imports alone averaged 4.48 million bbl/day in 1986; crude prices averaged \$14.79/bbl, compared with \$27.07 in 1985. The U.S. imported an average 378,300 bbl/day of gasoline in 1986, up 7.3% over 1985; 820,258 bbl/day in December were imported. Residual fuel imports jumped 27.9% to 753,926 bbl/day, and reached 850,258 bbl/day in December.

ARAMCO AGREEMENT WITH SAUDIS SEEN AS SUPPORTING \$18/BBL OIL

Exxon Corp., Chevron Corp., Texaco Inc., and Mobil Corp. reportedly signed a multi-year agreement to buy Saudi Arabian crude oil at a fixed price. The companies are shareholders in the Arabian American Oil Co. (Aramco). The agreement was widely interpreted as helping to stabilize oil prices at around \$18/bbl, which the Saudi finance minister recently called "a reasonable and sustainable price."

Aramco announced only that the companies had agreed on the volumes of crude to be delivered during the first 5 months of the multiyear contract, with adjustments to be made after this period. While volumes were not specified, in the past the Aramco partners were taking about 1 million bbl/day, nearly a quarter of Saudi Arabia's total output. The oil is to be sold at the official government price, which is \$17.52/bbl for Arabian Light.

U.S. CRUDE OIL PRODUCTION



API HEAD WARNS OF NEW, WORSE ENERGY CRISIS

Speaking to the National Press Club in Washington, Chevron Corp. chairman George M. Keller, who is chairman of the American Petroleum Institute, warned that the U.S. could face a major energy crisis in the next few years and that time is running out to do something about it.

Keller told the journalists that last year's oil price collapse — the worst in 50 years — led to widespread cutbacks in oil exploration and development projects and the shutdown of thousands of marginal wells in the U.S. As a result, domestic crude production dropped some 800,000 bbl/day from February to December 1986, the first such decline in several years; total U.S. oil consumption rose nearly 500,000 bbl/day; and oil imports increased by more than 1 million bbl/day to an average 6 million bbl/day in 1986 — the highest level since 1980.

"We're now facing a much more unstable energy future that will include a sharp dependence on America's dependence on foreign oil," said Keller. "Within 3 or 4 years, the combination of declining domestic production and rising imports could make our nation extremely vulnerable to another major energy crisis." The potential crisis could be significantly worse than the oil shock of 1973-74, he added, since there are no major non-OPEC discoveries awaiting development to provide additional oil production.

While there are no quick or painless remedies, Keller said the first step is for the Administration and Congress to recognize the urgency of the problem and try this year to review and modify all government policies which discourage domestic production. Among his suggestions were development of the Arctic National Wildlife Refuge and the California Outer Continental Shelf; repeal of the windfall profits tax, which he termed a "tremendous deterrent to drilling"; and incentives to encourage oil and gas exploration. Keller continued to favor a price floor in the $14-$17/bbl range, and said that while he isn't yet ready to support an oil import fee, ultimately this may be "the only answer."

RIG COUNT DECLINE SLOWS DOWN, BUT WORLDWIDE DRILLING NEARS RECORD LOW

According to the latest report on rotary rig activity by Hughes Tool Co., the rate of decline in drilling is slowing down. The 826 rigs making hole the week ending January 30 were only 11 less than the previous week. This compares with 1594 rigs active a year earlier. However, the recent decline compares with a drop of 77 rigs for the same week in 1986.

By state, increases were reported for Ohio, Mississippi, Oklahoma, Arkansas, Michigan, New Mexico, Utah, Wyoming, and New York. States reporting declines included Texas, Colorado, Nebraska, Pennsylvania, Alabama, and Florida.

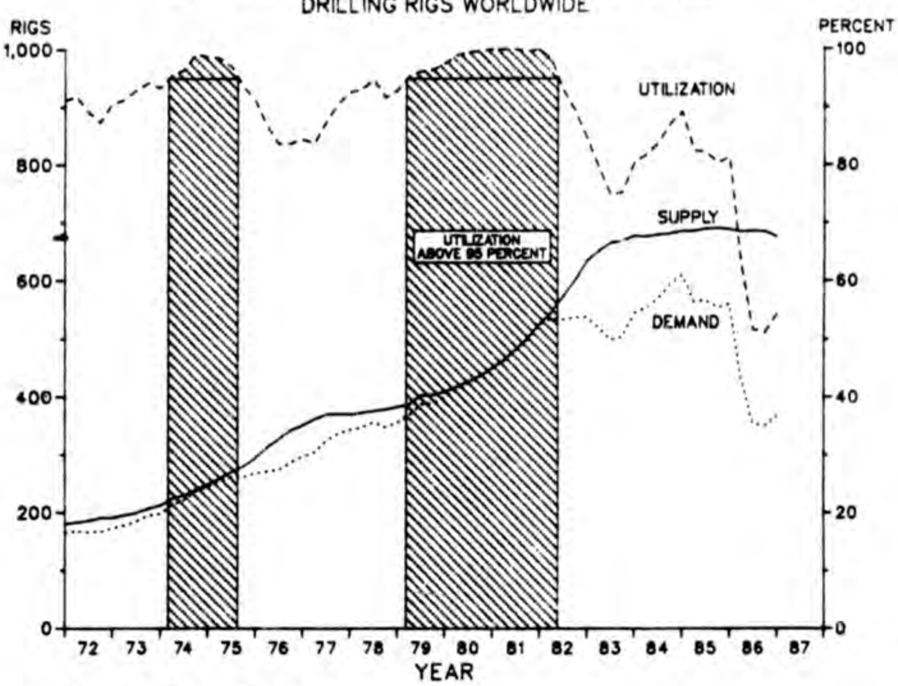
The decline in drilling activity has been more pronounced in Canada, where only 139 rigs were working the last week of January, compared with 178 rigs the previous week and 324 a year earlier.

Worldwide, the utilization rate for offshore mobile rigs is 54%, approaching the all-time low, with only 367 rigs working out of a total fleet of 676. According to E.F. Hutton, at the beginning of 1986 the utilization rate stood at 81%, while in two past periods — from 1973 to mid-1976 and from mid-1975 to 1979 — it exceeded 95%, as the figure shows. The supply of rigs rose from just over 200 in 1974 to nearly 700 in 1983 and has remained constant since then. "The offshore drilling industry continues to struggle through the worst crisis in its history," comments E.F. Hutton.

MAJORS DRASTICALLY CUT INVESTMENT IN ALTERNATIVE ENERGY PROJECTS IN 1985, BUT RAISE R&D SPENDING SLIGHTLY

An Energy Information Administration report, *Performance Profiles of Major Energy Producers 1985*, notes that 22 major U.S. energy companies cut their domestic investment in alternative energy by nearly 80% to $131.5 million in 1985 — only 10% of the 1982 level. Overall, the companies' net income declined 18.3% to $17.4

SUPPLY, DEMAND, AND UTILIZATION OF OFFSHORE DRILLING RIGS WORLDWIDE



SOURCE: OFFSHORE DATA SERVICES, INC.
NOTE: SUPPLY AND DEMAND (LEFT SCALE), UTILIZATION (RIGHT SCALE).

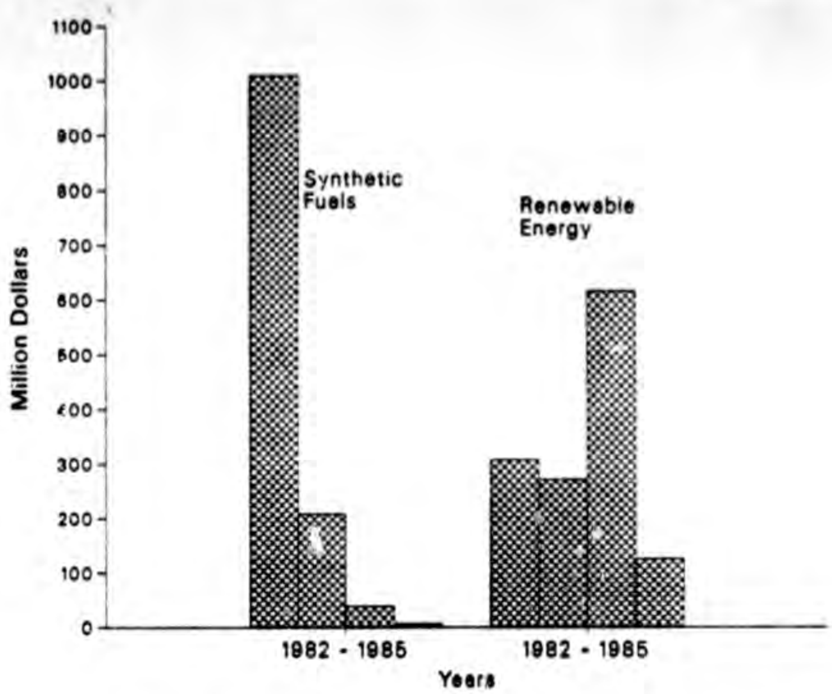
billion, the lowest level since 1978.

Domestic spending on synthetic fuels projects showed the steepest decline: Investments in oil shale, coal gasification/liquefaction, and tar sands projects totaled only $6.5 million in 1985, compared with $38.6 million in 1984, $208.4 million in 1983, and $1.01 billion in 1982. Spending on geothermal, solar, and other alternative energy sources dropped from $30_.9 million in 1982 to $131.5 million in 1985 (after peaking at $613.2 million in 1984 because of the acquisition of geothermal assets by Unocal and Phillips). The figure shows the relative importance of alternative energy investments in the U.S. by the 22 reporting companies.

Total foreign investments were off .1% to $163.4 million. Funding of Canadian tar sands projects went up slightly from $123.8 million in 1984 to $125.2 million in 1985, but other foreign investments declined 21.3% to $38.1 million.

Despite declining income, the companies spent slightly more on research and development in 1985 than in 1984. Their R&D spending rose 1.1% to $4.11 billion, mainly due to increased investment in petroleum and nonenergy areas. Oil and gas recovery R&D funding rose 15.7% to $801.4 million, higher than any of the 3 previous years. Other spending increases were reported for tar sands research, up 19.8% to $32 million; coal gasification and liquefaction, up 14.1% to $116.7 million; and solar and geothermal, up 43.7% to $78.3 million. However, declines were reported for other petroleum R&D, down 12.7% from 1984 to $536.2 million, and oil shale R&D, down 35.4% to $68.8 million. Nonenergy R&D investments increased 2.5% to $2.21 billion in 1985.

The 22 companies which file Form EIA-22 with the EIA's Financial Reporting System each year, are Amerada Hess Corp., American Petrofina Inc., Amoco Corp., Ashland Oil Inc., Atlantic Richfield Co., Burlington Northern Inc., Chevron Corp., Coastal Corp., E.I. du Pont de Nemours and Co., Exxon Corp; Kerr-McGee Corp., Mobil Corp., Occidental Petroleum



Source: Form EIA-28

Additions to PP&E in Domestic Alternative Energy for FRS Companies, 1982-1985

Corp., Phillips Petroleum, Shell Oil Co., Standard Oil Co., Sun Co., Tenneco Inc., Texaco Inc., Unocal Corp., Union Pacific Corp. and United States Steel Corp.

EVEN SHARING OF TAKE-OR-PAY COSTS RECOMMENDED BY FERC HEAD

According to *Inside F.E.R.C.*, Federal Energy Regulatory Commission Chairman Martha Hesse has proposed that pipelines and their customers share evenly the costs of removing take-or-pay liability. The proposal, circulated to the other 5 commmissioners on January 23, is part of the "comprehensive gas strategy" announced last month (*IGT Highlights*, January 26, 1987). A timetable has reportedly not been set for a decision on take-or-pay. A group of major producers is seeking input into policymaking.

Hesse's proposal is said to involve the levy of separate charges on customers for 3 kinds of take-or-pay expenses: contract buyouts, contract buydowns, and future inventory carrying costs. The first two would be allocated on the basis of customers' historical purchases. Future supply reservation costs would be allocated on the basis of the difference between anticipated and actual takes.

A critical part of the new policy will be the method of recovering the costs from customers. Historical sales customers that are still buying gas from the pipeline could be billed directly through the demand charge or the commodity charge. However, the proposal apparently recommends against passing through costs in the commodity charge, an approach supported by Reps. John Dingell and Philip Sharp and by some state commissioners.

CONSUMERS, DOW FINALIZE AGREEMENT TO CONVERT MIDLAND PLANT TO GAS

Consumers Power Co. and The Dow Chemical Co. have signed agreements to convert the $4.1 billion mothballed nuclear power plant at Midland, Mich., to a natural gas combined-cycle cogeneration plant. The two companies agreed to this in principle on September 17 (*IGT Highlights*, October 6). They also moved to end their 3-year-old litigation.

Under the agreement, Dow's subsidiary Rofan Energy Inc. invested $115 million for a minority interest in the project; Consumers Power, through its subsidiaries, will contribute about $1.5 billion of its assets at Midland in return for 49% equity and interest-bearing notes totaling $1.27 billion. Consumers Power also has the option of receiving a $103 million payment from the partnership and will receive $16 million/year for the first 9 years after commercial operation begins. Other equity participants will be announced this spring.

Fluor Daniel and Dow Engineering Co. are preparing bids for the engineering/construction work. Design work is scheduled to begin in April and site work in late 1987. Eight of 12 combined-cycle turbines and heat-recovery steam generators to support the conversion of Unit I of Consumer Power's existing plant will be installed in 1989 and 1990. Electricity generation and steam production is expected to begin by early 1990. The project will provide the electricity and steam requirements for Dow's plant at Midland for 25 years. The rest of the generating capacity will be available to Consumers Power.

GAMA REPORTS INCREASES IN SHIPMENTS OF MAJOR GAS APPLIANCES IN NOVEMBER

The Gas Appliance Manufacturers Assn. reports increases in shipments of several categories of major appliances last November and in the first 11 months of 1986.

In November, shipments of gas water heaters rose 2.0% to 293,919 units, compared with a 5.4% decline to 253,895 electric water heating units. Gas range shipments went up 6.7% to 172,890 units. Shipments of central heating units rose 9.2% to 224,872, due to a 11.6% gain in gas furnace deliveries to 202,080. For the first 11 months of the year, GAMA reports a 5.8% increase in gas water heater shipments, a 5.8% boost in sales of gas ranges, and a 14.7% hike for central heating units.

Heating systems for recreational vehicles rose 9.6% to 14,685 units shipped in November, but residential gas wall furnace deliveries declined 16.6% to 20,800. Shipments of gas unit heaters and gas duct furnaces decreased by 13.1% and 5.1%, respectively, to 19,706 and 2216 units.

VALUE OF CANADA'S FUEL PRODUCTION FALLS SHARPLY IN 1986 DUE MAINLY TO CRUDE OIL PRICE DROP

Energy, Mines and Resources Canada reports that the value of Canada's petroleum production declined 47.2% to $9.72 billion in 1986 (Canadian $), although the actual production volume was down only 0.7%, reflecting last year's sharp drop in oil prices.

The value of natural gas fell 16.2% to $6.74 billion, with a 9.5% drop in actual output; the value of natural gas byproducts dropped 35.0% to $1.83 billion, with a 3.9% production decline; while the value of coal declined 7.0% to $1.72 billion, with actual output down 4.4%. Overall, the value of energy commodities fell 35.7% from $31.1 billion in 1985 to $20 billion in 1986.

IGT SEEKS PAPERS FOR 6TH GAS ODORIZATION SYMPOSIUM

IGT has issued a call for papers for its 6th quadrennial gas odorization symposium to be held August 24-26 in Chicago.

Technical subjects include properties of odorants, commercial odorant systems, selection of odorants and odorization level, methods of odor addition, measurement of odorant levels, factors affecting odorant stability, human olfactory response to gas odorants, and current odorant research. Legal issues include documentation for odorization, the need for judicious sampling and analysis after a gas fire and explosion, and response to odorization-related incidents.

Abstracts 150-250 words in length should be sent by March 10, 1987, to Amir Attari, IGT.

IGT WILL HOLD 3RD SYMPOSIUM ON PC USE IN THE GAS INDUSTRY JUNE 22-24

IGT will hold its third annual symposium on Personal Computer Applications in the Gas Industry June 22-24 in St. Charles, Ill.

Papers will be presented on applications in 3 areas: regulation, management, and accounting; marketing and market analysis; and engineering and operations. Specific topics include gas supply and dispatching optimization, life cycle analysis, and the development of expert systems. All papers and software presented at the 3-day symposium will reflect the latest advances in information, data control, and system operation within the gas industry.

For more information, contact Susan Robertson, IGT: 312/567-3881.

IGT **INTERNATIONAL GAS TECHNOLOGY HIGHLIGHTS**

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f. SJR 8

Alaska State Legislature

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Senate

April 13, 1987

Mr. Tom Burns
Manager, Economic Department
Chevron U.S.A., Inc.
3001 "C" St.
Anchorage, AK 99503

Lobo

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Sincerely,

Bettye Fahrenkamp
Chairman

BF:dc

Enclosure

File - mail
disk - work
oilga

Testimony given by:

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Washington, D.C. 20510

34 Tim Dowd, Executive Director
Interstate Oil Compact Committee 3195
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35 Raymond Plank, Chair
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UNOCAL Corporation
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f- SJR 8

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(907) 465-4525

March 4, 1987

Mr. Raymond Plank, Chair
Apache Corporation
1700 Lincoln Street, Suite 4900
Denver, Colorado 80203-4549

Dear Mr. Plank,

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Again, Mr. Plank, thank you for your time and contribution to our important hearing.

With best wishes, I am

Sincerely,

Joe Josephson

Joe P. Josephson
State Senator

f SJR 8 MAY 8 1987

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Chairman and Chief Executive Officer 303/831-6597

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May 1, 1987

Senator Bettye Fahrenkamp
Chairman, Oil and Gas Committee
Alaska State Legislature
515 7th Avenue, Suite 130
Fairbanks, Alaska 99701

Dear Bettye:

It was a pleasure to participate in your February 26 hearing. Thank you for writing me and enclosing the minutes.

If I can be of assistance in the future, please let me know.

Very truly yours,

Raymond

Raymond Plank

RP/ek

j- O+G SJR 8

Alaska State Legislature

Senate

Official Business

FEB 9 1987

Pouch V
State Capitol
Juneau, Alaska 99811

February 9, 1987

The Honorable Bettye Fahrenkamp
Chair
Senate Special Committee on
Oil and Gas
Alaska State Senate
P.O. Box V
Juneau, Alaska 99811

Dear Bettye:

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Murkowski noted that the U.S. now imports nearly 40 percent of its domestic needs.

"Energy security is what the legislation is all about," he said. "Although we currently enjoy reasonably priced oil supplies sufficient to meet our daily needs, our proven oil reserves are shrinking and our dependency on foreign supplies of crude oil is growing each and every day."

Fairbanks Daily News Miner - 2/7/87

CORRECTION

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TO ASSURE LEGIBILITY

02–576(2/77)

f. SJR 8

Alaska State Legislature

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THE SEAL OF THE STATE OF ALASKA

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f- SJR 8

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f- O+G SJR 8

Alaska State Legislature
Senate

FEB 9 1987

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Juneau, Alaska 99811

February 9, 1987

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Alaska State Senate
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Fairbanks Daily News Miner - 2/7/87

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January 30, 1987

The Honorable Bettye Fahrenkamp
Chair
Senate Special Committee On Oil and Gas
P.O. Box V
Juneau, Alaska 99811

Dear Senator Fahrenkamp:

On January 20, I introduced Senate Joint Resolution 8, which relates to a federal tax on imported oil. This Resolution was referred to your committee. I would be grateful if you would consider scheduling this measure for a committee meeting in the near future. I take the liberty of suggesting a meeting between February 15 and March 1; I have asked for the recommendations of our Alaska delegation in Washington, D.C. and should have responses by then. I feel that this proposal is clearly in the interest of Alaska and Alaskans and a matter the Legislature should address this session.

If you need any information or should have any questions regarding SJR 8, please do not hesitate to contact my office.

With best wishes, I am

Sincerely,

Joe

Joe P. Josephson
State Senator

JPJ:mas

-OTG- SJR 8

Energy & Environmental Policy Center

Discussion Paper Series

John F. Kennedy School of Government
Harvard University

OIL TARIFF POLICY

IN AN UNCERTAIN MARKET

HARRY G. BROADMAN
WILLIAM W. HOGAN

NOVEMBER 1986 E-86-11

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ACKNOWLEDGEMENTS

A large number of people provided very helpful comments on early drafts of this paper. They include Morry Adelman, Doug Bohi, Tom Burns, Bob Fri, Dermot Gately, Jim Griffin, Henry Lee, Mike Lynch, Don Marshall, Bijan Mossavar-Rahmani, Ray Plank, Elliot Ranard, Harry Rowen, Irwin Stelzer, Bill Tell, Ray Vernon, and John Weyant. All remaining errors of fact, theory, and interpretation, however, are solely our responsibility. We would also like to acknowledge the administrative, research, and secretarial support of Linda Buffett, Constance Burns, Viet Dinh, Nancy Kingston, Richard Thomas, and Charley Wilhite. Financial support for this research was provided by the Associates of Harvard's International Energy Program and Energy Security Policy, Inc.

Harry G. Broadman
William W. Hogan
November 1986

EXECUTIVE SUMMARY

Rising U.S. dependence on imported oil poses a renewed threat to the country's energy security and economic stability. U.S. oil imports are averaging over 5 million barrels a day — the highest level since 1981 — as lower prices have led to increases in overall consumption and decreases in domestic production. Unchecked, these trends could expose the United States to the risks of future price disruptions in the world oil market, triggered by events in the volatile Middle East.

Imposition of a large fixed fee on imports of both crude and refined oil would greatly enhance U.S. energy security. The study estimates that the tariff required to bring about a "socially optimal" level of U.S. oil imports is between $10 and $11 a barrel.

The price paid by the U.S. for imported oil in the world market does not reflect the true, or social, cost to the nation of dependence on insecure sources of supply; given this gap between social cost and market price, more oil is consumed in the U.S. than is optimal. In other words, there are market imperfections associated with U.S. oil imports, just as there are market imperfections associated with the pollution created from burning high-sulfur coal. Collectively, these market imperfections give risk to an "oil import premium," which reflects the additional amount that society should be willing to pay above the world price for imported oil.

There are two sets of market imperfections that comprise the premium. One of these is the "economic component" of the premium. Because the United States is such a large purchaser in the world oil market, the price paid for foreign oil is not independent of how much the country imports. In particular, the greater the volume imported, the higher the price, and vice versa. Importantly, this means that, within the U.S., a given increase in demand for oil imports leads to a higher price that all pre-existing importers must pay. Moreover, rising world oil prices adversely affect both our macroeconomic performance and trade balance. Yet, individual U.S. purchasers of foreign oil do not pay a price that fully reflects these costs.

The "security component" of the premium reflects costs that stem from sudden, unanticipated, and large changes (i.e., disruption), in the price of oil in the world market. The U.S. economy is vulnerable, in the event of an oil price run-up, to an increased transfer of wealth abroad and its attendant costs. This vulnerability is a direct function of the volume of oil imports prior to a disruption. Another element of the security component of the premium is a function of the importance of oil *per se* in the economy. The greater the value share of oil in the economy at the time of a disruption and the greater the economy's inability to shift quickly away from oil in the face of a change in its price, the greater the macroeconomic costs from the price shock. It is well-known that these macroeconomic costs are substantial.

A model is developed to quantify the sources of market failure which prevent private actors from recognizing the true costs of the marginal barrel of U.S. oil imports and to derive the appropriately-sized tariff that closes the gap between social cost and market price. Sensitivity analyses are conducted to test how the estimate of the optimal tariff changes with alternative assumption and judgments about oil prices, the probability and size of disruptions, and so on. While the resulting tariff estimates are sensitive to assumptions about market conditions, this sensitivity is much less than is commonly believed. The size of the optimal tariff is large; our preferred set of assumptions set the optimal tariff at between $10 and $11 per barrel.

The form of a U.S. tariff on imported oil could vary across a range of alternatives, including a simple fixed fee, a variable fee designed to establish a floor price, or a fee defined in proportion to the price of oil. We argue that the fixed fee is the simplest and most effective tariff form. In addition, we note that the granting of exemptions or exceptions, either to a special category of foreign suppliers or to a special category of U.S. consumers, would reduce the economic savings produced by a tariff.

Finally, although a tariff on imported oil will result in a real saving for the nation as a whole, it will redistribute resources throughout the economy, creating "winners" and "losers." But because the gains enjoyed by the "winners" are larger than the costs suffered the "losers," the tariff will produce positive net benefits for the nation in the aggregate.

OIL TARIFF POLICY IN AN UNCERTAIN MARKET

I. INTRODUCTION

OIL TARIFF

A $10 to $11 per barrel tariff on U.S. oil imports is justified by the special characteristics of oil and oil markets. Unlike other commodities, oil production and prices have been manipulated successfully by foreign producers for protracted periods. Moreover, unlike most other products, the price and availability of oil significantly affect macroeconomic variables such as our trade balance, the rate of inflation, and aggregate level of economic activity. And, more than most commodities, oil is crucial to our national security. For these reasons, the full cost of U.S. oil imports is not reflected in the price we pay in the world market. The gap between the true cost of oil to the nation and the market price justifies imposition of an offsetting tariff.

This paper examines the issues raised by current proposals for restrictions on U.S. oil imports through the use of a tariff. The discussion reviews the general policy arguments, describes a framework for estimating the costs to the United States of its free market policy in oil, estimates the size of optimal U.S. oil import tariff with special attention to world oil price uncertainty, compares the efficacy of different tariff instruments, and appraises the most salient issues that arise in implementing a tariff policy.

ENERGY SECURITY POLICY

Energy policy has returned to the national agenda. Unlike the last decade, however, when disruptions in the world oil market meant shortages and high prices, today the "crisis" is a supply glut and low prices. And whereas before, consumers were the losers and producers the winners, now these positions have been reversed.[1]

But one thing has not changed: government action is being advocated as a solution to a problem in the energy marketplace. Beleaguered domestic oil producers have called for a tariff on imported petroleum supplies.[2] Such a protectionist measure would, in effect, provide them with price guarantees in the face of soft market conditions. Behind the producers' argument is the belief that world oil prices will remain low for a sustained period of time and that, as a result, there will be an appreciable decline in U.S. exploration, development, and production activity, posing a major threat to the future viability of the U.S. oil industry.

The effects of the drop in oil prices have been widely reported. The general expectation is that with lower prices there will be an increase in the demand for oil but also a reduction in the level of output from high-cost domestic wells. The result will be growth in the volume of oil imported into the United States and a corresponding decrease in the market share of indigenous supplies.[3]

The most recent data available for the United States confirm these forces are very much at work.[4] Total demand for petroleum is projected to in-

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1 For a survey of the data and a history as well as analysis of the price collapse, see Dermot Gately, "The 1986 Oil Price Collapse: What Happened and What Did We Learn?, Economics Department, New York University, August 28, 1986.

2 They are supported by those anxious to find new sources of revenue to reduce Federal budget deficits.

3 For the most recent assessment and summary of the effects of sharply lower prices, see Conoco Corporation, World Energy Outlook Through 2000, September 1986.

4 The following data are taken from the U.S. Department of Energy, Energy Information Administration, Short-Term Energy Outlook October, 1986

crease by about 3 percent in 1986. Domestic production of crude is projected to fall off by 150,000 barrels a day. Imports of crude and refined products will rise by about 18 percent, averaging over 5.0 million barrels a day (mmbd), the highest level since 1981. Total imports will thus reach about 32 percent of U.S. demand this year. Persistent soft market conditions will exacerbate these trends. Substantial reductions in drilling activity — the domestic rig count has dropped from approximately 4500 in October 1981 to about 800 in October 1986 — should result in continuing declines in U.S. crude production in the years ahead.

To be sure, the dramatic fall in the price of oil points to the need to reconsider U.S. energy security policy. However, the message implied by the current turn of events is not so much that public policy may need to be revised simply because now oil prices are low, but rather because they <u>can be</u> low. In other words, the critical question is how should government respond to a world oil market characterized by prices which move <u>down</u> as well as up.

The focus of U.S. energy security policy has been the development of the Strategic Petroleum Reserve (SPR), a large inventory of oil under government control that can be brought quickly to replace lost supplies. Previous analyses of the SPR reinforce its importance and point to the need to add oil to the inventory.[5] In addition, these same analyses highlight the value of other, complementary policies, including an oil tariff, that could enhance energy security.

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5 Thomas J. Teisberg, "A Dynamic Programming Model of the U.S. Strategic Petroleum Reserve," <u>Bell Journal of Economics</u>, Volume 12, Number 2, Autumn, 1981; and William W. Hogan, "Oil Stockpiling: Help Thy Neighbor," <u>Energy Journal</u>, Vol. 4, Number 3, July 1983.

Notwithstanding the development of the (SPR), U.S. government response to the problem of energy security since the late 1970s has been primarily one of laissez faire. The roots of this free market policy lie partly in the costly experience with price controls in the early and mid 1970s, and with good reason. The result is, in many analysts' view, a myopic energy security policy: placing all of our energy security eggs in one basket — the SPR — is too narrow an insurance policy for the nation.

The re-emergence of volatility in oil prices has rekindled this concern and renewed the search for policy instruments to supplement the SPR. An import tariff has been the most frequently mentioned one. In this regard, a tariff has been advocated as a way for the United States to maintain downward pressure on otherwise rising oil prices; as a way to foster investment in capital equipment that has flexibility in fuel usage, and thus to make the economy more resilient to oil price shocks; and as a way to counteract deleterious effects on our trade balance with oil exporters. All of these rationales for a tariff are independent from its effect on protecting domestic oil producers in a soft market. Indeed, such arguments were advanced when oil prices were high.[6]

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6 See, for example, Harry G. Broadman, "Review and Analysis of Oil Import Premium Estimates," Discussion Paper D-82C, Energy and National Security Series, Resources for the Future, Washington, D.C., December 1981; and William W. Hogan, "Import Management and Oil Emergencies," in Energy and Security, David Deese and Joseph S. Nye, eds., (Cambridge, MA: Ballinger, 1981); and James L. Plummer (ed.), Energy Vulnerability, (Cambridge, MA: Ballinger, 1982).

II. THE OIL IMPORT PREMIUM: A CONCEPTUAL FRAMEWORK

The idea of applying a tariff to U.S. oil imports is not new.[7] However, the usual argument made by economists in support of such a policy does not derive from the notion of protecting the U.S. oil industry, but rather the objective of insuring that the United States consumes the "optimal" level of imported oil, i.e., where the nation's benefit from oil imports is maximized.

At the core of this argument is the fact that a large fraction of the free world's oil reserves are concentrated in a few volatile regions and that, as a result, oil prices are exposed to an appreciable risk of being disrupted. This feature of the world oil market, together with the fact that the United States is a large purchaser of oil and thus, the volume of its oil imports directly affects the market price, suggests that the price paid by U.S. oil consumers does not fully reflect the true national cost of imported oil. In other words, there are market imperfections associated with U.S. consumption of imported oil — just as there are some associated with the pollution created from burning high-sulfur coal.[8] To the extent these oil market imperfections — commonly thought of as collectively giving rise to an "oil import premium" — are not incorporated into the purchase price of imported oil by, say, imposing a tariff, U.S. consumption of oil imports will exceed the optimal level.

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7 Use of a U.S. oil import tariff actually dates back to the 1930s. See our discussion of the tariff's history below.

8 Nordhaus used the analogy to environmental pollution in proposing a $10 tariff on oil imports. Nordhaus, William, "Put a Tax on Oil Pollution," <u>New York Times</u>, April 18, 1982.

The oil import premium concept suggests, then, that a tariff could be used to reduce U.S. oil import levels to the point where the costs to society of importing the incremental barrel of oil just balance the benefits. Importantly, the premium notion implies that the optimal level of U.S. oil imports may not be zero. In other words, the idea that the United States should strive to eliminate completely its consumption of imported oil is bad public policy.[9]

Another important implication of analyzing U.S. energy security policy in terms of the oil import premium is that support for a tariff need not directly hinge on whether oil prices are low or high. Rather, from this perspective, a tariff is seen as an instrument — in addition to the SPR — that addresses imperfections that are endemic to the world oil market. As long as volatile regions continue to account for a large fraction of world oil reserves, and as long as the volume of foreign oil purchased by the United States influences the market price, an oil import premium exists for the United States. Thus, while transitory variations in market conditions — gluts as well as shortages — will alter the magnitudes and signs of individual components of the premium, the total value of the premium need not vary appreciably.

The oil import premium implies that the full cost of imported oil is not incorporated into private consumption and production decisions. Thus, individual consumers will pay too low a price and use more imported oil than is

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9 This, of course, was the original objective of Project Independence, introduced by President Nixon. See, for example, Douglas R. Bohi and Milton Russell, Limiting Oil Imports: An Economic History and Analysis (Washington, D.C.: Resources For the Future/Johns Hopkins University Press, 1978).

optimal, and domestic oil producers will face a return below the true value of the incremental barrel of oil and produce too little. In theory, then, the premium reflects the additional amount that society should be willing to pay above the world price for imported oil (or its substitutes). Alternatively, the premium can be interpreted as a measure of the net social benefits of reducing the consumption of imported oil. Or, to take another example, the premium serves as a guide for how much the nation should be willing to pay for military protection of oil supplies.

It should be clear that the oil import premium provides a systematic framework for analyzing energy security problems beyond ways in which the currently low level of oil prices threatens the viability of domestic producers. Rather than viewing a tariff as a short term policy prescription, the premium framework takes the long run view. It recognizes that the energy security problems we face today are, in fact, not fundamentally different from those that have been present for the past decade or are likely to arise in the next decade. The "energy crisis" is not one of high prices, or low prices. It is instead, one intrinsic to the nature of oil — where it is found and its role in the economy — and in the structure of the world oil market. The challenge for public policy is to deal with an energy security problem that is chronic and large.

COMPONENTS OF THE OIL IMPORT PREMIUM

There are two sets of market imperfections that comprise the premium. One of these is the "economic component" of the premium. The economic component reflects imperfections arising from the fact that the price the United States pays for oil on the world market is affected by the level of U.S. import demand, and from the fact that systematic changes in oil prices directly influence U.S. macroeconomic performance. The other portion of the premium is the "security component." The security component reflects the market imperfections associated with the total costs of oil supply disruptions and with the risks arising from vulnerability to such disruptions.

The Economic Component

Because the United States is a large oil purchaser in the world market, the price we pay for oil imports is not independent of how much we buy. The greater the volume of oil imports, the higher the price, and vice versa. Importantly, this means that a given increase in U.S. demand for oil imports leads to a higher price that all pre-existing U.S. oil importers must pay. Thus, not only does the party responsible for the increase in oil import demand cause it to face a price that is higher than what it otherwise would pay, but also its contribution to demand affects the price that must be paid by all other U.S. oil importers.

This element of the economic component of the premium can be illustrated using a simple numerical example. Suppose U.S. oil imports stand at 4 mmbd and the world price is $18.00 per barrel. Now assume that if U.S. oil import demand was to increase by 1 mmbd, the price would rise to $20.00 per barrel. The total oil import bill for the United States would increase from $72 million to $100 million per day. The total cost to the United States of each of the additional one million barrels would be $28.00 per barrel. However, the private cost of the marginal barrel would be only $20.00, the market price. Thus, in effect, the United States pays a premium of $8.00 for the last barrel imported.

This is akin to pricing in a market structure characterized by "monopsony" (i.e., buyer market power), where the buyer faces an upward sloping input supply curve for oil import purchases. It can be depicted graphically, as in Figure 1. At a level of Q_0 oil imports into the United States, the price paid per barrel is P_0. An increase in demand, which results in imports rising to Q_1, increases the per barrel price to P_1. The entire shaded area represents the total increase in the social cost of oil imports due to the rise in demand. (Alternatively, it depicts the total social benefits of reducing oil imports from Q_1 to Q_0.) Area B shows the portion of the additional social costs that is borne by the marginal importer. Area A shows the portion borne by other U.S. oil importers.

An important corollary of the notion that the supply curve for U.S. oil imports is upward sloping is that the social costs generated by a rise in import demand increase disproportionately with the level of imports. This proposition is illustrated in Figure 2. The increase in imports between Q_0 and Q_1 is less than the increase between Q_1 and Q_2; the increase between Q_1 and Q_2 is less than the increase between Q_2 and Q_3; and the increase between Q_2 and Q_3 is less than the increase between Q_3 and Q_4. On the other hand, the increase in price between P_0 and P_1 is equal to the increase between P_1 and P_2; between P_2 and P_3; and so on. Now, note that whereas the increase in social costs generated by a rise in imports from Q_0 to Q_1 is area D + area H, the increase in social costs associated with a rise in imports from Q_1 to Q_2 is area C (=area D) + G (>area H). Analogously, the increase in social costs associated with imports rising from Q_2 to Q_3 is area B (=area C) + area F (>area G). And, the increase in social costs generated by a rise in imports from Q_3 to Q_4 is area A (=area B) + area E (>area F).

Since the social costs created by a rise in import demand increase disproportionately with the level of imports, this means that the difference between the marginal social cost and the market price of a barrel of oil im-

FIGURE 1

Private Purchases Increase National Costs

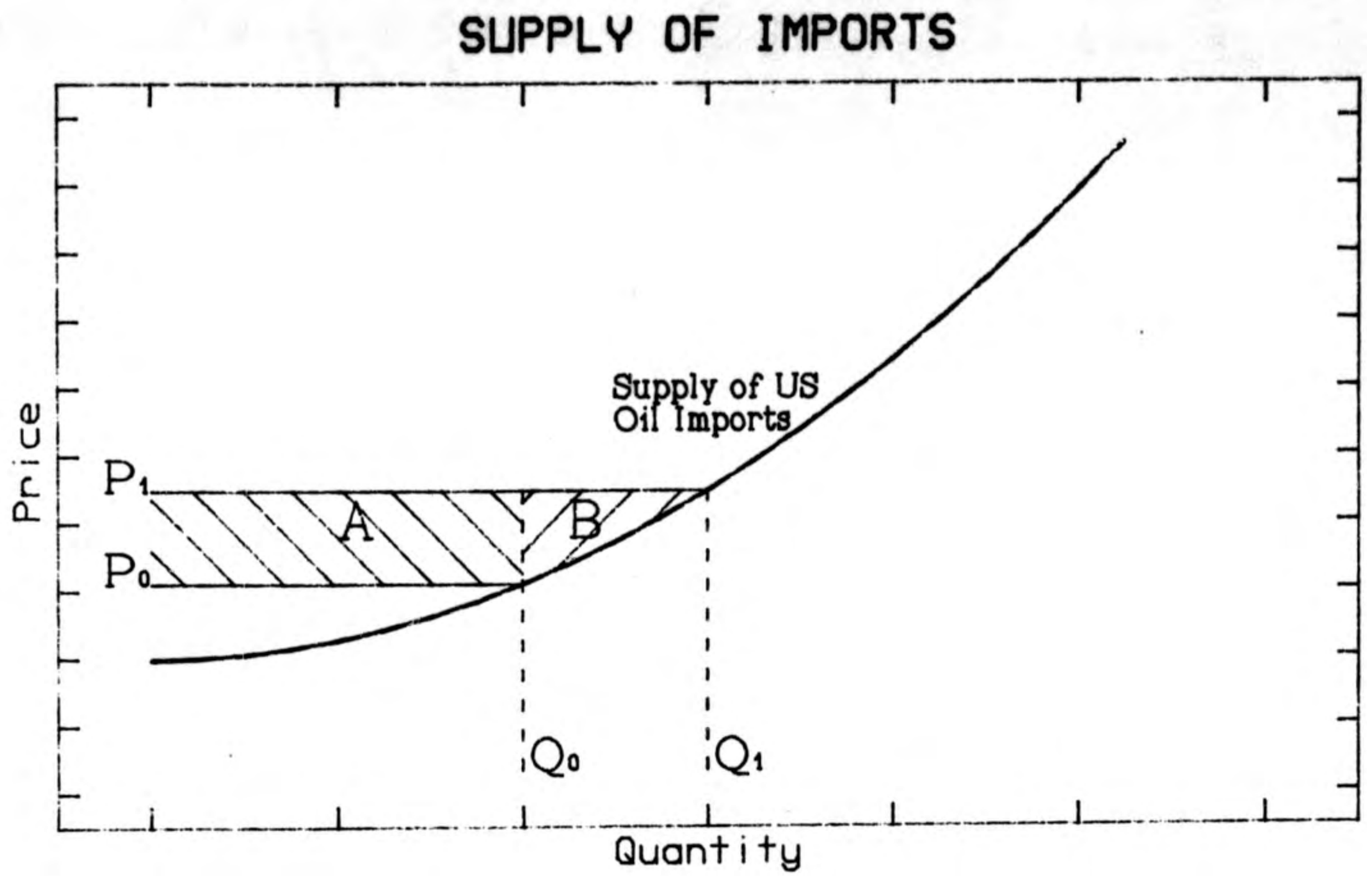
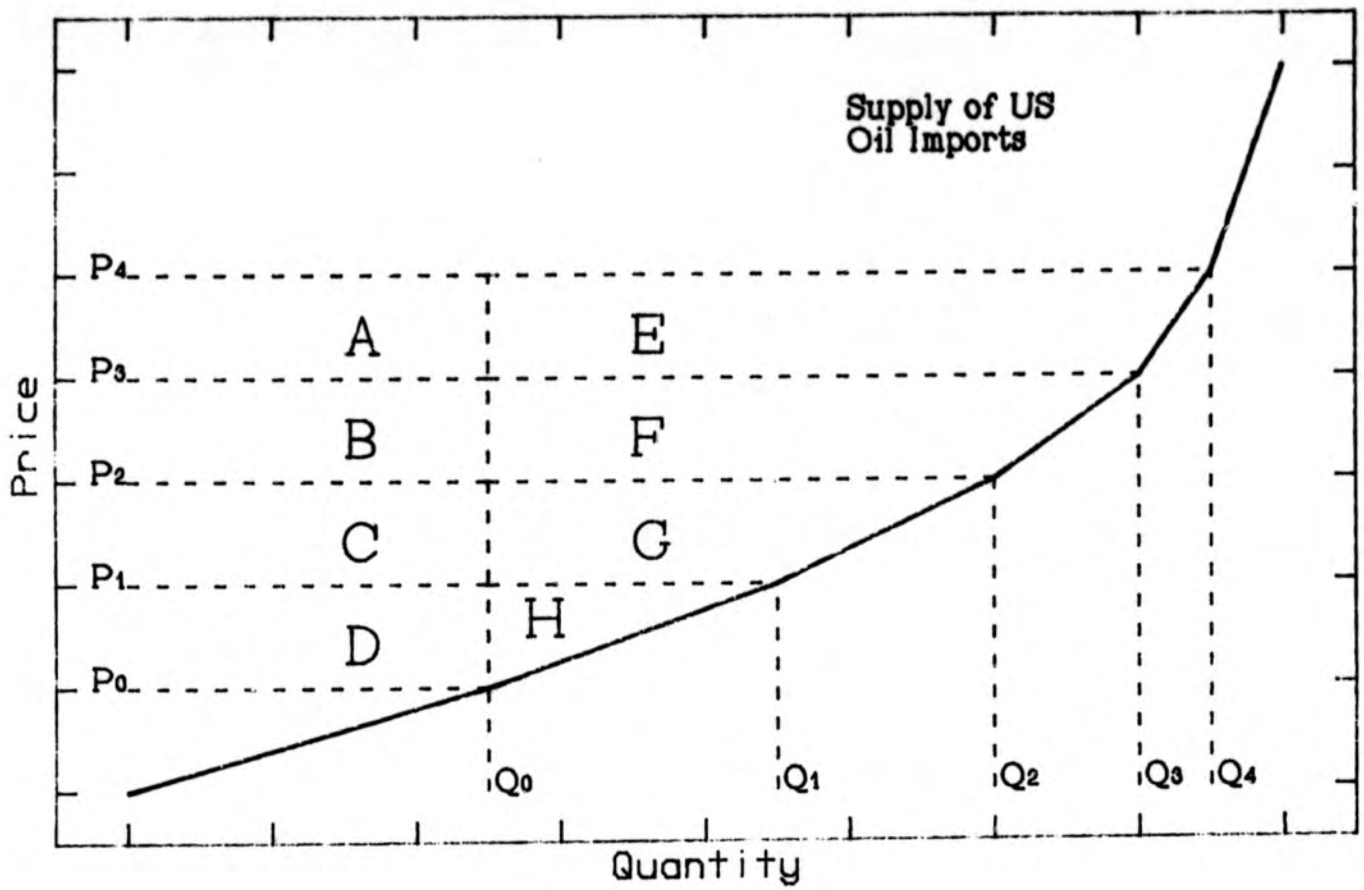


FIGURE 2

Marginal Cost of Oil Rises with Import Levels



ported into the United States increases with the level of imports; this is illustrated in Figure 3. This implies that in general the magnitude of the "monopsony wedge" element of the premium varies directly with the import volume. With low oil prices and rising import demand — the present market situation — it implies that the gap between the marginal social cost and the market price of oil imports is relatively large. Overall, given that there are variations in import demand, it is important in designing a policy instrument aimed at eliminating the market imperfection represented by this element of the premium to develop one which accounts for such changes.

The idea that a premium exists on U.S. oil imports implies that reducing U.S. consumption of imported oil, say, by imposing an appropriately-sized tariff[10] will result in a real cost saving for the United States. To be sure, a tariff will redistribute resources throughout the economy, creating winners and losers. But the status quo has winners and losers as well. Indeed, the existence of a premium means that the market price of imported oil does not fully reflect social costs and, therefore, marginal consumers of that oil are effectively being subsidized by all other consumers. In this regard, by incorporating the premium into the price of oil imports, the U.S. economy would be "internalizing" costs that are already being borne.

Figure 4 formalizes this argument graphically. At Q_0 there is a difference between the marginal social costs and marginal social benefits of U.S. oil imports, represented by the distance between A and B; this distance is (a portion of) the premium.[11] It should be clear that as import levels are

10 Defining and estimating the "optimal tariff" are precisely the core tasks of this paper.

11 Area AB represents only a portion of the premium because it doesn't account for terms of trade and inflationary elements of the economic component (see below); nor does it account for the market imperfections that give rise to the

FIGURE 3

Gap Between Public and Private Cost Grows with Import Volume

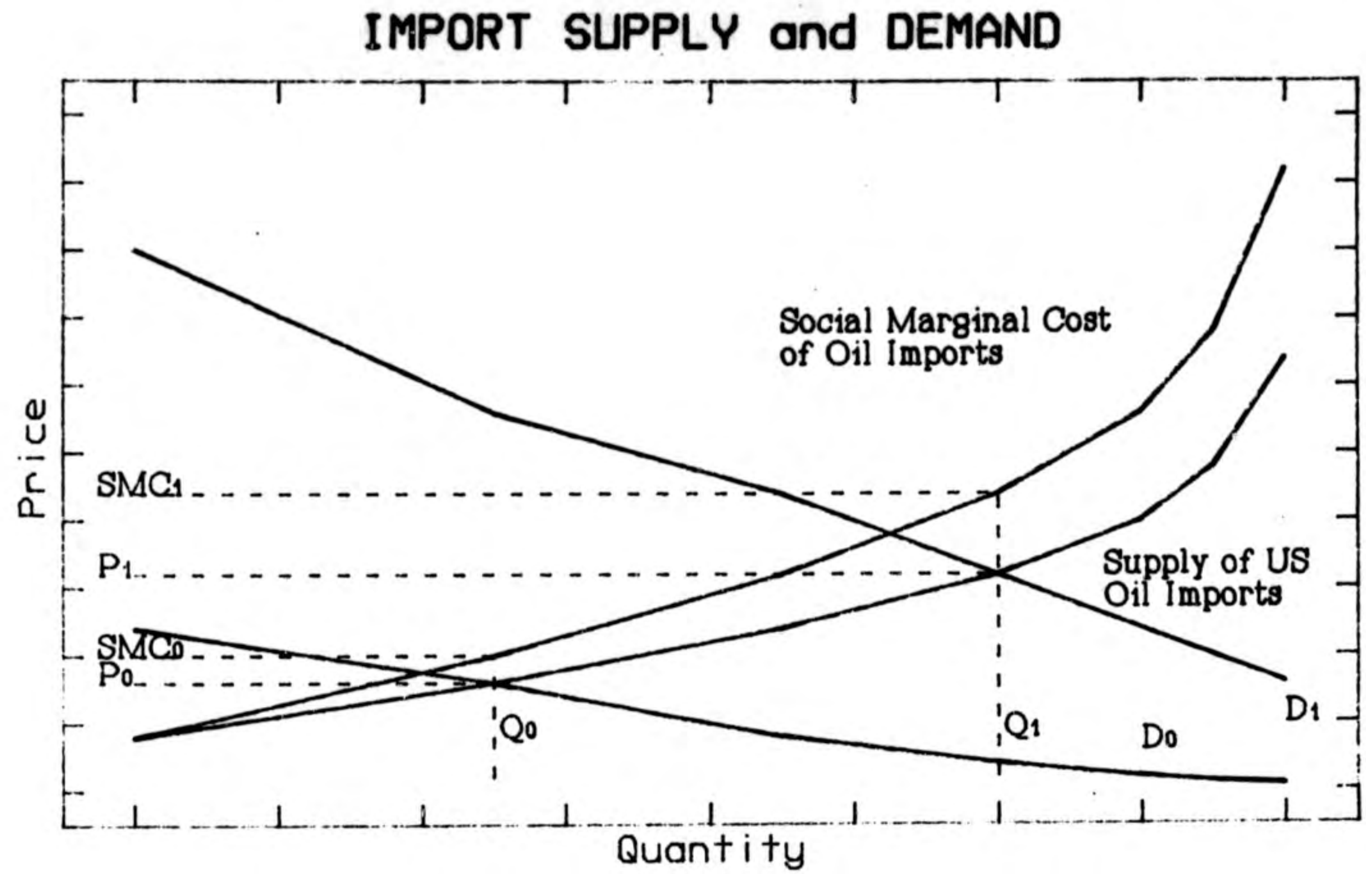
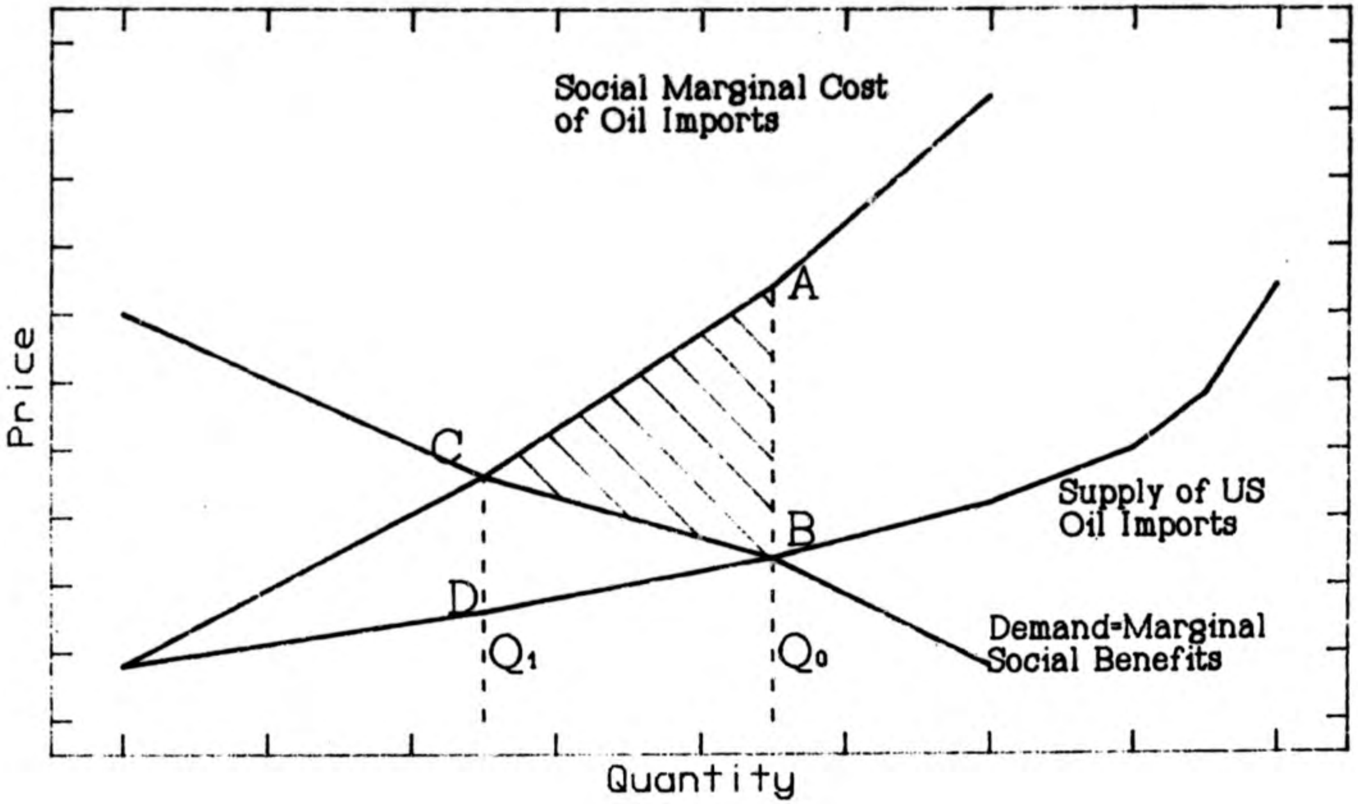


FIGURE 4

Optimal Tariff Balances Total Costs And Benefits

IMPORT SUPPLY and DEMAND



reduced towards Q_1, the difference between marginal social costs and marginal social benefits is reduced. Since at Q_1 the marginal social costs and marginal social benefits of imported oil are equal, the shaded area ABC reflects the total benefits, or avoided costs, of reducing oil imports from Q_0 to Q_1. An alternative interpretation of area ABC is that it depicts the total cost of a free market policy of consuming Q_0 barrels of imported oil. As we will show more fully below, in order to achieve a level of import reduction that results in Q_1 imports, a tariff the size of CD would be required.

In addition to the monopsony wedge element, there are two other elements that comprise the economic component of the oil import premium. The first is perhaps the most obvious. Changes in the price of a commodity like oil, so central to an industrial economy, will have a direct effect on the general price level, all other things equal. A long-run trend of rising (falling) oil prices will increase (reduce) the rate of inflation. To the extent that large reductions (increases) in GNP are needed to reduce (increase) inflation, purchases of imported oil generate "externalities"; that is to say, buyers of imported oil do not pay a price that recognizes that their purchases impose macroeconomic costs. The magnitude of these externalities depends on how oil import volumes and changes in oil prices affect the underlying, or "inertial," rate of inflation, and on the response to this inflation by macroeconomic policy makers.

If oil prices followed a smooth trend over time, then increases (or decreases) might be anticipated and incorporated in the underlying rate of inflation. Moreover, given full anticipation, there could be complete accom-

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security component of the premium.

modation by policy makers and thus no loss in aggregate output. But as we have seen, oil prices follow an erratic path, both up and down.[12] This means that only some of the price changes are incorporated into the underlying inflation rate and that policy makers can provide for only partial accommodation. As a result, some fraction of oil-induced increases in inflation is removed by deliberately constricting output in the economy; therefore, inevitably, "external" macroeconomic costs are associated with U.S. purchases of imported oil.

The other element of the economic component of the premium arises from effects created because changes in the relative price of imported oil result in transfers of wealth abroad. The specific consequence of higher oil imports will be a deterioration in the U.S. terms of trade. To maintain our trade balance in the face of an increase in the total payment for imported oil, either an increase in U.S. export earnings or a decrease in U.S. import expenditures on non-petroleum products would be required. Accordingly, the dollar exchange rate would adjust, making U.S. exports more competitive on the world market and imports more expensive for U.S. consumers. Since at equilibrium total imports available to the U.S. economy would be reduced and U.S. exports would increase, domestic consumers are made unambiguously worse off. The purchaser of the incremental barrel of imported oil does not fully consider this "terms of trade" effect, which is diffused across the economy.

The magnitude of this in terms of trade externality is determined by two factors. First, many of our major trading partners are also oil im-

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12 For an analysis of oil price paths and uncertainty, see William W. Hogan and Paul N. Leiby, "Oil Market Risk Analysis," EEPC Discussion Paper, Harvard University, December 1985.

porters. To the extent they are similarly affected by h.gher oil prices, the dollar exchange rate for their currencies will not change and that portion of our trade will not be affected. Second, the size of the externality will depend on how quickly the foreign dollar holdings of oil exporters are respent on U.S. goods and services, restoring the balance of trade.

The Security Component

At the most fundamental level, the security component of the premium reflects external costs that stem from sudden, unanticipated and large changes — in a word, disruptions — in the relative price of oil. For this analysis, it is important to think of disruptions in the world oil market not so much in terms of embargoes, production cutbacks, or other disturbances (such as wars and revolutions), but in terms of the price effects of these actions. We focus on disruptions created by price increases in a fully employed economy.

There are two elements of the security component. The first might best be thought of as reflecting the extent to which the economy is exposed, or vulnerable, to an increased transfer of wealth abroad and its attendant macroeconomic and trade balance costs. This vulnerability is directly a function of the volume of imports prior to a disruption. The larger the import level at the disruption's start, the greater the externalities associated with the wealth transfer for any given price rise. In measuring this vulnerability component, the uncertainties in the duration, timing, and intensity of prospective disruptions must be taken into account.

Whereas vulnerability to the wealth transfer effects is related to the importance of imported oil both in absolute terms and relative to our total oil supplies, the other element of the security component is a function of the importance of oil per se to the economy. The greater the value share of oil in the economy at the time of a disruption and the greater the economy's inability to shift quickly away from oil in the face of a change in its relative price, the greater the macroeconomic costs from the price shock. Empirical studies of previous oil price disruptions show quite clearly that these macroeconomic costs are substantial.[13]

To be sure, given these sizeable costs, private agents adjust their investment plans to disruption risks. Thus, investment decisions by households to purchase oil-using durable goods, and by firms to purchase oil-using equipment and processes, will incorporate — either implicitly or explicitly — expectations about the probability of a disruption occurring, about its magnitude and duration, and about the path that disrupted prices will take. This is because once such investments are made, a major alteration of oil consumption patterns due to a change in relative prices can be very costly. This suggests that in light of the tremendous volatility in oil prices a natural incentive exists for consumers and firms to select investments in oil-using goods and services that enhance flexibility in fuel usage; in economic terms, this means investing in a capital stock that makes the short-run demand for oil more elastic. An example of such an investment is a multi-fired boiler which allows for instantaneous fuel-switching.

The problem is, however, that an insufficient amount of these types of precautionary "shockproofing" investments is made from a societal perspective

13 Michael Bruno and Jeffrey Sachs, "Import Price Shocks and the Slowdown in Economic Growth: The Case of U.K. Manufacturing," Review of Economic Studies, vol. 49, no. 5 (1982):679-706.

and thus the short run demand for oil remains very inelastic. In part, this is because disruption costs are largely macroeconomic in nature and, as a result, the benefits of shockproofing are not appropriated solely by those making the investments. That is to say, these types of investments have "public good" characteristics.

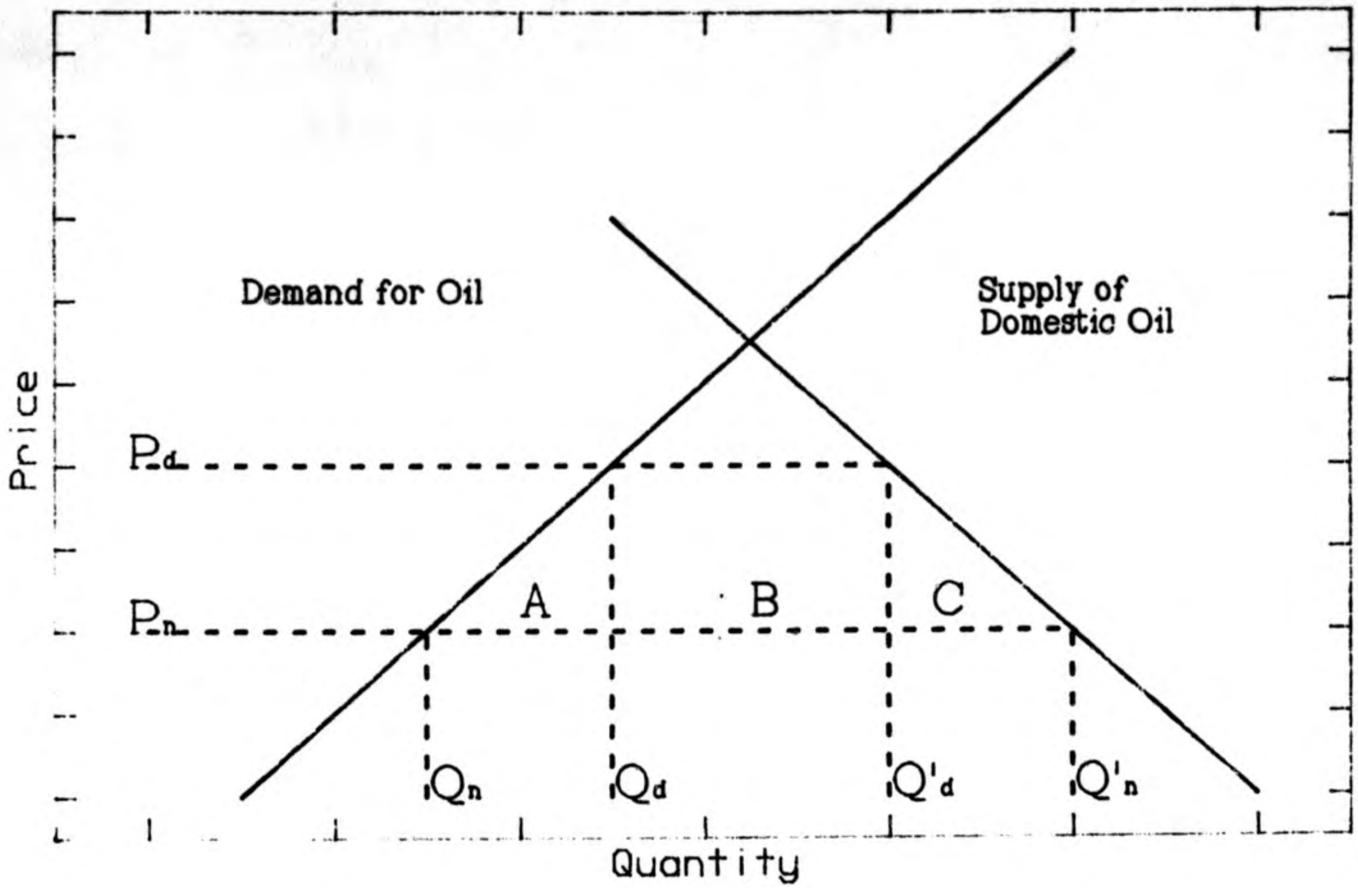
If there is one attribute common to the two elements of the security component, it is that the costs associated with oil supply disruptions arise because of the economy's failure to adjust smoothly to such price shocks. Empirical research on the macroeconomic effects of disruptions generally concludes that the costs of adjustment tend to increase disproportionately with the severity of disruptions and their duration.[14]

It is useful to illustrate graphically how in the aggregate a change in the relative price of oil in a disruption imposes costs on the economy. In Figure 5, P_N is the world oil price in "normal" periods, and P_D is the price during a disruption. At P_N, total U.S. oil consumption is Q_N', of which Q_N is supplied by domestic producers and $Q_N' - Q_N$ is imported. At P_D, total oil consumption falls to Q_D', domestic supplies increase to Q_D, and imports fall to $Q_D' - Q_D$. The total net social cost to the U.S. economy from the higher price is the sum of areas A, B, and C. Area C reflects a direct loss in our social surplus: the reduction in consumption of $Q_N' - Q_D$ barrels of oil means there is a decline in GNP corresponding to the value of goods and services that otherwise was being produced with that oil. Area A also reflects a GNP loss. It is a measure of the real resources the economy must transfer away from producing other goods and services to produce a commodity that is other-

14 See George Horwich and David Weimer, Oil Price Shocks, Market Response, and Contingency Planning (Washington, D.C.: American Enterprise Institute, 1984) for a review of the relevant studies.

FIGURE 5

Disruptions Create Real Costs and Wealth Transfers



wise cheaper to import. Area B reflects an increase in our oil import bill. For each of the $Q_D' - Q_D$ barrels of oil we import after the disruption, we must pay an extra $P_D - P_N$ dollars. Thus, Area B shows a transfer of wealth from U.S. oil consumers to foreign oil producers.

The Total Premium

As the preceding discussion shows, the magnitudes of the economic and the security components of the premium are both influenced by the level of oil imports. Therefore, the two components are interrelated. For example, if consumers and firms were to anticipate correctly the prospects for and the effects of a disruption, and incorporate these expectations into their investment decisions, the size of the security component would decline; however, as a result, normal period imports would also be reduced, reducing the magnitude of the economic component (recall that the gap between the marginal social. cost of oil imports and the market price varies directly with import volumes). To take a reverse example, imposing a tariff designed to exploit the monopsony-wedge element of the economic component will induce consumers and firms, now faced with higher oil prices, to reorient their investment plans in such a way that prospective disruption costs will be lower than they otherwise would be; consequently, the security component would be reduced.

The message here should be clear. The size of the total premium is not the simple sum of its individual components. Therefore, in estimating the magnitude of the total premium, the sizes of the various components should be determined simultaneously, taking into account the interactions and complementarities between them.

TOTAL COST ANALYSIS OF USING THE PREMIUM AS A POLICY INSTRUMENT

Using a simple comparative static framework, the aggregate implications of using the oil import premium as a guide for policy making are illustrated in Figure 6.

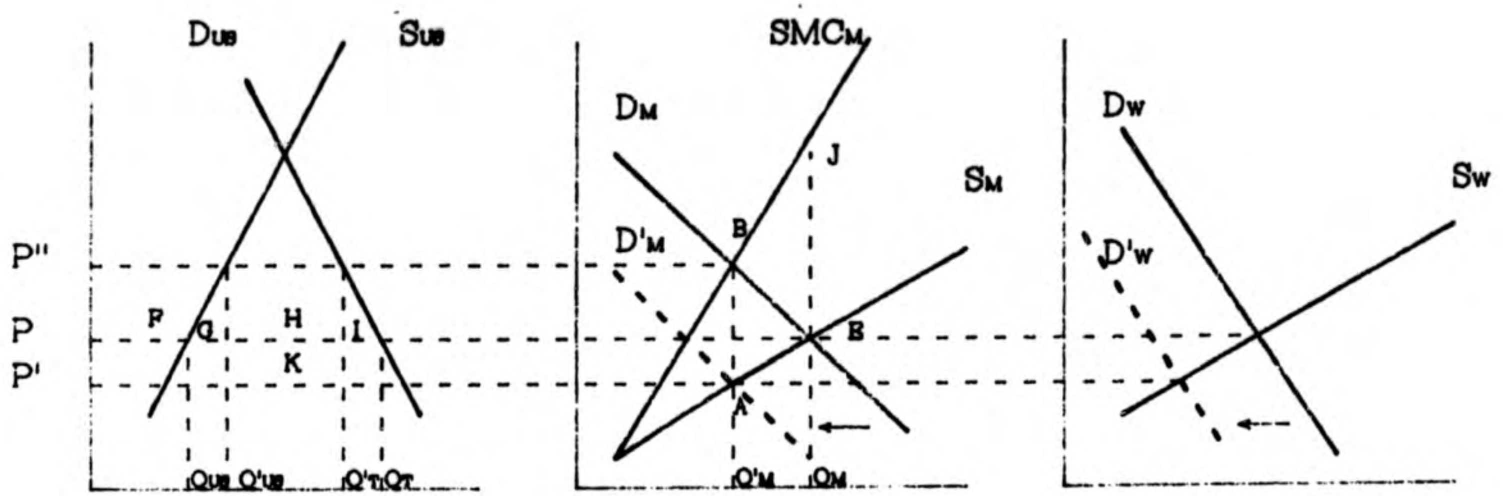
Three panels comprise Figure 6. The first depicts the total U.S. oil market; the second, the market for U.S. oil imports; and the third, the world oil market. The premium is illustrated in the second panel, where the social marginal cost of oil imports (SMC_M) exceeds the market price at an increasing rate as the quantity of oil imports supplied (S_M) rise. At a world price of P, U.S. production is Q_{US} and U.S. imports are $Q_T - Q_{US}$ in panel number I; note Q_M in Panel number II is equal to $Q_T - Q_{US}$. At Q_M level of imports, the premium is equal to the difference in height between J and E; in other words, at Q_M the social cost of the incremental barrel of oil imported into the United States is greater than the market price by J - E dollars. This means that at Q_M the United States is overconsuming imported oil.

One way to internalize this premium is to impose a tariff on imported oil, where the size of the tariff is equal to B - A. Implementing a tariff of this magnitude reduces U.S. demand for oil imports from D_M to D_M'. The decline in U.S. oil import demand results in lower demand in the world market and thus there is a reduction in the world price of oil from P to P'.[15] With a downward shift in U.S. oil import demand, the level of U.S. oil imports declines from Q_M to Q_M' in panel number II; this decline is equivalent to the difference between $[Q_T - Q_{US}]$ and $[Q_T' - Q_{US}']$ in panel number I. Domestic oil consumers now face of price of P" rather than P. It is important to note that this means that U.S. consumers do not bear the full burden of the tariff,

15 Note that in this simple analysis we assume oil exporters do not retaliate, say, by imposing an export tariff.

FIGURE 6

Total Cost Analysis of Oil Tariffs



I
Total US
Market

II
Net US
Import Market

III
World
Market

which is equal to $P'' - P'$. Oil exporters, on the other hand, no longer receive P, but rather P'; hence they share the burden of paying the tariff. As this demonstrates, <u>ex post</u> a tariff creates a wedge for the United States between the world price of oil (P') and the domestic price of oil (P'').

Let us be more specific about the distribution of the gains and losses. In panel number I the area denoted by F reflects the gain in "producer surplus"; it represents a transfer from U.S. consumers to U.S. oil producers and U.S suppliers of non-oil energy resources. (Note that some of the transfer accruing to domestic oil producers is actually returned to consumers under the Windfall Profits Tax.) Area G reflects the real resource costs of producing more domestic oil supplies and non-oil energy substitutes. Area I is a deadweight loss; it reflects the decline in social surplus associated with our reduction of oil consumption as a result of the tariff. The sum of areas H and K is the tariff revenues accruing to the United States Treasury. Area H is the portion directly paid by U.S. oil consumers. Area K is what oil exporters in effect pay: without the tariff, oil exporters would receive P dollars for each of the $Q'_T - Q'_{US}$ barrels of oil imported into the US; with the tariff, they receive only P' dollars. Note that although area K is what U.S. consumers actually pay to the Treasury (in addition to area H), because it is what otherwise would have been paid to oil exporters, it is in effect a tariff payment by the latter.

Overall, then, what are the social benefits and costs of pursuing such a policy? The costs to the United States are given by areas G and I; areas F and H are simply intra-country transfers. The benefits to the United States are given by area K, the effective subsidy provided to the Treasury by oil exporters.

To be sure, as this analysis shows, imposing a tax to correct for market imperfections is never costless. But to the extent that at the margin the benefits engendered are greater than the costs, there is little question about the soundness of such a policy. Thus, the objective for public policy is to select the optimally-sized tax, i.e., one that maximizes the net social benefits. In this particular example, the optimal tariff is one that maximizes the area [K - (G + I)].

III. ESTIMATION OF THE OPTIMAL U.S. OIL IMPORT TARIFF

Since the late 1970s, there have been a number of attempts to estimate quantitatively the magnitude of the premium on U.S. oil imports. Since a detailed review of the seventeen most prominent estimates is presented elsewhere,[16] only a brief summary is required here.

Previous estimates of the total premium span a wide range, from as low as $2.00 per barrel to as high as $124.00 per barrel. However, most of the analytically supportable estimates fall between $2.00 per barrel and $15.00 per barrel. In part, the high-end estimates reflect extreme assumptions about world oil market behavior or oil supply and demand parameters. To take an example of the former, several estimates are predicated on the assumption that changes in the demand for oil imports by the United States are matched by other oil-importing industrial countries; not surprisingly, this produces a rather large estimate of the economic component (because it magnifies the effect of the United States exercising its monopsony power.)

But the upward bias in some of the estimates is also due to a serious conceptual flaw, namely calculation of the total premium as the simple sum of its individual components, rather than incorporating some type of interaction effect. It should be noted that this weakness is not unique to the estimates at the high-end; in fact, most of the estimation methodologies have this problem.

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16 See Harry G. Broadman, "The Social Cost of Imported Oil," Energy Policy, June 1986. A new estimate is presented in Frederick M. Murphy et al., "An Integrated Analysis of U.S. Oil Security Policy," The Energy Journal, July 1986, pp. 67-82. See also Henry S. Rowen and John P. Weyant, "The Oil Price Collapse and Growing American Vulnerability," Working Paper, Stanford University, September 1986.

The foregoing analysis suggests that what is required to empirically calculate the premium correctly is a model that maximizes the expected net social benefits of oil imports for normal and disrupted periods and that allows for simultaneous estimation of the premium's individual components. To be sure, this is easier said than done, given the many uncertainties that exist about key parameters. For example, how should the behavior of oil exporting countries be characterized in such a model? Similarly, what assumptions should be made about the way U.S. energy and macroeconomic policy makers respond to oil price shocks? And, how should the responses of our oil importing allies be incorporated in such a model?

These problems notwithstanding, we have developed such a model, albeit a relatively simple one. A detailed description of its structure, assumptions made about its parameter values, and estimation procedure is contained in the appendix. Here we present a summary of the estimates obtained.

The basic model provides simultaneous estimates of the optimal tariff, prices, and oil import volumes. Since implementation of this model requires assumptions about a range of inputs whose values are uncertain, we first establish a base case of most likely values, and then examine modifications that seem of most interest in light of current oil market conditions. In short, we prepare sensitivity analyses to examine the likely range of alternative tariff estimates.

The first sensitivity analysis focuses on a base case and the implications of changes in prices. The second sensitivity test examines the importance of the security component by calculating the optimal tariff under the assumption of a secure world oil market with no threat of interruption. Finally, the uncertainties surrounding the full range of inputs enter in a risk analysis that calculates the probability distribution for the optimal tariff.

Estimating the optimal tariff requires assumptions about use of the SPR since the size of the optimal tariff depends on SPR drawdown policy during the interruption. Studies of the use of the SPR suggest both the complexity of an optimal drawdown policy in particular disruption scenarios and the wisdom of a general rule of thumb. If there is a reasonable possibility that a disruption will last for more than one year, then part of the SPR should be used immediately and part should be held for contingencies. Furthermore, given the value of the SPR for later emergencies, part of the disruption should be met with reductions in demand. Our rule of thumb for using the SPR is to draw it down to either meet half the total interruption or half the size of the reserve.

Calculating the optimal tariff allows us to measure the cost of a free market policy, i.e., the cost to the United States of ignoring the premium associated with our consumption of imported oil. As we noted earlier (Figure 4), since the premium measures the difference between price and social cost, the oil import supply curve plus the premium captures the full social cost of imported oil. We also noted that the demand curve measures the corresponding social value of imported oil. This means that once we know the optimal level of oil imports (and thus the optimal tariff), we can calculate the total cost that the economy bears at a market-determined level of oil imports.

BASE CASE

The base case includes nominal assumptions for each of the input parameters specified in the development of the model. The most likely values draw on the literature and the authors' judgment. These values provide the first estimate of the optimal tariff and the cost of a free market policy.

In addition to these parameters, the base case specifies the probability distribution for oil supply interruptions over possible interruption sizes. For purposes of the sensitivity analysis, we consider four different views of the probability of one-year long interruptions of 1 mmbd, 3 mmbd, and 6 mmbd for the United States. In Table 1, we characterize the decade probabilities of one or more such interruptions for each of these world views.

TABLE 1

DECADE PROBABILITIES

ONE YEAR INTERRUPTIONS[17]

World View	1 mmbd	3 mmbd	6 mmbd
W0	.0	.0	.0
W1	.50	.10	.05
W2	.75	.30	.05
W3	.95	.50	.20

Hence, under world view one (W1) there is a 50 percent chance of at least a 1 mmbd interruption to the United States. Since the United States would face only a portion of the world loss of supply, this corresponds to a loss of from 2 to 3 mmbd in the world. The chance of the very large interruption, 6 mmbd for the United States and 12 to 18 mmbd for the world is 5 percent over the same decade. This 5 percent probability over a decade is the same as predicting an average of one such large interruption every 200 years.

The last three world views correspond to increasingly pessimistic views of the likelihood of oil supply interruptions. The zero case (W0) pro-

17 Values correspond to disruption sizes before use of the SPR is taken into account.

vides a benchmark from which to separate disruption effects from the other constituents of the oil import premium. The nominal assumptions adopt world view two (W2).

HIGH PRICE

The combination of these base case assumptions produce estimates of the optimal tariff and the cost of a free market policy. Using a price of $27 per barrel to represent the high price case, estimates are:

Economic Tariff:	$ 3.25
Security Tariff:	$ 7.78
Combined Tariff:	$11.03/barrel

Cost of free market policy: $12.44 billion/year

LOW PRICE ESTIMATION

The first sensitivity test takes the base case parameters but changes the assumption for oil prices. Specifically, we assume that imports are supplied for $15 rather than $27 per barrel. Starting at this new price level, which implies that, under the model, the market is at a disequilibrium, we solve for the equilibrium levels where domestic demand, domestic supply and import supply balance. The solution produces a higher tariff and a higher cost of a free market policy:

Economic Tariff:	$ 5.48
Security Tariff:	$ 7.07
Combined Tariff:	$12.55/barrel

Cost of free market policy: $25.77 billion/year

The lower price increases demand, which in turn raises the expected level of imports, and increases the economic component of the premium more than it decreases the security component. Hence, although some of the costs are reduced with the lower oil price, under the base case assumptions the effect of lower oil prices is to raise the size of the optimal tariff.

SECURE IMPORTS

The estimate of the optimal tariff includes both economic and security components of the premium. Naturally a reduction in the risk of oil supply interruptions should have a beneficial effect for oil consumers and, thereby, lower the optimal tariff. However, as argued above, changes in the size of one element of the premium can change the size of the other elements. There is a feedback effect. The interaction may cause the various elements to shift so that the aggregate change in the optimal tariff is less than the change in its individual components.

The total optimal tariff under the condition of no oil supply interruptions is larger than the economic component of the tariff in the base case. With the high price case and the extreme assumption of no threat of supply interruptions, the estimate of the optimal tariff, and the cost of the free market policy, would change to:

Economic Tariff:	\$ 5.08
Security Tariff:	\$ 0.00
Combined Tariff:	\$ 5.08/barrel

Cost of free market policy: \$ 2.43 billion/year

It is clear that the simultaneity and complementarity between the economic and security components of the premium imply a significant optimal tariff even if security problems are eliminated.

RISK ANALYSIS ESTIMATION

These few sensitivity tests illustrate the principal responses of the optimal tariff calculation to changes in the input assumptions. The high and low oil price cases, or the secure world oil market scenario, produce changes in the estimate of the optimal tariff. However, the optimal tariff still continues to be a large fraction of the price of oil and large relative to any tariff that might be considered politically acceptable. Unfortunately, the few sensitivity tests do not exhaust the major uncertainties that could affect the size of the optimal tariff. Higher or lower assumptions about inflation could have a significant impact on both the quantity of oil imported and the estimate of the optimal tariff. Similarly, changes in elasticity estimates, alternative views about the probability of interruptions, or uncertainties in any of the other parameters could alter the optimal import tariff estimate.

It is not possible to examine all potential combinations of the long list of important input parameters. The number of scenarios would quickly exhaust our capacity to absorb the data. As an alternative, therefore, a "risk analysis" of the optimal tariff estimate captures a range of possible tariff policies that should be considered, given our uncertainty in the input parameters.

Under risk analysis, the analyst specifies the uncertainties in terms of probabilities for different values of the input parameters. For instance, we assume the most likely estimate of the aggregate demand elasticity is 0.5. This demand elasticity reflects the estimates from a variety of studies, some of which produce higher values and some of which produce lower values.[18] For

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18 See, for example, Douglas R. Bohi, Analyzing Demand

purposes of the sensitivity analysis, it is easy to argue that there is a significant chance that the elasticity could be as high as 0.7 or low as 0.3. A wider range is possible, but in our view highly unlikely: the principal range of uncertainty should be captured by these values. The probability that the elasticity will be as high as 0.7 or as low as 0.3 is not as great as the probability that the most likely case is correct. Using our judgment, we assign probabilities of 30 percent to the elasticity of 0.7, 50 percent to the elasticity of 0.5 and 20 percent to the elasticity of 0.3. A similar probabilistic analysis across the range of possible values for the other key inputs establishes a probability distribution for all of the uncertain parameters; see Figure A.1 in the Appendix.

Table 2 shows the probability included using this risk analysis and focusing on the key sensitivity test between low and high oil prices.

<u>Behavior: A Study of Energy Elasticities</u> (Baltimore: Resources for the Future/Johns Hopkins University Press, 1981).

TABLE 2

OPTIMAL TARIFF AND COST OF FREE MARKET POLICY PROBABILITY DISTRIBUTIONS

High price case ($27)

	Lower 25%	Median	Upper 25%	Expected Value
Economic Tariff	1.95	2.85	3.90	3.14
Security Tariff	3.63	5.64	8.52	6.44
COMBINED TARIFF ($ per barrel)	7.00	8.96	11.26	9.58
COST OF FREE MARKET POLICY ($billion/year)	4.64	8.24	13.18	10.60

Low price case ($15)

	Lower 25%	Median	Upper 25%	Expected Value
Economic Tariff	4.03	5.68	6.87	5.86
Security Tariff	2.80	4.20	6.65	5.23
COMBINED TARIFF ($ per barrel)	8.71	10.81	11.89	11.09
COST OF FREE MARKET POLICY ($billion/year)	11.72	17.90	27.93	22.44

SUMMARY

The optimal import tariff balances all the costs and benefits of oil imports. Although any operational estimate of the tariff will depend upon an array of assumptions and judgments, it is possible to make these judgments and organize them in an internally consistent set of calculations. These estimates quantify the several possible sources of market failure which prevent private actors from recognizing the true costs of the marginal barrel of oil imports. The resulting tariff estimates are sensitive to the assessment of market conditions, but this sensitivity appears to be much less than is commonly believed. There is a significant amount of interaction among the tariff components. A change in assumption which reduces one element tends to produce a compensating increase in others, and the whole is less sensitive than the parts.

This complementarity and the numerical results provide a guide for action. The size of the tariff is large. Our preferred set of assumptions sets the optimal tariff at between $10 and $11 per barrel. Under the High Price case, there is a 75 percent chance that the optimal tariff is at least $7 per barrel. And under the Low Price case, this estimate to an optimal tariff of at least $8.70 per barrel. When compared with the usual political discussions, where an adventuresome conversation involves tariffs that are half this range, the direction of policy is clear: higher tariffs can be justified. Based on the estimates of market failure, a figure in the range of $7 per barrel and $9 per barrel is as low as can be supported by the analysis and the judgments on the range of uncertainty in the parameters.

IV. POLICY ISSUES

COMPARISON OF TARIFF INSTRUMENTS

The form of a U.S. tariff on imported oil could vary across a range of alternatives. Several issues should be discussed in this regard. Perhaps the most important is whether the tariff should be set as (i) a simple fixed fee, (ii) a variable fee, or (iii) a fee defined in proportion to the price of oil. Other issues having to do with the form of a tariff concern the relationship between crude and product tariffs and adjusting the magnitude of a tariff to changes in the general price level.

Fixed versus Variable versus Ad Valorem Tariffs

A fixed tariff is the simplest instrument. Given a political decision on the optimal level of oil imports and the optimal tariff, we establish a fixed price as the tariff, say $10 per barrel. Each purchaser of a barrel of imported oil pays a $10 fee in addition to the price. If the price of oil goes up or down, the tariff stays the same. Hence, as a percentage of the price of oil, the tariff will vary as the price of oil varies. However, the tariff is simple to understand and explain and, with the reasonable estimation of the size of the tariff, can capture most of the long run benefits.

The principal alternative to a fixed dollar amount is a fixed percentage tariff. Here the tariff might be set as 60 percent of the price of oil. If the price of oil rises, the absolute value of the tariff would increase. And as the price of oil fell, the absolute value of the tariff would fall. The chief advantage of the fixed percentage tariff, sometimes known as the *ad valorem* tariff, is in preserving the incentives for foreign oil producers. Faced with a constant percentage tariff, producers would not see any incentive to raise the price of oil, because this would raise the tariff and more than proportionately decrease demand. Conversely, lowering the price of oil would lower the absolute tariff and compensate for the lost revenue by increasing demand more than proportionally than the tariff change.

Although the long run incentives are right for the ad valorem tariff, it carries with it a special problem during interruptions.[19] In the face of a sudden loss of supply, with a sharp increase in price, the optimal short-run policy would be to reduce or eliminate the tariff. Yet it is difficult to imagine the administrative system responding rapidly enough to adjust the size of a tariff during an interruption. The danger of the ad valorem tariff is that we would see an automatic increase in the size of the tariff at just the time when such change would do the greatest macroeconomic damage. Compared to the fixed tariff, therefore, the ad valorem tariff does a poor job of approximating the optimal policy during interruptions. Furthermore, our sensitivity analysis suggests that the size of the optimal tariff, although not constant in real dollar terms, is far from constant in percentage terms. As a simplified approximation to the sensitivity analysis of different oil prices, therefore, we conclude that the fixed tariff would be preferred to the ad valorem tariff.

A third variant of the type of tariff often proposed is to create what is known as a "variable" tariff that sets a target price for domestic oil.[20] By

19 Note the change in argument from William W. Hogan, "Import Management and Oil Emergencies," in Energy and Security, David Deese and Joseph S. Nye, eds., (Cambridge, MA: Ballinger, 1981); and William W. Hogan, "Oil Gluts and Oil Tariffs," Discussion Paper #H-82-04 (Cambridge, MA: Energy and Environmental Policy Center, May 1982), which neglected the problems of the different tariff instruments during an interruption.

20 The case for the variable tariff appears in S. Fred Singer, "The Case for a Variable Import Fee on Oil,"

this argument, there is an optimal domestic price, say $25 per barrel, which will provide adequate development of domestic supply and provide some protection against insecure imports. The tariff would be set at the difference between this target price and the world price. Hence, if the price of oil is $15 on the world market, and the target price is $25, then the tariff would be set at $10. If the world price rose to $20, the tariff would fall by $5, and so on.

Although this proposal has an appeal if the purpose of the tariff is to protect domestic suppliers and guarantee them a minimum price, it is inconsistent with the general argument about externalities of oil imports developed in this paper. The problem is not any particular level of domestic supply; the problem is to internalize the costs of oil imports. As our sensitivity analyses show, this externality or optimal premium for oil imports does not fall dramatically as prices rise, nor does it rise dramatically as prices fall. Hence the variable tariff as proposed, with the price threshold, works only when prices are well below the threshold.

The second difficulty with the variable tariff is in deciding on the optimal threshold. There is no framework for selecting the tariff except that provided by a view of promoting or protecting domestic suppliers. With the optimal tariff framework, however, protection of domestic suppliers is incidental to the analysis, not the direct purpose.

A third difficulty with the variable tariff is the perverse incentive provided to oil suppliers in the world market. To the extent that foreign producers can manipulate the market in order to extract higher rents, the var-

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Georgetown University Center for Strategic and International Studies, June 1986.

iable tariff guarantees no penalty for raising prices. Higher world prices result only in a reduction in the size of the tariff, not in a reduction in the price paid by the domestic market. Hence, higher world prices result in no reduction in demand by the United States. To the extent that this protection of the market removes the constraints on producers, it tends to promote and subsidize higher world oil prices for all customers. The incentives, therefore, work exactly against the reduction of cost for the United States. Despite the simplicity of its preference for domestic production, the variable tariff works at the margin to reduce the welfare of the United States. Depending upon the final reaction of foreign oil producers, and the aggregate size of the tariff, therefore, the variable tariff may provide significantly lower benefits than the ad valorem or fixed fee alternatives.

On balance, therefore, the simplest and most straightforward approach is to levy a fixed fee on each barrel of imported oil. This provides approximately the right incentives at the margin, provides the closest simple approximation to the optimal tariff calculations revealed by our sensitivity analyses, and avoids the difficulties of managing the macroeconomic costs during an interruption.

Product Tariffs and Inflationary Adjustments

Of course, even this approach is not without its details that gradually erode the simplicity of the concept. For example, in a world of high inflation, the fixed tariff should be set in real terms, indexed to adjust with the level of inflation. Furthermore, a tariff on crude oil implies the necessity for a corresponding tariff on imported products. The tariff on products should reflect the increased costs of crude oil to avoid creating incentives for importers to switch from crude to products but not change the total volume of oil imports. Hence, the product tariff should reflect the increase in crude oil costs implied by the crude oil tariff. These and other modifications would be found in any real tariff proposal, but the basic arguments remain. The fixed fee appears to be the best combination of simplicity and close approximation of the optimal tariff policy.

TARIFFS AND FREE TRADE

The struggle to reduce trade barriers and promote world economic growth through expanded trade flows has been a hallmark of modern economic policy. Despite the many continuing barriers to trade, the presumption in favor of free trade has been a central component of official rhetoric. Practical experience with excessive trade limits and the theoretical arguments of comparative advantage all point to the economic benefits available through expanded trade.[21] It follows, therefore, that any argument for a U.S. oil tariff must bear a heavy burden of proof:

> "A majority of economists have consistently favored letting nations trade freely with few tariffs or other barriers to trade. Indeed, economists have tended to be even more critical of trade barriers than have other groups in society, even though economists have taken great care to list the exceptional cases in which they feel trade barriers can be justified. Such consistent agreement is rare within the economics profession."[22]

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21 For a review of the unhappy history of general trade restrictions and the theory of economy health through free trade, see any of the standard texts, e.g., Peter H. Lindert and Charles P. Kindleberger, International Economics, Richard D. Irwin Company, Homewood, Illinois, (7th edition), 1982; or R. E. Caves, World Trade and Payments, Little, Brown and Company, Boston 1981.

22 Peter H. Lindert and Charles P. Kindleberger, International Economics, Richard D. Irwin Company, Homewood, Illinois, (7th edition), 1982, p.111

Despite the nearly universal assumption in favor of free trade, theorists in international economics have long recognized that exceptions to the rule of free trade may exist for particular commodities and countries. The subject of the 'optimal tariff' has a long history:

"The theoretical literature on this subject is vast, and the lineage is ancient."[23]

Although aggregate world economic welfare may be lessened by tariffs or other trade restrictions, the welfare of an individual country may be expanded through the pursuit of such policies. The exceptions are unusual and depend on a number of special circumstances, but the exceptions are an integral part of the theory of international trade. They center on the existence of market imperfections such as externalities and monopolistic or monopsonistic market structures. When such imperfections exist, uninhibited trade may not maximize the welfare of the country. Hence there can be an unrecognized cost of following a free market trade policy. Intervention in the market to restrict trade could lower or eliminate these costs.

Examples of such imperfections in the literature on international trade are many, including everything from arguments for protecting the development of infant or strategic industries to the use of trade restrictions to compensate for market distortions created by the actions of other countries. In fact, arguments in support of free trade build on the notion that if one country restricts trade in a particular commodity then other countries can be expected to respond. If the market is not operating according to the competitive ideal, an opportunity is created for individual countries to increase their aggregate economic welfare by intervening in the free trade of that com-

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23 W. M. Corden, Trade Policy and Economic Warfare, Clarendon Press, Oxford, 1978, p. 159.

modity.

Notable in the international trade literature is that the principal example of an exception to the rule of free trade is the case of oil. Oil markets have violated the general proposition that producers acting collectively cannot long restrict output and capture significant rents. By now, standard international trade texts cite oil as the principal commodity where a tariff may well be in the interest of the consuming countries. For example, Lindert and Kindleberger argue that

> "OPEC has gained far more than John D. Rockefeller's Standard Oil Company or any other monopoly or cartel ever did. This judgment would stand even if OPEC were to break up tomorrow and start slashing its prices competitively."[24]

> "No other cartel has yet approached the resounding success of OPEC. Before OPEC, the average life expectancy of cartels had been so short that the economic analysis of cartels tended to stress the inevitability of their collapse. The usual analysis has correctly pointed to pressures that tend to make cartel power erode, as some cartel members defect and turn competitive and as some buyers find ways of avoiding purchases from the cartel. One of the central tasks of international economics is to reconcile this presumption that cartels inevitably fail with OPEC's continuing success."[25]

> "If the United States could force the members of the OPEC oil cartel or some other potentially hostile foreign suppliers to sell at a lower price by imposing a tariff, then the tariff is in the U.S. national interest."[26]

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24 Peter H. Lindert and Charles P. Kindleberger, International Economics, Richard D. Irwin Company, Homewood, Illinois, (7th edition), 1982, p.6

25 Peter H. Lindert and Charles P. Kindleberger, International Economics, Richard D. Irwin Company, Homewood, Illinois, (7th edition), 1982, p.190

26 Peter H. Lindert and Charles P. Kindleberger, International Economics, Richard D. Irwin Company, Homewood, Illinois, (7th edition), 1982, p.150

Clearly, the received literature recognizes that an opportunity may exist for a welfare-improving tariff on U.S. oil imports. Still, the pursuit of such a policy requires greater justification. What characteristics, more or less unique to oil and oil markets, warrant departure from the economists' preference for free trade? First, as we have argued above, oil is an important enough commodity to affect our balance of trade, the path of inflation, and if supply is interrupted, the welfare of our citizens and our national security. For the past decade, oil has constituted about 26 percent by value of imports, and total consumption of oil and closely related products amounted to about 9 percent of GNP.[27] Second, as the premium analysis demonstrates, significant externalities are associated with the importation of oil. If the price of imported oil reflected true social costs, there might be no need for government to intervene in the market. But as we have seen, the (private) price and the social cost of imported oil differ. The larger this difference, the greater the cost of the current free market policy in U.S. oil trade. The greater the cost of this policy, the more compelling the case for intervention through the imposition of an oil tariff.

TARIFFS AND THE LIMITS OF POLICY

Even accepting the special nature of the oil market, objections to a U.S. oil tariff may flow from conflicting policy goals, criticism that the market analysis is overly simplistic, or practical political limitations. The principal objections fall into three general categories: (i) oil market imperfections are relatively small and, therefore, there is no significant saving

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27 U.S. Department of Energy, Annual Energy Review, various years.

by trying to correct them; (ii) other trading arrangements will be compromised and, therefore, there are costs created elsewhere despite gains in the oil market; and (iii) government programs to intervene in a market often go awry and an oil tariff will be part of this pattern, i.e., such a tariff will produce more costs than benefits.

Each of these arguments has merit. The first, dealing with the measurement of market imperfections, is the subject of much of this paper. The bulk of our analysis points to significant imperfections and large external costs associated with the current U.S. free trade policy in oil. However, to the extent that there is disagreement with these estimates, a demanding standard is created for the objectors, given the robustness of our results. While there is room for debate here, the strongest case against a U.S. oil tariff lies elsewhere.

The second objection emphasizes linkages between U.S. oil trade policy and U.S. trade policy in general. Even if there are significant market imperfections associated with oil imports, opponents of a U.S. oil tariff argue that adoption of such a tariff would trigger a reaction in the trade policies of other countries. Foreign oil producers will respond by lowering production and raising prices, despite falling demand, and traders in other goods will use the precedent of a U.S. oil tariff to support similar restrictions on, for example, lumber, computers or automobiles.

"The orthodox optimal trade argument is concerned about maximizing national income; world income as a whole is reduced, but at the same time is redistributed towards the trade-restricting country... The simple model assumes that foreign tariffs are given and that foreign governments will happily stand by and allow income to be redistributed against them... one might assume that if our country does not impose a tariff the foreign country will not do so either, but that the adoption of orthodox optimum tariff policy by us will provoke foreigners to embark on the same policy. Thus we we would start with free trade, and once we abandon it

> would provoke the reaction process...There is an element of 'retaliation', the foreign country retaliating by initiating the reaction process."[28]

There is a danger here. If oil trade policy has a significant effect on all trade policies, then the cost of the current U.S. free market policy in oil may be the price we have to pay for free trade in other goods. A few of our oil trading partners have substantial additional trade with us. For example, a large percentage of U.S. non-oil imports come from Canada. If this trade would be adversely affected by a tariff on oil imports, then the linkage may be important. In this case, there will be pressures for exemptions from the tariff for certain producers.

If foreign oil producers respond to shrinking markets by raising prices or retaliating in other ways, then our oil trade policy faces still another market imperfection that may balance the cost calculations of a free market policy discussed above. Such a response by foreign oil producers has been suggested:

> "Such a vociferous demand for the imposition of trade restrictions, on account of low prices, as is currently prevalent, could constitute an invitation to producers to raise prices again, to restore them to their former levels."[29]

But to the extent that use of an oil U.S. tariff can be made to be seen only as a response to the initial restrictions on oil trade by foreign producers and the special instability of world oil supplies, and U.S. oil trade

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28 W. M. Corden, Trade Policy and Economic Warfare, Clarendon Press, Oxford, 1978, p. 172-173. (emphasis in the original)

29 Ahmed Zaki Yamani, "Oil Markets, Past Present and Future", speech delivered at Harvard University, Energy and Environmental Policy Center Symposium in conjunction with the 350th Anniversary celebrations, September 4, 1986.

policy can be separated from other U.S. trade decisions, then the argument for a tariff based on measured external costs should prevail. The determination of whether such a separation of oil trade policy from general trade policy can be achieved involves a largely subjective judgment and one that is crucial to choosing the correct U.S. policy toward oil imports. But the danger of adverse consequences in other markets, even it it materializes, does not dispose of the argument for an oil tariff. Such a reaction is merely one of the costs of an oil tariff, to be weighed against its benefits.

The final, and oft repeated, criticism of an oil tariff raises the specter of policy implementation that falls far short of the lofty ideals of policy design. As we discuss more fully below, an oil tariff would have a significant impact on the economy. There would be wealth transfers from domestic consumers to domestic producers of oil. Industries dependent on oil as a feedstock would face higher costs and more difficult competitive pressures in the world market. Each of these affected groups could be expected to ask for special consideration. There would also be requests for tariff exemptions for particular oil suppliers, especially secure suppliers in the Western Hemisphere.

In general, the more exceptions, the less the negative impact of a tariff. But, too, the more exceptions the less the economic saving produced by a tariff. The induced adjustments in consumption and production are the source of the economic benefits of a tariff and, therefore, any policy which exempts consumers and producers from making adjustments will correspondingly reduce these savings.

From a strongly ideological perspective, these arguments about the pressures for exemptions and exceptions generalize into a presumption that the bureaucratic detail of a tariff will create too many opportunities for special interests — in other words, government cannot implement such a policy without causing more harm than good. Or the intervention now will create a precedent for other interventions later, repeating the drama of the mid 1970s when price controls subsidized oil imports. Although there is certainly truth to the position that the tariff instrument actually employed would not match the pristine ideal suggested by our analysis, this judgment must be tempered in part by size of the optimal tariff and the magnitude of the savings from avoiding a free market policy. If the optimal tariff is large and the savings are significant, then a less than perfect implementation should still produce net economic benefits.

Nevertheless, the possibility of extensive exemptions and exceptions raises a significant problem. Our analysis of the optimal tariff assumes these special appeals will go unheeded.[30] A large number of exemptions and exceptions or a very small tariff, would result in little gain for the economy as a whole. In that case, the fear of the costs of the impact of such a precedent on broader trade policy might carry the day. The challenge is to implement a tariff without avoiding the economic adjustments that a tariff is intended to achieve. If by assumption this adjustment process is simply too hard in the real world of the politics of special interests, then by assumption the tariff is a bad policy.

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30 Any exemption program involves a transfer of rents which may reduce the overall welfare of the nation. But it is possible to design the exemptions to preserve most of the incentives at the margin, thereby preserving the benefits of lower exposure to macroeconomic problems and oil supply interruptions. The key feature would be to limit the exemptions to inframarginal oil imports.

COSTS AND BENEFITS

The most obvious effect of an oil tariff would be to raise the price of oil to domestic consumers. How could an increase in the price of an important product result in a net economic benefit for the country as a whole? This is a reasonable question and a major obstacle to those who argue in favor of an oil tariff. In addition to raising the cost of oil to domestic consumers, an oil tariff could produce major shifts in income flow between consumers and oil producers, both domestic and abroad. These major transfers could be significantly larger than the aggregate change in the total cost for the economy. Recognizing these effects, it is important nevertheless to separate out the real resource costs from the change in the wealth position of different groups in the economy.

Domestic Distribution

The market imperfections reflected by the oil import premium create real resource costs. Higher levels of inflation, greater economic disruptions, and so on, are economic factors that have a significant impact on the general economic well-being of the country. However, almost by definition, these imperfections are invisible to the individual consumer. The consumer sees the price paid directly for the oil but does not see the impact on macroeconomic performance or changes in the overall costs of oil supply interruptions. If the consumer did see these costs, they would be internalized, and then there would be no premium. Hence, any argument for market intervention and a reduction in total cost through the use of a tariff is inherently involved in the trade-off between the visible cost of the price paid for the oil and the invisible but real costs of the premium.

The import premium framework takes the perspective of maximizing the economic benefit to the nation as a whole and recognizes that an increase in the price of oil from imposing a tariff has several effects. The price increase has the direct effect of reducing the economic welfare of the ultimate consumer. There is a transfer payment to domestic oil producers which increases their economic welfare. And there is a macroeconomic effect wherein output is expanded and the balance of trade is improved, both to the benefit of producers and as well as consumers. Our calculation of the optimal tariff suggests that the direct cost to consumers is less than the direct benefit to producers plus the indirect benefit to the economy as a whole. As members of the larger economy, consumers enjoy the indirect benefits. To the extent that consumers are beneficiaries of the higher profits of the oil industry, either through their role as taxpayers — the higher profits flowing to the government in increased tax payments — or through their ownership position (either directly or through intermediate vehicles such as pension systems), consumers receive the benefits that flow to producers. In the aggregate, of course, producers and consumers are the same people. Hence the transfer payments net out and the increase and the indirect benefit of moving from the free market policy expands the economic welfare of the nation as a whole.

In our estimation of the optimal premium we calculate this indirect benefit, the difference between the social and private costs of imported oil at the margin. On average, the costs for oil imports will be significantly lower than the calculation at the margin. Hence, in estimating the total net benefit of abandoning a free market oil import policy, the analysis must account for changes in the optimal premium at different levels of oil imports. Our calculations suggest that the aggregate benefit to the economy of imposing the optimal tariff could be substantial. In the high price case, i.e., at $27 a barrel, when oil imports are relatively low, the benefits of moving to the

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optimal tariff are approximately $12 billion dollars per year. In the low price case, i.e., at $15 a barrel, when oil imports tend to be high, the benefits of the optimal policy are about $26 billion dollars per year. Hence, by imposing the optimal tariff, the United States will realize a savings that is one-third to one-half of the expenditures it makes on imported oil.

<u>International Distribution</u>

Imposing the optimal oil import tariff increases the net economic welfare of the United States. Part of the increase in welfare comes from the improvement of the performance of the macroeconomy during normal times and during interruptions. The tariff, by inducing lower oil imports, lessens the impact of higher oil prices and thereby avoids the pressures to maintain a depressed economy in order to wring out the pressures of inflation. Similarly, reducing oil imports in advance of an interruption lowers the impact of the disruption with the attendant economic recession that imposes such great costs on the nation.

These macroeconomic savings are a straight plus. The benefits accrue to the United States, but they <u>do not</u> come at the expense of other nations. The improved U.S. economic performance flows a more efficient and fuller use of our capital stock and labor force, and this improved performance can only help bolster general economic health in the world. Hence, the avoidance of the costs of disruptions is a positive sum game.

Of course, not all the benefits flow with no costs to others. A significant part of the savings from a tariff comes from a reduction in the payments to oil exporters. In short, both the lower volume of purchases and the expected reduction in the world price contribute to the reduction in total cost to the United States, but at the expense of oil exporters. For many oil exporters, their share in the reduced oil market, at lower prices, will present a significant economic problem. From one perspective, these losses represent only a twist in the competition for economic rents. After all, major exporters are interfering in the market by constraining production and inflating the world price of oil. The rents they would be losing are only the profits of their oligopolistic game. Consumers merely play the same game in the use of a tariff to constrain demand and depress the world price. Morality and fair play provide little guidance in the economic competition for rents. If the ability to exercise market power exists and is used by others, why not shift the losses back on the exporters restricting production?

However, given the broad interests of the United States in dealing with many of the oil exporting countries, ranging from Saudi Arabia to Mexico or even Canada, these losses may be unacceptable. If this is true, then the high payments to oil exporters must be viewed as a benefit to the United States. Or at least the cost must be justified, much like other defense or foreign aid expenditures, as worth the pursuit of larger goals and values. In this case, much as with the support for subsidizing domestic consumers, it might be better to make these payments an explicit part of our foreign policy rather than support the inefficient use of oil imports.

The international redistribution of wealth does not stop with oil exporters. Other importers of oil share in the costs paid by U.S. consumers. The higher the level of oil imports in one country, the greater the cost everywhere. Hence, the Europeans and Japanese are paying the cost of part of our oil imports, and we are paying the cost of part of their oil imports. If the United States imposes an oil import tariff, and reduces its demand, prices will fall for all oil importers. Hence Europe and Japan will enjoy a free ride on our account. This fact has often inhibited progress in capturing the benefits of reduced oil imports. Apparently out of a sense of fair sharing of the burden, there have been arguments that the United States should not further reduce its imports without comparable action by other oil importers. But with cooperation among oil importers, our analysis would support an even larger tariff. A combined oil-importer tariff may well be twice as high as calculated above. However, because of a lack of agreement, no such action is possible, at least at present.

Although it is easy to understand the motivation for resenting the free riders, it is wrong to conclude that we should do nothing without a sharing of the burden. Our analysis of the optimal oil import tariff assumes that the United States acts alone. If it is in our interests to reduce our oil imports, it should not concern us that it helps others as well. In fact, since the other major oil importers are our allies in many other respects, we might veiw their free ride as an added benefit of our oil import reductions.

For those who fear that we might go too far in imposing an oil import tariff, an analysis of the effects of tariff policies in other countries only reinforces the analysis here. As shown in elsewhere,[31] oil import tariffs in other countries tend to decrease the world price of oil and, therefore, to increase the demand for oil in the United States. Hence, the larger the tariff in other oil importing countries, the larger the optimal tariff for the United States. Consideration of the interactions with other oil importers only raises the estimate of the optimal tariff already at the bounds of political possibility. Hence the fact that other consumers gain something should not stand in the way of the pursuit of the optimum U.S. policy.

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31 H.P. Chao and S. Peck, "Coordination of OECD Oil Import Policies: A Gaming Approach," Electric Power Research Institute, 1980.

Of course, it should be pointed out that many of our allies already have in place price instruments which reduce significantly their oil consumption, for example, steep gasoline consumption taxes. In this regard, they are ahead of any U.S. policy that imposes a tariff on imported oil.

Other Oil Reduction Policies

Given the existence of the premium, to the extent that the actual tariff falls short of the optimal level, there is room for additional policies to reduce the demand for imported oil.[32] Conservation regulations, such as the automobile efficiency standards, or domestic subsidies for production of new (non-oil) energy technologies, may well be justified. To the extent that oil demand reductions or non-oil supply expansions cost less than the market price plus the premium, there is a case for government intervention to promote reduced oil import demand. The most direct route would be through the tariff, but to the extent that politics and institutions block the way, other approaches should be pursued, to the extent that they are demonstrably cost effective.

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32 This discussion assumes the existence of an optimally-sized SPR, i.e., one devised in line with the premium.

V. IMPLEMENTATION ISSUES

Whatever tariff instrument is selected by the Congress and the President, there will be a variety of issues related to the best way to implement it. The most directly affected parties will raise a large number of questions in this regard. In an effort to anticipate these questions, we review the principal issues: the effect of a tariff on the U.S. competitive position, exemptions, transition costs, and use of the collected revenues.

COMPETITIVE POSITION

The most energy- and oil-intensive industries in the United States will face increased raw material costs following the imposition of a tariff. For example, petrochemical plants which depend upon oil as a primary feedstock will see a significant increase in the costs of their inputs. The increase in costs will reduce or eliminate any competitive advantage that these companies have in the international market. If producers of the same petrochemical products in other countries do not face a similar tariff, then they can sell their products at prices that will be lower than those that could be charged by U.S. petrochemical producers.

This evident fact will be characterized as a loss of competitive position for the United States. While true, the description of this as a "loss of competitive position" disguises the true problem. If these oil-intensive industries are now purchasing oil and paying a private cost which is less than the social cost, then the difference, — the oil import premium — amounts to a subsidy from society as a whole to this particular industry. In short, if a company is buying oil at $15 and producing products which are competitive at $15, but the cost to the country for the same oil is $20 or $25, then this is a bad business for the nation as a whole.

In the process of internalizing the external social costs, the country will reduce the use of crude oil and related products. This will come in part because goods and services produced with those products are not worth the cost that has been internalized. As painful as this will be for the industries that need to adjust, the adjustment is part of the problem of eliminating the subsidy and lowering the total cost to society. Hence, proposals for granting exceptions for U.S. manufacturing exporters who face suddenly higher crude oil costs amount to no more than a request that the implicit subsidies for those exports now be made explicit. As a matter of national policy the country may decide to continue these subsidies. But it is better to make these subsidies explicit for the targeted industries rather than to continue the subsidies for all.

EXEMPTIONS FOR FOREIGN SUPPLIERS

U. S. oil imports come from a variety of sources. Not all sources of supply are equally vulnerable to disruption. Furthermore, many oil producing countries are our allies and depend heavily on oil revenues. It stands to reason, therefore, that there will be proposals to exempt certain sources from paying an import tariff to the United States. These separate arguments, the difference in supply security among foreign oil producers and the economic interests of these producers, have separate implications for the design of a U.S. oil tariff.

The differences in supply security matter relatively little. Oil is a fungible good. Hence, the particular source of supply to the United States has little impact on the cost or security of oil imports at the margin. Even if the United States had no direct imports from unstable sources of supply, and all imports came from countries which would continue to produce no matter what the state of the market, the problem of security would remain. During an oil supply interruption the oil produced in secure countries would be diverted to other countries to replace oil lost as a result of the disruption. At the margin, therefore, all sources of supply in world trade can be thought of as subject to the same security risk. Hence, from the security perspective, all sources of supply should be subject to the same import tariff.

Although the security argument cuts against exempting certain suppliers from an oil tariff, the economic rent transfer argument could work the other way. To the extent that oil prices drop as a result of a fall in U.S. consumption, induced by a tariff, all oil in world trade would be affected by the imposition of a tariff. This transfer of wealth, in fact, is part of the gain for the United States. For many producers, this transfer of wealth could be significant, and it could create problems for the United States.

The effect of granting certain oil producing countries an exemption would be to transfer income from the United States to these countries. Foreign oil suppliers exempted from the tariff become similar to domestic oil suppliers.

Foreign suppliers favored with tariff-exempt oil would see the value and the price of that oil in the U. S. market rise to include the world price plus the tariff. Hence, just as domestic oil producers would enjoy higher prices and a transfer of wealth, so, too, would the exempt supplier to the import market. Since part of this transfer has been counted as a net gain to the United States, it is clear that any exemptions alter the calculation of the optimal tariff.

From one perspective, if we think of the transfer to the favored foreign supplier as a cost to the United States, the exemption reduces the benefits of a tariff and correspondingly lowers the size of the optimal tariff. On the other hand, presumably the reason for the exemption is to transfer a benefit to the foreign supplier. In this case, the exemption is similar to starting with a lower assumed level of oil imports. In either case, however, the net effect of the exemption is to reduce the size of the optimal oil tariff. In the extreme case, where the exemptions are so large as to replace all oil imports, the tariff is ineffective. With smaller, inframarginal exemptions, there would be little effect on the measurement of the tariff at the margin.

As we noted above, our calculation of the optimal tariff assumes there will be no exemptions. Introduction of exemptions lowers the benefits of a tariff and creates problems in its implementation. But our analytic framework has the advantage of being able to accommodate such exemptions, and to provide guidance as to the necessary adjustments in the optimal tariff.

TRANSITION COSTS

Our calculation of the optimal U.S. oil tariff is a comparative static analysis. The calculations compare the average economic and security conditions with and without a tariff. Hence, the analysis focuses on long-run conditions and is silent on the transition. But imposition of any tariff will create costs during the process of adjustment to the selected tariff level. The addition of a tariff to the price of oil creates a one-time shock to the aggregate price level. Hence, although a lower level of oil consumption may reduce the impacts of higher oil prices on inflation in the long run, the tariff itself increases the effect of oil inflation in the short run.

The adjustment of consuming industries could lead to transition costs in the form of (unwanted) unemployment. If the petrochemical industry is not competitive even at variable cost, then workers in that industry will be searching for new jobs. Our optimal tariff calculation makes the usual heroic assumption of a frictionless adjustment in which these workers find employment quickly and their wages reflect their productivity. Perhaps they shift to meet the expanding demand for labor in the domestic oil industry that will experience transition benefits in addition to long-run benefits that accrue from a tariff. Nonetheless, these costs are real and will create significant political pressures for modification of a tariff or exceptions as noted above. However, they are one-time costs as opposed to the continuing costs of a free market oil trade policy. Hence, the assumption underlying our analysis is that these transition costs are modest compared to the long-term benefits of a tariff.

In the short run, comparison with what might have been today may be less relevant than comparison with what was only yesterday. Given the natural tendency to compare current oil prices against those of the past, and not against foregone opportunities, this period of low prices offers the best moment to adopt a significant oil import tariff. With oil prices at a low level, and the economy adjusting to the change from higher prices, there should be relatively little transition problem if a tariff is imposed before oil prices would start to rise again. In the circumstances which motivate this appraisal of imposing a tariff, transition costs are a less significant problem than in previous years where the objection carried the day despite similar analysis about the long-run oil import premium.[33]

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33 See Harry G. Broadman, "Review and Analysis of Oil Import Premium Estimates," Discussion Paper D-82C, Energy and National Security Series, Resources for the Future, Washington, D.C., December 1981; and William W. Hogan, "Import Management and Oil Emergencies," in Energy and Security, David

REVENUES

Taxes and tariffs have an important revenue-raising function in addition to their policy impacts. For the most part, the assumption is that taxes and tariffs have negative incentive effects which should be moderated but nonetheless are necessary in order to raise revenues. Interpretation of the present analysis suggests that an oil tariff has the advantage of raising revenues and promoting optimal policies for maximizing the welfare of the United States. Hence, the revenues from such a tariff are an added benefit that can be applied to a variety of uses.

The sources and magnitudes of possible revenues present a separate, complicated analysis of the impacts of an oil import tariff. Such a tariff would raise tax payments of domestic oil producers, reduce tax payments of oil-consuming industries, cause shifts in employment patterns which would have short- and long-run effects on social security and other transfer payments, and so on. There are a number of possible uses for the revenues raised. One possibility is to finance further purchases of oil for the SPR. Another is to help alleviate U.S. federal budget deficits. The latter has generated the greatest interest.

Estimates of how much revenue would be raised for the federal budget have been the subject of several detailed studies. For example, the Congressional Budget Office prepared an extensive analysis of a $5 and $10 oil import tariff that could have been applied starting in 1982.[34] More recently, in light of the changed economic conditions and lower world oil prices, the CBO

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34 Congressional Budget Office (CBO), "Oil Import Tariff's: Alternative Scenarios and Their Effects," Staff Working Paper, Washington DC, April 1982.

prepared a new analysis of these same revenue effects.[35] These studies suggest that a tariff could raise a significant amount of revenue. However, the total amount would be much less than might be expected. For example, with approximately 6 million barrels per day of oil imports and a $10 tariff, we might expect that this would produce about $22 billion per year, by multiplying the tariff times the volume of imports. However, as estimated by the CBO, the net revenue benefits for the federal budget come after deducting other compensating effects and impacts on transfer payments. As a result, net revenue would be in the range of about $8 billion to $12 billion.[36]

Overall, our analysis is silent on the use of tariff revenues. They are included as part of the aggregate welfare calculation, and the implicit assumption is that they will be used in the best interests of the country.

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35 Congressional Budget Office, <u>The Budgetary and Economic Effects of Oil Taxes</u>, April 1986. See also the Department of Energy, <u>The Impact of Lower World Oil Prices and Alternative Energy Tax Proposals on the U.S. Economy</u>, Energy Information Administration, April 18, 1986.

36 Congressional Budget Office, <u>The Budgetary and Economic Effects of Oil Taxes</u>, April 1986, p.15.

VI. HISTORY OF U.S. OIL TARIFF POLICY

U.S. imports of oil actually have been subject to a tariff for more than fifty years.[37] In 1932, to raise general federal revenues, Congress passed the Revenue Act.[38] Among the taxes introduced into the Internal Revenue Code by the Act was a flat "excise tax" of $0.21 per barrel of all imported crude oil.

In 1940 a crude oil quota system was established that was linked to the excise tax schedule. This reflected a trade agreement with Venezuela, which reduced the tax on crude to $0.105 per barrel, provided that imports did not exceed a quota of 5 per cent of the previous year's refinery runs. Above the quota, the $0.21 per barrel rate still applied. This quota system prevailed through 1942.[39]

Beginning in 1943, as a result of a trade agreement with Mexico, the tariff rate on crude oil was reduced to a simple $0.105 per barrel. This lasted until 1950, when the quota system employing a rate of $0.21 per barrel on imports above 5 percent of the prior year's refinery runs was reintroduced. In late October 1952 another trade agreement was reached with Venezuela, which established a two-tier tax rate: for crude with an API gravity below 25°, it was $0.0525; for crude with a rating above 25° (so called "high test" crude)

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37 See Bernard Gelb and Salvatore Lazzari, "Oil Import Taxes: Revenue and Economic Effects," Report #86-572E, U.S. Congressional Research Service, Library of Congress, Washington, D.C., May 28, 1986.

38 Public Law 154.

39 William H. Peterson, American Enterprise Association, <u>The Question of Governmental Oil Import Restrictions</u>, 1959, pp. 14-17.

the rate remained at $0.105.[40] It should be noted that following such trade agreements the revised tax rates were applicable to virtually all oil exporting nations under "most favored nation" clauses.

The two-tiered tax on crude oil of $0.105 above 25°, and $0.0525 below 25°, remained unchanged until the Kennedy Round of trade agreements and the resultant Trade Expansion Act of 1963. As part of a general reorganization of the U.S. tariff schedules that occurred during this period, the taxes on crude imports were replaced by customs duties. The customs duties were the same as the previous tax rates.[41]

Crude oil import duties remained unchanged until President Nixon, by Presidential proclamation, eliminated the Mandatory Oil Import Program in the spring of 1973 and suspended crude oil duties.[42] A system of license fees was introduced in their place. These fees began at $0.105 per barrel, and in gradual steps, were increased to $0.21 per barrel by May 1975. It should be noted, however, that this policy was a <u>de facto</u> reduction in the applicable duties.[43] The license fee system initially excluded all crude for which quota allocations still existed, the legacy of the MOIP. Only crude imported above

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40 National Petroleum Council, <u>Report of the National Petroleum Council Committee on Petroleum Imports</u>, May 5, 1956, p.12.
41 See Douglas R. Bohi and Milton Russell, <u>Limiting Oil Imports: An Economic History and Analysis</u> (Washington, D.C.: Resources For the Future/Johns Hopkins University Press, 1978), p.231.

42 Message to Congress (April 18, 1973) and Proclamation 4210 (April 18, 1973) (Federal Register vol. 38, p. 9645, April 19, 1973). The MOIP began in 1959. See Douglas R. Bohi and Milton Russell, <u>Limiting Oil Imports: An Economic History and Analysis</u> (Washington, D.C.: Resources For the Future/Johns Hopkins University Press, 1978).

43 "Nixon's Energy Medicine: Will It Cure the Patient?" <u>Oil and Gas Journal</u>, April 30, 1973, pp.81-85.

outstanding quota allocations incurred a fee. Previously every barrel imported was dutiable. Hence the net effect, at least until a gradual phase out of exempt allocations could be completed, was a reduction in the duties paid.

In 1975 President Ford added a supplemental oil import fee to the existing license fees. The supplemental fee began at $1.00 per barrel in February 1975 and was scheduled to increase in steps to $3.00 by April 1975.[44] As a result of a court challenge, however, a $2.00 per barrel supplemental fee was instituted in June instead. Following the passage of the Energy Policy and Conservation Act in December 1975, the supplemental fee was removed.[45]

In April 1979, President Carter temporarily suspended the license fees and customs duties on crude oil. In their place he instituted an import quota regime which restricted imports to the 1977 level. However, since that limit was never exceeded, the quotas were never effectively binding. Early in 1980, citing energy and national security reasons, Carter issued an Executive Order[46] imposing an import fee of $4.62 per barrel. A suit by members of Congress, however, resulted in a court decision voiding the Order.[47]

Since July 1980 only the two-tiered customs duty ($0.0525 per barrel below 25° and $0.105 per barrel above 25°) has been applicable. While a license is still required to import crude oil, no license fees are currently

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44 Petroleum Intelligence Weekly, February 3, 1975, p.12.

45 Bohi and Russell (1978), p.235.

46 Presidential Proclamation 4744, April 2, 1980.

47 INDEPENDENT GASOLINE MARKETERS COUNCIL, INC., et al., Plaintiffs, v. Charles W. DUNCAN, Jr., Secretary, Department of Energy, et al., Defendants; MARATHON OIL CORPORATION, Plaintiff, v. James Earl CARTER, President of the United States, et al., Defendants., Cit. A. Nos. 80-1116, 80-1181., United States District Court, District of Columbia., 492 F. Supp. 614, May 13, 1980µ As Amended May 14, 1980.

has ranged between 3 and 30 percent of the import price. By comparison, current tariff proposals of $5.00 to $10.00 per barrel would account for between 30 and 65 percent of today's price (of $15.00 to $18.00 per barrel).

TABLE 3

US OIL TARIFFS AND IMPORT PRICES

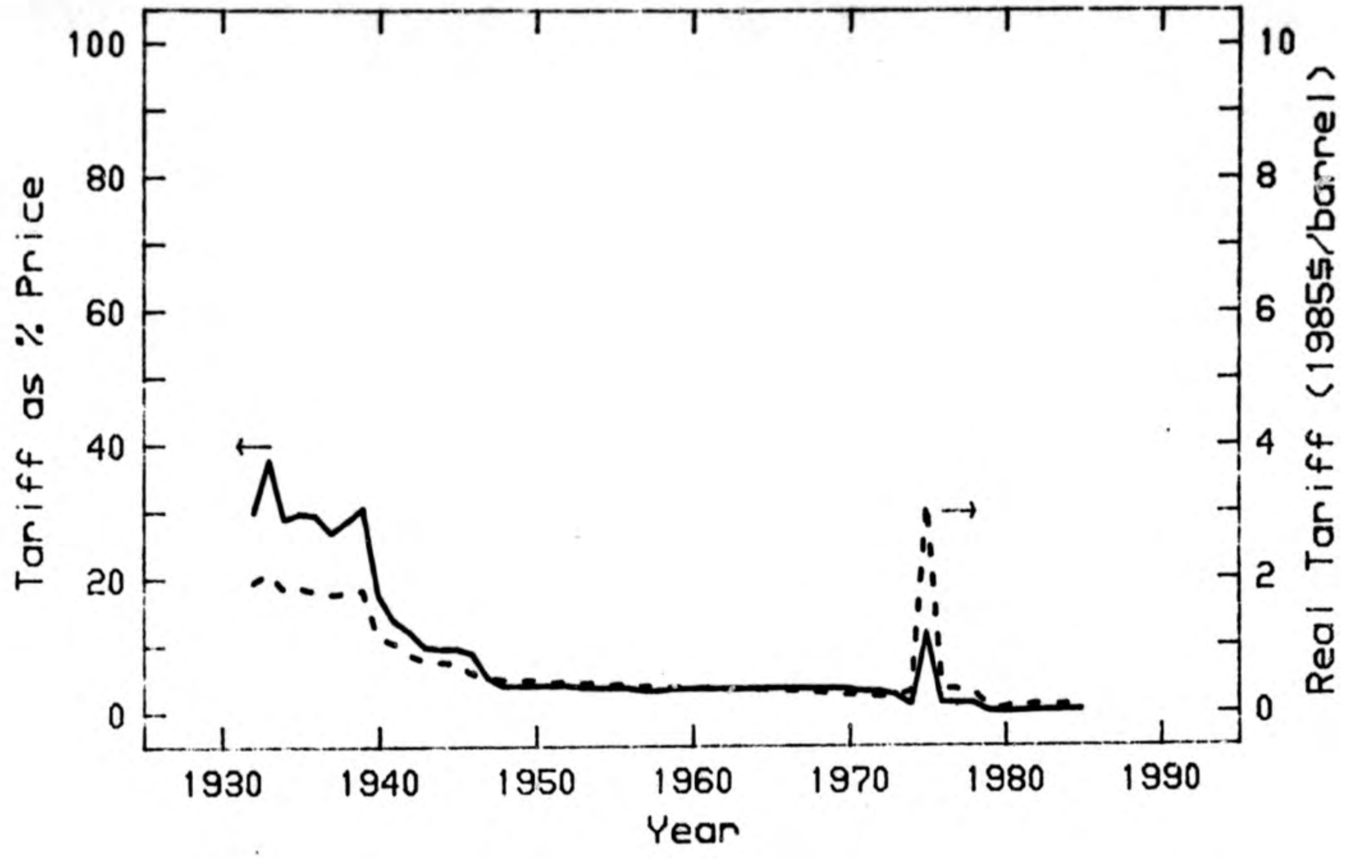
Year	Real[a] Tariff $/bbl	Real[b] Price $/bbl	Year	Real[a] Tariff $/bbl	Real[b] Price $/bbl
1932	$1.96	$ 6.505	1959	$0.39	$10.662
1933	$2.10	$ 5.550	1960	$0.38	$10.397
1934	$1.86	$ 6.407	1961	$0.38	$10.358
1935	$1.88	$ 6.295	1962	$0.37	$10.140
1936	$1.83	$ 6.174	1963	$0.36	$ 9.966
1937	$1.79	$ 6.615	1964	$0.36	$ 9.763
1938	$1.81	$ 6.302	1965	$0.35	$ 9.439
1939	$1.84	$ 6.009	1966	$0.34	$ 9.201
1940	$1.15	$ 6.457	1967	$0.33	$ 9.097
1941	$1.05	$ 7.516	1968	$0.31	$ 8.580
1942	$0.88	$ 7.174	1969	$0.29	$ 7.865
1943	$0.78	$ 7.874	1970	$0.28	$ 7.872
1944	$0.77	$ 7.971	1971	$0.26	$ 7.985
1945	$0.74	$ 7.589	1972	$0.25	$ 7.740
1946	$0.60	$ 6.672	1973	$0.25	$ 9.210
1947	$0.53	$ 9.747	1974	$0.32	$25.921
1948	$0.50	$12.322	1975	$3.13	$26.234
1949	$0.50	$12.095	1976	$0.37	$23.858
1950	$0.49	$11.729	1977	$0.35	$24.096
1951	$0.47	$11.244	1978	$0.33	$22.554
1952	$0.46	$11.096	1979	$0.08	$30.781
1953	$0.45	$11.552	1980	$0.07	$44.185
1954	$0.45	$11.830	1981	$0.12	$44.002
1955	$0.43	$11.352	1982	$0.12	$37.486
1956	$0.42	$11.071	1983	$0.11	$31.539
1957	$0.40	$11.839	1984	$0.11	$29.835
1958	$0.39	$11.316	1985	$0.11	$27.030

[a]Weighted tariffs on imported crude oil in constant 1985 dollars.

[b]Crude oil price in constant 1985 dollars: 1932–1946 is FOB price; 1947–1967 is US wellhead price; 1968–1985 is US Refiner's Acquisition Cost of imports.

FIGURE 7

US Oil Tariffs Have Been Low



APPENDIX

OIL IMPORT TARIFF CALCULATION

A SUMMARY

This appendix summarizes a model for the oil import tariff calculation. Evaluating the critique in Broadman[1], which examined at least seventeen different analyses of the oil import premium, we conclude that the approach developed in Hogan[2] is as complete a taxonomy of the premium components as is necessary to capture the main direction of oil tariff policy. We summarize the arguments of that analysis and borrow the model,. with minor extensions, as the framework for our revised estimate of the optimal oil import tariff. The model addresses the case of a long-run tariff imposed to correct oil market imperfections, including the effect of oil supply disruptions.

In this model there are five channels of market failure that add to the social cost of U.S. oil imports. Here we characterize each of

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1 Broadman, H. G., "Review and Analysis of Oil Import Premium Estimates," Discussion Paper D-82C, Energy and National Security Series, Resources for the Future, Washington DC, December 1981. H.G. Broadman, "The Social Cost of Imported Oil," Energy Policy, June 1986.

2 Hogan, W., "Import Management and Oil Emergencies," in Energy and Security, D. Deese and J. Nye (eds.), Ballinger Publishing Company, Cambridge MA, 1981.

these elements of the oil import premium, the gap between social cost and the market price. The premium consists of two main categories, the "economic component" and the "security component."

ECONOMIC COMPONENT

Market imperfections associated with oil imports arise for both traditional economic reasons and as a result of the special problems posed by supply interruptions. The economic component of the premium, that which would exist even in the presence of a secure supply of oil, reflects the contribution of oil to inflation, the attendant shifts in the balance of trade and the judgment that a change in U.S. oil demand could have a significant effect on the world price of oil.

Inflation

Control of inflation has been a persistent problem in the United States. Even in the mid-1980's, with inflation at relatively low levels, there is a fear of higher inflation and the restrictive monetary or fiscal policies that would follow. Nordhaus[3] was the first to observe that the impact on inflation might be a significant externality associated with

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3 William D. Nordhaus, "The Energy Crisis and Macroeconomic Policy," Energy Journal, Vol.1, No. 1, January 1980.

oil price movements.

According to the conventional wisdom[4], the high cost of controlling inflation arises from the combination of market rigidities in the economy and the difficulty of predicting the course of prices, especially oil prices. With perfect anticipation of prices and complete flexibility, the economy could adjust to any level of inflation, in the long run. But in the short run, with price shocks and inflexibility, the economy adjusts slowly. The policy response is to constrain the economy in order to wring out part or all of the inflation. The cost of this adjustment can be substantial.

Our characterization of the cost of adjustment combines two rules of thumb from macroeconomics. The first is the short run Phillips curve, which relates the change in 'inertial' inflation to the change in unemployment above the 'full employment ', or 'natural', rate. Inertial inflation refers to the anticipated rate of inflation that gets built into contracts and pricing policies. Without shocks, the economy can sustain a given inertial rate, but price shocks can change the inertial rate, and induced unemployment is the policy tool for moving from one inertial rate

4 The analysis of the high cost of inflation follows from the summary of the arguments and evidence presented by William D. Nordhaus and Paul A. Samuelson in Economics, Twelfth Edition, 1985, pp. 437-439. The principal dissent from this analysis comes from the 'rational expectations' school which argues that macroeconomic policy is fully anticipated and recessions results from voluntary unemployment. Nordhaus and Samuelson summarize the dissent as well as the conventional theory.

to another. Although the estimate is uncertain, the consensus is that it takes two points of increased unemployment for a year to eliminate one point from the inertial rate of inflation[5].

The second rule of thumb, known as Okun's law, summarizes the changes in operations that affect output and are correlated with a change in the level of unemployment. Firms take many other steps before or in conjunction with changing their number of employees, e.g. altering the use of over time. These other actions have effects on output, at the margin, that imply that each percentage point change in the unemployment rate has more than a one point impact on the level of output. Again, there is some uncertainty. In the 1960's, "Okun's law" was as high as three points of GNP lost for each point of unemployment[6]. The more recent estimates put the ratio at closer to two to one.[7]

With a short run Phillips curve implying a two to one link between unemployment and inflation, and Okun's law implying a two to one link between unemployment and output, there is a four to one link between output and reduction of inertial inflation. In a $4000 billion economy, the cost of eliminating one point from the inertial rate of inflation would be $160 billion. Nordhaus and Samuelson estimate the range as between $100 and

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5 Nordhaus and Samuelson, 1985.

6 Sherman J. Maisal, <u>Macroeconomics</u>, W.W. Norton Company, New York, 1982, p. 447.

7 Nordhaus and Samuelson, 1985.

$270 billion![8]

The price of oil is determined by the price of oil imports. Because oil is an important commodity, a long-run trend of rising (falling) oil prices will increase (reduce) the general inflation rate. The large reduction (increase) in GNP needed to reduce (increase)[9] inflation is an externality not recognized by individual buyers of imported oil. Hence it adds a (potentially) significant externality to the use of imported oil. The size of this externality depends on how the level of imports and changes in the price of oil affect the inertial rate of inflation, and on how much of the inertial rate is accomodated (removed) by expansionary (contractionary) macroeconomic policy.

If oil prices follow a smooth upward (downward) path, then virtually all of the increase (decrease) should be anticipated and incorporated in the inertial rate of inflation. However, because of full anticipation, we could assume that there would be full policy accomodation, and therefore, no change in GNP. But if oil prices follow an erratic path, both up and down, some of the price changes will be incor-

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8 Nordhaus and Samuelson, 1985.

9 Of course, the policy would not be to increase inflation when oil prices fall. But falling oil prices would eliminate the need to reduce inflation caused by other shocks. Assuming that in the dynamic economy there are plenty price shocks, the directional effect of policy will be to expand output and increase inflation from what it would have been otherwise, whenever blessed with falling oil prices.

porated in the inertial rate and the policy response will allow for only partial accomodation. Therefore, in the case of rising prices, only a fraction of the oil induced addition to inflation will be removed from the inertial rate through induced unemployment.

The history of oil prices has been one of erratic price movements, usually associated with unexpected shocks to the system. The future will be no different, with a volatile market disguising an uncertain long run trend.[10] In this world, the ups and downs of price will not be neutral, and policy can be expected to constrict the economy to remove part of the oil induced inflation. An approximation to the sequence of short run responses is to calculate the long run impact on inertial inflation, assuming full anticipation and accomodation, and then apply a judgment as to the percentage of incremental oil inflation that will be eliminated from inertial inflation through macroeconomic policy actions.

Long-run inflation in the price of oil will create similar inflation in the price of natural gas and other oil substitutes. If the policy is to accomodate the inflation, the resulting impact on the general price level will be in proportion to the value share of oil and related products. Let:

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10 For a review and analysis of uncertainty in the oil market, see William W. Hogan and Paul N. Leiby, "Oil Market Risk Analysis", Discussion Paper, Energy and Environmental Policy Center, Harvard University, December 1985.

r = oil inflation rate in real (nominal - inertial) terms,

s = oil import price,

q_d = domestic oil demand (millions of barrels per day, mmbd),

q_n = domestic demand for oil substitutes (mmbd),

q = oil import level (mmbd),

p = domestic price of oil and its substitutes,

t = $(p-s)$ the implicit tariff,

w = value share of oil and its substitutes,

π = inflation impact from oil.

Then the contribution to inflation from oil is

$$\pi = r(s/p)w.$$

Now,

$$w \approx pQ(0.365)/GNP,$$

where

$$Q = q_d + q_n .$$

Therefore,

$$\pi = rs(Q(0.365)/GNP).$$

The change in the inflation trend caused by a change in the level of oil imports is

$$\frac{\delta\pi}{\delta q} = (0.365/GNP)\left[\ \frac{\delta r}{\delta q}\ sQ + r\,\frac{\delta s}{\delta q}\ Q + rs\,\frac{\delta Q}{\delta q}\ \right]$$

Our Phillip's curve ratio (estimated above as requiring two points of unemployment for one year to eliminate one point of inflation) is uncertain and is treated as a parameter ϕ. Similarly, Okun's law (requiring two points in output lost for each point of unemployment) is denoted by the parameter β.

As Nordhaus[11] observed, full accomodation of this inflation is not likely; nor is no accomodation at all. The former would impose politically unacceptable burdens, for example, in the redistribution of wealth. The latter would cause a great reduction in real output. This is essentially a policy matter, without a clear empirical guide. If we let U represent the fraction of inflation that will be eliminated through real output reductions, then the loss in real output per barrel of incremental imports is

$$t_1 = \phi\beta U\left[\ (\ r's + rs'\ )Q + \frac{\delta Q}{\delta q}\ rs\ \right],$$

where,

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11 Nordhaus, 1980.

ϕ = Phillip's curve ratio of unemployment to inflation reduction,

β = Okun's law ratio of output loss to unemployment,

U = unaccommdated portion of inflation,

r = oil inflation rate in real terms,

r' = $\delta r/\delta q$,

s = oil import price,

s' = $\delta s/\delta q$,

Q = domestic demand for oil and for oil substitutes (mmbd),

q = oil import level.

The large costs of this inflation come from the unsought redistribution of income and from government attempts to prevent the redistribution by slowing economic growth and dampening the price increases. As long as the policy response to high inflation is to induce unemployment and a slack economy, we cannot ignore this expensive costs of oil imports.

Balance of Payments

Higher oil imports at higher prices increase the need to export goods and services or to receive investment payments in anticipation of future exports. The change in the balance of payments will lead in part to a change in the terms of trade through adjustments in exchange rates, which impose a real economic burden on each oil importing country. Whether or not a significant externality arises turns on a number of factors. For example, if oil exporters immediately recycle all their funds in the form of increased purchases of our products, or investments in our assets, then there is no externality.

Following Nordhaus (1980) we assume that an increase in oil imports will lead to a partial increase in exports as foreign oil producers recycle their revenues and a partial depreciation of the dollar to restore a balance of payments. Let:

p_d = domestic price level;

p_f = foreign currency price level;

e = exchange rate (p_f/p_d);

s = dollar price of imported oil;

X = quantity of exports

M = quantity of nonoil imports;

q = quantity of oil imports in (MMBD);

n_E = price elasticity of exports demand;

n_I = price elasticity of imports demand.

A balance of payments (with units on a daily basis) requires,

$$p_d X(p_d e) - (p_f/e)M(p_f/e) - sq = 0.$$

At a given aggregate price level[12], and with perfectly elastic supply functions, the change in the balance of trade caused by a change in the exchange rate, Δe, is

$$p_d \frac{\delta X}{\delta(p_d e)} p_d \Delta e + (p_f/e)\frac{\delta M}{\delta(p_f/e)} (p_f/e^2)\, \Delta e + (p_f/e^2)M\, \Delta e - \frac{\delta s}{\delta e}\, \Delta e\; q\ .$$

Suppose that B percent of any increase in oil import payments is returned by oil foreign producers through higher U.S. export purchases. Then, at the margin the change in exchange rates must satisfy $\Delta e = (\delta e/\delta q)$ and the unrecycled oil payments must just balance the shift in the balance of payments for other goods, i.e.,

$$p_d \frac{\delta X}{\delta(p_d e)} p_d \frac{\delta e}{\delta q} + (p_f/e)\frac{\delta M}{\delta(p_f/e)} (p_f/e^2)\, \frac{\delta e}{\delta q} + (p_f/e^2)M\, \frac{\delta e}{\delta q}$$

$$- \frac{\delta s}{\delta e}\, \frac{\delta e}{\delta q}\, q \; - (1-B)\left[\, s + \frac{\delta s}{\delta q}\, q\, \right] = 0.$$

or

$$[n_E p_d X+(n_I+1)p_d M\ ]\ \frac{\delta \ln e}{\delta q} - \frac{\delta \ln s}{\delta \ln e}\, \frac{\delta \ln e}{\delta \ln q}\ s - (1 - B)\left[\, s + \frac{\delta s}{\delta q}\, q\, \right]=0.$$

The first term is the change in imports and exports valued at the domestic dollar price. The last term is the real resource cost of incremental oil

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12 Assuming a fixed dollar price level in the United States, then changes in the price of foreign goods must be accompanied by changes in other domestic real prices in order to adjust relative prices and maintain the same price level.

imports (excluding the percent recycled immediately and not adding to the balance-of-payments deficit). The middle term, therefore, is the balance-of-payments externality, which consists of the elasticity of real dollar oil prices as a function of the exchange rate and the elasticity of the exchange rate as a function of import levels.[13]

From this last equation we obtain

$$\frac{\delta \ln e}{\delta \ln q} = \frac{(1-B)\left[\, s + \frac{\delta s}{\delta q}\, q \,\right] q}{n_E p_d X + (n_I+1) p_d M - \frac{\delta \ln s}{\delta \ln e}\, q\, s} \, .$$

Hence, if the elasticity of demand for exports or imports is high, or B is close to 1, then the elasticity of exchange rate with respect to import quantity is low. But if B, n_E, and n_I are small, then the reverse holds true.

The elasticity of the price of oil with respect to the exchange rate is uncertain. If oil producers are willing to fix the price of oil in dollars or to make purchases only in the United States, possibly later, then this term should be near 0. If oil producers' dollars are converted

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13 We have ignored the second-order effect of partial recycling.

to other currencies, and producers wish to maintain the purchasing power of their oil, then this elasticity is -1.

In summary, the balance-of-payments import externality per barrel is

$$t_2 = s n_{se} n_{eq},$$

where,

$$n_{se} = \frac{\delta \ln s}{\delta \ln e} = \text{elasticity of oil import price to the exchange rate,}$$

$$n_{eq} = \frac{\delta \ln e}{\delta \ln q} = \text{elasticity of exchange rate to oil import level.}$$

According to these definitions, we assume that (1-B) of the marginal oil revenues end up in the Eurodollar market where they cause a marginal devaluation of the dollar. The decrease in the exchange rate of other currencies for the dollar affects the balance of trade in other goods and services, and presents a problem to oil producers because the oil they sell is priced in dollars. The elasticity n_{se} summarizes a subjective judgment about producer response in terms of the effect on the price of oil.

Price Reduction

As we've argued in the text, for a country like the U.S. that purchases a significant volume of oil on the world market, the price of those purchases will depend in part on the volumes taken. Thus, the U.S. can affect the world oil price by changing the volume of its oil purchases. Since the resulting price difference would be paid on all oil imported into the U.S., the true cost of the incremental barrel to the nation as a whole is higher than the market price.

The direct cost of oil imports purchased by the U.S. is simply the import price times the import volume, or

$$sq \ .$$

Given the sizable share enjoyed by the U.S. in the world oil market, an increase in the volume of import purchases, over the long run, will change this direct cost by the amount

$$s + s'q \ .$$

The first term is just the price, s, which is the private cost. The incremental buyer of imported oil will pay this cost directly and thus internalize one component of the increased oil import bill. But the incremental buyer does not see how its purchase increases the cost for everyone else. The second term reflects this market imperfection and enters the calculation of the economic component of the premium as

$$t_3 = s'q .$$

SECURITY COMPONENT

When an interruption comes, the damage to our economy will depend in part on the level of oil imports. Even if changing the preinterruption level of imports has no effect on the size of the shortage during the interruption, the burden of suddenly higher oil prices and the attendant shocks on our economy will be reduced if imports are lower. Here we separate the security component of the premium into two elements. The first captures the economy's vulnerability to damage for a given oil price shock. The second captures the link between imports and the size of the price shock. For both of these contributions to the security component of the premium, the use of a Strategic Petroleum Reserve can reduce the effective size of the supply interruption and lower the optimal tariff.

Vulnerability

The long-run level of imports defines a reference point for short-run supply and demand curves in an interrupted market. Following the analysis in Hogan[14], we incorporate a model of short-run macroeconomic

14 Hogan, W. "Oil Stockpiling: Help Thy Neighbor," Energy Journal, Volume 4, Number 3, July 1983.

shock that employs a GDP elasticity with respect to sudden increases in the price of oil.

Let,

q_t = quantity of oil imports that would be demanded with reduced GDP and no price change,

q_s = quantity of oil imports during interruption.

We assume that the real GDP during an interruption is

$$GDP = GDP_o((\Delta p+p)/p)^{-u},$$

where,

GDP_o = the normal GDP at price p,

Δp = shock induced change in domestic oil price,

u = elasticity of GDP with respect to oil price,

and the unemployment caused by higher oil prices is spread uniformly across the economy. We assume that this shock-induced unemployment will reduce the demand for oil in the same percentage as the reduced GDP, and this will be a principal (expensive) means of adjusting to the oil shortage.

Therefore,

$$q_t = q - q_d u\Delta p/p \ .$$

We assume the interruption lasts for one year. The short-run supply function during an interruption is determined by the size of the interruption, ε, and a short-run response relative to the import price, s. The short run supply of imports is very inelastic; a large change in price produces a small increment in curtailed supply. We further assume that the tariff implied by the pre-interruption price difference, p − s, is maintained during the interruption; hence, the short-run supply curve with slope b is

$$q_s = q - \varepsilon + b\Delta p \ ,$$

where,

ε = *ex ante* size of the disruption, and

b = slope of the linear short-run import supply curve,

The short-run import demand curve for quantity q_r at price w, relative to pre-interruption price p(q) and quantity q, is assumed to be linear with slope c; that is

$$q_r = q_t - c\Delta p.$$

where,

c = slope (minus) of the short-run oil demand curve.

These short run supply and demand equations yield the shock to oil prices, up to linear approximation, as

$$\Delta p = s/[b+c+q_d u/p] .$$

With these definitions, the market clearing quantity during an interruption is q_u. Hence, the social cost of interruption is equal to

$$(q_t - q_u)[.5\Delta p + (p - s)] + q_u\Delta p + uGDP(\Delta p/p) .$$

Taking the derivative with respect to the oil import level yields the change in the social costs as a function of the import level:

$$[(q_t - q_u)(p'-s') - uGDP(\Delta p)p'/(p^2) + .5(\Delta p(\delta(q_t - q_u)/\delta q)] +$$
$$[(.5(q_t - q_s) + uGDP/p)\delta(\Delta p)/\delta q]$$

The terms in the first set of brackets capture the social cost given a price shock Δp. These costs reflect the vulnerability to economic disruption caused by a given level of imports. The terms in the second set of brackets capture the impact of a possible change in the size of the interruption and the resulting price shock.

Focusing on the first, the size of the externality depends in part upon the probability of a supply interruption of given size. Hence, the first element of the security component is

$$t_4 = \sum v^j[(q_t{}^j - q_u{}^j)(p'-s') - uGDP\Delta p^j p'/(p^2) + .5(\Delta p^j(\delta(q_t{}^j - q_u{}^j)/\delta q)] .$$

where,

v^j = probability of disruption state j.

Price Shock

Reducing the level of oil demand during normal times is likely to leave excess capacity in the total oil market, capacity that could be brought to market during an oil interruption and lessen the effective size of the supply loss. The extent to which any one country can count on this gain is problematic. Adjustments in capacity over time, sharing of benefits under the International Energy Program (IEP) formulas, or the possibility of losing capacity as well as production all mitigate against the efficacy of reducing oil imports as a means of lowering the size (or likelihood) of an oil supply interruption.

Hence there are several judgmental parameters that must be included in the analysis to capture the possibility of reducing the size of an interruption and, therefore, reducing the size of the price shock. With the adjustments described above for dealing with macroeconomic costs of a disruption, this second element of the security component is

$$t_5 = \sum v^j [\{.5(q_t^{\,j} - q_s^{\,j}) + uGDP/p\}\delta(\Delta p^j)/\delta q] .$$

In order to calculate this element of the premium, we need to provide

$\delta s/\delta q$ = the change in interruption size induced by a change in imports.

In Hogan [1981], the likely range for this value is established as .13 to .48. With proportional IEA sharing of shortages according to demand, and a complete elimination of a barrel of shortage for each barrel of reduced demand, we would have for the United States $\delta s/\delta q = 0.33$.[15]

Finally, in calculating several of the derivatives we will need the fact that

15 The United States consumed an average of 15.9 mmbd out of a world consumption of 47.2 mmbd between 1980 and 1983. Hence, with proportional sharing of disruptions, each barrel reduction in the short run demand for imports would have a 33% impact on the size of the effective disruption.

$$\delta q_d/\delta q = n_d q_d/(n_d q_d - n_s(q_d - q)) ,$$

where,

n_s = long-run elasticity of domestic supply.

Hence, the change in the price shock induced by a change in the level of imports is

$$\frac{\delta \Delta p}{\delta q} = \frac{s}{[b+c+q_d u/p]^2} \left[\frac{\delta q_d}{\delta q} (u/p) - q_d (u/p^2) \frac{\delta p}{\delta q} \right] + \frac{\delta s}{\delta q} \left[\frac{1}{[b+c+q_d u/p]} \right]$$

STRATEGIC PETROLEUM RESERVE

Oil supply disruptions create substantial costs for the economy. The principal protection from these losses, short of preventing the disruption *per se*, would be to provide substitute supplies of oil. This fact suggests the need for a substantial supply of oil that can be injected in the market in large volumes on short notice, i.e., for a strategic petroleum reserve. Every analysis of energy security problems has pointed to the need for a substantial oil reserve.[16] Its prompt use would be the

16 For example, Teisberg, T.J., "A Dynamic Programming Model of the U.S. Strategic Petroleum Reserve," *Bell Journal of Economics*, Vol. 12, No. 2, Autumn 1981, presented an analysis of the link between a strategic oil supply and a tariff. Although partial substitutes, the optimal result

most effective means for mitigating the damages of a supply interruption.

Whatever the size of the such a reserve, however, the volume of imports will affect the economic cost of a disruption. The greater the volume of oil imports at the start of the interruption, the greater the cost of the interruption. It follows that a tariff, which would reduce the volume of imports, and a strategic oil reserve, which would substitute for the lost supply, are complementary. The larger the reserve, the smaller the optimal tariff, but the need for a tariff remains. Our purpose is to capture the effects of a significant reserve on the size of the optimal tariff.

For a given size of the U.S. Strategic Petroleum Reserve, the size of the optimal tariff depends on the use of the SPR during an interruption. The studies of the best use of the SPR suggest both the complexity of the optimal drawdown policy in particular disruption scenarios and a reasonable general rule of thumb for purposes of the present analysis.[17]

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called for both a large reserve and a significant tariff. See also Alm, A. and E. Krapels, "Building Buffer Stocks in a Bear Market: Policy Choices for Emergency Reserves," Discussion Paper Series, H-82-01, Energy and Environmental Policy Center, Kennedy School of Government, Harvard University, March 1982. Chao, H.P. and S. Peck, "Coordination of OECD Oil Import Policies: A Gaming Approach," Electric Power Research Institute, Palo Alto CA, September 1980. National Petroleum Council, Emergency Preparedness for Interruption of Petroleum Imports into the United States, Washington DC, April 1981.

17 See Teisberg (1981) and Hogan (1983).

If there is a reasonable possibility that a disruption will last for more than one year, then part of the SPR should be used immediately and part should be held for contingencies. Furthermore, given the value of the SPR for later emergencies, part of the disruption should be met from the SPR and part should be met with demand reductions. Our rule of thumb is to meet the disruption up to half the total interruption or half the size of the SPR. The drawdown from the SPR reduces the effective size of the disruption, s, and the resulting price increase and economic loss. Therefore, we set

$$s = \mathrm{MAX}\{0.5s_{ex\ ante}, s_{ex\ ante} - 0.5(\delta s/\delta q)(SPR/365)\},$$

where $s_{ex\ ante}$ is the interruption size expected without the use of the SPR. Since the use of the SPR will benefit everyone in the world market, the drawdown affects the interruption only in proportion to the assumed derivative of the interruption size for each barrel change in the size of import demand.

COMBINED PREMIUM

As we argued in the text, the individual components of the premium are not additive. Moreover, we have argued that, taken together, they are equivalent to the optimal tariff only at the optimal level of the premium; that is, for the premium associated with the level of oil imports that internalizes all externalities. As shown in Hogan (1981), the optimal premium can be found by maximizing an appropriate objective function over the total level of oil imports. This objective function combines the annualized benefits of oil use, cost of inflation and balance of payments adjustments, payment for oil imports, and the expected loss during oil interruptions. Using linear approximations for several derivatives, the objective function is:

$$OBJ = \int_0^q [p(x)\delta x] - (t_1 + t_2)q - sq$$

$$- \sum v^j [(q_t{}^j - q_u{}^j)(.5\Delta p^j + (p-s)) + q_u{}^j \Delta p^j + uGDP\Delta p^j/p] .$$

The solution to the optimization of OBJ over q yields

$$W(p - s) = t_1 + t_2 + t_3 + t_4 + t_5 ,$$

where W is a scaling factor that adjusts for losses in tariff payments during an interruption:

$$W = 1 - \sum v^j [\delta(q_t{}^j - q_s{}^j)/\delta q] .$$

Therefore, we refer to the five elements of the economic and security components of the premium, p-s, as

$$T_k = t_k/W ,$$

$k = 1,2,\ldots,5.$

These equations can be solved numerically to identify the five elements of the optimal oil import tariff. The basic model includes constant elasticity long-run supply and demand curves, with linear short-run supply and demand curves with a traditional analysis of consumer and producer surplus to calculate welfare changes. Disequilibrium during an interruption reduces GDP and the demand for oil. And the long-run inflation and balance of payment contributions are incorporated simultaneously in the solution of the model. Hence, we impose consistency of assumption across the premium components and recognize the interaction in the quantitative estimates of the total optimal premium and optimal tariff.

AGGREGATE COST SAVING

An estimate of the combined premium allows a further estimate of the aggregate cost of oil market imperfections. Since the premium measures the difference between price and social cost, the import supply curve plus the premium captures the full social cost of oil imports. The demand curve measures the corresponding social value of the same imports. At the market level of imports — with no tariff — the social cost is above the social value. At the optimal level of imports — by definition at the optimal tariff — marginal social cost just equals marginal social value. Hence the excess of cost over value, as imports increase from the optimal to the market level, is cost of the oil import externalities.

(See Figure 4 in the text.)

Let q^* be the optimal level of imports and q_0 be the market level. Let T^* be the premium at the market level. Then the aggregate net cost of oil import market imperfections, or the saving engendered by imposing the optimal tariff, is given by

$$C = T^*(q_0 - q^*)/2 .$$

Calculation of C requires only that we estimate the premium and import volume at the market level, where p = s, and at the optimum import level, where $T^* = p - s$.

OPTIMAL TARIFF ESTIMATES

With this technical summary complete, we can turn to the quantification and sensitivity analysis. An estimate of the optimal oil import tariff depends upon many assumptions. In Broadman[18] there is a discussion of the uncertainties that result in a very wide range of estimates from \$2 to \$124 per barrel. To be sure, this range encompasses all arguable values for input assumptions. However, we can narrow it considerably by choosing more plausible parameter values. For present purposes we will not discuss all possible combinations of parameters. Ra-

18 Broadman (1986).

ther, we shall establish a base case of most likely values, and then examine excursions that seem of most interest in the light of the nature of the oil market in 1986.

Base Case Parameters

The basic model provides simultaneous estimates of the optimal tariff, prices, and oil import quantity. Implementation of this model requires assumptions about a range of inputs. One of the principal difficulties in preparing optimal tariff estimates is the uncertainty surrounding the parameters. Many of the essential elements, such as demand elasticities and behavioral responses of suppliers, are not known with certainty. In order to proceed, therefore, it is important to prepare sensitivity analyses to examine the likely range of alternative tariff estimates.

The first sensitivity analysis focuses on a base case and the implications of changes in prices. The second sensitivity test examines the importance of the security component by calculating the optimal tariff under the assumption of a secure world oil market with no threat of interruption. Finally, the uncertainties surrounding the full range of inputs enter in a risk analysis that calculates the probability distribution for the optimal tariff.

The base case includes the nominal assumptions for each of the inputs specified in the development of the model. The most likely values draw on the literature and the authors' judgment. These most likely values provide the first estimate of the optimal tariff and the cost of a free market policy. The base case assumptions include:

U = 30%, unaccommdated portion of inflation;

r = 3%/yr, oil inflation rate in real terms. The rate of real price increase between 1970 and 1985 averaged 6.9%/yr. At 3%/yr, the real price would double in 24 years;

r' = 0.1%/mmbd, derivative of oil inflation rate with respect to changes in the level of imports. According to the usual theory of depletable resources, r is the same as the nominal interest rate, independent of the level of oil production or imports. Even under the opposite extreme case of production targets, r is independent of oil imports. For our sensitivity analysis, we assume that imports have a small effect on the rate of oil price change, implying a small, positive value for r'. For our base case assumptions, we take r = 3% and r' = 0.1%;

ϕ = 2, Phillips curve derivative ratio of excess unemployment to inflation, as described in Nordhaus and Samuelson, 1985;

β = 2, Okun's law, ratio of lost output to unemployment, as described in Nordhaus and Samuelson, 1985;

p = $27/bbl, base domestic oil price,

s = $27/bbl , base oil import price;

s' = $.50/bbl/mmbd, derivative of normal oil import supply curve;

q_d = 16 mmbd , base domestic oil demand, approximately thr level in 1985;

q_n = 5.4 mmbd, domestic demand for oil substitutes, the level in 1985;

q_s = 10 mmbd, base domestic oil production, the level in 1985;

n_d = -0.5, long-run elasticity of US demand for oil. Estimates drawn from the Department of Energy and an independent analysis of the data imply a long run elasticity of -0.9 with respect to the crude oil price[19]. The lower value used here is intended to capture an approximation of the decade long horizon reasonable for design of tariff policy;

n_s = 0.5, long-run domestic oil supply elasticity. The Department of Energy's oil market model uses an elasticity of 0.9.[20] Again, the smaller value used here reflects the average over a decade;

n_{se} = -1., elasticity of oil import price to the exchange rate;

B = 25% , fraction of marginal oil revenues recycled to US;

n_x = -2., elasticity of demand for exports;

n_m = -1.5, elasticity of demand for imports other than oil. This figure and the elasticity for exports are drawn from the surveys reported in Corden, Caves and Evans[21];

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19 Hogan and Leiby, 1985.

20 Hogan and Leiby, 1985.

21 W.M. Corden, Trade Policy and Economic Welfare, Clarendon Press, Oxford 1974, pp. 183-184; R. E. Caves, World Trade and Payments, Little, Brown and Company, Boston 1981, p. 283; M. K. Evans, Macroeconomic Activity, Harper and Row, New York, 1969, pp. 227-228.

X = \$227. billion, value of exports, the value in 1985;

M = \$285. billion, value of imports other than oil, the value in 1985;

GDP_o = \$4525. billion, the normal GDP, the value in 1985;

u = 0.05, elasticity (minus) of GDP with respect to oil price shock. Several studies have used similar estimates drawn from the analysis of past supply interruptions and simulation with more detailed macroeconomic models[22];

$\delta s/\delta q$ = 0.36, the change in interruption size induced by a change in long-run import demand, based on the evaluation of the U.S. share of the world market, see Hogan[23];

A_d = 0.1 adjustment rate for domestic oil demand[24];

A_s = 0.1 adjustment rate for domestic oil supply[25];

$n_{i:short}$ = 0.1 short-run imported oil supply elasticity;

SPR_Size = 500 million barrels.

In addition to these parameters, the base case specifies the probability distribution for oil supply interruptions over the possible interruption sizes, s. For purposes of the sensitivity analysis, we consider

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22 See Murphy et al 1986; Rowen and Weyant 1986.

23 Hogan 1981.

24 Hogan and Leiby, 1985.

25 Hogan and Leiby, 1985.

four different views of the world about the probability of one-year long interruptions of 1 mmbd, 3 mmbd, and 6 mmbd, for the United States. For each of these world views we characterize the decade probabilities of one or more such interruptions:

Table A.1

Decade Probabilities

One Year Interruptions[26]

World View	1 mmbd	3 mmbd	6 mmbd
W0	.0	.0	.0
W1	.50	.10	.05
W2	.75	.30	.05
W3	.95	.50	.20

The last three world views correspond to increasingly pessimistic views of the likelihood of oil supply interruptions. The zero (W0) case provides a benchmark from which to separate the disruption effects from the other constituents of the oil import premium. The nominal assumptions adopt world view two (W2).

26 Values for s ex ante, i.e., before use of the Strategic Petroleum Reserve.

High Price Estimation

The combination of these base case assumptions produce estimates of the individual components of the premium and the optimal tariff as wells as the cost of the free market policy. Using a price of $27 per barrel to represent the high price case, the estimates are:[27]

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27 Calculation of the optimal tariff includes a number of intermediate calculations. For the high price case, for instance, these include:

Hi Price Case $27

OPTIMAL TARIFF CALCULATION INTERMEDIATE CALCULATIONS

q:base	6.00	base oil import level
b	0.022	derivative of the short run import supply curve
c	0.048	derivative (minus) of short run import demand curve
$\delta q_d/\delta p$	-0.19	derivative of long run domestic demand for oil
$\delta q_s/\delta p$	0.185	derivative of long run domestic supply of oil
n_d:short	-0.05	short-run elasticity of US demand for oil
n_s:short	0.05	short-run domestic oil supply elasticity
n_{eq}	-0.03	elasticity of exchange rate to the oil import price le
$\delta Q/\delta q$	0.53	derivative of Q with respect to q
p'	-2.66	derivative of domestic inverse demand curve
W	0.97	scale factor for tariff loss during interruption

OPTIMAL TARIFF CALCULATION INTERRUPTION WORK CALCULATIONS

Decade_p	Prob_j	GDP_j	s_j	Δp_j	δΔp/δq_j
0.75	0.129	4478	0.75	8.42	3.82
0.30	0.035	4388	2.75	30.79	3.29
0.05	0.005	4300	5.75	64.33	2.49

OPTIMAL TARIFF CALCULATION High Price Case
($/Barrel)

s		25.08	IMPORT PRICE
T_1	1.45		
T_2	0.69		
T_3	1.11		
		3.25	ECONOMIC PREMIUM
T_4	2.82		
T_5	4.96		
		7.78	SECURITY PREMIUM
T		11.03	TOTAL PREMIUM
p		36.10	DOMESTIC PRICE
q:d	13.84 DEMAND		
q:s	11.69 SUPPLY		
q	2.15 IMPORTS		

Optimum	Economic Tariff	3.25	
	Security Tariff	7.78	
	Combined Tariff		11.03
Base	Economic Premium	7.31	
	Security Premium	10.40	
	Combined Premium		17.71
Cost of Free Market Policy ($million/day)			34.07

Low Price Estimation

The first sensitivity test takes the base case parameters but changes the assumption for oil prices. We continue to assume that the benchmark level for energy demand is 16 mmbd at $27 per barrel, with a 10 mmbd domestic supply, implying a 6 mmbd demand for imports. However, now we assume that imports can be supplied for $15 per barrel. Starting at this new price, we solve for the equilibrium levels where the domestic demand, domestic supply and import supply balance. The solution produces a higher premium, a higher tariff and a higher cost of a free market policy:

OPTIMAL TARIFF CALCULATION Low Price Case
($/Barrel)

s	11.76	IMPORT PRICE	
T_1	0.98		
T_2	0.68		
T_3	3.82		
		5.48	ECONOMIC PREMIUM
T_4	1.77		
T_5	5.30		
		7.07	SECURITY PREMIUM
T	12.55	TOTAL PREMIUM	
p	24.32	DOMESTIC PRICE	
q:d	16.86	DEMAND	
q:s	9.33	SUPPLY	
q	7.53	IMPORTS	

Optimum	Economic Tariff	5.48	
	Security Tariff	7.07	
	Combined Tariff		12.55
Base	Economic Premium	11.24	
	Security Premium	9.16	
	Combined Premium		20.40
Cost of Free Market Policy ($million/day)			70.60

The increased demand, associated with the lower price, raises the expected level of imports and increases the economic component of the premium more than it decreases the security component, leading to a higher cost for a free market policy. Hence, although some of the externalities are reduced with lower oil price, under the base case assumptions the effect of lower oil prices is to raise the size of the premium and the optimal tariff.

Secure Imports Estimation

The estimate of the optimal tariff includes both economic and security components of the premium. Naturally a reduction in the risk of oil supply interruptions should have a beneficial effect on oil consumers and, thereby, lower the optimal tariff. However, as we argued above, changes in one element of the premium ca change the size of the other elements. There is a feedback effect. The interaction may cause the various elements to shift so that the aggregate change in the optimal tariff is less than the change in the individual components of the premium.

The optimal tariff under the condition of no oil supply interruptions is larger than the economic component of the tariff in the base case. With the high price case and the extreme assumption of no threat of supply interruptions, the optimal tariff, the premium and the cost of a free market policy, would change to include:

OPTIMAL TARIFF CALCULATION Secure Imports Case
($/Barrel)

s	26.07	IMPORT PRICE
T_1	1.52	
T_2	1.49	
T_3	2.07	
		5.08 ECONOMIC PREMIUM
T_4	0.00	

T_5	0.00	
	0.00	SECURITY PREMIUM
T	5.08	TOTAL PREMIUM
p	31.14	DOMESTIC PRICE
q:d	14.90	DEMAND
q:s	10.77	SUPPLY
q	4.13	IMPORTS

Optimum	Economic Tariff	5.08	
	Security Tariff	0.00	
	Combined Tariff		5.08
Base	Economic Premium	7.12	
	Security Premium	0.00	
	Combined Premium		7.12
Cost of Free Market Policy ($million/day)			6.65

It is clear that the simultaneity and complementarity between the economic and security components of the premium imply a significant optimal tariff even if security problems are eliminated.

Risk Analysis Estimation

These few sensitivity tests illustrate the principal responses of the optimal tariff calculation to changes in the input assumptions. The high and low oil price cases, or the secure world oil market scenario, produce changes in the estimate of the optimal tariff. However, the optimal tariff still continues to be a large fraction of the price of oil and large relative to any tariff that might be considered politically acceptable. Unfortunately, the few sensitivity tests do not exhaust the major uncertainties that could affect the size of the optimal tariff. Higher or lower assumptions about inflation could have a significant impact on both the quantity of oil imported and the estimate of the optimal tariff. Similarly, changes in elasticity estimates, alternative views about the probability of interruptions, or uncertainties in any of the other parameters could alter the optimal import tariff estimate.

It is not possible to examine all potential combinations of the long list of important input parameters. The number of scenarios would quickly exhaust our capacity to absorb the data. As an alternative, therefore, a "risk analysis" of the optimal tariff estimate captures a range of possible tariff policies that should be considered given our uncertainty in the input parameters.

Under risk analysis, the analyst specifies the uncertainties in terms of probabilities for different values of the input parameters. For instance, the most likely estimate of the aggregate demand elasticity is

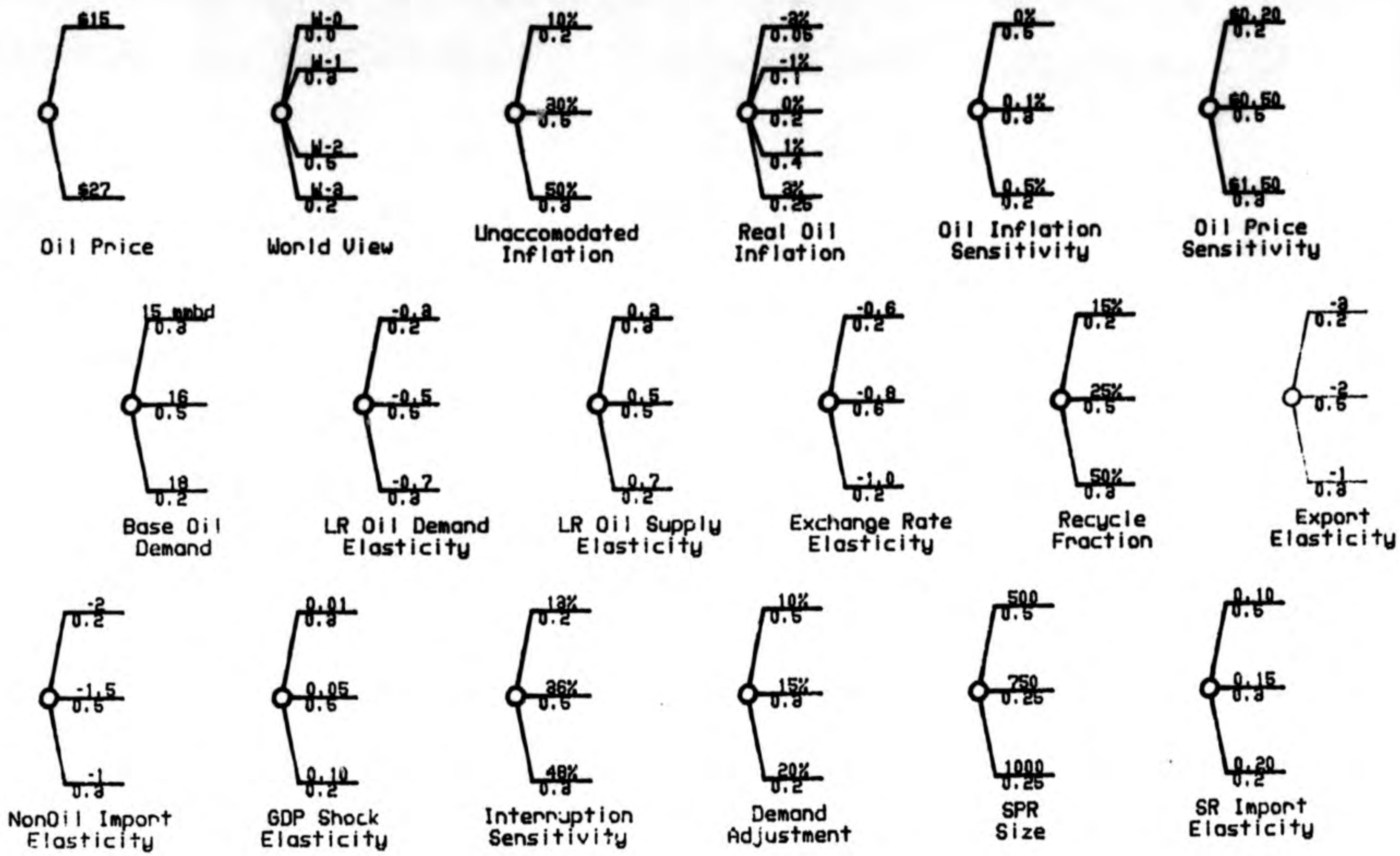
0.5. This demand elasticity reflects the estimates from a variety of studies, some of which produce higher values and some of which produce lower values. For purposes of the sensitivity analysis, it is easy to argue that there is a significant chance that the elasticity could be as high as 0.7 or low as 0.3. A wider range is possible but the principal range of uncertainty should be captured by these values. The probability that the elasticity will be as high as .7 or as low as .3 is not as great as the probability that the most likely case is correct. Using our judgment, we assign probabilities of 30% to the elasticity of 0.7, 50% to the elasticity of 0.5 and 20% to the elasticity of 0.3.

A similar probabilistic analysis across the range of possible values for the other key inputs establishes a probability distribution for all of the uncertain parameters. An event tree summarizes these probability judgments as shown in figure A.1. This event tree assigns one node to each uncertainty and the branches describe the possible alternative values for the respective input parameters. The probability represent the judgments on the uncertainty that should be applied to the sensitivity analysis.

Given the event tree, it is a straightforward matter to apply the optimal tariff model to calculate the probability distribution of the tariff components and the cost of a free market policy. This simulation also provides the probability distribution for the optimal tariff. Application of the event tree to the optimal tariff model produces the probability distributions shown in figures A.2 through A.4. Each probability distrib-

FIGURE A.1

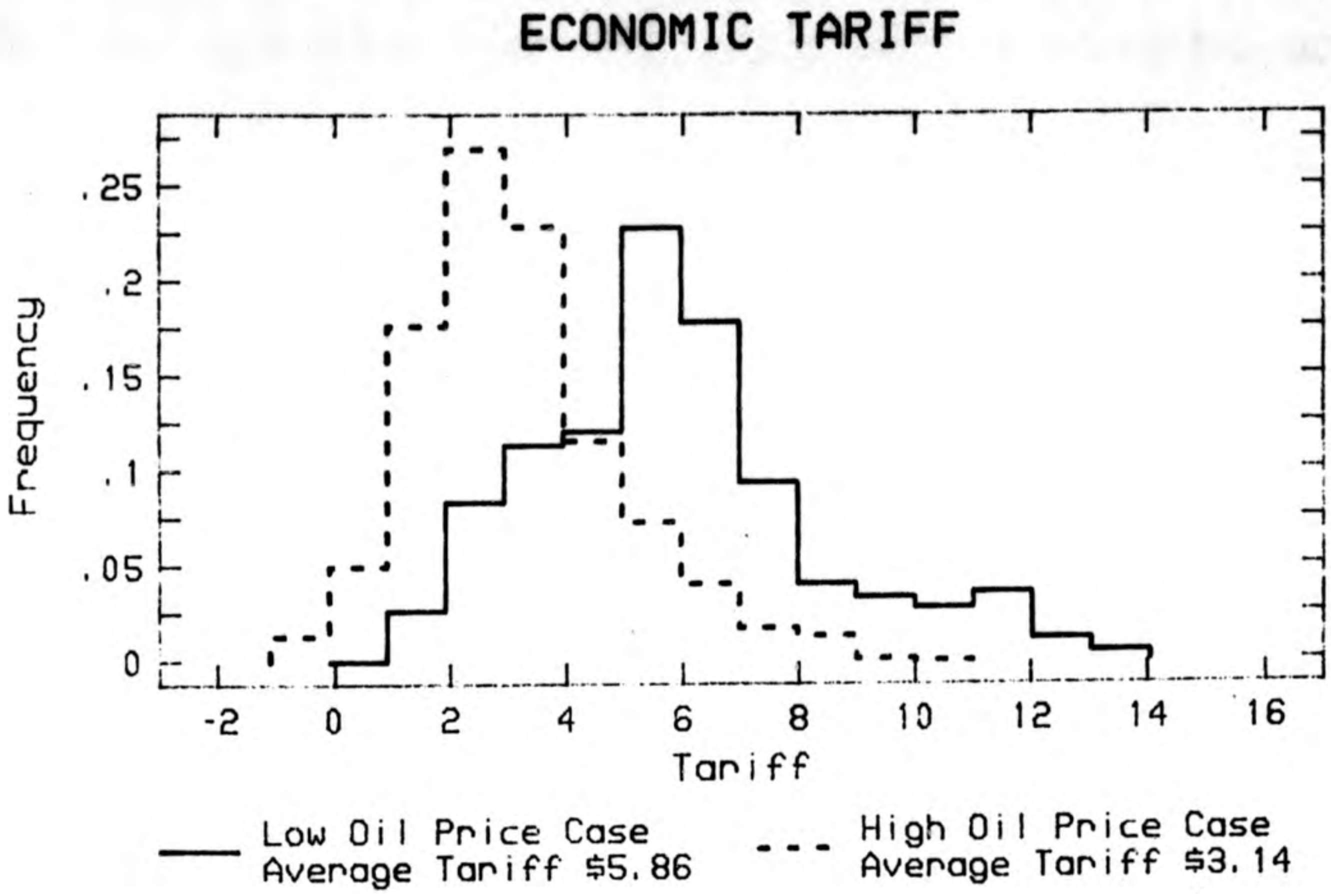
Oil Premium Inputs are Uncertain



Prices in 1985 dollars per barrel.

FIGURE A.2

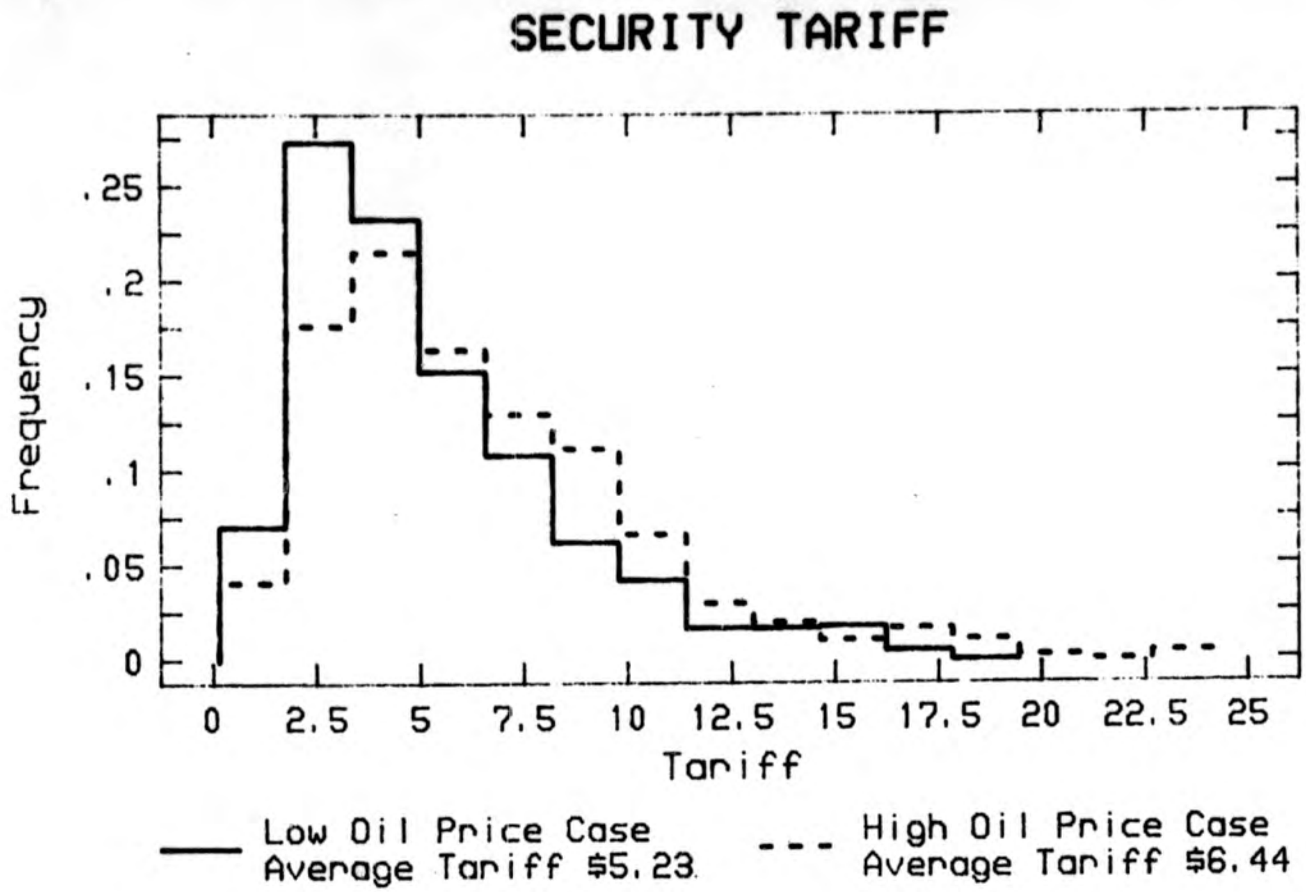
Lower Oil Prices Produce a Higher Economic Tariff



Prices in 1985 dollars per barrel.

FIGURE A.3

Lower Oil Prices Produce a Lower Security Tariff

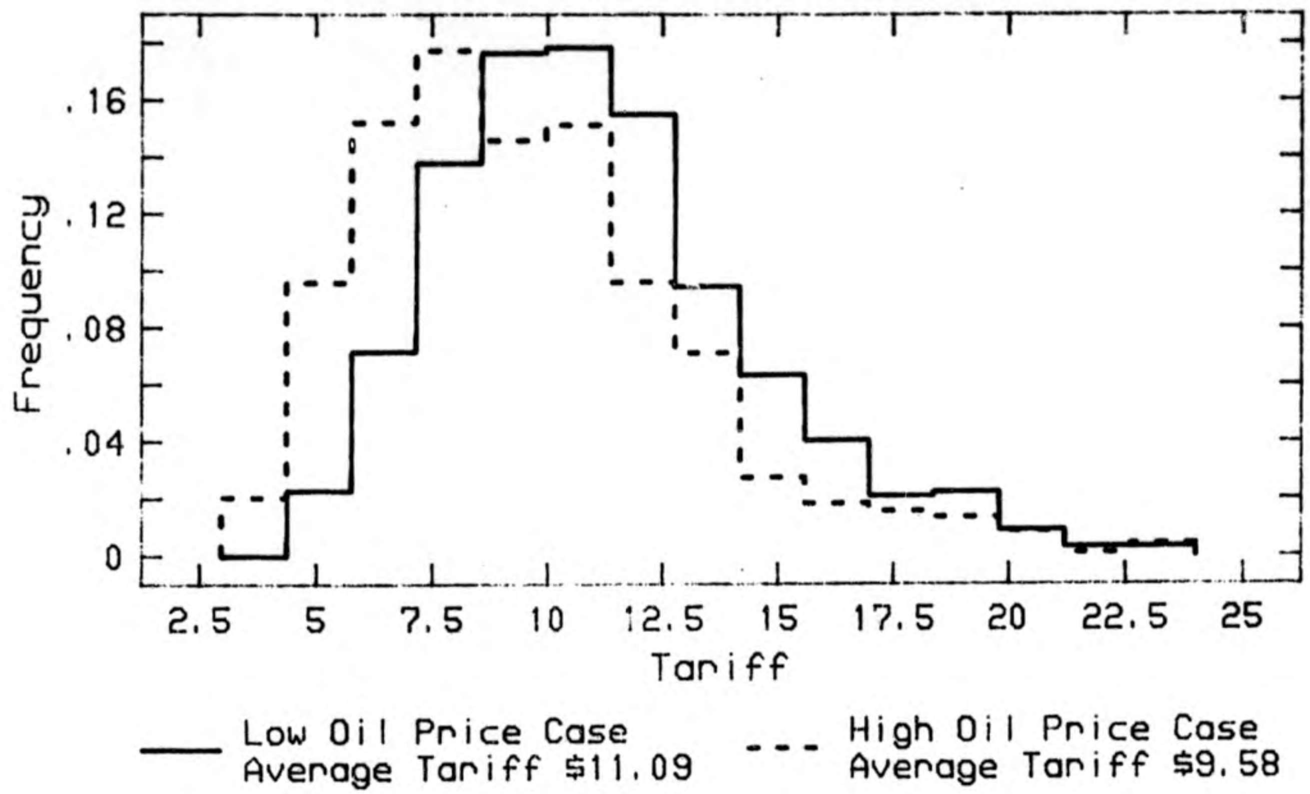


Prices in 1985 dollars per barrel.

FIGURE A.4

After Netting Out Compensating Effects Oil Prices Have Little Impact on the Optimal Tariff

COMBINED TARIFF



Prices in 1985 dollars per barrel.

ution summarizes the range of uncertainty in the optimal tariff estimates policy and the costs of a free market policy.

Focusing on the key sensitivity test between low and high oil prices, the probability distributions include:

Optimal Tariff and Cost Probability Distributions
($/Barrel)

High Price Case ($27)

	Lower 25%	Median	Upper 25%	Expected Value
Economic Tariff	1.95	2.85	3.90	3.14
Security Tariff	3.63	5.64	8.52	6.44
Total Optimal Tariff	7.00	8.96	11.26	9.58
Cost of Free Market Policy ($million/day)	12.71	22.58	36.11	29.03

Low Price Case ($15)

	Lower 25%	Median	Upper 25%	Expected Value
Economic Tariff	4.03	5.68	6.87	5.86
Security Tariff	2.80	4.20	6.65	5.23
Total Optimal Tariff	8.71	10.81	11.89	11.09
Cost of Free Market Policy ($million/day)	32.10	49.03	76.51	61.48

SUMMARY

The optimal import tariff balances all the costs and benefits of oil imports. Although any operational estimate of the tariff will depend upon an array of assumptions and judgments, it is possible to make these judgments and organize them in an internally consistent set of calculations. These estimates quantify the several possible sources of market failure which prevent private actors from recognizing the true costs of the marginal barrel of oil imports. The resulting tariff estimates are sensitive to the assessment of market conditions, but this sensitivity appears to be much less than commonly believed. There is a significant amount of interaction among the tariff components. A change in assumption which reduces one element tends to produce a compensating increase in others, and the whole is less sensitive than the parts.

This complementarity and the numerical results provide a guide for action. The size of the tariff is large. Our preferred set of assumptions sets the optimal tariff about $10 and $11 per barrel. Under the High Price case, there is a 75% chance that the optimal tariff is at least $7 per barrel. And under the Low Price case, this estimate to an optimal tariff of at least $8.70 per barrel. When compared with the usual political discussions, where the most adventuresome conversation involves tariffs that are half this range, the direction of policy is clear: higher tariffs can be justified. Based on the estimates of market failure, a figure in the range of $7 per barrel and $9 per barrel is as low as can be supported by the analysis and the judgments on the range of uncertainty in the parameters.

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Zeise, Lauren, Richard Wilson, and Edmund A.C. Crouch, "The Dose Response Relationships For Carcinogens: A Review," Discussion Paper Series, Kennedy School of Government, Harvard University, June 1986, #E-86-07.

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Kalt, Joseph P., Henry Lee, and James T. Hamilton, "A Review of the Adequacy of Electric Power Generating Capacity in the United States, 1985-93 and 1993-Beyond," Discussion Paper Series, Kennedy School of Government, Harvard University, June 1986, #E-86-09.

Mayer, Frederick W. and Henry Lee (editors), "Environmental Risk Management: Research Needs and Opportunities," Discussion Paper Series, Kennedy School of Government, Harvard University, October 1986, #E-86-10.

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ENERGY & SECURITY PROGRAM

DISCUSSION PAPER SERIES

Alm, Alvin and Edward Krapels, "Building Buffer Stocks in a Bear Market: Policy Choices for Emergency Oil Reserves," Discussion Paper Series, Kennedy School of Government, Harvard University, March 1982, #H-82-01.

Hogan, William W., "Oil Stockpiling: Help thy Neighbor," Discussion Paper Series, Kennedy School of Government, Harvard University, March 1982, #H-82-02.

Deagle, Edwin A. Jr. and Bijan Mossavar-Rahmani, "Oil Demand and Energy Markets: An Interpretation of Forecasts for the 1980s," Discussion Paper Series, Kennedy School of Government, Harvard University, May 1982, #H-82-03.

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Greer, Boyce I. and Jeremy L. Russell, "European Reliance on Soviet Gas Exports: the Yamburg-Urengoi Natural Gas Project," Discussion Paper Series, Kennedy School of Government, Harvard University, February 1982, #H-82-05.

Devarajan, Shantayanan and R. Glenn Hubbard, "Drawing Down the Strategic Petroleum Reserve: The Case for Selling Futures Contracts," Discussion Paper Series, Kennedy School of Government, Harvard University, June 1982, #H-82-06.

Hubbard, R. Glenn and Robert Weiner, "The 'Sub-Trigger' Crisis: An Economic Analysis of Flexible Stock Policies," Discussion Paper Series, Kennedy School of Government, Harvard University, June 1982, #H-82-07.

Hubbard, R. Glenn, "Policy Analysis With Your Hands Tied: The Disruption Tariff Under Oil Price Controls," Discussion Paper Series, Kennedy School of Government, Harvard University, June 1982, #H-82-08.

Kelman, Steven, "Revenue Recycling: An Implementation Plan," Discussion Paper Series, Kennedy School of Government, Harvard University, March 1983, #H-83-01.

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Krapels, Edward N., E. William Colglazier, Barbara Kates-Garnick, Robert Weiner, Thomas Dreves and Erik Jonnaert, "Crude Oil Access in Disruptions in the 1980s: Analysis of Public Policy Implications," Discussion Paper Series, Kennedy School of Government, Harvard University, May 1983, #H-83-03 (Comes in two volumes).

SJR

43

May 5, 1987

SJR 43, RELATING TO THE SHIPPING OF ALASKAN OIL

1) Review CDS Tanker issue

Four supertankers have been allowed to operate in the domestic trade on the condition that they repay their Construction Differential Subsidies (CDS)

In January, the U.S. District Court of Appeals vacated this rule, but allowed the ships to operate until July 16, 1987.

2) Update on U.S Department of Transportation Action

Maritime Administration has filed a Notice of Proposed Rulemaking on the CDS Repayment.

3) Update on Congressional Action

House Supplemental Appropriations Bill has language that would prevent U.S. Department of Transportation from adopting new rules.

Senate amendment was defeated last week by a 14-11 vote in the Senate Appropriations Committee. Could be reinserted on the Senate floor. It may be on the floor by the end of this week.

If its out of the Senate bill, it will be a conferenceable item.

TO TESTIFY:

JIM PALMER, Standard Alaska Production Company

VINCE WRIGHT, Chief of Research Section, Department of Revenue

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Arco battles smaller tankers in showdown for Alaska crude

By DON IRWIN
Los Angeles Times

WASHINGTON — Lobbyists and legislators are bracing for the showdown in a long-running contest for dominance in the seaborne traffic that moves Alaskan crude oil to the Lower 48 states.

The struggle, which is approaching a climax in Congress and the executive branch, involves millions of dollars in government and corporate funds, as well as some of the largest ships afloat. In the end, it may well decide whether a few supertankers are to replace smaller vessels as the principal haulers of North Slope oil.

In its current phase, the fight primarily involves Atlantic Richfield, the Los Angeles-based owner of two 262,000-ton tankers. To make the ships eligible for the Alaska trade, Arco has repaid the U.S. Maritime Administration $86.4 million for federal subsidies that helped pay for their construction. The subsidies were granted originally on the condition that the vessels be used only for foreign traffic.

Working in Congress to scotch the deal are the owners of the smaller, less efficient ships that require crews almost as large as the supertankers and must charge higher rates per barrel of crude transported.

They have asked Congress to stand by the original terms of the subsidies and keep the supertankers out of the domestic market, arguing that the competition would seriously harm all smaller operators.

The owners are also trying to force the Transportation Department to drop its approval of such payback arrangements. In accordance with the department's earlier clearance for two subsidized supertankers owned by other firms to enter domestic traffic, a federal court has ordered that the department issue a rule by July 16 that would allow all subsidized vessels to do the same. Arco is seeking to take advantage of the rule.

On Capitol Hill, the House Appropriations Committee has voted, 18 to 16, for a measure that would effectively bar completion of work on the rule.

The bill will go to the full House after Congress returns on April 21 from its Easter recess. If it becomes law, it may well require eventual return of more than $100 million in subsidy repayments by shipping companies.

The tangled dispute began in the 1970s, when shipping companies first offered subsidy "buybacks" in exchange for permission to operate domestically. The construction of seven supertankers had been subsidized under a 1936 provision of the Maritime Act of 1920, which was designed to make U.S. vessels more competitive in world commerce.

After a court challenge, the Supreme Court ruled that such a reimbursement arrangement would be legal for tankers of at least 100,000 tons.

Why people quit

The Associated Press

NEW YORK — Saying no to nap breaks during work or to having a talking mynah bird in the office may seem reasonable, but those refusals were enough to make somebody walk off the job, according to a survey of why people quit their jobs.

An independent research firm, hired by Accountemps, a temporary personnel agency, asked personnel managers at 100 large corporations around the country for the most unusual reasons employees have given for quitting.

Here are some of the answers:

- "They said I couldn't take short nap breaks twice a day."
- "They wouldn't let me keep my mynah bird in a cage in my office."
- "My salary was so high, it made me uncomfortable."
- "My office did have a window, but I didn't like the view."
- "I got tired of driving to work, and the company wouldn't pay for taxis."
- "The job was fine, but it was no place to meet men. Too many of them were bald, with bow ties, suspenders and white socks."
- "I'm going to be happier as a dog trainer than as a management consultant."
- "I want to write poetry on the beach."

HOUSE JOINT RESOLUTION 33

HISTORY

On January 16, 1987, the U.S. Court of Appeals decision (First Attransco Tanker Corp. vs. Dole) vacated a Department of Transportation ruling. The DOT ruling permitted three very large crude carrier ships to repay the remainder of their construction subsidies in 1985/6. In doing so, they became Jones Act ships rather than just U.S. flag ships.

The Court ruled that the Secretary of Transportation was well within her authority to permit this repayment. However, the Court also ruled there were procedural defects in that she did not adequately explain the effect of this action on other Jones Act ships. Thus the ruling was unjustified. The decision requires all three ships to cease Alaskan service on July 16, 1987, unless the Department of Transportation explains the effect on other Jones Act ships to the Court's satisfaction.

Prior to repaying the subsidy, these three large, efficient U.S. flag ships were not allowed to carry Alaskan oil unless there were no suitable Jones Act ships available. Even under those circumstances these ships could only be used part time (no more than six months out of the year). A fourth ship which entered Jones Act trade under generally similar circumstances in 1983 is also vulnerable to the ruling.

In total these four ships are currently moving 200,000 barrels of Alaskan oil to market every day. If they are taken out of the fleet, then a large number of much smaller, less efficient and more expensive ships must take their place if the Alaskan oil is to get to market. This would raise the market price for all Jones shipping by an estimated 25 cents to $1.00 per barrel.

An increase in the cost of transportation not only reduces oil company income and incentive in Alaska but also reduces the netback value of all Alaskan production. For example, each 50 cent increase in per barrel transportation cost would reduce state income by roughly $75 million per year.

Given this situation, Alaska should support the DOT's intention to issue a new rule confirming that these vessels should remain Jones Act vessels as soon as possible because of the July 16, 1987 deadline.

Attached is further information regarding this "Repayment of Construction Differential Subsidies (CDS)".

Repayment of Construction Differential Subsidies (CDS)
(also called "CDS Sanitization")

DISCUSSION ISSUES:

The following information should be noted in discussion of CDS Sanitization:

- This is a significant economic issue for Alaska. Removal of the four large efficient ships will require using nearly all the smaller ships available, driving the market price for all shipping up by $.25 to $1 per barrel. Netback values on the crude oil will decline accordingly. Each $.50 per barrel reduction in netback represents roughly $75 MM per year in lost state revenues.

- Alaskan oil production has increased significantly in the last year, highlighting the need for efficient transportation. The Lisburne field (40-50 MBD) began commercial production in early 1986, Prudhoe Bay production increased with natural gas liquid (NGL) recovery in early 1987 (50 MBD). Kuparuk has reached peak production, and Endicott field is expected to begin production in the fourth quarter of 1987 (up to 100 MBD).

- Largely because of the increased Alaskan production the four large, efficient VLCC vessels in question have been in continuous service since repayment of their remaining subsidy: the BROOKLYN and the BAYRIDGE under charter to EXXON, and the ARCO INDEPENDENCE and the ARCO SPIRIT under long term charter to Standard Oil.

- Larger vessels make the transport of crude oil to the West Coast and Gulf Coast more economically efficient than smaller vessels. This is especially true to the Gulf Coast, which accounts for a substantial portion of the Alaskan oil delivered.

5-1050A
Bannister
4/9/87

IN THE SENATE BY FAHRENKAMP

SENATE JOINT RESOLUTION NO.

IN THE LEGISLATURE OF THE STATE OF ALASKA

FIFTEENTH LEGISLATURE - FIRST SESSION

Relating to the shipping of Alaskan oil.

BE IT RESOLVED BY THE LEGISLATURE OF THE STATE OF ALASKA:

WHEREAS on January 16, 1987, the United States Court of Appeals for the District of Columbia vacated a United States Department of Transportation rule under which three very large crude oil carrier ships were allowed to operate in the United States domestic shipping market; these ships are the Arco Independence, the Arco Spirit, and the Brooklyn; and

WHEREAS the court decision would require all three ships to stop domestic shipping of Alaskan oil by July 16, 1987, unless the United States Department of Transportation adopts another rule to allow the ships to continue their domestic shipping; and

WHEREAS a fourth ship, the Bayridge, that is used in Alaskan oil shipping may also be affected by the court decision; and

WHEREAS Alaskan oil production has increased significantly in the last year, and these four ships currently move 200,000 barrels of Alaskan oil to market every day; and

WHEREAS if the four ships are prohibited from engaging in domestic shipping, a large number of much smaller, less efficient and more expensive ships will be required to take their place to transport Alaskan oil to market; this change would raise the cost of ~~transportation~~ costs ~~market price~~ for all Alaskan oil shipped in these smaller ships by an estimated $.25 to $1.00 per barrel, and netback values on the oil would decline accordingly; each approximately $.50 ~~[illegible]~~ per barrel reduction in the netback value of the oil transported by these four ships represents roughly 1,500,000 $75,000,000 per year in lost revenue to the state; and

WHEREAS if the United States Department of Transportation does not adopt a rule by July 16, 1987, allowing these four ships to operate in the domestic shipping market ~~in the United States,~~ the transportation of Alaskan oil ~~will~~ may be ~~severely~~ disrupted, the transportation costs will increase dramatically, and the state and federal government ~~will~~ may lose a significant amount of revenue;

BE IT RESOLVED that the Alaska State Legislature respectfully urges the Secretary of the United States Department of Transportation to adopt before July 16, 1987, a rule that would enable the Arco Independence, the Arco Spirit, the Bayridge, and the Brooklyn to continue to operate in the United States domestic shipping market without interruption.

COPIES of this resolution shall be sent to the Honorable Elizabeth H. Dole, Secretary of the U.S. Department of Transportation; and to the Honorable Ted Stevens and the Honorable Frank Murkowski, U.S. Senators, and the Honorable Don Young, U.S. Representative, members of the Alaska delegation in Congress.

5-1050A
Bannister
4/9/87

IN THE SENATE BY FAHRENKAMP

SENATE JOINT RESOLUTION NO.

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WHEREAS a fourth ship, the Bayridge, that is used in Alaskan oil shipping may also be affected by the court decision; and

WHEREAS Alaskan oil production has increased significantly in the last year, and these four ships currently move 200,000 barrels of Alaskan oil to market every day; and

WHEREAS if the four ships are prohibited from engaging in domestic shipping, a large number of much smaller, less efficient and more expensive ships will be required to take their place to transport Alaskan oil to market; this change would raise the market price for all Alaskan oil shipped in these smaller ships by an estimated $.25 to $1.00 per barrel, and netback values on the oil would decline accordingly; each $50 per barrel reduction in the netback value of the oil represents roughly $75,000,000 per year in lost revenue to the state; and

WHEREAS if the United States Department of Transportation does not adopt a rule by July 16, 1987, allowing these four ships to operate in the domestic shipping market in the United States, the transportation of Alaskan oil will be severely disrupted, the transportation costs will increase dramatically, and the state will lose a significant amount of revenue;

BE IT RESOLVED that the Alaska State Legislature respectfully urges the Secretary of the United States Department of Transportation to adopt before July 16, 1987, a rule that would enable the Arco Independence, the Arco Spirit, the Bayridge, and the Brooklyn to continue to operate in the United States domestic shipping market without interruption.

COPIES of this resolution shall be sent to the Honorable Elizabeth H. Dole, Secretary of the U.S. Department of Transportation; and to the Honorable Ted Stevens and the Honorable Frank Murkowski, U.S. Senators, and the Honorable Don Young, U.S. Representative, members of the Alaska delegation in Congress.

ALASKA STATE LEGISLATURE

SENATE SPECIAL COMMITTEE
ON OIL AND GAS

Senator Bettye Fahrenkamp
Chairman
Senator Jack Coghill
Senator Paul Fischer

P.O. Box V, State Capitol
Juneau, Alaska 99811
(907) 465-3834

M E M O R A N D U M

TO: Members, Senate Special Committee on Oil and Gas

FROM: Committee Staff

RE: Committee Meeting, May 5, 1987

DATE: May 4, 1987

On Tuesday, May 5, at 3:30 pm in the Beltz Room, the Senate Special Committee on Oil and Gas will hear SJR 43, Relating to the shipping of Alaskan oil.

Four of the supertankers currently used to transport oil from Valdez to the West coast and to Panama (for delivery to the Gulf and East coasts) are allowed to operate under a special waiver from the U.S. Department of Transportation. A recent U.S. Court of Appeals decision held that these rules were improperly drafted, but allowed the ships to operate until July 16, 1987. If new rules are not adopted by that date, these ships will have to be replaced with smaller, less effficient vessels. The resulting increase in the transportation costs for Alaska North Slope oil will decrease wellhead values and could result in a loss of revenue to the state of from \$18 - \$150 million annually.

These ships were built with federal construction differential subsidies (CDS), a program designed to help U.S. built ships to compete in foreign trade markets. To alleviate the shortage of suitable Jones Act tankers, the U.S. Department of Transportation has allowed these ships to enter the domestic trade after repaying the subsidy.

In response to the court decisions, the U.S. Department of Transportation is in the process of adopting new rules that would allow the four ships to remain in the domestic trade. However, pending amendments in Congress may prohibit such new rulemaking.

SJR 43 urges the Secretary of the U.S. Department of Transportation to adopt new rules by July 16, 1987.

STEVE COWPER
GOVERNOR

RECEIVED
ALASKA DEPARTMENT OF REVENUE
APR 1 1987
OFFICE OF THE COMMISSIONER

STATE OF ALASKA
OFFICE OF THE GOVERNOR
WASHINGTON, D.C.

April 8, 1987

MEMORANDUM

TO: BRAD GILMAN, U.S. Senate Commerce Committee

FROM: EO ERIC OSTROVSKY, Associate Director for Fisheries and the Environment

THROUGH: JWK JOHN W. KATZ, Director of State/Federal Relations and Special Counsel to the Governor

SUBJECT: 1) ALASKA REVENUE IMPACT CAUSED BY DENYING THREE VLCC CDS SHIPS TO THE ALASKA TRADE
2) THE NUMBER OF NEW JOBS CREATED BY USING SMALLER TANKERS

REVENUE IMPACT

The Alaska Department of Revenue, Petroleum Research Section (Research Section) in a recent analysis has indicated that if three CDS tankers owned by ARCO and Standard Oil were taken out of the Alaska trade, the direct ecomomic loss to the State of Alaska would be $18 - $150 million annually. This revenue loss would result from a decrease in Alaska's oil royalty and severance taxes. The decrease would be caused by a decrease in the wellhead price of oil, which is calculated as the price of oil at its final destination minus pipeline shipping and other allowable costs.

Each CDS super oil tanker can carry significantly more oil than its smaller counterparts, and the CDS tanker transports oil at a cheaper rate. A study last year by the Research Section showed that CDS tankers could save an average of 45 percent in shipping costs over non-CDS tankers. This amounts to $1.25/bbl for Gulf Coast shipments and $0.57/bbl for West Coast shipments. Since the three CDS tankers were introduced into the Alaska trade in between July, 1985 and May, 1986, the average tanker rate overall to the Gulf Coast has dropped by $0.75/bbl.

The three CDS tankers now engaged in Alaska North Slope (ANS) oil shipments are transporting about 60 million barrels annually. The following equation reflects the reason why the Research Section predicts that the State would lose at least $18 million annually:

Royalty Effect

60 (million barrels of oil) x \$1.25 (\$1.25 savings) x 0.125 (12.5 percent royalty) = \$9.4 million.

plus

Severance Tax Effect

60 x 1.25 x 0.15 (severance rate) x 0.84 (economic life factor) x 1 - 0.125 (severance tax adjustment) = \$8.3 million.

TOTAL \$17.7 million

The severance tax adjustment is needed because this severance tax is levied only on non-royalty oil, ie,. a tax on the oil left after the royalty oil is subtracted. The economic life factor, which reduces the effective severance tax rate as well productivity declines, is estimated to be 0.84 percent over the near term.

The reason why \$18 million is a conservative estimate is that the reduced competition from the removal of the tankers (the tanker market is currently fully extended) could raise the transportation cost for all ANS oil, so that, the State could lose over \$50 million annually if tanker rates on all shipments to the Gulf Coast returned to the previous level. The following equation shows how the \$50 million figure was derived:

Royalty Effect

300 (millions of barrels of ANS oil delivered to the Gulf Coast) x 0.75 (actual overall rate reduction when the three CDS vessels were introduced into the trade) x 0.125 = \$28.1 million

plus

Severance Tax Effect

300 x \$0.75 x 0.15 x 0.84 x (1 - 0.125) = \$24.8 million

TOTAL \$52.9 million

If the shipping rate on all ANS oil shipments both to the Gulf and West Coast were to increase the full 45 percent, Research Section estimates that the revenue impact on the State could go as high as \$150 million annually.

POTENTIAL JOBS CREATED BY THE CHANGE

The United States Maritime Administration (MarAd) predicts that about 500 new jobs would ultimately be created by prohibiting the CDS ships in the Alaska trade. MarAd predicated this figure based on the assumption that the smaller tankers replacing the CDS tankers would hire about 800 crewmen. On the other hand, about 300 jobs would be lost on the three CDS tankers, reducing the new jobs created to 500.

With the tanker market in the Alaska trade currently fully extended, it is not certain whether new seafarer jobs would be created or that only transportation costs would rise due to increased demand. Moreover, if the wellhead price drops, ANS oil could not compete against the world market price, and ANS oil production would decrease, which is what happened recently when the Milne Point oil field shut down. This effect would also limit potential jobs. The ability of ANS oil to compete on the world market will become a greater factor as new, more costly methods are needed to extract ANS oil, and the cost of transportation may become an even more significant component in determining whether ANS oil can compete.

Finally, there would be a $114 million direct and immediate loss to the Federal Treasury caused by denying the Alaska trade to the three CDS tankers. Part of the costs, $105.8 million would come from the CDS repayments, and, the remainder, another $8 million would be in interest. According to the U.S. Maritime Administration, the Federal government would also lose about $44 million annually in Federal income taxes due to the less profitable trade caused by the use of non-CDS tankers. MarAd determined the tax loss by estimating that it would cost an extra $128 million in shipping expenses to transport ANS oil in non-CDS ships.

Please let us know if you need further additional information on this subject.

cc: Greg Chapados
John Moseman
C.J. Zane
Bill Wolfe
Rod Moore
Rebecca Range

STATE OF ALASKA 1987 LEGISLATIVE SESSION
FISCAL NOTE

REQUEST

Bill Version: SJR 43
Publish Date:

Revision Date:
Title: Shipping State Oil

Agency Affected: Revenue
BRU:

Sponsor: Sen. Fahrenkamp
Requestor: Senate Oil and Gas

Components:

EXPENDITURES/REVENUES: (Thousands of Dollars)

	FY 87	FY 88	FY 89	FY 90	FY 91	FY 92
OPERATING						
PERSONAL SERVICES	-	-	-	-	-	-
TRAVEL	-	-	-	-	-	-
CONTRACTUAL	-	-	-	-	-	-
SUPPLIES	-	-	-	-	-	-
EQUIPMENT	-	-	-	-	-	-
LANDS & STRUCTURES	-	-	-	-	-	-
GRANTS, CLAIMS	-	-	-	-	-	-
MISCELLANEOUS	-	-	-	-	-	-
TOTAL OPERATING	-	-	-	-	-	-
CAPITAL	-	-	-	-	-	-
REVENUE	(Revenue Impact $17.7 Mil to $52.9 Mil Per Year)					

FUNDING: (Thousands of Dollars)

GENERAL FUND	-	-	-	-	-	-
FEDERAL FUNDS	-	-	-	-	-	-
OTHER	-	-	-	-	-	-
TOTAL	-	-	-	-	-	-

POSITIONS:

FULL-TIME	-	-	-	-	-	-
PART-TIME	-	-	-	-	-	-
TEMPORARY	-	-	-	-	-	-

ANALYSIS: Attach a separate page if necessary

See attachment.

Prepared By: Royce Weller
Phone: 465-2300
Division: Commissioner's Office/Revenue
Date: May 5, 1987

Approved by Commissioner: Hugh Malone
Date: May 5, 1987
Agency: Department of Revenue

Distribution (by Agency preparing fiscal note):
- Legislative Finance
- Legislative Sponsor
- Requestor
- Office of Management and Budget
- Impacted Agency(ies)
- Senate Secretary

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 8672
1538 SCOMM 57: SENATE SPECIAL COMMITTEE ON OIL & GAS, 1987-1988 /335

MEMORANDUM

[illegible]

[illegible]

TO: Eric [illegible], Governor's Office, Washington, D.C.
FROM: Roger Marks, Petroleum Economist
SUBJECT: CDS Tankers
DATE: April 2, 1987

Our June 1985 analysis showed that CDS tankers could save 45% on average shipping costs over non-CDS tankers. This amounted to $1.25/bbl for Gulf Coast shipments and $0.57/bbl for West Coast shipments. Since repayment we have seen average tanker rates to destinations east of Panama drop 75 cents.

The three CDS tankers now engaged in ANS trade are moving oil to the U.S. Gulf Coast, and can carry 60 million barrels of ANS per year.

The losses to the State from removal of these tankers would accrue from lower wellhead values due to higher transportation costs. We estimate these losses to be a minimum of $10 million and as much as $50 million annually:

Royalty Effect

60 X 1.25 X .125 = $9.4

Severance Tax Effect

60 X 1.25 X (1 - .125) X .15 X .84 = $8.3

TOTAL $17.7 million

(The severance tax is levied on non-royalty oil. The severance tax rate is 15 percent. The economic limit factor (ELF), which reduces the effective severance tax rate as well productivity declines, is estimated to be 0.84 over the near term.)

This can be considered a conservative estimate. The reduced competition from removal of the tankers (the tanker market is tight now) could raise transportation cost for all ANS, in which case the State could stand to lose over $50 million annually if tanker rates on all shipments to the Gulf Coast returned to the previous level:

Royalty Effect

300 X 0.75 X .125 = 28.1

Severance Tax Effect

300 X 0.75 X (1 - .125) X .15 X .84 = 24.8

TOTAL $52.9 million

MAR 19 '87 16:02 STD OIL HDQ P.2/2 LNM

The Standard Oil Company
200 Public Square
Cleveland, Ohio 44114-2375

F. E. Mosier
President

March 18, 1987

The Honorable Elizabeth H. Dole
Secretary
Department of Transportation
400 Seventh Street S.W.
Room 10200
Washington, D.C. 20590

STANDARD OIL

Dear Secretary Dole:

The Standard Oil Company is the major shipper of Alaskan crude oil. Two of the three VLCC class CDS vessels that were "sanitized" in 1985 are in our service under long term charter. In fact, any action which affects the supply and demand for Jones Act tonnage is of concern to us. As a result, we are closely following the Department's response to the U.S. Court of Appeals' decision in First Attransco Tanker Corp. vs. Dole which vacated the Department of Transportation's ruling on the payback rule.

It is our view that the outcome of this case may also impact an earlier court ruling regarding the Department of Transportation's rule for allowing CDS ships to enter Jones Act service temporarily under six-month waiver. That rule specified that the Secretary need only consider the impact on Jones Act vessels of over 100,000 DWT prior to issuing a waiver for temporary entry of CDS ships into the Alaskan trade. However, the Court held that the Secretary must also consider the impact on smaller Jones Act ships and directed the Secretary to reconsider the present rule.

Standard believes that the need for these ships is quite evident. CDS ships were routinely employed in Alaskan trade prior to the sanitization of vessels under the payback rule. In the meantime, production from Prudhoe Bay and Kuparuk has increased, the Lisburne field has begun production, and the Endicott field is expected to begin production in the fourth quarter of 1987. If the two rules were overturned, it is difficult to see how Alaskan oil flow could be maintained without a significant economic penalty. Essentially all available ships will be required all of the time to satisfy normal coastwise trade and move the Alaskan oil.

Given the current situation, I urge you to take the following actions. First, reduce uncertainty in the marketplace by issuing your proposed new rule on payback in a timely fashion relative to the July 16, 1987 date after which the sanitized ships would otherwise be obliged to exit Jones Act service. Second, use the rulemaking to clarify the status of the Bayridge, a vessel sanitized earlier whose status remains unclear. Third, do not join the CDS payback issue with the CDS waiver issue in the context of the proposed rulemaking. The CDS waiver issue is best considered separately after the outcome of the sanitization issue is known.

Sincerely,

FE Mosier

FEM:drc

Repayment of Construction Differential Subsidies (CCS) (also called "CDS Sanitization")

DISCUSSION ISSUES:

The following information should be noted in discussion of CDS Sanitization:

- This is a significant economic issue for Alaska. Removal of the four large efficient ships will require using nearly all the smaller ships available, driving the market price for all shipping up by $.25 to $1 per barrel. Netback values on the crude oil will decline accordingly. Each $.50 per barrel reduction in netback represents roughly $75 MM per year in lost state revenues.

- Alaskan oil production has increased significantly in the last year, highlighting the need for efficient transportation. The Lisburne field (40-50 MBD) began commercial production in early 1986. Prudhoe Bay production increased with natural gas liquid (NGL) recovery in early 1987 (50 MBD). Kuparuk has reached peak production, and Endicott field is expected to begin production in the fourth quarter of 1987 (up to 100 MBD).

- Largely because of the increased Alaskan production the four large, efficient VLCC vessels in question have been in continuous service since repayment of their remaining subsidy: the BROOKLYN and the BAYRIDGE under charter to EXXON, and the ARCO INDEPENDENCE and the ARCO SPIRIT under long term charter to Standard Oil.

- Larger vessels make the transport of crude oil to the West Coast and Gulf Coast more economically efficient than smaller vessels. This is especially true to the Gulf Coast, which accounts for a substantial portion of the Alaskan oil delivered.

Repayment of Construction Differential Subsidies (CDS) (also called "CDS Sanitization")

On January 16, 1987, the U.S. Court of Appeals decision in First Attransco Tanker Corp. vs. Dole vacated a Department of Transportation ruling under which three very large crude carrier ships (VLCC's) repaid the remainder of their construction subsidies in 1985/86 and thus became Jones Act ships, rather than just U.S. flag ships. The Court ruled that the Secretary of Transportation was well within her authority to permit this repayment, but that procedural defects in not adequately explaining the effect of this action on other Jones Act ships rendered the rule unjustified. The decision requires all three ships to exit Alaskan service on July 16, 1987, unless the Department of Transportation explains the effect on other Jones Act ships to the court's satisfaction.

Prior to repaying the subsidy these three large, efficient U.S. flag ships were not allowed to carry Alaskan oil unless there were no suitable Jones Act ships available. Even under those circumstances these efficient ships could only be used part time (no more than six months out of the year). A fourth ship which entered Jones Act trade under generally similar circumstances in 1983 is also vulnerable to the ruling. In total these four ships are currently moving 200,000 barrels of Alaskan oil to market every day. If they are taken out of the fleet then a large number of much smaller, less efficient and more expensive ships must take their place if the Alaskan oil is to get to market. This increased demand will raise the market price for all Jones shipping, by an estimated \$.25 to \$1.00 per barrel.

Any action which affects the supply and demand for Jones Act tonnage is of concern to Alaskan oil producers and to the State of Alaska. An increase in the cost of transportation not only reduces oil company income and incentives in Alaska but also reduces the netback value of all Alaskan production. For example each \$.50 increase in per barrel transportation costs would reduce state income by roughly \$75 MM per year.

Given this situation, the State of Alaska should support the DOT's intention to issue a new rule in a timely fashion relative to the July 16, 1987 deadline. The DOT should use the rulemaking to clarify the status of the BAYRIDGE, the fourth vessel referred to above, as well as confirming that the three other vessels at issue (ARCO SPIRIT, ARCO INDEPENDENCE, and the BROOKLYN) should remain as Jones Act vessels.

IN THE SENATE BY FAHRENKAMP

SENATE JOINT RESOLUTION NO. 43

IN THE LEGISLATURE OF THE STATE OF ALASKA

FIFTEENTH LEGISLATURE - FIRST SESSION

Relating to the shipping of Alaska oil.

BE IT RESOLVED BY THE LEGISLATURE OF THE STATE OF ALASKA:

WHEREAS on January 16, 1987, the United States Court of Appeals for the District of Columbia vacated a United States Department of Transportation rule under which three very large crude oil carrier ships, the Arco Independence, the Arco Spirit, and the Brooklyn were allowed to operate in the United States domestic shipping market; and

WHEREAS the court decision would require all three ships to stop domestic shipping of Alaska oil by July 16, 1987, unless the United States Department of Transportation adopts another rule to allow the ships to continue their domestic shipping; and

WHEREAS a fourth ship, the Bayridge, that is used in Alaska oil shipping may also be affected by the court decision; and

WHEREAS Alaska oil production has increased significantly in the last year, and these four ships currently move 200,000 barrels of Alaska oil to market every day; and

WHEREAS if the four ships are prohibited from engaging in domestic shipping, a large number of much smaller, less efficient and more expensive ships will be required to take their place to transport Alaska oil to market, and this change would raise the cost of transportation for all Alaska oil shipped in these smaller ships by an estimated $.25 to $1.00 per barrel, and netback values on the oil would decline accordingly; and

WHEREAS if the Arco Independence, the Arco Spirit, and the Brooklyn are not allowed to engage in the domestic shipment of Alaska oil, the direct economic loss to the state will be between $18,000,000 and

$150,000,000 annually; and

WHEREAS if the United States Department of Transportation fails to adopt a rule by July 16, 1987, allowing these four ships to operate in the domestic shipping market, the transportation of Alaska oil may be disrupted, the transportation costs will increase dramatically, and the state and the federal government will lose a significant amount of revenue; and

WHEREAS the substitution of a large number of smaller ships could disrupt the transportation of Alaska oil because the smaller ships are often older, less well-equipped, and less safe, and because the increased number of ships could cause congestion at docking facilities; and

WHEREAS the best-equipped and safest ships should be used for the transportation of oil in order to protect the environment and communities through which the ships pass;

BE IT RESOLVED that the Alaska State Legislature respectfully urges the Secretary of the United States Department of Transportation to adopt before July 16, 1987, a rule that would enable the Arco Independence, the Arco Spirit, the Bayridge, and the Brooklyn to continue to operate in the United States domestic shipping market without interruption.

COPIES of this resolution shall be sent to the Honorable Elizabeth H. Dole, Secretary of the U.S. Department of Transportation; and to the Honorable Ted Stevens and the Honorable Frank Murkowski, U.S. Senators, and the Honorable Don Young, U.S. Representative, members of the Alaska delegation in Congress.

5-1050A
Bannister
4/15/87

IN THE SENATE BY FAHRENKAMP

SENATE JOINT RESOLUTION NO.

IN THE LEGISLATURE OF THE STATE OF ALASKA

FIFTEENTH LEGISLATURE - FIRST SESSION

Relating to the shipping of Alaska oil.

BE IT RESOLVED BY THE LEGISLATURE OF THE STATE OF ALASKA:

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WHEREAS the court decision would require all three ships to stop domestic shipping of Alaska oil by July 16, 1987, unless the United States Department of Transportation adopts another rule to allow the ships to continue their domestic shipping; and

WHEREAS a fourth ship, the Bayridge, that is used in Alaska oil shipping may also be affected by the court decision; and

WHEREAS Alaska oil production has increased significantly in the last year, and these four ships currently move 200,000 barrels of Alaska oil to market every day; and

WHEREAS if the four ships are prohibited from engaging in domestic shipping, a large number of much smaller, less efficient and more expensive ships will be required to take their place to transport Alaska oil to market, and this change would raise the cost of transportation for all Alaska oil shipped in these smaller ships by an estimated $.25 to $1.00 per barrel, and netback values on the oil would decline accordingly; and

WHEREAS each $.50 per barrel reduction in the netback value of the oil formerly transported by these four ships would represent roughly $7,500,000 per year in lost revenue to the state; and

WHEREAS if the United States Department of Transportation fails to adopt a rule by July 16, 1987, allowing these four ships to operate in the domestic shipping market, the transportation of Alaska oil may be disrupted, the transportation costs will increase dramatically, and the state and the federal government may lose a significant amount of revenue; and

WHEREAS the substitution of a large number of smaller ships could disrupt the transportation of Alaska oil because the smaller ships are often older, less well-equipped, and less safe, and because the increased number of ships could cause congestion at docking facilities; and

WHEREAS the best-equipped and safest ships should be used for the transportation of oil in order to protect the environment and communities through which the ships pass;

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COPIES of this resolution shall be sent to the Honorable Elizabeth H. Dole, Secretary of the U.S. Department of Transportation; and to the Honorable Ted Stevens and the Honorable Frank Murkowski, U.S. Senators, and the Honorable Don Young, U.S. Representative, members of the Alaska delegation in Congress.

APR 10 1987

Billing Code No. 4910-81

DEPARTMENT OF TRANSPORTATION
Maritime Administration

[Docket No. 110]

Construction-Differential Subsidy Repayment

AGENCY: Maritime Administration, Department of Transportation.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: This rule would allow four vessels that repaid their construction-differential subsidy (CDS) in exchange for the right to operate in the domestic trade to remain in that trade. Three of those vessels have been operating in the Alaska oil trade after repaying their CDS under a 1985 Department of Transportation rule. A recent court decision vacated that rule, but delayed the effective date of its order to July 16, 1987. The fourth vessel was approved to repay its CDS by an administrative decision in 1980 under conditions of an interim rule that was subsequently vacated by the court. However, the court allowed the vessel to remain in the domestic trade pending agency reconsideration of the rule. In response to those court decisions, this proposed rule would allow those four vessels to remain in the domestic trade in furtherance of the purposes and policies of the Merchant Marine Act, 1936, as amended.

DATES: Comments must be received by May ~~14~~ 15, 1987, 1987.

ADDRESS: Submit comments to James E. Saari, Secretary, Maritime Administration, Room 7300, 400 Seventh Street, S.W., Washington, D.C. 20590. The Maritime Administration requests that commenters send six copies of their comments.

FOR FURTHER INFORMATION CONTACT: Lynne Adams-Whitaker, Chief, Division of Regulations, 400 Seventh Street, S.W., Washington, D.C. 20590, Tel. (202) 366-5181.

SUPPLEMENTARY INFORMATION:

Background

The Jones Act (46 U.S.C. 883) generally provides that all cargo transported in the domestic trade between points in the United States must be carried on vessels built in the United States, documented under United States law and owned by United States citizens. While United States vessels in the domestic trade operate under the protection of the Jones Act (46 U.S.C. 883), vessels operating in the foreign trade do not have such protection. Thus, vessels operating in the foreign trade must compete with foreign-flag vessels that have lower operating and construction costs. To offset these higher U.S. construction costs, Congress passed Title V of the Merchant Marine Act, 1936, as amended ("the Act"), which authorized the payment of construction-differential subsidy (CDS) for the purpose of building ships in U.S. shipyards to be operated in foreign

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commerce. 46 App. U.S.C. 1151 *et seq*. The Secretary of Transportation, through the Maritime Administration (MARAD), may pay as much as half the construction costs of vessels used in the U.S. foreign trade. 46 App. U.S.C. 1152. There is no corresponding subsidy program for vessels constructed by U.S. owners exclusively for use in the domestic trade. In 1970, Congress expanded the scope of the Act to include bulk (i.e., tanker or dry bulk) vessels. Merchant Marine Act of 1970, Pub. L. 91-469, 84 Stat. 1018.

In addition, Title VI of the Act authorized the payment of an operating-differential subsidy (ODS) for U.S.-flag vessels manned by U.S. citizens and operated in accordance with U.S. safety standards. 46 App. U.S.C. 1171. By a policy decision, ODS was not paid to CDS-built bulk-vessels over 100,000 DWT. Because of the large economy of scale of these vessels, labor costs, which are the essential subsidized item under the ODS program, are relatively small in terms of the overall project cost.

CDS-built vessels are subject to certain restrictions. Under section 506 of the Act, vessels constructed with CDS "shall be operated exclusively in foreign trade or on a round-the-world voyage. . . ." 46 App. U.S.C. 1156. Section 506 of the Act allows CDS vessels to be operated in the domestic trade in the following limited circumstances: (1) on a round voyage from the west coast of the United States to European ports which includes Intercoastal U.S. ports; (2) on a round voyage from the Atlantic coast of the U.S. to the Orient which includes Intercoastal ports of the U.S.; (3) on a foreign voyage including a stop in Hawaii or an island possession or territory of the U.S. In addition, CDS vessels may be operated in the domestic trade with the consent of the Secretary of Transportation for up to six months in any year under authority of section 506 with the requirement that the vessel owner repay the subsidy on a *pro rata* basis. All domestic trading restrictions for each CDS-built vessel lapse at the end of the vessel's statutory life. Section 9 of Pub. L. 86-318 (74 Stat. 216) sets a 20 year economic life for tankers.

The overall objectives of the 1970 amendments to the Act were to encourage U.S. shipbuilding, thus enhancing the U.S. merchant marine fleet, and to serve the needs of national commerce and defense. The specific goal of the 1970 amendments was to build 30 ships per year over ten years, with emphasis on building bulk carriers, including tankers, for operation in the foreign commerce.1/ Prior to the 1970 amendments, the direct subsidy programs of the Merchant Marine Act had been confined to liner vessels, which operated scheduled services in foreign commerce under the regulatory supervision of the Federal Maritime

1/ In fact, only 34 petroleum tankers were built with CDS authorized by the 1970 amendments.

Commission. The Congress, in extending the reach of these programs to the unregulated bulk trades, specifically recognized the need to make these vessels "competitive" with foreign flag ships. See H. Rep. No. 1073, 91st Cong., 1st Sess., 38 (1969); Merchant Marine Act, 1936, 603(b), 46 U.S.C. 1173(b). There was however, no guarantee that even with these subsidies U.S.-flag vessels could compete in the U.S. foreign commerce.

Unfortunately, the governmental subsidy programs offered to U.S.-flag very large crude carriers ("VLCCs", i.e., tankers over 160,000 DWT) has not enabled them to be competitive in the foreign trade. In 1970, Congress did not foresee, and perhaps could not have foreseen, the drastic changes that would occur in the world oil market. The decline in export of crude oil from the Middle East, in addition to an oversupply of world tankers built since 1970, has been financially devastating for the world tanker market. Further, the gap between foreign construction costs and U.S. construction costs widened beyond the level Congress authorized under the CDS program. As a consequence, the two ultra large crude carriers and nine VLCCs constructed with CDS under the 1970 amendments were left with no significant competitive opportunities in the foreign commerce.

The domestic market, however, has not fared as poorly. With the opening in 1977 of the Trans-Alaska Pipeline System, the demand for U.S.-flag tanker tonnage has increased and that demand has not been completely met by the existing Jones Act (domestic) fleet. To alleviate the shortage of suitable Jones Act tanker vessels, MARAD has allowed CDS-built tankers to enter the trade for up to six month periods after repaying the subsidy *pro rata* under section 505 of the Act and in accordance with 46 CFR Part 250.2/ Since 1977, MARAD has approved 43 such applications for CDS-built tanker service in the Alaska oil trade (of those approvals, 37 were for VLCCs). However, because of the limited duration and availability of these temporary permissions and the depressed market conditions confronting tankers in the foreign trade, several CDS tanker owners (predominantly those owning VLCCs) applied for permission to enter the domestic market on a permanent basis in exchange for the total repayment of any unamortized CDS received plus interest.

Prior to 1978, requests for permanent repayment were handled *ad hoc*. No hearings were held on these requests and notice of the proposed determinations was not given to the public. However, after MARAD admitted the VLCC STUYVESANT (operated by Seatrain Lines) to the domestic trade, competitors in that trade

2/ 46 CFR Part 250 establishes procedures by which MARAD may temporarily waive (i.e., for no more than six months in any twelve month period) the domestic trade restrictions on CDS-built vessels over 100,000 deadweight tons (DWT) in the Alaska-Panama Canal trade. Applications for such waiver must be accompanied by information showing that suitable vessels (i.e., those over 100,000 DWT) of a competitor would not be available for the prospective voyage.

brought suit challenging MARAD's action. The ultimate disposition of the suit was that, on writ of certiorari, the Supreme Court held that the Secretary's broad contracting powers and discretion to administer the Act encompass the authority to grant permenent release to vessels under CDS restriction. Seatrain Shipbuilding Corp. v. Shell Oil Co., 444 U.S. 572 (1980).

In 1978, MARAD issued a notice of proposed rulemaking (NPRM) that would have set guidelines for permanent CDS repayment. Charterers and owners of six CDS-built vessels applied for CDS repayment. On October 15, 1980, MARAD adopted and made immediately effective an interim rule to govern applications for CDS repayment. Under the interim rule, MARAD retained greater discretion than proposed in the (NPRM) to determine whether to grant or deny CDS repayment applications. Approvals would be granted only for vessels of at least 100,000 DWT and only in exceptional circumstances, after a determination that no favorable opportunities existed for viable employment of the vessel in foreign trade during a protracted period. MARAD was to consider a number of factors in determining whether exceptional circumstances existed.

On November 13, 1980, through an adjudicative decision, MARAD approved the CDS repayment application for the BAY RIDGE, another

Seatrain vessel. MARAD deferred action on the other pending CDS repayment applications. On November 25, 1980, the Independent U.S. Tanker Owners Committee filed a complaint in the U.S. District Court for review of the interim rule and the BAY RIDGE decision, alleging substantive and procedural defects in connection with both actions. The District Court granted summary judgment for defendants on all counts. An appeal was taken.

The Court of Appeals considered the alleged substantive and procedural defects of the interim rule. The Court concluded that MARAD was not legally obligated to issue regulations limiting its discretion and that the interim rule itself did not constitute an abuse of MARAD's statutory discretion. Nevertheless, the Court vacated the interim rule on procedural grounds. It concluded that the rule lacked a general statement of basis and purpose, as required by the Administrative Procedure Act (5 U.S.C. 551 _et seq_.), to explain MARAD's position on the various issues raised during the rulemaking proceeding. The Court also found that adjudication allowing the BAY RIDGE repayment was procedurally and substantively flawed.

The Court of Appeals remanded the case to the District Court with instructions to vacate the interim rule and to order new rulemaking procedures, and to vacate the approval of the BAY RIDGE application, but to allow the BAY RIDGE to continue in domestic operation pending reconsideration of the BAY RIDGE adjudication. The Court left to MARAD's discretion whether the new BAY RIDGE decision should await publication of a permanent rule regarding CDS repayment. The Court also left to MARAD's discretion whether to adopt a permanent rule similar to the interim rule so long as the justification for the rule adopted was "clearly and thoughtfully presented in a statement published contemporaneously with the rule". Independent U.S. Tanker Owners Committee v. Lewis, 690 F.2d 906, 920 (D.C. Cir. 1982) [hereinafter referred to as ITOC v. Lewis].

The Department of Transportation published a new NPRM on January 31, 1983, 48 FR 4408. That NPRM, which was issued by the Secretary, proposed to permit total CDS repayment for all U.S. tanker vessels. The notice reviewed the entire history of this issue since the MARAD first accepted total repayment on the VLCC STUYVESANT and reviewed the comments received on earlier MARAD rulemakings pertaining to total repayment in return for domestic trading privileges. It invited further comment on these issues and assessed the economic impact of allowing the owner/operators of these vessels to determine on their own whether to repay their CDS. The rulemaking concluded that the Government was not in a position to assess, on its own, which vessels should, and which should not, be allowed to meet the needs for additional capacity in the domestic trade. For example, it pointed out that only allowing operators in financial jeopardy to repay their CDS was not consistent with the objectives of the 1936 Act. 48 FR at 4412.

The Department concluded that the marketplace decisions of individual operators would best serve the needs of the fully deregulated domestic tanker trade, provided that those operators that repaid were placed on an equal competitive cost footing with the existing Jones Act fleet. Id. at 4409-4410. Accordingly, the proposed rule would require repayment of an additional amount consisting of compound interest on the unamortized subsidy from the date of its original receipt. The addition of this amount, which frequently would exceed the unamortized subsidy itself, would duplicate the financial conditions inherent in a private sector decision to commit any comparable new asset to the domestic trade, with an allowance only for its age, by allowing the amortization of the subsidy pursuant to its statutory useful life of 20 years. See 48 FR 4408-4414. Since the Government does not otherwise regulate entry of new capacity in the domestic trade, duplicating the conditions ordinarily governing such entry was deemed the most appropriate approach.3/

3/ Similarly, damaged foreign-built vessels may be acquired and reconstructed for use in the domestic trade under the Wrecked Vessels Act without prior government approval, provided a specific amount is expended in the reconstruction (i.e., three times their salvage value). 46 App. U.S.C. 14.

Shortly after the close of the comment period on the NPRM, the Congress took action to prevent the Secretary from promulgating a final rule. The DOT FY 84 Appropriations Act (Pub. L. 96-78, August 15, 1983) prohibited the enforcement of any rule with respect to the repayment of CDS until 60 days following the promulgation of any such rule. Thereafter, the Commerce Department's FY 84 Appropriations Act (Pub. L. 98-166, November 28, 1983) imposed an additional restriction that prohibited DOT from enforcing any CDS repayment rule until after June 15, 1984. In August of 1984, the FY 85 Appropriations Act for Commerce, Justice and State, which provides appropriations for MARAD, imposed yet another restriction. That Act prohibited the Department from enforcing any CDS repayment rule until May 15, 1985 (Pub. L. 96-411, August 30, 1984). Thereafter, Congress considered, but did not extend, these prohibitions.

On May 7, 1985, the Department published in the Federal Register a final rule which allowed any owner or operator of a tanker built with CDS to repay its subsidy (with interest) and consequently obtain a permanent removal of domestic trading restrictions. The amount of repayment included the unamortized CDS on the vessels plus compounded interest on that amount. The interest rate, to be used for computational purposes, was the rate at which the original Title XI obligation was made or the

Title XI long-term bond rate at the vessel's delivery. The final rule included a one-year time limit after the rule's effective date during which total CDS repayment had to be made irreversibly.

That time limit was from June 6, 1985 to June 6, 1986. During that time, three VLCCs repaid their CDS: the ARCO INDEPENDENCE (262,400 DWT), ARCO SPIRIT (262,400 DWT), and the BROOKLYN (226,200 DWT). The total amount of CDS repaid by these ships was $105.8 million. Those ships are now operating in the domestic trade.

On January 16, 1987, the Court of Appeals for the District of Columbia held that the Secretary of Transportation violated section 553(c) of the Administration Procedure Act by adopting a final rule on CDS repayment which did not contain a statement of basis and purpose giving an adequate account of how the rule served the objectives of the Act and why alternatives were rejected in light of them. Independent U.S. Tanker Owners Committee v. Dole, Civil Action Nos. 85-01555, 85-01740, 85-01752 and 85-1771. (D.C. Cir. January 16, 1987) [hereinafter referred to as ITOC v. Dole]. The court found that the Secretary's failure to provide an adequate statement of basis and purpose was arbitrary and capricious. The court vacated the rule, but withheld issuance of its mandate until July 16, 1987 "to avoid further disruptions in the domestic market and to allow the Secretary to undertake further proceedings to address the problems of the merchant marine trade." Slip op. at 16. The court ruled that, as of July 16, 1987, the present rule will be vacated and conditions will be returned to the status quo ante, before the CDS repayment rule took effect, subject to any "further action" that the agency may have taken in the interim.

By letter dated March 10, 1987, counsel for the BAY RIDGE requested that a proceeding on the BAY RIDGE should be conducted independently of proceedings with respect to the three vessels which repaid CDS pursuant to the repayment rule that has been vacated by the Court of Appeals. The court in ITOC v. Lewis specifically left to MARAD's discretion whether or not the BAY RIDGE decision should await publication of a permanent rule governing repayment applications. MARAD has decided that it would be appropriate to consider the BAY RIDGE in this rulemaking, since it affects the same domestic trade as the other three vessels at issue.

The Proposed Rule:

This proposed rule would reaffirm the allowance of the repayment of CDS, with interest, and rescission of the domestic trading restriction for tankers that applied to and were approved by

MARAD between June 6, 1985 and June 6, 1986. The approved applications were for the ARCO INDEPENDENCE, ARCO SPIRIT and BROOKLYN. Further, this proposed rule would reaffirm the allowance of the repayment of CDS, with interest, and rescission of the domestic trading restrictions for the BAY RIDGE, which was approved to repay its CDS in November 1980. It would impose the same conditions on the BAY RIDGE that were imposed in 1980.

This proposed rule would differ from the 1985 CDS repayment rule in that it does not provide a one-year window for applicants to seek MARAD approval of their CDS repayment. This proposed rule would impose the same terms and conditions on the three tankers that repaid during the one-year window as were required in the 1985 CDS repayment rule.

Comments:

MARAD solicits comments on this proposed rule from all interested parties. In particular, MARAD seeks comments on the future of the Alaska North Slope (ANS) trade.

The Purposes and Policies of the Merchant Marine Act:

The preamble to the Merchant Marine Act, 1936, as amended, states that the intent of the Act is "[t]o further the development and maintenance of an adequate and well-balanced American merchant marine, to promote the commerce of the United States, to aid in the national defense. . . ." The specific goals of the Merchant Marine Act, 1936, as amended, as set out in section 101 of the Act, are to foster the development and encourage the maintenance of an American merchant marine that is

> (a) sufficient to carry its domestic water-borne commerce and a substantial portion of the water-borne export and import foreign commerce of the United States and to provide shipping service essential for maintaining the flow of such domestic and foreign water-borne commerce at all times, (b) capable of serving as a naval auxiliary in time of war or national emergency, (c) owned and operated under the United States flag by citizens of the United States, insofar as may be practicable, (d) composed of the best-equipped, safest, and most suitable types of vessels, constructed in the United States and manned with a trained and efficient citizen personnel, and (e) supplemented by efficient facilities for shipbuilding and ship repair.
> 46 App. U.S.C. 1101.

MARAD believes that this proposed rule, which would allow the four CDS-built very large crude carriers ("the four VLCCs") to remain in the domestic trade, would benefit the domestic water-borne commerce by providing vessels that are the "most suitable" for the Alaska-Panama oil trade, which would result in a "well-balanced" American merchant marine. Although originally built to operate in the foreign trade, these VLCCs are not competitive in that trade. If not allowed to operate in the domestic trades, the four VLCCs would likely be unemployed and possibly scrapped.

The balance of this statement discusses how this proposed rule would fulfill the objectives of the Act. The suitability of these vessels for the Alaska-Panama trade is discussed in more detail in Section I. Section II discusses the effect of this proposed rulemaking on the U.S. tanker fleet operating in the foreign commerce. Section III analyzes the effect of this proposed rulemaking on the naval auxiliary. Section IV addresses the effects of this rulemaking on shipyards. Section V considers other objectives of the Act that support this rulemaking. Section VI addresses the alternatives considered by MARAD.

I. The Alaska Oil Trade and the Need for Suitable Tankers

The main purpose for allowing the four VLCCs to remain in the domestic trade is to foster the development of suitable vessels for that trade. "Suitability" is determined not only by the physical ability of a vessel to carry a certain product, but by market conditions. As will be shown below, market conditions in the oil trade have fluctuated drastically since the advent of the CDS program, affecting the distribution of oil in both foreign and domestic markets.

A. ANS Crude Oil Production

When the Trans-Alaska Pipeline opened in 1977, Alaska North Slope (ANS) crude oil loadings averaged 629,000 barrels per day (b/d). Average loadings have steadily increased since then. In 1982, average loadings reached 1.62 million b/d. Production for 1987 is expected to be 1.8

million b/d. The most rapid growth occurred between 1978 and 1980 when average loadings grew at an annual rate of 18.4 percent. Average loadings from 1980 to 1986 grew at an annual rate of 2.2 percent. (See Table 11-2 in Regulatory Impact Analysis).

B. The Distribution of ANS Crude Oil

While ANS crude oil production has grown steadily since 1977, the distribution of that oil has changed dramatically. ANS crude oil is shipped to the West Coast, to Panama, to the Gulf and East Coasts from Panama, and to the Virgin Islands around Cape Horn.4/ In the five months of 1977 when ANS oil production began, approximately 75 percent of the oil from Valdez, Alaska was shipped to the West Coast, 24 percent to Panama (to be shipped to the Gulf/East Coasts), and two percent to the Virgin Islands. Shipments to Panama increased to 30 percent of total loading in 1980, and peaked at 43 percent in 1982. During this period, the volume of oil going to the West Coast dropped from 63 percent to 50 percent. During 1986, 32 percent of the Alaska oil was shipped to Panama, and 62 percent to the West Coast.

4/ All of the oil carried to the Virgin Islands currently is moved in foreign-flag vessels via Cape Horn.

The amount of future ANS shipments to Panama will likely decline, for several reasons. More ANS crude oil will likely be shipped to the West Coast during 1988 due to the imminent opening of the All-American pipeline from Southern California to the Texas Gulf, assuming the pipeline is completed in that time frame. This pipeline will have a capacity of 300,000 b/d and will ship surplus West Coast crude to the Gulf Coast for refining. While increases in West Coast crude production are anticipated, the surplus pipeline capacity would probably eliminate some need for vessels to carry the oil to Panama (to be shipped to the Gulf). Valdez loadings may decline in the 1990's due to production reduction as well as the potential construction of a 105,000 b/d (rated capacity) refinery at Valdez by Alaskan Refining, Inc. Products from the refinery may be transported abroad on foreign-flag tankers, thus reducing the shipments of oil from Valdez for U.S.-flag tankers.

C. Tanker Demand in the ANS Crude Oil Trade

Tanker demand in the ANS trade depends on ANS oil production and the distribution of the oil. As production increases, so does the amount of tonnage needed to carry the oil. However, the increase in demand for tankers may not be proportional to oil production if there is also a change in the distribution of the oil. For example, tanker demand peaked in 1982 when approximately 182 billion-barrel miles of oil were shipped. This peak in demand was due not only to the increased production of oil, but also due to the peak in shipments to Panama (43 percent of total loadings). A drop in ANS crude oil shipments between 1982 and 1984 (from 7.2 million DWT to 5.9 million DWT) was attributable not to production, which remained fairly constant, but to a drop in oil shipments to Panama and corresponding rise in shipments to the West Coast.

The distribution of oil affects the demand for certain size tankers. Historically, VLCCs have carried the majority of oil from Alaska to Panama (See Table 111-2 in the Regulatory Impact Analysis). During 1986, about half the full-time equivalent tanker employment in the Alaska-Panama trade was for vessels from 200,000 DWT to 265,000 DWT; most of the other half was for VLCCs from 170,000 DWT to 190,000 DWT. A small percentage was carried by tankers from 110,000 DWT - 137,000 DWT, while only 0.6 percent in 1986 was carried by vessels under 100,000 DWT. (Historically, the share carried by tankers under 100,000 DWT has been no more than six percent.) Even prior to the 1985 CDS repayment by four of the VLCCs, the Valdez-Panama trade was dominated by tankers over 100,000 DWT. Many of these were CDS built VLCCs operating under six month permissions in the domestic trade.

Several factors contribute to the suitability of the four VLCCs for this trade. VLCCs are more suitable for long-haul, high volume trades than smaller tankers, due to economies of scale. That is, tanker operating costs do not rise as fast as cargo volumes. Thus, VLCCs are more efficient and economical than smaller tankers for long-haul, high-volume trades. Studies of optimal ship size have shown that optimal ship size is determined by minimizing costs per ton at sea and in port. (In port, costs per ton increase with ship size; at sea, however, costs per ton decline with ship size). J.O. Jansson and D. Shneerson, "The Optimal Ship Size," Journal of Transport Economic and Policy, 217, 223 (Sept. 1982). VLCCs are more suitable for the Panama leg of the ANS trade because of the length of the voyage (approximately 4,950 miles). The at-sea time is significantly longer than any other legs of U.S.-flag oil shipments in the U.S. Another factor contributing to the suitability of the VLCCs for the Panama leg is the deep-draft of the Panama port, which can accommodate those larger tankers. Because of these factors, VLCCs are able to carry oil in that trade more efficiently than smaller tankers under 100,000 DWT.

Conversely, smaller tankers are more suitable for the West Coast and upcoast (Gulf/East Coast) trade than the Panama trade. The Valdez-West Coast ANS trade has been served by vessels in all DWT ranges: 47 percent of the full-time equivalent tanker employment in that trade is carried by vessels under 100,000 DWT; 53 percent is carried by tankers over 100,000 DWT.

Once the oil reaches Panama, smaller tankers (i.e., under 150,000 DWT) are needed to carry the oil to the Gulf and East Coasts. (VLCCs are less suitable than smaller tankers for such short haul, low volume trades, because their capital and port charges, which are higher than those for smaller tankers, are spread over smaller cargo volumes.) Tankers under 55,000 DWT carry 22 percent of the Panama-Gulf/East Coast ANS oil. Tankers in the 55,000 DWT to 92,000 DWT range now carry about two-thirds of the ANS oil in this trade. Such tankers are more suitable for that trade than larger tankers because they often stop at many ports (which would not be economical for larger tankers to do), and most Gulf/East Coast ports are not deep-draft.

Further, the at-sea time is much less because of the shorter distances involved.

The Regulatory Impact Analysis indicates certain trends in the distribution of oil by trade and by vessel tonnage. Since the permanent entrance of the three CDS-built VLCCs in the domestic trade (i.e., from 1985-1986), the percentage of full-time equivalent tanker employment for VLCCs over 200,000 DWT in the Alaska-Panama trade has risen considerably, and employment by vessels under that tonnage range has decreased correspondingly. It appears that the trend of these VLCCs carrying the majority of Valdez-Panama ANS trade will continue.[5]

Allowing the four VLCCs to remain in the domestic trade makes the domestic fleet better balanced than it would be without these vessels in the trade. It should be noted that, even with the four VLCCs in the domestic trade, shortages of tankers have led to one smaller CDS-built tanker, the BEAVER STATE, entering the trade for a month

[5] It should be noted, however, that in some years, the full-time equivalent of three VLCCs operated in the ANS trade under six month waivers pursuant to 46 CFR Part 250.

under a section 506 waiver. (See Regulatory Impact Analysis). Further, only six percent of the domestic tankers (12 tankers) were in lay-up as of February 1987. This percentage is quite low, considering that February is a slow month for the upcoast oil trade and is a reasonable reserve to cover temporary losses from the active fleet due to casualties, safety inspections and repairs as well as seasonal increases in upcoast petroleum movements. As for the future, while ANS tanker loadings have increased from 629 thousand barrels per day in 1977 to 1,788 thousand barrels per day in 1986, loadings are expected to fall over the period 1988-95, due to a gradual decline in ANS production (Table II-2 of the Regulatory Impact Analysis) with uncertain consequences. Comments are invited specifically on the extent and the consequences of this decline in ANS production.

Finally, no data has been developed yet on the extent that the lower costs of transporting ANS crude on VLCCs, including those that repaid their CDS, has increased shipments to Panama since those four vessels were admitted to the trade. To the extent that occurs, overall tanker demand in the trade would be increased, and the displacement caused by the entry of those vessels thereby reduced. Commenters are invited to submit such data.

D. Availability of Tankers in the Trade

When ANS crude oil loadings began in 1977, there were 215 privately-owned unsubsidized tankers (8.0 million DWT) in the U.S.-flag fleet (excluding special product tankers). Of those, only seven were over 100,000 DWT (totaling 848,000 DWT). An additional 15 tankers (2.3 million DWT) were on order for the domestic trade, of which 12 (2.0 million DWT) were over 100,000 DWT. Two tankers (totaling 259,900 DWT) were rebuilt under the Wrecked Vessel Act in 1981 and 1983 respectively. Five VLCCs repaid their CDS from 1977 to 1986 (totaling 1.2 million DWT). One new EXXON tanker was delivered in November 1986 and the second in April 1987 (those two vessels total 418,000 DWT). Both are currently operating in the domestic trade. No other U.S. tankers are currently under construction.

With the opening of the Alaskan pipeline in 1977, there has been a recurring shortage of suitable tankers in the ANS oil trade. MARAD has tried to alleviate this shortage in several ways. First, MARAD issued a rule in 1977 allowing CDS tankers over 100,000 DWT to carry ANS crude oil in the domestic trade for six months in a twelve month period in exchange for a pro rata repayment of their CDS (46 CFR Part 250). Under that rule ("Part 250 rule") MARAD has approved temporary transfers of CDS-built VLCCs to the Alaska-Panama trade on 37 occasions. Such transfers peaked between 1980 and 1983 when there were approximately three CDS vessels (totaling 750,000 DWT) operating in the trade on a full-time basis.

Permissions for three CDS-built VLCCs -- ARCO INDEPENDENCE, MARYLAND and WILLIAMSBURGH -- to operate temporarily in the Alaskan oil trade were terminated on January 12, 1984. Their approval had been conditioned on the acquisition of suitable employment (by January 1984 when they would become available) of four over 100,000 DWT Jones Act vessels -- OVERSEAS BOSTON, OVERSEAS JUNEAU, OGDEN COLUMBIA, and PRINCE WILLIAM SOUND. When the latter two were not chartered, the conditional approvals were terminated in accordance with the order of October 7, 1983. No CDS-built VLCCs entered the ANS trade after that until the MARYLAND on November 15, 1984. Two additional VLCCs were granted waivers in January 1985 and January 1986. In addition, a CDS-built 90,000 DWT tanker (the BEAVER STATE) made two voyages in the Valdez to West Coast trade under a section 506 waiver in March 1986.

From 1977 to the last approved transfer on November 1, 1985, eight CDS VLCCs operated under six month waivers at various times in the ANS trade. Of those eight, four are the subject of this rulemaking.

The other four CDS-built vessels are the MARYLAND, MASSACHUSETTS, and NEW YORK (each 264,100 DWT), and the WILLIAMSBURGH (225,100). None of those vessels has applied to enter the ANS trade under Part 250 since November 1985. (The NEW YORK applied in November 1985 and operated until July 1986). At present, those four are in lay-up.

While the Part 250 rule alleviated the shortage of tankers to a large extent, it did not totally solve the problem. To alleviate the shortage, MARAD began accepting total repayment of CDS in exchange for domestic trading privileges. Since 1977, five vessels have totally repaid their CDS. The first was the VLCC STUYVESANT (224,700 DWT), which was allowed to enter the domestic trade in August 1977.

The second was the BAY RIDGE (225,000 DWT) which repaid its CDS in November 1980, after entering the trade for six months under a Part 250 temporary waiver in 1979. The other three VLCCs repaid their CDS pursuant to the most recent rule, and are still operating in the domestic trade. The four VLCCs in the trade that are the subject of this rulemaking total 976,000 DWT. They represent approximately 43 percent of the capacity operating in the Valdez-Panama trade.

Employment prospects for the four VLCCs in the ANS trade appear to be positive at least for the near future. It is with this near future in mind that these vessels repaid their CDS. Domestic trading restrictions for CDS-built vessels are lifted at the end of their statutory life (i.e., 20 years). The ARCO INDEPENDENCE and ARCO SPIRIT were built in 1977, the BROOKLYN in 1973, and the BAY RIDGE in 1979.6/ Since no new tankers are on order, and prospects for newbuildings seem unlikely, these four VLCCs would be among the most suitable vessels for the Alaska-Panama trade. If the four VLCCs remain in the domestic trade, there would

6/ Even without the present rulemaking, these vessels would be allowed to enter the domestic trade at the end of their 20 year useful life. Thus, the effects of this rulemaking ~~would expire~~ in the mid to late 1990s.

be an adequate supply of suitable tonnage to carry oil in that trade even if other older tankers are scrapped and if no new tankers are built.

If the four VLCCs were removed from the domestic trade, a shortage of the most suitable tonnage in the Alaska-Panama trade would occur, necessitating the entrance of smaller, less suitable tankers in that trade, and would also likely result in those VLCCs being laid up, since they are unable to compete in the foreign trade (see Section II of this proposed rule).

In conclusion, as far as can reliably be foreseen, the continued employment in the Alaskan oil trade of the four VLCCs that repaid CDS would benefit the U.S. domestic waterborne commerce by providing vessels that are most suitable for the Alaska-Panama oil trade and by providing an employed well-balanced merchant marine. The following other benefits would flow: The Treasury would retain the CDS repaid amount ($142 million), the shipping public would receive transportation savings (estimated $664-674 million) and the State of Alaska would earn revenues from reduced tanker rates (estimated $186-189 million). It is not clear that there would be any negative impact on the domestic fleet by allowing such repayment. It is recognized that 12 tankers were in lay-up in February and with their lay-up, the seamen to operate them were unemployed. This is only six percent of the total U.S.-flag domestic tanker fleet and provides a needed reserve for peak demand.

E. Safety of the VLCCs

Allowing the four VLCCs to remain in the domestic trade would also further the goal of section 101 of the Act to encourage the development of a fleet composed of the "safest" vessels. As is shown in the Environmental Assessment prepared for this proposed rule, these VLCCs are among the safest tankers, in terms of environmental risks. The change in oil spill risk for the ANS fleet is expected to continue to improve as more VLCCs and other large tankers replace, where permitted by navigation channel depths, smaller tankers. If the four VLCCs were not allowed to remain in the domestic trade, a tonnage shortfall could cause a greater oil spill risk if additional small vessels such as barges were to be employed to compensate for the shortfall.

II. The Foreign Trade

One of the goals of the Act is to encourage the development and maintenance of a merchant marine sufficient to carry "a substantial portion of the waterborne export and import foreign commerce of the United States..." 46 U.S.C. 1101(a). The Court of Appeals criticized the previous CDS repayment rule for its "dubious proposition that the fleet will remain able to carry 'a substantial portion' of foreign commerce..." ITOC v. Dole, slip op. at 11.

The Court noted in a footnote to its decision overturning the prior CDS rule:

It may be, of course, that present conditions in the world shipping market make it impossible for the Secretary to find a way to meet all of the statutory objectives. If this is a problem, she should discuss it frankly and directly when she considers which measures to adopt in light of the objectives explicitly set out in the Act. Id. at 13-14, n.4.

While this proposed rulemaking would provide a domestic tanker fleet that is (1) sufficient to carry the domestic waterborne commerce of the United States and (2) composed of the "best equipped, safest, and most suitable types of vessels," MARAD acknowledges that it would have no effect on the U.S.-flag share of the water-borne export and import bulk foreign commerce of the United States.

The U.S.-flag foreign trade tanker fleet currently consists of 26 CDS-built tankers totaling three million deadweight tons, including six VLCCs and two ULCCs. (This excludes the four VLCCs that are the subject of this rulemaking and three CDS-built integrated tug-barges, but includes two CDS-built ore-bulk-oil carriers built with CDS.) This tonnage is insufficient to carry a substantial portion of the bulk foreign commerce. The six CDS-built VLCCs and two ULCCs (ultra large crude carriers) are currently laid up. Only one of the CDS-built tankers under 100,000 DWT is laid up. Seven of the tankers are employed in the foreign trade, while the remaining 12 tankers are under charter to the Military Sealift Command (6) or are employed in the preference trades (6) carrying Strategic Petroleum Reserve oil.

While the intent of MARAD's CDS and ODS programs was to provide a basis for a U.S.-flag fleet that is sufficient to carry a substantial portion of our bulk import and export trade, the assumptions of those programs were not met for VLCC tankers and most of these tankers built under the 1970 program are not competitive in the international market, as evidenced by the lay-ups. Moreover, even with the benefit of CDS, the capital costs of CDS-built VLCCs exceeds those of comparable foreign-built tankers. In addition, even the provision for full ODS could not offset the cost disadvantages of operating U.S.-flag tankers in the foreign trades, let alone address the capital cost disadvantages faced by these carriers.

The United States currently imports approximately 6.0 million barrels per day of crude oil and refined product, of which only three percent is carried on U.S.-flag tankers. Furthermore, a substantial portion of our crude oil imports--approximately 45 percent--are received from nearby sources including Canada, Mexico, Venezuela and the Caribbean region. The CDS-built VLCCs are unsuitable for these nearby import trades. (The CDS-built VLCCs are more suitable for long-haul voyages; see Section I above). Approximately 32 percent of U.S. crude oil imports are received from the distant Arabian Gulf and North Sea regions for which VLCCs would be suitable. In contrast, ten years ago U.S. crude oil and refined product imports averaged 8.8 million barrels per day. Only 14 percent of our crude oil imports were received from nearby sources while over 40 percent of our oil imports were received from the Arabian Gulf and North Sea regions.

During the last year, there has been an increase in oil exports from the Arabian Gulf region and a corresponding rise in demand for VLCCs in the international trade. Despite this increase it is unlikely that the U.S.-flag share of U.S. oil imports would increase, due to an oversupply of tonnage in the world tanker fleet.

As of January 1987, the world fleet contained over 235 million deadweight tons, of which approximately 200 million deadweight tons (85 percent) were actively employed. The remaining 35 million deadweight tons (15 percent) were idle; however, 30 million deadweight tons were in the over 200,000 DWT size class. The amount of idle capacity in the over 200,000 DWT size class represents more than 26 percent of the available tonnage in that class. Therefore, given the relative higher operating costs for U.S.-flag tankers and the amount of idle tonnage over 200,000 DWT in the world fleet, it is very likely that the four VLCCs that are the subject of this rulemaking would be laid up if they are required to leave the domestic trade, with loss of jobs to Jones Act seamen, or possibly scrapped.

In fact, of the nine VLCCs and two ULCCs built with CDS under the 1970 program, none has had any significant employment in the foreign commercial trades, other than occasional shipments of oil to the Strategic Petroleum Reserve, which are reserved to U.S.-flag carriage. The BAY RIDGE, which repaid its CDS in 1980, has been operating actively in the domestic trade since 1980. The other three VLCCs have been operating in the domestic trade regularly under six month waivers under Part 250 (a total of 17 times since 1978). Thus, the deployment of these four VLCCs to the domestic trade would have no impact on U.S.-flag tanker presence in foreign trades. Finally, should world market conditions even reach the point where U.S.-flag VLCCs could be employed in the U.S. foreign or foreign-to-foreign trades, VLCCs that have continued to be active in the domestic trade would be much more readily available to the foreign fleet than vessels that are laid up and wasting or scrapped.

III. <u>The Naval Auxiliary</u>

One of the objectives of the Act is to foster the development of a merchant marine fleet "capable of serving as a naval and military auxiliary in time of war or national emergency, ..." 46 U.S.C. 1101(b).

In its comments on the prior CDS rule, the Defense Department expressed concern over the security implications of losing militarily-useful (i.e., product) tankers as a result of CDS repayment. MARAD has considered the effect on the naval auxiliary of allowing the four VLCCs to remain in the domestic trade (see Regulatory Impact Analysis). Market conditions and statutory requirements have contributed to a reduction in the number of U.S.-flag product tankers, including a declining upcoast (U.S. Gulf/East Coast) petroleum trade (the principal market for U.S.-flag product tankers), the opening of the Trans-Panama Pipeline in 1982, and the anti-pollution standards of the Port and Tanker Safety Act (PTSA).

As a result of these factors, over a three year period for 1984 to 1986, 41 tankers, of the type considered highly military useful, were scrapped (see Regulatory Impact Analysis, Appendix I). All had exceeded their statutory life of 20 years (see Regulatory Impact Analysis, Appendix 1). The average age of these tankers was 34 years. Further, the 1978 Port and Tanker Safety Act (PTSA) set certain anti-pollution requirements for tankers entering United States waters. By January 1, 1986, vessels between 20,000 and 40,000 DWT were required to have certain anti-pollution systems to prevent the discharge of oil-tainted water. To comply with the PTSA requirements, tanker owners had the option of retrofitting existing systems, reducing load lines (so as to carry less than 20,000 DWT), using port reception facilities to dispose of oily water, or scrapping ships. Due to the cost of retrofitting and resulting loss of cargo capacity, and the inherent limitations of reducing load lines or using port reception facilities to discharge oily water, many tanker owners scrapped their older, less efficient vessels. The PTSA served to speed up the natural process of scrapping that occurs when tankers exceed their useful life.

Of those 41 that were scrapped, 25 were scrapped in 1984, nine in 1985, and seven in 1986. The vast majority of those lacked some or all of the anti-pollution features required by the PTSA.

These figures indicate that the scrapping that has occurred in the past three years is not attributable to CDS repayment but rather to the age of the vessels, their inability to economically retrofit to satisfy PTSA requirements and poor market conditions. Since the effective date of the PTSA (January 1, 1986), the number of product tankers scrapped has declined. MARAD believes that this decline will continue, since many older, more inefficient tankers have now been scrapped. In addition, since the enactment of the PTSA, a number of new product tankers have been built.

Further, any effect that the four VLCCs would have on the militarily-useful tankers would be indirect, unlike the above factors. VLCCs and these smaller tankers generally do not compete in the same trades. As discussed above, VLCCs have historically served the Alaskan-Panama trade, and smaller tankers serve the Panama Gulf/East Coast trades. While a mix of vessels serve the West Coast, the four VLCCs have not entered that trade. Thus, any effect the VLCCs may have on the smaller tankers would be through an indirect displacement. That is, the VLCCs, being more cost-effective, may "bump" other large tankers that could serve the Alaska-Panama trade. In turn, these large tankers could operate in the West Coast and Panama/Gulf trade, picking up oil that could have been carried by smaller tankers. A trend in this direction is indicated by Table III-2 in the Regulatory Impact Analysis. However, such "bumping" effects are much more remote than the effects of the PTSA, the Trans-Panama Pipeline, and declining market conditions, over which MARAD has no control.

Moreover, the current goal of the Navy is to increase the number of tankers in the Ready Reserve Force from eight to twenty by the year FY 1992. Even if there were a direct corrollary to CDS repayment and the 12 tankers laid up in February 1987, the Navy has the opportunity to purchase those vessels for their military usefulness at such time as they became commercially unattractive.

Based solely upon these objectives of section 101 of the Act, the Secretary concludes that the CDS repayment rule proposed herein furthers those objectives. The four VLCCs would increase the most suitable U.S. domestic fleet with minimal impact on the existing fleet, and they are not expected to have a significant impact on carriage of U.S. foreign commerce, U.S. shipyard construction, or the U.S. Naval auxiliary capacity. Their retention in the Jones Act fleet will also result in $142 to the U.S. Treasury for CDS repayment, transportation savings to the shipping public and increased revenues for the State of Alaska.

IV. Shipyards

One of the objectives of the Act is to encourage the development of a merchant marine fleet "supplemented by efficient facilities for shipbuilding and ship repair." While this proposed rulemaking would not actively promote this goal, it also would not have a significant adverse effect on U.S. shipbuilding. MARAD acknowledges that future shipbuilding prospects with or without this proposed rule do not look positive. Even without CDS repayment, the growth prospects for the domestic petroleum trades are not sufficient to require the construction of additional tanker capacity.

No orders for the construction of unsubsidized tankers over 100,000 DWT were placed between April 1976 and August

1984. On August 27, 1984, EXXON placed an order for construction of two 209,000 DWT tankers in the United States for employment in the ANS trade. Since then, no orders have been placed to build unsubsidized tankers over 100,000 DWT.

Two foreign-flag tankers over 100,000 DWT were rebuilt in the United States for the ANS crude oil trade in 1981 and 1983 under the Wrecked Vessel Act (46 U.S.C. 14). Under this Act, foreign-built vessels that are wrecked off the U.S. coast are eligible to enter the U.S. domestic trade provided the vessel is purchased by a U.S. citizen and rebuilt in the United States at a cost that is at least three times the appraised salvage value.

The first vessel, the OVERSEAS BOSTON (123,700 DWT), was rebuilt in 1981 and the second vessel, the OGDEN COLUMBIA (136,000 DWT), was rebuilt in 1983. Due to the existing capacity in the domestic trade and the predicted growth patterns in the petroleum trade, allowing the four CDS-built VLCCs to remain in the domestic Jones Act fleet permanently will have little effect on the amount of domestic tanker construction.

V. Other Objectives of the Act

While section 101 of the Act establishes the general objectives of the Act, other parts of the Act give more specific guidance on interpretation and implementation of these goals. The Act explicitly and implicitly establishes other policy goals in furtherance of the maintenance and development of the U.S. merchant marine fleet. Among these goals, mentioned in the prior CDS final rule (50 FR 19170), are efficiency and competition. Each of these goals has been recognized by the courts as valid policies for promoting the U.S. merchant marine fleet.

A. Efficiency

The goal of efficiency of the fleet is mentioned throughout the Act. Among the express goals of section 101 is that the merchant marine shall be composed of "suitable" vessels manned by "efficient" crews. Certainly, the idea of "suitable" vessels should encompass efficiency as a principal component.

The goal of efficiency is particularly important in the CDS program, which is designed to produce vessels of "high transport capability and productivity." Merchant Marine Act, 1936, as amended, sec. 501 (46 U.S.C. App. 1151). Other provisions in the Act are intended to promote fleet modernization. Under section 213, the Secretary is required to report to Congress annually on the scrapping of old vessels, and the relative cost of ship construction and reconditioning in U.S. shipyards. The capital construction reserve fund was established in section 511 to promote construction or acquisition of new vessels. The Secretary's authority to acquire obsolete vessels for an allowance of credit under section 510(b) is intended "to promote construction of new, safe, and efficient vessels to carry the domestic and foreign waterborne commerce of the United States...."

While the Act appears to clearly promote the policy of efficiency, the Department of Transportation authorization statute further declares it to be an overriding purpose that national transportation policies and programs be "conducive to the provision of fast, safe, efficient, and convenient transportation at the lowest cost consistent there with. . . ." 49 U.S.C. 1101. Any ambiguity in the Merchant Marine Act regarding the goal of promotion of efficiency is resolved in favor of that goal through the purposes and policies established in the Department's statute.

In addition to these explicit statutory provisions promoting efficiency of the U.S. merchant marine fleet, several recent court decisions have affirmed that one objective of the Act is to encourage modernization and efficiency. For example, the Supreme Court's decision confirming the Secretary's statutory authority to grant permanent release to vessels under CDS restrictions found that a basic goal of the Act was to encourage the maintenance of an "effective merchant marine" with a "fleet [that] was to be modern and efficient." Seatrain Shipbuilding Corp. v. Shell Oil Co., 444 U.S. 572, 584 (1980). Further, the D.C. Circuit recently described the first goal of the Act as promoting "a well-equipped and efficient merchant fleet." American Trading Transportation Co., v. United States, 791 F.2d 942, 944 (D.C. Cir. 1986); see also Sea-Land v. Dole, 723 F.2d 975, 976 (D.C. Cir. 1983).

The above statutory provisions and judicial interpretations strongly support the goal of promoting efficiency and modernization of the U.S. merchant marine fleet. These goals would be furthered by this proposed rulemaking, which will allow the four VLCCs, which are among the most efficient U.S. tankers in the fleet, to remain active in the domestic trade.

B. Competition

While the Act does not explicitly list competition as one of its goals, the promotion of competition in the foreign and domestic trades is implicit in the Act. The Act's ODS and CDS programs are intended to give the U.S. merchant marine fleet certain financial resources to compete with lower-cost foreign fleets while not guaranteeing any profit. In particular, Congress made this objective clear in enacting the Merchant Marine Act of 1970, which extended those programs to the unregulated bulk trades. See Merchant Marine Act, 1936, 603(b) 46 U.S.C. 1173(b); H. Rep. No. 1073, 91st Cong., 1st Sess., 38 (1969). The Jones Act trade does not receive such financial assistance, but is insulated from foreign competition by the Act's bifurcation of the foreign and domestic trades. That is, the Act restricts competition in the Jones Act trade only to the extent necessary to protect unsubsidized U.S. operators from the benefits of the Act's financial assistance programs (such as ODS and CDS) which assist the U.S. foreign trade vessels in competing against low-cost foreign-flag competition. In the domestic trade, the Secretary has a duty "to minimize interference with the free market forces normally at work. . . ." ITOC v. Lewis, supra, 690 F.2d at 917.

In its seminal case on the relation between the foreign and domestic trades, the D.C. Circuit stated that "competition is not 'unfair' within the meaning of the Act when it does not involve diversion of money to unsubsidized domestic operations from subsidized foreign operations, to the disadvantage of an unsubsidized operator. Congress plainly did not intend to prevent that sort of competition." Pacific Far East Line, Inc., v. Federal Maritime Board, 275 F.2d 184, 186 (D.C. Cir. 1960). Other courts have likewise recognized the overriding public policy in favor of competition in the domestic trade and in national transportation policy. See e.g., Matson Navigation Co., v. Connor, 258 F. Supp. 144, 158 (N.D.Cal. 1966), aff'd per curiam, 394 F.2d 514 (9th Cir. 1968); Bowman Transportation, Inc., v. Arkansas-Best Freight System, Inc., 419 U.S. 281, 198-99 (1974).

Finally, the Supreme Court made clear its preference for fair competition (as opposed to regulated entry under six month permissions) in its decision confirming the Secretary's authority to accept permanent repayment in Seatrain Shipbuilding Corp. v. Shell Oil Co. 444 U.S. 572, 589-90 (1980):

> Section 506 . . . permit[s] a vessel that enjoys the benefits of CDS to operate outside the foreign market only in narrow circumstances, generally upon a highly discretionary administrative decision, and no more than six months a year. And we have no doubt that it would be flatly inconsistent with one congressional intent were the Secretary or this court to conclude that a temporary release not meeting these conditions was proper. But a permanent release upon full repayment is quite different. It irrevocably locates the vessel in

> the unsubsidized fleet and, thus, poses no danger of a supercompetitor skimming the cream from each market. It creates no long-term instability. And it confers no windfall. On the contrary, at least where repayment of the CDS includes some amount reflecting capital costs which would have been incurred had no subsidy been available, such a transaction merely permits a once subsidized vessel to enter the domestic trade on a footing equal to that of vessels already in that trade. It was not the purpose of the Act to prohibit such entry . . . .

Thus, to the extent that the capacity allowed to enter the domestic trade under CDS repayment would have been allowed to participate in the trade under six month permissions, allowing total CDS repayment therefore would necessarily be consistent with the "purpose of the Act" Id.

In fact, where the Secretary issued the NPRM on total CDS repayment in January 1983, the full time equivalent of three CDS built VLCCs had been operating in the trade under six month permissions. Thus, allowing total repayment for three VLCCs under that rulemaking is squarely within the Supreme Court's holding.

VI. Alternatives

MARAD has considered three alternatives in preparing this rulemaking. The first is to maintain the status quo, i.e., to allow the four VLCCs to remain in the domestic trade. The costs and benefits of this alternative have been discussed at length in this statement, and in the Regulatory Impact Analysis. Further costs, evaluated in the Regulatory Impact Analysis, include the recent Title XI defaults of three VLCCs that were previously in the domestic trade under six-month waivers, and partial defaults of two other CDS-built VLCCs (STUYVESANT and BAY RIDGE). These costs were not necessarily attributable to CDS repayment and in any event are irreversibly expended at this time (i.e., returning the four VLCCs to the foreign trade would not recover this money). The total default cost to the government has been $137.5 million.

Another relevant consideration is the effect on the existing Jones Act (i.e., domestic) fleet. As of February 19, 1987, twelve Jones Act tankers were laid up (totaling approximately 650,000 DWT). On the other side of the ledger, if CDS repayment is not allowed for the four VLCCs, they are likely to be laid up (approximately 705,000 DWT).

MARAD believes that the suitability of the four VLCCs for the Alaska-Panama trade outweighs any possible disadvantages. Of the twelve tankers that are laid up, three tankers (totaling 146,000 DWT) are over 20 years old. The remaining nine tankers include the one tanker (the

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PRINCE WILLIAM SOUND, 123,400 DWT) and eight smaller tankers that could serve in the ANS trade, although at a much higher cost per ton than VLCCs currently operating in that trade (see Regulatory Impact Analysis). For example, the cost of operating a 50,000 DWT tanker in the Valdez-Panama trade is approximately, $25.00 per ton, compared to $9.19 per ton for a 265,000 DWT VLCC operating in the same trade. Further, as noted above, larger tankers are more suitable than smaller tankers from an environmental standpoint because they make fewer voyages and port calls than smaller tankers to carry the same amount of oil, thus reducing the risk of collisions and oil spills (see Environmental Assessment)

A second alternative considered would be for MARAD to do nothing, i.e., to allow the rule to be vacated as of July 16, 1987, and for the three VLCCs to leave the domestic trade, and to consider the BAY RIDGE separately. The costs of doing nothing would be a shortage of the most suitable tonnage for the Valdez-Panama trade and the likely lay-up of the three VLCCs that repaid CDS under the 1985 rule. Other costs of this alternative would be the loss to the government of CDS repayments of $105.8 million from those three VLCCs, the reduction of Alaska state revenues due to higher transportation costs in later years, and the loss of transportation savings to the shipping public.

The benefits of this alternative could be reduced government loan exposure risk on existing Jones Act tankers and the possibility of some of the laid up domestic tankers operating in the ANS trade. However, due to the age and small size of most of those tankers, they would be unsuitable for the Valdez-Panama trade. Further, only six percent of the domestic tanker fleet is laid up. A six percent lay-up is a reasonable reserve for covering temporary losses from the active fleet due to casualties (three in 1986), surveys and repairs, as well as seasonal increases on the upcoast petroleum movements.

Under this second alternative, shipbuilding demand for new crude tankers would still be minimal, if any, due to the high cost of U.S. shipbuilding, the unlikely availability of future CDS funds due to budget constraints, and the predicted future decline in the volume of crude carried in the Alaska-Panama trade.

The third alternative considered would provide for other U.S.-flag tanker owners to repay CDS in return for unrestricted domestic trading privileges. Under this approach, those vessel owners with the best prospects for employment would likely choose to repay within the specified time period. Unrestricted repayment would reduce the need for federal issuance of temporary permission to enter the ANS trade. Fiscal benefits could also be the greatest under this alternative. However, it is unlikely that any more vessels would repay under this alternative, since only three repaid when the window was open for one year and two EXXON 209,000 DWT Jones Act tankers have recently been delivered. This alternative would cause the most disruption to the Jones Act as there would be uncertainty in the market. Shipyard demand for new crude tankers would remain at a minimal or non-existent level.

E.O. 12291, Statutory Requirements and DOT Procedure

The Maritime Administrator has determined that this rule is major under the criteria of Executive Order 12291. Pursuant to the Department of Transportation's Regulatory Policies and Procedures (February 26, 1979), this rule is also considered to be "significant" because it concerns a matter on which there is substantial public interest.

The Maritime Administrator certifies that it would have no significant economic impact on a substantial number of small entities pursuant to the Regulatory Flexibility Act of 1980 (5 U.S.C. 601 et seq.) The companies owning and chartering the four VLCCs at issue, and companies owning or chartering tankers possibly affected by the rulemaking in the foreign and domestic trades, are either large oil companies or large independent shipping companies. ?

A draft Regulatory Impact Analysis has been prepared and is available for public review and copying in the Docket (R-110) in the Office of the Secretary, Maritime Administration (room 7300). It discusses the important economic aspects of this proposed rule.

An Environmental Assessment of the proposed rule has also been prepared, and may be inspected at the Office of the Secretary, Maritime Administration, room 7300. The Environmental Assessment concludes that the effect of the proposed rule would be that greater quantities of ANS oil would be transported in VLCCs than in smaller vessels, fewer total trips would be made by a smaller number of vessels, the risk of accidental oil spill would be reduced as the number of trips decreases. In addition, the tankers which have repaid CDS include a number of safety and environmental features required by statute. Overall, the risk to the environment would be reduced with the proposed rule as compared to without it. On the basis of this environmental assessment, the Maritime Administration has tentatively concluded that the proposed rule would not result in a significant environmental impact to the human environment.

PART 276 - [AMENDED]

46 CFR Part 276.3 is revised to read as follows:

1. The authority citation for Part 276 continues to read as follows:

Authority: Secs. 204(b), 207, 506, and 714, Merchant Marine Act, 1936, as amended (46 U.S.C. 1114(b), 1117, 1156 and 1204) Pub. L. 86-518 (74 Stat. 216); Reorganization Plans No. 21 of 1980 (64 Stat. 1273) and No. 7 of 1981 (75 Stat. 840), as amended by Pub. L. 91-469 (84 Stat. 1036); and Dept. of Commerce Organization Order 10-8 (36 FR 19707), July 23, 1973), unless otherwise noted.

2. 276.3 Total Repayment.

(a) The Maritime Administration reaffirms the allowance of the irreversible total repayment of unamortized construction-differential subsidy (CDS), with interest, and rescission permanently of the domestic trading restrictions related to the grant of CDS for tankers of any deadweight tonnage for applications and approval between June 6, 1985 and June 5, 1986, in accordance with the terms and conditions of subsection (b). The approved applications were for the ARCO INDEPENDENCE, ARCO SPIRIT and BROOKLYN.

(b) Repayment Terms. The full repayment amount consists of the unamortized CDS, as determined by the Maritime Administration, with compounded interest on that amount. The interest rate is the same as the long-term interest rate the owner obtained, or would have obtained if long-term debt financing had been used, in financing the owner's portion of the tanker. Unless the Maritime Administrator determined that using interest rates other than long-term bond rates was justified, such rates are used. If more than one long-term bond was issued to finance the owner's portion of a specific tanker, or if one or more of such bonds has more than one rate (such as a serial bond) an average interest rate is computed weighted by the proportion of each bond par value to the total par value of all long-term bonds issued to finance the owner's tanker. The interest payable on the unamortized CDS is computed by continuous compounding of the interest until the day of repayment. For purposes of this paragraph, "long-term bond rates" are either actual Title XI bond rates on a specific owner's tanker or the Title XI long-term bond rate at the time the tanker's statutory life began.

DRAFT REGULATORY IMPACT ANALYSIS

CONSTRUCTION DIFFERENTIAL SUBSIDY REPAYMENT

GOVERNMENT AFFAIRS

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March 1987

I. EXECUTIVE SUMMARY

This Regulatory Impact Analysis provides background information and examines the various impacts and effects of the proposed rule to allow the owners of tankers built with Construction Differential Subsidies (CDS) to repay those subsidies and use those vessels in the domestic trades.

A. BACKGROUND

i. Jones Act Oil Trade. Section 27 of the Merchant Marine Act, 1920 (The Jones Act), generally requires that all cargo transported in the domestic trades be carried on vessels built in the United States, documented under United States law, crewed by U.S. seamen, and owned by U.S. citizens. Jones Act tankers are built without construction subsidy and operate in the domestic trades without direct federal operating assistance. Tankers built with construction-differential subsidy (CDS) are also U.S.-built, U.S.-manned, and U.S.-owned, but, under the Merchant Marine Act, 1936, these vessels are not permitted permanent trading privileges in the domestic trades.

Section 506 of the Merchant Marine Act, 1936, as amended, grants the Secretary of Transportation the authority to permit the temporary transfer of CDS-built ships into the domestic trades, provided the transfer of any ship does not exceed a six-month period in any year, and provided CDS is repaid on a pro rata basis. The Secretary also has the authority in appropriate cases to eliminate all domestic trade restrictions on a vessel constructed with CDS in exchange for full repayment, with interest, of the carrier's outstanding CDS obligation.

ii. The 1970 Tanker Program. The Merchant Marine Act of 1970, amended the Merchant Marine Act of 1936 to authorize for the first time tankers to be built with CDS for use in the foreign trades. Thirty-four petroleum tankers have been built under this program, including nine VLCCs and two ULCCs.

iii. Alaskan Oil Trade. In 1977, following the opening of the Trans Alaska Pipeline System (TAPS), the demand for large U.S.-flag crude tankers to carry Alaskan crude oil from Valdez, Alaska, to Panama (for transshipment to Gulf and East Coast ports) was greater than the Jones Act fleet could accommodate. In order to alleviate the shortage of suitable tanker capacity, a regulation was promulgated to allow very large crude carriers (VLCCs are vessels in excess of 160,000 deadweight tons (DWT))* built with CDS to enter the Alaskan trades on a temporary basis.

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* London Tanker Brokers' Panel Ltd. Publishers of AFRA (Average Freight Rate Assessments) defines VLCC as 160,000 to 319,999 DWT tanker.

B. RULEMAKING ON CDS REPAYMENT

1. History of Rulemaking. In 1977, the Maritime Administration (MARAD) adopted regulations to allow CDS-built tankers over 100,000 deadweight tons to enter the Alaskan crude oil trade on six-month waivers, provided they repay a pro rata portion of their outstanding CDS obligation. In addition, MARAD in 1977 allowed total CDS repayment on the VLCC STUYVESANT. In Seatrain Shipbuilding Corp. v. Shell Oil Co., 444 U.S. 572 (1980), the Supreme Court upheld the Secretary's authority to accept total CDS repayment, but did not address the issue of when such authority should be exercised. In 1978 MARAD published a Notice of Proposed Rulemaking that would allow CDS repayment. After the adoption of its interim rule, on November 13, 1980, MARAD allowed total repayment for the VLCC BAY RIDGE, an action that was contested by the Independent U.S. Tanker Owners' Committee.

In Independent U.S. Tanker Owners Committee v. Drew Lewis 690 F. 2d 908, the Court of Appeals concluded that MARAD was not legally obliged to issue rules limiting its discretion with regard to CDS payback, but vacated the interim rules on procedural grounds.

The Department of Transportation published a new NPRM on January 31, 1983 (48 FR 4408). That NPRM, which was issued by the Secretary, proposed to permit total CDS repayment for U.S. tanker vessels and formed the basis for the final DOT rule.

Shortly after the close of the comment period on the NPRM, the Congress took action to prevent the Secretary from promulgating a final rule. The DOT FY 84 Appropriations Act (Pub. L. 96-78, August 15, 1983) prohibited the enforcement of any rule with respect to the repayment of CDS until 60 days following the promulgation of any such rule. Thereafter, the Commerce Department's FY 84 Appropriations Act (Pub. L. 98-166, November 28, 1963) imposed an additional restriction that prohibited DOT from enforcing any CDS repayment rule until after June 15, 1984. However, in August of 1984, the FY 85 Appropriations Act for Commerce, Justice and State, which provided appropriations for the Maritime Administration, imposed yet another restriction. That Act prohibited the Department from enforcing any CDS repayment rule until May 15, 1985 (Pub. L. 96-411, August 30, 1984).

On May 7, 1985, the Department published in the Federal Register a final rule which allowed any owner or operator of a tanker built with CDS to repay its subsidy (with interest) and consequently obtain a permanent removal of the ban on domestic trading privileges. The amount of repayment included the unamortized CDS on the vessels plus compounded interest on that amount. The interest rate to be used for computational purposes was the rate of the original Title XI obligation on the tanker or the Title XI long term bond rate at the time of delivery. The final rule included a one-year time limit after the rule's effective date during which total CDS repayment had to be made. That time limit was from June 6, 1985 through June 6, 1986. During that time, three VLCCs repaid their CDS: the ARCO INDEPENDENCE, ARCO SPIRIT, and the BROOKLYN. The total amount of CDS repaid by these ships was $105.8 million. Those ships are now operating in the domestic trade.

On January 16, 1987, the Court of Appeals for the District of Columbia held that the Secretary of Transportation violated section 553(c) of the Administrative Procedure Act by adopting this final rule on CDS repayment. The Court vacated the rule, but withheld issuance of its mandate until July 16, 1987 "to avoid further disruptions in the domestic market and to allow the Secretary to undertake further proceedings to address the problems of the merchant marine trade." Independent U.S. Tanker Owners Committee v. Dole, Civil Action Nos. 85-01555, 85-01740, 85-01752 and 85-1771 (D.C. Cir. January 16, 1987). The Court ruled that, as of July 16, 1987, the present rule will be vacated and conditions will be returned to the status quo ante, before the CDS repayment rule took effect, subject to any "further action" that the agency may have taken in the interim.

By letter dated March 10, 1987, counsel for the BAY RIDGE requested that a proceeding on the BAY RIDGE be conducted independently of proceedings with respect to the three vessels which repaid CDS pursuant to the repayment rule that has been vacated by the Court of Appeals. However, this rulemaking will take the BAY RIDGE into consideration.

The Proposed Rule:

The proposed rule would reaffirm the allowance of the repayment of CDS, with interest, and rescission of domestic trading restrictions for tankers that applied and were approved from June 6, 1985 through June 6, 1986. The approved applications were for the ARCO INDEPENDENCE, ARCO SPIRIT, and BROOKLYN. Further, this proposed rule would reaffirm the allowance of the repayment of CDS, with interest, and rescission of the domestic trading restriction for the BAY RIDGE, which was approved to repay its CDS in November 1980.

The Purposes and Policies of the Merchant Marine Act

MARAD believes that promulgation of the proposed rule will further the ability of the U.S.-flag tanker fleet to meet the objectives of the Merchant Marine Act, 1936, as amended (Act).

The goals of the Act are to foster the development and encourage the maintenance of an American merchant marine that is "(a) sufficient to carry its domestic waterborne commerce and a substantial portion of the waterborne export and import foreign commerce of the United States and to provide shipping service essential for maintaining the flow of such domestic and foreign waterborne commerce at all times, (b) capable of serving as a naval auxiliary in time of war or national emergency, (c) owned and operated under the United States flag by citizens of the United States, insofar as may be practicable, (d) composed of the best-equipped, safest, and most suitable types of vessels, constructed in the United States and manned with a trained and efficient citizen personnel, and (e) supplemented by efficient facilities for shipbuilding and ship repair."

C. TRANSPORTATION IMPACT ANALYSIS

Based on the operating and demand characteristics of each market, CDS repayment results in the possible displacement of less suitable vessels by more suitable vessels. VLCCs are more suitable for long-haul, high volume trades, e.g., Valdez-Panama, than smaller tankers, simply because vessel operating costs do not rise as fast as cargo volumes. 1/ VLCCs are less suitable than smaller tankers for short haul, low volume trades because their capital costs and port charges, which are higher than those for smaller tankers, are spread over smaller cargo volumes. The combination of economies of tanker size, length of voyage, tanker operating costs, size restrictions, and the demand for Alaskan crude oil at specific ports are the main factors that determine tanker deployment. As a result of these forces, the most suitable tankers would serve each distinct market.

The competitive displacement process just described has and will, for two reasons, result in substantial transportation savings. First, as outlined above, readjustment in the size composition of vessels operating in each market occurs. Larger vessels with lower operating costs replace smaller, higher cost tankers; therefore, the average size of the vessels operating in each trade increases. Second, allowing CDS VLCCs permanent entry into the domestic trades increases competition and ensures that tanker rates correspond more closely to the cost of operating the most suitable vessels for each trade.

D. OTHER IMPORTANT IMPACTS

1. Fiscal Impacts. In addition to the tanker owners and shippers, the federal and State of Alaska governments benefit by repayment of CDS for the four vessels.

a. Construction Differential Subsidy Repayment. The CDS repayment, itself, is the most immediate fiscal impact. MARAD received $142 million in CDS repayments from the four VLCCs: ARCO INDEPENDENCE ($44 million), ARCO SPIRIT ($42 million), BAY RIDGE ($36 million), and BROOKLYN ($19 million).

b. Alaska State Revenues. The State of Alaska receives revenues from the sale of Alaskan crude oil from a royalty on production and a severance tax. On average, Alaska receives about 28 cents of each dollar of increase in the wellhead price, resulting from reductions in transportation costs, i.e., wellhead price as equal to refinery price less transportation costs. CDS repayment by the four VLCCs nets the State of Alaska 28 cents for each dollar of transportation savings.

1/ See, for example, J.O. Jansson and D. Shneerson. "The Optimal Ship Size," Journal of Transport Economics and Policy, September 1982, pp. 228-238.

ii. National Security Issues. The Defense Department has expressed concern over losing additional numbers of the tankers under 100,000 deadweight tons from the active fleet. Three factors have worked over time to decrease the number of militarily useful tankers: a declining product tanker trade, the start-up of the Trans-Panama Pipeline, and the recently enacted Port and Tanker Safety Act. As a result of these factors, 41 U.S.-flag tankers of 1.3 million DWT of the type considered highly militarily useful have been scrapped over the period 1984-86. As of February 1, 1987, there were 49 militarily useful tankers at least 20 years old in the U.S.-flag fleet compared to a total of 82 under 20 years of age.

iii. Foreign Trades. The decline in world petroleum demand, changes in the geographic pattern of U.S. petroleum trades, i.e., reduced U.S. dependence on distant sources of crude oil, and the high cost of operating U.S.-flag vessels have made U.S.-flag VLCCs unsuitable for U.S. foreign trades. For example, the cost of operating a U.S.-flag, 225,000 DWT tanker is three times that for a similar size foreign-flag tanker. MARAD cannot provide new subsidies to offset the cost disadvantages of operating U.S.-flag VLCCs in the foreign trades. CDS repayment has not reduced the U.S.-flag participation in foreign commerce. If not allowed to operate in the domestic trades, the four VLCCs would be unemployed and possibly scrapped.

iv. Shipyards. Even without CDS repayment, the growth prospects for the domestic petroleum trades are not sufficient to require the construction of significant additional tanker capacity. Therefore, allowing these four CDS-built vessels to enter the domestic Jones Act fleet permanently will have little effect on the amount of domestic tanker construction.

E. CONCLUSION

Allowing the four VLCCs to repay the outstanding CDS (plus interest) in return for unrestricted access to the Jones Act crude oil trades furthers the policy and purposes of the Act by making the domestic segment of the American merchant marine better balanced than it would be without these vessels in the trade. In addition, these vessels because of their characteristics, including size, permit the Secretary to make progress toward the goal of developing a merchant marine with well equipped, safe and suitable vessels. That is, the four VLCCs are more suitable vessels for the long-haul, high volume ANS trades than smaller ships. Furthermore, the elimination of the current uncertainty on the use of the VLCCs in the ANS trade would make it easier for oil companies and tanker owners to plan for the future. Given the high operating costs for U.S.-flag tankers (relative to foreign-flag tankers) and the amount of idle tonnage over 200,000 DWT in the world fleet, it is very likely that the four VLCCs would be laid up if they were required to leave the domestic trade.

In summary, allowing the four VLCCs which repaid CDS under the final rule to remain in the domestic trades would ensure that the most suitable U.S.-flag vessels are deployed in these trades in accordance with the purposes and policies of the Merchant Marine Act of 1936.

II. INTRODUCTION

A. HISTORY

Section 27 of the Merchant Marine Act, 1920 (the Jones Act), generally requires that all cargo transported in the domestic trades be carried on vessels built in the United States, documented under United States law, crewed by U.S. seamen, and owned by U.S. citizens. Under the Merchant Marine Act, 1936, Jones Act tankers must be built without construction subsidy and must operate without direct federal operating assistance. Tankers built with construction-differential subsidy (CDS) are also U.S.-built, U.S.-manned, and U.S.-owned, but these vessels are not permitted permanent trading privileges in the domestic trades because of the subsidy they received.

Since the end of World War II, water transportation of petroleum products has declined in importance, as pipelines have become the dominant mode for domestic, long-haul, petroleum product shipments. For example, domestic coastwise movements of petroleum products have trended down from 195 billion ton-miles in 1980 to 131 billion ton-miles in 1984. Moreover, within the water transportation mode, the importance of ocean barge movements has increased at the expense of tanker movements. More and more, tanker traffic in petroleum products has relied upon the movement of residual fuel oil (the so-called "dirty trades") and other nonpipeline compatible products, rather than refined products, such as gasoline and jet fuel ("clean trades"). By the late 1960s, the Jones Act tanker fleet consisted primarily of small, less than 55,000 deadweight ton (DWT) product tankers that operated between the Gulf and East Coasts, supplemented by a limited number of small crude carriers operating in that same area.

When Alaska North Slope (ANS) oil was first discovered in the late 1960s, it was expected that West Coast markets would require virtually all the ANS oil. Large tankers in the 120,000 to 130,000 DWT size category were ordered in anticipation of the ANS crude trade. By the time the TAPS opened in 1977, it was obvious that West Coast markets could not absorb all ANS crude for three reasons: ANS production was much higher than originally anticipated; West Coast demand had not grown as rapidly as expected; and California oil production was higher than expected. It thus became necessary to transport ANS crude to other markets through the Panama Canal to the Gulf Coast, East Coast, and Puerto Rico. The distance from Valdez to Panama is approximately twice that from Valdez to Long Beach; thus increases in crude oil movements from Valdez to Panama expanded the demand for tankers over 200,000 DWT in the domestic trades.

ANS crude was carried to Panama by tankers over 200,000 DWT, by some of the 120,000 to 130,000 DWT tankers built to serve the West Coast trades, as well as by smaller vessels. At Panama the oil was offloaded to smaller tankers for shipment through the Panama Canal. Some of this oil was transported by 55,000 to 90,000 DWT crude tankers; a large number of small product tankers less than 55,000 DWT also transported ANS crude through the Canal. Many of these product tankers were built more than 20 years ago for the then extensive domestic product trade.

By 1977, demand for large U.S.-flag crude tankers to carry ANS oil from Valdez, Alaska, to Panama was greater than the Jones Act fleet could satisfy. In order to alleviate the shortage of large, Jones Act crude tanker capacity, VLCCs built with CDS were given permission to enter the ANS trade on a temporary basis. These vessels were originally built for the foreign crude trade, but the decline in world petroleum demand, changes in the geographic pattern of U.S. petroleum trades, i.e., reduced dependence on distant sources of crude oil, and the high cost of operating U.S.-flag vessels have made U.S.-flag VLCCs unsuitable for U.S. import trades. For example, the operating cost for a U.S.-flag, 225,000 DWT tanker is three times that for a similar size foreign-flag tanker. Given current budget restrictions, MARAD cannot offset the cost disadvantages of U.S.-flag tankers, e.g., through new operating-differential subsidy (ODS) or CDS contracts, in the foreign trades. Vessels over 100,000 DWT have never received ODS.

Section 506 of the Merchant Marine Act, 1936, grants the Secretary of Transportation authority to permit the temporary transfer of CDS-built ships into the domestic trades, provided the transfer of any ship does not exceed a six-month period in any year, and provided CDS is repaid on a pro rata basis (i.e., in proportion to the vessel's statutory life).

The Secretary also has the authority to eliminate all domestic trade restrictions on a vessel constructed with CDS in exchange for full repayment (with interest) of the CDS obligation. A 1980 Supreme Court decision on full repayment of CDS and release of Jones Act trading restrictions addressed the differences between pro rata repayment under six-month permissions and full repayment.

> ...a permanent release upon full repayment is quite different (from temporary permission). It irrevocably locates the vessel in the unsubsidized fleet, and thus poses no danger of a super-competitor skimming the cream from each market. It creates no long-term instability. And it confers no windfall. On the contrary, at least where repayment of the CDS includes some amount reflecting capital costs which would have been incurred had no subsidy been available, such a transaction merely permits a once subsidized vessel to enter the domestic trade on a footing equal to that of vessels already in the trade. It was not the purpose of the Act to prohibit such entry 2/

Five CDS-built VLCCs have been allowed to repay their CDS obligation: the STUYVESANT (224,700 DWT) on an ad hoc basis in August 1977, the BAY RIDGE (225,000 DWT) through an ajudicative decision in November 1980; and the BROOKLYN (226,200 DWT), the ARCO SPIRIT (262,400 DWT), and ARCO INDEPENDENCE (262,400 DWT) under a DOT final rule in 1985-86.

2/ Seatrain Shipbuilding Corp. vs. Shell Oil Co., 44 U.S. 572 (1980).

The 1978 Port and Tanker Safety Act (PTSA) set certain antipollution requirements for all tankers over 20,000 DWT entering United States waters. By January 1, 1986, vessels between 20,000-40,000 DWT were required to have certain antipollution systems to prevent the discharge of oil-tainted water. Tanker owners had several compliance options: retrofit existing systems, reduce load lines (so as to carry less than 20,000 DWT), use port reception facilities to dispose of oily water, or scrap ships and construct replacement vessels. The cost of retrofit, as well as the loss of cargo capacity that it entails, has accelerated the scrappage of older vessels. While the PTSA requirements should have no effect on the demand for tanker capacity, it has contributed to the scrappage of the older, less-efficient product tankers — the U.S.-flag tanker fleet has fallen from 226 vessels of 11.0 million DWT in January 1983 to 165 vessels of 10.4 million DWT in January 1987. 3/

B. ALASKA CRUDE OIL TRANSPORTATION: 1978-1986

1. Historical Production and Distribution of ANS Crude Oil. ANS crude oil loadings have grown steadily since 1977, as shown in Table II-1. The most rapid growth occurred between 1978 and 1980 when average loadings grew at an annual rate of 18.4 percent. In contrast, average loadings grew at an annual rate of 2.2 percent from 1980 to 1986.

At the same time that ANS crude oil production was growing, the distribution of the oil changed dramatically. In 1980, long-haul shipments from Alaska to Panama were 459,000 b/d (30 percent) of total loadings. By 1982, the volume of oil going to the Gulf/East Coasts via Panama climbed to 701,000 b/d (43 percent). During this same period, the volume of oil going to the West Coast (including Alaska and Hawaii) dropped from 956,000 b/d (63 percent) to 817,000 b/d (50 percent).

After 1982, the distribution of ANS crude shifted again, with an increase in the share of oil going to the West Coast and a decrease in the share of oil going to the Gulf/East Coasts. Between 1982 and the 1986, shipments to the West Coast rose from 817,000 b/d (50 percent) to 1.11 million b/d (62 percent), while shipments to Panama fell from 701,000 b/d (43 percent) to 569,000 b/d (32 percent).

3/ Petroleum tankers not including integrated tug barge units.

ii. Forecast of Alaska Crude Oil Production and Distribution. While ANS tanker loadings have increased from 629 thousand barrels per day in 1977 to 1,788 thousand barrels per day in 1986, loadings are expected to fall over the period 1988-95, due to a decline in ANS production (Table II-2).

The opening of the All American Pipeline in 1988 will likely further dampen the demand for VLCCs in the Valdez-Panama trades. The pipeline will have a capacity to move 300,000 barrels per day of either California or ANS crude oil Southern California to the Texas Gulf. To the extent that ANS crude oil is shipped through the pipeline or more ANS crude oil is shipped to California to replace California crude, less oil will be shipped from Valdez to Panama.

Another factor which may reduce the demand for U.S.-flag tankers in the ANS trades in the early 1990's is the potential construction of a 105,000 barrel per day (rated capacity) refinery at Valdez by Alaskan Refining, Inc. Products from the refinery may be transported abroad on foreign-flag tankers, thus reducing Valdez loadings for U.S.-flag tankers.

Given the uncertainty regarding tanker demand in the Valdez-Panama trade in the 1990's, it is highly unlikely that new ships will be built for the trade. Thus, the four VLCCs which repaid their CDS should remain among the most suitable vessels for the trade in the near future.

Furthermore, even without CDS repayment, the growth prospects for the domestic petroleum trades are not sufficient to require the construction of significant additional tanker capacity. Therefore, allowing the four CDS-built vessels to enter the domestic Jones Act fleet permanently will have little effect on the amount of domestic tanker construction.

Table II-1

Average ANS Crude Oil Loadings at Valdez
(Thousands of Barrels Per Day)

Destination	1977- 5 mos.	1978	1979	1980	1981	1982	1983	1984	1985	1986
West Coast	458	681	841	901	813	760	775	887	936	1,005
Alaska	11	14	7	11	21	19	27	33	59	70
Hawaii	-	15	30	44	34	38	35	46	44	38
Panama	150	344	306	459	528	701	698	574	629	569
Virgin Islands	10	38	81	106	126	100	107	118	119	99
Gulf/East Coasts (via Panama)	-	-	4	13	14	3	7	2	7	6
TOTAL	629	1,092	1,269	1,534	1,536	1,621	1,649	1,660	1,794	1,788

Source: Maritime Administration.

Table II-2

Forecast of Alaska Crude Oil Production
(thousands of barrels per day)

	North Slope	Cook Inlet	Total
1987	1,806	40	1,846
1988	1,726	32	1,758
1989	1,662	27	1,689
1990	1,538	22	1,560
1991	1,481	20	1,501
1992	1,369	17	1,386
1993	1,274	15	1,289
1994	1,346	13	1,359
1995	1,228	10	1,238
2000	767	8	775

Source: Alaska Department of Revenue, Petroleum Production Revenue Forecast--Quarterly Report, December 1986.

C. CURRENT CDS REGULATIONS AND THEIR APPLICATION

i. Six-Month Permissions. As shown in Table II-3, 43 temporary permissions have been granted to CDS-built tankers since 1977. CDS-built VLCCs secured 37 of these permissions; CDS-built 90,000 DWT tankers secured six. Prior to total CDS repayment the domestic service permissions to VLCCs, normally for six-month periods, had been the only recent employment for five of the seven CDS-built VLCCs. CDS-built 90,000 DWT tankers have secured six grants of permission ranging from 14 days to two months. Since 1980, the only employment outside of the ANS trades for CDS-built VLCCs has been for movements of oil for the Strategic Petroleum Reserve. There have been no applications for six-month VLCC waivers since November 1, 1985.

Permissions for three CDS-built VLCCs — ARCO INDEPENDENCE, MARYLAND and WILLIAMSBURGH — to operate temporarily in the Alaskan oil trade were terminated on January 12, 1984. Their approval had been conditioned on the acquisition of suitable employment (by January 1984 when they would become available) of four Jones Act vessels over 100,000 DWT -- OVERSEAS BOSTON, OVERSEAS JUNEAU, OGDEN COLOMBIA, and PRINCE WILLIAM SOUND. When the latter two were not chartered, the conditional approvals were terminated in accordance with the order of October 7, 1983. No CDS-built VLCCs entered the ANS trade after that until the MARYLAND on November 15, 1984. Two additional VLCCs were granted waivers in January 1985 and January 1986. In addition, a CDS-built 90,000 DWT tanker made two voyages in the Valdez to West Coast trade under a section 506 waiver in March 1986.

ii. 100,000 DWT Full Employment Rule. Before a CDS-built VLCC tanker receives permission to temporarily enter the ANS trade under section 506 of the Merchant Marine Act of 1936, Jones Act tankers over 100,000 DWT not employed may object and block approval (see 46 CFR Part 250). In May 1986, the U.S. Court of Appeals for the District of Columbia Circuit, remanded a case involving six-month waivers for two VLCCs back to MARAD for consideration of the impact of such waivers on vessels under 100,000 DWT.

D. OPTIONS FOR CHANGE OF CDS REGULATION

This proposed rulemaking considers three main options. The first option (rulemaking) is to allow the four tankers that have repaid CDS under the interim and existing rule (June 1985) to remain in the domestic trades. These vessels, BAY RIDGE (225,000 DWT), BROOKLYN (226,200 DWT), ARCO SPIRIT (262,400 DWT), and ARCO INDEPENDENCE (262,400 DWT) are presently active in the long-haul ANS trades. They are among the most suitable U.S.-flag tankers for the ANS-Panama trade (Table II-3). The second is to vacate the rule and prevent the BAY RIDGE, BROOKLYN and two Arco vessels from operating in the domestic trades. A variation of this option would permit temporary waivers to be continued. The third option would provide a six-month period for other U.S.-flag tanker owners to repay CDS in return for unrestricted domestic trading privileges.

Table II-3

Section 506 Waivers in Alaskan Oil Trade

Vessel	Docket No.	Dates of Operation From	To
AMERICAN INDEPENDENCE	S-594	3/18/78	9/18/78
" "	S-658	3/2/80	9/5/80
" "	S-697	9/23/81	3/18/82
ARCO INDEPENDENCE (ex AMERICAN INDEPENDENCE)	S-719	10/1/82	4/3/83
" "	S-741	11/14/83	1/9/84
AMERICAN SPIRIT	None	1/2/78	3/1/78
" "	S-633	2/18/79	3/9/79
" "	S-638	3/23/79	4/13/79
" "	S-656	12/19/79	6/13/80
" "	S-682	1/24/81	7/22/81
ARCO SPIRIT (ex AMERICAN SPIRIT)	S-710	3/21/82	9/19/82
" "	S-731	3/22/83	9/13/83
BAY RIDGE	S-662	4/17/80	11/20/80
BEAVER STATE	None	1/25/79	2/18/79
" "	None	2/19/79	3/4/79
" "	S-709	2/25/82	4/27/82
" "	S-786	3/27/86	4/26/86
BROOKLYN	S-654	12/25/79	6/12/80
"	S-683	2/14/81	9/6/81 1/
"	S-712	5/24/82	11/28/82
"	S-734	5/27/83	11/14/83
"	S-762	1/2/85	6/22/85
CHESTNUT HILL	S-595	2/18/78	3/5/78
KITTANNING	S-714	3/30/82	4/18/82
MARYLAND	S-592	4/3/78	10/9/78
"	S-644	8/25/79	3/31/80
"	S-675	11/4/80	5/10/81
"	S-703	11/19/81	4/24/82
"	S-721	10/28/82	4/18/83
"	S-742	10/18/83	1/12/84
"	S-761	11/15/84	5/12/85

Vessel	Docket No.	Dates of Operation From	To
MASSACHUSETTS	S-600	6/27/78	1/10/79
"	A-139	12/19/79	6/21/80
"	S-681	1/1/81	3/7/81
NEW YORK	S-566	8/10/77	11/12/77
" "	S-669	7/16/80	2/15/81 2/
" "	S-713	5/22/82	11/9/82
" "	S-733	5/9/83	11/10/83
" "	S-780	1/19/86	7/18/86
WILLIAMSBURGH	S-666	5/29/80	12/1/80 1/
"	S-704	1/15/82	5/8/82
"	S-720	11/23/82	5/15/83
"	S-743	12/10/83	12/25/83

1/ Includes one intermediate foreign trade voyage
2/ Includes oil storage in Delaware Bay

III. SUITABILITY ANALYSIS

The preamble of the Merchant Marine Act, 1936, as amended (Act), states that the purpose for enactment is "To further the development and maintenance of an adequate and well-balanced (emphasis added) American merchant marine, to promote the commerce of the United States, to aid in the national defense, to repeal certain former legislation, and for other purposes." In Title I — Declaration of Policy (Section 101) it is stated further that "It is necessary for the national defense and development of its foreign and domestic commerce that the United States shall have a merchant marine (a) etc.

It is noted that a key section of the policy statement covers a description of what kinds of vessels should compose the American merchant marine — one that is composed of the best-equipped, safest, and most suitable (emphasis added) types of vessels."

Allowing the four VLCCs to remain in the Jones Act trades furthers the policy and purposes of the Act by making the domestic segment of the American merchant marine better balanced than it would be without these vessels in the trade. In addition, these vessels because of their characteristics, including size, permit the Secretary to make progress toward the goal of developing a merchant marine with well-equipped, safe and suitable vessels.

It is the view of the Secretary that the four VLCCs are more suitable vessels for the long-haul, high volume ANS trades than ships of a smaller size, because of their efficiencies and economy of scale.

Based on the operating and demand characteristics of the long-haul, high-volume ANS trades, CDS repayment has resulted in the displacement of smaller vessels with more suitable, large ships. The negative impact of this displacement on the employment of smaller tankers is offset by the benefit of having more suitable vessels in the domestic trade.

The cost of transporting a barrel of oil varies significantly, depending upon the size of the vessel. Large tankers carry crude at a lower cost per barrel than small tankers simply because operating costs do not increase as fast as cargo volumes. The relative efficiency of larger tankers becomes even more pronounced over longer hauls because the vessel's fixed costs can be spread over more barrel-miles. 4/ The demand for oil in each market, of course, affects the tanker size used in that trade. Finally, port draft restrictions and terminal restrictions prevent vessels over a certain size from entering specific ports and terminals. (The port draft restrictions can sometimes be overcome by light loading or lightering, which increases barrel-mile costs). Thus, the combination of economies of tanker size, length of voyage, tanker operating costs, size restrictions, and the quantity of ANS crude demand at specific ports are the main factors that determine ANS tanker deployment.

4/ See, for example, J.O. Jansson and D. Shneerson. "Optimal Ship Size," Journal of Transport Economics and Policy, September 1982, pp. 228-238.

The data presented in Table III-1 illustrate the operating economies of larger tankers in the long-haul Valdez to Panama oil trade. For example, a 90,000 DWT tanker has total costs per delivered long ton of crude oil (Valdez to Panama) which are 57 percent greater than those of 265,000 DWT tanker in the same trade.

Table III-1

U.S.-Flag Tanker Operating and Capital Costs, Valdez-Panama*

Tanker Size	$ Per Long Ton
265,000 DWT	9.19
225,000 DWT	11.09
170,000 DWT	12.42
120,000 DWT	13.44
90,000 DWT	14.17
50,000 DWT	25.00

* - Fuel and operating expenses from Maritime Administration's Estimated Vessel Operating Costs, 1984. Capital costs based on actual vessel cost at 10 percent interest rate.

Furthermore, large tankers are more suitable than smaller tankers from an environmental standpoint because they make fewer voyages and port calls than smaller tankers to carry the same amount of oil, thus reducing the risk of collisions and oil spills. 5/

As Table III-2 shows, the distribution of full time equivalent employment in the Alaska to Panama trade, and other ANS tades, has changed in favor of larger tankers since the CDS-built vessels (ARCO SPIRIT, ARCO INDEPENDENCE (July 1985) and BROOKLYN (June 1986)) repaid their subsidy. The apparent displacement, or bumping of smaller tankers from the trade has led to increased overall efficiency and safety in the distribution of ANS crude.

5/ See U.S. Dept. of Transportation, Environmental Asessment, CDS Repayment, March 1987.

Table III-2

Estimated Full-Time Equivalent Tanker Employment*
in the ANS Trade
(Deadweight in Thousands)

	1982	1983	1984	1985	1986
Employment by Trade and Size:					
Valdez-West Coast					
170-190	322.9	198.4	353.0	353.4	439.0
110-137	705.4	615.0	459.9	511.0	599.3
55-92	694.0	731.3	729.9	827.6	816.3
Under 55	66.9	91.2	262.9	165.1	105.9
Subtotal	1,789.2	1,635.8	1,805.6	1,857.0	1,960.4
Valdez-Panama					
Over 200	1,249.4	1,174.7	506.5	708.0	1,071.8
170-190	1,405.0	1,440.3	1,276.8	1,310.9	1,050.5
110-137	529.8	531.7	632.8	644.5	288.7
55-92	204.5	87.7	138.9	47.4	11.5
Under 55	0.0	0.0	7.4	0.0	3.9
Subtotal	3,388.7	3,234.3	2,562.3	2,710.7	2,426.4
Panama-Gulf/East					
110-137	0.0	0.0	0.0	4.4	115.6
55-92	837.5	856.6	814.2	868.7	721.4
Under 55	1,236.1	634.4	315.4	329.3	241.7
Subtotal	2,073.6	1,491.0	1,129.6	1,202.3	1,078.7
TOTAL	7,251.5	6,361.0	5,497.4	5,769.9	5,465.5

* Numbers may not add due to rounding.

Source: Maritime Administration.

IV. TRADE AND FLEET ANALYSIS

A. Trade

The demand for U.S.-flag tankers with domestic trading privileges, particularly VLCCs, increased sharply with the opening of the TransAlaskan Pipeline in 1977. The primary market for Alaska oil has been the West Coast, followed by the Gulf and East Costs (Table II-1).

B. Ship Deployment

There were 5.5 million DWT of tanker capacity (full-time equivalents) in the Alaskan crude oil trades in 1986 which included 2.0 million DWT operating from Valdez to the West Coast, 2.4 million DWT deployed from Valdez to Panama and 1.1 million DWT transshipping ANS oil from Panama to the U.S. Gulf and East Coasts; 200,000 + DWT tankers, e.g., the four that repaid CDS, have been deployed only in the Valdez-Panama trades, due to draft restrictions of West Coast ports (see Table III-2).

C. Availability of Large Crude Oil Tankers for the ANS Trades

i. Unsubsidized U.S.-Flag Tankers

At the time that ANS crude oil loadings began, there were 215 privately owned unsubsidized tankers (8.0 million DWT) in the U.S.-flag fleet (excluding special product tankers), of which only 7 were over 100,000 DWT (848,000 DWT). An additional 15 tankers (2.3 million DWT) were on order for the domestic trade, of which 12 were over 100,000 DWT (2.0 million DWT). Table IV-1 lists the unsubsidized U.S.-flag tankers over 100,000 DWT.

Table IV-1

Unsubsidized U.S.-Flag Tankers
Over 100,000 Deadweight Tons

	Year Built/ Rebuilt	Deadweight Tons
In Fleet as of August 1, 1977		
ARCO ANCHORAGE	1973	120,600
ARCO FAIRBANKS	1974	120,600
ARCO JUNEAU	1974	120,600
MANHATTAN	1962/69	113,900
MOBIL ARCTIC	1972	129,000
OVERSEAS JUNEAU	1973	120,000
PRINCE WILLIAM SOUND	1975	123,400
		848,100

Table IV-1 (cont'd)

	Year Built/ Rebuilt	Deadweight Tons
On Order as of August 1, 1977		
ATIGUN PASS	1977	173,400
KEYSTONE CANYON	1978	173,400
B.T. ALASKA	1978	188,100
TONSINA	1978	122,900
BROOKS RANGE	1978	173,400
THOMPSON PASS	1978	173,400
B.T. SAN DIEGO	1978	188,100
KENAI	1979	123,100
EXXON NORTH SLOPE	1979	173,400
EXXON BENECIA	1979	172,800
ARCO ALASKA	1979	188,400
ARCO CALIFORNIA	1980	188,400
		2,038,800
Rebuilt Under the Wrecked Vessel Act		
OVERSEAS BOSTON	1974/81	123,700
OMI COLUMBIA	1974/83	136,200
		259,900
CDS Repayment		
STUYVESANT	1977	224,700
BAY RIDGE	1979	225,000
ARCO INDEPENDENCE	1977	262,400
ARCO SPIRIT	1977	262,400
BROOKLYN	1973	226,200
		1,200,700
New Construction		
EXXON VALDEZ	1986	209,000
EXXON LONG BEACH	1987	209,000
		418,000
TOTAL AVAILABILITY		4,765,500

No orders for the construction of unsubsidized tankers over 100,000 DWT were placed between April 1976 and August 1984. However, on August 27, 1984, Exxon placed an order for the construction of two 209,000 DWT tankers in the United States for employment in the ANS crude oil trade. The first vessel was delivered in November 1986 and the second in April 1987.

Two foreign-flag tankers over 100,000 DWT were rebuilt in the United States for the ANS crude oil trade in 1981 and 1983 under the Wrecked Vessel Act (46 USC 14). Under this Act, foreign-built vessels that are wrecked off the U.S. coast are eligible to enter the U.S. domestic trade provided the vessel is purchased by a U.S. citizen and rebuilt in the United States at a cost that is at least three times the appraised salvage value. The first vessel, the OVERSEAS BOSTON (123,700 DWT), was rebuilt in 1981 and the second vessel, the OGDEN COLUMBIA (136,000 DWT), was rebuilt in 1983.

ii. Temporary Transfer of CDS-Built VLCCs

In June 1977, MARAD approved the temporary transfer of the CDS-built tanker, AMERICAN SPIRIT (262,400 DWT), to the Alaska-Panama trade for six months prior to 46 CFR Part 250 becoming final. Although tankers over 100,000 DWT were under construction at that time, there was insufficient suitable capacity available to meet the immediate shipping requirements in that segment of the Alaskan crude oil trade.

MARAD has approved the temporary transfer of CDS-built tankers to the Alaska-Panama trade on 43 occasions. The temporary transfers were at their highest level between 1980 and 1983 when there were approximately three CDS-built VLCCs (750,000 DWT) in the trade on a full time basis. Table II-3 lists the MARAD approvals for the temporary transfer of CDS-built vessel to the Alaska trade.

iii. Total CDS Repayment

In August 1977, MARAD approved the total repayment of CDS on the VLCC STUYVESANT (224,700 DWT). Competitors in the ANS crude oil trade filed suit, challenging MARAD's authority to grant full CDS repayment in exchange for permanent release of domestic trading restrictions. In February 1980, the U.S. Supreme Court ruled that the Secretary does have authority to grant permanent release from domestic trading restrictions in exchange for total CDS repayment, plus interest.

MARAD issued its second approval for CDS repayment in November 1980 on the BAY RIDGE (225,000 DWT). However, the U.S. Court of Appeals vacated the interim rule and ordered MARAD to conduct new rulemaking proceedings.

By letter dated March 10, 1987, counsel for the BAY RIDGE requested that a proceeding on the BAY RIDGE should be conducted independently of proceedings with respect to the three vessels which repaid CDS pursuant to the repayment rule that has been vacated by the Court of Appeals. However, this rulemaking will take the BAY RIDGE into consideration.

On January 31, 1983, the Department of Transportation issued a Notice of Proposed Rulemaking concerning the policy for total CDS repayment in an effort to increase efficiency and minimize Federal Government intervention in the allocation of large tankers to the ANS crude oil trade.

Shortly after the close of the comment period on the NPRM, the Congress took action to prevent the Secretary from promulgating a final rule. The DOT FY 84 Appropriations Act (Pub. L. 96-78, August 15, 1983) prohibited the enforcement of any rule with respect to the repayment of CDS until 60 days following the promulgation of any such rule. Thereafter, the Commerce Department's FY 84 Appropriations Act (Pub. L. 98-166, November 28, 1963) imposed an additional restriction that prohibited DOT from enforcing any CDS repayment rule until after June 15, 1984. However, in August of 1984, the FY 85 Appropriations Act for Commerce, Justice and State, which provided appropriations for the Maritime Administration, imposed yet another restriction. That Act prohibited the Department from enforcing any CDS repayment rule until May 15, 1985 (Pub. L. 96-411, August 30, 1984).

On May 7, 1985, the Department published in the Federal Register a final rule which allowed any owner or operator of a tanker built with CDS to repay its subsidy (with interest) and consequently obtain a permanent removal of domestic trading privileges. The amount of repayment included the unamortized CDS on the vessels plus compounded interest on that amount. The interest rate to be used for computational purposes was the rate of the original Title XI obligation on the tanker or the Title XI long term bond rate at the time of delivery. The final rule included a one-year time limit after the rule's effective date during which total CDS repayment had to be made. That time limit was from June 6, 1985 through June 6, 1986. During that time, four tankers repaid their CDS: the ARCO INDEPENDENCE, ARCO SPIRIT, BAY RIDGE, and the BROOKLYN. The total amount of CDS repaid by these ships was $142 million. Those ships are now operating in the domestic trade.

On January 16, 1987, the Court of Appeals for the District of Columbia held that the Secretary of Transportation violated section 553(c) of the Administrative Procedure Act by adopting this final rule on CDS repayment. The Court vacated the rule, but withheld issuance of its mandate until July 16, 1987 "to avoid further disruptions in the domestic market and to allow the Secretary to undertake further proceedings to address the problems of the merchant marine trade." Independent U.S. Tanker Owners Committee v. Dole, Civil Action Nos. 85-01555, 85-01740, 85-01752 and 85-1771 (D.C. Cir. January 16, 1987). The Court ruled that, as of July 16, 1987, the present rule will be vacated and conditions will be returned to the status quo ante, before the CDS repayment rule took effect, subject to any "further action" that the agency may have taken in the interim.

Since the one-year window for total CDS repayment expired no CDS-built tankers have been temporarily transferred to the Alaska-Panama trade under 46 CFR Part 250. The last transfer was approved for the NEW YORK (264,100 DWT) and the vessel left the trade on July 18, 1986.

D. **Laid-up Tonnage Available for the ANS Trades**

Domestic tankers in long-term lay-up or temporarily idled as of February 1987 totaled 12 vessels of 649,609 DWT. Of these, 3 tankers totaling 146,600 DWT are over 20 years old. The remaining nine tankers include the PRINCE WILLIAM SOUND (123,400 DWT) and smaller tankers that could serve in the ANS trades, though at much higher cost per ton delivered than the VLCCs currently operating in the trade.

Table IV-2

Privately-Owned Petroleum Domestic Tankers Laid-up*
(as of February 1987)

Vessel Name	Year Built/Rebuilt	DWT
FALCON COUNTESS	1972	37,276
FALCON LADY	1971	37,276
COVE TRADER	1959	46,400
DELAWARE TRADER	1982	50,057
ASPEN	1971	80,600
PRINCE WILLIAM SOUND	1975	123,400
MOUNT WASHINGTON	1963	49,400
BENNINGTON	1963	50,800
CHARLESTON	1956/80	39,400
FREDERICKSBURG	1958/80	39,000
JACKSONVILLE	1982	48,000
NEW YORK	1983	48,000
TOTAL	Avg. 14 years	649,609

* This list does not include vessels waiting to go into the National Defense Reserve Fleet and tankers of less than 6,000 DWT.

E. **The Foreign Trade**

One of the goals of the Act is to encourage the development and maintenance of a merchant marine sufficient to carry "a substantial portion of the waterborne export and import foreign commerce of the United States..." 46 USC 1101(a). The Court of Appeals criticized the previous CDS repayment rule for its conclusion that the fleet will remain "more than adequate to carry an appropriate share of U.S. foreign oil commerce if such opportunities should arise." The Court then concludes that the rule "will make it impossible to retain a fleet that can carry all domestic traffic and" a substantial portion 'of foreign traffic' at all times which is explicitly set out as an objective in section 101(a) of the statute. ITOC, supra at 12.

The Court noted in a footnote to its decision overturning the prior CDS rule

> It may be, of course, that present conditions in the world shipping market make it impossible for the Secretary to find a way to meet all of the statutory objectives. If this is a problem, she should discuss it frankly and directly when she considers which measures to adopt in light of the objectives explicitly set out in the Act.

While this proposed rulemaking would provide a domestic tanker fleet that is (1) sufficient to carry the domestic waterborne commerce of the United States and (2) composed of the "best-equipped, safest, and most suitable types of vessels...", there would be no effect on the U.S.-flag share of the waterborne export and import foreign commerce of the United States.

The U.S.-flag foreign trade tanker fleet currently consists of 26 CDS-built tankers totaling 3 million DWT. (This excludes the four VLCCs that are the subject of this rulemaking and three CDS-built integrated tug-barges, but includes two CDS-built ore-bulk-oil carriers built with CDS.) The six CDS-built VLCCs and ULCCs (ultra large crude carriers) are currently laid-up as is one CDS-built 90,000 DWT tanker. Seven of the tankers are employed in the competitive foreign trade, while the remaining 12 tankers are under charter to MSC (6) or are employed in the preference trades (6).

While the intent of MARAD's CDS and ODS programs was to provide a U.S.-flag fleet that is sufficient to carry a substantial portion of our import and export trade, most of the large tankers built under the 1970 program are not competitive in the international market. MARAD cannot provide new subsidies to offset the cost disadvantages of operating U.S.-flag tankers in the foreign trades.

The United States currently imports approximately 6.0 million barrels per day of crude oil and refined product, of which only 3 percent is carried on U.S.-flag tankers. Furthermore, a substantial portion of our crude oil imports—approximately 45 percent—are received from nearby sources including Canada, Mexico, Venezuela and the Caribbean region. The CDS-built VLCCs are unsuitable for these short haul import trades. Approximately 32 percent of U.S. crude oil imports are received from the distant Arabian Gulf and North Sea regions for which VLCCs would be suitable.

In contrast, ten years ago U.S. crude oil and refined product imports averaged 8.8 million barrels per day. Only 14 percent of our crude oil imports were received from nearby sources while over 40 percent of our oil imports were received from the Arabian Gulf and North Sea regions.

During the last year, there has been an increase in oil exports from the Arabian Gulf region and a corresponding rise in demand for VLCCs in the international trade. Despite this increase, the supply of tonnage in the world tanker fleet is more than adequate to carry the United States' current volume of oil imports and will remain adequate to carry our future oil imports.

As of January 1987, the world fleet contained over 235 million DWT, of which approximately 200 million DWT (85 percent) were actively employed. The remaining 35 million DWT (15 percent) were idle; however, 30 million DWT were in the over 200,000 DWT size class. The amount of idle capacity in the over 200,000 DWT size class represents more than 26 percent of the available tonnage in that class. Therefore, given the relative higher operating costs for U.S.-flag tankers and the amount of idle tonnage over 200,000 DWT in the world fleet, it is very unlikely that the four VLCCs that are the subject of this rulemaking would be laid up if they are required to leave the domestic trade.

In fact, of the nine VLCCs and two ULCCs built with CDS under the 1970 program, none has had any significant employment in the foreign commercial trades, other than occasional shipments of oil to the Strategic Petroleum Reserve, of which a share is reserved for U.S.-flag carriage. The deployment of four CDS-built VLCCs to the domestic trade thus would have no impact on the U.S.-flag tanker presence in foreign trades.

V. NATIONAL SECURITY ISSUES

The Defense Department has expressed concern over the national security implications of losing product tankers from the U.S.-flag fleet. Three principle factors have contributed to a reduction in the number of U.S.-flag product tankers: a declining upcoast (U.S. Gulf-East Coast) petroleum trade, the principal market for U.S.-flag product tankers, start-up of the Trans-Panama Pipeline (October 1982), and the anti-pollution standards of the Port and Tanker Safety Act (PTSA) which required product tankers in the 20,000-40,000 DWT range to be retrofitted by January 1, 1986 for operation in U.S. ports. As a result of these factors, 41 U.S.-flag tankers of 1.3 million DWT of the type considered highly militarily useful have been scrapped over the period 1984-86 (see Appendix I).

As of February 1987, there were 12 U.S.-flag privately-owned domestic tankers of 649,609 DWT in lay-up. Of these, nine of 503,003 DWT were less than 20-years old — the statutory economic life of a tanker. These tankers represent a reasonable reserve, 6 percent of the total U.S.-flag domestic tanker fleet, to cover temporary losses from the active fleet due to casualties, (three in 1986), safety inspections and repairs; as well as seasonal increases in upcoast petroleum movements — February is traditionally a slack month in the U.S. Gulf-East Coast trade.

In fact, as recently as March 24, 1986, the BEAVER STATE (90,000 DWT CDS-built vessel) was admitted to ANS-West Coast trade for one month on a section 506 (Merchant Marine Act of 1936) waiver because no suitable unsubsidized vessel was available for the trade. (Action upheld by District Court in Civil Action No. 86-0896, American Trading and Transportation Co., Inc. et al., vs. United States of America et al.) The action reflects the need to have slack non-VLCC capacity available, i.e., tankers in temporary lay-up to meet peak demand situations in the domestic tanker trades.

As shown in Table V-1, as of February 1, 1987, 32 percent of the U.S.-flag domestic tanker tonnage under 100,000 DWT was at least 20 years old. Given the age distribution and potential scrapping rates for militarily useful tankers (less than 100,000 DWT), it does not appear that allowing the four VLCCs which repaid CDS to remain in the domestic trade will result in unemployment for domestic tankers beyond that which is necessary to meet peak demand situations.

Thus, allowing the four VLCCs to remain in the domestic trades will further the Agency's statutory objectives of promoting a suitable, well-balanced merchant marine, i.e., capable of efficiently serving normal as well as peak demands in the domestic petroleum trades.

Table V-1

Age Distribution of U.S.-flag Privately-Owned Tankers with Domestic Trading Privileges February 1, 1987*

	Less than 10 Yrs.		10-14 Yrs.		15-19 Yrs.		20 Yrs. or More		Total	
	No.	000 DWT	No.	000 DWT	No.	000 DWT	No.	000 DWT	No.	000 DWT
Less than 100,000 DWT	28	1,345	19	828	35	1,810	49	1,859	131	5,842
100,000 DWT or greater	15	2,559	11	1,883	-	-	1	114	27	4,556
TOTAL	43	3,904	30	2,711	35	1,810	50	1,973	158	10,398

* Excludes chemical tankers, integrated tug/tank barge units and tankers of less than 6,000 DWT.

Source: Maritime Administration.

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VI. EVALUATION OF REGULATORY OPTIONS

To evaluate the options available to the Department on this issue, the transportation costs that would result under each option were calculated over a four-year period (1985 to 1988). Changes in the trade after 1988, such as the all-American pipeline, declining ANS crude oil production, increasing share of ANS crude oil shipments to the West Coast, possibility of the Valdez Refinery, will provide transportation savings which will be small when discounted back to 1987. Based upon 1986 tanker demand, recent tanker rates and the most likely changes in tanker demand projected for the future, the supply of tankers in various size ranges was determined since the total CDS payback rule became effective through 1988. In addition to transportation costs the other important impacts for each option are evaluated.

A. Rulemaking

This option would allow the four VLCCs totalling 976,000 DWT, which have repaid their CDS to remain in the trade. This option permits the most efficient use of the U.S.-flag tanker fleet in the various Alaskan tanker trades and gives employment to four VLCCs which have no employment in the U.S. foreign commerce. CDS repayment for the three vessels totaled $105.8 million.

MARAD estimates that the transportation savings resulting from CDS repayment will be approximately $674 million (present value). Appendix II shows the transportation savings for the years 1985 through 1988 by trade. Appendix III shows the rates used to estimate the transportation savings by trade and vessel size. These rates reflect market rates and also include fuel costs.

Since the payback rule became effective four VLCCs that were previously in the trade on six-month waivers have defaulted and two VLCCs have partially defaulted on a total of $137.5 million in Title XI. These losses are irreversible. Shipyard demand for new crude tankers would be little affected, remaining at the minimal levels of the past. With regard to shipbuilding, Congress has not appropriated funds to build the 300 ships contemplated in the 1970 Act.

Existing tanker owners would incur the least disruption as for any other option. The Court of Appeal's decision to vacate the rule has caused considerable uncertainty in the market. This option would reduce uncertainty about the future. This option will further the general goals of the Act by offsetting the adverse impact on the small tankers with the benefit of employing the VLCCs.

B. Do Nothing

If no action is taken on July 16, 1987, the rule is vacated and the four VLCCs would have to leave the domestic trade. There would not be enough Jones Act tonnage to meet the demands as shown in the Do Nothing table without section 506 waivers. Table VI-1 shows the expected tanker employment for 1987 under both options. The table shows that without four VLCCs in the trade the 170-190,000 DWT replace the over 200,000 DWT in the Panama trade. The size vessel most affected by allowing the four VLCCs to remain the trade can be seen by comparing the total column in each option.

Table VI-1

Expected Tanker Employment
In the ANS Crude Oil Trade - 1987
(Full Time Equivalent (000 DWT)

Rulemaking

DWT	Valdez-Panama	Valdez-West Coast	Panama Gulf/East Coast	Total
>200	1,532.7	0	0	1,532.7
170-190	900.4	588.0	0	1,488.4
114-140	0	1,092.4	0	1,092.4
55-92	0	639.6	843.6	1,483.2
<55	0	0	241.1	241.1
Total	2,433.1	2,320.0	1,084.7	5,837.8
Demand	2,443.1	2,320.0	1,084.7	5,837.8
Surplus/Deficit	0	0	0	0

Do Nothing

DWT	Valdez-Panama	Valdez-West Coast	Panama Gulf/East Coast	Total
>200	817.3	0	0	817.3
170-190	1,615.8	26.0	0	1,641.8
114-140	0	1,234.1	0	1,234.1
55-92	0	1,059.9	423.3	1,483.2
<55	0	0	661.4	661.4
Total	2,43[illegible].1	2,320.0	1,084.7	5,837.8
Demand	2,433.1	2,320.0	1,084.7	5,837.8
Surplus/Deficit	0	0	-156.1	-156.1

Do Nothing With 506 Waivers

DWT	Valdez-Panama	Valdez-West Coast	Panama Gulf/East Coast	Total
>200	773.5	0	0	773.5
170-190	1,659.6	19.3	0	1678.9
114-140	0	1,234.8	0	1,234.8
55-92	0	1,065.9	417.4	1,483.3
<55	0	0	667.3	667.3
Total	2,433.1	2,320.0	1,084.7	5,837.8
Demand	2,433.1	2,320.0	1,084.7	5,837.8
Surplus/Deficit	0	0	0	0

Fiscal benefits would be less than the Rulemaking option: No CDS repayments of $142 million from the four VLCCs; Alaska state revenues would be reduced because of the higher transportation costs in later years. There would be less risk on government loan exposure on existing Jones Act tankers. Shipyard demand for new crude tankers would continue to be minimal, just as under the Rulemaking option.

C. Unrestricted CDS Repayment

The third option would provide a six month window for other U.S.-flag tanker owners to repay CDS in return for unrestricted domestic trading privileges. Under this approach those vessel owners with the best prospects for employment would likely choose to repay within the specified time period. Unrestricted repayment would reduce the need for federal issuance of temporary permission to enter the ANS trade. Fiscal benefits could also be the greatest under this option. However, it is unlikely that any more vessels would repay under this option, since only three repaid when the window was open for one year and two 209,000 DWT Jones Act tankers have been or will be delivered soon. These four vessels were chartered by Sohio and Exxon. It would not matter if a three-month or one year window was chosen, the result would still be that the same four VLCCs would repay. This option would cause the most disruption to the Jones Act as there would be uncertainty in the market for another six months. Shipyard demand for new crude tankers would remain at the minimal levels of the past under this option.

D. Other Options Considered

A number of other options were considered including keeping only one, two or three VLCCs in the trade.

There would be great difficulty deciding which of the four VLCCs would be removed from the trade. Alternatives could be in the order in which they repaid, by length of their charters, by the company with the greatest fiscal difficulties, etc. This would be a somewhat arbitrary means of making a decision on this matter.

E. Conclusion

The Rulemaking is the option which best meets the purposes and policies of the Act. Allowing the four VLCCs to repay the outstanding CDS (plus interest) in return for unrestricted access to the Jones Act crude oil trades furthers the policy and purposes of the Act by making the domestic segment of the American merchant marine better balanced than it would be without these vessels in the trade. In addition, these vessels because of their characteristics, including size, permit the Secretary to make progress toward the goal of developing a merchant marine with well equipped, safe and suitable vessels. That is, the four VLCCs are more suitable vessels for the long-haul, high volume ANS trades than smaller ships. Furthermore, the elimination of the current uncertainty on the use of the VLCCs in the ANS trade would make it easier for oil companies and tanker owners to plan for the future. Given the relative higher operating costs for U.S.-flag tankers and the amount of idle tonnage over 200,000 DWT in the world fleet, it is very likely that the four VLCCs would be laid up if they were required to leave the domestic trade.

Table VI-2

Fiscal Impacts of CDS Repayment Option
Four Year Period
(In Million of 1987 Dollars)

Option	Transportation Savings	Repaid CDS	Increase in Alaska Revenues	Title XI Defaults
A. Rulemaking	\$664-\$674 1/	\$142	\$186-\$189	\$88
B. Do Nothing	0	0	0	0
C. Unrestricted CDS Repayment	\$674.4	\$142	\$186-189	\$88

1/ \$664 is savings with 506 waivers, while \$674 is without.

Table VI-3

Other Impacts of CDS Repayment Option
Occurring through 1988

	Total Tankers Displaced	Handy-Sized Tankers Displaced	Jones Act Seaman Displaced	New Crude Tankers Orders	Potential Title XI Defaults
A. Rulemaking	12	12	600	0	5
B. Do Nothing	0	0	0	0	0
C. Unrestricted CDS Repayment	12	12	600	0	5

VI. REGULATORY FLEXIBILITY DETERMINATION

The Regulatory Flexibility Act of 1980 (RFA) was enacted by Congress in order to ensure, among other things, that small entities are not disproportionately affected by government regulations. The RFA requires agencies specially to review rules which may have a "significant economic impact on a substantial number of small entities." The Maritime Administrator certifies that it would have no significant economic impact on a substantial number of small entities pursuant to the Regulatory Flexibility Act of 1980 (5 U.S.C. 601 et seq.) The companies owning and chartering the four VLCCs at issue, and companies owning or chartering tankers possibly affected by the rulemaking in the foreign and domestic trades are either large oil companies or large independent shipping companies.

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Appendix I

U.S.-flag Tankers Deleted from the Fleet 1984-86

Vessel Name	DWT	Built	Year Rebuilt	Deleted	Age at Scrapping*	Coating	Militarily Useful (JSCAP88)**	PTSA Features	ANS Trade	Reason for Deletion
Achilles	41,208	1960		1984	24	No	Yes	IGS/COW/SBT	Yes	Scrapped
American Eagle	32,600	1959		1984	25	Yes	Yes	None	Yes	Lost at sea
American Osprey	33,100	1958		1984	26	Yes	Yes	None	Yes	Reserve Fleet
Bangor	28,163	1953		1984	31	Yes	Yes	IGS/SBT		Scrapped
Bordeaux	27,154	1945		1984	39	Yes	Yes	None		Scrapped
Capricorn	24,400	1943		1984	41	Yes	Yes	None		Scrapped
Cheyenne	28,608	1956		1984	28	Yes	Yes	None	Yes	Scrapped
Coastal Florida	25,088	1944		1984	40	Yes	Yes	None		Scrapped
Cove Spirit	25,200	1954		1984	30	No	Yes	None	Yes	Scrapped
Exxon Chester	28,583	1952		1984	32	Yes	Yes	None		Scrapped
Exxon Huntington	28,112	1953		1984	31	Yes	Yes	IGS/SBT		Scrapped
Exxon Newark	28,553	1952		1984	32	Yes	Yes	None		Scrapped
Frio	25,455	1945		1984	39	Yes	Yes	None		Scrapped
George Whitlock II	1,500	1942		1984	42	Yes	Yes	n/a		Out of documentation
Houston	25,729	1942		1984	42	Yes	Yes	None		Scrapped
Llano	25,145	1944		1984	40	Yes	Yes	SBT		Scrapped
Medina	30,200	1953		1984	31	No	Yes	None		Scrapped
Mobiloil	31,759	1959		1984	25	No	Yes	IGS/COW	Yes	Scrapped
Monticello Victory	47,056	1961		1984	23	No	Yes	n/a		Scrapped
Overseas Anchorage	50,562	1960		1984	24	Yes	Yes	SBT	Yes	Scrapped
Overseas Joyce	49,842	1961		1984	23	Yes	Yes	SBT	Yes	Scrapped
Pisces	24,430	1945	1962	1984	39	No	Yes	None		Scrapped
Puma	31,145	1958		1984	26	Yes	Yes	n/a		Scrapped
Red River	26,900	1945	1961	1984	39	Yes	Yes	SBT		Scrapped
Sabine	33,000	1949	1966	1984	35	Yes	Yes	SBT		Scrapped
San Jacinto	26,900	1944	1962	1984	40	Yes	Yes	SBT	Yes	Scrapped
San Marcos	27,400	1949		1984	35	Yes	Yes	SBT		Scrapped
Texaco New Jersey	20,836	1944	1959	1984	40	Yes	Yes	None		Scrapped
Worth	91,800	1976		1984	8	Yes	Yes	IGS/COW		Conv. to hosp. ship
Subtotal, vessels deleted in 1984				29						
Aero	30,100	1959		1985	26	Yes	Yes	None		Scrapped
American Trader	27,600	1943	1967	1985	22	Yes	Yes	None		Scrapped
Comanche	28,600	1954		1985	31	Yes	Yes	None		Scrapped
Cove Mariner	30,200	1955		1985	30	Yes	Yes	IGS/SBT		Scrapped
Cove Sailor	34,900	1959		1985	26	Yes	Yes	SBT		Scrapped
Fairwind	25,700	1942	1962	1985	43	Yes	Yes	None		Scrapped
Hillyer Brown	17,700	1953		1985	32	Yes	Yes	None		Out of documentation
Mobil Fuel	31,145	1957		1985	28	Yes	Yes	None	Yes	Reserve Fleet
Mona	19,900	1944	1958	1985	41	Yes	Yes	None		Scrapped
Overseas Aleutian	39,838	1953	1971	1985	32	Yes	Yes	None	Yes	Scrapped
Reliable	1,450	1942		1985	39	Yes	Yes	n/a		Classed to
Rose City	91,800	1976		1985	9	Yes	Yes	IGS/COW		Conv. to hosp. ship
Texaco Wisconsin	33,200	1958		1985	27	No	Yes	None		Scrapped
Subtotal, vessels deleted in 1985				13						

Vessel Name	DWT	Built	Year Rebuilt	Deleted	Age at Scrapping*	Coating	Militarily Useful (JSCAP88)**	PTSA Features	ANS Trade	Reason for Deletion
Champion	50,900	1959		1986	27	No	Yes	IGS/SBT	Yes	Scrapped
Cove Navigator	32,000	1951		1986	35	Yes	Yes	None		Scrapped
Montpelier Victory	49,500	1962		1986	24	No	Yes	IGS/COW/SBT	Yes	Scrapped
Scorpio	24,500	1944	1961	1986	42	No	Yes	None		Scrapped
Suzanne	19,900	1945	1958	1986	41	Yes	Yes	None		Scrapped
Texas Trader	27,500	1944	1969	1986	42	Yes	Yes	None		Scrapped
Washington Trader	43,500	1959	1976	1986	27	Yes	Yes	IGS	Yes	Scrapped
Subtotal, vessels deleted in 1986				7						

Total number of vessels deleted--86
Total number of vessels in ANS trade--26
Total number of vessels with PTSA features--23
Total number of ANS vessels with PTSA features--12
Average age of vessels deleted--32.1 years
Average age excluding three vessels deleted at 8 or 9 years of age--32.9 years

*Based upon year of construction
**Militarily useful includes coated and uncoated petroleum tankers, chemical tankers and integrated tug barges between 6,000 and 100,00DWT, plus selected coated tankers below 6,000 DWT.

n/a--Information regarding PTSA equipment on these vessels is not available.

PVIF 10%; 1985-1988, Base Year 1987

Discount Rate 10%

Transportation Savings

Year	Route	Bbl/Day	Bbl/Year	Savings/ Barrel	Annual Savings	Pres. Val. Savings
1985	Valdez-Gulf/East	636	232,140	$0.13	$29,702	$35,940
	Valdez-WC	1,038	378,870	$0.03	$12,061	$14,594
	Total	1,674	611,010	$0.07	$41,764	$50,534
1986	Valdez-Gulf/East	576	210,240	$0.46	$97,276	$107,003
	Valdez-WC	1,112	405,880	$0.14	$56,434	$62,077
	Total	1,688	616,120	$0.25	$153,709	$169,080
1987 (4 Out w/o 506)	Valdez-Gulf/East	533	194,545	$0.73	$142,242	$142,242
	Valdez-WC	1,254	457,710	$0.26	$117,718	$117,718
	Total	1,787	652,255	$0.40	$259,959	$259,959
1987 (4 Out w/506)	Valdez-Gulf/East	533	194,545	$0.69	$134,680	$134,680
	Valdez-WC	1,254	457,710	$0.25	$115,239	$115,239
	Total	1,787	652,255	$0.38	$249,918	$249,918
1988 (4 Out)	Valdez-Gulf/East	280	102,200	$0.68	$69,967	$63,606
	Valdez-WC	1,378	502,970	$0.29	$144,393	$131,266
	Total	1,658	605,170	$0.35	$214,360	$194,873

	Annual Savings	Pres. Val. Savings
Total Benefits		
4 Out w/o 506	$669,792	$674,446
4 Out w/506	$659,751	$664,405

APPENDIX III

Estimated Transportation Costs With and Without CDS Repayment 1/
(Dollars per Ton)

985 Without CDS Repayment:

ize Range 000) DWT	Valdez-Panama	Valdez-Los Angeles	Valdez-San Francisco	Valdez-Puget Sound	Valdez-Hawaii	Valdez-Alaska	Panama-Gulf/East
00 to 265	10.21						
70 to 190	15.92	7.73	6.72				
14 to 140	17.22	8.33	7.24	5.60			6.34
55 to 92	17.77	8.59	7.46	5.77	9.53	3.10	6.52
ess than 55	21.68	10.44	9.07	6.99	11.59	3.82	7.90

985 With CDS Repayment:

ize Range 000) DWT	Valdez-Panama	Valdez-Los Angeles	Valdez-San Francisco	Valdez-Puget Sound	Valdez-Hawaii	Valdez-Alaska	Panama-Gulf/East
00 to 265	9.38						
70 to 190	10.58	5.09	4.42				
14 to 140	14.56	7.01	6.09	4.69			5.31
55 to 92	16.73	8.07	7.01	5.41	8.96	2.91	6.12
ess than 55	22.20	10.70	9.29	7.17	11.88	3.92	8.11

986 Without CDS Repayment:

ize Range 000) DWT	Valdez-Panama	Valdez-Los Angeles	Valdez-San Francisco	Valdez-Puget Sound	Valdez-Hawaii	Valdez-Alaska	Panama-Gulf/East
00 to 265	8.81						
70 to 190	14.17	6.97	6.09				
14 to 140	14.94	7.34	6.41	5.01			5.63
55 to 92	15.11	7.43	6.49	5.07	8.22	2.88	5.69
ess than 55	18.07	8.89	7.76	6.07	9.83	3.55	6.78

986 With CDS Repayment:

ize Range 000) DWT	Valdez-Panama	Valdez-Los Angeles	Valdez-San Francisco	Valdez-Puget Sound	Valdez-Hawaii	Valdez-Alaska	Panama-Gulf/East
00 to 265	7.99						
70 to 190	8.84	4.33	3.78				
14 to 140	12.27	6.03	5.26	4.11			4.60
55 to 92	14.07	6.92	6.04	4.72	7.65	2.69	5.28
ess than 55	18.59	9.15	7.99	6.24	10.11	3.64	6.98

1987 Without CDS Repayment:

Size Range (000) DWT	Valdez-Panama	Valdez-Los Angeles	Valdez-San Francisco	Valdez-Puget Sound	Valdez-Hawaii	Valdez-Alaska	Panama-Gulf/East
200 to 265	10.19						
170 to 190	12.04	5.92					
114 to 140	16.01	7.87	6.87	5.37			6.05
55 to 92	18.23	8.98	7.85	6.14	9.93	3.44	6.90
Less than 55	23.78	11.73	10.25	8.02	12.96	4.58	9.01

1987 With CDS Repayment:

Size Range (000) DWT	Valdez-Panama	Valdez-Los Angeles	Valdez-San Francisco	Valdez-Puget Sound	Valdez-Hawaii	Valdez-Alaska	Panama-Gulf/East
200 to 265	7.99						
170 to 190	8.84	4.33	3.78				
114 to 140	12.27	6.03	5.26	4.11			4.60
55 to 92	14.07	6.92	6.04	4.72	7.65	2.69	5.28
Less than 55	18.59	9.15	7.99	6.24	10.11	3.64	6.98

1988 Without CDS Repayment:

Size Range (000) DWT	Valdez-Panama	Valdez-Los Angeles	Valdez-San Francisco	Valdez-Puget Sound	Valdez-Hawaii	Valdez-Alaska	Panama-Gulf/East
200 to 265	10.19	4.38					
170 to 190	12.04	5.92					
114 to 140	16.01	7.87	6.87	5.37			6.05
55 to 92	18.23	8.98	7.85	6.14	9.93	3.44	6.90
Less than 55	23.78	11.73	10.25	8.02	12.96	4.58	9.01

1988 With CDS Repayment:

Size Range (000) DWT	Valdez-Panama	Valdez-Los Angeles	Valdez-San Francisco	Valdez-Puget Sound	Valdez-Hawaii	Valdez-Alaska	Panama-Gulf/East
200 to 265	7.99	3.35					
170 to 190	8.84	4.33	3.78				
114 to 140	12.27	6.03	5.26	4.11			4.60
55 to 92	14.07	6.92	6.04	4.72	7.65	2.69	5.28
Less than 55	18.59	9.15	7.99	6.24	10.11	3.64	6.98

1/ Includes fuel costs.

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STATE OF ALASKA
OFFICE OF THE GOVERNOR
JUNEAU

April 28, 1987

The Honorable John C. Stennis
Chairman
Senate Appropriations Committee
SD-135 Dirksen Senate Office Bldg.
Washington, D.C. 20510

Dear Senator Stennis:

As a member of the Senate Appropriations Committee participating in this year's Supplemental Appropriations mark up, you will be considering an issue involving the Construction Differential Subsidy (CDS) provided by the United States for four oil supertankers.

A condition of the subsidy was that the supertankers built under the program could only operate in international shipping. The transportation companies that received these subsidies paid the money back to the United States so that the supertankers could ply the American shipping trade. The provision in the Supplemental Appropriations bill would return the CDS paybacks for the four supertankers and would eliminate these ships from the domestic market.

I urge you to reject this provision.

The provision would cause $142 million in direct refunds to supertanker owners who repaid the subsidy. Litigation costs may also be incurred by the Federal government, if the supertankers are denied access to the American trade. To my knowledge, none of these costs has been considered in either the House or Senate versions of the budget resolution.

The CDS repayments would also mean long term tax loses to the Federal government and to my state. Supertankers carry significantly more oil and are more efficient to operate than their smaller counterparts. According to the U.S. Maritime Administration (MarAd), the Federal government would lose about $44 million annually in income taxes, owing to the less profitable trade which would result from the use of smaller non-CDS tankers. These figures were derived for three CDS tankers, and now that a fourth tanker may also be involved, the Federal tax loss would probably be even greater.

The CDS issue was debated and supposedly settled in the last Congress. The transportation companies, after participation in a lengthy rulemaking process with the Federal government, relied on this legislation to pay back the CDS on their supertankers. The U.S. Department of Transportation established its rules and developed its plans around this law. After only a short period of time, certain special interests are contending that the ground rules should be changed again. Without hearings or consideration by the appropriate authorizing committee, these interests were successful in inserting a rider in the House version of the Supplemental Appropriations bill.

As you are no doubt aware, the CDS administrative rulings, growing out of previous Congressional action, have been the subject of extensive litigation. In the eleventh hour of those determinations, we believe that it would not be sound public policy for the Congress to intervene. Several of the parties to the litigation relied on the legislation recently enacted by Congress; all parties are well-represented in the judicial forum.

Additionally, the CDS provision is not a "jobs" issue. Although the U.S. Maritime Administration (MarAd) predicts that about 500 new jobs would ultimately be created by prohibiting the CDS ships in the Alaska trade, even this figure is in dispute. MarAd calculated this number based on the assumption that the smaller tankers replacing the CDS ships would hire about 800 crewmen. However, 300 jobs would be lost on the three CDS tankers. Further, the transportation companies point out that some supertankers would continue to ply the Alaska North Slope oil trade under the current six month waiver rule. Therefore, fewer jobs would be created than MarAd has predicted. In any case, the costs to the Federal government and the State of Alaska associated with the creation of each new job would be immense.

As Congress and all Americans search for new ways of "competitiveness" in the world market, we will need to develop and transport our natural resources on an economical basis. The CDS supertankers represent an asset that was manufactured in the United States, and we believe that it would be irresponsible to prohibit these ships from transporting American products on an efficient, year-round basis.

For the reasons outlined above, I urge you to reject the provision which would force these ships out of the American trade. At the very least, I respectfully suggest that before Congress acts, hearings be held to consider the important policy implications of the proposed amendment.

Thank you for your consideration of this matter.

Sincerely

John W. Katz for

Steve Cowper
Governor of Alaska

cc: Senator Ted Stevens
Senator Frank H. Murkowski
Congressman Don Young
0872 22

<u>Identical Letters Sent to Each Committee Member</u>

FIRST ATTRANSCO TANKER CORP., et al., Appellants,

v.

Elizabeth H. DOLE, Secretary, U.S. Department of Transportation, et al.

Nos. 85-6066, 85-6069, 85-6134 to 85-6138 and 85-6163.

United States Court of Appeals, District of Columbia Circuit.

Argued Nov. 10, 1986.

Decided Jan. 16, 1987.

Owners and operators of United States flag tankers built entirely with private capital and employed in domestic trade filed suit challenging rule which purportedly would allow subsidized vessels to enter domestic shipping market upon repayment of subsidy. The United States District Court for the District of Columbia, Thomas Penfield Jackson, J., 620 F.Supp. 1289, sustained validity of rule. Owners and operators appealed. The Court of Appeals, Bork, Circuit Judge, held that: (1) promulgation of "payback rule" was well within Secretary of Transportation's authority under Merchant Marine Act, but (2) Secretary's statement of basis and purpose failed to provide adequate account of how rule served Merchant Marine Act's objectives.

Rule vacated.

1. Shipping ⟹3

Promulgation of "payback rule" releasing tanker vessels built with assistance of federal construction differential subsidy from foreign-trade-only requirement if they agreed to repay unamortized portion of subsidy plus interest during specified one-year period, fell within Secretary of Transportation's statutory authority under Merchant Marine Act. Merchant Marine Act of 1936, §§ 501-506, as amended, 46 U.S.C.A. §§ 1151-1156.

2. Administrative Law and Procedure ⟹405

Shipping ⟹3

Secretary of Transportation's statement of basis and purpose for "payback rule," releasing tanker vessels built with assistance of federal construction differential subsidy from foreign-trade-only requirement if they agreed to repay unamortized portion of subsidy plus interest during specified one-year period, failed to give adequate account of how that rule served objectives of Merchant Marine Act and why alternative measures were rejected in favor thereof; statement expressed belief that rule would benefit U.S. Merchant Marine and would leave industry in healthier, more viable condition but gave unsatisfying responses to concerns about its effect on fleet's ability to carry substantial portion of foreign commerce and to serve as naval auxiliary. 5 U.S.C.A. § 553(c); Merchant Marine Act of 1936, § 101, as amended, 46 U.S.C.A. § 1101.

3. Administrative Law and Procedure ⟹816, 819

In fashioning remedy for administrative agency's failure to present adequate statement of basis and purpose for rule as required by Administrative Procedure Act, Court of Appeals may either remand for specific procedures to cure deficiency without vacating rule or may vacate rule, thus requiring agency to initiate another rulemaking proceeding if it would seek to confront problem anew. 5 U.S.C.A. § 553(c).

Appeals from the United States District Court for the District of Columbia (Civil Action Nos. 85-01555, 85-01740, 85-01752 and 85-1771).

Joseph A. Klausner, with whom Allan A. Tuttle, Washington, D.C., was on brief for appellant, Independent U.S. Tanker Owners Committee in Nos. 85-6068 and 85-6134.

Amy Loeserman Klein, with whom William E. Cohen and Marc A. Bernstein, New York City, were on brief for appellants, Atramasco Tanker Corp., et al. in Nos. 85-6136 and 85-6168.

Daniel P. Levitt, with whom Richard J. Wertheimer, Washington, D.C., was on brief for appellant, Overseas Shipbuilding Group, Inc. in No. 85-6138.

Robert J. Blackwell, Anne E. Mickey, Jeffrey R. Masi and Linda L. Martin, Washington, D.C., were on brief for appellant, Alaska Bulk Carriers, Inc., et al. in No. 85-6069.

William E. McDaniels, Kevin T. Baine and Jonathan Blank, Washington, D.C., were on brief for appellant, Seatrain Lines, Inc. in Nos. 85-6134, 85-6135, 85-6136 and 85-6137.

Kenneth N. Weinstein, Deputy Asst. Gen. Counsel for Litigation, Dept. of Transp., with whom Richard K. Willard, Asst. Atty. Gen., Dept. of Justice, was on brief for appellees, Secretary of Transp., et al. in Nos. 85-6068, et al. Michael Kimmel and Robert S. Greenspan, Attys., Dept. of Justice, Washington, D.C., entered appearance for appellees.

Roy G. Bowman and Richard H. Saltsman, Washington, D.C., were on brief for appellee, American Petrofina Inc. in Nos. 85-6068, et al.

Michael Joseph, Mark P. Schlefer, Thomas L. Mills and Donald M. Squires, Washington, D.C., were on brief for appellees, Atlantic Richfield Co., et al. in Nos. 85-6068, et al.

Before EDWARDS and BORK, Circuit Judges, and SWYGERT,* Senior Circuit Judge.

Opinion for the Court filed by Circuit Judge BORK.

BORK, Circuit Judge:

These consolidated cases are before us on appeal from a decision of the district court, 620 F.Supp. 1289 (1985), which sustained the validity of a rule promulgated by the Secretary of Transportation. Appellants challenge the rule as exceeding the Secretary's statutory authority and as arbitrary and capricious agency action; they also raise a battery of specific procedural objections to the manner in which the rule was promulgated. We find that the Secretary was well within her statutory authority in promulgating the rule, but that she failed to provide an adequate account of how the rule serves the objectives set out in the governing statute, the Merchant Marine Act of 1936, ch. 858, 49 Stat. 1985 (codified as amended at 46 U.S.C. §§ 1101–1295g (1982)).

I.

The rulemaking that gives rise to this case is the latest of numerous attempts by the Congress, the Maritime Administration, and the Department of Transportation to address the recurrent problems of the United States merchant marine fleet. The American fleet has had great difficulty competing in foreign commerce. American ships typically have higher construction and operating costs than their foreign competitors, not only because they typically must meet more stringent environmental and safety standards, but also because foreign ships often are subsidized and otherwise assisted by their own governments. Congress confronted these problems in 1936 and authorized the United States government to pay up to half the construction costs of American ships that will operate in foreign commerce. 46 U.S.C. §§ 1151–1152 (1982). In addition, Congress authorized the government to subsidize the operating costs of these ships where necessary to meet foreign competition. *Id.* §§ 1171–1172. Despite these provisions, American ships have continued to fare poorly against their competitors in foreign commerce.

Merchant ships that operate in the domestic shipping market do not receive these government subsidies. They are protected from the rigors of foreign competi-

* Of the United States Court of Appeals for the Seventh Circuit, sitting by designation pursuant to 28 U.S.C. § 294(d) (1982).

tion, however, by the Jones Act, which requires all cargo transported between points in the United States to be carried on ships built in the United States, registered in the United States, and owned by American citizens. 46 U.S.C. § 883 (1982).[1] They are also protected from having to compete against any of the ships that have received construction subsidies or operating subsidies from the government, except in a few specific and very limited instances.[2] Since the Trans-Alaska Pipeline opened in 1977, however, the domestic fleet has been unable to satisfy the great new demand for large tankers to carry Alaskan oil to other points in the country. The Maritime Administration has responded to this situation by invoking its statutory authority to allow certain subsidized ships to operate in the domestic market for up to six months in a given year if the ships repay a proportional share of the construction subsidy that they have received. 46 C.F.R. Part 250 (1984). Yet this step has only partly solved the problem.

The rule at issue in this case permitted tanker vessels built with the assistance of a federal construction-differential subsidy, which had been barred from competing in domestic trade on account of that subsidy, to undertake domestic operations if they agreed to repay the unamortized portion of the subsidy plus interest during a period that began on June 6, 1985, and closed one year later. *See* Construction-Differential Subsidy Repayment; Total Payment Policy, 50 Fed.Reg. 19,170 (1985) (codified at 46 C.F.R. § 276.3 (1985)) (hereafter the "payback rule"). This rule addressed problems in both the foreign and domestic markets by providing an opportunity for ships that are not competitive in foreign commerce to enter the domestic market where the demand for their services has increased, but only by agreeing to relinquish their financial advantage over unsubsidized ships. The Maritime Administration has considered proposals for individual ships to repay their subsidies at least since 1964. In 1977, several owners of unsubsidized ships challenged the Administration's approval of repayment by one vessel in particular. The Supreme Court upheld the government's authority to approve subsidy repayment in exchange for permission to enter the domestic market. *See Seatrain Shipbuilding Corp. v. Shell Oil Co.,* 444 U.S. 572, 100 S.Ct. 800, 63 L.Ed.2d 36 (1980). Shortly thereafter, the Administration established an interim rule that extended this authorization to undertake domestic shipping, upon repayment of the full subsidy plus interest, to a limited class of large tankers whose owners demonstrated "exceptional circumstances" of dismal prospects in foreign commerce to justify the application of the rule. *See* 45 Fed. Reg. 68,393 (1980). The interim rule was challenged, and this court invalidated it, finding that although the Administration had statutory authority to promulgate the rule, it had acted arbitrarily and capriciously by providing an inadequate discussion of the basis and purpose of the rule. *See Independent U.S. Tanker Owners Comm. v. Lewis,* 690 F.2d 908, 918–20 (D.C.Cir. 1982). At that point, the Secretary of Transportation proposed the payback rule. This rule is similar to the earlier proposed interim rule except that it covers all tankers and does not require tankers to make any showing of "exceptional circumstances" to qualify for the benefits of subsidy repayment.

II.

Appellants initially question the Secretary's statutory authority to promulgate

1. Congress has also established a loan guarantee program to assist the financing of domestic ships. 46 U.S.C. §§ 1271–1276 (1982).

2. A subsidized ship is not permitted to operate in domestic commerce except in a few limited circumstances, such as on the first or last leg of an overseas voyage if the owner repays a prorated portion of the original subsidy, or upon the Secretary of Transportation's determination that an exemption is necessary or appropriate to carry out the purposes of the Merchant Marine Act, although the latter exception does not allow a subsidized ship to operate in the domestic trade for more than six months in a given year. 46 U.S.C. § 1156 (1982).

the payback rule. In *Seatrain*, however, the Supreme Court expressly recognized the government's authority under the Merchant Marine Act to approve the repayment of a ship's construction subsidy in return for the lifting of restrictions on domestic operations by that ship. 444 U.S. at 588, 100 S.Ct. at 809. Although in *Seatrain* the subsidy repayments were granted on an individualized basis and on a showing of exigent circumstances that justified the need for the government's action, the Court did not rely on either of these facts. Instead, the Court rested its conclusion on "the Secretary's broad contracting powers and discretion to administer the Act," especially the power to approve measures that "directly further the general goals of the Act." *Id.* In particular, the Court stressed the difference between a permanent release from the foreign-trade-only requirement, which requires a vessel to repay its subsidy before it can enter the domestic market, and a temporary release that might render a subsidized ship "capable of taking advantage of every shift in trade and profitability, skimming the cream and leaving what remains to those less mobile." *Id.* The Court stated that a temporary release would be very problematic, but a permanent release was not, at least insofar as it was conditioned on "full repayment" of the subsidy so as to confer no "windfall." *Id.* at 589 & n. 31, 100 S.Ct. at 810 & n. 31.

[1] The payback rule satisfies these criteria and thus its promulgation falls within the Secretary's statutory authority under the Merchant Marine Act. *See* 46 U.S.C. §§ 1151–1156 (1982); *see also Independent U.S. Tanker Owners Comm.*, 690 F.2d at 917–18 (finding the earlier interim rule to be in harmony with the statutory mandate of the Merchant Marine Act). Indeed, this rule comes much closer to satisfying the Court's concern about "cream-skimming" in the domestic market by subsidized ships than did the Maritime Administration's previous response to the problem, undertaken pursuant to specific congressional authorization, which was to allow certain subsidized ships to operate in the domestic market for up to six months in a given year if they agree to repay a proportional share of their subsidy. *See id.* § 1156; 46 C.F.R. Part 250 (1984).[3]

III.

Appellants contend that even if the Secretary acted within her statutory authority in promulgating the payback rule, it should be invalidated because it is the product of agency action that was "arbitrary, capricious, an abuse of discretion, or not otherwise in accordance with law." 5 U.S.C. § 706(2)(A) (1982). In particular, appellants contend that the Secretary failed to provide a sufficiently reasoned discussion of why this rule was adopted and alternatives were rejected in light of the purposes of the Merchant Marine Act, which are the very purposes Congress intended the Secretary to serve when it gave her "broad" discretion to administer the Act. *See* 46 U.S.C. § 1151 (1982); *Seatrain*, 444 U.S. at 588, 100 S.Ct. at 809–10.

It is unfortunate that, once more, we must agree with this contention. This court vacated the previous interim rule because the government "failed completely to fulfill its obligations" to set out an adequate statement of basis and purpose for the rule. *Independent U.S. Tanker Own-*

3. In the Notice of Proposed Rulemaking, the Secretary identified facts that might be sufficient to establish the kind of exceptional circumstances that were touched on in *Seatrain* as justifying subsidy repayment. *See* 444 U.S. at 577, 100 S.Ct. at 803–04. In particular, she noted that American tankers operating in foreign commerce "have not been financially successful," largely because of recent events that have been "financially devastating for the world tanker market." 48 Fed.Reg. 4408 (1983). Yet we do not hold that these exceptional circumstances are a *sine qua non* to the Secretary's statutory authority to adopt this rule, given her "broad contracting powers and discretion to administer the Act." *Seatrain*, 444 U.S. at 588, 100 S.Ct. at 809. As long as the rule consists of a permanent release from restrictions upon full repayment of the subsidy plus interest, it is within the Secretary's authority under the Merchant Marine Act.

ers Comm., 690 F.2d at 919. Now, four years later, we must vacate a similar rule on similar grounds.

Under the Administrative Procedure Act, when an agency initiates a rulemaking that the governing statute does not require to be undertaken "on the record," the agency is nonetheless bound to comply with the requirements for "notice and comment" rulemaking set out in 5 U.S.C. § 553 (1982). *See, e.g., United States v. Florida East Coast Ry.*, 410 U.S. 224, 234–41, 93 S.Ct. 810, 815–19, 35 L.Ed.2d 223 (1973). One requirement is that after the agency considers the comments presented by the participating parties, it "shall incorporate in the rules adopted a concise general statement of their basis and purpose." 5 U.S.C. § 553(c). This statement need not be an exhaustive, detailed account of every aspect of the rulemaking proceedings; it is not meant to be the more elaborate document, complete with findings of fact and conclusions of law, that is required in an on-the-record rulemaking. *See id.* § 557(c). On the other hand, this court has cautioned against "an overly literal reading of the statutory terms 'concise' and 'general'.... [which] must be accommodated to the realities of judicial scrutiny." *Automotive Parts & Accessories Ass'n v. Boyd*, 407 F.2d 330, 338 (D.C.Cir.1968). At the least, such a statement should indicate the major issues of policy that were raised in the proceedings and explain why the agency decided to respond to these issues as it did, particularly in light of the statutory objectives that the rule must serve. *See National Wildlife Fed'n v. Costle*, 629 F.2d 118, 134 (D.C.Cir.1980); *Automotive Parts*, 407 F.2d at 338; *see also* S.Doc. No. 248, 79th Cong., 2d Sess. 20 (1946) ("The statement of the 'basis and purpose' of rules issued will vary with the rule, but in any case should be fully explanatory of the complete factual and legal basis as well as the object or objects sought.").

In *Seatrain*, the Supreme Court indicated that Congress gave the government broad power to implement the Merchant Marine Act so that the government could take steps that "directly further the general goals of the Act." 444 U.S. at 558, 100 S.Ct. at 809. Those objectives are to foster the development and encourage the maintenance of an American merchant marine, in both foreign and domestic commerce, that is:

> (a) sufficient to carry its domestic waterborne commerce and a substantial portion of the water-borne export and import foreign commerce of the United States and to provide shipping service essential for maintaining the flow of such domestic and foreign water-borne commerce at all times, (b) capable of serving as a naval and military auxiliary in time of war or national emergency, (c) owned and operated under the United States flag by citizens of the United States, insofar as may be practicable, (d) composed of the best-equipped, safest, and most suitable types of vessels, constructed in the United States and manned with a trained and efficient citizen personnel, and (e) supplemented by efficient facilities for shipbuilding and ship repair.

46 U.S.C. § 1101 (1982).

[2] The Secretary's statement of basis and purpose fails to give an adequate account of how the payback rule serves these objectives and why alternative measures were rejected in light of them. The Secretary's treatment of these objectives, and of the concerns raised about them in the comment proceedings, is cursory at best. For example, concerns about whether this rule meets the statutory objective of maintaining an American merchant marine "sufficient to carry its domestic water-borne commerce and a substantial portion of the water-borne export and import foreign commerce" are met with the statement: "The Department believes that the [rule] will benefit the U.S. Merchant Marine." 50 Fed.Reg. 19,170, 19,173 (1985). Her discussion continues further, but it hardly improves:

> Although it is true, as many commenters pointed out, that some tankers will be forced out of service by more efficient operators, the industry should be more

> competitive and efficient in the future, especially since some of the most efficient tankers in the U.S. flag fleet would be fully utilized. . . . Overall, the industry should be left in a healthier, more viable condition.

Id. at 19,173–74. On the more dubious proposition that the fleet will remain able to carry "a substantial portion" of foreign commerce, the Secretary candidly acknowledges that "the final rule merely recognizes the existing condition of the U.S. tanker fleet. There currently exist few foreign trade employment opportunities for these vessels and the prospects for future employment in the foreign trade are far from bright." *Id.* at 19,174. Though this statement strongly suggests the view that this rule will hasten an American retreat from carriage of foreign commerce, the Secretary surprisingly asserts that the fleet will remain "more than adequate to carry an appropriate share of the U.S. foreign oil commerce if such opportunities should arise." *Id.* This remark is hard to fathom. If there is currently little hope for the employment of American vessels in foreign trade, then the payback rule will permit the total size of the American fleet to follow its natural tendency to decrease toward the level required by the domestic market. Under present conditions, therefore, the rule will make it impossible to retain a fleet that can carry all domestic traffic and "a substantial portion" of foreign traffic "at all times," which is explicitly set out as an objective in section (a) of the statute.

The Secretary's response to concerns about the rule's effects on the fleet as a naval auxiliary, to take another example, is similarly unsatisfying. The Navy warned that the projected loss under this rule of "handy-sized" tankers might have adverse implications for national security. The Secretary brushes aside this comment by stating her belief that "the outlook for these old, small product tankers is poor regardless of whether or not this rule is promulgated because of their age and the decline of the U.S. products trade." *Id.* She also claims that other non-fleet ships could fill in the gap, *id.*, even though this observation may not help to satisfy the statutory objective that the fleet itself should constitute "a naval and military auxiliary in time of war or national emergency." 46 U.S.C. § 1101(b) (1982).

Rather than providing a more extensive discussion of the Merchant Marine Act's objectives, the Secretary chooses to rely on other policies in defending the rule. She identifies some of the "most important" reasons for the rule as being "economic efficiency," "use of underemployed resources," "increased competition," and "deregulation." 50 Fed.Reg. at 19,172. As she later elaborates: "It is the Department's position that the competitive forces of the market, rather than government regulation, should be relied upon, whenever feasible, to allocate transportation capacity and resources in the domestic trade. This rule reflects that position." *Id.* at 19,175. The central thrust of her approach, quite obviously, is to subject the merchant marine fleet to the discipline of the free market. Thus she finds it significant that the rule will leave the industry "in a healthier, more viable condition," *id.* at 19,174, and she finds it permissible that the condition of the fleet should depend on what economic opportunities become available in the world market. *See id.* This policy may well be defensible, yet it is not among the objectives specified in the Act, and if the Secretary has decided that it is implicit in or compatible with the statutory objectives, it would be useful for her to explain this decision somewhat more fully. She has failed to do so. The closest she comes is the conclusory statement that "it would not be appropriate to let the various program objectives reflected in the Act stand in the way of achieving the Act's broader policy mandates, including that of promoting a more competitive and efficient merchant fleet." *Id.* It may, however, be entirely appropriate for the Act's objectives to stand in the way of the payback rule, and perhaps to favor other alternatives, unless the Secretary can offer a fuller and more persuasive explanation for her view that the "broader policy mandates" of the Act include the promotion of a "more competitive and efficient merchant fleet." [4]

The Secretary's failure to link the policies served by this rule to the objectives set out in the Merchant Marine Act is particularly problematic because she does not explain in the statement of basis and purpose why she rejects proposed alternatives to the payback rule. One can find this explanation in the Regulatory Impact Analysis, Joint Appendix ("J.A.") at 1049, where the Secretary considers and rejects at least a half-dozen other suggested measures. Once again, however, her account focuses on non-statutory criteria that favor this rule, such as lower transportation costs, collateral fiscal benefits, and more "efficient" use of the fleet. J.A. at 1089, 1093. She admits that the rule "has a number of adverse impacts," including "the displacement of about 13 tankers ... most of which are militarily useful handy-sized tankers, loss of employment opportunities for about 800 seamen, and the possible default on several government loans," *id.* at 1093, problems that impinge on the statutory objectives and that might be avoided under some of the alternative measures. *See, e.g., id.* at 1091–92 (describing effects of "full-time permissions" option, "status quo" option, and "eliminate permissions" option).

In exercising her decisionmaking authority, the Secretary is certainly free to consider factors that are not mentioned explicitly in the governing statute, yet she is not free to substitute new goals in place of the statutory objectives without explaining how these actions are consistent with her authority under the statute. Her failure to link these non-statutory criteria with Congress' stated objectives in the Act thus makes it impossible for us to uphold the Secretary's decision to reject other measures and adopt this rule in response to the current problems of the merchant marine fleet. Her reliance on these non-statutory criteria is consistently a key point in her justifications for adopting this rule. In order to defend this action as "reasoned decisionmaking," the Secretary must spell out in more detail how her decision to adopt this rule and reject alternative measures by relying on policies of competition and deregulation can be squared with the statutory objectives that Congress specified as the primary guidelines for administrative action in this area. We take no position on whether these policies can be squared with the Act. But in the absence of any such discussion, this court can only conclude that her action is "arbitrary, capricious, ... or not otherwise in accordance with law." 5 U.S.C. § 706(2)(A) (1982). *See also Citizens to Preserve Overton Park, Inc. v. Volpe*, 401 U.S. 402, 412–13, 416, 91 S.Ct. 814, 821–22, 823–24, 28 L.Ed.2d 136 (1971) (choice made by the agency must be "in accordance with law" as it can be understood in light of the statutory indicia).[5]

IV.

[3] We therefore conclude that the Secretary violated section 553(c) of the Administrative Procedure Act by adopting this rule. In fashioning a remedy for an agency's failure to present an adequate statement of basis and purpose, this court may either remand for specific procedures to cure the deficiency without vacating the rule, *see, e.g., National Nutritional Foods Ass'n v. Weinberger*, 512 F.2d 688, 701, 703–04 (2d Cir.), *cert. denied*, 423 U.S. 827, 96 S.Ct. 44, 46 L.Ed.2d 44 (1975), or it may vacate the rule, thus requiring the agency to initiate another rulemaking proceeding if it would seek to confront the problem anew. *See, e.g., Tabor v. Joint Bd. for*

4. It may be, of course, that present conditions in the world shipping market make it impossible for the Secretary to find a way to meet all of the statutory objectives. If this is the problem, she should discuss it frankly and directly when she considers which measures to adopt in light of the objectives explicitly set out in the Act.

5. The grounds of our decision make it unnecessary to discuss the array of more specific procedural objections that appellants have made to this rulemaking. The district court found each of those objections to be without merit, but we take no position on the correctness of those findings.

Enrollment of Actuaries, 566 F.2d 705, 709-12 (D.C.Cir.1977). In this case, we vacate the rule because the Secretary's omissions are quite serious and raise considerable doubt about which of the proposed alternatives would best serve the objectives set out in the Merchant Marine Act. Yet we exercise our power to withhold issuance of our mandate until July 16, 1987, to avoid further disruptions in the domestic market and to allow the Secretary to undertake further proceedings to address the problems of the merchant marine trade. *See* Fed.R.App.P. 41(a). As of that date, the present rule will be vacated and conditions returned to the *status quo ante*, before the payback rule took effect, subject of course to any further action that may have been taken in the interim.

So ordered.

PROFESSIONAL AIRWAYS SYSTEMS SPECIALISTS, MEBA, AFL–CIO, Petitioner,

v.

FEDERAL LABOR RELATIONS AUTHORITY, Respondent.

PROFESSIONAL AIRWAYS SYSTEMS SPECIALISTS, MEBA, AFL–CIO, Petitioner,

v.

FEDERAL LABOR RELATIONS AUTHORITY, Respondent.

Nos. 85–1769, 85–1827.

United States Court of Appeals, District of Columbia Circuit.

Argued Nov. 18, 1986.

Decided Jan. 16, 1987.

Union sought review of Federal Labor Relations Authority order which found that Federal Aviation Administration had committed unfair labor practices, but which refused to grant back pay. The Court of Appeals, Starr, Circuit Judge, held that: (1) FLRA may apply "but for" test under the Back Pay Act to determine whether to award back pay because of procedural violation of bargaining duties by agencies; (2) per se rule against back pay for violation of impact and implementation bargaining requirements is not proper under the Act; and (3) FLRA did not adequately explain departure from past precedent.

Petitions granted and case remanded.

1. United States ⇐39(8)

"But for" test is properly applied in determining to award back pay under the Back Pay Act to government employee who establishes procedural violation of the federal service labor-management relations statute. 5 U.S.C.A. §§ 5596, 7116.

2. Labor Relations ⇐632

There is no per se prohibition on award of back pay under the Back Pay Act for federal employee who establishes that agency committed unfair labor practice by failing to engage in impact and implementation bargaining. 5 U.S.C.A. §§ 5596, 7116.

3. Labor Relations ⇐632

In applying the "but for" test to determine whether to award back pay for procedural violations of government's bargaining duties, Federal Labor Relations Authority must recognize the value of procedural integrity and must allow for the fact that it is highly difficult for adversely affected employees to establish that bargaining which never occurred because of the agency's violation would have prevented the loss of pay occasioned by the change implemented by the agency. 5 U.S.C.A. §§ 5596, 7116.

4. Administrative Law and Procedure ⇐507

Labor Relations ⇐598

Federal Labor Relations Authority statement that it had "been engaged in the

STEVE COWPER, GOVERNOR

MAY 4 1987

STATE OF ALASKA
OFFICE OF THE GOVERNOR
JUNEAU

April 28, 1987

The Honorable John C. Stennis
Chairman
Senate Appropriations Committee
SD-135 Dirksen Senate Office Bldg.
Washington, D.C. 20510

Dear Senator Stennis:

As a member of the Senate Appropriations Committee participating in this year's Supplemental Appropriations mark up, you will be considering an issue involving the Construction Differential Subsidy (CDS) provided by the United States for four oil supertankers.

A condition of the subsidy was that the supertankers built under the program could only operate in international shipping. The transportation companies that received these subsidies paid the money back to the United States so that the supertankers could ply the American shipping trade. The provision in the Supplemental Appropriations bill would return the CDS paybacks for the four supertankers and would eliminate these ships from the domestic market.

I urge you to reject this provision.

The provision would cause $142 million in direct refunds to supertanker owners who repaid the subsidy. Litigation costs may also be incurred by the Federal government, if the supertankers are denied access to the American trade. To my knowledge, none of these costs has been considered in either the House or Senate versions of the budget resolution.

The CDS repayments would also mean long term tax loses to the Federal government and to my state. Supertankers carry significantly more oil and are more efficient to operate than their smaller counterparts. According to the U.S. Maritime Administration (MarAd), the Federal government would lose about $44 million annually in income taxes, owing to the less profitable trade which would result from the use of smaller non-CDS tankers. These figures were derived for three CDS tankers, and now that a fourth tanker may also be involved, the Federal tax loss would probably be even greater.

The CDS issue was debated and supposedly settled in the last Congress. The transportation companies, after participation in a lengthy rulemaking process with the Federal government, relied on this legislation to pay back the CDS on their supertankers. The U.S. Department of Transportation established its rules and developed its plans around this law. After only a short period of time, certain special interests are contending that the ground rules should be changed again. Without hearings or consideration by the appropriate authorizing committee, these interests were successful in inserting a rider in the House version of the Supplemental Appropriations bill.

As you are no doubt aware, the CDS administrative rulings, growing out of previous Congressional action, have been the subject of extensive litigation. In the eleventh hour of those determinations, we believe that it would not be sound public policy for the Congress to intervene. Several of the parties to the litigation relied on the legislation recently enacted by Congress; all parties are well-represented in the judicial forum.

Additionally, the CDS provision is not a "jobs" issue. Although the U.S. Maritime Administration (MarAd) predicts that about 500 new jobs would ultimately be created by prohibiting the CDS ships in the Alaska trade, even this figure is in dispute. MarAd calculated this number based on the assumption that the smaller tankers replacing the CDS ships would hire about 800 crewmen. However, 300 jobs would be lost on the three CDS tankers. Further, the transportation companies point out that some supertankers would continue to ply the Alaska North Slope oil trade under the current six month waiver rule. Therefore, fewer jobs would be created than MarAd has predicted. In any case, the costs to the Federal government and the State of Alaska associated with the creation of each new job would be immense.

As Congress and all Americans search for new ways of "competitiveness" in the world market, we will need to develop and transport our natural resources on an economical basis. The CDS supertankers represent an asset that was manufactured in the United States, and we believe that it would be irresponsible to prohibit these ships from transporting American products on an efficient, year-round basis.

For the reasons outlined above, I urge you to reject the provision which would force these ships out of the American trade. At the very least, I respectfully suggest that before Congress acts, hearings be held to consider the important policy implications of the proposed amendment.

Thank you for your consideration of this matter.

Sincerely

John W. Katz for

Steve Cowper
Governor of Alaska

cc: Senator Ted Stevens
Senator Frank H. Murkowski
Congressman Don Young

Identical Letters Sent to Each Committee Member

STEVE COWPER, GOVERNOR

STATE OF ALASKA
OFFICE OF THE GOVERNOR
JUNEAU

May 20, 1987

The Honorable Jamie Whitten
U.S. House of Representatives
2314 Rayburn House Office Bldg.
Washington, D.C. 20515

Dear Congressman Whitten:

As a member likely to be appointed to the Supplemental Appropriations Conference Committee, you will probably be considering an issue involving the Construction Differential Subsidy (CDS) provided by the United States for four oil supertankers. The CDS provision is in the House bill, but after full debate it was stricken from the measure that passed the Appropriations Committee. As you know, the Supplemental Appropriations bill has yet to be considered on the Senate floor.

I urge that the House accede to the Senate on the CDS provision.

The provision would cause $142 million in direct refunds to supertanker owners who repaid the subsidy. Litigation costs may also be incurred by the Federal government, if the supertankers are denied access to the American trade.

To my knowledge, none of the CDS cost has been considered in either the House or Senate versions of the budget resolution. In fact, the 1988 report on the House Concurrent Budget Resolution begins by stating that the Committee recognizes, "the need to reduce substantially and permanently the large budget deficits which have weakened the economy, enlarged the trade deficit, eroded the Nation's international competitiveness and destroyed American businesses and jobs." With this goal in mind, there is no compelling reason to create another $142 million in costs to the Federal government, especially when the overall budget authority for the transportation function in the House Budget Resolution has been decreased by $1.35 billion.

The CDS repayments would also mean long term tax loses to the Federal government and to my state. Supertankers carry significantly more oil and are more efficient to operate than their smaller counterparts. According to the U.S. Maritime Administration (MarAd), the Federal government would lose about $44 million annually in income taxes, owing to the less profitable trade which would result from the use of smaller non-CDS tankers. These figures were derived for three CDS tankers, and now that a fourth tanker may also be involved, the Federal tax loss would probably be even greater.

The CDS issue was debated and supposedly settled in the last Congress. The transportation companies, after participation in a lengthy rule making process with the Federal government, relied on this legislation to pay back the CDS on their supertankers. The U.S. Department of Transportation established its rules and developed its plans around this law. After only a short period of time, certain special interests are contending that the ground rules should be changed again.

As you are no doubt aware, the CDS administrative rulings, growing out of previous Congressional action, have been the subject of extensive litigation. In the eleventh hour of those determinations, we believe that it would not be sound public policy for the Congress to intervene. Several of the parties to the litigation relied on the legislation recently enacted by Congress; all parties are well-represented in the judicial forum.

Additionally, the CDS provision is not a "jobs" issue. Although the U.S. Maritime Administration (MarAd) predicts that about 500 new jobs would ultimately be created by prohibiting the CDS ships in the Alaska trade, even this figure is in dispute. MarAd calculated this number based on the assumption that the smaller tankers replacing the CDS ships would hire about 800 crewmen. However, 300 jobs would be lost on the three CDS tankers (and the proposed rule making has expanded its scope to four CDS tankers). Further, the transportation companies point out that some supertankers would continue to ply the Alaska North Slope oil trade under the current six month waiver rule. Therefore, fewer jobs would be created than MarAd has predicted. In any case, the costs to the Federal government and the State of Alaska associated with the creation of each new job would be immense.

As Congress and all Americans search for new ways of "competitiveness" in the world market, we will need to develop and transport our natural resources on an economical basis. The CDS supertankers represent an asset that was manufactured in the United States, and we believe that it would be irresponsible to prohibit these ships from transporting American products on an efficient, year-round basis.

For the reasons outlined above, I urge you to reject the provision which would force these ships out of the American trade. At the very least, I respectfully suggest that before Congress acts, hearings be held to consider the important policy implications of the proposed amendment.

Thank you for your consideration of this matter.

Sincerely

John W. Katz for
Steve Cowper
Governor

cc: Senator Ted Stevens
Senator Frank H. Murkowski
Congressman Don Young

<u>Identical Letters Sent to Each Likely House Conference Committee Member</u>

FRANK H. MURKOWSKI
ALASKA

COMMITTEES:
VETERANS' AFFAIRS (RANKING MEMBER)
ENERGY AND NATURAL RESOURCES
FOREIGN RELATIONS
INDIAN AFFAIRS
INTELLIGENCE

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United States Senate

WASHINGTON, DC 20510
(202) 224-6665

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U.S. FEDERAL BUILDING
BOX 1647, 99802
(907) 586-7400

May 15, 1987

Honorable Bettye M. Fahrenkamp
515 Seventh Avenue, Suite 320
Fairbanks, Alaska 99701

Dear Bettye:

Thank you for your May 7 letter advising me of the approval of House Joint Resolution 33.

The potential loss of four VLCC (supertanker) ships from the Alaska oil trade is a grave concern, and I very much appreciate your support for a new rule-making to allow these vessels to enter the trade permanently.

There is no gain saying the fact that we face stiff opposition from certain quarters, primarily the maritime unions, but I am hopeful that our point of view will prevail.

As this is a matter of great mutual interest, let me briefly describe events since the January 16 U.S. Court of Appeals decision:

* On April 15 of this year, the Department of Transportation (DOT) published a new proposed rule, intended to satisfy the court's concerns.

* On April 23, the House passed H.R. 1827, the supplemental budget for fiscal year 1987, which included a provision preventing the Department of Transportation from using any portion of its funding to proceed with this rulemaking.

* Also on April 23, DOT Secretary Elisabeth Dole wrote to Senator John Stennis, Chairman of the Senate Appropriations Committee, expressing the Administration's strong opposition to the House language.

* April 30, The Senate Appropriations Committee met to mark up its own version of the supplemental. During this meeting, the House language was stricken from the Senate version of the bill.

Throughout this process, I have maintained a very active personal interest. In conversation and in formal correspondence, I have repeatedly urged key members of the committee from both parties to reject the House provision. My staff has also been working closely on this matter with other Senate staff, with the Governor's office and with others.

The next step is up to the other side, which may or may not choose to offer the same language as a floor amendment. I do not believe this will occur, but if it does I am prepared to argue our case on the floor.

It is more likely that proponents of this prohibition will attempt to achieve their goal when the supplemental goes to conference. It is impossible to predict the outcome at this point; however, I have prepared strong arguments which will be forwarded to the Senate conferees at the appropriate time. I remain hopeful.

Incidentally, I am enclosing a recent New York Times editorial you'll enjoy. The Times' perspective may be from a slightly different angle, but the message is clear.

Sincerely,

Frank H. Murkowski

Frank H. Murkowski
United States Senator

Enclosure

5/13/87

The New York Times

Founded in 1851

ADOLPH S. OCHS, *Publisher 1896-1935*
ARTHUR HAYS SULZBERGER, *Publisher 1935-1961*
ORVIL E. DRYFOOS, *Publisher 1961-1963*

ARTHUR OCHS SULZBERGER, *Publisher*

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ELISE J. ROSS, *V.P., Systems*

Senator Hollings's Tanker Ploy

Faced with such a big budget deficit, Congress might be expected to embrace owners of oil tankers who have, voluntarily, repaid $142 million in Federal subsidies. In fact, many members of Congress are demanding that the Transportation Department return the money. Leading the fight is Senator Ernest Hollings, who as co-author of the Gramm-Rudman-Hollings balanced budget law ought to be doubly embarrassed by the naked defense of special interests.

In 1970, shipyard interests persuaded Congress to subsidize a new fleet of very large oceangoing oil tankers. Eleven were built, with Uncle Sam paying about half the cost. But even with the subsidy, the tankers couldn't compete in a world market glutted with more-efficient foreign vessels.

Hope for the idle tankers centered on the opening of the Trans-Alaska pipeline in 1977, combined with a prohibition against exports of Alaskan oil. This generated enormous demand for tankers to carry crude to refineries in the lower 48 states. But present law prohibits use of foreign-built ships or ships built with Government subsidies to serve the coastal trade when unsubsidized domestic vessels are available. These coastal tankers are old, slow and small. To prevent shipping rates from soaring, the Transportation Department permitted a few of the large ocean tankers temporarily to enter the protected trade.

Overcoming fierce opposition from coastal shipping interests, the Reagan Administration ruled in 1985 that the big tankers could repay thei[r] subsidies and join the coastal fleet permanently. Everyone benefited — except the coastal-ship owners. Earlier this year, they convinced a Federal appeals court that the Administration hadn't adequately documented the case for a payback.

Most analysts expected the Transportation Department to meet the court's objections. What they didn't anticipate was Congressional intervention. Without hearings or debate, the House prohibited Transportation from spending a dime to rewrite the rule. But Ernest Hollings, who does much of the heavy lifting for the rust bucket fleet, failed with the same ploy in the Senate. He will still represent his colleagues when the two bills are reconciled.

Coastal shipowners claim they will go broke if forced to compete and thus wouldn't be available for military emergencies. If the vessels were worth saving, though, the Navy could buy them at scrap value and put them in mothballs.

The only real issue is whether Congress will be able to resist the lure of PAC politics. Shipping interests learned long ago that it was more profitable to start political action committees and invest in "Congressional access" than in more efficient ships or retraining. In 1985-86, the tiny seafarers' union alone contributed $1.2 million just to House members. With money like that floating around, there's reason to wonder if a majority of conferees will have the conscience to put the public's financial interest ahead of their own.

Legal Life Jacket for Mr. Meese

It's no longer remarkable to find the U.S. Attorney General under investigation by a special prosecutor. The case of the Wedtech Corporation marks the third time that an independent counsel, appointed by a court under the Ethics in Government

The public cannot be expected to believe that Justice would prosecute its boss vigorously or give him a believable clean bill of health. That's why Mr. Meese, confident of vindication, asked to transfer that investigation to an independent counsel. Such a

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BITS FROM BETTYE

ALL ALASKA WEEKLY

TELECOPY TO TOM SNAPP

456-6426

May 6, 1987

Four of the oil supertankers that transport Alaskan oil from Valdez to the lower 48 may be removed from the trade on July 16. These large, efficient tankers have been allowed to operate under a special waiver from the U.S. Department of Transportation. A recent U.S. Court of Appeals decision held that these waivers were improperly drafted, but allowed the ships to operate until July 16, 1987. If new rules are not adopted by that date, these ships will have to be replaced with smaller, less effficient vessels. The resulting increase in the transportation costs for Alaska North Slope oil will decrease wellhead values and could result in a loss of revenue to the state of from $18 - $150 million annually.

These ships were built with federal construction differential subsidies (CDS), a program designed to help U.S. built ships to compete in foreign trade markets. To alleviate the shortage of suitable Jones Act tankers, the U.S. Department of Transportation has allowed these ships to enter the domestic trade after repaying the subsidy.

In response to the court decisions, the U.S. Department of Transportation is in the process of adopting new rules that would allow the four ships to remain in the domestic trade. However, pending amendments in Congress may prohibit such new rulemaking. Maritime unions and owners of smaller ships are urging Congress to stand by the original terms of the subsidies and keep the supertankers out of the domestic market, arguing that the competition would seriously harm all smaller operators. A supplemental appropriations bill containing prohibitive language has passed the U.S. House of Representatives. The U.S. Senate version of the bill, which has deleted this amendment, may be voted on this week.

State oil revenues are based on "wellhead" values. The wellhead value is determined by taking the market price of the oil delivered in the lower 48 and subtracting transportation costs. The use of smaller, less efficient tankers will increase shipping costs by $.25 to $1.00 per barrel. This will decrease our wellhead values and result in a loss of state revenues from taxes and royalties of from $18 to $150 million a year.

In terms of environmental risks, these supertankers are among the safest ships built. By replacing them with many smaller and older ships, the chances of accidental oil spills may increase.

I have introduced legislation (SJR 43) that urges the Secretary of the U.S. Department of Transportation to adopt new rules by July 16, 1987 that would enable these ships to continue to operate without interruption. The Legislature has recognized the urgency of this issue and the resolution should be approved by both bodies by the end of this week.

It is possible that Congress may be acting on this critical issue as early as this week. SJR 43 will send a clear message that it is in the best interest of all the people of our state that these supertankers be allowed to continue plying our waters.

TO: DONNA WALKER

STATE OF ALASKA

THE LEGISLATURE

1987

Source

HJR 33

Legislative Resolve No.

16

Relating to the shipping of Alaska oil.

BE IT RESOLVED BY THE LEGISLATURE OF THE STATE OF ALASKA:

WHEREAS on January 16, 1987, the United States Court of Appeals for the District of Columbia vacated a United States Department of Transportation rule under which three very large crude oil carrier ships, the Arco Independence, the Arco Spirit, and the Brooklyn, were allowed to operate in the United States domestic shipping market; and

WHEREAS the court decision would require all three ships to stop domestic shipping of Alaska oil by July 16, 1987, unless the United States Department of Transportation adopts another rule to allow the ships to continue their domestic shipping; and

WHEREAS a fourth ship, the Bayridge, that is used in Alaska oil shipping may also be affected by the court decision; and

WHEREAS Alaska oil production has increased significantly in the last year, and these four ships currently move 200,000 barrels of Alaska oil to market every day; and

WHEREAS if the four ships are prohibited from engaging in domestic shipping, a large number of much smaller, less efficient, and more expensive ships will be required to take their place to transport Alaska oil to market, and this change would raise the cost of transportation for all Alaska oil shipped in these smaller ships by an estimated \$.25 to \$1.00 per barrel, and netback values on the oil would decline accordingly; and

WHEREAS if the Arco Independence, the Arco Spirit, and the Brooklyn are not allowed to engage in the domestic shipment of Alaska oil, the direct economic loss to the state will be between \$18,000,000 and \$150,000,000 annually; and

WHEREAS if the United States Department of Transportation fails to adopt a rule by July 16, 1987, allowing these four ships to operate in the domestic shipping market, the transportation of Alaska oil may be disrupted, the transportation costs will increase dramatically, and the state and the federal government will lose a significant amount of revenue; and

WHEREAS the substitution of a large number of smaller ships could disrupt the transportation of Alaska oil because the smaller ships are often older, less well-equipped, and less safe, and because the increased number of ships could cause congestion at docking facilities; and

WHEREAS the best-equipped and safest ships should be used for the transportation of oil in order to protect the environment and communities through which the ships pass;

BE IT RESOLVED that the Alaska State Legislature respectfully urges the Secretary of the United States Department of Transportation to adopt before July 16, 1987, a rule that would enable the Arco Independence, the Arco Spirit, the Bayridge, and the Brooklyn to continue to operate in the United States domestic shipping market without interruption.

COPIES of this resolution shall be sent to the Honorable Elizabeth H. Dole, Secretary of the U.S. Department of Transportation; and to the Honorable Ted Stevens and the Honorable Frank Murkowski, U.S. Senators, and the Honorable Don Young, U.S. Representative, members of the Alaska delegation in Congress.

AUTHENTICATION

The following officers of the Legislature certify that the attached enrolled resolution, House Joint Resolution No. 33, was passed in conformity with the requirements of the constitution and laws of the State of Alaska and the Uniform Rules of the Legislature.

Passed by the House May 6, 1987

Ben Grussendorf
Speaker of the House

ATTEST:

Irene Cashen
Chief Clerk of the House

Passed by the Senate May 7, 1987

Janice O. Faiks
President of the Senate

ATTEST:

Peggy Mulligan
Secretary of the Senate

Steve Cowper
Governor of Alaska

d - SJR 43

STEVE COWPER, GOVERNOR

STATE OF ALASKA
OFFICE OF THE GOVERNOR
JUNEAU

May 14, 1987

MAY 18 1987

The Honorable Elizabeth Hanford Dole
Secretary
Department of Transportation
400 7th Street, S.W.
Washington, D.C. 20590

Dear Secretary Dole:

On behalf of the State of Alaska, I hereby submit the following comments in support of the proposed rule published at 52 Federal Register, Volume 52, 12199 (April 15, 1987). This rule would reaffirm the allowance of the repayment of Construction Differential Subsidies (CDS), with interest, which permits four U.S.-flag vessels to engage in the American trade. These vessels received CDS pursuant to section 506 of the Merchant Marine Act of 1936, 46 United States Code 1156. The four vessels have repaid their CDS and are currently transporting Alaska crude oil.

The State of Alaska urges that the four CDS-tankers, the ARCO Independence, the ARCO Spirit, the Brooklyn and the Bay Ridge, be allowed to continue in the American maritime trade. These ships are urgently needed to meet existing and future transportation needs for Alaska crude oil. About 22 percent of our nation's oil production comes from Alaska North Slope crude oil (ANS), and this percentage should continue to increase.

The State agrees with the premises of the new regulation namely:

- o that full-time operations by the four CDS-tankers is urgently needed to meet the demands associated with the Trans- Alaska Pipeline System, since demand for U.S.-flag tanker tonnage has increased after the pipeline opened in 1977 and has not been met by the existing Jones Act fleet;
- o that revision affirms previous rules which allowed the four CDS-tankers to pay back their Construction Differential Subsidies with interest in exchange for permission to carry crude oil from Alaska to the lower 48 states and will encourage the development of a more efficient U.S. - flag merchant marine; and
- o that the proposed regulation represents an important step in the efforts to minimize the Federal

government's interference with the marketplace decisions of vessel operators.

When the Trans-Alaska Pipeline System was first opened in 1977, it was assumed that ANS oil would be used primarily to meet West Coast demand. In 1977, ANS production was 0.63 million bbl/day. By 1986, approximately 1.8 million bbl/day of Alaskan crude oil were produced and transported by U.S.-flag tankers; and in 1987, production is expected to increase by another 200,000 bbl/day.

For the last several years, there have not been enough Jones Act tankers to meet ANS oil transport demand. As you know, this situation led the U.S. Department of Transportation to initiate a six-month per year waiver program which permitted CDS-tankers into the American trade on a temporary basis. Waivers became less common after 1986, when five CDS-tankers (including the four tankers involved in this proprosed rule making) were involved in the ANS trade.

If the four tankers are not allowed into the American trade on a full time basis, but only on a six-month basis, increased costs and inefficiencies would result. Under the waiver rule, CDS-tankers, for all practical purposes, can only be used for six months out of the year, forcing their owners to include their lay up costs in their charter rates. Also, under the six-month waiver program Jones Act carriers can engage in a practice known as "blocking." Blocking involves the refusal of employment by a Jones Act vessel unless it receives an artificially high charter price. A higher charter rate could be obtained from a charterer for the laied up Jones Act vessel because the lower cost CDS-tankers are not allowed to be chartered until <u>all</u> the large crude Jones Act tankers are employed.

Not only are the CDS-tankers needed to move the full capacity of ANS oil from Alaska, but also to provide economical transshipment of ANS oil to Panama. The majority of smaller Jones Act tankers were built to transport oil on medium-haul voyages, for example to the Puget Sound and California refineries from Valdez, and from Panama to East and Gulf Coast refineries. In the last few years, however, West Coast oil demand has not kept up with increased ANS oil production. Current law prohibits ANS oil from being exported abroad. Because ANS oil production exceeds West Coast demand, much more ANS oil than originally anticipated is being transported to the Gulf and East Coasts. This oil is primarily transshipped to Panama by CDS tankers and transferred by pipeline to Jones Act tankers.

Overall, the CDS tankers have lower fuel, labor and insurance costs than their smaller counterparts. Analysis by the State of Alaska Department of Revenue, Petroleum Research Section in June 1985 showed that CDS-tankers save

45 percent on average shipping costs over non-CDS-tankers. This amounts to \$1.25/bbl for Gulf Coast shipments and \$0.57/bbl for West Coast shipments. Since the CDS transportation companies made the repayments, there has been a drop in the average tanker rate to Alaska of \$0.75/bbl. Because increased transportation costs on ANS oil ultimately reduce the severance taxes and royalties that the State of Alaska receives, elimination of the four CDS-tankers would significantly reduce the State's revenue.

The CDS-tankers are among the most efficient vessels in the world. From an environmental standpoint, these ships are safer because they are newer and make fewer trips than smaller tankers. Environmental concerns are a major factor for Alaska with its scenic, recreational, marine mammal and fishery resources.

The loss of the CDS-tankers would have direct national economic ramifications. Removing the four CDS-tankers from the American trade would cause \$142 million in direct refunds to supertanker owners who repaid the subsidy. Litigation costs may also be incurred by the Federal government, if the supertankers are denied access to the American trade. Additionally, the CDS repayments would mean long-term tax loses to the Federal government in lost income taxes owing to the less profitable trade which would result from the use of smaller Jones Act tankers. The adverse economic effects of revoking a CDS payback have not been considered by the House and Senate in their 1988 Federal Budget Resolutions and would cause an increased Federal budget deficit.

Other major industrial maritime nations have developed large fleets of supertankers to deliver and transport oil to their countries. For example, most of the oil that Japan receives from the Middle East is shipped by over 90 supertankers that are either owned or controlled by the Japanese. As we have already mentioned, free market economics dictate that it is much more efficient to use supertankers to transport oil over long distances than to use small tankers.

The CDS provision is not a "jobs" issue. Some new jobs would probably be created by prohibiting CDS-tankers from the domestic trade because Jones Act tankers are more labor intensive. However, the six-month waiver program, allowing CDS-tankers into the trade on a limited basis, would minimize the amount of new jobs actually created. As maritime transportation costs increase, especially transshipment charters to Panama, pipelines in the United States, such as the Four Corners Pipeline, would be able to compete effectively with the maritime trade. This would also minimize the creation of more jobs and the use of Jones Act vessels.

The Alaska Legislature has recently considered the issue that is currently pending before the Department of Transportation in this proposed rule making and has passed a resolution urging you to allow the four vessels to continue in the American trade. We are enclosing a copy of House Joint Resolution Number 33 which was unanimously passed by both Houses of the Legislature.

In our opinion, the proposed rule addresses a very real problem in a constructive manner, and is in the best interests of a sound U.S. merchant marine, domestic shippers, and consumers of petroleum products. For this reason, the State strongly supports the proposal.

Thank you for your consideration of these comments.

Sincerely,

John W. Katz for
Steve Cowper
Governor

Enclosure

cc: Senator Ted Stevens
Senator Frank Murkowski
Congressman Don Young

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STEVE COWPER
GOVERNOR

STATE OF ALASKA
OFFICE OF THE GOVERNOR
JUNEAU

May 12, 1987

The Honorable Ben Grussendorf
Speaker of the House
Alaska State Legislature
P.O. Box V
Juneau, AK 99811

Dear Representative Grussendorf:

I have signed the following resolution and am transmitting the engrossed and enrolled copies to the Lieutenant Governor's Office for permanent filing:

HOUSE JOINT RESOLUTION NO. 33
(Relating to the shipping of Alaska oil.)
Legislative Resolve No. 16

Sincerely,

Steve Cowper
Governor

OFFICE OF THE GOVERNOR

JOHN W. KATZ
Director of State/Federal Relations
And Special Counsel to the Governor

Hall of the States
444 North Capital Street, N.W.
Suite 518
Washington, D.C. 20001
(202) 624-5858

Pouch A
Juneau, Alaska 99811
(907) 465-3500

OFFICE OF THE GOVERNOR

ERIC OSTROVSKY
ASSOCIATE DIRECTOR
FINANCE AND HUMAN RESOURCES

Hall of the States
444 North Capitol Street, N.W.
Suite 518
Washington, D.C. 20001

(202) 624-5858

f. SJR 43

MAY 1 9 1987

STEVE COWPER
GOVERNOR

THE SEAL OF THE STATE OF ALASKA

STATE OF ALASKA
OFFICE OF THE GOVERNOR
WASHINGTON, D.C.

May 15, 1987

To Whom It May Concern:

The State of Alaska has sent a corrected version of its comments on the proposed rule making on CDS-tankers to the U.S. Department of Transportation.

The only change to the comments are at page 3, paragraph 1, second to last sentence. Instead of stating that "there has been a drop in the average tanker rate to Alaska of $0.75/bbl.", the revised version states that "there has been a drop in the average tanker rate to destinations east of Panama of $0.75/bbl."

We are enclosing a copy of the revised third page for your information.

Thank you for your attention to this matter.

Sincerely,

Eric Ostrovsky

Eric Ostrovsky

HALL of the STATES — Suite 518 — 444 North Capitol Street N.W. — (202) 624-5858

45 percent on average shipping costs over non-CDS-tankers. This amounts to $1.25/bbl for Gulf Coast shipments and $0.57/bbl for West Coast shipments. Since the CDS transportation companies made the repayments, there has been a drop in the average tanker rate to destinations east of Panama of $0.75/bbl. Because increased transportation costs on ANS oil ultimately reduce the severance taxes and royalties that the State of Alaska receives, elimination of the four CDS-tankers would significantly reduce the State's revenue.

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Most analysts expected the Transportation Department to meet the court's objections. What they didn't anticipate was Congressional intervention. Without hearings or debate, the House prohibited Transportation from spending a dime to rewrite the rule. But Ernest Hollings, who does much of the heavy lifting for the rust bucket fleet, failed with the same ploy in the Senate. He will still represent his colleagues when the two bills are reconciled.

Coastal shipowners claim they will go broke if forced to compete and thus wouldn't be available for military emergencies. If the vessels were worth saving, though, the Navy could buy them at scrap value and put them in mothballs.

The only real issue is whether Congress will be able to resist the lure of PAC politics. Shipping interests learned long ago that it was more profitable to start political action committees and invest in "Congressional access" than in more efficient ships or retraining. In 1985-86, the tiny seafarers' union alone contributed $1.2 million just to House members. With money like that floating around, there's reason to wonder if a majority of conferees will have the conscience to put the public's financial interest ahead of their own.

Legal Life Jacket for Mr. Meese

It's no longer remarkable to find the U.S. Attor-

The public cannot be expected to believe that

MAY 1 0 1987

STEVE COWPER
GOVERNOR

STATE OF ALASKA
OFFICE OF THE GOVERNOR
WASHINGTON, D.C.

April 22, 1987

MEMORANDUM

TO: FILE

FROM: ERIC OSTROVSKY, Associate Director for Revenue

THROUGH: JOHN W. KATZ, Director of State/Federal Relations and Special Counsel to the Governor

SUBJECT: 1) ALASKA REVENUE IMPACT CAUSED BY DENYING THREE VLCC CDS SHIPS TO THE ALASKA TRADE
2) THE NUMBER OF NEW JOBS CREATED BY USING SMALLER TANKERS

REVENUE IMPACT

The Alaska Department of Revenue, Petroleum Research Section (Research Section) in a recent analysis has indicated that if three CDS tankers owned by ARCO and Petrofina were taken out of the Alaska trade, the direct ecomomic loss to the State of Alaska would be $18 - $150 million annually. This revenue loss would result from a decrease in Alaska's oil royalty and severance taxes. The decrease would be caused by a decrease in the wellhead price of oil, which is calculated as the price of oil at its final destination minus pipeline shipping and other allowable costs.

The U.S. Maritime Administration and the major oil companies effected by the issue predict that Alaska would likely lose about $50 million annually. The Research Section indicates that the $50 million estimate is probably accurate. Since the time that the Research Section determined the revenue impact, the U.S. Department of Transportation in its proposed rule making has indicated that a fourth VLCC CDS tanker, the Bay Ridge, would also have to be taken out of the Alaskan trade if the ruling in Independent U.S. Tanker Owners Committee v. Dole takes effect. If the Bay Ridge is also taken out of the Alaska trade, the revenue impact that follows would have to be increased by roughly 33 percent.

Each CDS super oil tanker can carry significantly more oil than its smaller counterparts, and the CDS tanker transports oil at a cheaper rate. A study last year by the Research

Section showed that CDS tankers could save an average of 45 percent in shipping costs over non-CDS tankers. This amounts to $1.25/bbl for Gulf Coast shipments and $0.57/bbl for West Coast shipments. Since the three CDS tankers were introduced into the Alaska trade in between July, 1985 and May, 1986, the average tanker rate overall to the Gulf Coast has dropped by $0.75/bbl.

The three CDS tankers (the Bay Ridge is not included in the following calculations) now engaged in Alaska North Slope (ANS) oil shipments are transporting about 60 million barrels annually. The following equation reflects the reason why the Research Section predicts that the State would lose at least $18 million annually:

Royalty Effect

60 (million barrels of oil) x ($1.25 savings) x 0.125 (12.5 percent royalty) = $9.4 million

plus

Severance Tax Effect

60 x 1.25 x 0.15 (severance rate) x 0.84 (economic limit factor) x 1 - 0.125 (severance tax adjustment) = $8.3 million

TOTAL $17.7 million.

The severance tax adjustment is needed because this severance tax is levied only on non-royalty oil, ie, a tax on oil left after the royalty oil is subtracted. The economic limit factor, which reduces the effective severance tax rate as well productivity declines, is estimated to be 0.84 percent over the near term.

The reason why $18 million is a conservative estimate is that the reduced competition from the removal of the tankers (the tanker market is currently fully extended) could raise the transportation cost for all ANS oil, so that, the State could lose over $50 million annually if tanker rates on all shipments of the Gulf Coast returned to the previous level. The following equation shows how the $50 million figure was derived:

Royalty Effect

300 (millions of barrels of ANS oil delivered to the Gulf Coast) x 0.75 (actual overall rate reduction when the three CDS vessels were introduced into the trade) x 0.125 = $28.1 million

plus

Severance Tax Effect

300 x \$0.75 x 0.15 x 0.84 x (1 - 0.125) = \$24.8 million

TOTAL \$52.9 million.

If the shipping rate on all ANS oil shipments both to the Gulf and West Coast were to increase the full 45 percent, Research Section estimates that the revenue impact on the State could go as high as \$150 million annually.

POTENTIAL JOBS CREATED BY THE CHANGE

The United States Maritime Administration (MarAd) predicts that about 500 new jobs would ultimately be created by prohibiting the CDS ships in the Alaska trade. MarAd predicated this figure based on the assumption that the smaller tankers replacing the CDS tankers would hire about 800 crewmen. On the other hand, about 300 jobs would be lost on the three CDS tankers, reducing the new jobs created to 500.

The oil companies point out that CDS tankers could continue to be waived into the Alaska trade on a six month basis even if the proposed amendment passes. Under this scenario, CDS tankers could fill in the gap for the four vessels taken out of the trade on a full time basis. Because large tankers would still be in use, no new jobs would be created. Nevertheless, the tankers waiving into the trade for six month periods would still have much higher transportation costs than the four CDS tankers taken out of the trade. The tankers waived into the trade for six months would most likely be docked for the rest of the year and the six months of inactivity would have to be factored into the tankers' over all operating costs.

Assuming that CDS tankers are not allowed to waive into the Alaska trade for a six month period and with the tanker market in the Alaska trade currently fully extended, it is not certain whether new seafarer jobs would be created or that only transportation costs would rise due to increased demand. Moreover, if the wellhead price drops, ANS oil could not compete against the world market price, and ANS oil production would decrease, which is what happened recently when the Milne Point oil field shut down. This effect would also limit potential jobs. The ability of ANS oil to compete on the world market will become a greater factor as new, more costly methods are needed to extract ANS oil, and the cost of transportation may become an even more significant component in determining whether ANS oil can compete.

Finally, there would be a \$114 million direct and immediate loss to the Federal Treasury caused by denying the Alaska trade to the three CDS tankers. Part of the costs, $105.8 million would come from the CDS repayments, and, the remainder, another $8 million would be in interest. According to the U.S. Maritime Administration (MarAd), the Federal government would also lose about $44 million annually in Federal income taxes due to the less profitable trade caused by the use of non-CDS tankers. MarAd determined the tax loss by estimating that it would cost an extra $128 million in shipping expenses to transport ANS oil in non-CDS ships. On top of these expenses there would be additional expenses for the Bay Ridge if it is also forced to discontinue in the Alaska trade.

Attached is a copy of the proposed U.S. DOT rule making which recently appeared in the Federal Register.

The theoretical maximal residue contribution (TMRC) for existing tolerances is 0.001256 mg/kg/day for the total U.S. population. The proposed use will contribute an additional 0.000004 mg/kg/day (a 0.3 percent increase).

The nature of the residues is adequately understood and an adequate analytical method, gas chromatography, is available for enforcement purposes. Analytical enforcement methods are currently available in the Pesticide Analytical Manuals (PAM) Volumes I and II. There are presently no actions pending against the continued registration of this chemical.

Based on the data and information considered, and the fact that tabasco peppers are not considered an animal feel commodity, the Agency concludes that the proposed tolerance will protect the public health. Therefore, it is proposed that the tolerance be established as set forth below.

Any person who has registered or submitted an application for registration of a pesticide, under the Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA) as amended, which contains any of the ingredients listed herein, may request within 30 days after publication of this notice in the Federal Register that this rulemaking proposal be referred to an Advisory Committee in accordance with section 408(e) of the Federal Food, Drug, and Cosmetic Act. As provided for in the Administrative Procedure Act [5 U.S.C. 553(d)(3)], the comment period is shortened to less than 30 days because of the necessity to expeditiously provide a means for weed control in tabasco pepper production.

Interested persons are invited to submit written comments on the proposed regulation. Comments must bear a notation indicating the document control number, [PP 6E3378/P414]. All written comments filed in response to this petition will be available in the Information Services Section, at the address given above from 8 a.m. to 4 p.m., Monday through Friday, except legal holidays.

The Office of Management and Budget has exempted this rule from the requirements of section 3 of Executive Order 12291.

Pursuant to the requirements of the Regulatory Flexibility Act (Pub. L. 96–354, 94 State. 1164, 5 U.S.C. 601–612), the Administrator has determined that regulations establishing new tolerances or raising tolerance levels or establishing exemptions from tolerance requirements do not have a significant economic impact on a substantial number of small entities. A certification statement to this effect was published in the Federal Register of May 4, 1981 (46 FR 24950).

List of Subjects in 40 CFR Part 180

Administrative practice and procedure, Agricultural commodities, Pesticides and pests, Reporting and recordkeeping requirements.

Dated: April 3, 1987.

Edwin F. Tinsworth,

Director, Registration Division, Office of Pesticide Programs.

PART 180—[AMENDED]

Therefore, it is proposed that 40 CFR Part 180 be amended as follows:

1. The authority citation for Part 180 continues to read as follows:

Authority: 21 U.S.C. 346a.

2. Section 180.368 is amended by removing the entry for "peppers, chili. . . . . 0.5" from the table in paragraph (a), by revising the introductory paragraphs to the list of commodities in paragraphs (a) and (b), and by adding paragraph (c) to read as follows:

§ 180.368 Metolachlor; tolerances for residues.

(a) Tolerances are established for the combined residues of the herbicide metolachlor (2-chloro-*N*-(2-ethyl-6-methylphenyl)-*N*-(2-methoxy-1-methylethyl)acetamide)and its metabolites, determined as the derivatives, 2-[(2-ethyl-6-methylphenyl)amino]-1-propanol and 4-(2-ethyl-6-methylphenyl)2-hydroxy-5-methyl-3-morpholinone, each expressed as the parent compound in or on the following raw agricultural commodities:

* * * * *

(b) Tolerance are established for indirect or inadvertent residues of metolachlor in or on the following raw agricultural commodities when present wherein as a result of the application of metolachlor to growing crops listed in paragraph (a) of this section to read as follows:

* * * * *

(c) Tolerances with regional registration as defined in § 180.1(n), are established for the combined residues of the metolachlor and its metabolites in or on the following raw agricultural commodities:

Commodities	Parts per million
Peppers, chili	0.5
Peppers, tabasco	0.5

[FR Doc. 87–8161 Filed 4–14–87; 8:45 am]

BILLING CODE 6560-50-M

DEPARTMENT OF TRANSPORTATION

Maritime Administration

46 CFR Part 276

[Docket NO. 110]

Construction-Differential Subsidy Repayment

April 10, 1987.

AGENCY: Maritime Administration, Department of Transportation.

ACTION: Notice of proposed rulemaking.

SUMMARY: This rule would allow four vessels that repaid their construction-differential subsidy (CDS) in exchange for the right to operate in the domestic trade to remain in that trade. Three of those vessels have been operating in the Alaska oil trade after repaying their CDS under a 1985 Department of Transportation rule. A recent court decision vacated that rule, but delayed the effective date of its order to July 16, 1987. The fourth vessel was approved to repay its CDS by an administrative decision in 1980 under conditions of an interim rule that was subsequently vacated by the court. However, the court allowed the vessel to remain in the domestic trade pending agency reconsideration of the rule. In response to those court decisions, this proposed rule would allow those four vessels to remain in the domestic trade in the furtherance of the purposes and policies of the Merchant Marine Act, 1936, as amended.

DATES: Comments must be received by May 15, 1987.

ADDRESS: Submit comments to James E. Saari, Secretary, Maritime Administration, Room 7300, 400 Seventh Street SW., Washington, DC 20590. The Maritime Administration requests that commenters send six copies of their comments.

FOR FURTHER INFORMATION CONTACT: Lynne Adams-Whitaker, Chief, Division of Regulations, 400 Seventh Street SW., Washington, DC 20590, Tel (202) 366–5181.

SUPPLEMENTARY INFORMATION:

Background

The Jones Act (46 U.S.C. 883) generally provides that all cargo transported in the domestic trade between points in the United States must be carried on vessels built in the United States, documented under United States law and owned by United States citizens. While United States vessels in the domestic trade operate under the protection of the Jones Act (46 U.S.C. 883), vessels operating in the foreign trade do not have such protection. Thus, vessels operating in the foreign trade must compete with foreign-flag vessels that have lower operating and construction costs. To offset these higher U.S. construction costs, Congress passed Title V of the Merchant Marine Act, 1936, as amended ("the Act"), which authorized the payment of construction-differential subsidy (CDS) for the purpose of building ships in U.S. shipyards to be operated in foreign commerce. 46 App. U.S.C. 1151 *et seq.* The Secretary of Transportation, throught the Maritime Administration (MARAD), may pay as much as half the construction costs of vessels used in the U.S. foreign trade. 46 App. U.S.C. 1152. There is no corresponding subsidy program for vessels constructed by U.S. owners exclusively for use in the domestic trade. In 1970, Congress expanded the scope of the Act to include bulk (i.e., tanker or dry bulk) vessels. Merchant Marine Act of 1970, Pub. L. 91–469, 84 Stat. 1018.

In addition, Title VI of the Act authorized the payment of an operating-differential subsidy (ODS) for U.S.-flag vessels manned by U.S. citizens and operated in accordanced with U.S. safety standards. 46 App. U.S.C. 1171. By a policy decision, ODS was not paid to CDS-built bulk-vessels over 100,000 DWT. Because of the large economy of scale of these vessels, labor costs, which are the essential subsidized item under the ODS program, are relatively small in terms of the overall project cost.

CDS-built vessels are subject to certain restrictions. Under section 506 of the Act, vessels constructed with CDS "shall be operated exclusively in foreign trade or on a round-the-world voyage. . . ." 46 App. U.S.C. 1156. Section 506 of the Act allows CDS vessels to be operated in the domestic trade in the following limited circumstances: (1) On a round voyage from the west coast of the United States to European ports which includes Intercoastal U.S. ports; (2) on a round voyage from the Atlantic coast of the U.S. to the Orient which includes intercoastal ports of the U.S.; (3) on a foreign voyage including a stop in Hawaii or an island possession or territory of the U.S. In addition, CDS vessels may be operated in the domestic trade with the consent of the Secretary of Transportation for up to six months in any year under authority of section 506 with the requirement that the vessel owner repay the subsidy on a *pro rata* basis. All domestic trading restrictions for each CDS-built vessel lapse at the end of the vessel's statutory life. Section 9 of Pub. L. 86–318 (74 Stat. 216) sets a 20 year economic life for tankers.

The overall objectives of the 1970 amendments to the Act were to encourage U.S. shipbuilding, thus enhancing the U.S. merchant marine fleet, and to serve the needs of national commerce and defense. The specific goal of the 1970 amendments was to build 30 ships per year over ten years, with emphasis on building bulk carriers, including tankers, for operation in the foreign commerce.[1] Prior to the 1970 amendments, the direct subsidy programs of the Merchant Marine Act had been confined to liner vessels, which operated scheduled services in foreign commerce under the regulatory supervision of the Federal Maritime Commission. The Congress, in extending the reach of these programs to the unregulated bulk trades, specifically recognized the need to make these vessels "competitive" with foreign flag ships. *See* H. Rep. No. 1073, 91st Cong., 1st Sess., 38 (1969); Merchant Marine Act, 1936, 603(b), 46 U.S.C. 1173(b). There was however, no guarantee that even with these subsidies U.S.-flag vessels could compete in the U.S. foreign commerce.

Unfortunately, the governmental subsidy programs offered to U.S.-flag very large crude carriers ("VLCCs", i.e., tankers over 160,000 DWT) has not enabled them to be competitive in the foreign trade. In 1970, Congress did not foresee, and perhaps could not have foreseen, the drastic changes that would occur in the world oil market. The decline in export of crude oil from the Middle East, in addition to an oversupply of world tankers built since 1970, has been financially devastating for the world tanker market. Further, the gap between foreign construction costs and U.S. construction costs widened beyond the level Congress authorized under the CDS program. As a consequence, the two ultra large crude carriers and nine VLCCs constructed with CDS under the 1970 amendments were left with no significant competitive opportunities in the foreign commerce.

The domestic market, however, has not fared as poorly. With the opening in 1977 of the Trans-Alaska Pipeline System, the demand for U.S.-flag tanker tonnage has increased and that demand has not been completely met by the existing Jones Act (domestic) fleet. To alleviate the shortage of suitable Jones Act tanker vessels, MARAD has allowed CDS-built tankers to enter the trade for up to six month periods after repaying the subsidy *pro rata* under section 506 of the Act and in accordance with 46 CFR Part 250.[2] Since 1977, MARAD has approved 43 such applications for CDS-built tanker service in the Alaska oil trade (of those approvals, 37 were for VLCCs). However, because of the limited duration and availability of these temporary permissions and the depressed market conditions confronting tankers in the foreign trade, several CDS tanker owners (predominantly those owning VLCCs) applied for permission to enter the domestic market on a permanent basis in exchange for the total repayment of any unamortized CDS received plus interest.

Prior to 1978, requests for permanent repayment were handled *ad hoc.* No hearings were held on these requests and notice of the proposed determinations was not given to the public. However, after MARAD admitted the *VLCC Stuyvesant* (operated by Seatrain Lines) to the domestic trade, competitors in that trade brought suit challenging MARAD's action. The ultimate disposition of the suit was that, on writ of certiorari, the Supreme Court held that the Secretary's broad contracting powers and discretion to administer the Act encompass the authority to grant permanent release to vessels under CDS restriction. *Seatrain Shipbuilding Corp.* v. *Shell Oil Co.*, 444 U.S. 572 (1980).

In 1978, MARAD issued a notice of proposed rulemaking (NPRM) that would have set guidelines for permanent CDS repayment. Charterers and owners of six CDS-built vessels applied for CDS repayment. On October 15, 1980, MARAD adopted and made immediately effective an interim rule to govern applications for CDS repayment. Under the interim rule, MARAD retained greater discretion than proposed in the (NPRM) to determine whether to grant or deny CDS repayment applications. Approvals would be granted only for vessels of at least 100,000 DWT and only in exceptional circumstances, after a

[1] In fact, only 34 petroleum tankers were built with CDS authorized by the 1970 amendments.

[2] 46 CFR Part 250 establishes procedures by which MARAD may temporarily waive (i.e., for no more than six months in any twelve month period) the domestic trade restrictions on CDS-built vessels over 100,000 deadweight tons (DWT) in the Alaska-Panama Canal trade. Applications for such waiver must be accompanied by information showing that suitable vessels (i.e., those over 100,000 DWT) of a competitor would not be available for the prospective voyage.

determination that no favorable opportunities existed for viable employment of the vessel in foreign trade during a protracted period. MARAD was to consider a number of factors in determining whether exceptional circumstances existed.

On November 13, 1980, through an adjudicative decision, MARAD approved the CDS repayment application for the *Bay Ridge*, another Seatrain vessel. MARAD deferred action on the other pending CDS repayment applications. On November 25, 1980, the independent U.S. Tanker Owners Committee filed a complaint in the U.S. District Court for review of the interim rule and the *Bay Ridge* decision, alleging substantive and procedural defects in connection with both actions. The District Court granted summary judgment for defendants on all counts. An appeal was taken.

The Court of Appeals considered the alleged substantive and procedural defects of the interim rule. The Court concluded that MARAD was not legally obligated to issue regulations limiting its discretion and that the interim rule itself did not constitute an abuse of MARAD's statutory discretion. Nevertheless, the Court vacated the interim rule on procedural grounds. It concluded that the rule lacked a general statement of basis and purpose, as required by the Administrative Procedure Act (5 U.S.C. 551 *et seq.*), to explain MARAD's position on the various issues raised during the rulemaking proceeding. The Court also found that adjudication allowing the *Bay Ridge* repayment was procedurally and substantively flawed.

The Court of Appeals remanded the case to the District Court with Instructions to vacate the interim rule and to order new rulemaking procedures, and to vacate the approval of the *Bay Ridge* application, but to allow the *Bay Ridge* to continue in domestic operation pending reconsideration of the *Bay Ridge* adjudication. The Court left to MARAD's discretion whether the new *Bay Ridge* decision should await publication of a permanent rule regarding CDS repayment. The Court also left to MARAD's discretion whether to adopt a permanent rule similar to the interim rule so long as the justification for the rule adopted was "clearly and thoughtfully presented in a statement published contemporaneously with the rule". *Independent U.S. Tanker Owners Committee* v. *Lewis*, 690 F.2d 906, 920 (D.C. Cir. 1982) [hereinafter referred to as *ITOC* v. *Lewis*].

The Department of Transportation published a new NPRM on January 31, 1983, 48 FR 4408. That NPRM, which was issued by the Secretary, proposed to permit total CDS repayment for all U.S. tanker vessels. The notice reviewed the entire history of this issue since the MARAD first accepted total repayment on the *VLCC Stuyvesant* and reviewed the comments received on earlier MARAD rulemakings pertaining to total repayment in return for domestic trading privileges. It invited further comment on these issues and assessed the economic impact of allowing the owner/operators of these vessels to determine on their own whether to repay their CDS. The rulemaking concluded that the Government was not in a position to assess, on its own, which vessels should, and which should not, be allowed to meet the needs for additional capacity in the domestic trade. For example, it pointed out that only allowing operators in financial jeopardy to repay their CDS was not consistent with the objectives of the 1936 Act. 48 FR at 4412.

The Department concluded that the marketplace decisions of individual operators would best serve the needs of the fully deregulated domestic tanker trade, provided that those operators that repaid were placed on an equal competitive cost footing with the existing Jones Act fleet. *Id.* at 4409–4410. Accordingly, the proposed rule would require repayment of an additional amount consisting of compound interest on the unamortized subsidy from the date of its original receipt. The addition of this amount, which frequently could exceed the unamortized subsidy itself, would duplicate the financial condtions inherent in a private sector decision to commit any comparable new asset to the domestic trade, with an allowance only for its age, by allowing the amortization of the subsidy pursuant to its statutory useful life of 20 years. *See* 48 FR 4408–4414. Since the Government does not otherwise regulate entry of new capacity in the domestic trade, duplicating the conditions ordinarily governing such entry was deemed the most appropriate approach.[3]

Shortly after the close of the comment period on the NPRM, the Congress took action to prevent the Secretary from promulgating a final rule. The DOT FY 84 Appropriations Act (Pub. L. 96–78), August 15, 1983) prohibited the enforcement of any rule with respect to the repayment of CDS until 60 days following the promulgation of any such rule. Thereafter, the Commerce Department's FY 84 Appropriations Act (Pub. L. 98–166, November 28, 1983) imposed an additional restriction that prohibited DOT from enforcing any CDS repayment rule until after June 15, 1984. In August of 1984, the FY 85 Appropriations Act for Commerce, Justice and State, which provides appropriations for MARAD, imposed yet another restriction. That Act prohibited the Department from enforcing any CDS repayment rule until May 15, 1985 (Pub. L. 96–411, August 30 1984). Thereafter, Congress considered, but did not extend, these prohibitions.

On May 7, 1985, the Department published in the Federal Register a final rule which allowed any owner or operator of a tanker built with CDS to repay its subsidy (with interest) and consequently obtained a permanent removal of domestic trading restrictions. The amount of repayment included the unauthorized CDS on the vessels plus compounded interest on that amount. The Interest rate, to be used for computational purposes, was the rate at which the original Title XI obligation was made or the Title XI long-term bond rate at the vessel's delivery. The final rule included a one-year time limit after the rule's effective date during which total CDS repayment had to be made irreversibly.

That time limit was from June 6, 1985 to June 6, 1986. During that time, three VLCCs repaid the CDS: the Arco Independence (262,400 DWT), ARCO SPIRIT (262,400 DWT), and the Brooklyn (226,200 DWT). The total amount of CDS repaid by these ships was $105.8 million. Those ships are now operating in the domestic trade.

On January 16, 1987, the Court of Appeals for the District of Columbia held that the Secretary of Transportation violated section 553(c) of the Administration Procedure Act by adopting a final rule on CDS repayment which did not contain a statement of basis and purpose giving an adequate account of how the rule served the objectives of the Act and why alternatives were rejected in light of them. *Independent U.S. Tanker Owners Committee* v. *Dole*, Civil Action Nos. 85–01555, 85–01740, 85–01752 and 85–1771. (D.C. Cir. January 16, 1987) [hereinafter referred to as *ITOC* v. *Dole*]. The court found that the Secretary's failure to provide an adequate statement of basis and purpose was arbitrary and capricious. The court vacated the rule, but withheld issuance of its mandate until July 16, 1987 "to avoid further disruptions in the domestic market and to allow the Secretary to undertake

[3] Similarly, damaged foreign-built vessels may be acquired and reconstructed for use in the domestic trade under the Wrecked Vessels Act without prior government approval, provided a specific amount is expended in the reconstruction (i.e., three times their salvage value). 46 App. U.S.C. 14.

further proceedings to address the problems of the merchant marine trade." Slip op. at 16. The court ruled that, as of July 16, 1987, the present rule will be vacated and conditions will be returned to the *status quo ante*, before the CDS repayment rule took effect, subject to any "further action" that the agency may have taken in the interim.

By letter dated March 10, 1987, counsel for the *Bay Ridge* requested that a proceeding on the *Bay Ridge* should be conducted independently of proceedings with respect to the three vessels which repaid CDS pursuant to the repayment rule that has been vacated by the Court of Appeals. The court in *ITOC* v. *Lewis* specifically left to MARAD's discretion whether or not the *Bay Ridge* decision should await publication of a permanent rule governing repayment applications. MARAD has decided that it would be appropriate to consider the *Bay Ridge* in this rulemaking, since it affects the same domestic trade as the other three vessels at issue.

The Proposed Rule

This proposed rule would reaffirm the allowance of the repayment of CDS, with interest, and rescisison of the domestic trading restriction for tankers that applied to and were approved by MARAD between June 6, 1985 and June 6, 1986. The approved applications were for the *Arco Independence*, *Arco Spirit* and *Brooklyn*. Further, this proposed rule would reaffirm the allowance of the repayment of CDS, with interest, and rescission of the domestic trading restrictions for *the Bay Ridge*, which was approved to repay its CDS in November 1980. It would impose the same conditions on the *Bay Ridge* that were imposed in 1980.

This proposed rule would differ from the 1985 CDS repayment rule in that it does not provide a one-year window for applicants to seek MARAD approval of their CDS repayment. This proposed rule would impose the same terms and conditions on the three tankers that repaid during the one-year window as were required in the 1985 CDS repayment rule.

Comments

MARAD solicits comments on this proposed rule from all interested parties. In particular, MARAD seeks comments on the future of the Alaska North Slope (ANS) trade.

The Purposes and Policies of the Merchant Marine Act

The preamble to the Merchant Marine Act, 1936, as amended, states that the intent of the Act is "[t]o further the development and maintenance of an result and well-balanced American merchant marine, to promote the commerce of the United States, to aid in the national defense. . . ." The specific goals of the Merchant Marine Act, 1936, as amended, as set out in section 101 of the Act, are to foster the development and encourage the maintenance of an American merchant marine that is

(a) sufficient to carry its domestic water-borne commerce and a substantial portion of the water-borne export and import foreign commerce of the United States and to provide shipping service essential for maintaining the flow of such domestic and foreign water-borne commerce at all times, (b) capable of serving as a naval auxiliary in time of war or national emergency, (c) owned and operated under the United States flag by citizens of the United States, insofar as may be practicable, (d) composed of the best-equipped, safest, and most suitable types of vessels, constructed in the United States and manned with a trained and efficient citizen personnel, and (e) supplemented by efficient facilities for shipbuilding and ship repair. 46 App. U.S.C. 1101.

MARAD believes that this proposed rule, which would allow the four CDS-built very large crude carriers ("the four VLCCs") to remain in the domestic trade, would benefit the domestic water-borne commerce by providing vessels that are the "most suitable" for the Alaska-Panama oil trade, which would result in a "well-balanced" American merchant marine. Although originally built to operate in the foreign trade, these VLCCs are not competitive in that trade. If not allowed to operate in the domestic trades, the four VLCCs would likely be unemployed and possibly scrapped.

The balance of this statement discusses how this proposed rule would fulfill the objectives of the Act. The suitability of these vessels for the Alaska-Panama trade is discussed in more detail in Section I. Section II discusses the effect of this proposed rulemaking on the U.S. tanker fleet operating in the foreign commerce. Section III analyzes the effect of this proposed rulemaking on the naval auxiliary. Section IV addresses the effects of this rulemaking on shipyards. Section V considers other objectives of the Act that support this rulemaking. Section VI addresses the alternatives considered by MARAD.

I. The Alaska Oil Trade and the Need for Suitable Tankers

The main purpose for allowing the four VLCCs to remain in the domestic trade is to foster the development of suitable vessels for that trade. "Suitability" is determined not only by the physical ability of a vessel to carry a certain product, but by market conditions. As will be shown below, market conditions in the oil trade have fluctuated drastically since the advent of the *CDS* program, affecting the distribution of oil in both foreign and domestic markets.

A. ANS Crude Oil Production

When the Trans-Alaska Pipeline opened in 1977, Alaska North Slope (ANS) crude oil loadings averaged 629,000 barrels per day (b/d). Average loadings have steadily increased since then. In 1982, average loadings reached 1.62 million b/d. Production for 1987 is expected to be 1.8 million b/d. The most rapid growth occurred between 1978 and 1980 when average loadings grew at an annual rate of 18.4 percent. Average loadings from 1980 to 1986 grew at an annual rate of 2.2 percent. (See Table 11-2 in Regulatory Impact Analysis).

B. The Distribution of ANS Crude Oil

While ANS crude oil production has grown steadily since 1977, the distribution of that oil has changed dramatically. ANS crude oil is shipped to the West Coast, to Panama, to the Gulf and East Coasts from Panama, and to the Virgin Islands around Cape Horn.[4] In the five months of 1977 when ANS oil production began, approximately 75 percent of the oil from Valdez, Alaska was shipped to the West Coast, 21 percent to Panama (to be shipped to the Gulf/East Coasts), and two percent to the Virgin Islands. Shipments to Panama increased to 30 percent of total loading in 1980, and peaked at 43 percent in 1982. During this period, the volume of oil going to the West Coast dropped from 63 percent to 50 percent. During 1986, 32 percent of the Alaska oil was shipped to Panama, and 62 percent to the West Coast.

The amount of future ANS shipments to Panama will likely decline, for several reasons. More ANS crude oil will likely be shipped to the West Coast during 1988 due to the imminent opening of the All-American pipeline from Southern California to the Texas Gulf, assuming the pipeline is completed in that time frame. This pepeline will have a capacity of 300,000 b/d and will ship surplus West Coast crude to the Gulf Coast for refining. While increases in West Coast crude production are anticipated, the surplus pipeline capacity would probably eliminate some need for vessels to carry the oil to Panama (to be shipped to the Gulf).

[4] All of the oil carried to the Virgin Islands currently is moved in foreign-flag vessels via Cape Horn.

Valdez loading may decline in the 1990's due to production reduction as well as the potential construction of a 105,000 b/d (rated capacity) refinery at Valdez by Alaskan Refining, Inc. Products from the refinery may be transported abroad on foreign-flag tankers, thus reducing the shipments of oil from Valdez for U.S.-flag tankers.

C. Tanker Demand in the ANS Crude Oil Trade

Tanker demand in the ANS trade depends on ANS oil production and the distribution of the oil. As production increases, so does the amount of tonnage needed to carry the oil. However, the increase in demand for tankers may not be proportional to oil production if there is also a change in the distribution of the oil. For example, tanker demand peaked in 1982 when approximately 182 billion-barrel miles of oil were shipped. This peak in demand was due not only to the increased production of oil, but also due to the peak in shipments to Panama (43 percent of total loadings). A drop in ANS crude oil shipments between 1982 and 1984 (from 7.2 million DWT to 5.9 million DWT) was attributable not to production, which remained fairly constant, but to a drop in oil shipments to Panama and corresponding rise in shipments to the West Coast.

The distribution of oil affects the demand for certain size tankers. Historically, VLCCs have carried the majority of oil from Alaska to Panama (see Table III-2 in the Regulatory Impact Analysis). During 1986, about half the full-time equivalent tanker employment in the Alaska-Panama trade was for vessels from 200,000 DWT to 265,000 DWT; most of the other half was for VLCCs from 170,000 DWT to 190,000 DWT. A small percentage was carried by tankers from 110,000 DWT–137,000 DWT, while only 0.6 percent in 1986 was carried by vessels under 100,000 DWT. (Historically, the share carried by tankers under 100,000 DWT has been no more than 6 percent.) Even prior to the 1985 CDS repayment by four of the VLCCs, the Valdez-Panama trade was dominated by tankers over 100,000 DWT. Many of these were CDS built VLCCs operating under six month permissions in the domestic trade.

Several factors contribute to the suitability of the four VLCCs for this trade. VLCCs are more suitable for long-haul, high volume trades than smaller tankers, due to economies of scale. That is, tanker operating costs do not rise as fast as cargo volumes. Thus, VLCCs are more efficient and economical than smaller tankers for long-haul, high-volume trades. Studies of optimal ship size have shown that optimal ship size is determined by minimizing costs per ton at sea and in port. (In port, costs per ton increase with ship size; at sea, however, costs per ton decline with ship size). J.O. Jansson and D. Shneerson, "The Optimal Ship Size," *Journal of Transport Economic and Policy*, 217, 223 (Sept. 1982). VLCCs are more suitable for the Panama leg of the ANS trade because of the length of the voyage (approximately 4,950 miles). The at-sea time is significantly longer than any other legs of U.S.-flag oil shipments in the U.S. Another factor contributing to the suitability of the VLCCs for the Panama leg is the deep-draft of the Panama port, which can accommodate those larger tankers. Because of these factors, VLCCs are able to carry oil in that trade more efficiently than small tankers under 100,000 DWT.

Conversely, smaller tankers are more suitable for the West Coast and upcoast (Gulf/East Coast) trade than the Panama trade. The Valdez-West Coast ANS trade has been served by vessels in all DWT ranges: 47 percent of the full-time equivalent tanker employment in that trade is carried by vessels under 100,000 DWT; 53 percent is carried by tankers over 100,000 DWT.

Once the oil reaches Panama, smaller tankers (i.e., under 150,000 DWT) are needed to carry the oil to the Gulf and East Coasts. (VLCCs are less suitable than smaller tankers for such short haul, low volume trades, because their capital and port charges, which are higher than those for smaller tankers, are spread over smaller cargo volumes.) Tankers under 55,000 DWT carry 22 percent of the Panama-Gulf/East Coast ANS oil. Tankers in the 55,000 DWT to 92,000 DWT range now carry about two-thirds of the ANS oil in this trade. Such tankers are more suitable for that trade than larger tankers because they often stop at many ports (which would not be economical for larger tankers to do), and most Gulf/East Coast ports are not deep-draft. Further, the at-sea time is much less because of the shorter distances involved.

The Regulatory Impact Analysis indicates certain trends in the distribution of oil by trade and by vessel tonnage. Since the permanent entrance of the three CDS-built VLCCs in the domestic trade (i.e., from 1985–1986), the percentage of full-time equivalent tanker employment for VLCCs over 200,000 DWT in the Alaska-Panama trade has risen considerably, and employment by vessels under that tonnage range has decreased correspondingly. It appears that the trend of these VLCCs carrying the majority of Valdez-Panama ANS trade will continue.[5]

Allowing the four VLCCs to remain in the domestic trade makes the domestic fleet better balanced than it would be without these vessels in the trade. It should be noted that, even with the four VLCCs in the domestic trade, shortages of tankers have led to one smaller CDS-built tanker, the *Beaver State*, entering the trade for a month under a section 506 waiver. (See Regulatory Impact Analysis). Further, only six percent of the domestic tankers (12 tankers) were in lay-up as of February 1987. This percentage is quite low, considering that February is a slow month for the upcoast oil trade and is a reasonable reserve to cover temporary losses from the active fleet due to casualties, safety inspections and repairs as well as seasonal increases in upcoast petroleum movements. As for the future, while ANS tanker loadings have increased from 629 thousand barrels per day in 1977 to 1,788 thousand barrels per day in 1986, loadings are expected to fall over the period 1988–95, due to a gradual decline in ANS production (Table II-2 of the Regulatory Impact Analysis) with uncertain consequences. Comments are invited specifically on the extent and the consequences of this decline in ANS production.

Finally, no data has been developed yet on the extent that the lower costs of tranporting ANS crude on VLCCs, including those that repaid their CDS, has increased shipments to Panama since those four vessels were admitted to the trade. To the extent that occurs, overall tanker demand in the trade would be increased, and the displacement caused by the entry of those vessels thereby reduced. Commenters are invited to submit such data.

D. Availability of Tankers in the Trade

When ANS crude oil loadings began in 1977, there were 215 privately-owned unsubsidized tankers (8.0 million DWT) in the U.S.-flag fleet (excluding special product tankers). Of those, only seven were over 100,000 DWT (totaling 848,000 DWT). An additional 15 tankers (2.3 million DWT) were on order for the domestic trade, of which 12 (2.0 million DWT) were over 100,000 DWT. Two tankers (totaling 259,900 DWT) were rebuilt under the Wrecked Vessel Act in 1981 and 1983 respectively. Five VLCCs repaid their CDS from 1977 to 1986

[5] It should be noted, however, that in some years, the full-time equivalent of three VLCCs operated in the ANS trade under six month waivers pursuant to 46 CFR Part 250.

(totaling 1.2 million DWT). One new EXXON tanker was delivered in November 1986 and the second in April 1987 (those two vessels total 418,000 DWT). Both are currently operating in the domestic trade. No other U.S. tankers are currently under construction.

With the opening of the Alaskan pipeline in 1977, there has been a recurring shortage of suitable tankers in the ANS oil trade. MARAD has tried to alleviate this shortage in several ways. First, MARAD issued a rule in 1977 allowing CDS tankers over 100,000 DWT to carry ANS crude oil in the domestic trade for six months in a twelve month period in exchange for a *pro rata* repayment of their CDS (46 CFR Part 250). Under that rule ("Part 250 rule") MARAD has approved temporary transfers of CDS-built VLCCs to the Alaska-Panama trade on 37 occasions. Such transfers peaked between 1980 and 1983 when there were approximately three CDS vessels (totaling 750,000 DWT) operating in the trade on a full-time basis.

Permissions for three CDS-built VLCCs—*Arco Independence, Maryland and Williamsburgh*—to operate temporarily in the Alaskan oil trade were terminated on January 12, 1984. Their approval had been conditioned on the acquisition of suitable employment (by January 1984 when they would become available) of four over 100,000 DWT Jones Act vessels—*Overseas Boston, Overseas Juneau, Ogden Columbia,* and *Prince William Sound.* When the latter two were not chartered, the conditional approvals were terminated in accordance with the order of October 7, 1983. No CDS-built VLCCs entered the ANS trade after that until the *Maryland* on November 15, 1984. Two additional VLCCs were granted waivers in January 1985 and January 1986. In addition, a CDS-built 90,000 DWT tanker (the *Beaver State*) made two voyages in the Valdez to West Coast trade under a section 506 waiver in March 1986.

From 1977 to the last approved transfer on November 1, 1985, eight CDS VLCCs operated under six month waivers at various times in the ANS trade. Of those eight, four are the subject of this rulemaking.

The other four CDS-built vessels are the *Maryland, Massachusetts,* and *New York* (each 264,100 DWT), and the *Williamsburgh* (225,100). None of those vessels has applied to enter the ANS trade under Part 250 since November 1985. (The *New York* applied in November 1985 and operated until July 1986). At present, those four are in lay-up.

While the Part 250 rule alleviated the shortage of tankers to a large extent, it did not totally solve the problem. To alleviate the shortage, MARAD began accepting total repayment of CDS in exchange for domestic trading privileges. Since 1977, five vessels have totally repaid their CDS. The first was the VLCC *Stuyvesant* (224,700 DWT), which was allowed to enter the domestic trade in August 1977.

The second was the *Bay Ridge* (225,000 DWT) which repaid its CDS in November 1980, after entering the trade for six months under a Part 250 temporary waiver in 1979. The other three VLCCs repaid their CDS pursuant to the most recent rule, and are still operating in the domestic trade. The four VLCCs in the trade that are the subject of this rulemaking total 976,000 DWT. They represent approximately 43 percent of the capacity operating in the Valdez-Panama trade.

Employment prospects for the four VLCCs in the ANS trade appear to be positive at least for the near future. It is with this near future in mind that these vessels repaid their CDS. Domestic trading restrictions for CDS-built vessels are lifted at the end of their statutory life (i.e., 20 years). The *Arco Independence* and *Arco Spirit* were built in 1977, the Brooklyn in 1973, and the *Bay Ridge* in 1979.[6] Since no new tankers are on order, and prospects for new buildings seem unlikely, these four VLCCs would be among the most suitable vessels for the Alaska-Panama trade. If the four VLCCs remain in the domestic trade, there would be an adequate supply of suitable tonnage to carry oil in that trade even if other older tankers are scrapped and if no new tankers are built.

If the four VLCCs were removed from the domestic trade, a shortage of the most suitable tonnage in the Alaska-Panama trade would occur, necessitating the entrance of smaller, less suitable tankers in that trade, and would also kikely result in those VLCCs being laid up, since they are unable to compete in the foreign trade (see Section II of this proposed rule).

In conclusion, as far as can reliably be foreseen, the continued employment in the Alaskan oil trade of the four VLCCs that repaid CDS would benefit the U.S. domestic waterborne commerce by providing vessels that are most suitable for the Alaska-Panama oil trade and by providing an employed well-balanced merchant marine. The following other benefits would flow: The Treasury would retain the CDS repaid amount ($142 million), the shipping public would receive transportation savings (estimated $664–674 million) and the State of Alaska would earn revenues from reduced tanker rates (estimated $186–189 million). It is not clear that there would be any negative impact on the domestic fleet by allowing such repayment. It is recognized that 12 tankers were in lay-up in February and with their lay-up, the seamen to operate them were unemployed. This is only six percent of the total U.S.-flag domestic tanker fleet and provides a needed reserve for peak demand.

E. Safety of the VLCCs.

Allowing the four VLCCs to remain in the domestic trade would also further the goal of section 101 of the Act to encourage the development of a fleet composed of the "safest" vessels. As is shown in the Environmental Assessment prepared for this proposed rule, these VLCCs are among the safest tankers, in terms of environmental risks. The change in oil spills risk for the ANS fleet is expected to continue to improve as more VLCCs and other large tankers replace, where permitted by navigation channel depths, smaller tankers. If the four VLCCs were not allowed to remain in the domestic trade, a tonnage shortfall could cause a greater oil spill risk if additional small vessels such as barges were to be employed to compensate for the shortfall.

II. The Foreign Trade

One of the goals of the Act is to encourage the development and maintenance of a merchant marine sufficient to carry "a substantial portion of the waterborne export and import foreign commerce of the United States . . ." 46 U.S.C. 1101(a). The Court of Appeals criticized the previous CDS repayment rule for its "dubious proposition that the fleet will remain able to carry 'a substantial portion' of foreign commerce . . ." *ITOC* V. *Dole,* slip op. at 11.

The Court noted in a footnote to its decision overturning the prior CDS rule:

> It may be, of course, that present conditions in the world shipping market make it impossible for the Secretary to find a way to meet all of the statutory objectives. If this is a problem, she should discuss it frankly and directly when she considers which measures to adopt in light of the objectives explicitly set out in the Act. *Id.* at 13–14, n. 4.

While this proposed rulemaking would provide a domestic tanker fleet that is (1) sufficient to carry the domestic waterborne commerce of the

[6] Even without the present rulemaking, these vessels would be allowed to enter the domestic trade at the end of their 20 year useful life. Thus, the effects of this rulemaking would expire in the mid to late 1990s.

United States and (2) composed of the "best equipped, safest, and most suitable types of vessels," MARAD acknowledges that it would have no effect on the U.S.-flag share of the water-borne export and import bulk foreign commerce of the United States.

The U.S.-flag foreign trade tanker fleet currently consists of 26 CDS-built tankers totaling three million deadweight tons, including six VLCCs and two ULCCs. (This excludes the four VLCCs that are the subject of this rulemaking and three CDS-built integrated tug-barges, but includes two CDS-built ore-bulk-oil carriers built with CDS.) This tonnage is insufficient to carry a substantial portion of the bulk foreign commerce. The six CDS-built VLCCs and two ULCCs (ultra large crude carriers) are currently laid up. Only one of the CDS-built tankers under 100,000 DWT is laid up. Seven of the tankers are employed in the foreign trade, while the remaining 12 tankers are employed under charter to the Military Sealift Command (6) or are employed in the preference trades (6) carrying Strategic Petroleum Reserve oil.

While the intent of MARAD's CDS and ODS programs was to provide a basis for a U.S.-flag fleet that is sufficient to carry a substantial portion of our bulk import and export trade, the assumptions of those programs were not met for VLCC tankers and most of these tankers built under the 1970 program are not competitive in the international market, as evidenced by the lay-ups. Moreover, even with the benefit of CDS, the capital costs of CDS-built VLCCs exceeds those of comparable foreign-built tankers. In addition, even the provision for full ODS could not offset the cost disadvantages of operating U.S.-flag tankers in the foreign trades, let alone address the capital cost disadvantages faced by these carriers.

The United States currently imports approximately 6.0 million barrels per day of crude oil and refined product, of which only three percent is carried on U.S.-flag tankers. Furthermore, a substantial portion of our crude oil imports—approximately 45 percent—are received from nearby sources including Canada, Mexico, Venezuela and the Caribbean region. The *CDS*-built VLCCs are unsuitable for these nearby import trades. (The CDS-built VLCCs are more suitable for long-haul voyages; see section 1 above). Approximately 32 percent of U.S. crude oil imports are received from the distant Arabian Gulf and North Sea regions for which VLCCs would be suitable. In contrast, ten years ago U.S. crude oil and refined product imports averaged 8.8 million barrels per day. Only 14 percent of our crude oil imports were received from nearby sources while over 40 percent of our oil imports were received from the Arabian Gulf and North Sea regions.

During the last year, there has been an increase in oil exports from the Arabian Gulf region and a corresponding rise in demand for VLCCs in the international trade. Despite this increase it is unlikely that the U.S.-flag share of U.S. oil imports would increase, due to an oversupply of tonnage in the world tanker fleet.

As of January 1987, the world fleet contained over 235 million deadweight tons, of which approximately 200 million deadweight tons (85 percent) were actively employed. The remaining 35 million deadweight tons (15 percent) were idle; however, 30 million deadweight tons were in the over 200,000 DWT size class. The amount of idle capacity in the over 200,000 DWT size class represents more than 26 percent of the available tonnage in that class. Therefore, given the relative higher operating costs for U.S.-flag tankers and the amount of idle tonnage over 200,000 DWT in the world fleet, it is very likely that the four VLCCs that are the subject of this rulemaking would be laid up if they are required to leave the domestic trade, with loss of jobs to Jones Act seamen, or possibly scrapped.

In fact, of the nine VLCCs and two ULCCs built with CDS under the 1970 program, none has had any significant employment in the foreign commercial trades, other than occasional shipments of oil to the Strategic Petroleum Reserve, which are reserved to U.S.-flag carriage. The *Bay Ridge*, which repaid its CDS in 1980, has been operating actively in the domestic trade since 1980. The other three VLCCs have been operating in the domestic trade regularly under six month waivers under Part 250 (a total of 17 times since 1978). Thus, the deployment of these four VLCCs to the domestic trade would have no impact on U.S.-flag tanker presence in foreign trades. Finally, should world market conditions even reach the point where U.S.-flag VLCCs could be employed in the U.S. foreign or foreign-to-foreign trades, VLCCs that have continued to be active in the domestic trade would be much more readily available to the foreign fleet than vessels that are laid up and wasting or scrapped.

III. The Naval Auxiliary

One of the objectives of the Act is to foster the development of a merchant marine fleet "capable of serving as a naval and military auxiliary in time of war or national emergency. . . ." 46 U.S.C. 1101(b).

In its comments on the prior CDS rule, the Defense Department expressed concern over the security implications of losing militarily-useful (i.e., product) tankers as a result of CDS repayment. MARAD has considered the effect on the naval auxiliary of allowing the four VLCCs to remain in the domestic trade (see Regulatory Impact Analysis). Market conditions and statutory requirements have contributed to a reduction in the number of U.S.-flag product tankers, including a declining upcoast (U.S. Gulf/East Coast) petroleum trade (the principal market for U.S.-flag product tankers), the opening of the Trans-Panama Pipeline in 1982, and the anti-pollution standards of the Port and Tanker Safety Act (PTSA).

As a result of these factors, over a three year period for 1984 to 1986, 41 tankers, of the type considered highly military useful, were scrapped (see Regulatory impact Analysis, Appendix 1). All had exceeded their statutory life of 20 years (see Regulatory Impact Analysis, Appendix 1). The average age of these tankers was 34 years. Further, the 1978 Port and tanker Safety Act (PTSA) set certain anti-pollution requirements for tankers entering United States waters. By January 1, 1986, vessels between 20,000 and 40,000 DWT were required to have certain anti-pollution systems to prevent the discharge of oil-tainted water. To comply with the PTSA requirements, tanker owners had the option of retrofitting existing systems, reducing load lines (so as to carry less than 20,000 DWT), using port reception facilities to dispose of oily water, or scrapping ships. Due to the cost of retrofitting and resulting loss of cargo capacity, and the inherent limitations of reducing load lines or using port reception facilities to discharge oily water, many tanker owners scrapped their older, less efficient vessels. The PTSA served to speed up the natural process of scrapping that occurs when tankers exceed their useful life.

Of these 41 that were scrapped, 25 were scrapped in 1984, nine in 1985, and seven in 1986. The vast majority of those lacked some or all of the anti-pollution features required by the PTSA.

These figures indicate that the scrapping that has occurred in the past three years is not attributable to CDS repayment but rather to the age of the vessels, their inability to economically retrofit to satisfy PTSA requirements and poor market conditions. Since the effective date of the PTSA (January 1, 1986), the number of product tankers scrapped has declined. MARAD believes that this decline will continue, since many older, more inefficient tankers have now been scrapped. In addition, since the enactment of the PTSA, a number of new product tankers have been built.

Further, any effect that the four VLCCs would have on the militarily-useful tankers would be indirect, unlike the above factors. VLCCs and these smaller tankers generally do not compete in the same trades. As discussed above, VLCCs have historically served the Alaskan-Panama trade, and smaller tankers serve the Panama Gulf/East Coast trades. While a mix of vessels serve the West Coast, the four VLCCs have not entered that trade. Thus, any effect the VLCCs may have on the smaller tankers would be through an indirect displacement. That is, the VLCCs, being more cost-effective, may "bump" other large tankers that could serve the Alaska-Panama trade. In turn, these large tankers could operate in the West Coast and Panama/Gulf trade, picking up oil that could have been carried by smaller tankers. A trend in this direction is indicated by Table 111-2 in the Regulatory Impact Analysis. However, such "bumping" effects are much more remote than the effects of the PTSA, the Trans-Panama Pipeline, and declining market conditions, over which MARAD has no control.

Moreover, the current goal of the Navy is to increase the number of tankers in the Ready Reserve Force from eight to twenty by the year FY 1992. Even if there were a direct corrollary to CDS repayment and the 12 tankers laid up in February 1987, the Navy has the opportunity to purchase those vessels for their military usefulness at such time as they became commercially unattractive.

Based solely upon these objectives of section 101 of the Act, the Secretary concludes that the CDS repayment rule proposed herein furthers those objectives. The four VLCCs would increase the most suitable U.S. domestic fleet with minimal Impact on the existing fleet, and they are not expected to have a significant impact on carriage of U.S. foreign commerce, U.S. shipyard construction, or the U.S. Naval auxiliary capacity. Their retention in the Jones Act fleet will also result in $142 to the U.S. Treasury for CDS repayment, transportation savings to the shipping public and increased revenues for the State of Alaska.

IV. Shipyards

One of the objectives of the Act is to encourage the development of a merchant marine fleet "supplemented by efficient facilities for shipbuilding and ship repair." While this proposed rulemaking would not actively promote this goal, it also would not have a significant adverse effect on U.S. shipbuilding. MARAD acknowledges that future shipbuilding prospects with or without this proposed rule do not look positive. Even without CDS repayment, the growth prospects for the domestic petroleum trades are not sufficient to require the construction of additional tanker capacity.

No orders for the construction of unsubsidized tankers over 100,000 DWT were placed between April 1976 and August 1984. On August 27, 1984, EXXON placed an order for construction of two 209,000 DWT tankers in the United States for employment in the ANS trade. Since then, no orders have been placed to build unsubsidized tankers over 100,000 DWT.

Two foreign-flag tankers over 100,000 DWT were rebuilt in the United States for the ANS crude oil trade in 1981 and 1983 under the Wrecked Vessel Act (46 U.S.C. 14). Under this Act, foreign-built vessels that are wrecked off the U.S. coast are eligible to enter the U.S. domestic trade provided the vessel is purchased by a U.S. citizen and rebuilt in the United States at a cost that is at least three times the appraised salvage value.

The first vessel, the Overseas Boston (123,700 DWT), was rebuilt in 1981 and the second vessel, the Ogden Columbia (136,000 DWT), was rebuilt in 1983. Due to the existing capacity in the domestic trade and the predicted growth patterns in the petroleum trade, allowing the four CDS-built VLCCs to remain in the domestic Jones Act fleet permanently will have little effect on the amount of domestic tanker construction.

V. Other Objectives of the Act

While section 101 of the Act establishes the general objectives of the Act, other parts of the Act give more specific guidance on interpretation and implementation of these goals. The Act explicitly and implicitly establishes other policy goals in furtherance of the maintenance and development of the U.S. merchant marine fleet. Among these goals, mentioned in the prior CDS final rule (50 FR 19170), are efficiency and competition. Each of these goals has been recognized by the courts as vaild policies for promoting the U.S. merchant marine fleet.

A. Efficiency

The goal of efficiency of the fleet is mentioned throughout the Act. Among the express goals of section 101 is that the merchant marine shall be composed of "suitable" vessels manned by "efficient" crews. Certainly, the idea of "suitable" vessels should encompass efficiency as a principal component.

The goal of efficiency is particularly important in the CDS program, which is designed to produce vessels of "high transport capability and productivity." Merchant Marine Act, 1936, as amended, section 501 (46 U.S.C. App. 1151). Other provisions in the Act are intended to promote fleet modernization. Under section 213, the Secretary is required to report to Congress annually on the scrapping of old vessels, and the relative cost of ship construction and reconditioning in U.S. shipyards. The capital construction reserve fund was established in section 511 to promote construction or acquisition of new vessels. The Secretary's authority to acquire obsolete vessels for an allowance of credit under section 510(b) is intended "to promote construction of new, safe, and efficient vessels to carry the domestic and foreign waterborne commerce of the United States. . . ."

While the Act appears to clearly promote the policy of efficiency, the Department of Transportation authorization statute further declares it to be an overriding purpose that national transportation policies and programs be "conducive to the provision of fast, safe, efficient, and convenient transportation at the lowest cost consistent there with. . . ." 49 U.S.C. 1101. Any ambiguity in the Merchant Marine Act regarding the goal of promotion of efficiency is resolved in favor of that goal through the purposes and policies established in the Department's statute.

In addition to these explicit statutory provisions promoting efficiency of the U.S. merchant marine fleet, several recent court decisions have affirmed that one objective of the Act is to encourage modernization and efficiency. For example, the Supreme Court's decision confirming the Secretary's statutory authority to grant permanent release to vessels under *CDS* restrictions found that a basic goal of the Act was to encourage the maintenance of an "effective merchant marine" with a "fleet [that] was to be modern and efficient." *Seatrain Shipbuilding Corp.* v. *Shell Oil Co.*, 444 U.S. 572, 584 (1980). Further, the DC Circuit recently described the first goal of the Act as promoting "a well-equipped and efficient merchant fleet." *American Trading Transportation Co.* v. *United States*, 791 F.2d 942, 944 (D.C. Cir. 1986); *see also Sea-Land* v. *Dole*, 723 F.2d 975, 976 (D.C. Cir. 1983).

The above statutory provisions and judicial interpretations strongly support the goal of promoting efficiency and modernization of the U.S. merchant marine fleet. These goals would be furthered by this proposed rulemaking, which will allow the four VLCCs, which are among the most efficient U.S. tankers in the fleet, to remain active in the domestic trade.

B. Competition

While the Act does not explicitly list competition as one of its goals, the promotion of competition in the foreign and domestic trades is implicit in the Act. The Act's ODS and CDS programs are intended to give the U.S. merchant marine fleet certain financial resources to compete with lower-cost foreign fleets while not guaranteeing any profit. In particular, Congress made this objective clear in enacting the Merchant Marine Act of 1970, which extended those programs to the unregulated bulk trades. *See* Merchant Marine Act, 1936, 603(b) 46 U.S.C. 1173(b); H. Rep. No. 1073, 91st Cong., 1st. Sess., 38 (1969). The Jones Act trade does not receive such financial assistance, but is insulated from foreign competition by the Act's bifurcation of the foreign and domestic trades. That is, the Act restricts competition in the Jones Act trade only to the extent necessary to protect unsubsidized U.S. operators from the benefits of the Act's financial assistance programs (such as ODS and CDS) which assist the U.S. foreign trade vessels in competing against low-cost foreign-flag competition. In the domestic trade, the Secretary has a duty "to minimize interference with the free market forces normally at work. . . ." *ITOC* v. *Lewis, supra*, 690 F.2d at 917.

In its seminal case on the relation between the foreign and domestic trades, the DC Circuit stated that "competition is not 'unfair' within the meaning of the Act when it does not involve diversion of money to unsubsidized domestic operations from subsidized foreign operations, to the disadvantage of an unsubsidized operator. Congress plainly did not intend to prevent that sort of competition." *Pacific Far East Line, Inc.* v. *Federal Maritime Board*, 275 F.2d 184, 186 (D.C. Cir. 1960). Other courts have likewise recognized the overriding public policy in favor of competition in the domestic trade and in national transportation policy. *See e.g., Matson Navigation Co.*, v. *Connor*, 258 F. Supp. 144, 158 (N.D.Cal. 1966), *aff'd per curiam*, 394 F.2d 514 (9th Cir. 1968); *Bowman Transportation, Inc.*, v. *Arkansas-Best Freight System, Inc.*, 419 U.S. 281, 198–99 (1974).

Finally, the Supreme Court made clear its preference for fair competition (as opposed to regulated entry under six month permissions) in its decision confirming the Secretary's authority to accept permanent repayment in *Seatrain Shipbuilding Corp.* v. *Shell Oil Co.* 444 U.S. 572, 589–90 (1980):

> Section 506 . . . permit[s] a vessel that enjoys the benefits of CDS to operate outside the foreign market only in narrow circumstances, generally upon a highly discretionary administrative decision, and no more than six months a year. And we have no doubt that it would be flatly inconsistent with one congressional intent were the Secretary or this court to conclude that a temporary release not meeting these conditions was proper. But a permanent release upon full repayment is quite different. It irrevocably locates the vessel in the unsubsidized fleet and, thus, poses no danger of a supercompetitor skimming the cream from each market. It creates no long-term instability. And it confers no windfall. On the contrary, at least where repayment of the CDS includes some amount reflecting capital costs which would have been incurred had no subsidy been available, such a transaction merely permits a once subsidized vessel to enter the domestic trade on a footing equal to that of vessels already in that trade. It was not the purpose of the Act to prohibit such entry. . . .

Thus, to the extent that the capacity allowed to enter the domestic trade under CDS repayment would have been allowed to participate in the trade under six month permissions, allowing total CDS repayment therefore would necessarily be consistent with the "purpose of the Act" *Id.*

In fact, where the Secretary issued the *NPRM* on total CDS repayment in January 1983, the full time equivalent of three CDS built VLCCs had been operating in the trade under six month permissions. Thus, allowing total repayment for three VLCCs under that rulemaking is squarely within the Supreme Court's holding.

VI. Alternatives

MARAD has considered three alternatives in preparing this rulemaking. The first is to maintain the *status quo*, i.e., to allow the four VLCCs to remain in the domestic trade. The costs and benefits of this alternative have been discussed at length in this statement, and in the Regulatory Impact Analysis. Further costs, evaluated in the Regulatory Impact Analysis, include the recent Title XI defaults of three VLCCs that were previously in the domestic trade under six-month waivers, and partial defaults of two other CDS-built VLCCs (*Stuyvesant* and *Bay Ridge*). These costs were not necessarily attributable to CDS repayment and in any event are irreversibly expended at this time (i.e., returning the four VLCCs to the foreign trade would not recover this money). The total default cost to the government has been $137.5 million.

Another relevant consideration is the effect on the existing Jones Act (i.e., domestic) fleet. As of February 19, 1987, twelve Jones Act tankers were laid up (totaling approximately 650,000 DWT). On the other side of the ledger, if CDS repayment is not allowed for the four VLCCs, they are likely to be laid up (approximately 705,000 DWT).

MARAD believes that the suitability of the four VLCCs for the Alaska-Panama trade outweights any possible disadvantages. Of the twelve tankers that are laid up, three tankers (totaling 146,000 DWT) are over 20 years old. The remaining nine tankers include the one tanker (the *Prince William Sound*, 123,400 DWT) and eight smaller tankers that could serve in the *ANS* trade, although at a much higher cost per ton than VLCCs currently operating in that trade (see Regulatory Impact Analysis). For example, the cost of operating a 50,000 DWT tanker in the Valdez-Panama trade is approximately, $25.00 per ton, compared to $9.19 per ton for a 265,000 DWT VLCC operating in the same trade. Further, as noted above, larger tankers are more suitable than smaller tankers from an environmental standpoint because they make fewer voyages and port calls than smaller tankers to carry the same amount of oil, thus reducing the risk of collisions and oil spills (see Environmental Assessment).

A second alternative considered would be for MARAD to do nothing, i.e., to allow the rule to be vacated as of July 16, 1987, and for the three VLCCs to leave the domestic trade, and to consider the *Bay Ridge* separately. The costs of doing nothing would be a shortage of the most suitable tonnage for the Valdez-Panama trade and the likely lay-up of the three VLCCs that repaid CDS under the 1985 rule. Other costs of this alternative would be the loss to the government of CDS repayments of $105.8 million from those three VLCCs, the reduction of Alaska state revenues due to higher transportation costs in later years, and the loss of transportation savings to the shipping public.

The benefits of this alternative could be reduced government loan exposure risk on existing Jones Act tankers and the possibility of some of the laid up domestic tankers operating in the *ANS* trade. However, due to the age and small size of most of those tankers, they would be unsuitable for the Valdez-Panama trade. Further, only six percent of the domestic tanker fleet is laid up. A six percent lay-up is a reasonable reserve for covering temporary losses from the active fleet due to casualties (three in 1986), surveys and repairs, as well as seasonal increases on the upcoast petroleum movements.

Under this second alternative, shipbuilding demand for new crude tankers would still be minimal, if any, due to the high cost of U.S. shipbuilding, the unlikely availability of future CDS funds due to budget constraints, and the predicted future decline in the volume of crude carried in the Alaska-Panama trade.

The third alternative considered would provide for other U.S.-flag tanker owners to repay CDS in return for unrestricted domestic trading privileges. Under this approach, those vessel owners with the best prospects for employment would likely choose to repay within the specified time period. Unrestricted repayment would reduce the need for Federal issuance of temporary permission to enter the ANS trade. Fiscal benefits could also be the greatest under this alternative. However, it is unlikely that any more vessels would repay under this alternative, since only three repaid when the window was open for one year and two EXXON 209,000 DWT Jones Act tankers have recently delivered. This alternative would cause the most disruption to the Jones Act as there would be uncertainty in the market. Shipyard demand for new crude tankers would remain at a minimal or non-existent level.

E.O. 12291, Statutory Requirements and DOT Procedure

The Maritime Administrator has determined that this rule is major under the criteria of Executive Order 12291. Pursuant to the Department of Transportation's Regulatory Policies and Procedures (February 26, 1979), this rule is also considered to be "significant" because it concerns a matter on which there is substantial public interest.

The Maritime Administrator certifies that it would have no significant economic impact on a substantial number of small entities pursuant to the Regulatory Flexibility Act of 1980 (5 U.S.C. 601 *et seq.*) The companies owning and chartering the four VLCCs at issue, and companies owning or chartering tankers possibly affected by the rulemaking in the foreign and domestic trades, are either large oil companies or large independent shipping companies.

A draft Regulatory Impact Analysis has been prepared and is available for public review and copying in the Docket (R-110) in the Office of the Secretary, Maritime Administration (room 7300). It discusses the important economic aspects of this proposed rule.

An Environmental Assessment of the proposed rule has also been prepared, and may be inspected at the Office of the Secretary, Maritime Administration, room 7300. The Environmental Assessment concludes that the effect of the proposed rule would be that greater quantities of ANS oil would be transported in VLCCs than in smaller vessels, fewer total trips would be made by a smaller number of vessels, the risk of accidental oil spill would be reduced as the number of trips decreases. In addition, the tankers which have repaid CDS include a number of safety and environmental features required by statute. Overall, the risk to the environment would be reduced with the proposed rule as compared to without it. On the basis of the environmental assessment, the Maritime Administration has tentatively concluded that the proposed rule would not result in a significant environmental impact to the human environment.

List of Subjects in 46 CFR Part 276

Grant programs—transportation, Maritime carriers, Reporting and recordkeeping requirements.

PART 276—[AMENDED]

It is proposed to amend 46 CFR Part 276 as follows:

1. The authority citation for Part 276 continues to read as follows:

Authority: Secs. 204(b), 207, 506, and 714, Merchant Marine Act, 1936, as amended (46 U.S.C. 1114(b), 1117, 1156 and 1204) Pub. L. 86-518 (74 Stat. 216); Reorganization Plans No. 21 of 1950 (64 Stat. 1273) and No. 7 of 1961 (75 Stat. 840), as amended by Pub. L. 91-469 (84 Stat. 1036); and Dept. of Commerce Organization Order 10-8 (36 FR 19707, July 23, 1973), unless otherwise noted.

2. 46 CFR 276.3 is revised to read as follows:

§ 276.3 Total Repayment

(a) The Maritime Administration reaffirms the allowance of the irreversible total repayment of unamortized construction-differential subsidy (CDS), with interest, and rescission permanently of the domestic trading restrictions related to the grant of CDS for tankers of any deadweight tonnage for applications and approval between June 6, 1985 and June 5, 1986, in accordance with the terms and conditions of subsection (b). The approved applications were for the *Arco Independence, Arco Spirit* and *Brooklyn.*

(b) *Repayment terms.* The full repayment amount consists of the unamortized CDS, as determined by the Maritime Administration, with compounded interest on that amount. The interest rate is the same as the long-term interest rate the owner obtained, or would have obtained if long-term debt financing had been used, in financing the owner's portion of the tanker. Unless the Maritime Administrator determined that using interest rates other than long-term bond rates was justified, such rates are used. If more than one long-term bond was issued to finance the owner's portion of a specific tanker, or if one or more of such bonds has more than one rate (such as a serial bond) an average interest rate is computed weighted by the proportion of each bond par value to the total par value of all long-term bonds issued to finance the owner's tanker. The interest payable on the unamortized CDS is computed by continuous compounding of the interest until the day of repayment. For purposes of this paragraph, "long-term bond rates" are either actual Title XI bond rates on a specific owner's tanker or the Title XI long-term bond rate at the time the tanker's statutory life began.

(c) The Maritime Administration reaffirms the allowance of the irreversible total payment of unamortized construction-differential subsidy with interest and recission permanently of the domestic trading restrictions relating to the grant of CDS for the *Bay Ridge*, which repaid on November 1980.

Dated: April 10, 1987.

By Order of the Maritime Administrator.

James E. Saari,

Secretary, Maritime Administration.

[FR Doc. 87-8472 Filed 4-14-87; 8:45 am]

BILLING CODE 4910-81-M

FEDERAL MARITIME COMMISSION

46 CFR Part 502

[Docket No. 87-7]

Implementation of the Equal Access to Justice Act in Commission Proceedings

AGENCY: Federal Maritime Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Maritime Commission proposes to adopt rules implementing the Equal Access to Justice Act, as revised, for its formal adjudicatory proceedings. These rules will provide for the award of attorney fees and other expenses to parties who

Alaska State Legislature

REPRESENTATIVE
PAT POURCHOT

HOUSE FINANCE COMMITTEE,
VICE CHAIR

HOUSE ETHICS COMMITTEE, CHAIR

LEGISLATIVE BUDGET & AUDIT
COMMITTEE

House of Representatives

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May 7, 1987

The Honorable Frank Murkowski
United States Senate
720 Hart Building
Washington, D.C. 20510

Dear ~~Senator~~ Frank:

On Thursday, May 7, 1987, the Alaska Legislature unanimously approved House Joint Resolution 33, which we sponsored, urging the Secretary of Transportation to adopt new rules to permit continued shipment of Alaskan oil by four large tankers. Although you will be receiving a copy of this resolution from the Lieutenant Governor's office shortly, we are forwarding a copy for your early review and use.

As you know, on January 16, 1987, the U.S. Court of Appeals decision (First Attransco Tanker Corp. vs. Dole) vacated a Department of Transportation ruling. The DOT ruling permitted three very large crude carrier ships to repay the remainder of their construction subsidies in 1985-86. In doing so, they became Jones Act ships rather than just U.S. flag ships.

The Court ruled that the Secretary of Transportation was well within her authority to permit this repayment. However, the Court also ruled there were procedural defects in that she did not adequately explain the effect of this action on other Jones Act ships. Thus the ruling was unjustified. The decision requires all three ships to cease Alaskan service on July 16, 1987, unless the Department of Transportation explains the effect other Jones Act ships to the Court's satisfaction. A fourth ship which entered Jones Act trade under generally similar circumstances is also vulnerable to the ruling.

In total these four ships are currently moving 200,000 barrels of Alaskan oil to market every day. If they are taken out of the fleet, then a large number of much smaller, less efficient and more expensive ships must take their place if the Alaskan oil is to get to market.

Page two

This issue is significant to the State of Alaska as well as the oil industry. The financial effect on the State of Alaska in reduced royalties and severance taxes due to the increased transportation costs is estimated to be between $18,000,000 and $150,000,000 annually if new rules are not adopted.

We hope that this resolution will help you in your efforts to expedite the needed actions by the U.S. Department of Transportation. Thank you.

Sincerely,

Pat

Representative Pat Pourchot

Bettye Fahrenkamp

Senator Bettye Fahrenkamp

enclosure

Alaska State Legislature

REPRESENTATIVE
PAT POURCHOT

HOUSE FINANCE COMMITTEE, VICE CHAIR

HOUSE ETHICS COMMITTEE, CHAIR

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May 7, 1987

The Honorable Elizabeth H. Dole
U.S. Department of Transportation
400 7th Street, SW, Room 10200
Washington, D.C. 20590

Dear Madam Secretary:

On Thursday, May 7, 1987, the Alaska Legislature unanimously approved House Joint Resolution 33, which we sponsored, urging you to adopt new rules to permit continued shipment of Alaskan oil by four large tankers.

Although you will be receiving a copy of this Resolution from the Alaska Lieutenant Governor's office shortly, we are forwarding a copy for your review and use. Specifically, we are requesting that the Resolution be included in the record on the Department of Transportation's proposed rulemaking for Construction-Differential Subsidy Repayment.

As you know, this issue is significant to the State of Alaska as well as the oil industry. The financial effect on the State of Alaska in reduced royalties and severance taxes due to the increased transportation costs is estimated to be between $18,000,000 and $150,000,000 annually if new rules are not adopted.

We appreciate your efforts on this matter. Thank you.

Sincerely,

Pat Pourchot　　Bettye Fahrenkamp

Representative Pat Pourchot　　Senator Bettye Fahrenkamp

enclosure

Alaska State Legislature

REPRESENTATIVE
PAT POURCHOT

HOUSE FINANCE COMMITTEE,
VICE CHAIR

HOUSE ETHICS COMMITTEE, CHAIR

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MEMORANDUM

DATE: May 7, 1987

TO: Members of the Senate

FROM: Rep. Pat Pourchot Pat

SUBJECT: HJR 33 - Relating to the Shipping of Oil

House Joint Resolution 33, relating to the shipping of Alaska oil, is scheduled for consideration in the Senate.

This resolution urges the Secretary of the United States Department of Transportation to adopt before July 16, 1987, a rule that would enable four very large crude oil carrier ships to continue to operate in the United States domestic shipping market without interruption.

Attached is a brief background and summary of the reason for this resolution. It is important that we act expeditiously on the resolution because if the U.S. Department of Transportation fails to adopt a rule by July 16, 1987, the transportation of Alaska oil may be disrupted. In addition, the transportation costs will increase substantially, and the state government could stand to lose a significant amount of money.

I appreciate your consideration on this resolution. Thank you.

HOUSE JOINT RESOLUTION 33

HISTORY

On January 16, 1987, the U.S. Court of Appeals decision (First Attransco Tanker Corp. vs. Dole) vacated a Department of Transportation ruling. The DOT ruling permitted three very large crude carrier ships to repay the remainder of their construction subsidies in 1985/6. In doing so, they became Jones Act ships rather than just U.S. flag ships.

The Court ruled that the Secretary of Transportation was well within her authority to permit this repayment. However, the Court also ruled there were procedural defects in that she did not adequately explain the effect of this action on other Jones Act ships. Thus the ruling was unjustified. The decision requires all three ships to cease Alaskan service on July 16, 1987, unless the Department of Transportation explains the effect on other Jones Act ships to the Court's satisfaction.

Prior to repaying the subsidy, these three large, efficient U.S. flag ships were not allowed to carry Alaskan oil unless there were no suitable Jones Act ships available. Even under those circumstances these ships could only be used part time (no more than six months out of the year). A fourth ship which entered Jones Act trade under generally similar circumstances in 1983 is also vulnerable to the ruling.

In total these four ships are currently moving 200,000 barrels of Alaskan oil to market every day. If they are taken out of the fleet, then a large number of much smaller, less efficient and more expensive ships must take their place if the Alaskan oil is to get to market. This would raise the market price for all Jones shipping by an estimated 25 cents to $1.00 per barrel.

An increase in the cost of transportation not only reduces oil company income and incentive in Alaska but also reduces the netback value of all Alaskan production. For example, each 50 cent increase in per barrel transportation cost would reduce state income by roughly $75 million per year.

Given this situation, Alaska should support the DOT's intention to issue a new rule confirming that these vessels should remain Jones Act vessels as soon as possible because of the July 16, 1987 deadline.

Attached is further information regarding this "Repayment of Construction Differential Subsidies (CDS)".

Repayment of Construction Differential Subsidies (CDS)
(also called "CDS Sanitization")

DISCUSSION ISSUES:

The following information should be noted in discussion of CDS Sanitization:

3

- This is a significant economic issue for Alaska. Removal of the four large efficient ships will require using nearly all the smaller ships available, driving the market price for all shipping up by $.25 to $1 per barrel. Netback values on the crude oil will decline accordingly. Each $.50 per barrel reduction in netback represents roughly $75 MM per year in lost state revenues.

- Alaskan oil production has increased significantly in the last year, highlighting the need for efficient transportation. The Lisburne field (40-50 MBD) began commercial production in early 1986, Prudhoe Bay production increased with natural gas liquid (NGL) recovery in early 1987 (50 MBD). Kuparuk has reached peak production, and Endicott field is expected to begin production in the fourth quarter of 1987 (up to 100 MBD).

- Largely because of the increased Alaskan production the four large, efficient VLCC vessels in question have been in continuous service since repayment of their remaining subsidy: the BROOKLYN and the BAYRIDGE under charter to EXXON, and the ARCO INDEPENDENCE and the ARCO SPIRIT under long term charter to Standard Oil.

- Larger vessels make the transport of crude oil to the West Coast and Gulf Coast more economically efficient than smaller vessels. This is especially true to the Gulf Coast, which accounts for a substantial portion of the Alaskan oil delivered.

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United States Senate
COMMITTEE ON APPROPRIATIONS
WASHINGTON, DC 20510-6025

June 15, 1987

The Honorable Bettye Fahrenkamp
515 7th Street, Suite 130
Fairbanks, Alaska 99701

Dear Bettye:

Thank you for your letter regarding the Construction Differential Subsidy (CDS) payback rule.

As you know, a recent court decision required the Secretary of Transportation to reconsider the rule. In the interim period, Congressman Carr succeeded in attaching an amendment to the House Supplemental Appropriations bill which would prohibit the Arco vessels from continuing to operate in the domestic tanker trade.

We managed to defeat that amendment in the Senate. It will be considered shortly in conference, but I am hopeful that the amendment will ultimately be stripped from the bill.

With best wishes,

Cordially,

TED STEVENS

JUN 22 1987

HJR 33

M E M O R A N D U M

TO: Members, Senate Special Committee on Oil and Gas

FROM: Committee Staff

RE: Committee Meeting, May 5, 1987

DATE: May 4, 1987

On Tuesday, May 5, at 3:30 pm in the Beltz Room, the Senate Special Committee on Oil and Gas will hear SJR 43, Relating to the shipping of Alaskan oil.

Four of the supertankers currently used to transport oil from Valdez to the West coast and to Panama (for delivery to the Gulf and East coasts) are allowed to operate under a special waiver from the U.S. Department of Transportation. A recent U.S. Court of Appeals decision held that these rules were improperly drafted, but allowed the ships to operate until July 16, 1987. If new rules are not adopted by that date, these ships will have to be replaced with smaller, less effficient vessels. The resulting increase in the transportation costs for Alaska North Slope oil will decrease wellhead values and could result in a loss of revenue to the state of from $18 - $150 million annually.

These ships were built with federal construction differential subsidies (CDS), a program designed to help U.S. built ships to compete in foreign trade markets. To alleviate the shortage of suitable Jones Act tankers, the U.S. Department of Transportation has allowed these ships to enter the domestic trade after repaying the subsidy.

In response to the court decisions, the U.S. Department of Transportation is in the process of adopting new rules that would allow the four ships to remain in the domestic trade. However, pending amendments in Congress may prohibit such new rulemaking.

HJR 33 ~~SJR 43~~ urges the Secretary of the U.S. Department of Transportation to adopt new rules by July 16, 1987.

May 5, 1987

SJR 43, RELATING TO THE SHIPPING OF ALASKAN OIL

1) Review CDS Tanker issue

Four supertankers have been allowed to operate in the domestic trade on the condition that they repay their Construction Differential Subsidies (CDS)

In January, the U.S. District Court of Appeals vacated this rule, but allowed the ships to operate until July 16, 1987.

2) Update on U.S Department of Transportation Action

Maritime Administration has filed a Notice of Proposed Rulemaking on the CDS Repayment.

3) Update on Congressional Action

House Supplemental Appropriations Bill has language that would prevent U.S. Department of Transportation from adopting new rules.

Senate amendment was defeated last week by a 14-11 vote in the Senate Appropriations Committee. Could be reinserted on the Senate floor. It may be on the floor by the end of this week.

If its out of the Senate bill, it will be a conferenceable item.

TO TESTIFY:

JIM PALMER, Standard Alaska Production Company

VINCE WRIGHT, Chief of Research Section, Department of Revenue

NOTICE: This opinion is subject to formal correction before publication in the Pacific Reporter. Readers are requested to bring typographical or other formal errors to the attention of the Clerk of the Appellate Courts, 303 K Street, Anchorage, Alaska 99501, in order that corrections may be made prior to permanent publication.

THE SUPREME COURT OF THE STATE OF ALASKA

STATE OF ALASKA, WILLIAM SHEFFIELD, Governor of the State of Alaska, MARSHALL LIND, Commissioner of Education, ELEANOR ANDREWS, Commissioner of Administration, EMIL NOTTI, Commissioner of Community & Regional Affairs, LOREN LOUNSBURY, Commissioner of Commerce & Economic Development, MILTON BARKER, Acting Commissioner of Revenue, all in their official capacities,	
Appellants, Cross-Appellees,	Nos. S-2122/2141
v.	OPINION
FAIRBANKS NORTH STAR BOROUGH and FAIRBANKS NORTH STAR BOROUGH SCHOOL DISTRICT,	
Appellee, Cross-Appellants.	[No. 3180 - May 6, 1987]

Appeal from the Superior Court of the State of Alaska, Fourth Judicial District, Fairbanks, James Blair, Judge.

Appearances: Robert M. Maynard, Assistant Attorney General, Grace Berg Schaible, Attorney General, Juneau, for Appellants/Cross-Appellees. Mark Andrews, Assistant Borough Attorney, Gordon W. Duval, Staff Attorney, Paul H. Cragan, Borough Attorney, Fairbanks, for Appellee/Cross-Appellants.

Before: Burke, Matthews, Compton, and Moore, Justices. (Rabinowitz, Chief Justice, not participating).

PER CURIAM.

The judgment is affirmed on the opinion of the superior court, except as noted hereafter. The traditional rule that judicial decisions should apply retroactively governs this case as the resolution of the issue presented was foreshadowed by prior opinions of the state attorney general, there has been no irremediable reliance on the statute in question, and inequity would result if only the appellees were to receive the benefit of this ruling. <u>See</u> <u>Commercial Fisheries Entry Commission v. Byayuk</u>, 684 P.2d 114, 117 (Alaska 1984).

Accordingly, we remand this case to the superior court with instructions to modify its judgment to allow for total retroactivity.

AFFIRMED on the merits, REMANDED as to effect.

Each party is to bear its own costs and attorney fees in the Supreme Court in this matter.

J- STR 43

CDS Tankers —

Appeals court — new rules —
have been issued — are in effect.

→ new action says new rulemaking is flawed

→ congress —

CARR amendment
prevent DOT —

passed in supplemental
went back in conference

works prospectively

President stated in signing

591's dealt w/ CDS

1) prospective
2) unconstitutional to deny MARAD
authority to defend rules

for new tankers CARR amendment
would apply

original case going to Supreme Court

probably not be heard.

ARCO - petrofina appealing.

Carr introduced again in FY88

in Senate, subcommittee has not met yet.
Hollings chairman may introduce language
traditional ally of maritime
try for more restrictive language.
Barbara McCulskey

5 ships —

1 allowed Supreme court [Seatrain
1 seatrain — DOT ships affected by court.

of legis
recess Aug 7 - Sept 9

HB
58

<u>Senate Special Committee on Oil and Gas</u>

Legislation Checklist

Bill number: CS HB 58(Fin) am Sponsor: L B&A

Date referred to committee: Further referrals: SA

Prior committee report: Finance

Back up from sponsor:

Fiscal note(s): w/ House bill

Agency: (H) Fin Requested: Received:

Agency: Requested: Received:

Position paper(s):

Agency: Requested: Received:

Agency: Requested: Received:

Sectional Analysis:

Scheduled: Heard: Reported out:

Items for committee packet:

To Testify:

Other Contacts:

Offered: 3/6/87
Referred: Rules

5-0321L

Original sponsor: Rules/Legislative
Budget and Audit

IN THE HOUSE BY THE FINANCE COMMITTEE

CS FOR HOUSE BILL NO. 58 (Finance) am

IN THE LEGISLATURE OF THE STATE OF ALASKA

FIFTEENTH LEGISLATURE - FIRST SESSION

A BILL

For an Act entitled: "An Act relating to confidential tax information; relating to the filing of tax returns; and providing for an effective date."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

* Section 1. LEGISLATIVE FINDINGS AND PURPOSE. (a) The legislature finds that

(1) the majority of the state's revenue is derived from taxation;

(2) tax revenue enables the state to provide essential services to the citizens of the state to ensure the public health and welfare;

(3) the elected representatives of the people of the state must be assured that the state is receiving all of the income to which it is entitled and that the tax laws are operating in the manner intended by the legislature;

(4) the legislature must exercise its oversight authority to ensure that tax revenue collection by the Department of Revenue is efficient, fair, prompt, and in the best interest of the state;

(5) there is a legitimate and compelling governmental interest in the legislature having adequate access to tax-related information to allow responsible oversight;

(6) without sufficient information, the legislature cannot adequately determine that the state's tax revenue collection functions are properly administered and that tax revenue due the state is promptly received;

(7) tax returns and return information contain confidential information, often regarding sensitive business information;

(8) taxpayers have protections against public disclosure of certain tax information;

(9) exchange agreements with the Internal Revenue Service require that certain tax information not be publicly disclosed;

(10) protection of confidentiality fosters full disclosure by taxpayers to taxing authorities and therefore promotes effective administration of tax programs; and

(11) legislators and legislative employees who improperly disclose confidential tax information should be subject to the same sanctions imposed against executive branch employees.

(b) The purpose of this Act is to ensure that

(1) the state is receiving all the tax revenue due the state;

(2) oversight of the tax revenue collection function is effectively provided;

(3) tax revenue due to the state is available to provide for the public health and welfare of the citizens of the state;

(4) taxpayers are protected from improper disclosure of tax information;

(5) the exchange agreements with the Internal Revenue Service regarding tax information are not jeopardized;

(6) tax programs are administered fairly; and

(7) the right of the people to privacy is recognized and may not be infringed.

* Sec. 2. AS 24.10 is amended by adding a new section to article 2 to read:

Sec. 24.10.070. CONFIDENTIALITY OF INFORMATION. A present or former employee or agent of the legislature may not disclose tax

information contained in a report or return filed under AS 43.05.230 and furnished to the person under AS 43.05.232.

* Sec. 3. AS 24.60.060 is amended by adding a new subsection to read:

(b) A person to whom this chapter applies may not disclose tax information contained in a report or a return filed under AS 43 and furnished to the person under AS 43.05.232.

* Sec. 4. AS 24.60 is amended by adding a new section to read:

Sec. 24.60.172. SPECIAL PROCEEDINGS BEFORE THE COMMITTEE. Notwithstanding AS 24.60.170, if a complaint before the committee involves an allegation that a person to whom this chapter applies has disclosed tax information contained in a report or return filed under AS 43 with the Department of Revenue and furnished to the person under AS 43.05.232, and if the taxpayer or a third party whose tax information is alleged to have been improperly disclosed does not agree to the public disclosure of the identity of the taxpayer, the third party, or the tax information,

(1) the hearing may not be held in open session;

(2) a transcript containing confidential tax information shall be edited to prevent the disclosure of the confidential information;

(3) a decision, if made public, shall be edited to prevent the disclosure of the tax information and to protect the identity of the taxpayer or the third party; and

(4) a public statement may not contain information identifying the taxpayer, a third party, or the tax information.

* Sec. 5. AS 43.05.230(a) is amended to read:

(a) It is unlawful for a current or former officer, employee, or agent of the state to divulge the amount of income or the particulars set out or disclosed in a report or return made under this title,

except

(1) in connection with official investigations or proceedings of the department, whether judicial or administrative, involving taxes due under this title;

(2) in connection with official investigations or proceedings of the child support enforcement agency, whether judicial or administrative, involving child support obligations imposed or imposable under AS 25 or AS 47;

(3) as provided in AS 38.05.036 pertaining to audit functions; and

(4) as otherwise provided in this section <u>or in AS 43.05.232</u>.

* Sec. 6. AS 43.05.230(f) is repealed and reenacted to read:

(f) A person who knowingly violates a provision of this section is guilty of a class A misdemeanor. A person whose gross negligence results in a violation of this section is subject to a civil penalty of $5,000.

* Sec. 7. AS 43.05 is amended by adding a new section to read:

Sec. 43.05.232. DISCLOSURE OF CONFIDENTIAL TAX RETURNS AND RETURN INFORMATION TO THE LEGISLATURE. (a) Confidential tax returns and return information may not be requested by a legislative committee under (b) of this section or transferred to a legislative committee under (c) of this section,

(1) unless the purpose of the committee's request under (b) of this section or of the transfer under (c) of this section is

(A) to assist the committee in carrying out its responsibilities to consider tax legislation;

(B) to oversee the effective and efficient administration of the state's tax laws, including the review of audits,

litigation, or settlements; or

(C) to estimate future state revenue;

(2) if the purpose of the request or transfer is to direct the executive branch in its audit, litigation, or settlement efforts, or to collect information to embarrass, harass, or discriminate against a taxpayer.

(b) After a legislative committee identifies the scope of an investigation or inquiry relating to matters of taxation, and after adoption by either house of the legislature of a simple resolution giving the committee authority to receive confidential tax information, the committee chair or co-chair may request confidential tax returns and return information and the commissioner of revenue shall provide the requested returns or return information. The request shall be in writing and may identify a particular taxpayer. During the interim between legislative sessions, the chair or co-chair of the Legislative Budget and Audit Committee may request confidential tax returns and return information under this subsection without a simple resolution, if a majority of the members of the Legislative Budget and Audit Committee vote to approve making the request.

(c) When consistent with the purposes set out in (a) of this section, the commissioner may transfer unrequested confidential taxpayer returns or return information to a legislative committee after making a written determination that the transfer of the return or return information is in the best interest of the state. Before the return or return information is transferred, the commissioner shall provide a copy of the commissioner's determination to the taxpayer whose return or return information is to be transferred. In determining whether the transfer of the return or return information is in the best interest of the state, the commissioner shall consider

(1) if the legislative committee is reviewing the administration of a tax imposed by this title, whether the return or return information would demonstrate the application of a tax;

(2) if the legislative committee is considering adding a new tax or amending an existing tax, whether the return or return information would demonstrate the effect on taxpayers of a change in tax law;

(3) whether the return or return information would assist the legislative committee in estimating future state revenue;

(4) whether the return or return information would clarify or rectify information provided by a taxpayer to a legislative committee;

(5) the potential harm the taxpayer may suffer by the possible subsequent disclosure of the return or return information illegally;

(6) any other interest of the taxpayer in avoiding the transfer of the return or return information.

(d) A legislative committee shall consider tax returns and return information transferred under (b) or (c) of this section in executive session only, unless the taxpayer and any third party whose tax return or return information is being considered in conjunction with the taxpayer's return or return information consent in writing to a disclosure in open session. The executive session must be open to all legislators. The committee chair or co-chair may designate legislative employees and agents to inspect the confidential tax returns and return information, but the chair or co-chair shall seek to minimize the number of employees and agents designated. The designated employees and agents may attend the executive session. The chair or co-chair may allow a taxpayer whose confidential tax return or return information is being considered to attend the portion of the executive session that considers that taxpayer's confidential tax return or return information.

(e) When confidential tax returns or return information concerning a specific taxpayer are provided to a legislative committee under this section, the commissioner shall notify the taxpayer of the content and delivery of the return and return information to the committee.

(f) Before providing confidential tax return or return information under (b) or (c) of this section, the commissioner shall review the purpose of the proposed transfer of the return or return information to determine what types of confidential tax return or return information will provide the needed information. If more than one type of confidential tax return or return information will provide the needed information, the commissioner shall choose the return or return information that, in the commissioner's discretion, is the least commercially sensitive.

(g) Disclosure contrary to the provisions of this section by a member or former member of the legislature or by a present or former employee or agent of the legislature of a return or return information that is confidential under AS 43.05.230 and transferred to the legislature under this section is a violation of AS 43.05.230. A member of the legislature or an employee or agent of the legislature, before receiving or reviewing a return or return information provided by the commissioner under (b) or (c) of this section, shall, on a form prepared by the commissioner,

(1) acknowledge that the return or return information is confidential and that a disclosure of the return or return information contrary to the provisions of this section is prohibited by law; and

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(2) execute an agreement with the department to keep the return or return information confidential, to abide by regulations adopted by the department under (h) of this section, and to return the documents to the department.

(h) The commissioner shall adopt regulations governing the transmittal, receipt, safekeeping, duplication, accounting for, and return of the confidential tax return and return information transferred under (b) and (c) of this section.

(i) This section does not permit the transfer to the legislature of confidential tax returns and return information provided by the Internal Revenue Service under exchange agreements with the department.

(j) In this section

(1) "return" has the meaning given in 26 U.S.C. 6103(b)(1), except that "secretary" is read as "department" and "this title" means AS 43;

(2) "return information" has the meaning given in 26 U.S.C. 6103(b)(2)(A), except that "secretary" is read as "department" and "this title" means AS 43.

* Sec. 8. AS 43.20.030 is amended by adding a new subsection to read:

(h) The department may grant an extension for filing a return required under this section. The extension may not exceed 30 days beyond the filing date or the extension granted to the taxpayer by the Internal Revenue Service for filing the taxpayer's federal income tax return, whichever is later. Granting the extension does not affect the due dates for payment of the tax.

* Sec. 9. AS 43.05.232, as enacted by sec. 7 of this Act, applies to all confidential tax returns and return information in the possession of the department on or after the effective date of this Act.

* Sec. 10. This Act takes effect immediately under AS 01.10.070(c).

ALASKA STATE LEGISLATURE

SENATE SPECIAL COMMITTEE ON OIL AND GAS

Senator Bettye Fahrenkamp
Chairman
Senator Jack Coghill
Senator Paul Fischer

P.O. Box V, State Capitol
Juneau, Alaska 99811
(907) 465-3834

March 23, 1987

SCS CSHB 58am (Oil and Gas), RELATING TO CONFIDENTIAL TAX INFORMATION; RELATING TO THE FILING OF TAX RETURNS.

COMPARISON OF CSHB 58 (Finance)am, PROPOSED SENATE CS AND PROPOSED INDUSTRY DRAFT

Section 1: A finding and purpose section is included to assist the courts in interpreting the bill. A taxpayer's right to privacy under Alaska Constitution Article 1, Section 22 must be balanced with the legislature's need for information on how the state's tax laws are working.

All three versions contain this identical section.

Section 2: Adds a new section to Title 24, Article 2, on legislative employees. It would prohibit a present or former employee or agent of the legislature from disclosing confidential tax information.

All three versions contain this identical section.

Section 3: Adds a new section to the Legislative Standards of Conduct Code. Disclosure of confidential tax information by persons covered by the Code would be prohibited.

All three versions contain this identical section.

Section 4: Also adds to the Legislative Standards of Conduct Code a section to protect confidential information that may have been a source of a complaint before the Legislative Ethics Committee.

All three versions contain this identical section.

Section 5: Amends existing statute that prohibits disclosure of confidential tax information by state employees to allow the transfer of information to the legislature.

All three versions contain this identical section.

Section 6: Establishes penalties for violation of the confidentiality provisions. Current statute provides penalties only for an "intentional" violation.

House version: A "knowing" violation is a class A misdemeanor (Maximum penalties: 1 year imprisonment and $5,000); a "grossly negligent" violation is subject to a civil penalty of $5,000.

Senate version: A "knowing" violation is a class A misdemeanor (Maximum penalties: 1 year imprisonment and $5,000); a "grossly negligent" violation is subject to a civil penalty of $5,000. Clarifies that the Department of Revenue will enforce and collect the civil penalties.

Industry version: Reduces standard for civil penalty from "gross negligence" to simple "negligence". A "knowing" violation is a class A misdemeanor (Maximum penalties: 1 year imprisonment and $5,000); a "negligent" violation is subject to a civil penalty of $5,000.

Section 7: Creates a new section of statute to deal specifically with the transfer of confidential tax information to the legislature.

(a) Establishes purposes for which tax information may be transferred to the legislature (to assist in consideration of tax legislation, oversight of the administration of tax laws, including the review of settlements, litigation, and audits, or estimation of future state revenues), and purposes for which information may not be transferred (to direct the executive branch in its audit, litigation, or settlement efforts, or to embarrass, harass, or discriminate against a taxpayer).

All three versions contain this identical subsection.

(b) Establishes a procedure for requesting tax information.

House version: After adoption of a simple resolution that identifies the scope of the inquiry and allows a committee to receive information, a committee chair or co-chair may make a written request. During the interim, the chairman of the Legislative Budget and Audit Committee may request information if a majority of the committee agree.

Senate version: Does not include provision for interim requests. Requires adoption of simple resolution.

Industry version: Does not include provision for interim requests. Requires adoption of simple resolution.

(c) Allows the commissioner to transfer unrequested information under certain conditions.

House version: Only if a written finding is filed showing that the transfer is in the best interest of the state. Lists points the commissioner must consider (whether the information would demonstrate the application of a tax or the effect of a change in tax law, assist in estimating revenues, or clarify information provided by a taxpayer, and the potential harm a taxpayer may suffer by the possible subsequent illegal disclosure of the information). Requires the commissioner to provide affected taxpayers with a copy of the written finding before the information is transferred.

Senate version: Identical to House.

Industry version: Only if a taxpayer has testified before a committee and the department has information that is inconsistent with that testimony.

(d) Requires that confidential information be considered only in executive session.

House version: Specifies that all legislators may attend the session. Authorizes the chair or co-chair to designate employees and agents allowed to attend and review the tax information, but to minimize the number of such employees. Authorizes the chair to allow the taxpayer whose returns are being considered to attend the executive session.

Senate version: Identical to House.

Industry version: Specifies that all legislators may attend the session. Requires the chair or co-chair to limit the number of employees and agents allowed to attend. There is no provision for allowing employees or agents to review the tax information. Authorizes the chair to allow the taxpayer whose returns are being considered to attend the executive session.

(e) Requires that the commissioner notify the taxpayer of the contents of the information transferred to the committee.

All versions contain this identical subsection.

(f) This section restricts the commissioner's ability to transfer commercially sensitive tax information.

House version: Requires that, when more than one type of information will satisfy the legislature's request, the commissioner must choose the least commercially sensitive information.

Senate version: Identical to House.

Industry version: Requires written determination that commercially sensitive information is in the least intrusive form. Requires contracts or transactional documents to be edited or summarized.

(g) Specifies that anyone authorized to receive confidential information must sign a form acknowledging that disclosure of the information is prohibited by law, and agreeing to abide by procedures adopted by the department.

All versions contain this identical subsection.

(h) Establishes procedures for handling confidential tax information.

House version: Requires the commissioner to adopt regulations governing the transmittal, receipt, safekeeping, duplication, accounting for, and return of the information.

Senate version: Identical to House.

Industry version: Requires the commissioner to adopt regulations. Specifies centralized safekeeping and limitations on duplication and removal of documents.

(i) Ensures that the exchange of information agreement with the Internal Revenue Service will not be violated.

All three versions contain this identical subsection.

(j) Defines "return" and "return information".

House version: References definition used in federal law.

Senate version: Identical to House.

Industry version: Limits to six items:

1) taxpayer's identity,

2) tax returns required by law,

3) annual amount of collections for each tax,

4) the amouunt of an assessment for each issue and each taxpayer,

5) a description of the issues involved in the assessment,

6) the amount, nature and basis of settlements.

Section 8: Amends existing law to allow the department to grant taxpayers an extension for filing their returns.

House version: Allows only a 30 day extension beyond filing date or IRS extension.

Senate version: Identical to House.

Industry version: Allows a reasonable extension not more than one month beyond IRS maximum.

Section 9: Specifies that the act applies to all returns and return information in the possession of the department on the effective date of the act.

House and Senate versions contain this section.

Industry version does not contain this section.

Section 10: The bill has an immediate effective date.

House and Senate versions contain this section.

Industry version does not contain this section.

NOTE 1. SECT. 6: THIS CHANGE WOULD LOWER THE STANDARD OF REPROACHABLE CONDUCT TO "ORDINARY NEGLIGENCE". "GROSS NEGLIGENCE" IS AN INAPPROPRIATELY LOW STANDARD OF BEHAVIOR IN THE CONTEXT OF HANDLING CONFIDENTIAL TAXPAYER INFORMATION.

NOTE 2. SECT. 7(c): THIS CHANGE LIMITS THE COMMISSIONER OF REVENUE'S AUTHORITY TO PROVIDE TAXPAYER INFORMATION TO THE SITUATION IN WHICH A TAXPAYER HAS PROVIDED FALSE OR MISLEADING INFORMATION TO THE LEGISLATURE REGARDING ITS TAX MATTERS.

NOTE 3. SECT. 7(d): THIS CHANGE ESTABLISHES FIXED NUMBERS OF LEGISLATIVE EMPLOYEES AND AGENTS WHO WOULD HAVE ACCESS TO THE TAXPAYER INFORMATION SO AS TO MINIMIZE THE RISK OF UNAUTHORIZED DISCLOSURE.

NOTE 4. SECT. 7(f): THIS CHANGE WOULD PROVIDE FURTHER ASSURANCE TO THE TAXPAYERS OF THE STATE THAT HIGHLY SENSITIVE OR PROPRIETARY INFORMATION WAS TRANSFERRED TO THE LEGISLATURE ONLY IN THOSE INSTANCES IN WHICH THERE WAS NO LESS INTRUSIVE OR SENSITIVE FORM FOR PROVIDING THE INFORMATION.

NOTE 5. SECT. 7(h): THIS CHANGE WOULD PROVIDE FURTHER ASSURANCE THAT THE TAXPAYER INFORMATION WAS HANDLED IN THE SAFEST MANNER AND THAT RISKS OF UNAUTHORIZED OR INADVERTENT DISCLOSURE WERE MINIMIZED.

NOTE 6. SECT. 7(j): THIS CHANGE WOULD PERMIT THE TRANSFER OF THE VAST MAJORITY OF THE INFORMATION THAT THE DEPARTMENT OF REVENUE HAS. HOWEVER, THE DEPARTMENT OF REVENUE COULD NOT TRANSFER THE TRANSACTIONAL DOCUMENTS GOVERNING THE PURCHASE AND SALE OF OIL AND GAS PRODUCTION OR OTHER ASSETS. AS A RESULT, THIS HIGHLY SENSITIVE AND PROPRIETARY INFORMATION WOULD NOT BE EXPOSED TO THE RISKS OF UNAUTHORIZED OR INADVERTENT DISCLOSURE, WHILE AT THE SAME TIME THE LEGISLATURE WOULD HAVE ACCESS TO VAST AMOUNTS OF TAXPAYER INFORMATION NECESSARY TO CARRY OUT ITS RELATED RESPONSIBILITIES.

NOTE 7. SECT. 8: THIS SECTION GIVES THE COMMISSIONER THE ABILITY TO GRANT AN EXTENSION FOR FILING AN ALASKAN TAX RETURN. AOGA HAS REQUESTED THIS LANGUAGE TO GIVE GREATER FLEXIBILITY TO THE COMMISSIONER IN HIS ABILITY TO GRANT EXTENSION. THIS SECTION DOES NOT AFFECT THE DATE WHEN TAXES ARE DUE OR THE AMOUNT OWED.

Proposed industry amendments

For an Act entitled: "An Act relating to confidential tax information; relating to the filing of tax returns; and providing for an effective date."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

* Section 1. LEGISLATIVE FINDINGS AND PURPOSE.

(a) The legislature finds that

(1) the majority of the state's revenue is derived from taxation;

(2) tax revenue enables the state to provide essential services to the citizens of the state to ensure the public health and welfare;

(3) the elected representatives of the people of the state must be assured that the state is receiving all of the income to which it is entitled and that the tax laws are operating in the manner intended by the legislature;

(4) the legislature must exercise its oversight authority to ensure that tax revenue collection by the Department of Revenue is efficient, fair, prompt, and in the best interest of the state;

(5) there is legitimate and compelling governmental interest in the legislature having adequate access to tax-related information to allow responsible oversight;

(6) without sufficient information, the legislature cannot adequately determine that the state's tax revenue collection functions are properly administered and that tax revenue due the state is promptly received;

(7) tax returns and return information contain confidential information, often regarding sensitive business information;

(8) taxpayers have protections against public disclosure of certain tax information;

(9) exchange agreements with the Internal Revenue Service require that certain tax information not be publicly disclosed;

(10) protection of confidentiality fosters full disclosure by taxpayers to taxing authorities and therefore promotes effective administration of tax programs; and

(11) legislators and legislative employees who improperly disclose confidential tax information should be subject to the same sanctions imposed against executive branch employees.

(b) The purpose of this Act is to ensure that

(1) the state is receiving all the tax revenue due the state;

(2) oversight of the tax revenue collection function is effectively provided;

(3) tax revenue due to the state is available to provide for the public health and welfare of the citizens of the state;

(4) taxpayers are protected from improper disclosure of tax information;

(5) the exchange agreements with the Internal Revenue Service regarding tax information are not jeopardized;

(6) tax programs are administered fairly; and

(7) the right of the people to privacy is recognized and may not be infringed.

* Sec. 2. AS 24.10 is amended by adding a new section to article 2 to read:

Sec. 24.10.070. CONFIDENTIALITY OF INFORMATION. A present or former employee or agent of the legislature may not disclose tax

information contained in a report or return filed under AS 43.05.230 and furnished to the person under AS 43.05.232.

* Sec. 3. AS 24.60.060 is amended by adding a new subsection to read:

(b) A person to whom this chapter applies may not disclose tax information contained in a report or a return filed under AS 43.05.230 and furnished to the person under AS 43.05.232.

* Sec. 4. AS 24.60 is amended by adding a new section to read:

Sec. 24.60.172. SPECIAL PROCEEDINGS BEFORE THE COMMITTEE. Notwithstanding AS 24.60.170, if a complaint before the committee involves an allegation that a person to whom this chapter applies has disclosed tax information contained in a report or return filed under AS 43 with the Department of Revenue and furnished to the person under AS 43.05.232, and if the taxpayer or third party whose tax information is alleged to have been improperly disclosed does not agree to the public disclosure of the identity of the taxpayer, the third party, or the tax information,

(1) the hearing may not be held in open session;

(2) a transcript containing confidential tax information shall be edited to prevent the disclosure of the confidential information;

(3) a decision, if made public, shall be edited to prevent the disclosure of the tax information and to protect the identity of the taxpayer or the third party; and

(4) a public statement may not contain information identifying the taxpayer, a third party, or the tax information.

* Sec. 5 AS 43.05.230(a) is amended to read:

(a) It is unlawful for a current or former officer, employee, or agent of the state to divulge the amount of income or the particulars set out or disclosed in a report or return made under this title,

except

(1) in connection with official investigations or proceedings of the department, whether judicial or administrative, involving taxes due under this title;

(2) in connection with official investigations or proceedings of the child support enforcement agency, whether judicial or administrative, involving child support obligations imposed or imposable under AS 25 or AS 47;

(3) as provided in AS 38.05.036 pertaining to audit functions; and

(4) as otherwise provided in this section <u>or in AS 43.05.232.</u>

* Sec. 6. AS 43.05.230 (f) is repealed and reenacted to read:

(f) A person who knowingly violates a provision of this section is guilty of a class A misdemeanor. A person whose negligence results in a violation of this section is subject to a civil penalty of $5,000.

* Sec. 7. AS 43.05 is amended by adding a new section to read:

Sec. 43.05.232. DISCLOSURE OF CONFIDENTIAL TAX RETURNS AND RETURN INFORMATION TO THE LEGISLATURE. (a) Confidential tax returns and return information may not be requested by a legislative committee under (b) of this section or transferred to a legislative committee under (c) of this section,

(1) unless the purpose of the committee's request under (b) of this section or of the transfer under (c) of this section is

(A) to assist the committee in carrying out its responsibilities to consider tax legislation;

(B) to oversee the effective and efficient administration of the state's tax laws, including the review of audits, litigation, or settlements; or

(C) to estimate future state revenue;

(2) if the purpose of the request or transfer is to direct the executive branch in its audit, litigation, or settlement efforts, or to collect information to embarrass, harass, or discriminate against a taxpayer.

(b) After a legislative committee identified the scope of an investigation or inquiry relating to matters of taxation and after adoption by either house of the legislature of a simple resolution giving the committee authority to receive confidential tax information, the committee chair or co-chair may request confidential tax returns and return information and the commissioner of revenue shall provide the requested returns or return information. The request shall be in writing and may identify a particular taxpayer.

(c) When consistent with the purposes set out in (a) of this section, the commissioner may transfer unrequested confidential taxpayer returns or return information to a legislative committee.
If the taxpayer has testified before a legislative committee, either orally or in writing concerning a tax matter under this title and the Department of Revenue has taxpayer returns or return information that is inconsistent with the testimony or information offered by the taxpayer. [See NOTE 2]

(d) A legislative committee shall consider tax returns and return information transferred under (b) or (c) of this section in executive session only, unless the taxpayer and any third party whose tax return or return information is being considered in conjunction with the taxpayer's return or return information consent in writing to a disclosure in open session. The executive session must be open to all legislators. The committee chair or co-chair shall limit the number of employees and agents designated. [See NOTE 3]. The designated employees and agents may attend the executive session. The chair or co-chair may allow a taxpayer whose confidential tax return or return information is being considered to attend the portion of the executive session that considers that taxpayer's confidential tax return or return information.

(e) When confidential tax returns or return information concerning a specific taxpayer are provided to a legislative committee under this section, the commissioner shall notify the taxpayer of the content and delivery of the return and return information to the committee.

(f) Before providing confidential tax return or return information under (b) or (c) of this section, the commissioner shall make a written determination that the information to be provided is in the least intrusive form with regard to the taxpayer's commercially sensitive material. Contracts or other transactional documents shall not be transferred if they can be summarized or edited in a manner that does not disclose the details of the transaction or the identity of the taxpayer or the trading partner of the taxpayer. [See NOTE 4]

(g) Disclosure contrary to the provisions of this section by a member or former member of the legislature or by a present or former employee or agent of the legislature of a return or return information that is confidential under AS 43.05.230 and transferred to the legislature under this section is a violation of AS 43.05.230. A member of the legislature or an employee or agent of the legislature, before receiving or reviewing a return or return information provided by the commissioner under (b) or (c) of this section, shall, on a form prepared by the commissioner,

(1) acknowledge that the return or return information is confidential and that a disclosure of the return or return information contrary to the provisions of this section is prohibited by law; and

(2) execute an agreement with the department to keep the return or return information confidential, to abide by regulations adopted by the department under (h) of this section and to return the

documents to the department.

(h) The commissioner shall adopt regulations governing the transmittal, receipt, centralized safekeeping, limitations on duplication and removal, accounting for possession, and return of the confidential tax return and return information transferred under (b) and (c) of this section. [See NOTE 5]

(i) This section does not permit the transfer to the legislature of confidential tax returns and return information provided by the Internal Revenue Service under exchange agreements with the department.

(j) In this section "return" and "return information" shall include only the following items:

(1) the taxpayer's identity;

(2) the taxpayer's tax returns required by law;

(3) The annual amount of collections from a taxpayer for each tax;

(4) the amount of an assessment made by the Department of Revenue for each issue and each tax period;

(5) the issues involved in the assessment along with a complete description of the issue;

(6) the amount, nature, and basis of any executed settlement between the Department of Revenue and the taxpayer. [See NOTE 6]

* Sec. 8. AS 43.20.030 is amended by adding a new subsection to read:

(k) The department may grant a reasonable extension of time for filing a return by this section. Such extension shall not be for more than one month beyond the maximum period allowable under the Internal Revenue Code for extensions of time to file federal income tax returns. An extension of time to file the return shall not affect the date when payment is due. [See NOTE 7]

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Bannister
3/4/87

Original sponsor: Rules/Legislative
Budget and Audit

SENATE OIL + GAS

IN THE ~~HOUSE~~ BY THE ~~FINANCE~~ COMMITTEE

SENATE 70 (Oil + Gas)

CS FOR ~~HOUSE~~ BILL NO. ~~58 (Finance)~~

IN THE LEGISLATURE OF THE STATE OF ALASKA

FIFTEENTH LEGISLATURE - FIRST SESSION

A BILL

For an Act entitled: "An Act relating to confidential tax information; relating to the filing of tax returns; and providing for an effective date."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

* Section 1. LEGISLATIVE FINDINGS AND PURPOSE. (a) The legislature finds that

(1) the majority of the state's revenue is derived from taxation;

(2) tax revenue enables the state to provide essential services to the citizens of the state to ensure the public health and welfare;

(3) the elected representatives of the people of the state must be assured that the state is receiving all of the income to which it is entitled and that the tax laws are operating in the manner intended by the legislature;

(4) the legislature must exercise its oversight authority to ensure that tax revenue collection by the Department of Revenue is efficient, fair, prompt, and in the best interest of the state;

(5) there is a legitimate and compelling governmental interest in the legislature having adequate access to tax-related information to allow responsible oversight;

(6) without sufficient information, the legislature cannot adequately determine that the state's tax revenue collection functions are properly administered and that tax revenue due the state is promptly received;

(7) tax returns and return information contain confidential information, often regarding sensitive business information;

(8) taxpayers have protections against public disclosure of certain tax information;

(9) exchange agreements with the Internal Revenue Service require that certain tax information not be publicly disclosed;

(10) protection of confidentiality fosters full disclosure by taxpayers to taxing authorities and therefore promotes effective administration of tax programs; and

(11) legislators and legislative employees who improperly disclose confidential tax information should be subject to the same sanctions imposed against executive branch employees.

(b) The purpose of this Act is to ensure that

(1) the state is receiving all the tax revenue due the state;

(2) oversight of the tax revenue collection function is effectively provided;

(3) tax revenue due to the state is available to provide for the public health and welfare of the citizens of the state;

(4) taxpayers are protected from improper disclosure of tax information;

(5) the exchange agreements with the Internal Revenue Service regarding tax information are not jeopardized;

(6) tax programs are administered fairly; and

(7) the right of the people to privacy is recognized and may not be infringed.

* Sec. 2. AS 24.10 is amended by adding a new section to article 2 to read:

Sec. 24.10.070. CONFIDENTIALITY OF INFORMATION. A present or former employee or agent of the legislature may not disclose tax

information contained in a report or return filed under AS 43.05.230 and furnished to the person under AS 43.05.232.

* Sec. 3. AS 24.60.060 is amended by adding a new subsection to read:

(b) A person to whom this chapter applies may not disclose tax information contained in a report or a return filed under AS 43.05.230 and furnished to the person under AS 43.05.232.

* Sec. 4. AS 24.60 is amended by adding a new section to read:

Sec. 24.60.172. SPECIAL PROCEEDINGS BEFORE THE COMMITTEE. Notwithstanding AS 24.60.170, if a complaint before the committee involves an allegation that a person to whom this chapter applies has disclosed tax information contained in a report or return filed under AS 43 with the Department of Revenue and furnished to the person under AS 43.05.232, and if the taxpayer or a third party whose tax information is alleged to have been improperly disclosed does not agree to the public disclosure of the identity of the taxpayer, the third party, or the tax information,

(1) the hearing may not be held in open session;

(2) a transcript containing confidential tax information shall be edited to prevent the disclosure of the confidential information;

(3) a decision, if made public, shall be edited to prevent the disclosure of the tax information and to protect the identity of the taxpayer or the third party; and

(4) a public statement may not contain information identifying the taxpayer, a third party, or the tax information.

* Sec. 5. AS 43.05.230(a) is amended to read:

(a) It is unlawful for a current or former officer, employee, or agent of the state to divulge the amount of income or the particulars set out or disclosed in a report or return made under this title.

except

(1) in connection with official investigations or proceedings of the department, whether judicial or administrative, involving taxes due under this title;

(2) in connection with official investigations or proceedings of the child support enforcement agency, whether judicial or administrative, involving child support obligations imposed or imposable under AS 25 or AS 47;

(3) as provided in AS 38.05.036 pertaining to audit functions; and

(4) as otherwise provided in this section <u>or in AS 43.05.232</u>.

* Sec. 6. AS 43.05.230(f) is repealed and reenacted to read:

(f) A person who knowingly violates a provision of this section is guilty of a class A misdemeanor. A person whose gross negligence results in a violation of this section is subject to a civil penalty of $5,000. THE Department shall enforce + collect a civil penalty under this section.

* Sec. 7. AS 43.05 is amended by adding a new section to read:

Sec. 43.05.232. DISCLOSURE OF CONFIDENTIAL TAX RETURNS AND RETURN INFORMATION TO THE LEGISLATURE. (a) Confidential tax returns and return information may not be requested by a legislative committee under (b) of this section or transferred to a legislative committee under (c) of this section,

(1) unless the purpose of the committee's request under (b) of this section or of the transfer under (c) of this section is

(A) to assist the committee in carrying out its responsibilities to consider tax legislation;

(B) to oversee the effective and efficient administration of the state's tax laws, including the review of audits,

litigation, or settlements; or

(C) to estimate future state revenue;

(2) if the purpose of the request or transfer is to direct the executive branch in its audit, litigation, or settlement efforts, or to collect information to embarrass, harass, or discriminate against a taxpayer.

(b) After a legislative committee identifies the scope of an investigation or inquiry relating to matters of taxation, and after adoption by either house of the legislature of a simple resolution giving the committee authority to receive confidential tax information, the committee chair or co-chair may request confidential tax returns and return information and the commissioner of revenue shall provide the requested returns or return information. The request shall be in writing and may identify a particular taxpayer.

(c) When consistent with the purposes set out in (a) of this section, the commissioner may transfer unrequested confidential taxpayer returns or return information to a legislative committee after making a written determination that the transfer of the return or return information is in the best interest of the state. Before the return or return information is transferred, the commissioner shall provide a copy of the commissioner's determination to the taxpayer whose return or return information is to be transferred. In determining whether the transfer of the return or return information is in the best interest of the state, the commissioner shall consider

(1) if the legislative committee is reviewing the administration of a tax imposed by this title, whether the return or return information would demonstrate the application of a tax;

(2) if the legislative committee is considering adding a new tax or amending an existing tax, whether the return or return

information would demonstrate the effect on taxpayers of a change in tax law;

(3) whether the return or return information would assist the legislative committee in estimating future state revenue;

(4) whether the return or return information would clarify or rectify information provided by a taxpayer to a legislative committee;

(5) the potential harm the taxpayer may suffer by the possible subsequent disclosure of the return or return information illegally;

(6) any other interest of the taxpayer in avoiding the transfer of the return or return information.

(d) A legislative committee shall consider tax returns and return information transferred under (b) or (c) of this section in executive session only, unless the taxpayer and any third party whose tax return or return information is being considered in conjunction with the taxpayer's return or return information consent in writing to a disclosure in open session. The executive session must be open to all legislators. The committee chair or co-chair may designate legislative employees and agents to inspect the confidential tax returns and return information, but the chair or co-chair shall seek to minimize the number of employees and agents designated. The designated employees and agents may attend the executive session. The chair or co-chair may allow a taxpayer whose confidential tax return or return information is being considered to attend the portion of the executive session that considers that taxpayer's confidential tax return or return information.

(e) When confidential tax returns or return information concerning a specific taxpayer are provided to a legislative committee under this section, the commissioner shall notify the taxpayer of the content and delivery of the return and return information to the committee.

(f) Before providing confidential tax return or return information under (b) or (c) of this section, the commissioner shall review the purpose of the proposed transfer of the return or return information to determine what types of confidential tax return or return information will provide the needed information. If more than one type of confidential tax return or return information will provide the needed information, the commissioner shall choose the return or return information that, in the commissioner's discretion, is the least commercially sensitive.

(g) Disclosure contrary to the provisions of this section by a member or former member of the legislature or by a present or former employee or agent of the legislature of a return or return information that is confidential under AS 43.05.230 and transferred to the legislature under this section is a violation of AS 43.05.230. A member of the legislature and an employee or agent of the legislature, before receiving or reviewing a return or return information provided by the commissioner under (b) or (c) of this section, shall, on a form prepared by the commissioner,

(1) acknowledge that the return or return information is confidential and that a disclosure of the return or return information contrary to the provisions of this section is prohibited by law; and

(2) execute an agreement with the department to keep the return or return information confidential, to abide by regulations adopted by the department, and to return the documents to the department.

(h) The commissioner shall adopt regulations governing the transmittal, receipt, safekeeping, duplication, accounting for, and return of the confidential tax return and return information transferred under (b) and (c) of this section.

(i) This section does not permit the transfer to the legislature of confidential tax returns and return information provided by the Internal Revenue Service under exchange agreements with the department.

(j) In this section

(1) "return" has the meaning given in 26 U.S.C. 6103(b)(1), except that "secretary" is read as "department" and "this title" means AS 43;

(2) "return information" has the meaning given in 26 U.S.C. 6103(b)(2)(A), except that "secretary" is read as "department" and "this title" means AS 43.

* Sec. 8. AS 43.20.030 is amended by adding a new subsection to read:

(h) The department may grant an extension for filing a return required under this section. The extension may not exceed 30 days beyond the filing date or the extension granted to the taxpayer by the Internal Revenue Service for filing the taxpayer's federal income tax return, whichever is later. Granting the extension does not affect the due dates for payment of the tax.

* Sec. 9. AS 43.05.232, as enacted by sec. 7 of this Act, applies to all confidential tax returns and return information in the possession of the department on or after the effective date of this Act.

* Sec. 10. This Act takes effect immediately under AS 01.10.070(c).

Testimony of

Exxon Company, U.S.A.

Senate CS for CSHB-58 (O&G)

Senate Special Committee on Oil & Gas

April 30, 1987

Exxon appreciates the opportunity we have had to express our concerns about CSHB-58 to the Special Oil and Gas Committee members and other participants. We especially appreciate your efforts both in improving the security procedures which govern the transmittal of taxpayer information to the legislature and in affording the taxpayer the opportunity of notification and comment to a proposed transfer of information.

However, we continue to believe that this bill is unnecessary. Under AS 43.05.010, the Commissioner already has the responsibility to inform the legislature about the efficiency and effectiveness of the Department of Revenue and may communicate in general terms concerning the operations of his department and the tax laws. Since we believe the current law is sufficient to keep the legislature informed, we urge you to reconsider the need for this bill.

Thank you.

MLJ/570:dag
4/28/87

ALASKA STATE LEGISLATURE

SENATE SPECIAL COMMITTEE ON OIL AND GAS

Senator Bettye Fahrenkamp
Chairman
Senator Jack Coghill
Senator Paul Fischer

P.O. Box V, State Capitol
Juneau, Alaska 99811
(907) 465-3834

April 27, 1987

SCS CSHB 58am (Oil and Gas), RELATING TO CONFIDENTIAL TAX INFORMATION; RELATING TO THE FILING OF TAX RETURNS.

COMPARISON OF HOUSE PASSED AND PROPOSED SENATE BILLS.

INCLUDES APRIL 24 OIL AND GAS COMMITTEE SUBSTITUTE.

Section 1: A finding and purpose section is included to assist the courts in interpreting the bill. A taxpayer's right to privacy under Alaska Constitution Article 1, Section 22 must be balanced with the legislature's need for information on how the state's tax laws are working.

Both versions contain this identical section.

Section 2: Adds a new section to Title 24, Article 2, on legislative employees. It would prohibit a present or former employee or agent of the legislature from disclosing confidential tax information.

Both versions contain this identical section.

Section 3: Adds a new section to the Legislative Standards of Conduct Code. Disclosure of confidential tax information by persons covered by the Code would be prohibited.

Both versions contain this identical section.

Section 4: Also adds to the Legislative Standards of Conduct Code a section to protect confidential information that may have been a source of a complaint before the Legislative Ethics Committee.

Both versions contain this identical section.

Section 5: Amends existing statute that prohibits disclosure of confidential tax information by state employees to allow the transfer of information to the legislature.

Both versions contain this identical section.

Section 6: Establishes penalties for violation of the confidentiality provisions. Current statute provides penalties only for an "intentional" violation.

House version: A "knowing" violation is a class A misdemeanor (Maximum penalties: 1 year imprisonment and $5,000); a "grossly negligent" violation is subject to a civil penalty of $5,000.

April 24 Oil and Gas CS: A "knowing" violation is a class A misdemeanor (Maximum penalties: 1 year imprisonment and $5,000). Reduces standard for civil penalty from "gross negligence" to simple "negligence". Clarifies that penalties for negligence apply to only members or former members of the legislature and present or former employees or agents of the legislature. Directs the Department of Revenue to enforce and collect the civil penalties.

Section 7: Creates a new section of statute to deal specifically with the transfer of confidential tax information to the legislature.

(a) Establishes purposes for which tax information may be transferred to the legislature (to assist in consideration of tax legislation, oversight of the administration of tax laws, including the review of settlements, litigation, and audits, or estimation of future state revenues), and purposes for which information may not be transferred (to direct the executive branch in its audit, litigation, or settlement efforts, or to embarrass, harass, or discriminate against a taxpayer).

Both versions contain this identical subsection.

(b) Establishes a procedure for requesting tax information.

House version: After adoption of a simple resolution that identifies the scope of the inquiry and allows a committee to receive information, a committee chair or co-chair may make a written request. During the interim, the chairman of the Legislative Budget and Audit Committee may request information if a majority of the committee agree.

April 24 Oil and Gas CS: Removes mechanism for interim requests. Requires adoption of simple resolution.

(c) Allows the commissioner to transfer unrequested information under certain conditions.

House version: Only if a written finding is filed showing that the transfer is in the best interest of the state. Lists points the commissioner must consider (whether the information would demonstrate the application of a tax or the effect of a change in tax law, assist in estimating revenues, or clarify information provided by a taxpayer, and the potential harm a taxpayer may suffer by the possible subsequent illegal disclosure of the information). Requires the commissioner to provide affected taxpayers with a copy of the written finding before the information is transferred.

April 24 Oil and Gas CS: Requires written finding as in House version. Notification requirement moved to subsection (e).

(d) This section restricts the commissioner's ability to transfer commercially sensitive tax information.

House version: Requires that, when more than one type of information will satisfy the legislature's request, the commissioner must choose the least commercially sensitive information.

April 24 Oil and Gas CS: Adds a requirement that the commissioner shall transfer summary documents instead of transactional documents whenever possible.

(e) Requires the commissioner to provide the taxpayer with a comment period before transferring information to the Legislature. Under a transfer initiated by the commissioner, the finding and a notification of the contents of the information must be provided to the taxpayer ten days before information is transferred to the legislature. If the transfer is the result of a legislative request, the comment period is five days. Within the last 36 days of session, or during special sessions, the comment period is reduced to three days.

April 24 Oil and Gas CS: This is a new subsection.

(f) To ensure that any additional taxpayer comments will also be kept confidential, this subsection requires all written comments to be submitted to the department and then transferred to the committee within 24 hours.

April 24 Oil and Gas CS: This is a new subsection.

(g) Requires that confidential information be considered only in executive session.

House version: Specifies that all legislators may attend the session. Authorizes the chair or co-chair to designate employees and agents allowed to attend and review the tax information, but to minimize the number of such employees. Authorizes the chair to allow the taxpayer whose returns are being considered to attend the executive session.

April 21 Oil and Gas CS: Replaces the phrase "seek to minimize" with "limit".

(h) Specifies that anyone authorized to receive confidential information must sign a form acknowledging that disclosure of the information is prohibited by law, and agreeing to abide by procedures adopted by the department.

Both versions contain this identical subsection.

(i) Establishes procedures for handling confidential tax information.

House version: Requires the commissioner to adopt regulations governing the transmittal, receipt, safekeeping, duplication, accounting for, and return of the information.

April 24 Oil and Gas CS: Specifies that the department of revenue will be responsible for the duplication and numbering of documents transferred to the legislature. Also adds "removal from storage or filing location" and "accounting for possession" to the list of regulations that the department will adopt.

(j) Ensures that the exchange of information agreement with the Internal Revenue Service will not be violated.

Both versions contain this identical subsection.

(k) Defines "return" and "return information".

House version: References definition used in federal law.

April 24 Oil and Gas CS: Also references definition used in federal law. Specifies that "return and return information" does not include "transactional documents" prepared during a tax period within two years of the transfer. It also defines "transactional documents".

Section 8: Amends existing law to allow the department to grant taxpayers an extension for filing their returns.

House version: Allows only a 30 day extension beyond filing date or IRS extension.

April 24 Oil and Gas CS: Allows a reasonable extension not more than one month beyond IRS maximum.

Section 9: Specifies that the act applies to all returns and return information in the possession of the department on the effective date of the act.

Both versions contain this section.

Section 10: Clarifies that regulations will be adopted before confidential information is transferred.

April 24 Oil and Gas CS: This is a new section.

Section 11: The bill has an immediate effective date.

Both versions contain this section.

Standard Alaska
Production Company
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 561-5111

STANDARD
ALASKA PRODUCTION

MY NAME IS JIM PALMER. I AM THE MANAGER OF GOVERNMENTAL AFFAIRS FOR STANDARD ALASKA PRODUCTION COMPANY.

STANDARD APPRECIATES THE ATTENTION WHICH THIS COMMITTEE HAS PAID TO OUR CONCERNS ABOUT HOUSE BILL 58. CHANGES SUCH AS ALLOWING THE TAXPAYER AN OPPORTUNITY TO REVIEW THE CONTENTS OF THE INFORMATION TO BE TRANSFERRED AND TO COMMENT THEREON IS A VALUABLE PROTECTION TO ALL TAXPAYERS. THIS OPPORTUNITY BY THE TAXPAYER TO REVIEW AND COMMENT IS ALSO VALUABLE TO THE LEGISLATURE IN THAT THE LEGISLATURE IS MORE LIKELY TO RECEIVE A BALANCED PACKAGE OF INFORMATION. COMPARED TO EARLIER VERSIONS, THE CURRENT BILL STRIKES A FAR BETTER BALANCE OF THE TAXPAYER'S PRIVACY RIGHTS WITH THE LEGISLATURE'S NEED TO KNOW CERTAIN INFORMATION.

STANDARD DOES STOP SHORT OF ENDORSING THE BILL, HOWEVER, BECAUSE WITH 60 LEGISLATORS AND THEIR AIDES AND AGENTS HAVING ACCESS TO HIGHLY CONFIDENTIAL INFORMATION, THERE IS AN UNAVOIDABLE CONCERN ABOUT UNAUTHORIZED DISCLOSURE. ADDITIONALLY, THE BILL COULD ALLOW A FUTURE LEGISLATIVE BODY TO PERFORM EXECUTIVE FUNCTIONS. THIS COULD OCCUR WHERE THE LEGISLATURE UNDULY INFLUENCES THE DEPARTMENT IN THE EXECUTION OF AUDITS.

WHILE WE HAVE BASIC PROBLEMS WITH THE THRUST OF THE BILL, WE BELIEVE THIS COMMITTEE HAS INCORPORATED MANY SAFEGUARDS IN HB 58 WHICH ARE BENEFICIAL. IF THE LEGISLATURE BELIEVES THAT A BILL OF THIS TYPE IS NECESSARY, WE THINK THE OIL AND GAS COMMITTEE SUBSTITUTE CLOSES MANY OF THE LOOPHOLES THAT PREVIOUS VERSIONS HAD. STANDARD AGAIN THANKS THIS COMMITTEE FOR THE GOOD FAITH MANNER IN WHICH THE COMMITTEE LISTENED TO OUR CONCERNS AND FOR THE INCORPORATION OF CHANGES INTO THE BILL.

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

April 29, 1987

Senator Bettye Fahrenkamp
Chairman
Senate Oil & Gas Committee
Pouch V
Juneau, Alaska 99801

Dear Senator Fahrenkamp:

ARCO Alaska, Inc. greatly appreciated the opportunity to provide input during the shaping of what is now Senate CS for CS for HB 58. As a result of this process, the bill has, in our view, been substantially improved.

Unfortunately, we are still unable to endorse this bill because it permits unrequested information to be transferred out of the Department of Revenue and it subjects some of our most sensitive business documents to the risks of disclosure.

We do however, recognize the legislature's need for certain information and regret that we were unable to fully resolve our concerns during our extensive sessions.

Sincerely,

Hugh R Motley

Hugh R. Motley
Assistant Tax Officer

5-0321N
Bannister
4/24/87

Original sponsor: Rules/Legislative Budget and Audit

IN THE HOUSE

BY THE SENATE SPECIAL COMMITTEE ON OIL AND GAS

SENATE CS FOR CS FOR HOUSE BILL NO. 58 (O&G)

IN THE LEGISLATURE OF THE STATE OF ALASKA

FIFTEENTH LEGISLATURE - FIRST SESSION

A BILL

For an Act entitled: "An Act relating to confidential tax information; relating to the filing of tax returns; and providing for an effective date."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

* Section 1. LEGISLATIVE FINDINGS AND PURPOSE. (a) The legislature finds that

(1) the majority of the state's revenue is derived from taxation;

(2) tax revenue enables the state to provide essential services to the citizens of the state to ensure the public health and welfare;

(3) the elected representatives of the people of the state must be assured that the state is receiving all of the income to which it is entitled and that the tax laws are operating in the manner intended by the legislature;

(4) the legislature must exercise its oversight authority to ensure that tax revenue collection by the Department of Revenue is efficient, fair, prompt, and in the best interest of the state;

(5) there is a legitimate and compelling governmental interest in the legislature having adequate access to tax-related information to allow responsible oversight;

(6) without sufficient information, the legislature cannot adequately determine that the state's tax revenue collection functions are properly administered and that tax revenue due the state is promptly re-

(7) tax returns and return information contain confidential information, often regarding sensitive business information;

(8) taxpayers have protections against public disclosure of certain tax information;

(9) exchange agreements with the Internal Revenue Service require that certain tax information not be publicly disclosed;

(10) protection of confidentiality fosters full disclosure by taxpayers to taxing authorities and therefore promotes effective administration of tax programs; and

(11) legislators and legislative employees who improperly disclose confidential tax information should be subject to the same sanctions imposed against executive branch employees.

(b) The purpose of this Act is to ensure that

(1) the state is receiving all the tax revenue due the state;

(2) oversight of the tax revenue collection function is effectively provided;

(3) tax revenue due to the state is available to provide for the public health and welfare of the citizens of the state;

(4) taxpayers are protected from improper disclosure of tax information;

(5) the exchange agreements with the Internal Revenue Service regarding tax information are not jeopardized;

(6) tax programs are administered fairly; and

(7) the right of the people to privacy is recognized and may not be infringed.

* Sec. 2. AS 24.10 is amended by adding a new section to article 2 to read:

Sec. 24.10.070. CONFIDENTIALITY OF INFORMATION. A present or information contained in a report or return filed under AS 43 and furnished to the person under AS 43.05.232.

* Sec. 3. AS 24.60.060 is amended by adding a new subsection to read:

(b) A person to whom this chapter applies may not disclose tax information contained in a report or a return filed under AS 43 and furnished to the person under AS 43.05.232.

* Sec. 4. AS 24.60 is amended by adding a new section to read:

Sec. 24.60.172. SPECIAL PROCEEDINGS BEFORE THE COMMITTEE. Notwithstanding AS 24.60.170, if a complaint before the committee involves an allegation that a person to whom this chapter applies has disclosed tax information contained in a report or return filed under AS 43 with the Department of Revenue and furnished to the person under AS 43.05.232, and if the taxpayer or a third party whose tax information is alleged to have been improperly disclosed does not agree to the public disclosure of the identity of the taxpayer, the third party, or the tax information,

(1) the hearing may not be held in open session;

(2) a transcript containing confidential tax information shall be edited to prevent the disclosure of the confidential information;

(3) a decision, if made public, shall be edited to prevent the disclosure of the tax information and to protect the identity of the taxpayer or the third party; and

(4) a public statement may not contain information identifying the taxpayer, a third party, or the tax information.

* Sec. 5. AS 43.05.230(a) is amended to read:

(a) It is unlawful for a current or former officer, employee, or agent of the state to divulge the amount of income or the particulars

except

(1) in connection with official investigations or proceedings of the department, whether judicial or administrative, involving taxes due under this title;

(2) in connection with official investigations or proceedings of the child support enforcement agency, whether judicial or administrative, involving child support obligations imposed or imposable under AS 25 or AS 47;

(3) as provided in AS 38.05.036 pertaining to audit functions; and

(4) as otherwise provided in this section or in AS 43.05.232.

* Sec. 6. AS 43.05.230(f) is repealed and reenacted to read:

(f) A person who knowingly violates a provision of this section is guilty of a class A misdemeanor. If the negligence of a member or former member of the legislature, or a present or former employee or agent of the legislature results in a violation of this section, the member, employee, or agent is subject to a civil penalty of $5,000. The department shall enforce this section and collect the civil penalty established by this subsection.

* Sec. 7. AS 43.05 is amended by adding a new section to read:

Sec. 43.05.232. DISCLOSURE OF CONFIDENTIAL TAX RETURNS AND RETURN INFORMATION TO THE LEGISLATURE. (a) Confidential tax returns and return information may not be requested by a legislative committee under (b) of this section or transferred to a legislative committee under (c) of this section,

(1) unless the purpose of the committee's request under (b) of this section or of the transfer under (c) of this section is

responsibilities to consider tax legislation;

(B) to oversee the effective and efficient administration of the state's tax laws, including the review of audits, litigation, or settlements; or

(C) to estimate future state revenue;

(2) if the purpose of the request or transfer is to direct the executive branch in its audit, litigation, or settlement efforts, or to collect information to embarrass, harass, or discriminate against a taxpayer.

(b) After a legislative committee identifies the scope of an investigation or inquiry relating to matters of taxation, and after adoption by either house of the legislature of a simple resolution giving the committee authority to receive confidential tax information, the committee chair or co-chair may request confidential tax returns and return information and the commissioner of revenue shall provide the requested returns or return information. The request shall be in writing and may identify a particular taxpayer.

(c) When consistent with the purposes set out in (a) of this section, the commissioner may transfer unrequested confidential taxpayer returns or return information to a legislative committee after making a written determination that the transfer of the return or return information is in the best interest of the state. In determining whether the transfer of the return or return information is in the best interest of the state, the commissioner shall consider

(1) if the legislative committee is reviewing the administration of a tax imposed by this title, whether the return or return information would demonstrate the application of a tax;

(2) if the legislative committee is considering adding a

information would demonstrate the effect on taxpayers of a change in tax law;

(3) whether the return or return information would assist the legislative committee in estimating future state revenue;

(4) whether the return or return information would clarify or rectify information provided by a taxpayer to a legislative committee;

(5) the potential harm the taxpayer may suffer by the possible subsequent disclosure of the return or return information illegally;

(6) any other interest of the taxpayer in avoiding the transfer of the return or return information.

(d) Before providing confidential tax return or return information in response to a legislative request under (b) of this section or under a commissioner's determination made under (c) of this section, the commissioner shall review the purpose of the proposed transfer of the return or return information to determine what types of confidential tax return or return information will provide the needed information. If more than one type of confidential tax return or return information will provide the needed information, the commissioner shall choose the return or return information that, in the commissioner's discretion, is the least commercially sensitive. Whenever possible, instead of transactional documents, the commissioner shall transfer summary documents or analyses that have been prepared by the department. In this subsection, "summary documents or analyses" includes audit narratives, informal conference decisions, and formal hearing decisions.

(e) Before transferring the return or return information under (b) or (c) of this section, the commissioner shall notify the taxpayer whose return or return information is to be transferred of the proposed transfer and the content of the return or return information to be transferred, and, if the transfer is under (c) of this section, provide the taxpayer with a copy of the commissioner's determination. Within 10 days after receiving the determination and notification of a transfer proposed under (c) of this section, or within five days after receiving the notification of a transfer proposed under (b) of this section, the taxpayer may submit additional analysis, comment, or other information to the department, unless the legislative request or commissioner's determination is made after the 84th day of a regular session of the legislature or during a special session of the legislature, in which case the time period for the taxpayer to submit additional information is three days. When the period for submitting additional information has expired, the commissioner shall transfer to the committee the return or return information, including the additional information, if any, received by the commissioner from the taxpayer under this subsection. A taxpayer may waive the provisions of this subsection by providing the commissioner with a written waiver signed by the taxpayer.

(f) If, in addition to the additional analysis, comment, and other information filed by the taxpayer with the department under (e) of this section, a taxpayer wants to provide a legislative committee with analysis, comment, and other written information on the taxpayer's return or return information being considered by the committee under this section, the taxpayer shall file the information with the department and request that the department transfer the information to the legislative committee. The department shall transfer the information to the committee within 24 hours after receiving the information and the request.

(g) A legislative committee shall consider tax returns and return information transferred under (b), (c), (e), or (f) of this section in executive session only, unless the taxpayer and any third party whose tax return or return information is being considered in conjunction with the taxpayer's return or return information consent in writing to a disclosure in open session. The executive session must be open to all legislators. The committee chair or co-chair may designate legislative employees and agents to inspect the confidential tax returns and return information, but the chair or co-chair shall limit the number of employees and agents designated. The designated employees and agents may attend the executive session. The chair or co-chair may allow a taxpayer whose confidential tax return or return information is being considered to attend the portion of the executive session that considers that taxpayer's confidential tax return or return information.

(h) Disclosure contrary to the provisions of this section by a member or former member of the legislature or by a present or former employee or agent of the legislature of a return or return information that is confidential under AS 43.05.230 and transferred to the legislature under this section is a violation of AS 43.05.230. A member of the legislature or an employee or agent of the legislature, before receiving or reviewing a return or return information provided by the commissioner under (b), (c), or (e) of this section, shall, on a form prepared by the commissioner,

(1) acknowledge that the return or return information is confidential and that a disclosure of the return or return information contrary to the provisions of this section is prohibited by law; and

(2) execute an agreement with the department to keep the return or return information confidential, to abide by regulations

adopted by the department under (i) of this section, and to return the documents to the department.

(i) The commissioner shall adopt regulations governing the transmittal, receipt, safekeeping, removal from storage or filing location, accounting for possession, and return of the confidential tax return and return information transferred under (b), (c), and (e) of this section. The department shall have the exclusive responsibility for the duplication and numbering of the confidential tax return and return information provided to the legislature under this section.

(j) This section does not permit the transfer to the legislature of confidential tax returns and return information provided by the Internal Revenue Service under exchange agreements with the department.

(k) In this section

(1) "return" has the meaning given in 26 U.S.C. 6103(b)(1), except that "secretary" is read as "department" and "this title" means AS 43;

(2) "return information" has the meaning given in 26 U.S.C. 6103(b)(2)(A), except that "secretary" is read as "department" and "this title" means AS 43; "return information" does not include transactional documents prepared during a tax period that ended within two years of the date of the transfer of the "return information" under (b), (c), or (e) of this section;

(3) "transactional document" means a document that relates to the sale, exchange, or other transfer by a taxpayer of real property or tangible or intangible personal property and that

(A) constitutes all or part of a contract or agreement concerning the sale, exchange, or other transfer, including contract amendments, billings, and invoices; or

(B) summarizes one or more of the terms of the sale, exchange, or other transfer.

* Sec. 8. AS 43.20.030 is amended by adding a new subsection to read:

(h) The department may grant a reasonable extension of time for filing a return under this section. The extension may not be for more than 30 days beyond the maximum period allowable under 26 U.S.C. (Internal Revenue Code) for extensions of time to file federal income tax returns. An extension of time to file a return does not affect the date when the payment is due.

* Sec. 9. AS 43.05.232, as added by sec. 7 of this Act, applies to all confidential tax returns and return information in the possession of the department on or after the effective date of this Act.

* Sec. 10. The Department of Revenue shall adopt the regulations required by AS 43.05.232(i), enacted by sec. 7 of this Act, before the department transfers a return or return information to a legislative committee under AS 43.05.232.

* Sec. 11. This Act takes effect immediately under AS 01.10.070(c).

April 30, 1987

CSHB 58am (Finance), RELATING TO CONFIDENTIAL TAX INFORMATION; RELATING TO THE FILING OF TAX RETURNS.

A Committee Substitute has been prepared.

It is a result of a number of meetings with representatives of the state's major taxpayers.

TO TESTIFY:

DANNY CONSENSTEIN, Committee staff

Review section by section the provisions of the bill and the changes made in our proposed committee substitute.

JIM PALMER, Standard Alaska Production Company

The other companies will present written testimony only.

HUGH MALONE, Commissioner, Department of Revenue

1-29-87

BRIEFING by

DNR

DIV. of Oil & GAS

SENATE SPECIAL COMMITTEE ON
OIL AND GAS
January 29, 1987
3:30 p.m.

MEMBERS PRESENT

Senator Bettye Fahrenkamp, Chairman
Senator Jack Coghill
Senator Paul Fischer

COMMITTEE CALENDAR

Briefing on oil and gas matters by Jim Eason, Director, Division of Oil and Gas, Department of Natural Resources

ACTION NARRATIVE

TAPE ONE SIDE ONE
January 29, 1987

Number 001

The meeting was called to order at 3:30 p.m. by Chairman Fahrenkamp. She then invited Jim Eason to make his presentation to the committee.

Number 005

The first item Mr. Eason discussed was 8(g) revenue sharing, which is a section of the OCS Lands Act that was amended in 1978 to provide that when there is federal leasing of offshore submerged lands adjacent to tracts that are within three miles of a state's three mile limit, the states should have a "fair and equitable" share of those revenues. Between the time Congress enacted those amendments and the time Interior should have been paying money, no one could agree what a fair and equitable share was, and it ended up going to court. Congress resolved the dispute by providing a 27% share of revenues to the states.

Number 062

Senator Fahrenkamp asked if the state opposed that position. Mr. Eason responded that the state fought the Interior's position until Congress decided to act. However, he did not think it was fair to say they had fought the final decision.

Senator Fahrenkamp inquired if the fund had revenues set aside in it. Mr. Eason replied that there was in excess of

$5 billion, which was for all states with leases that had been issued in the 8(g) zone since the 1978 amendments. Alaska has received about $54 million and another $134 million will be received in installments over the next 15 years. There is a separate escrow account for the disputed acreage and under last year's amendments the state stands to get something from that escrow account.

Number 130

Senator Coghill questioned Mr. Eason as to whether the state was getting interest as a part of the settlement. Mr. Eason replied that interest was included in the Congressional settlement.

Number 224

A discussion followed on the Seal Island discovery and a Louisiana court case that will have an effect on that discovery.

Number 273

The second issue Mr. Eason discussed was the Petro Star-Chevron Contract. He said it was not certain if they would be asking the Legislature for a proposed amendment this session. As background, he said Commissioner Wunnicke had given tentative approval to come before the Legislature with Petro Star and Chevron to amend the contract. However, he said he had not had time to brief the new DNR Commissioner on the background or to get a sense if the Administration is going to support the proposed amendment.

Mr. Eason said the contract provides approximately 6500 barrels a day to Chevron and Petro Star from the Kuparuk River Unit. After the negotiation and the Legislature's review of the contract, a new policy of the TAPS carriers which made the Kuparuk oil more expensive to take than the Prudhoe Bay oil.

He said Commissioner Wunnicke had tentatively agreed that the Administration would have probably recommended to the Legislature that they approve an adjustment to offset the surcharge on oil delivered through TAPS. He told the committee that his department would keep them advised on what position the Administration is developing on amending the contract.

Number 420

Mr. Eason then addressed the suspension of production by Conoco, Inc., operators of the Milne Point Unit. He said the operator intends it to be a temporary measure. Last year Conoco requested a reduction in the state's 20%

royalty on production from the unit. However, the statutes that allow for royalty reduction also require two years of production and a showing of non-economics which had not occurred.

Number 466

The next issue discussed by Mr. Eason was the Arctic National Wildlife Refuge. He said no decisions have been made on the several issues under consideration. The state has sat in on several discussions between Fish & Wildlife and Interior representatives since the first week of December and no decisions have been made yet on the state's position.

Number 520

Senator Fahrenkamp asked if a decision will be binding upon the various agencies within the state. Mr. Eason responded that he did not know. Senator Fahrenkamp requested that if Mr. Eason is in attendance at further discussions on ANWR that from a legislative point of view, they'd like to have some kind of assurances that the Administration will speak with once voice.

Number 533

Senator Coghill questioned when the first seismic agreements were made. Mr. Eason responded that the first surveys were done three years ago.

Number 580

Next Mr. Eason discussed disputed acreage. The state generally owns three miles from the coastline outward and always, except off of ANWR, owns the islands. When the bill the was drafted it stipulated that ANWR includes the offshore islands, but he said what isn't clear is whether the water between the island and the mainland is included. The state contends that the submerged lands between the islands and mainland are state lands.

Number 607

Mr. Eason said the department has an oil and gas lease sale proposed for June of this year called the Camden Bay sale, which will lease submerged lands offshore of the islands. He said there is a lot of attention to that sale developing as a result of the fact that it is off of ANWR, and they believe it will be a very controversial sale and they will have to be very meticulous and careful on how they proceed. He said they would keep the committee informed on the status of that sale and their ongoing efforts to hold it on time.

TAPE ONE SIDE TWO
January 29, 1987

Number 650

Senator Fahrenkamp said that in discussions between some members of the Legislature and our Congressional delegation there seems to be some doubt as to what the state's share of revenue from federal lands will be. She asked Mr. Eason to bring the committee up to date on what he felt might happen.

Mr. Eason said that some people within the Department of Interior may be considering a recommendation that the state's entitlement be reduced.

Senator Fahrenkamp asked whether the state had not fully taken advantage of invitations to participate in Interior's planning in ANWR.

Mr. Eason responded that he was not aware of any opportunity that was not accepted at least as far as oil and gas was concerned. He said he had never heard of a formal or informal proposal by an agency or legislator for changing the revenue split.

Senator Fahrenkamp concluded that it was either some misinformation or lack of lines of communication.

Number 740

Mr. Eason said his division is expecting to receive more requests to allow flexibility under the lease for deferrals or opportunities to delay obligations.

He said that although they are aware that there's a need to allow more flexibility under the lease agreements when companies don't have the financial ability and resources to operate, they also realize they have an obligation to enforce leases equally.

Number 848

In response to questions by Senator Coghill, Mr. Eason said he favors a strict interpretation of lease diligence with minimal attempts to provide leeway.

Number 917

Mr. Eason next discussed the West Sak sands project. The estimates of oil contained in the area range up into the high billions of barrels, much larger than the main reservoir at Prudhoe Bay. Although ARCO has abandoned the project, they said publicly that they were impressed with the results.

Number 973

The next item on the agenda was the 1987 Five-Year Oil and Gas Leasing Schedule which provides for two lease sales each year as opposed to the former three per year. The division believes that its new schedule will provide the state with a strong, judicious leasing program over the next five years. They feel that although it is a lessening of the pace, they think it is appropriate under the circumstances and think that it also assures that they put their concentration and attention on legally defensible findings for the sales that are important to them and industry and, at the same time, deferring areas that are of no interest to industry.

Number 033

Senator Fahrenkamp then asked Mr. Eason about the outcome of Lease Sale 51 and how he thought we could make Alaska leases more attractive and more competitive. She also asked questions on the permitting system and an extensive discussion followed.

Number 170

The next area of discussion was exempt sales. Exempt sales allow the division to conduct competitive lease sales not on the formal five-year schedule under specific conditions. He said that this year two areas, one on the North Slope and the other in Cook Inlet, have been identified for exempt sales and they are reviewing their schedule now to determine whether they can do that.

Number 230

The next item was the TAPS Tariff. He said the state did conclude a settlement with the TAPS carriers last year. As a result of that settlement, and resulting reduced transportation costs, the state has received about $94 million in increased royalty payments.

Also, as an update to the committee, he said that the Alaska Public Utilities Commission was holding hearings on the intra-state tariff. He said it was not clear to him, at that time, what position the APUC was going to take, but there was a possibility that they are moving toward a decision to require a different rate for intra-state tariff than for inter-state tariff.

Number 247

The last item he spoke to, which was a very time consuming project, was the Cook Inlet Royalty Oil Sale. He said that after many months the federal regulations were amended, but didn't allow everything they had hoped. They allowed a limited export from Cook Inlet, but the ability to export Cook Inlet oil depends upon which side of the Inlet you're on. He said after the preliminary decision to sell approximately 3,600 barrels per day to Chinese Petroleum Corporation of Taiwan, and then following public comment, a final decision was issued on January 8, 1987.

TAPE TWO SIDE ONE
January 29, 1987

He concluded by saying delivery of 94 percent of the state's daily royalty oil production from the west side of Cook Inlet is expected to begin in July 1987.

Number 305

Following the conclusion of Mr. Eason's briefing, there was a lengthy question and answer period. He discussed problems with the denomination provision in royalty oil contracts, the status of the Valdez refinery project, gas valuation procedures discussed before the Federal Royalty Management and Advisory Committee, Beaufort Sea drilling restrictions, and BLM's proposed management plan for the Teshekpuk Lake area.

Number 566

Senator Fahrenkamp thanked Mr. Eason for the briefing and said the committee should be as up to date as possible and know where the problem areas were. She then adjourned the meeting at 5:22 p.m.

STATE OF ALASKA

POUCH V
JUNEAU, ALASKA 99811
(907) 465-4941

SENATE SPECIAL COMMITTEE ON OIL AND GAS

MEMORANDUM

TO: Members, Senate Special Committee on Oil and Gas

FROM: Committee Staff

RE: Committee Meeting, January 29, 1987

DATE: January 28, 1987

On Thursday, January 29 at 3:30 pm in the Beltz Room, the Senate Special Committee on Oil and Gas will recieve a briefing from the Department of Natural Resources, Division of Oil and Gas. Jim Eason, Director of the Division, will present an overview of the the division's functions and a review of current policy issues affecting oil and gas development. In addition to the issues listed on the attached agenda, Mr. Eason will provide an update on Cook Inlet gas contracts, the results of this week's Lease Sale #51, and a review of the January, 1987 documents "Five year Oil and Gas Leasing Program" and "Historical and Projected Oil and Gas Consumption". If you have not received copies of the above documents, committee staff will be glad to provide you with them.

OFFICE OF THE COMMISSIONER
Pouch M
Juneau, Alaska 99811
(907) 465-2400

Danny,

This is the draft outline for the presentation to the Senate Resources Committee on Wednesday.

It appears we could do one of several things:

1. Repeat the presentation
2. See if there are questions ~~[illegible]~~ from the presentation before Senate Resources*
3. Do #2 above + add
   - A. Cook Inlet Gas ~~[illegible]~~ Update
   - B. Results of Lease Sale 51
   - C. Other?

I'd suggest option #3.

Please call.

Bob

Alaska Department of
NATURAL
RESOURCES

* This assumes everyone attended the Senate Resources presentation

DIVISION OF OIL AND GAS
James E. Eason, Director

1. Division Responsibilities

2. Division Staff

3. Division Issues

   A. 8(g) Revenue Sharing

   B. Petro Star-Chevron Contract Amendment

   C. Milne Point Shutdown

   D. ANWR
      1. State supports opening for leasing
      2. Land trades
      3. Disputed acreage
      4. Revenue sharing
      5. Impacts of decisions on state sales

   E. Diligence provisions of state oil and gas leases

   F. West Sak Pilot Project Abandonment

   G. Five-Year Leasing Program
      1. Sale schedule reduced
      2. Exempt sales

   H. TAPS Tariff
      1. Settlement
      2. APUC rate setting

   I. Cook Inlet Royalty Oil Sale

Danny,

As requested, here is the agenda for the presentation to the Senate Resources Committee on 12/28.

R. Butts

DIVISION OF OIL AND GAS
James E. Eason, Director

1. Division Responsibilities
The Division of Oil and Gas' primary responsibilities are to assure that prospective oil, gas and geothermal lands are made available for competitive leasing and that the state receives full value for these resources; to assure that all revenues due the state from leasing and production are received; and, to assure that persons holding oil, gas or geothermal leases conduct their surface operations in an environmentally sound and socially conscious manner. The division is comprised of the Director's Office and three management sections: Lease Sales, Lease Administration and Royalty Accounting.

2. Division Staff
The Division of Oil and Gas has 39 employees as of January 1987. There are 38 employees in the Anchorage central office and one employee in the Juneau commissioner's office. The Juneau employee is project manager for formulating the department's response to oil and gas proposals and projects on federal lands, and acts as division liaison with Juneau agencies and the legislature.

3. Division Issues

A. 8(g) Revenue Sharing
The State of Alaska shares in revenues from the leasing of certain OCS tracts within three miles of state submerged lands. Congress amended the OCS Lands Act last year to provide for a 27 percent share of all bonuses, rentals and royalties from the leasing of these 8(g) tracts with the adjoining coastal states. As a result of Congress' action, certain funds, which had been escrowed pending the determination of each state's "fair and equitable" share were distributed. This resulted in the receipt of $51 million in unanticipated revenues for Alaska in 1986, with another $134 million to be received over the next 15 years. However, since the recent amendment was adopted, there has been another development that may affect the amount the state receives from OCS leasing in the 8(g) zone. The U.S. District Court for the Western District of Louisiana has ruled against the State of Louisiana in its lawsuit to compel the Secretary of the Interior to require joint unitization of federal leases which are claimed to be draining reserves from adjacent state leases. In reasserting its pre-1986 amendment position, Interior is claiming that Section 8(g) only requires reimbursement to states for drainage, and that Congress has determined that 27 percent of the revenues are sufficient compensation, regardless of the factual circumstances governing the actual ownership of the resources. Interior's adoption of this posture is likely to make it more difficult to negotiate joint state-federal unit agreements in which resources are allocated on the basis of tract ownership to determine revenue distribution.

B. Petro Star-Chevron Contract Amendment

Last session the legislature approved the department's long term sale of approximately 6500 bbls per day of royalty oil to Petro Star and Chevron. Under the price term of that contract, the purchasers buy royalty oil from the Kuparuk Unit, but pay the state a price which is calculated using the volume weighted average of the prices reported by the producers from the Prudhoe Bay Unit rather than the Kuparuk River Unit. Starting with this Prudhoe Bay price, all upstream transportation-related tariffs, quality-differential adjustments and field costs associated with purchasing Kuparuk River Unit oil vis a vis Prudhoe Bay Unit oil are then netted out to determine the interim (pre-Amerada Hess resolution) per barrel price paid by Petro Star and Chevron for the royalty oil.

It was the intent of the parties to "normalize" the price paid for Kuparuk oil with the price paid for Prudhoe Bay royalty oil without either penalty or benefit accruing to either of the parties. However, subsequent actions by the TAPS carriers have resulted in increased costs under the Petro Star and Chevron contract.

Since the legislature's review of this subject contract, all TAPS carriers have instituted a practice of charging a surcharge for oil delivered to TAPS from the Kuparuk River Unit. The amount charged is variable, but it appears that most carriers are charging $0.11 per barrel; however one carrier is currently charging $0.12 per barrel. This surcharge is not a transportation tariff, per se, and it is not a gravity-based quality adjustment. The stated basis for the adjustment is that it compensates the carriers for transporting oil with a "pumpability" factor different from that of the average Prudhoe Bay crude oil.

Chevron has asked the department to amend the contract to allow deduction of this new cost in calculating its purchase price, but the department has informed Chevron that it believes that an administrative remedy is impossible since the requested amendment would result in a material reduction in the price the state receives for the oil, and the contract itself and the applicable statute require legislative review and approval. Although the department has not yet received a formal request for a contract amendment, it expects Chevron to request the legislature's review of its price term this session.

C. Milne Point Shutdown

Conoco, Inc., operators of the Milne Point Unit, have suspended production. The "warm" shutdown means that production could be reinitiated with a minimum of effort and expense. The direct cost to the state of lost production from Milne Point is minimal because production had declined to about 9,000 bbls per day before the decision was made to suspend operations. During 1986, Conoco requested a reduction in the state's 20% royalty on production from the unit. Although the department worked with Conoco to explore alternatives, and supported a legislative amendment which would have given the commissioner explicit authority to reduce the royalty rate before two years of production had occurred, no reduction was granted. The division does not know whether Conoco will seek legislative relief from the royalty provisions this session.

D. ANWR

1. State supports opening for leasing

   The Department of Natural Resources strongly supports the opening of the Arctic National Wildlife Refuge (ANWR) for oil and gas leasing, and is actively participating with other agencies in the administration to develop a response to the Secretary of the Interior's proposed leasing in ANWR which is contained in the 1002 report released by the U.S. Fish and Wildlife Service late last fall.

2. Land trades

   On another front in the ANWR arena the Department is participating in discussion with Interior concerning proposed exchange of state lands for lands within ANWR. The U.S. Fish and Wildlife Service is also discussing potential trades with several Native corporations.

3. Disputed acreage

   Although the draft Interior report on ANWR recognizes the submerged lands ownership dispute between the state and federal governments regarding the coastal lagoons between the mainland and offshore barrier islands, it does not address the navigability status of inland waterways. The state also asserts ownership of the submerged lands underlying the Aichilik, Jago, Okilak, Hulahula, Sadlerochit, Staines and Canning rivers. The state maintains that these are navigable waterbodies with title vested to the state at the time of statehood.

4. Revenue sharing

   Under present law, the state is entitled to receive 90 percent of the revenues (bonus, rent and royalty) derived from oil and gas production on ANWR. Recent comments by Interior representative Bill Horn suggest that there is some discussion underway to determine Interior's position on whether Congress should take some action to reduce the state's share from future leasing of ANWR.

5. Impacts of decisions on state sales

   Currently, the state has two lease sales scheduled on state submerged lands offshore of ANWR (Sale 50, Camden Bay, June 1987; Sale 55, Demarcation Point, June 1988). These areas are considered highly prospective. It is important from the department's perspective that the state urge Congress to allow the potential for the siting in ANWR of oil and gas facilities needed to support offshore oil and gas development. As written, none of the alternatives contained in the draft Department of the Interior report titled "Arctic National Wildlife Refuge, Alaska, Coastal Plain Resource Assessment" (the 1002 report) specifically state that support facilities, if needed, would be permitted.

E. Diligence provisions of state oil and gas leases

In the state's present economic climate, it is likely that there will be increased pressure on the legislature, the administration and the division to relax the diligence provisions of the state's oil and gas leases, to extend drilling and development commitments, and to reduce lessees' royalty obligations. These actions represent major policy decisions which will continue to deserve careful review and thoughtful discussion to assure that the state's long-term interests are protected. It is likely that the proponents of such actions will focus on the current and near-term economic conditions to support their requests; however, petroleum industry activity and crude oil prices traditionally have been cyclical, and this fact should guide consideration of requests to amend the enforcement provisions of state oil and gas leases.

F. West Sak Pilot Project Abandonment

A pilot project by ARCO to evaluate the production characteristics of the West Sak sands has been abandoned. The wells have been plugged and abandoned, and the production facilities are for sale. The lack of firm development plans indicates to the division that the lease owners are not considering production of the West Sak heavy oil in the near future.

G. Five-Year Leasing Program

1. Sale schedule reduced

Since its inception in 1979, the state's formal Five-Year Oil and Gas Leasing Schedule has consisted of three sales a year. This year, in response to state agency budget cuts and reduced industry exploration funds, the division has developed a schedule of two lease sales each year through 1991. Comments were solicited last fall on this reduced schedule. As expected, a variety of opinion was expressed. Comments from industry were mixed. A majority of the companies supported decreasing the number of sales on the schedule, but wanted high potential areas left on the leasing program. Comments from agencies and environmental groups generally supported the reduced schedule. The division believes that its new schedule will provide the state with a strong, judicious leasing program over the next five years.

2. Exempt sales

The division receives several requests from industry each year to hold "exempt" oil and gas lease sales. Exempt sales are provided for in AS 38.05.180(d)(1) through (4), which allows the division to conduct competitive lease sales not on the formal five-year schedule under specific conditions. These conditions range from potential drainage situations to anticipation of early development and evaluation of the acreage being leased. In conducting an exempt sale the division must follow all of the considerable legal requirements imposed on regularly scheduled sales. Already this year the division has received one request for an unscheduled exempt acreage sale in Cook Inlet, and has had an informal inquiry from another company about the feasibility of a North Slope exempt sale. These sales have traditionally made money for the state, and I personally believe it is a good policy to make acreage available for releasing on an expedited basis particularly where there is known interest. However, the division's ability to respond to these requests will relate directly to the level of funding it receives in FY '88. The division anticipates that it will be able to respond to some exempt sale requests if funding is maintained at the FY '87 Revised level.

H. TAPS Tariff

1. Settlement

On October 23, 1985, the Federal Energy Regulatory Commission (FERC) approved an agreement between the State of Alaska and six of the eight owners of TAPS settling the TAPS tariff litigation. On June 27, 1986, FERC approved an amendment to extend the TAPS tariff settlement to the two remaining owners of TAPS. In the majority of cases, the new tariffs were less than the tariffs individually established by the eight separate pipeline companies, commonly referred to as "carriers".

Under the terms of the settlement, the approved TAPS tariffs were applied retroactively for TAPS shipments effective January 1, 1982. The carriers were required to give refunds to all who had shipped oil ("shippers") after that date. Similarly shippers were required to reimburse the state for any excess transportation charges that had been deducted in determining the royalty value of the state's oil. Because the well head value of North Slope oil increases in proportion to the decrease in tariffs, the value of Alaska's North Slope royalty oil was enhanced by the settlement. Consequently, producers of North Slope oil were required to make additional royalty payments to the state based on the royalty-in-value (R-I-V) taken by these producers. In addition to increased royalty payments from the producers, the state also received increased royalty payments from those who purchased Alaska royalty oil during the period covered by the settlement.

Many of the royalty-in-kind (R-I-K) contracts had clauses which used the producers' reported values (R-I-V) as the basis for the R-I-K value. Thus, as R-I-V values were revised upward, so also were R-I-K values, resulting in additional payments to the state. At the end of October 1986, the state had received almost $94 million in increased royalty payments resulting from the TAPS settlement.

2. APUC rate setting

The FERC tariff applies to interstate shipments of oil. The Alaska Public Utilities Commission (APUC) has authority to set tariffs for intrastate shipments of oil through the TAPS line. The APUC currently is considering the intrastate tariff question. Early indications are that the APUC will not accept the FERC tariff for intrastate shipments. This would result in different tariffs being charged for similar oil movements.

I. Cook Inlet Royalty Oil Sale

In 1986, marketing of Alaska's royalty oil entered a new era with the first offering of Cook Inlet royalty oil to a Pacific Rim country. On December 5, the Commissioner of Natural Resources issued a preliminary decision to sell approximately 3,600 barrels per day of Cook Inlet royalty oil to the Chinese Petroleum Corporation of Taiwan, which submitted a premium bid of $1.83 per barrel above the volume weighted average of producers' reported values plus cleaning and dehydrating charges and platform to shore charges. Following public comment, a final decision was issued on January 8, 1987, and delivery of 97 percent of the state's daily royalty oil production from the west side of Cook Inlet is expected to begin in July 1987.

The successful negotiation of this contract culminated a long and complicated lobbying effort on the part of the state to gain federal permission to export Cook Inlet oil and a detailed solicitation by the department to attract interest in the sale. The formal process which resulted in Alaska's first export sale of royalty oil began on July 15, 1986, when the department issued a Solicitation for Offers to Purchase West Side Cook Inlet Royalty Oil. The solicitation and its exhibits provided information on the proposed sale, under a one-year contract, of 97 percent of the state's daily royalty oil production (3,600 barrels per day) from fields on the west side of Cook Inlet. In response to the department's solicitation, seven companies submitted bids. Because the sale was a non-competitive disposal, the Commissioner was required to consider other factors in addition to the per barrel price offered by prospective purchasers, such as the effects of the sale on the state's economy, the projected positive and negative environmental effects of the transaction, and the effects on existing private commercial enterprise and investments.

0733R

1/29/87
3:32

✓BF
✓Fischer
✓Coghill

Eason

$\boxed{\text{8(g) Revenue sharing -}}$

Sec of OCS land Act amended. 1978
"fair and equitable" split.
in Court.

Congress - 27% share to state.
(also got 1979 lands)

AK re 54 million
+ 134 over next 15 yrs
another acc't for disputed acreage.

After boundary dispute

Tom Koester handling dispute.
Master's report to Supreme

* only within 3 miles of 3 mile bndy

ongoing discussion re: joint-fed
unitization.
like SEAL ISLAND

Louisiana pursuing legislative
solution —
compell Sec of Int to
unitize

check w/ Mark Worcester, LAW

2) Petro Star Chevron Contract Amendment

Chevron would like to pursue amendment.

Negotiated + approved last session

6500 / bbd

2500 Petro
4000 Chev

$$\begin{array}{r} 6500 \\ 15 \\ \hline 325 \\ 65 \\ \hline 975.00 \end{array}$$

~ $1000/day

wanted Kuparuk oil

price term based on Prudhoe price
deducted

Premium

35¢/b Petro
50¢/bl Chev.

TAPS is charging a "pumpability factor"
surcharge or credit allowed.

charging 15¢/bl as surcharge.

deducting it from in-value price
royalty payment

Ask Maynard —
settlement allows adjustment.
how much freedom do they have to rate surcharge.

(3) Shutdown of Milne Point.

Royalty relief —

Department agreed w/ Conoco —

Statutes require 2 years production
+ showing of non-economic

Check w/ Conoco —

would royalty relief have helped?

(4) ANWR —

reconvene 7:00 am

1) Caviton

2) Land Trades —

State participating.
no decision made

Cog

looking at broad federal issues?

BAF

assurance That administration speak w/ one voice.

Cog surveys a ANWR -

— 3 years ago - siesmic

ASRC well completed last fall

Sohio, BP, Chevron.

AOGCC has confidential data

State has geophysical data

deep siesmic data was

Disputed Acreage

state always owns islands

ANWR includes offshore island.

water between ~~state~~ islands + mainland.

disputed.

Camden Bay #50 in 6/87

3 miles seaward of islands

OCS sale offshore of it.

Revenue sharing –

Congress will want to see our share reduced.

w/in Interior effort to reduce

[Read RD's report]

~~Ba~~ WORK COMMITMENTS

or ~~diligence~~ diligence provisions.

supports keeping lesees to their contract.

don't use work commitments anymore

WEST SAK SANDS

2000 - 2800 ft. shallow.

geologically young.

heavy, low-gravity oil -

difficult to produce.

Arco – West Sak pilot project.
proved high rates of production

Arco has abandoned -

5-Year schedule —

reduced to 2/year.

concentrate on North Slope or
near Known production.

#51 289,000 Bonus Bid
100,000 in first year rentals.

much of it was reoffered acreage

favorable — 12% royalty
no net profit share
minimum bid $2/acre.

20% were bid on.

101,000 out of
500,000 acres.

Permit reform -
seems to be working.

Dave Johnson } working on
Wade Schock } stipulation study

Exempt sales.

looking at streamlining

potential in CI and North Slope

$\boxed{\text{TAPS Tariff}}$

94 million in increased royalties

$\boxed{\text{Export of CI Oil}}$

Still some prohibitions

West side is OK

East - pipeline crosses fed ROW
mixes w/ Fed oil from
Swanson River.

Bid for China Petro - Taiwan
1.83/bbl premium
3600/day for 1 year only
each delivery subject to cancellation in the
case of national emergency.

ROYALTY DENOMINATION

Tesoro denomination last year

in new contracts
would be something you could delete

continued

Valdez —

AK Pacific refing.
interested -
moved offices to anch -
negotiating directly w/ producers

Fed Royalty Management Advisory Committee

Gas valuation
regulations before Dept of Interior

Valuation procedures.

Beaufort Sea drilling restrictions

comments on Camden Bay which
NSB is happy.

Teshepuk -

decision not to sign

check This out

Petro Star - Mapco -
adjourned 5:20

2-3-87

Joint Special Committee on Tax Policy

STATE OF ALASKA

POUCH V
JUNEAU, ALASKA 99811
(907) 465-4941

SENATE SPECIAL COMMITTEE ON OIL AND GAS

MEMORANDUM

TO: Members, Senate Special Committee on Oil and Gas

FROM: Committee Staff

RE: Joint Special Committee on Tax Policy Meeting, February 3, 1987

DATE: February 2, 1987

On Tuesday, February 3, the regularly scheduled meeting of the Senate Special Committee on Oil and Gas has been cancelled so that members will be able to attend the Joint Special Committee on Tax Policy Meeting. The meeting will be held at 3:30 pm in House Finance. Attached please find a draft of the first report of the Tax Policy Committee. Discussion of oil and gas taxes, including options for changes to the Economic Limit Factor and the oil and gas income tax, should be of particular interest to committee members.

Also attached for your review is a letter from the Commissioner of the Department of Natural Resources regarding a determination to take royalty oil in money (in- value).

Alaska State Legislature

Official Business

Pouch V
State Capitol
Juneau, Alaska 99811

JOINT SPECIAL COMMITTEE ON TAX POLICY

AGENDA for February 3, 1987

1. Overview of Department of Revenue Tax Reports
   Vince Wright, Chief of Research

2. Review Draft of Tax Policy Committee Report

Alaska State Legislature

JOINT SPECIAL COMMITTEE ON TAX POLICY

Official Business

Pouch V
State Capitol
Juneau, Alaska 99811

January 27, 1987

MEMORANDUM

TO: Members, Joint Special Committee on Tax Policy

FROM: Rep. John Sund, House Co-Chair

RE: Draft Committee Report

Attached please find a draft of the first report of the Joint Special Committee on Tax Policy. The report is limited in scope for three reasons: The committee took no votes and made no recommendations, the Senate Chairman resigned from the Legislature, and the House Chairmanship changed hands (from Rep. Grussendorf to Rep. Sund) at the final meeting, in December.

Please review the report and Table of Contents of materials to be attached to the final report and let me know any changes you might recommend.

DRAFT TAX POLICY COMMITTEE REPORT

Table of Contents:

1. Memo from the Chairman
2. Committee Report Draft
3. SCR 42
4. Membership list
5. Bibliography
6. Income Tax Report
7. Minutes
8. ELF Reports
9. Revenue Projections by tax type
10. Misc. Revenues report

A. Introduction

The purpose of this report is to outline briefly issues of Alaska tax policy considered by the Joint Special Committee on Tax Policy.

The Committee was created by the passage of Senate Concurrent Resolution 42, in May 1986. It is scheduled to dissolve on the 11th day of the second session of the Fifteenth Alaska Legislature, in January 1988.

Membership on the Committee includes three members from the House, three from the Senate, two from the Administration, and three public members.

The Committee has a comprehensive charge of examining all issues relating to tax policy in Alaska.

The Committee has met three times, in Anchorage (see minutes, attached).

B. Issues explored by the Tax Policy Committee

Before evaluating any specific taxes, it is important to establish criteria for evaluation. The Department of Revenue, in a memo given to the Committee on alternative means for increasing revenues, listed five criteria for evaluating tax policies. The five are:

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Economic Efficiency: What effect does the proposed tax law change have on incentives and economic decision-making which may alter consumption, production or resource allocation decisions?

Equity: Who bears the burden of the tax and how does that burden compare with ability to pay or benefits received? Is the tax progressive or regressive with respect to income and/or wealth?

Elasticity: What is the sensitivity of the tax revenue yield to changes in economic or demographic conditions? As income or population increase and decrease does tax revenue increase or decrease in greater, lesser or equal proportion?

Administrative Efficiency: How costly is the tax to administer in terms of resources devoted to administration and compliance relative to the revenue yield of the tax? Who bears the burden of administrative cost, the taxpayer, the State, or the tax collector if different from the state?

Political Feasibility: How acceptable is a proposed tax law change to the legislature and/or the electorate given the existing social, political, and economic conditions? Who benefits, who loses, and who has the most political power?

In addition to these, the Committee considered several other tax evaluation criteria:

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Revenue raised for the state: How much revenue does the tax change raise for the State?

Employment Impact: What will be the impact on employment in the public and private sector?

Capital Impact: What will be the impact on investment capital availablity in Alaska?

New Federal Tax Code: How does the proposed tax law change relate to the new Federal Tax Code?

For oil and gas taxes, the Committee looked at several additional evaluation criteria:

Impact on exploration, development and production.

Relative impacts on small and large fields.

Impact on secondary and tertiary recovery and recoverable reserves.

Possibility of premature shutdown of producing fields, and future oil and gas production loss.

Impact on Cook Inlet fields.

Impact on royalty income.

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Impact on severance income.

Alaska Tax Policy

ELF

Much of the Committee's time has been spent on questions relating to the Alaska Severance Tax, in particular, the Economic Limit Factor (ELF). The purpose of the ELF is to provide severance tax relief to marginal oil fields in order to keep them in production, retaining economic benefits for the state. The ELF is calculated to be a number between zero and one and can be thought of as representing a percentage of the nominal severance tax rate (e.g. a field with an ELF of 0.6 means 60% of the nominal severance tax rate is applied to that field). The ELF is an issue at this time largely because an ELF provision that sets the ELF at 1.0 if the calculated ELF is greater than 0.7, expires after a field has been in production for ten years, and Prudhoe Bay will have been in production for ten years as of July 1987. When the ten-year exemption for Prudhoe Bay expires, and no changes are made to the law, the ELF for Prudhoe Bay will go to an estimated .82, reducing severance taxes by over $100 million per year. The oil industry opposes any change to the ELF formula, saying that it will reduce producer revenues available for reinvestment in Alaska, reduce research and development in Alaska and may cause premature shutdown of producing fields.

Eight options were considered for the ELF:

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1) Fix the per-barrel severance tax floor at $.80 to which ELF does not apply.

	FY 88	FY 89	FY 88-2005
Revenue from this option:	30 M	20 M	210 M (50% case)

[Source: Dept. of Revenue]

2) Same as #1, plus set 300 bbl/day PEL (Production Economic Limit) in statute (now a rebuttable presumption), and repeal the ELF exponent.

3) Set the per-barrel floor at $1.50 and index it with inflation. The $1.50 figure was selected based on applying a CPI inflator to the original $.80 floor. This option was rejected by the Committee based mainly on the fact that it would have a severe negative impact on oil production in Cook Inlet.

4) Repeal the ELF entirely on all fields. This option was rejected as the Committee supported the policy of giving marginal oil fields a tax break as with the ELF.

5) Modify the exponent of the ELF formula and base the PEL on field production rather than per-well production. The modification of the ELF exponent would have the effect of giving additional tax relief to marginal fields while increasing the tax receipts from very large fields. The net result would be an increase in severance tax income over present law.

	FY 88	FY 89	FY 88-2005
Revenue from this option:	140 M	140 M	1,670 M (50% case)

[Source: Dept. of Revenue]

DRAFT

6) Include the provisions of option 5 with the addition of a floor which is not affected by the ELF. This option was rejected by the Committee based on the negative effects on Cook Inlet oil fields stemming from the floor change.

7) Extend the ten-year Prudhoe Bay exemption to fifteen years.

8) No change in the law, i.e. allow the scheduled application of ELF to Prudhoe Bay.

Oil and Gas Income Tax

The major issues considered regarding the Oil and Gas Income Tax revolve around the question of separate accounting of oil and gas income in Alaska versus that of apportioning Alaska income by formula. Present law uses the 'modified apportionment' approach. Separate accounting was used in Alaska for the years 1978-1981, but was repealed because the State was exposed to the possibility of large tax refunds if the courts had ruled for the oil companies who brought suit. The State Supreme Court and the U.S. Supreme Court ruled in favor of the state, holding that separate accounting is within the prerogative of the legislature as a method of determining Alaska income for taxation.

Separate accounting is generally considered to more accurately reflect oil and gas income earned in Alaska. Separate accounting has the disadvantage of being more volatile, that is state income closely follows the rise and fall of oil prices on the world

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market. The oil and gas industry vigorously opposes the imposition of separate accounting in Alaska as they feel that it can expose them to taxation on more than 100% of their earnings. House Bill 353, which would have reinstated separate accounting was introduced in the Fourteenth Legislature, but did not pass either body. According the the most recent (January, 1987) report of the Alaska Department of Revenue, at current oil prices separate accounting would result in lower revenues for the state. They show a crossover point where separate accounting would result in more revenue for the state at $14-16/barrel wellhead value.

Individual Income Tax

The State of Alaska is one of seven states without an individual income tax. The Committee requested a report from the Department of Revenue on the revenue potential and economic impacts of a personal income tax. The report was completed at the end of December, 1986, and is attached. The report examines three types of state income taxes and examines revenue potentials of each against two possible economic scenarios for the state's future. It is interesting to note that were the State to reimpose the individual income tax with the same rate structure as was in effect before it was repealed, the tax would yield between $399 million (low economic scenario) and $436 million (moderate economic scenario) for tax year 1988. These amounts exceed previous estimates by approximately $100 million.

State Sales Tax

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The State of Alaska is one of five states without a statewide sales tax. The Department of Revenue recently completed a study of the revenue potential of a statewide sales tax. The report concludes that in calendar year 1988, if sales of food are not exempted, a retail sales tax would yield $38,355,000 per one percent tax. In addition, the service sector of the economy, could yield approximately $14 million per one percent tax.

Issues to be explored by Committee

There are a great many tax issues which could be productively explored by the Joint Special Committee on Tax Policy. An outline of some of these issues is provided below.

1. Corporate Income Tax
   a) Rates
   b) Worldwide Combination
   c) Separate entity
   d) Waters' edge
   e) Changes to Apportionment formula
2. Severance Tax
   a) Definition of a marginal field?
   b) Definition of Field, Unit
3. Motor Fuel taxes
4. Special tax incentives and credits
   a) Exploration Incentive
   b) Mining License 3.5-year moratorium

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c) Special Industrial Tax Credit

d) Credits included in adoption of IRS code

e) Investment Tax Credit

f) Non-Highway Use refund

g) Oil Gravity Adjustment

5. Oil and Gas Property Tax (ad valorem)

a) Municipal uniformity

6. Disputed taxes

a) DOR need for auditors, etc.

b) Taxpayer Confidentiality

c) Outlook for settlements

7. Lottery

8. Oil & Gas Reserves Tax

9. Tobacco Tax

10. Alcohol Tax

11. Gross Receipts Tax

12. School Tax

13. Fisheries Taxes

Conclusion The Joint Special Committee on Tax Policy has attempted to establish policy guidelines to examine Alaska's tax structure. The Committee has developed information regarding impacts of some proposed tax schemes. Other than rejecting certain proposals relating to the ELF, the Committee has reached no conclusions or recommendations regarding any specific tax proposal.

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* PLEASE NOTE: Circled reports are those which will be included in Table of Contents.

BIBLIOGRAPHY OF MATERIALS
JOINT SPECIAL COMMITTEE ON TAX POLICY
January, 1987

The following is a bibliography of research papers collected by the Joint Special Committee on Tax Policy as of January, 1987. A set of the materials is on file in the Office of Rep. John Sund, House Chair. (Rm 118, Capitol. 465-4919).

A. Individual Income Tax

1. Individual Income Tax Report, Mary Ellen Frank, Economist, et. al. State of Alaska, Department of Revenue, memo to Vince Wright, Chief of Research, State of Alaska, Department of Revenue, December 1986

2. Commuter Taxes as They Relate to Resident Hire, Memo to Rep. Mike Davis from Mary Jennings, Legislative Analyst, State of Alaska, House Research Agency, April 1986

B. State Sales Tax

1. Revenue Potential of a General Sales Tax, Vince Wright, Chief of Research, State of Alaska, Department of Revenue, December 1986

C. Oil Taxes - General

1. The Taxation of the Petroleum Industry Under Alaska's Corporate Income Tax: A Report Prepared for the Alaska Legislature and the Alaska Department of Revenue, Jerome Zeifman and Kenneth Ainsworth, January 1977

2. Alaska's Oil and Gas Tax Structure: A Study with Recommendations for Improvement. Alaska Department of Revenue, February 1977

3. Impact of Increased Taxation on Oil Exploration and Development in Alaska: A Report to the Alaska State Legislature, Tanzer Economic Associates, March, 1977

4. Recommended Changes in Alaska's Oil and Gas Production Tax Rates, A Report to Governor Jay Hammond, By the Alaska Department of Revenue, 1978

5. The History of Oil and Gas Taxation in Alaska, Thomas K. Williams, Commissioner of the Alaska Department of Revenue, 1978

6. Prudhoe Bay Field and Trans-Alaska Pipeline System: Comparative State Tax Burden Study, Arthur Anderson & Co. for the Alaska Oil and Gas Association, Februrary, 1979

7. Historical Review of Alaska Petroleum Taxes, 1955-1978, Mike Bradner for the Alaska State Legislature, April 1979

8. Alaska Oil and Gas Income Taxation, John Messinger, Gregg Erickson, and Lawrence Eppenbach for the Alaska State Legislature Joint Gas Pipeline Committee, April 1981

9. A Sound Strategy for Protecting Alaska's Oil and Gas Revenues: an Analysis of the Backstop Tax Legislation, Preston Thorgrimson, Ellis & Holman (John Messenger) for the

10. Legislative History Materials, 1981 Corporate Income Tax Amendments, Volumes I & II

11. Alaska Petroleum Revenues: The Influence of Federal Policy, University of Alaska, Institute of Social and Economic Research, for the State of Alaska, Office of the Governor October 1984

12. Impact of Tax Simplification Proposals on Oil and Gas Production and the Economy - Alaska, Interstate Oil Compact Commission, Februrary 1985

13. State, Federal and Industry Shares of Alaska Resource Income, Fiscal Years 1982-1985, State of Alaska, Office of the Governor, Office of Management and Budget, Tom Chester, April 1986

D. Severance Tax

1. Policy Considerations Behind the Severance Tax, Jon Tillinghast, Assistant Attorney General, State of Alaska, Attached to Memo to the Joint Special Committee on Tax Policy from Richard Monkman, Deputy Commissioner, Taxation, Department of Revenue, September 1986

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E. ELF

1. Transcript of Presentation on ELF given by Gregg Erickson State of Alaska, Office of the Governor, Office of Management and Budget, for the Tax Polcy Committee Meeting, September 1986

2. Memorandum on Proposed Changes to the Severance Tax ELF, Memo from G.J. Abraham to George Nelson, Standard Alaska Production, October 1986

3. Analysis of ELF Alternatives, Charles Logsdon, Petroleum Economist, State of Alaska, Department of Revenue, December 1986

4. Alternative ELF, Thomas Chester, State of Alaska, Office of the Governor, Office of Management and Budget, 1986

5. Low (Oil) Prices and the ELF, Memo from Charles Logsdon, Petroleum Economist, State of Alaska, Department of Revenue to Vincent Wright, Chief of Research, April 1986

6. Letter from John R. Kemp, Division Manager, Conoco, Inc. to Senator Frank Ferguson, Senate Chair, Joint Special Committee on Tax Policy, September 1986

7. The Economic Limit Factor in Alaska's Oil and Gas Properties Production Tax, Thomas K. Williams for Standard Alaska Production Company, September 1986

F. Separate Accounting

1. Affidavit of Edward B. Deakin, CPA, Ph.D. In the Superior Court, State of Alaska, in ARCO v. State of Alaska, November 1981

2. Interim Report of the House Finance Subcommittee on Oil and Gas, Louann Cutler and Sharman Piper, Alaska State Legislature, January 1986

3. Analysis of HB 353, Alaska Department of Revenue, Memo from Vince Wright, Director of Research to Commissioner Mary Nordale, October 1985

4. Sensitivity Analysis of House Bill 353, Memo from John Larson, Economist, et. al. State of Alaska, Department of Revenue, to Vince Wright, Chief of Research, State of Alaska, Department of Revenue, December 1986

5. Overview of Issues Involved in Consideration of HB 353, Memo from Louann Cutler, Special Assistant to Rep. Al Adams, Chair, House Finance Committee, State of Alaska, Alaska State Legislature, October 1985

6. White Paper Report to the Alaska State Legislature on Alaska Oil and Gas Resources, Alaska State AFL-CIO and Alaska Teamsters, Local 959, January 1986

7. The Effects of State Income Tax Policy on the Development of Marginal Oil Fields: An Analysis of the Impact of House Bill 353, House Research Agency, Alaska State Legislature, January 1986

8. Revenue from Separate Accounting, Memo to Mary Halloran, Office of the Speaker, State of Alaska, Alaska State Legislature, Gregg Erickson, Senior Economist, State of Alaska, Office of the Governor, Office of Management and Budget, December 1986

9. Overview and Sectional Analysis of House Bill 353, Deborah Vogt, Assistant Attorney General, State of Alaska,

G. Oil and Gas Conservation Tax

1. Memo to Governor Bill Sheffield and attached Proposed Legislation on the Oil and Gas Conservation Tax, Harold M. Brown, Attorney General, State of Alaska, November 1986

H. Corporate Income Tax

1. Sujong v. State of Alaska, Department of Revenue Court Decision, Alaska, 622 P.2d 967

2. Income Tax in Alaska, Deborah Vogt, Assistant Attorney General, State of Alaska, July 1986

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4. Container Corporation of America v. Francise Tax Board, U. S. Supreme Court Decision, June 1983

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J. Misc. Taxes

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2. Revenue Alternatives - Excise Taxes, Fisheries Taxes, Licenses and Permits, Vince Wright, Chief of Research, State of Alaska, Department of Revenue, December 1986

3. Alaska Mineral Taxation Compared to Taxes on Mines in Eleven States, Whitney & Whitney, Inc. for State of Alaska, Department of Commerce and Economic Development, Office of Mineral Development, January 1982

K. Disputed Taxes

1. Expidited Collections of Disputed Taxes, Memo to Rep. Al Adams, Chairman, House Finance Committee, State of Alaska, Department of Revenue, January 1986

2. Prepayment of Disputed Taxes, Memo to Rep. Al Adams, Chairman, House Finance Committee, State of Alaska, Department of Law, January 1986

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Alaska State Legislature

Senate

Office of the Secretary

Official Business

Pouch V
State Capitol
Juneau, Alaska 99811

January 30, 1987

M E M O R A N D U M

TO: Senator Bettye Fahrenkamp, Co-Chairman
Senate Special Committee on Oil & Gas

FROM: Peggy Mulligan PM
Secretary of the Senate

SUBJECT: Letter from Judith M. Brady, Commissioner, Department of Natural Resources regarding "Determination to Take Royalty in Money (In Value)"

The President has referred the attached letter to your committee for review.

Special oil and Gas Resources

RECEIVED JAN 2 8 1987

STATE OF ALASKA

STEVE COWPER, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

POUCH M
JUNEAU, ALASKA 99811
PHONE: (907) 465-2400

January 26, 1987

The Honorable Jan Faiks
President of the Senate
Alaska State Legislature
P.O. Box V
Juneau, Alaska 99811

Reference: Determination to Take Royalty in Money (In Value)

Dear Senator Faiks:

Under the provisions of AS. 38.05.182(b), I am writing to inform you of my determinations to accept royalty in value for certain royalties from production in the Prudhoe Bay, Kuparuk River and Milne Point Units on the North Slope, as well as from the Granite Point and Middle Ground Shoal fields and the McArthur River and Trading Bay Units in Cook Inlet. The rationale for these decisions is summarized below.

As you are aware, a fairly large percentage of royalty production from the North Slope Units remains committed to long-term negotiated contracts with Chevron, Mapco, Tesoro, Golden Valley Electric Association, and Petro Star, Inc. In addition, a percentage of the remaining production continues to be taken in value to ensure that the department has ample royalty production to offset the lessees' costs of cleaning, dehydrating and handling the state's share of the oil, and to ensure that the state has continued access to the producers' royalty sales reports. The remainder of the royalty production from the Prudhoe Bay Unit and approximately 80 percent from the Kuparuk River Unit, and all production from the Milne Point Unit remain in value. Following the department's February 4, 1986 competitive sale of royalty oil from Prudhoe Bay Unit, at which no bids were received, former Commissioner Wunnicke decided that additional competitive sales of state royalty oil should be deferred until world crude oil markets stabilized.

Currently, and until July 1987, all Cook Inlet royalty production is taken in value. The department has entered into a one year contract for the sale of 97 percent of west side Cook Inlet royalty oil with Chinese Petroleum Corporation with deliveries to commence July 10, 1987. This volume will comprise approximately 80 percent of available Cook Inlet royalty oil. Oil which is produced from the Middle Ground Shoal field on the east side of Cook Inlet and the remaining 3 percent of the west side royalty oil will be left in value. For logistical reasons--primarily resulting from insufficient storage capacity, rapidly declining volumes, and commingling of federal production--it was impractical to offer the east side volume with the rest of the Cook Inlet royalty oil. Consequently, because of its relatively small volume this oil will likely remain in value.

If you have any questions regarding these determinations, or would like to discuss the department's policies in more detail, please feel free to contact me.

Sincerely,

Judith M. Brady

Judith M. Brady
Commissioner

cc: James E. Eason, Director, Division of Oil and Gas
Donna Wood Johnson, Royalty Manager, Division of Oil and Gas
Steve Porter, Assistant Attorney General, DOL

0583E

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(h) Regulations adopted by the commissioner to implement this section shall be adopted in accordance with the Administrative Procedure Act (AS 44.62.010 — 44.62.650). (§ 1 ch 71 SLA 1971; am § 6 ch 104 SLA 1971; am §§ 34 — 36 ch 71 SLA 1972; am §§ 40, 41 ch 127 SLA 1974; am § 4 ch 175 SLA 1980)

Cross references. — For geothermal resources generally, see AS 41.06. For legislative policy with respect to geothermal resources, see § 1, ch. 175, SLA 1980 in the Temporary and Special Acts.

Effect of amendments. — The 1980 amendment rewrote the section.

Collateral references. — Construction and application of Geothermal Steam Act of 1970 (30 USCS § 1001 et seq.), pertaining to leases of government lands for development of geothermal steam resources, 40 ALR Fed 814.

Sec. 38.05.182. Royalty on natural resources. (a) Any royalty provided for in AS 38.05.135 — 38.05.181 may be taken in kind rather than in money if the commissioner determines that the taking in kind would be in the best interest of the state. However, royalties on oil and gas shall be taken in kind unless the commissioner determines that the taking in money would be in the best interest of the state.

(b) The commissioner shall submit a determination to take royalty in money to the legislature at the first opportunity during a current session or, if the legislature is not in session, at the next regular session. The legislature, within 60 days or by the adjournment of the session, whichever comes sooner, may revoke the determination by concurrent resolution. (§ 1 ch 56 SLA 1970; am § 7 ch 71 SLA 1971; am § 1 ch 9 SSSLA 1974; am § 5 ch 218 SLA 1976; am § 1 ch 146 SLA 1977; am § 8 ch 112 SLA 1980)

Revisor's notes. — Enacted as AS 38.05.362. Renumbered in 1970.

Effect of amendments. — The 1980 amendment deleted "(1)" following "in kind unless," and deleted "and (2) the Alaska Royalty Oil and Gas Development Advisory Board approves the taking in money" following "best interest of the state," and in subsection (b), deleted "approved under (a) of this section" following "to take royalty in money."

NOTES TO DECISIONS

Quoted in McKinnon v. Alpetco Co., Sup. Ct. Op. No. 2413 (File No. 5546), 633 P.2d 281 (1981).

Collateral references. — 38 Am. Jur. 2d, Gas and Oil, §§ 189-198.

58 C.J.S., Mines and Minerals, §§ 185 to 192, 213 to 219.

Acceptance of rents or royalties under oil and gas lease as waiver of forfeiture for breach of covenant or condition regarding drilling of wells, 80 ALR 461.

Lessor's acceptance of royalty under gas and oil lease after lease has expired as precluding him from insisting upon expiration, 113 ALR 396.

What constitutes "royalty" on oil or gas production within language of conveyance, exception or reservation. 4 ALR2d 492.

Construction and effect of provision in mineral lease excusing payment of minimum rent or royalty. 28 ALR2d 1013.

Solid mineral royalty as real or personal property. 68 ALR2d 728.

Solid mineral royalty under mining lease as real or personal property for purpose of payment of damages in condemnation proceedings. 68 ALR2d 735.

Payment of sh royalties or annual re eral lease as preclud forfeiture or aband 1076.

"Shut-in royalty" p oil and gas leases. 96

Rights of parties to royalty deed after exp where production ten ALR2d 885.

Sec. 38.05.183. Sale of royalty. (a) The sale, ex disposal of a mineral obtained by the state as a r 38.05.182, or the sale, exchange or other disposal in of a right to receive future mineral production un under this chapter, shall be by competitive bid and th or other disposal made to the highest responsible bi competitive bidding is not required when the commiss written notice to the Alaska Royalty Oil and G Advisory Board under AS 38.06.050, determines that of the state does not require it or that no competitio

(b) When competitive bids are required, the con prior written notice to the Alaska Royalty Oil and (Advisory Board, may reject all bids on a determinatio the amount of the bids, the lack of responsibility o bidders, or for reasons consistent with the criteri 38.06.070, the acceptance of the bids would not be in of the state.

(c) If the commissioner determines that a sale, e disposal of a mineral obtained by the state as a r 38.05.182 or of a right to receive future mineral pr state lease under this chapter shall be made otherwise tive bid, and the Alaska Royalty Oil and Gas Devel Board has been notified in writing of that determinat sioner shall make public in writing the specific find sions upon which that determination is based.

(d) Oil or gas taken in kind by the state as its royal be sold or otherwise disposed of for export from th commissioner determines that the royalty-in-kind oil to the present and projected intrastate domestic and The commissioner shall make public, in writing, the and reasons on which the determination is based an days of the convening of a regular session of the legi report showing the immediate and long-range domes needs of the state for oil and gas and an analysis of ho to be met.

2/3/87
3:40

BF
P. Fischer
Mary Hallman
Terry Moylan
Vince Wright

Brown
Sund
Kerttula
Coghill
Duncan

Tax Policy Committee Mtg.
Bart Garber
Dave Rasely
George Wilson

Income tax — 3 structures

1) benchmark.
2) piggyback to feds
tax tables, deductions, etc
3) flat tax —
some progressiveness. for equity.

1) Progressivity - equitable -
high income pay more.
#1 most progressive

2) Elasticity. —
more elastic, more unstable
enhances peaks in income
#1 is most elastic

3) ~~Inflation~~
= 400 million w/o indexing
300 w/indexing

4) Leakages.
1) deduct state taxes
transfer from fed → state
2) deduct property tax
leak from state → municipality

5) look to other states

4) PFD — tax or not?

(4) administrative compliance cost.
most complicated, more cost

Gov. introducing bill by end of month.

SALES TAX

1% = 35 million

exemptions — for food, drugs —
for lower income —

2% — does not double revenue =
reduced consumption.

1) regressivity —
lower pay higher percentage of income
2) isolated —
catalogue sales not taxed
3) double taxation —
municipality tax too.
could credit county tax
4) not deductible from fed tax.

5) non-residents —
tax exempt cards

advant

1) elastic
2) easy to administer.
3) 45 states have it

49% of all tax collected.

Alternative —

(1) excise —
alcohol
tobacco
fuel
1) not elastic → stable

2) administrative cost -
already are here

Cigarette.
1c ¢ = 10-11 million

Maine = 18¢ = 18 million = 7 million more

Alcohol -
equalize = 4.5 million more

Motor fuel -
refund + credits -
delete = would have to tax 2.2¢/gal addtl.
8¢/gal tax off highway, construction, 6¢/gals

(2) fishery
① credits limited to aid only certain processors
② tax linkage
③ ASMI assessment. 4.5 million
eliminate state subsidy

ELF — Malone wants approach
based on HB 545 - tax prolific field
heavier, marginal lighter —
stimulate production in marginal fields
suspend for 5 years —
or similar way to limit extra
production to be cut back.

Committee - 8 options
rejected 3 or 4.

* ① modify exemption
field rather than well production

Martin

Jones Act / Export of AK oil

major source of revenue.

Brown

extend ELF from 10 - 15 years?

Weight = $4/89 $150 million / year
90 143

JOHN SUND, REPRESENTATIVE
2505 2nd Avenue
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While in Juneau
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Juneau, Alaska 99811
(907) 465-4919

MEMORANDUM

2/3/87

TO: Members, Joint Special Committee on Tax Policy

FROM: Rep. John Sund, House Co-Chair, Joint Special Committee on Tax Policy

RE: Suggested changes to tax report

We have circulated the draft of the preliminary report of the Joint Special Committee on Tax Policy and are starting to get back comments and suggested changes.

The report, or course, should be viewed as attempting to briefly outline issues the Committee has considered. The actual Committee Report is due next year.

Based on comments received to date, I am suggesting the following changes:

1) Page 7, numbered paragraph 5: substitute "in addition to" for "rather than." This indicates that in an ELF proposal studied by OMB, field productivity would be used in addition to well productivity in calculating the ELF.

2) Page 7, where revenue estimates are used, use the 30% case instead of the 50% case.

3) On page 9 of the draft, first paragraph, delete the last two sentences and replace with:

"According to a January 1987 report from the Department of Revenue, substituting separate accounting for modified apportionment would increase FY 1988 revenues by almost $100 million, assuming current oil prices [Graph II-9-1, page 95]. Little or no additional revenue would be gained, however, if the change to separate accounting were accompanied by the severance tax reduction called for under HB 353, again assuming no change in oil prices [Graph II-9-3, page 95].

The DOR study suggests that the crossover point, above which separate accounting by itself would produce more FY 1988 revenue for the state, is between $5/barrel and $7/barrel wellhead value. The current wellhead value is about $8.75/barrel. The crossover point tends to increase in later years, as does the DOR forecast of wellhead value."

DRAFT TAX POLICY COMMITTEE REPORT
Volume I

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3. Revenue Projections by Tax Type

4. SCR 42

5. Membership List

6. Bibliography

Alaska State Legislature

JOINT SPECIAL COMMITTEE ON TAX POLICY

Official Business

Pouch V
State Capitol
Juneau, Alaska 99811

January 27, 1987

MEMORANDUM

TO: Members, Joint Special Committee on Tax Policy

FROM: Rep. John Sund, House Co-Chair

RE: Draft Committee Report

Attached please find a draft of the first report of the Joint Special Committee on Tax Policy. The report is limited in scope for three reasons: The committee took no votes and made no recommendations, the Senate Chairman resigned from the Legislature, and the House Chairmanship changed hands (from Rep. Grussendorf to Rep. Sund) at the final meeting, in December.

Please review the report and Table of Contents of materials to be attached to the final report and let me know any changes you might recommend.

A. Introduction

The purpose of this report is to outline briefly issues of Alaska tax policy considered by the Joint Special Committee on Tax Policy.

The Committee was created by the passage of Senate Concurrent Resolution 42, in May 1986. It is scheduled to dissolve on the 11th day of the second session of the Fifteenth Alaska Legislature, in January 1988.

Membership on the Committee includes three members from the House, three from the Senate, two from the Administration, and three public members.

The Committee has a comprehensive charge of examining all issues relating to tax policy in Alaska.

The Committee has met three times, in Anchorage (see minutes, attached).

B. Issues explored by the Tax Policy Committee

Before evaluating any specific taxes, it is important to establish criteria for evaluation. The Department of Revenue, in a memo given to the Committee on alternative means for increasing revenues, listed five criteria for evaluating tax policies. The five are:

DRAFT

Economic Efficiency: What effect does the proposed tax law change have on incentives and economic decision-making which may alter consumption, production or resource allocation decisions?

Equity: Who bears the burden of the tax and how does that burden compare with ability to pay or benefits received? Is the tax progressive or regressive with respect to income and/or wealth?

Elasticity: What is the sensitivity of the tax revenue yield to changes in economic or demographic conditions? As income or population increase and decrease does tax revenue increase or decrease in greater, lesser or equal proportion?

Administrative Efficiency: How costly is the tax to administer in terms of resources devoted to administration and compliance relative to the revenue yield of the tax? Who bears the burden of administrative cost, the taxpayer, the State, or the tax collector if different from the state?

Political Feasibility: How acceptable is a proposed tax law change to the legislature and/or the electorate given the existing social, political, and economic conditions? Who benefits, who loses, and who has the most political power?

In addition to these, the Committee considered several other tax evaluation criteria:

DRAFT

Revenue raised for the state: How much revenue does the tax change raise for the State?

Employment Impact: What will be the impact on employment in the public and private sector?

Capital Impact: What will be the impact on investment capital availablity in Alaska?

New Federal Tax Code: How does the proposed tax law change relate to the new Federal Tax Code?

For oil and gas taxes, the Committee looked at several additional evaluation criteria:

Impact on exploration, development and production.

Relative impacts on small and large fields.

Impact on secondary and tertiary recovery and recoverable reserves.

Possibility of premature shutdown of producing fields, and future oil and gas production loss.

Impact on Cook Inlet fields.

Impact on royalty income.

DRAFT

Impact on severance income.

Alaska Tax Policy

ELF

Much of the Committee's time has been spent on questions relating to the Alaska Severance Tax, in particular, the Economic Limit Factor (ELF). The purpose of the ELF is to provide severance tax relief to marginal oil fields in order to keep them in production, retaining economic benefits for the state. The ELF is calculated to be a number between zero and one and can be thought of as representing a percentage of the nominal severance tax rate (e.g. a field with an ELF of 0.6 means 60% of the nominal severance tax rate is applied to that field). The ELF is an issue at this time largely because an ELF provision that sets the ELF at 1.0 if the calculated ELF is greater than 0.7, expires after a field has been in production for ten years, and Prudhoe Bay will have been in production for ten years as of July 1987. When the ten-year exemption for Prudhoe Bay expires, and no changes are made to the law, the ELF for Prudhoe Bay will go to an estimated .82, reducing severance taxes by over $100 million per year. The oil industry opposes any change to the ELF formula, saying that it will reduce producer revenues available for reinvestment in Alaska, reduce research and development in Alaska and may cause premature shutdown of producing fields.

Eight options were considered for the ELF:

DRAFT

1) Fix the per-barrel severance tax floor at $.80 to which ELF does not apply.

	FY 88	FY 89	FY 88-2005	
Revenue from this option:	30 M	20 M	210 M (50% case)	30%

[Source: Dept. of Revenue]

2) Same as #1, plus set 300 bbl/day PEL (Production Economic Limit) in statute (now a rebuttable presumption), and repeal the ELF exponent.

3) Set the per-barrel floor at $1.50 and index it with inflation. The $1.50 figure was selected based on applying a CPI inflator to the original $.80 floor. This option was rejected by the Committee based mainly on the fact that it would have a severe negative impact on oil production, in Cook Inlet.

4) Repeal the ELF entirely on all fields. This option was rejected as the Committee supported the policy of giving marginal oil fields a tax break as with the ELF.

5) Modify the exponent of the ELF formula and base the PEL on field production in addition to ~~rather than~~ per-well production. The modification of the ELF exponent would have the effect of giving additional tax relief to marginal fields while increasing the tax receipts from very large fields. The net result would be an increase in severance tax income over present law.

	FY 88	FY 89	FY 88-2005	
Revenue from this option:	140 M	140 M	1,670 M (50% case)	30%

[Source: Dept. of Revenue]

DRAFT

6) Include the provisions of option 5 with the addition of a floor which is not affected by the ELF. This option was rejected by the Committee based on the negative effects on Cook Inlet oil fields stemming from the floor change.

7) Extend the ten-year Prudhoe Bay exemption to fifteen years.

8) No change in the law, i.e. allow the scheduled application of ELF to Prudhoe Bay.

Oil and Gas Income Tax

The major issues considered regarding the Oil and Gas Income Tax revolve around the question of separate accounting of oil and gas income in Alaska versus that of apportioning Alaska income by formula. Present law uses the 'modified apportionment' approach. Separate accounting was used in Alaska for the years 1978-1981, but was repealed because the State was exposed to the possibility of large tax refunds if the courts had ruled for the oil companies who brought suit. The State Supreme Court and the U.S. Supreme Court ruled in favor of the state, holding that separate accounting is within the prerogative of the legislature as a method of determining Alaska income for taxation.

Separate accounting is generally considered to more accurately reflect oil and gas income earned in Alaska. Separate accounting has the disadvantage of being more volatile, that is state income closely follows the rise and fall of oil prices on the world

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market. The oil and gas industry vigorously opposes the imposition of separate accounting in Alaska as they feel that it can expose them to taxation on more than 100% of their earnings. House Bill 353, which would have reinstated separate accounting was introduced in the Fourteenth Legislature, but did not pass either body. According the the most recent (January, 1987) report of the Alaska Department of Revenue, at current oil prices separate accounting would result in lower revenues for the state. They show a crossover point where separate accounting would result in more revenue for the state at $14-16/barrel wellhead value. Incorrect

Individual Income Tax

The State of Alaska is one of seven states without an individual income tax. The Committee requested a report from the Department of Revenue on the revenue potential and economic impacts of a personal income tax. The report was completed at the end of December, 1986, and is attached. The report examines three types of state income taxes and examines revenue potentials of each against two possible economic scenarios for the state's future. It is interesting to note that were the State to reimpose the individual income tax with the same rate structure as was in effect before it was repealed, the tax would yield between $399 million (low economic scenario) and $436 million (moderate economic scenario) for tax year 1988. These amounts exceed previous estimates by approximately $100 million.

State Sales Tax

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The State of Alaska is one of five states without a statewide sales tax. The Department of Revenue recently completed a study of the revenue potential of a statewide sales tax. The report concludes that in calendar year 1988, if sales of food are not exempted, a retail sales tax would yield $38,355,000 per one percent tax. In addition, the service sector of the economy, could yield approximately $14 million per one percent tax.

Issues to be explored by Committee

There are a great many tax issues which could be productively explored by the Joint Special Committee on Tax Policy. An outline of some of these issues is provided below.

1. Corporate Income Tax
   a) Rates
   b) Worldwide Combination
   c) Separate entity
   d) Waters' edge
   e) Changes to Apportionment formula
2. Severance Tax
   a) Definition of a marginal field?
   b) Definition of Field, Unit
3. Motor Fuel taxes
4. Special tax incentives and credits
   a) Exploration Incentive
   b) Mining License 3.5-year moratorium

DRAFT

c) Special Industrial Tax Credit

d) Credits included in adoption of IRS code

e) Investment Tax Credit

f) Non-Highway Use refund

g) Oil Gravity Adjustment

5. Oil and Gas Property Tax (ad valorem)

   a) Municipal uniformity

6. Disputed taxes

   a) DOR need for auditors, etc.

   b) Taxpayer Confidentiality

   c) Outlook for settlements

7. Lottery

8. Oil & Gas Reserves Tax

9. Tobacco Tax

10. Alcohol Tax

11. Gross Receipts Tax

12. School Tax

13. Fisheries Taxes

Conclusion The Joint Special Committee on Tax Policy has attempted to establish policy guidelines to examine Alaska's tax structure. The Committee has developed information regarding impacts of some proposed tax schemes. Other than rejecting certain proposals relating to the ELF, the Committee has reached no conclusions or recommendations regarding any specific tax proposal.

Introduced: 4/23/86
Referred: State Affairs

IN THE SENATE BY THE STATE AFFAIRS COMMITTEE

SENATE CONCURRENT RESOLUTION NO. 42

IN THE LEGISLATURE OF THE STATE OF ALASKA

FOURTEENTH LEGISLATURE - SECOND SESSION

Relating to a legislative committee to study the state's tax policy.

BE IT RESOLVED BY THE LEGISLATURE OF THE STATE OF ALASKA:

WHEREAS the State of Alaska has a tax structure that has not been comprehensively reviewed for fairness and equity; and

WHEREAS it is in the state's best interest to have a long-term tax policy that is broad, stable, and accountable; and

WHEREAS the State of Alaska lacks the necessary information to develop a comprehensive approach to existing state taxes, tax credits, licenses and user fees; and

WHEREAS an examination of the relationship between minimizing taxes and fostering economic growth is critical to the understanding of the state's tax structure;

BE IT RESOLVED by the Alaska State Legislature that under Uniform Rule 21 a joint special committee on tax policy is established consisting of three members of the senate appointed by the president of the senate, three members of the house of representatives appointed by the speaker of the house, three ex-officio members from the private sector appointed by the governor and one ex-officio representative each from the Office of Management of Budget and the Department of Revenue to conduct research, hold public hearings and take testimony and collect data on the state's tax policy; and be it

FURTHER RESOLVED that before the committee dissolves on the 11th day of the Second Session of the Fifteenth Legislature, it submit a written report to the legislature that addresses the merits of and makes recommendations concerning a long-term, broad-based and stable tax policy to minimize taxes and foster economic growth.

JOINT SPECIAL COMMITTEE ON TAX POLICY

List of Members

Appointed

Abood

d Eliason

John Sund, Co-Chair

Kay Brown

Terry Martin

cio

Programs
Alaska

Operating Engineers, Local 302

Production Company

Ex-Officio

gh Malone
Revenue

ement and Budget

BIBLIOGRAPHY OF MATERIALS
JOINT SPECIAL COMMITTEE ON TAX POLICY
January, 1987

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JOHN SUND, REPRESENTATIVE
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MEMORANDUM

2/2/87

TO: Senator Bettye Fahrenkamp, Chair,
Senate Special Committee on Oil and Gas

FROM: Rep. John Sund, House Co-Chair,
Joint Special Committee on Tax Policy

RE: Invitation to Meeting

Thanks very much for cancelling your committee meeting. I apologize for the conflict in scheduling.

As you know, the Joint Special Committee on Tax Policy has spent considerable time looking into issues relating to the oil industry in Alaska, for example the ELF issue. We would appreciate it very much if you could attend the Tax Policy Committee meeting Tuesday, at 3:30 in the House Finance Committee Room. We will be getting a presentation from the Department of Revenue and considering the Tax Policy Committee preliminary report.

2-5-87

STATE'S COMMENTS ON 1002 REPORT (ANWR) - TELE-CONFERENCE W/KATZ

STATE OF ALASKA

POUCH V
JUNEAU, ALASKA 99811
(907) 465-4941

SENATE SPECIAL COMMITTEE ON OIL AND GAS

MEMORANDUM

TO: Members, Senate Special Committee on Oil and Gas

FROM: Committee Staff

RE: Committee Meeting, February 5, 1987

DATE: February 4, 1987

On Thursday, February 5, at 3:30 pm in the Beltz Room, the Senate Special Committee on Oil and Gas will receive a presentation from the administration on the U.S Department of Interior's Draft Coastal Plain Resource Assessment for the Arctic National Wildlife Refuge, Alaska. It is also known as the 1002 report. The state will provide specific comments and recommendations to the Secretary of the Interior. The final report will include all public comments and should be presented to Congress sometime in March.

Participants at the hearing will include representatives from the Governor's office, OMB, the Departments of Natural Resources, Fish and Game, and Environmental Conservation. In addition, John Katz from the Governor's office in Washington, D.C. will be participating via the teleconference network. The hearing will be teleconferened for listening only to sites across the state.

In addition, Jim Hansen, Division of Geological and Geophysical Surveys will present a brief assessment of the petroleum potential of the coastal plain area of AMWR.

After the presentation, there will be discussion of the three different legislative resolutions regarding ANWR (HJR 7, HJR 9, and SJR 7)

The Senate Judiciary Committee has invited members of the Senate Special Committee on Oil and Gas to an attend overview of major oil and gas litigation. This hearing will be held on Thursday, February 5 at 1:30 in the Butrovich Room.

STATE OF ALASKA

SENATE JUDICIARY COMMITTEE

SEN. JAY KERTTULA
SEN. ARLISS STURGULEWSKI
SEN. RICK HALFORD
SEN. JOE JOSEPHSON
SEN. PAT RODEY

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Feb. 4, 1987

Senator Bettye Fahrenkamp
Chair, Senate Oil and Gas Committee
Box V
Juneau, Ak. 99811

Bettye

Dear Senator Fahrenkamp:

On Thursday, February 5, at 1:30 in the Butrovich Room, the Senate Judiciary Committee will be getting an overview on all major oil and gas litigation from the Department of Law.

You and all the members of your committee are cordially invited to attend.

Sincerely,

Jay

Jay Kerttula

JK/bk

SENATE SPECIAL COMMITTEE ON
OIL AND GAS
February 5, 1987
3:52 p.m.

MEMBERS PRESENT

Senator Bettye Fahrenkamp, Chairman
Senator Jack Coghill
Senator Paul Fischer

COMMITTEE CALENDAR

Arctic National Wildlife Refuge - Resource Potential, Department of Natural Resources and Teleconference with John Katz, Washington, D.C.

WITNESS REGISTER

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ACTION NARRATIVE

TAPE ONE SIDE ONE
February 5, 1987

Number 001

The Senate Special Committee on Oil and Gas meeting was called to order by Chairman Fahrenkamp at 3:52 p.m. She explained there were a lot of questions concerning what is happening with ANWR and conflicting information on the state's involvement, and she stated that John Katz of the Governor's staff in Washington, D.C. would be talking to the committee via the teleconference network to clarify what is going on with ANWR and the state's participation.

Number 031

John Katz, speaking via the teleconference network, said there were literally five or six manifestations of ANWR policy, ranging from the introduction of legislation to the Congress, through the proposed land trades, to a caribou agreement between the U.S. and Canada.

Concerning the legislative process itself, he said, to his knowledge, only one bill has been introduced so far (HR 39) which would designate the coastal plain of the ANWR as wilderness. It is likely that additional bills will be introduced in the foreseeable future.

There are literally four committees of the Congress which will claim jurisdiction over the ANWR issue in one form or another. To date, there has been no action in the Congress, and he thought it was likely that any intense congressional consideration would be postponed pending the submission by the Secretary of the Interior of his final ANWR report (1002 Report).

Mr. Katz stated that to date, the state has not been particularly active on Capitol Hill. He felt it was necessary to crystallize a policy which would reflect the consensus of both the Legislature and the Governor, which he feels is evolving.

He thought it very important that the state put in place a self-contained, independent advocacy effort of its own which is capable of expressing our particular position on ANWR.

Referring to the 1002 Report, he said by virtue of the original lands legislation that was passed in 1980, the Secretary was obligated, as of last September, to submit a report on the coastal plain of ANWR to the Congress. Because of the filing of litigation, that report has been delayed. In the litigation, it was held that the Secretary was compelled to go through a public environmental impact statement process and that is what he is involved in now. He noted that February 6 would be the deadline for the submission of public comment to the Secretary, and he said the State Administration will be providing comments in that process.

Another area of activity has been the negotiation of land trades involving the Interior Department and several native corporations. Since last October, the state has been an active participant in those discussions. He said the last major series of meetings occurred in Washington early in

January and he said they would be meeting again that week. He then outlined three principal doctrines that the discussions would be devoted to. Mr. Katz said it was contemplated by all concerned that if any of any of the trades are consummated, they must be submitted to the Congress for approval, and in the case of any trades that might involve the State of Alaska, they would have to be submitted to the State Legislature for approval.

Outlining the position the state has been reflecting in those discussions, Mr. Katz said they have made it clear to both the native corporations and the Interior Department that they have not yet taken a position on the wisdom or lack of wisdom inherent in the trades themselves. That is a subject that is under active deliberation now within the Administration for the purpose of trying to come to a definitive conclusion as soon as possible. In the interim, they have been participating on what they feel is a constructive basis, both as sovereign and as land owner, trying to identify problems and also strengths in the various documents that are under consideration.

Another area that has been of great concern and interest to some legislators is the possibility of a caribou agreement between the U.S. and Canada. He thought the discussions which have occurred so far would lead to a bilateral agreement between the two governments. The last series of meetings, which occurred in Seattle, led ultimately to a draft agreement which was initialized by the parties but not finalized. The agreement has been circulated to all interested parties, including the State of Alaska, for comments. They have approximately 60 days to submit their comments. He said the caribou agreement does bear upon the ANWR issue because it does create a bilateral regime for the consideration of issues affecting the Porcupine Caribou herd, and it also deals with general mandates relating to habitat protection.

Number 217

Senator Coghill said he was concerned about the perception that was brought forth by the Governor's press conference wherein the state was not at the table and there were negotiations going on outside of the legislative authority. He asked Mr. Katz if he would address the question of revenue sharing and whether it could be negotiated along with the negotiation of the land swaps.

Number 235

Mr. Katz responded that negotiations were not going on outside of the authority of the State Legislature to approve them. They have made it clear that if they get to to the point of consummating a land trade with the Interior

Department, that trade must submitted to the State Legislature for approval.

Concerning the 90/10 formula, they are contending that the 90/10 formulation is part of the solid compact between the people of Alaska and the Federal Government as embodied in the Statehood Act. They believe their best posture, both legally and strategically, is to argue strongly for the maintenance of the 90/10 formula , and if that changes by virtue of congressional action, then to examine what their options are at that point in time.

Number 302

Clarifying an earlier statement, Mr. Katz said he didn't think it was accurate to say that the state has been in the land trade discussions for the past two years. He thought the discussions began somewhere in that period with interest of the Kodiak Regional Corporation in exchanging their inholdings within the Kodiak Wildlife Refuge for lands and oil and gas interests within the coastal plain. The state's active involvement as a co-equal with the other parties at the table really began last October and was first manifested in concrete form in discussions that occurred in Washington in early December, 1986. Since then, they have been cognizant of what has been going on and have been permitted to represent themselves at the table.

Referring to when the Legislature should come involved, he said the AS 38.50 process affords that opportunity. He said they have been abiding by the Interior Department's rules in terms of how the discussions should be implemented and for that reason they have not been as forthcoming publicly as perhaps occurs on other issues. In that regard, they have kept confidential material that has been given to them by the Interior Department, but they have felt that under state law, any documents that they have submitted to the department are public record and they have made those letters available both to the press and to people who have requested them.

Number 340

Senator Fahrenkamp said she thought that was part of the confusion.

Mr. Katz explained there was a juncture in the process when the state felt that discussions were going on between the Interior and one or more native corporations that could clearly affect state sovereign interests. In addition, the state felt that in its own interest there might be some inholdings for the federal conservation system that it could put on the table in exchange for some possible rights in ANWR. The amount they have on the table now is approximately 260,000 acres, almost exclusively located as state inholdings within federal wildlife refuges.

Senator Fahrenkamp asked, through lack of knowledge of what is happening, if we go in now with a resolution asking the Department of Interior, the Congress, etc. not to allow or to go ahead with land trades, and yet we have been working at the table offering a 260,000 acre exchange, doesn't that seem like a contradiction?

Mr. Katz responded that he didn't think so, but he agreed with the thrust of her question. If, for any reason, it is deemed that land trades involving native corporations are not in either the state interest or the federal interest, then those back there feel it would be hypocritical for the state to continue to pursue a land trade on its own with the federal government. It was his personal view that if for any reason the Legislature were to decide against native trades, then the state must walk away from the negotiating table with respect to that 260,000 acres as well.

Senator Fahrenkamp said it behooves the Legislature as they are looking at resolutions, to know a little more about the background than they have known to date.

Number 411

Senator Fahrenkamp noted that Senator Sturgulewski had joined the committee and would be participating in the meeting.

Number 418

Mr. Katz said he was in favor of a resolution and felt there would be therapeutic value in it in that it would reflect a consensus of the Governor and the Legislature early in the process about what policies to pursue.

Number 443

Senator Fahrenkamp inquired if he could be more specific on what he meant by "early."

Mr. Katz said, so far, what they have seen in the legislative area is just a little bit of preliminary skirmishing --- there really hasn't been any definitive action. He felt that the kind of guidance that would be embodied in that sort of resolution is needed relatively soon.

Number 455

Senator Coghill asked if Mr. Katz had a Memorandum of Understanding between the state and the Interior Department as to information pass-throughs on seismic work done in the area below the Kaktovik area.

Senator Coghill said the compact that was made between the federal government on the 90/10 really disturbs him. If they have privied information on the seismic work and they can select before the state selects, what is going to be the process there and should that be done before the Secretary issues his 1002 Report, Senator Coghill asked.

Number 471

Mr. Katz replied that there was a Memorandum of Understanding that was negotiated by the prior administration by the Department of Natural Resources and the Interior Department. It provided some ground rules for the exchange of information between the federal government and the state. The memo provided some deadlines and a process for the state's dissemination of its analysis of ANWR. Recently, the Secretary of Interior granted his permission for the state to release its findings publicly.

In terms of the 90/10, Mr. Katz said it applies in any situation involving leasing by the federal government under the Mineral Leasing Act of 1920. The Attorney General has ruled that the 90/10 would not apply if land trades occur because the lands involved would then no longer be subject to the Act. From what he knows, state geologists have had pretty equal access to the information that is available. To his knowledge, nobody in the government has information relating to the results of the well that was drilled on the Kaktovik lands.

Number 498

Senator Sturgulewski said there seems to be some confusion among some in the Senate as to the potential role of the state in the land trades, and she wondered if the state does not participate in trading of land, what role, other than advisory, we have.

Number 540

Mr. Katz responded that they have sought to play two roles in the discussions. One is the role of state as land owner and the other is the state is sovereign. At the first level, the Interior Department has been much more interested and accommodating to them when they appear as land owner, a little less accommodating when they appear as a sovereign. He thought that the step of litigation could be viewed as being toward the end of the process, and he saw the Legislature having a role in providing guidance to the executive by either a resolution or organic legislation.

Senator Sturgulewski asked Mr. Katz if the Udall bill was moving forward, and in addition to the 1002 Report, what might the Legislature anticipate the Congress to do.

Mr. Katz responded that the Udall bill has not yet begun to move and he didn't expect much substantive consideration until the 1002 Report was completed. He said he suspected that the Secretary will submit legislative recommendations to the Congress accompanying the 1002 Report, probably in the form of legislation. In addition, he thought it was likely that one or more members of our congressional delegation will be considering the introduction of legislation. He knows for a fact that a group of other congressmen are considering a separate bill which might, in addition to other things, involve an attempted alteration of the 90/10 revenue formula.

Number 552

Senator Fahrenkamp said, in talking to the Interior Department, they indicated that in their legal sense, it was not necessary for this to go before the Congress, but was being done to meet a promise, and she asked if that had any bearing.

Mr. Katz replied that the Interior Department has promised the appropriate committees of Congress that it will not consummate these lands trades as a matter of administrative discretion, even if it has that discretion, but rather it will, in fact, submit the land trades to Congress for approval at the appropriate time. They have chosen, at least as a policy matter, to do so irrespective of what the legal requirements might be.

Number 568

Senator Fahrenkamp asked Mr. Katz what he saw at this stage as the position of union representatives, environmental groups, etc.

Mr. Katz said there is a coalition which has formed in Washington of groups and organizations which are interested in seeing ANWR opened subject to some set of stipulations. On the other hand, the environmentalists have formed an effective coalition of their own. He thought there were two maritime unions involved in the coalition to open ANWR. Many other unions are still on the sidelines pending some possible resolution of the local hire issue.

Number 594

Responding to a question from Senator Fahrenkamp, Mr. Katz said there is one school of opinion that feels that native land trades are very important to the opening of ANWR. The natives have about a million acres of inholdings on the table and some people feel that that will be very attractive to congressmen who are looking for good environmental reasons to support the bill. Secondly, the native corporations are good advocates and are well respected in the Congress.

Another school of opinion is that the existence of some land trades complicates an already very difficult issue and that it injects the concept of private ownership, even if it's just ownership of oil and gas rights.

Number 618

Rod Swope, Special Staff Assistant on Resources, Office of the Governor, related that the Administration's position would be ready the following day and they would come back and discuss that position with the committee, if desired.

Number 635

Senator Coghill added that public comment would close the following day, but as he understood it, the Secretary would continue to hear further comment from the legislative branch.

TAPE ONE SIDE TWO
February 5, 1987

Number 655

Mr. Katz, referring to his statement that discussions had really begun in earnest in October, said he didn't mean to imply that there had been no interaction with the Interior Department before that. He felt that in October, the state's role in the process was respected and they began to be treated as co-equals in all the discussions that occurred. Prior to that period of time, they had been exchanging, mainly through the Department of Natural Resources, information with the Interior Department. Since October, they have been at the table with the corporations and the department. He noted there was a documentary record that goes back considerably further than that, and said the committee may want to review that at some point.

Number 702

Senator Fahrenkamp stated that the interpretations they're getting from the Interior Department is that the chances of a 90/10 holding up on federal leases are not good.

Mr. Katz said he thought it would be necessary to fight for the 90/10 and explain the legal and policy justification. For a number of very different reasons, a lot of congressmen are coming to this issue with a predisposition to alter the formula, and we've really got our job cut out for us, he said. From what he can tell, the Interior Department will not be supportive of the the 90/10 in the congressional discussion.

Number 750

Senator Fahrenkamp thanked Mr. Katz for his participation in the meeting, saying not only did he and the Administration have their work cut out for them, but the members of the Legislature did as well. She said, as they are working on their revenue projections, she would appreciate him sharing that information with her.

Mr. Katz confirmed that they have been trying to work up some revenue projections which haven't been completed yet. The Interior Department's projections are confidential information and they have not been shared with anybody, to his knowledge.

Number 774

Senator Coghill noted that he and Senator Bennett would be in Washington, D.C. the following week and would be in contact with Mr. Katz at that time in order to further discuss ANWR.

Number 792

Senator Fahrenkamp, speaking to Rod Swope, noted there were a number of resolutions the Legislature was looking at, and she thought it was important that the Legislature and Administration work closely together. She asked what his advice was as to what a resolution should look like, and how should they try to coordinate and negotiate their position.

Number 810

Mr. Swope said he could offer some advice in terms of the Administration's position on some of the major policy questions. They support local hire to the extent that it is possible. Their position is that the 90/10 revenue share should be maintained. They still don't have a definitive position on land exchanges, so they can't speak to that issue. In terms of their position on the 1002 Report, the Administration has said they clearly would like to see exploration and development of the coastal plain in ANWR, provided it is done with the intent and the express purpose of the refuge. A major discussion they have had is how to best protect the Porcupine Caribou herd and still allow exploration and development.

Number 902

Jim Hansen, Chief Petroleum Geophysisist for the Department of Natural Resources, gave a brief and detailed slide presentation on why they say the ANWR has the high potential it does. He said the information he was giving was all taken from nonconfidential data.

He noted that committee members had just received a public data file, 87-1, which was released the previous day.

The slides shown pertained to the location of ANWR; the key elements necessary in order to have oil; and geologic features. He also pointed out on a map where they think the oil is located.

Number 058

Concluding, Mr. Hansen said what they firmly believe that the ANWR area has the highest potential of any onshore, unexplored area in the North American continent. All the key ingredients necessary for oil accumulation are there, he said.

Number 083

A brief discussion followed on the seismic information on the KIC land and the one well there. It was noted that that information was not available and is being shared only by the oil companies and the native corporations.

Mr. Hanson said the state Oil and Gas Conservation Commission receives data from all wells in the state. They have those logs, but they are kept in a vault and no one is allowed to look at them.

Number 107

Mr. Katz said the Arctic Slope Regional Corporation, which drilled the KIC well with its oil company partners, is not a party in the land exchange discussions in Washington, D.C. He explained that the other native corporations, which are parties, do not have access to ASRC's information. ASRC is in a unique position under ANILCA in that they don't need trades. If the Congress authorizes drilling in the coastal plain, then they can go forward with oil and gas development on their lands without the benefit of another trade, he stated.

There being no further questions or comments, Senator Fahrenkamp adjourned the meeting at 5:07 p.m.

STATE OF ALASKA

STEVE COWPER, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

DIVISION OF GEOLOGICAL & GEOPHYSICAL SURVEYS

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January 15, 1987

Representative Mike Davis
Pouch V
Juneau, Alaska 99801

Dear Representative Davis:

Per your request, I have enclosed three copies of U.S. Geological Survey map I-1791 that covers the Arctic National Wildlife Refuge. Your office said you would see that other members of the Interior delegation receive a copy. Unfortunately, the map is in short supply. I will be happy to forward additional copies when they become available.

I have also included 10 copies of DGGS Professional Report 90, 'Resource appraisal simulation for petroleum in the Arctic National Wildlife Refuge, Alaska.' Per our briefing last week, I thought it might be of interest to you and other members of the Interior delegation. The attached comments by Hansen and Kornbrath compare the results of the Department of Interior FAST study and DGGS RASP program.

Sincerely,

Cheri Daniels

Cheri L. Daniels, Chief
Resource Information Section

CLD/ram

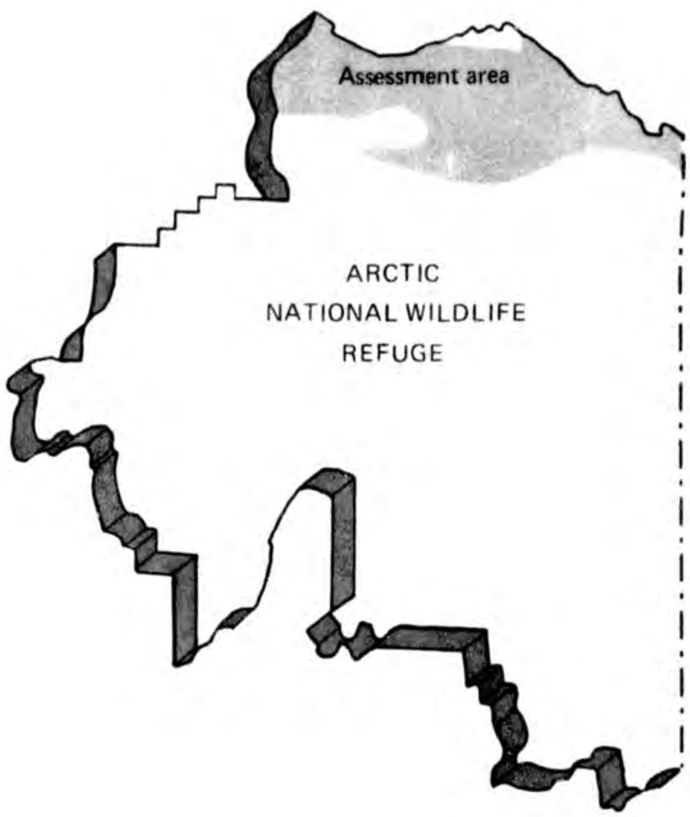
Enclosures

cc: Laurel Murphy
Dick Reger
Sally Wells

[redacted] Fahrenkamp

RESOURCE APPRAISAL SIMULATION FOR PETROLEUM IN THE ARCTIC NATIONAL WILDLIFE REFUGE, ALASKA

Compiled by J.J. Hansen and R.W. Kornbrath



PROFESSIONAL REPORT 90

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1986

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Compiled by J.J. Hansen and R.W. Kornbrath

Division of Geological & Geophysical Surveys
Professional Report 90

Fairbanks, Alaska
1986

STATE OF ALASKA

Bill Sheffield, ***Governor***

Esther C. Wunnicke, ***Commissioner,***
Department of Natural Resources

Ross G. Schaff, ***Director and State Geologist***

This report was prepared at the request of the U.S. Department of the Interior by the State of Alaska Department of Natural Resources according to the Memorandum of Understanding signed by both agencies in 1985. DGGS publications are available at: Alaska National Bank of the North Bldg. (2nd floor), Geist Rd. and University Ave., Fairbanks; 3601 C St. (10th floor), Anchorage; 400 Willoughby Center (4th floor), Juneau; and the State Office Bldg., Ketchikan. Mail orders should be addressed to DGGS, 794 University Ave. (Basement), Fairbanks, AK 99709. Cost $2.

FOREWORD

In 1985, the Secretary of the U.S. Department of the Interior and the Commissioner of the Alaska Department of Natural Resources signed an agreement to share geologic and geophysical data collected from the Arctic National Wildlife Refuge (ANWR). Scientists of the Department of Natural Resources analyzed these data and prepared estimates of the oil-and-gas potential of the coastal plain of ANWR, as stipulated in the agreement. These estimates are reported in this document.

Ross G. Schaff
Director and State Geologist

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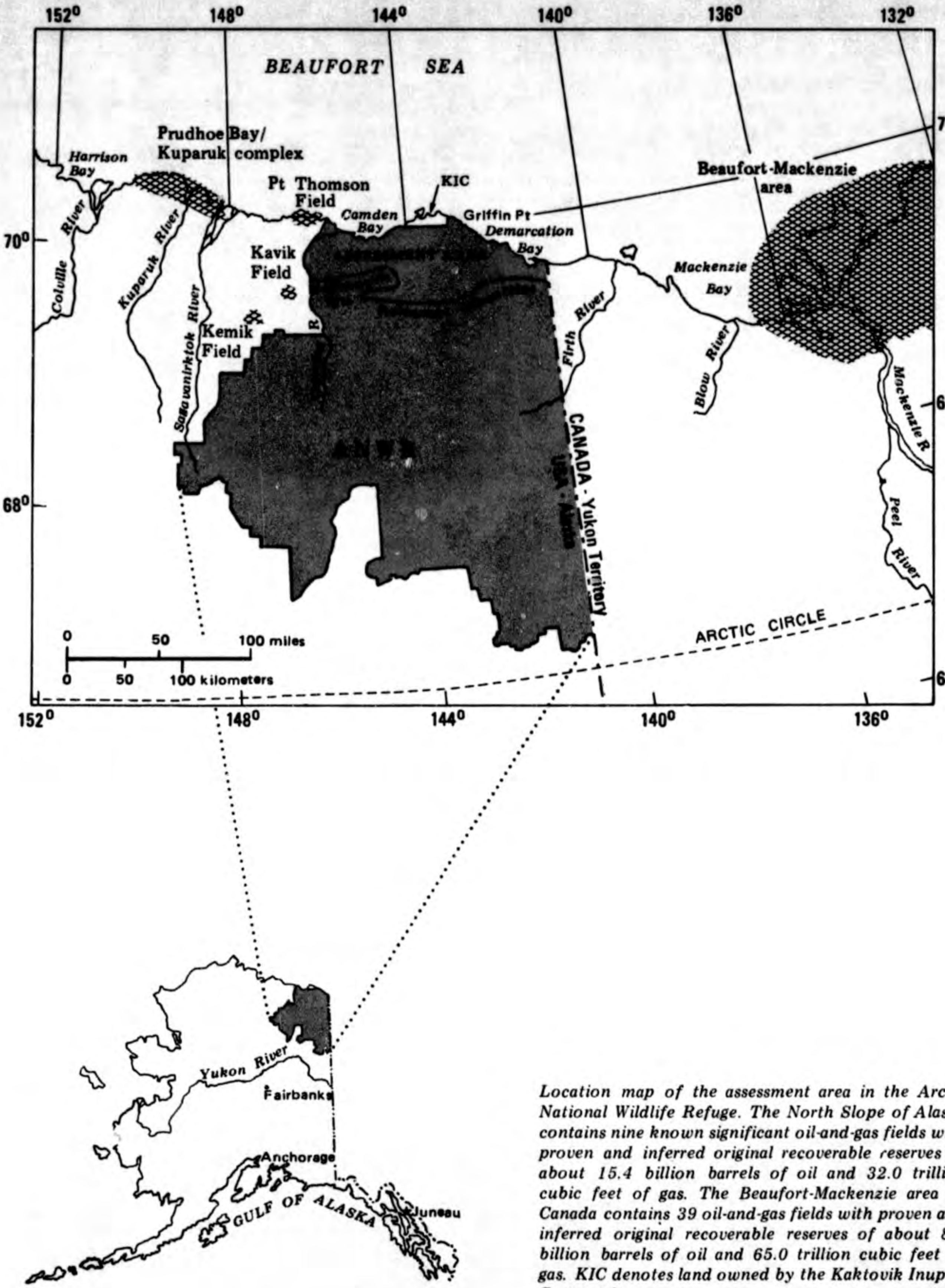

Location map of the assessment area in the Arctic National Wildlife Refuge. The North Slope of Alaska contains nine known significant oil-and-gas fields with proven and inferred original recoverable reserves of about 15.4 billion barrels of oil and 32.0 trillion cubic feet of gas. The Beaufort-Mackenzie area of Canada contains 39 oil-and-gas fields with proven and inferred original recoverable reserves of about 8.5 billion barrels of oil and 65.0 trillion cubic feet of gas. KIC denotes land owned by the Kaktovik Inupiat Corporation.

RESOURCE APPRAISAL SIMULATION FOR PETROLEUM IN THE ARCTIC NATIONAL WILDLIFE REFUGE, ALASKA

Compiled by J.J. Hansen[1] and R.W. Kornbrath[1]

INTRODUCTION

This report presents the results of the State's preliminary appraisal of the potential for undiscovered petroleum resources on the coastal plain of the Arctic National Wildlife Refuge (ANWR), Alaska. The assessment area is located north of the Sadlerochit and Romanzof Mountains between the Canning River and the Canadian border. The study area does not include that portion of the coastal plain from eastern Camden Bay to Griffin Point (owned by the Kaktovik Inupiat Corporation[2]) or state-submerged lands offshore from ANWR.

Members of the appraisal panel from the Alaska Department of Natural Resources include C. Ariey, J.E. Decker, J.J. Hansen, R.W. Kornbrath, D.L. Krouskop, C.G. Mull, G.H. Pessel, M.S. Robinson, T.N. Smith, and S.M. Weum. B.H. White and R. Anderson (U.S. Bureau of Mines) and E.L. Phillips (Alaska Department of Natural Resources) assisted in the computer analysis of the data.

A resource appraisal of ANWR was completed in 1980 by the U.S. Geological Survey. At that time, the available data consisted of limited gravity and aeromagnetic surveys augmented by some geologic mapping. Since then, additional geologic studies, two proprietary gravity surveys, and two seismic surveys have been conducted. Interpretation of this new information has resulted in revised hypotheses about the geologic evolution of the coastal plain.

The methodology used to assess the resource potential of the coastal plain of ANWR is the Resource Appraisal Simulation for Petroleum (RASP), which was developed by the U.S. Department of Interior Office of Minerals Policy and Research Analysis. RASP is a simulation (or modeling) procedure that geoscientists use to assess the undiscovered oil-and-gas potential of frontier basins. The basic unit of analysis is the geologic play, which is defined as a stratigraphic unit in a relatively homogeneous geologic setting. A basin will normally consist of one or more plays of interest; the geologic plays for this appraisal are presented in figures 1 through 7 (app.).

Resource estimates are presented as probability distributions that reflect the uncertainty inherent in appraising undiscovered resources. The resources estimated to exist in each play are combined to produce an estimate of the total 'undiscovered, conditional resources in place' as barrels of oil, cubic feet of gas, and barrels of oil equivalent for the study area. In addition, a probability distribution of the deposit size is generated for each play and for the total resources in place. Deposit size is important for economic considerations; for instance, less than 350 million barrels of recoverable oil in ANWR may not be commercially viable. A more detailed discussion of the RASP methodology is included on page 3.

ASSESSMENT RESULTS

The results of the petroleum-resource assessment are summarized in tables 1 through 4. Probability distributions for total oil, total gas, total barrels of oil equivalent, and oil-and-gas deposit sizes are presented at various fractiles that range from 0.99 to 0.01. The distribution values may be interpreted as follows. The 0.95 fractile means that there is a 95-percent chance that at least that amount of the associated resource is present. For oil, there is a 95-percent chance that ANWR contains at least 80 million barrels of oil. Similarly, there is a 1-percent chance that ANWR contains at least 45.78 billion barrels of oil. The 0.50 fractile is not the most likely case of occurrence. Rather, it is the median of the distribution and indicates a 50-percent chance that the quantity of resource present could be greater or less than its associated value.

The results in tables 1 and 2 show that in the range between the 95th and 5th fractiles, the resource potential of ANWR ranges from 0.08 to 26.52 billion barrels of oil (BBO) and from 0.71 to 43.62 trillion

[1]Alaska Division of Geological and Geophysical Surveys, P.O. Box 7028, Anchorage, Alaska 99510.

[2]An additional assessment that includes the KIC lands was performed by the Alaska Department of Natural Resources.

Table 1. *Total oil, ANWR petroleum-resource assessment.*

Fractile	Billion barrels
0.99	0.00
0.98	0.00
0.97	0.01
0.96	0.04
0.95	0.08
0.90	0.33
0.75	1.28
0.50	3.77
0.25	9.18
0.10	17.94
0.05	26.52
0.04	29.68
0.03	34.14
0.02	38.94
0.01	45.78

Minimum simulated oil	Maximum simulated oil
0.00	81.77

Average oil	Standard deviation
7.22	9.66

Table 2. *Total gas, ANWR petroleum-resource assessment.*

Fractile	Trillion ft^3
0.99	0.08
0.98	0.26
0.97	0.40
0.96	0.56
0.95	0.71
0.90	1.42
0.75	3.74
0.50	8.64
0.25	17.77
0.10	31.94
0.05	43.62
0.04	46.65
0.03	52.67
0.02	62.26
0.01	76.24

Minimum simulated gas	Maximum simulated gas
0.00	159.92

Average gas	Standard deviation
13.69	15.76

Table 3. *Total deposit size, ANWR petroleum-resource assessment.*

Fractile	Conditional, 100% oil (million barrels)	Conditional, 100% gas (billion ft^3)
0.99	3.202	5.797
0.98	6.115	10.252
0.97	8.766	14.854
0.96	11.154	19.368
0.95	14.556	23.382
0.90	30.865	45.115
0.75	102.155	143.645
0.50	354.131	509.171
0.25	1173.606	1721.490
0.10	3440.368	4846.398
0.05	6277.965	8912.465
0.04	7313.133	10861.937
0.03	8898.691	13492.098
0.02	11821.965	18052.875
0.01	18272.949	26867.359
Minimum simulated deposit	0.10	0.40
Average	1459.56	2143.70
Maximum simulated deposit	76941.38	125833.06
Standard deviation	3762.19	5768.84

Table 4. *Total resources, ANWR petroleum-resource assessment. (barrels of oil equivalent, BOE)*

Fractile	Billion BOE
0.99	0.05
0.98	0.17
0.97	0.25
0.96	0.35
0.95	0.47
0.90	0.96
0.75	2.54
0.50	6.05
0.25	12.42
0.10	22.50
0.05	31.54
0.04	35.56
0.03	40.15
0.02	44.75
0.01	53.01

Minimum simulated BOE	Maximum simulated BOE
0.00	89.93

Average BOE	Standard deviation
9.64	11.06

cubic feet of gas (TCFG) in place, with an average value of 7.22 BBO and 13.69 TCFG. The median value (the 50th fractile) is 3.77 BBO and 8.64 TCFG (tables 1 and 2).

The resource distributions are strongly skewed toward the low-probability, high-resource values, as indicated by the difference between the average and median values (tables 1 and 2). This indicates that while only small quantities of resources are assured, there is a small chance that very large quantities of resources exist in ANWR.

Deposit-size estimates are equally important. For oil, the potential deposit sizes at the 1-percent confidence level range up to 18.27 BBO in place, with an average value of 1.46 BBO and a median value of 0.35 BBO. For gas, the potential deposit sizes at the 1-percent confidence level range up to 26.87 TCFG in place, with an average value of 2.14 TCFG and a median value of 0.51 TCFG (table 3).

In summary, the results of this evaluation indicate that the ANWR coastal plain may contain large petroleum deposits. On the basis of current data, large quantities of resources and large individual deposit sizes may occur within the coastal plain of ANWR. There is a 1-percent chance that the requisite parameters of source rock, timing, migration, reservoir rock, and trapping mechanisms have combined to generate up to 45.78 BBO and 76.24 TCFG in place in ANWR (tables 1 and 2). Assuming a recovery factor of 35 percent for oil, up to 16 billion barrels of recoverable oil may be present. This compares favorably with the original recoverable oil reserves of about 10 billion barrels in the Prudhoe Bay field.

GEOLOGIC PLAYS

The geologic play is the basic unit of analysis for resource assessment using the RASP methodology. Reservoir-quality rocks, known production, and trapping mechanisms are the most important parameters used to define specific plays in this assessment. Parameters such as thermal maturity, source-rock distribution, and timing are also requisite for a successful play. Specific plays used to assess the resource potential of ANWR include Kekiktuk (fig. 1), Lisburne North and South (figs. 2 and 3), Permian-Triassic Clastics North and South (figs. 4 and 5), Kemik-Thomson (fig. 6), and Post-Albian Clastics (fig. 7). A stratigraphic column and oil-and-gas summary for these plays are shown in figure 8 (app.).

The sandstone, conglomerate, and carbonate lithologies of these plays have produced large quantities of oil and gas on the North Slope and in the Mackenzie Delta area of Canada. The combination of generation and migration of hydrocarbons from source shales and timing of trap formation has produced large fields. On the basis of surface studies and geologic modeling, similar favorable conditions may be present in the subsurface of ANWR.

Geologic field studies conducted by DGGS indicate the existence of complex relationships between various rock groups that comprise the geologic plays in the subsurface of the ANWR coastal plain. Simple structural closures, thrust-fault repetitions of rock units, and complex folds could provide mechanisms to structurally trap hydrocarbons. Truncation of rock units and facies changes could also result in stratigraphic traps.

Plays of the Kekiktuk, Kemik-Thomson, and Post-Albian Clastics (figs. 1, 6, and 7) are broad in scope and are anticipated to be present throughout the study area. However, based on possible truncation of the rock units by a major unconformity, plays of the Lisburne North and Permian-Triassic Clastics North (figs. 2 and 4) are less likely to occur in the study area.

PROCEDURES FOR OIL-AND-GAS RESOURCE APPRAISALS

The procedure for the Resource Appraisal Simulation for Petroleum (RASP) incorporates a 'play' approach to petroleum-resource assessment. The methodology focuses on the concept of a geologic play as the basic unit of geologic analysis. The play is defined as a stratigraphic unit in a relatively homogeneous geologic setting.

A play approach to resource assessment of large basins or regions was chosen for the following reasons:

- The approach provides a direct assessment of the geologic characteristics—and their uncertainty—for the area of interest.
- The level of geologic detail provided by the play approach is sufficient to support a meaningful analysis.
- The approach does not require explicit identification and substantial detail for individual prospects.
- The approach recognizes regional trends within a play that enable prospects to be geologically correlated.

In essence, the play approach divides the traditional dry-hole risk factor into two components. The first component is the risk that is common to all prospects in the play because they share a common potential for source material, migration, timing, and reservoir rock. The second component is the risk that an individual prospect may have a geologic flaw specific to it and independent of other prospects in the play. Finally, the approach does not require actual discoveries in a play for assessment purposes. Judgments may be based on existing data and can explicitly reflect the uncertainty in those data.

Geoscientists familiar with the geology are asked to make three sets of probability judgments for each play.

CORRECTION

THIS DOCUMENT
HAS BEEN REPHOTOGRAPHED
TO ASSURE LEGIBILITY

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In essence, the play approach divides the traditional dry-hole risk factor into two components. The first component is the risk that is common to all prospects in the play because they share a common potential for source material, migration, timing, and reservoir rock. The second component is the risk that an individual prospect may have a geologic flaw specific to it and independent of other prospects in the play. Finally, the approach does not require actual discoveries in a play for assessment purposes. Judgments may be based on existing data and can explicitly reflect the uncertainty in those data.

Geoscientists familiar with the geology are asked to make three sets of probability judgments for each play.

The first set of judgments concerns the individual probabilities that each of four regional geologic characteristics common to the play area is favorable for the existence of petroleum accumulations. These regional characteristics are the existence of a petroleum source, favorable timing, potential migration paths, and reservoir rock. The product of these four probabilities is the marginal-play probability, that is, the joint probability that all regional geologic characteristics necessary for the accumulation of petroleum in the play area are simultaneously favorable. The existence of each geologic characteristic is necessary, but not sufficient to forecast the existence of oil or gas deposits in the play. If oil or gas have been found in a particular play, the marginal-play probability is 1.0. If none have been discovered in a play, additional probability judgments are necessary to determine the existence of hydrocarbon deposits.

The number of potentially drillable prospects in the play area, reservoir lithology (sandstone or carbonate), and petroleum mix (proportion of deposits within the play that are anticipated to be oil rather than nonassociated gas) are also needed to evaluate each play. The RASP program assumes that petroleum accumulations exist only as gas deposits below 15,000 feet.

The second set of judgments is a set of probabilities that concerns the presence of three geologic characteristics that are common to the individual prospects within each play:

- Trapping mechanism. This defines the method that restricts hydrocarbon migration, which can be related to structure or stratigraphy, or both. A trap must have an areal extent of at least 600 acres with vertical closure of at least 5 feet.

- Effective porosity. The interconnected void space that may hold hydrocarbons must be equal to or greater than 3 percent.

- Hydrocarbon accumulation. Oil and gas must exist in at least 1 percent of a trap. This expresses the favorable relationships of source rock to reservoir rock and timing of hydrocarbon generation to trap formation.

The probability judgment is conditional on the existence of these three geologic characteristics. The product of the three attribute probabilities is the conditional-deposit probability, that is, the probability that a particular prospect is an actual accumulation of oil or gas, given that all play attributes are favorable. The familiar dry-hole risk factor is equal to one minus the product of the marginal-play probability and the conditional-deposit probability.

The third set of probability judgments involves the geologic parameters of the reservoir that determine the size of the potential deposits. These reservoir characteristics are area of closure, reservoir thickness, effective porosity, trap fill, reservoir depth, reservoir lithology, and hydrocarbon mix. Jointly, these parameters determine the potential reservoir volume for a deposit.

These three basic sets of judgments—geologic characteristics common to the play area, geologic characteristics common to the individual prospects within each play, and geologic parameters that determine the size of the potential deposits—are made for each identified play and comprise the basic geologic data necessary for a resource appraisal.

The probability distribution for each characteristic is randomly sampled to simulate one possible state of geologic nature. For example, the probability distribution for the number of potentially drillable prospects is sampled to determine the number of prospects that will be simulated for the play. The marginal-play probability is then sampled to determine whether the play will be simulated as unproductive or potentially productive. For each simulated prospect in a productive play, the conditional-deposit probability is sampled to determine whether that prospect will be treated as dry or as a deposit. The petroleum-mix probability is sampled for each deposit to simulate whether it contains oil or gas, but not both. All prospects in an unproductive play are automatically simulated to be dry. Each reservoir-parameter distribution is sampled for each deposit to simulate its volume and reservoir characteristics. This sampling procedure is repeated 3,000 times in a typical Monte Carlo method, and the results are combined to develop probability distributions for oil, gas, barrels of oil equivalent in place, and deposit size.

APPENDIX

Areal distribution, input parameters, and
resources in place for geologic plays

Gas fraction = 0.40
Conditional resources in place

Fractile	Oil (million barrels)	Gas (billion ft^3)	BOE (million)
0.99	0.00	0.00	0.00
0.95	0.00	0.00	0.00
0.90	0.00	0.00	0.00
0.75	0.00	0.00	0.00
0.50	0.00	0.00	0.00
0.25	0.00	0.00	0.00
0.10	0.00	0.00	0.00
0.05	0.00	75.28	48.54
0.01	234.23	670.64	325.42

Fractile	Deposit size Conditional, 100% oil (million barrels)	Deposit size Conditional, 100% gas (billion ft^3)
0.99	3.720	15.887
0.95	9.020	25.298
0.90	17.780	73.341
0.75	42.483	146.806
0.50	95.310	292.110
0.25	234.471	617.343
0.10	461.101	1723.089
0.05	536.209	1832.462
0.01	3207.997	4330.336

	Attribute		Probability that attribute is favorable or present						
Play attributes	Hydrocarbon sources		1						
	Timing		1						
	Migration		0.8						
	Potential reservoir facies		0.5						
	Marginal-play probability		0.4						
Prospect attributes	Trapping mechanism		0.3						
	Effective porosity (>3%)		0.1						
	Hydrocarbon accumulation		0.4						
	Conditional-deposit probability		0.012						
Hydrocarbon-volume parameters	Reservoir lithology	Sand	0						
		Carbonate	1						
	Hydrocarbon mix	Gas	0.4						
		Oil	0.6						
	Attribute \ Fractiles		Probability of equal to or greater than						
			1.00	0.95	0.75	0.50	0.25	0.05	0
	Area of closure ($\times 10^3$ acres)		0.6	3	10	12	15	30	100
	Reservoir thickness/ vertical closure (ft)		5	50	125	200	350	500	750
	Effective porosity (%)		3	3	4	4	5	6	10
	Trap fill (%)		1	5	25	50	75	95	100
	Reservoir depth ($\times 10^3$ ft)		6	9	11	13	19	23	29
Number of drillable prospects (a play characteristic)			2	4	4	5	8	10	20

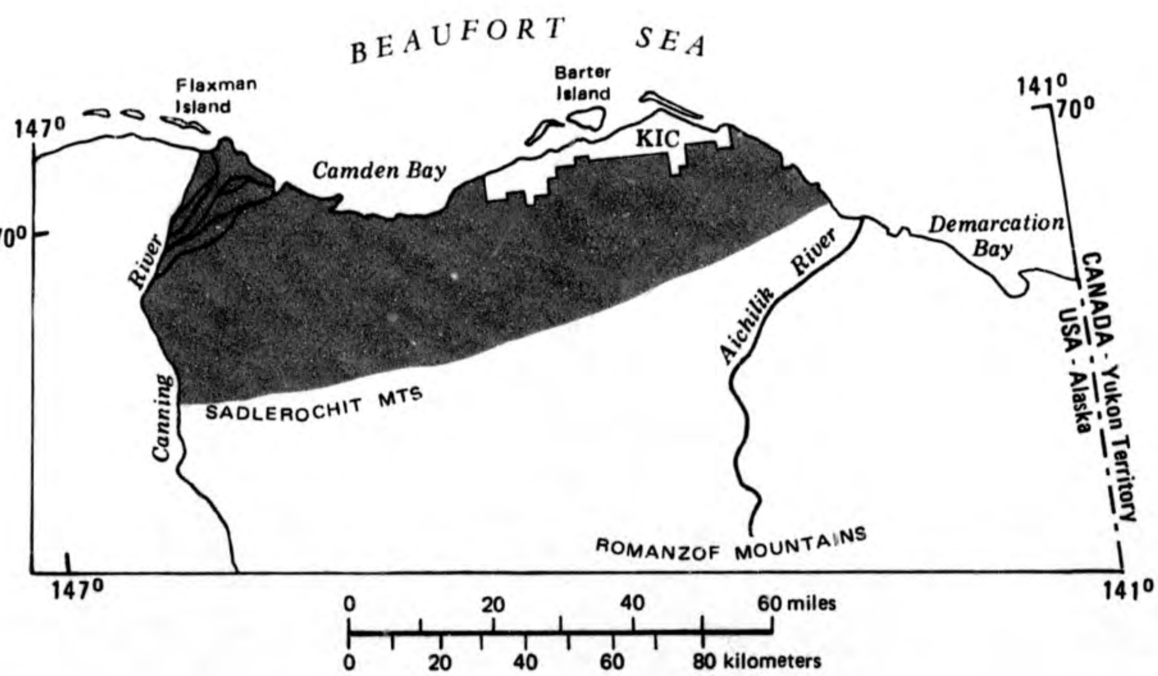

Figure 2. Areal distribution, input parameters, and resources in place for the Lisburne North Play, Arctic National Wildlife Refuge, Alaska.

Gas fraction = 0.40
Conditional resources in place

Fractile	Oil (million barrels)	Gas (billion ft^3)	BOE (million)
0.95	0.00	0.00	0.00
0.90	0.00	0.00	0.00
0.75	0.00	0.00	0.00
0.50	0.00	0.00	0.00
0.25	0.00	0.00	0.00
0.10	0.00	13.85	10.04
0.05	64.03	170.30	129.34
0.01	624.02	1021.80	777.91

Fractile	Deposit size Conditional, 100% oil (million barrels)	Deposit size Conditional, 100% gas (billion ft^3)
0.99	3.812	2.779
0.95	11.388	9.681
0.90	19.488	17.355
0.75	54.967	56.067
0.50	163.679	172.416
0.25	406.565	454.902
0.10	796.095	1280.341
0.05	1536.064	2064.430
0.01	2277.339	5454.289

	Attribute	Probability that attribute is favorable or present
Play attributes	Hydrocarbon sources	1
	Timing	1
	Migration	1
	Potential reservoir facies	1
	Marginal-play probability	1
Prospect attributes	Trapping mechanism	0.25
	Effective porosity (>3%)	0.1
	Hydrocarbon accumulation	0.4
	Conditional-deposit probability	0.01
Hydrocarbon-volume parameters	Reservoir lithology: Sand	0
	Reservoir lithology: Carbonate	1
	Hydrocarbon mix: Gas	0.4
	Hydrocarbon mix: Oil	0.6

	Attribute \ Fractiles	Probability of equal to or greater than 1.00	0.95	0.75	0.50	0.25	0.05	0
Hydrocarbon-volume parameters	Area of closure (x10^3 acres)	0.6	1	3	5	10	30	100
	Reservoir thickness/ vertical closure (ft)	5	100	225	350	425	600	1200
	Effective porosity (%)	3	3	4	4	5	6	10
	Trap fill (%)	1	5	25	50	75	95	100
	Reservoir depth (x10^3 ft)	2	5	7	9	12	14	20
Number of drillable prospects (a play characteristic)		1	5	8	10	15	25	100

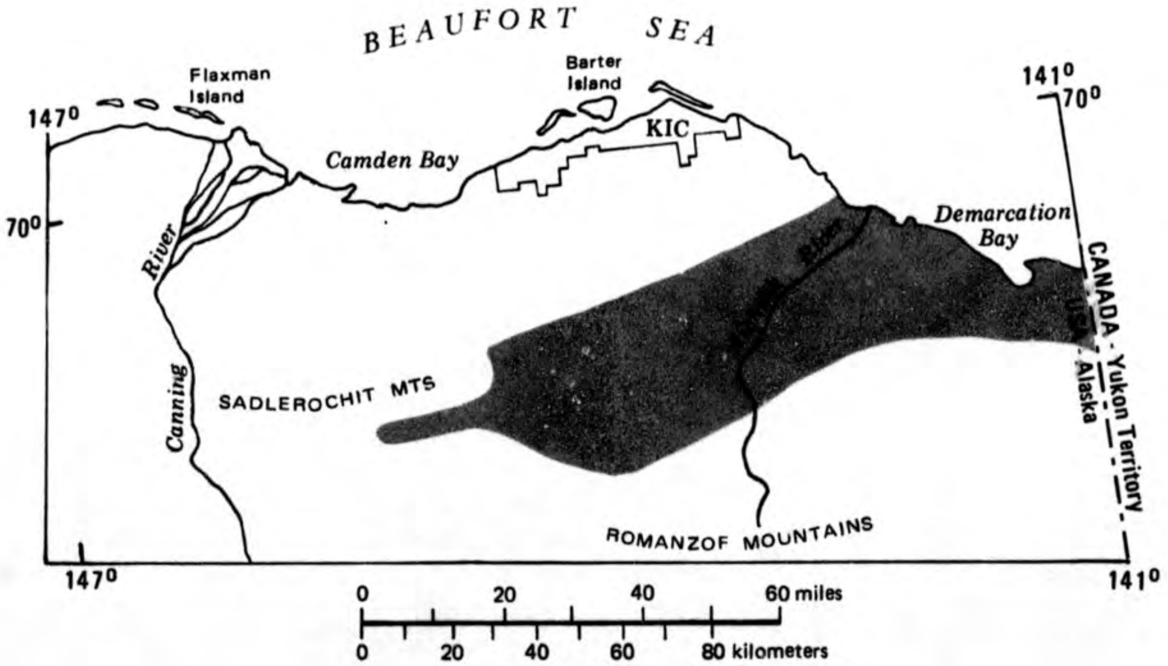

Figure 3. Areal distribution, input parameters, and resources in place for the Lisburne South Play, Arctic National Wildlife Refuge, Alaska.

Gas fraction = 0.40
Conditional resources in place

Fractile	Oil (million barrels)	Gas (billion ft^3)	BOE (million)
0.99	0.00	0.00	0.00
0.95	0.00	0.00	0.00
0.90	0.00	0.00	0.00
0.75	0.00	0.00	0.00
0.50	0.00	0.00	0.00
0.25	0.00	689.02	292.14
0.10	948.85	2927.37	1339.20
0.05	1927.34	5123.80	2619.52
0.01	5981.70	11366.90	7005.12

Fractile	Deposit size Conditional, 100% oil (million barrels)	Deposit size Conditional, 100% gas (billion ft^3)
0.99	11.112	15.476
0.95	41.465	53.727
0.90	70.171	148.026
0.75	174.012	417.946
0.50	538.918	1163.055
0.25	1323.921	2905.923
0.10	2925.320	5803.098
0.05	4333.508	7478.438
0.01	9932.547	14709.691

	Attribute		Probability that attribute is favorable or present
Play attributes	Hydrocarbon sources		1
	Timing		1
	Migration		1
	Potential reservoir facies		0.5
	Marginal-play probability		0.5
Prospect attributes	Trapping mechanism		0.3
	Effective porosity (>3%)		0.8
	Hydrocarbon accumulation		0.4
	Conditional-deposit probability		0.096
Hydrocarbon-volume parameters	Reservoir lithology	Sand	1
		Carbonate	0
	Hydrocarbon mix	Gas	0.4
		Oil	0.6

	Attribute \ Fractiles	1.00	0.95	0.75	0.50	0.25	0.05	0
		Probability of equal to or greater than						
Hydrocarbon-volume parameters	Area of closure (x10^3 acres)	0.6	3	10	12	15	30	100
	Reservoir thickness/ vertical closure (ft)	5	50	125	200	350	500	750
	Effective porosity (%)	3	7	13	15	18	23	30
	Trap fill (%)	1	5	25	50	75	95	100
	Reservoir depth (x10^3 ft)	5	8	10	12	18	22	28
Number of drillable prospects (a play characteristic)		2	4	4	5	8	10	20

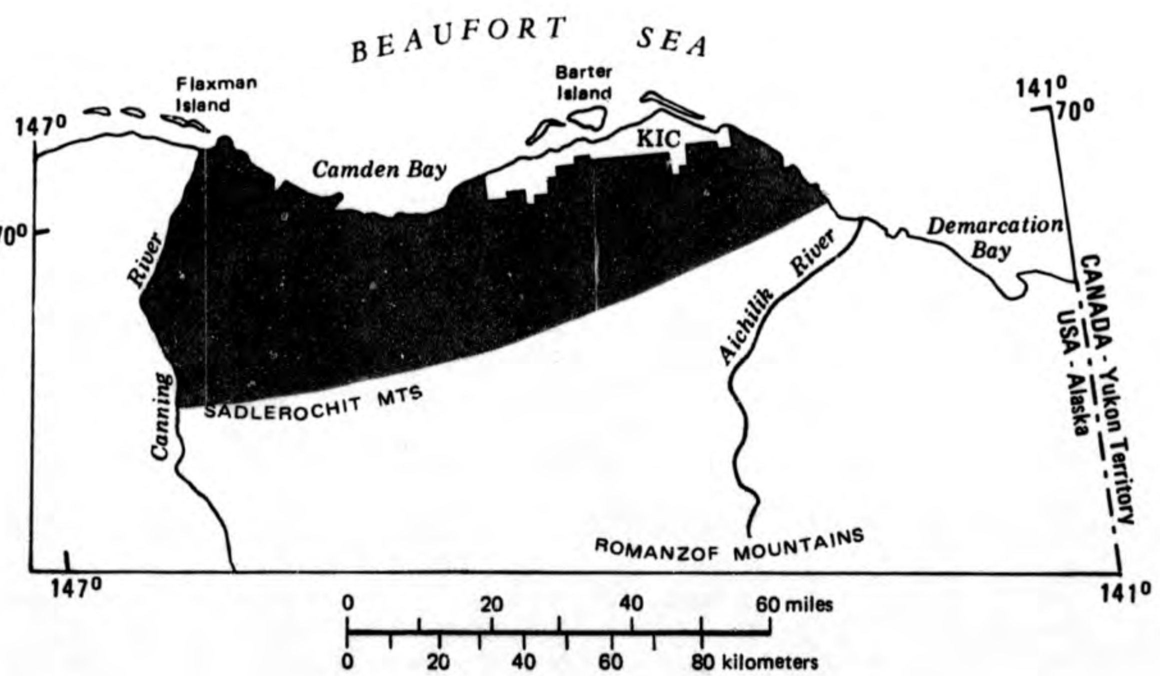

Figure 4. Areal distribution, input parameters, and resources in place for the Permian-Triassic Clastics North Play, Arctic National Wildlife Refuge, Alaska.

Gas fraction = 0.40

Conditional resources in place

Fractile	Oil (million barrels)	Gas (billion ft^3)	BOE (million)
0.99	0.00	0.00	0.00
0.95	0.00	0.00	0.00
0.90	0.00	0.00	0.00
0.75	0.00	0.00	0.00
0.50	0.00	75.45	50.04
0.25	420.35	847.34	704.19
0.10	1923.32	2875.17	2514.74
0.05	3892.57	5362.30	4698.88
0.01	9535.30	13478.01	11477.75

Fractile	Deposit size Conditional, 100% oil (million barrels)	Deposit size Conditional, 100% gas (billion ft^3)
0.99	5.751	6.613
0.95	19.493	23.007
0.90	41.787	53.101
0.75	141.340	156.387
0.50	424.294	545.440
0.25	1127.179	1495.480
0.10	2926.288	3769.860
0.05	4662.223	6053.766
0.01	9940.250	19075.750

	Attribute		Probability that attribute is favorable or present
Play attributes	Hydrocarbon sources		1
	Timing		1
	Migration		1
	Potential reservoir facies		1
	Marginal-play probability		1
Prospect attributes	Trapping mechanism		0.25
	Effective porosity (>3%)		0.8
	Hydrocarbon accumulation		0.4
	Conditional-deposit probability		0.08
Hydrocarbon-volume parameters	Reservoir lithology	Sand	1
		Carbonate	0
	Hydrocarbon mix	Gas	0.4
		Oil	0.6

	Attribute \ Fractiles	Probability of equal to or greater than 1.00	0.95	0.75	0.50	0.25	0.05	0
Hydrocarbon-volume parameters	Area of closure ($\times 10^3$ acres)	0.6	1	3	5	10	30	100
	Reservoir thickness/ vertical closure (ft)	5	100	225	350	425	600	1000
	Effective porosity (%)	3	7	13	15	18	23	30
	Trap fill (%)	1	5	25	50	75	95	100
	Reservoir depth ($\times 10^3$ ft)	2	4	6	8	11	13	20
Number of drillable prospects (a play characteristic)		1	5	8	10	15	25	100

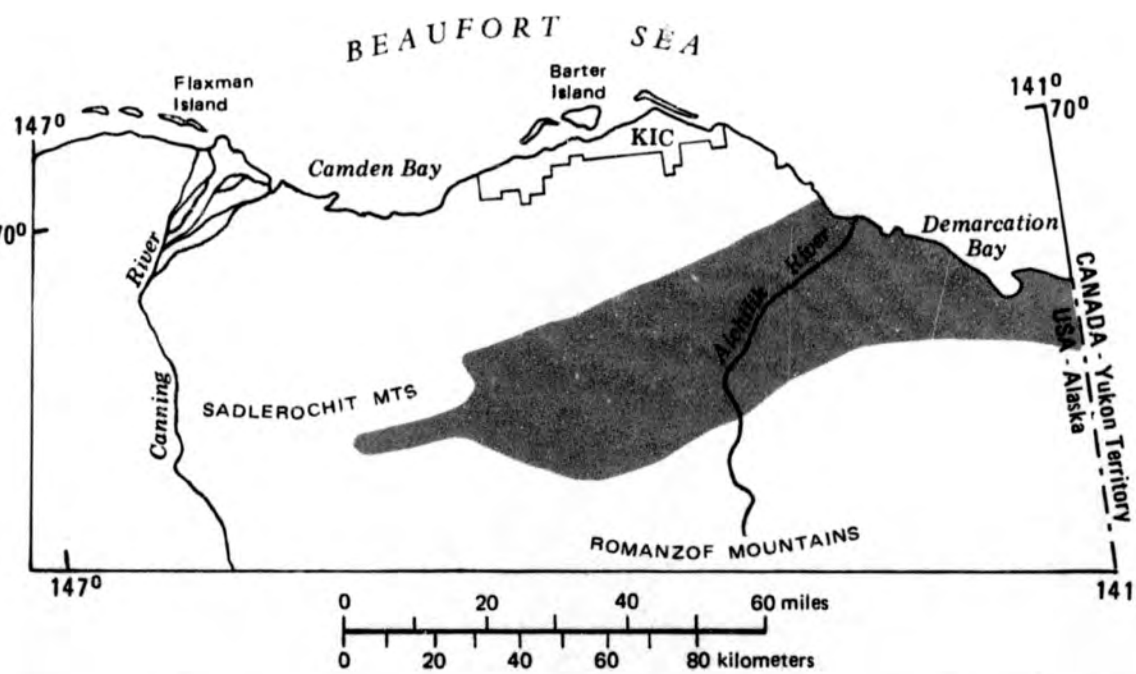

Figure 5. Areal distribution, input parameters, and resources in place for the Permian-Triassic Clastics South Play, Arctic National Wildlife Refuge, Alaska.

Gas fraction = 0.40
Conditional resources in place

Fractile	Oil (million barrels)	Gas (billion ft^3)	BOE (million)
0.99	0.00	0.00	0.00
0.95	0.00	0.00	0.00
0.90	0.00	0.00	0.00
0.75	0.00	0.00	0.00
0.50	0.00	124.91	77.60
0.25	327.71	1075.43	654.49
0.10	1607.76	3468.63	2248.06
0.05	3122.80	5929.73	4097.80
0.01	7838.41	15008.58	9200.97

Fractile	Deposit size Conditional, 100% oil (million barrels)	Deposit size Conditional, 100% gas (billion ft^3)
0.99	1.902	3.359
0.95	7.342	14.279
0.90	14.607	28.752
0.75	47.014	88.333
0.50	163.259	283.541
0.25	523.658	891.588
0.10	1602.893	2668.084
0.05	2813.698	4705.582
0.01	7445.875	14078.285

	Attribute		Probability that attribute is favorable or present
Play attributes	Hydrocarbon sources		1
	Timing		1
	Migration		1
	Potential reservoir facies		1
	Marginal-play probability		1
Prospect attributes	Trapping mechanism		0.25
	Effective porosity (>3%)		0.9
	Hydrocarbon accumulation		0.4
	Conditional deposit probability		0.09
Hydrocarbon-volume parameters	Reservoir lithology	Sand	1
		Carbonate	0
	Hydrocarbon mix	Gas	0.4
		Oil	0.6

	Attribute \ Fractiles	Probability of equal to or greater than 1.00	0.95	0.75	0.50	0.25	0.05	0
Hydrocarbon-volume parameters	Area of closure (x10^3 acres)	0.6	2	3	5	15	40	100
	Reservoir thickness/ vertical closure (ft)	5	25	50	100	200	350	600
	Effective porosity (%)	3	5	10	15	20	25	30
	Trap fill (%)	1	6	30	60	80	96	100
	Reservoir depth (x10^3 ft)	2	5	8	10	15	20	25
Number of drillable prospects (a play characteristic)		2	3	6	12	25	50	100

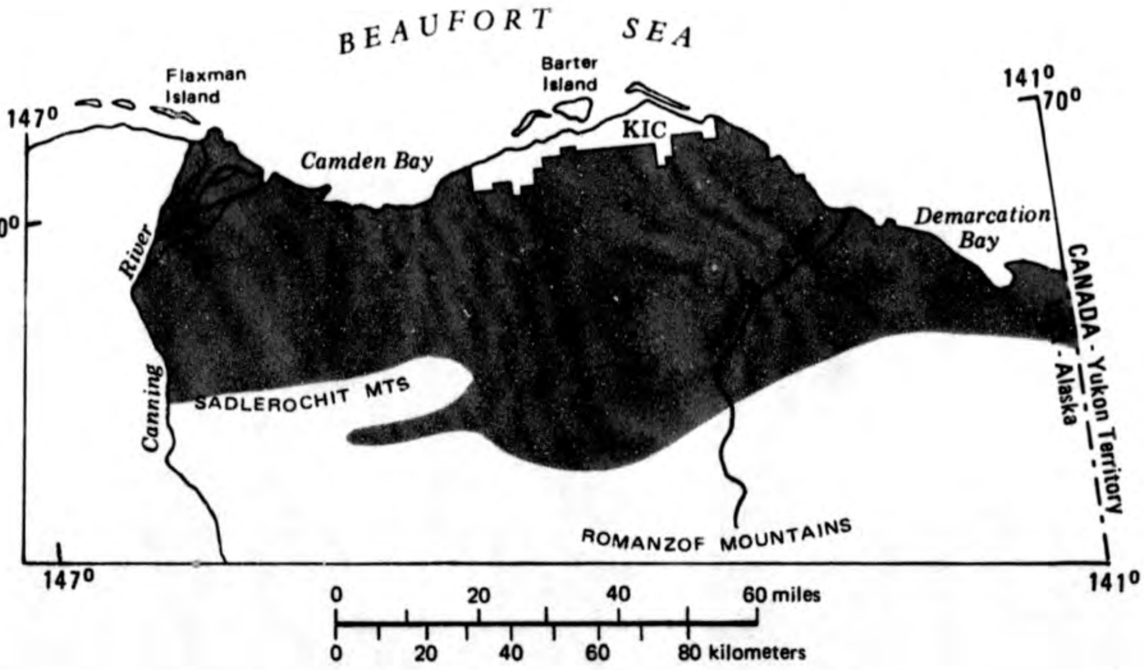

Figure 6. Areal distribution, input parameters, and resources in place for the Kemik-Thomson Play, Arctic National Wildlife Refuge, Alaska.

Gas fraction = 0.50
Conditional resources in place

Fractile	Oil (million barrels)	Gas (billion ft^3)	BOE (million)
0.99	0.00	0.00	0.00
0.95	0.00	12.35	9.06
0.90	0.00	224.04	146.23
0.75	326.40	1498.50	1044.79
0.50	2097.78	5544.16	3785.89
0.25	6972.20	13623.56	9514.61
0.10	15625.20	28032.78	19546.79
0.05	24230.45	38904.07	29454.32
0.01	43382.48	74349.25	48926.22

Fractile	Deposit size Conditional, 100% oil (million barrels)	Deposit size Conditional, 100% gas (billion ft^3)
0.99	5.803	7.255
0.95	22.006	28.025
0.90	44.099	54.634
0.75	137.593	171.947
0.50	462.298	603.463
0.25	1542.427	2044.293
0.10	4489.004	5808.051
0.05	7927.445	10985.301
0.01	24037.582	32045.930

	Attribute		Probability that attribute is favorable or present
Play attributes	Hydrocarbon sources		1
	Timing		1
	Migration		1
	Potential reservoir facies		1
	Marginal-play probability		1
Prospect attributes	Trapping mechanism		0.25
	Effective porosity (>3%)		1
	Hydrocarbon accumulation		0.5
	Conditional-deposit probability		0.125
Hydrocarbon-volume parameters	Reservoir lithology	Sand	1
		Carbonate	0
	Hydrocarbon mix	Gas	0.5
		Oil	0.5

	Attribute \ Fractiles	Probability of equal to or greater than 1.00	0.95	0.75	0.50	0.25	0.05	0
Hydrocarbon-volume parameters	Area of closure (x10^3 acres)	0.6	1	2	4	12	30	75
	Reservoir thickness/ vertical closure (ft)	50	100	200	300	800	1200	2000
	Effective porosity (%)	3	5	10	15	19	23	30
	Trap fill (%)	1	6	30	60	80	96	100
	Reservoir depth (x10^3 ft)	2	3	4	6	9	12	20
Number of drillable prospects (a play characteristic)		5	10	25	40	70	100	200

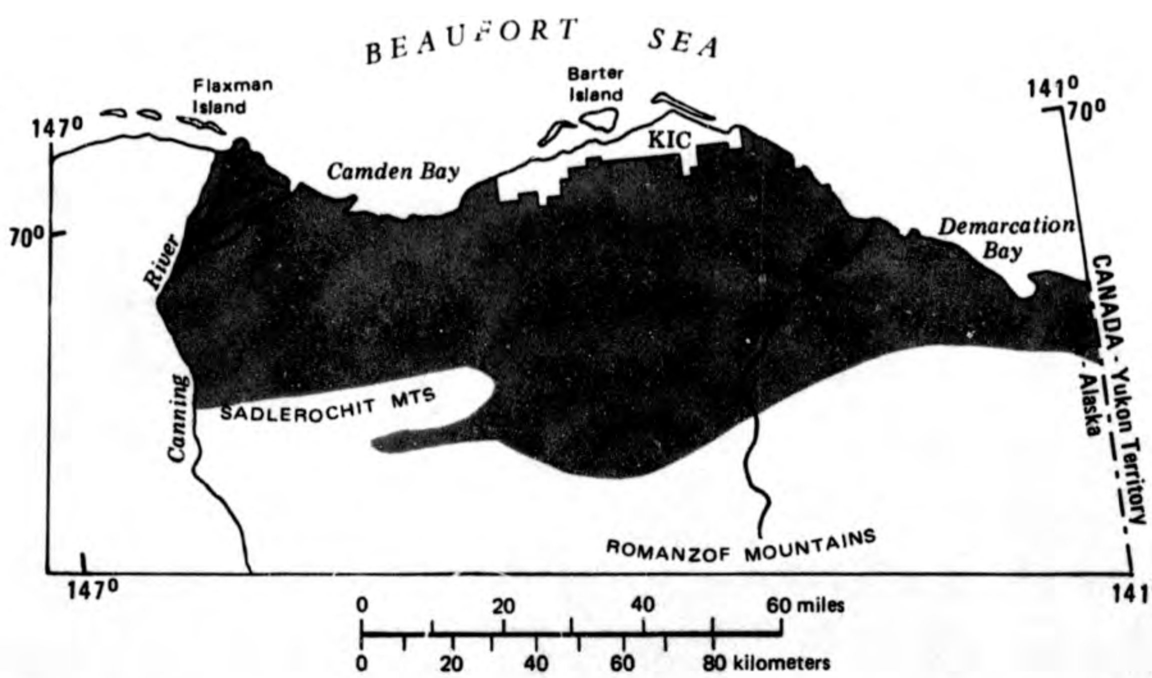

Figure 7. Areal distribution, input parameters, and resources in place for the Post-Albian Clastics Play, Arctic National Wildlife Refuge, Alaska.

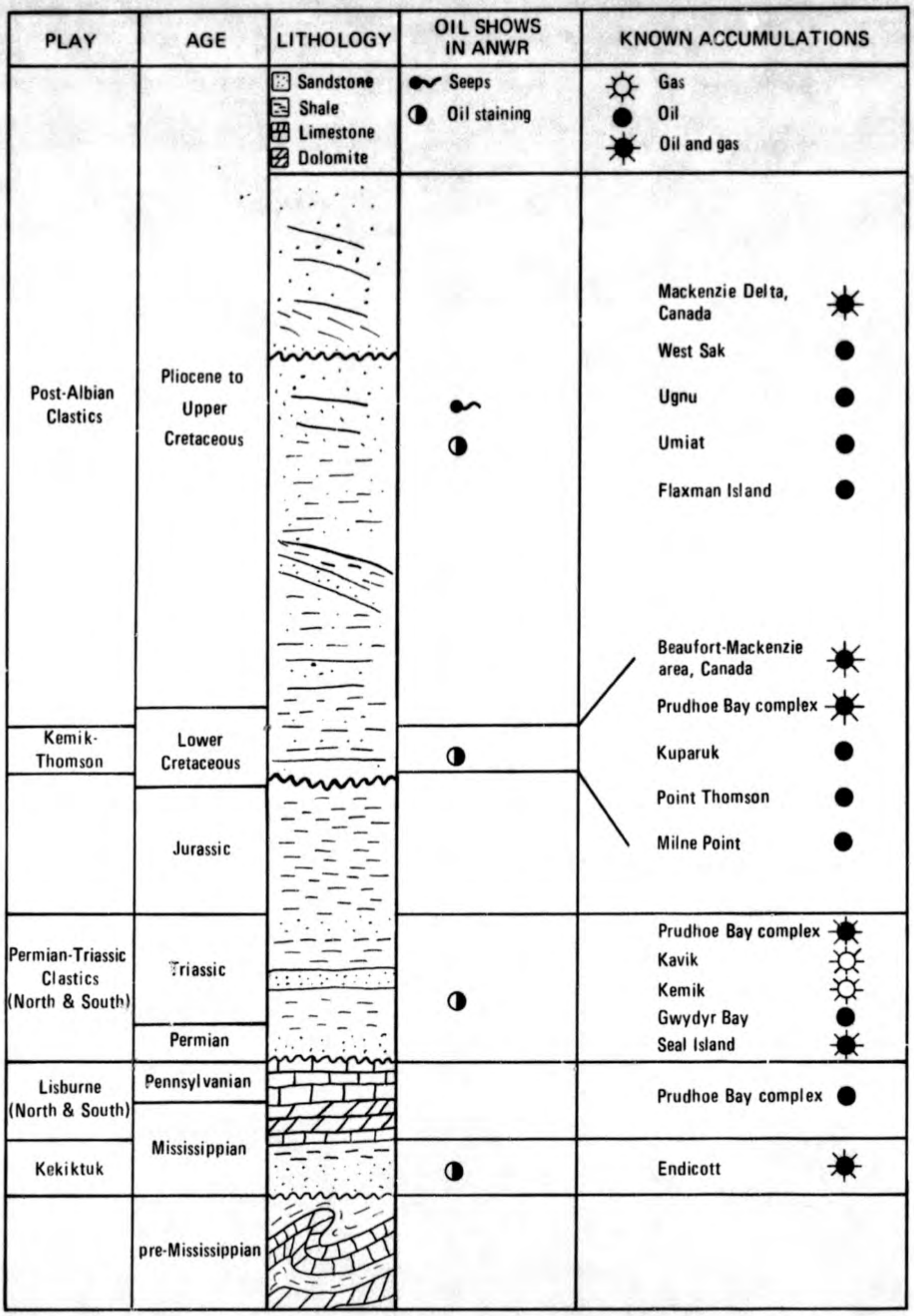

Figure 8. Stratigraphic column and oil-and-gas summary for plays in the Arctic National Wildlife Refuge, Alaska.

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A Comparison of State and Federal Appraisals of the Arctic National Wildlife Refuge Coastal Plain

by

James J. Hansen
Richard W. Kornbrath

The Alaska Department of Natural Resources Professional Report 90 presents the State's preliminary appraisal of the petroleum resource potential in the coastal plain of the Arctic National Wildlife Refuge (ANWR). The results of this study are compared with the resource estimates in the Department of Interior draft report titled "Arctic National Wildlife Refuge, Alaska, Coastal Plain Resource Assessment", which was issued for public review and comment on November 24, 1986.

To assess the potential for in-place oil and gas in this frontier area each study uses the geologic play as the basic unit of analysis. A geologic play is an area which can be viewed as an aggregate of prospects (areas of potential hydrocarbon accumulation) that have similar geologic characteristics and share common geologic elements. In analyzing the hydrocarbon potential of geologic plays, geoscientists familiar with the regional geology make three sets of probability judgments concerning the geological characteristics of these plays. These judgments comprise the basic geologic data necessary for a resource appraisal.

The first set of judgments concerns the individual probabilities that each geologic characteristic common to the play area is favorable for petroleum accumulation. These characteristics are: petroleum source, favorable timing of oil generation and migration, availability of potential migration paths, and reservoir rocks in which to retain the oil. These individual probabilities are multiplied together to arrive at the "marginal-play probability".

The second set of judgments involves probabilities that concern the presence of three geologic characteristics common to the individual prospects within each play area: trapping mechanism, effective porosity of the reservoir rock and hydrocarbon accumulation. The product of these probabilities is the "conditional-deposit probability".

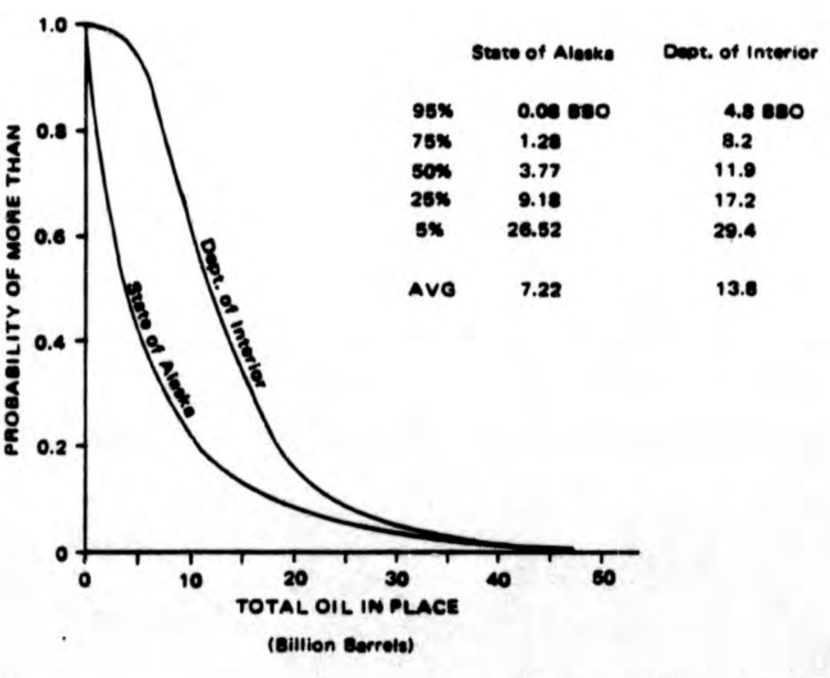
The "success factor", which gives the probability of a well encountering commercial accumulations of oil, is a product of the marginal-play probability and the conditional-deposit probability.

The third set of judgments involves the geologic parameters that determine the potential reservoir volume for a deposit. These reservoir characteristics include area of closure, trap fill, reservoir depth, reservoir lithology, and relative hydrocarbon mix (oil vs. gas).

Once a range of values for each of these characteristics is determined, computer simulation programs are used to analyze these characteristics and to arrive at a probability distribution for in-place oil and gas for each play, and for the frontier area as a whole. The State uses the Resource Appraisal Simulation for Petroleum (RASP) program, which employs a Monte Carlo method of randomly sampling probability distributions for each geological characteristic as many as 3,000 times. The Interior study uses Fast Appraisal Simulation for Petroleum (FASP), which utilizes a statistical approach to probability theory. The FASP method is based on a seven-point probability distribution for each geologic characteristic (i.e., a 95% probability of a given sandstone having 10 feet of net pay, a 90% probability of it having 15 feet of net pay, etc.). FASP computes a mean and the standard deviation from each distribution, then combines these figures to arrive at the oil in-place for each probability level.

Both RASP and FASP simulations yield lognormal distributions that show the probability of these being a given quantity of in-place oil or gas. The lognormal distribution, when plotted as a "bell type" curve, is skewed to the right. This means that the simulation processes result in the generation of many small values for oil in-place and relatively few large ones. Mathematically, the generation of a lognormal distribution is the result of a multiplicative relationship of the input parameters and of the random sampling that is conducted. The effect of the multiplicative relationship is that small variance in the input parameters can result in significant changes in the final numbers.

The following figure compares the probability distribution curves for in-place oil from the two appraisals:



The Department of Interior distribution curve is right-shifted relative to the State curve, meaning that for any given probability, Interior estimates that there is more oil in-place. Alternately, Interior estimates that there is a higher probability for a given amount of oil to be in-place, relative to the State estimate. Geoscientists make subjective judgments to select the geologic characteristics that are input into these two modeling programs. Because there are limited subsurface data in ANWR, there will understandably be differences in the geologic characteristics input into each modeling program. In comparing the two studies conducted, there are four main differences concerning the input data that can account for the divergence between these two distributions:

1. Difference in Geologic Plays

   With the exception of the Kemik-Thomson Sand Play, the two studies analyzed different geologic plays. For example, the State's Post-Albian Play encompasses Interior's Topset, Turbidite, and Imbricate Fold Belt plays.

2. Appraisal of Ellesmerian sequence rocks

   The Interior appraisal attributes approximately 50% of the oil to Ellesmerian rocks, with an average estimated oil in-place of 7.2 BBO. The State's appraisal only assigns a small probability of there being a significant quantity of this rock sequence in the subsurface; the average estimated oil in-place is 1.13 BBO. At probability levels above 25% the State appraisal exhibits little confidence of there being any Ellesmerian rocks; the federal report indicates that above this probability level there could exist Ellesmerian rocks capable of containing up to 9 BBO. However, the Interior report does state that if most of the Ellesmerian rocks are missing in most of the 1002 area, their assessment number would be reduced considerable (DOI Report, p. 54)

3. Success factors

   The State's success factor varied from 8% to 1% for the Ellesmerian rocks, was 9% for the Kemik-Thomson Sand Play, and was the highest, at 12.5%, for the Post-Albian Clastics Play. Though the success factors are not presented in the Interior appraisal, it can be inferred that their percentages were considerably higher (on the order of 10 - 25%) for all plays, since assigning higher success factors will shift the distribution curves further to the right.

4. Appraisal of pre-Mississippian rocks

   State geologists disagree with Interior geologists as to the contribution of pre-Mississippian rocks for oil accumulation. Though they have little effect on the distribution curve, Interior's appraisal includes these rocks, while the State appraisal does not.

Volumes of yet undiscovered petroleum resources in frontier areas are extremely difficult to estimate with a high degree of reliability. In the case of ANWR, the lack of sufficiently detailed subsurface geologic information results in a wide variance in the geologic characteristics that form the framework for the resource appraisal methods. In fact, geoscientists will differ in their opinion as to what should constitute a geologic play. It is not surprising (in fact, it should be expected) that these somewhat subjective scientific judgments, based on limited geologic data, will vary from group to group.

In addition to the variance in geologic input, inherent problems exist in the applied methodology and presentation of the resulting data. Lognormal distributions are the result of the multiplicative relationship of the input data; small variances in these input parameters can result in large differences in the resulting totals. It is important to note the fact that both probability distributions show the possibility for a wide range of resources. This is simply a reflection of the high uncertainty in the input data, and it should not be interpreted in a negative manner.

A comparison of the results of the two studies reveals the following:

1. Both reports conclude that the key elements requisite for petroleum accumulations have been demonstrated to be present beneath the coastal plain of ANWR.

2. Both reports conclude that there is a small possibility that significant and unusually large petroleum resources are present beneath the coastal plain.

3. Both reports conclude that there is a greater likelihood that the resources present are smaller in size. However, prior to its discovery, some industry officials had estimated that there was only a two percent probability that the Prudhoe Bay area contained two billion barrels of oil. They did not anticipate the twenty three and a half billion barrels of oil that are now calculated to have been initially in-place.

4. While the State study indicates smaller resources at the higher probability levels relative to the Interior study, there is close agreement between both studies at the lower probability levels.

5. Neither study can be labeled right or wrong. Both studies are valid professional estimates of resource potential under ANWR's coastal plain. Exploratory drilling will ultimately determine which estimate was more accurate.

3:50
2/5/87

BF
Coghill
Fischer.

O&G

BF to Katz.

participation in land swaps —

1) HR 39 only bill —

not much presence on hill —

2) 1002 report —
delayed by suit

3) land trades. —
1) state as sovereign —
views should be considered
2) as land owner.
260,000 acres to trade..
4K at table w DOI + Natives

Tract selection. —
must be ~~app~~ approved by Cong.

Not taken a position

4) Caribou Treaty w/ Canada
will lead to Bilateral agreement
creates regime for discussion of
habitat protection.

90-10 — is part of Salmon compact between State —

compensates for not participating in fed reclamation.

In discussion for last 2 years?

began last October - ~~last~~ December.
permitted to be at table.

38.50

lookat land exchange documents

260,000 acres.

Supports resolution —

reflect consensus of leg + gov.

no action until 1002 report to Congress

late March + Early April.

Cog

MOU on seismic data?

get copy of

90.10 - any leasing under - mineral leasing not apply if un Act of 1920

Role of state in trades —

DOI has promised [illegible] it will submit to Congress

COALITION < pro 30 members

ENVIRONMENTAL -

State separate -

Maritime unions support. — others on side.

1) Natives trades - give Congressmen reason to support ANWR.
Native - effective lobby

2) Premature to consider land trades until after ANWR is open.

Legislative comment still open! (Coghill)

Interior dept has some revenue projections

2-10-87

State's Comments on 1002 Report (ANWR)

SENATE SPECIAL COMMITTEE ON
OIL AND GAS
February 10, 1987
3:30 p.m.

MEMBERS PRESENT

Senator Bettye Fahrenkamp, Chairman
Senator Jack Coghill

MEMBERS ABSENT

Senator Paul Fischer

CALENDAR

State's comments on U.S. Department of Interior Draft 1002 Report on Arctic National Wildlife Refuge

WITNESS REGISTER

Rod Swope
Special Assistant for Resources
Office of the Governor
P.O. Box A
Juneau, Alaska 99811

Kurt Fredriksson,
Project Analyst, Governmental Coordination
Office of Management & Budget
P.O. Box AW
Juneau, Alaska 99811

Norman Cohen Acting Deputy
Commissioner
Department of Fish & Game
P.O. Box 3-2000
Juneau, Alaska 99802

Lou Pamplin
Department of Fish & Game
333 Raspberry Road
Anchorage, Alaska 99502

Dennis Kelso, Commissioner
Department of Environmental Conservation
P.O. Box O
Juneau, Alaska 99811

Bob Butts
Division of Oil & Gas
Department of Natural Resources

P.O. Box M
Juneau, Alaska 99811

ACTION NARRATIVE

TAPE ONE SIDE ONE
February 10, 1987

Number 001

The meeting was called to order by Senator Fahrenkamp at 3:30 p.m. She stated the committee would be hearing the state's position on the 1002 Report.

Number 014

The first person to appear before the committee was Rod Swope, special staff assistant to the Governor for resources. Mr. Swope discussed how they developed their position on the 1002 Report. When first received, they immediately requested each of their resource agencies to look at the information relative to their particular expertise and establish a department position. That began the process whereby departments began to formulate a position on the report and worked collectively to resolve the different issues that were involved. The issues that they weren't able to reach some consensus agreement on, or for which they required some higher policy direction, were directed to the director level. Remaining issues were eventually given to the Commissioners of the three resource agencies to try to resolve.

He added that throughout their own process, they also took a look at any public comments that were provided to the state by any interested person, public sector or state government.

Number 077

Senator Fahrenkamp asked if after the position is finally arrived at, is it again reviewed by various commissioners or does it go directly from the Office of Management & Budget, and the Governor's office without further review.

Number 085

Kurt Fredriksson, project analyst in the Office of Management and Budget, responded that there had been two commissioner meetings. Based on their first meeting another draft was circulated to the commissioners which led to a final meeting between the commissioners and the Governor. Following that meeting, a final paper was put together and again directed back to the commissioners for approval.

Number 100

Rod Swope continued by saying that the state has recommended to the Secretary of Interior that Congress immediately open up the 1002 area to oil and gas leasing, with exception of the area described by the U.S. Fish & Wildlife Service as the "core" caribou calving area. The state recommended that leasing in the "core" calving area be deferred (that is, no leasing occur for a 10-year period). During that period the Department of Interior would work to establish some sort of caribou impact assessment study group that they feel would be composed of federal, state and private sector researchers to further study the potential impacts of oil and gas activities in the calving area on the Porcupine Caribou herd. It would also include impacts from oil and gas activities on other caribou within the United States as well as the Canadian Arctic.

Number 130

Senator Fahrenkamp referred Mr. Swope to his statement regarding the Department of Interior establishing a caribou impact assessment study group, and asked if that was agreed upon between the state and the Department of Interior before the state arrived at its decision. Mr. Swope responded it would only be their recommendation to them.

Number 135

Mr. Swope recommended the study be done over a 7-year period following the commencement of the first exploration well and it would probably result in a report that would document the effects of oil and gas activities on caribou, including any information they might gather on potential impacts to the Porcupine herd. Based on the information provided in the report, they would recommend that both the Governor and the Secretary collectively provide a recommendation to Congress as to whether or not leasing should go forward in that core calving area. If Congress did not act on the joint recommendation by the Governor and Secretary of Interior within a 10-year period, then that recommendation would go into effect.

Number 154

Senator Coghill inquired as to when the staff level started to generate their position on ANWR.

Number 168

Mr. Swope responded that specifically with the 1002 Report staff started working on it when they received it approximately at the end of November or the first week of December 1986.

Number 195

Senator Coghill said he was concerned with their recommendation for a seven-year study on the calving area because there had been so many studies done earlier on that herd.

Number 230

Lou Pamplin of the Department of Fish & Game said that most of the detailed study analysis that has been done from the mid-seventies to the present time is work that has been done on the central Arctic heard. There has been some intermittent work done by the state and U.S. Fish and Wildlife Service on the Porcupine Caribou herd, but not with any consistency.

He said in regard to Senator Coghill's question concerning when the state had started formulating their response, that a couple of years ago Fish & Game had tried working with Fish & Wildlife Service to initiate more detailed studies on the Porcupine Caribou herd. The state did not have the funding, but Fish & Wildlife did some census work. They attempted getting draft copies of their report and preliminary input from Fish & Wildlife and the Department of Interior and they were denied. He added that the same thing had occurred on ANWR land exchanges.

Number 270

Senator Fahrenkamp asked if the state was working in any way with Canada during those periods of time. Mr. Pamplin responded that the way the state worked with Canada primarily was to get data from them on the winter use of habitat in the Canadian portion of the range.

Number 294

Senator Coghill inquired if the department had the consultant information from the consortiums of the pipeline, to which Mr. Pamplin replied that staff had seen the data but he did not know if they had exact copies. He said the final data in the 1002 Report on caribou is a composite of consultant data, state data, and Fish & Wildlife Service data.

A discussion followed on the migration and overlap of the Porcupine herd and the 40-Mile herd.

Number 406

Dennis Kelso, Commissioner of Environmental Conservation, said his department's approach to 1002 was to see how adequately it had dealt with basic issues of air, land and water quality as well as how well the document positioned the state in order to promote its policy objectives in Washington, D.C. He said their position is that it can be done right as far as environmental protection is concerned, and the state should take the steps to assure that it happens.

Number 495

Mr. Kelso said that his department thinks the experience in Prudhoe and in other North Slope development provides a valuable stepping stone and a point to learn from. He said their criticism of the 1002 Report is that the Interior Department has not done an adequate job of laying the ground work and it leaves many questions unanswered. He continued by saying that Interior needs to go back and look at the major areas it has not addressed in the 1002 Report and the state can take its own steps to make sure that those gaps don't swing around and end up costing the state an important policy decision when Congress takes up the matter. He said the Governor's supplemental budget request includes funding to provide appropriate representation in Washington, D.C.

representation.

Mr. Kelso concluded by saying that there has never been the opportunity to pull all the existing information together. Industry has not been able to do so and had no reason to do so. The state has never been staffed to do that kind of bringing together of existing data and identifying whether there are gaps that need to be addressed. He suggested the first thing the state needs to do is pull that data together in consultation with industry.

Number 570

Kurt Fredriksson, governmental coordination, said the 1002 Report speaks to the requirement for a plan of operation to be submitted to the Federal government. He did not know if they will require an environmental impact statement. He said with respect to state authorizations, there would not be a requirement for an EIS.

Number 578

Bob Butts, Department of Natural Resources, said the state doesn't have an environmental impact statement requirement, but the Federal government does if there are federal permits involved, even on state land. He said it would be necessary to do an EIS for the bigger projects. One was done on Endicott and it looked like there would have to be one done for the Lisburne project. He was reasonably sure that there would have to be one done for ANWR. In answer to a question from Rod Swope, he said that development on private land would probably also require an EIS. Lou Pamplin added that there would probably be a NEPA statement required also.

TAPE ONE SIDE TWO
February 10, 1987

Number 675

Bob Butts of the Department of Natural Resources, said first that it was important to the department that the state's position be consistent with the policies in existence on state land. A second important part was that provisions be made by the Federal government and by Congress to allow the siting of onshore support facilities for offshore development. He said another general concern was that the total package was not so restrictive that oil and gas development and production in ANWR was uneconomical. He concluded by saying that it was clear to the department that opening ANWR has benefits in terms of making existing marginal fields and potential marginal fields offshore ANWR economical.

Number 738

Norman Cohen, Acting Deputy Commissioner, Department of Fish and Game, said that the department attempted to inventory the resources of concern in the coastal plain and come up with mitigation measures for specific resources and address them individually. After that they then went through the process with DEC and DNR to come up with a package that was consistent with the Governor's position of going forward in an environmentally safe manner.

Number 790

Senator Fahrenkamp commented that in the past there has been implied difficulties between the Department of Interior and the State and asked if that was a fair statement and, if so, what process are we going through now to try and improve that.

Number 811

Rod Swope responded that, in his perspective, in the time that he has been involved, he thought they have had good cooperation from the Department of Interior. He said although they had asked for them to try to hold hearings in several areas, and which they were not able to accommodate the State, they did provide some additional time in which to review and respond to the 1002 Report. He felt that generally they have tried to keep the lines of communication open with the Administration as well as their offices in Washington, D.C.

Number 825

Senator Fahrenkamp noted that the Resources Committee would be holding hearings in other areas of the state. She also asked what was being done to make sure that the state is working with the Canadian government on ANWR.

Number 848

Norman Cohen responded that in December 1986 there was a meeting between representative of the U.S. Government and the Canadian Government to discuss an agreement for the conservation of the Porcupine Caribou herd. The agreement was initialed by the representatives of each country and has been under review by the Administration, user groups, industry, the Department of Interior and the State Department. He said that over the next few months people will be able to make recommendations to the State Department as to whether this initial document should be signed by the United States.

Number 868

Senator Fahrenkamp asked if there were conflicts in that area, to which Mr. Cohen responded that at this time there were not conflicts with Canada over issues dealing with the Porcupine herd.

Bob Butts agreed that there hadn't been any disagreements in that area. However, the Canadian government did oppose the recommendation in the 1002 Report because of perceived concerns over caribou. They felt the Department of Interior did not adequately consult the Canadian government prior to making the decision.

Number 895

Senator Fahrenkamp said although there doesn't appear to be a great deal of conflict right now, there has been some in the past. Mr. Butts said that in the context of the 1002 Report, the Canadian government does not believe adequate protection for the caribou will be made under the Interior's chosen alternative. He said the state has provided some additional protection and because of the Canadian concerns.

Number 917

Senator Fahrenkamp closed by saying she was disappointed that the state is getting in the "loop" a little late and hopes that everyone can work together. She adjourned the meeting at 4:40 p.m.

OIL AND GAS COMMITTEE

FEBRUARY 10, 1987

STATE'S COMMENTS ON THE DEPARTMENT OF INTERIOR'S DRAFT 1002 REPORT

TO TESTIFY:

Rod Swope, Special Assistant to the Governor

Commissioner Judy Brady, DNR

Commissioner Denny Kelso, DEC

Norm Cohen, Department of Fish and Game

R.C

STATE'S RECOMMENDATIONS:

Fully supports opening of the coastal plain subject to appropriate and effective mitigation.

Governor should work closely with Interior. Not enough of that has been done.

Defer leasing in the core calving area for at least 10 years.

Establish ANWR Caribou Impact Assessment Study Group.

Governor and Secretary make recommendations after 7 years.

Implement recommendations if Congress fails to act within 10 years.

Based on 1) high level of protection of fish and game mandated by Congress

2) not enough information about Porcupine Caribou

3) concern for Canadian interests

Recognized FISH and WILDLIFE, SUBSISTENCE, and OIL AND GAS as important national resources there.

Encourage use of best and latest technology.

DOI should establish formal consultation process with the state for planning and resolving disputes.

Identified 8 topics that need further discussion.

HAVE EACH COMMISSIONER REVIEW THEIR COMMENTS.

DNR and FISH AND GAME

REVIEW COMMENTS ON STIPULATIONS (ENCLOSURE A)

SUBSISTENCE Implementation of ANILCA requirements

DEC

ENCLOSURE B STATE AUTHORITIES PERTINENT TO ANWR

QUESTIONS:

In the past there seems to have been a lack of coordination between the state and Department of Interior. HOW DO YOU EXPECT TO IMPROVE THAT PROCESS IN THE FUTURE?

The comments mentioned a concern for our Canadian neighbors. DO YOU HAVE ANY SPECIFIC RECOMMENDATIONS FOR RESOLVING THESE CONFILICTS?

STATE OF ALASKA

OFFICE OF THE GOVERNOR
JUNEAU

STEVE COWPER
GOVERNOR

NEWS RELEASE

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Reports from ONC
" " Fish + Game

FOR IMMEDIATE RELEASE
February 6, 1987
No. 87-11

STATE URGES EXPLORATION IN ANWR
MORATORIUM IN CARIBOU "CORE" CALVING AREA

JUNEAU--Oil and gas exploration should be permitted in the Arctic National Wildlife Refuge, but delayed in the "core" caribou calving area for at least 10 years pending a study of the impact of exploration on the Porcupine caribou herd, according to the state of Alaska's response to a federal report on ANWR.

In a nine-page letter to the U.S. Interior Department, the state says oil and gas potential in the refuge is extremely promising and therefore, exploration should proceed. At the same time, the state says not enough is known about the potential impact exploration may have in the area of most concentrated caribou calving.

As a result, the state proposes creatior of a group composed of federal, state, university and private researchers to study the issues and offer recommendations to the Interior secretary and Alaska's governor about future exploration in the core calving area.

The proposal is contained in the state's formal response to the Interior's Draft Arctic National Wildlife Refuge Coastal Plain Resource Assessment 1002 report. The response, delivered to Interior officials in Washington, D.C., today, details the state's concerns with the draft report.

-MORE-

The comments follow testimony offered by the state in Anchorage on Jan. 5 in which Gov. Steve Cowper said he supports exploration in ANWR with the proper environmental protections.

"Alaska's coastal plain contains the best prospects in this country for a significant oil and gas find," Cowper said, upon release of the state's comments. "I think we can go after it responsibly and with a minimum of disruptions if we follow the guidelines outlined in our response to the federal report."

The state says two key facts are at issue in the debate over development of the coastal plain: (1) ANWR is home to fish and wildlife resources which are of significant national and international importance as well as necessary to the subsistence way of life of those who live in and near the refuge, and (2) the area contains the most outstanding oil and gas frontier remaining in the U.S.

State officials point out that Alaska has more than two decades of experience with oil exploration and that, using the best and latest technology, safe development of the coastal plain is possible. One way to ensure minimum disruption of the caribou is a thorough report on the potential impacts of the core calving area.

After seven years of careful study, the Interior secretary and governor would submit a report to Congress for a decision on whether to open or defer leasing in the core area, under the state's proposal. That study would seek to document the biological importance of the core calving area, the effects of oil and gas activities and the effectiveness of mitigation measures.

-MORE-

The state's comments are the result of months of discussions among state resources agencies, the oil industry and environmental groups. A final 1002 report is expected to be delivered in April to Congress, which then begins debate on opening ANWR to exploration.

-30-

(A copy of the state of Alaska's response to Interior's 1002 report is attached.)

STEVE COWPER
GOVERNOR

STATE OF ALASKA
OFFICE OF THE GOVERNOR
JUNEAU

February 6, 1987

The Honorable Donald P. Hodel
Secretary
Department of the Interior
Interior Building, Room 6151
C Street between Eighteenth
and Nineteenth Streets, NW
Washington, DC 20240

Dear Mr. Secretary:

I wish to take this opportunity to thank you for providing the state with the additional two weeks to review and comment on the draft Arctic National Wildlife Refuge, Alaska, Coastal Plain Resource Assessment. The additional time enabled us to conduct a more thorough and useful review of this important document. Enclosed is a copy of the state's comments on the draft assessment.

Like you, I feel it is extremely important that Congress be persuaded to open the coastal plain to oil and gas leasing consistent with the purposes of the refuge to preserve its fish and wildlife values. The state is committed to this objective and with your cooperation will work to see that it is accomplished. I look forward to reviewing the final report to Congress and hope to meet with you in the near future to discuss how we might best advance a cooperative effort to move forward with oil and gas leasing in the Arctic National Wildlife Refuge.

Sincerely,

Steve Cowper
Governor

Enclosure

cc/enc: Senator Ted Stevens
Senator Frank Murkowski
Representative Don Young
William Horn, Department of the Interior, Washington, DC
John Katz, Office of the Governor, Washington, DC
Alaska Senate Resources Committee
Alaska House Resources Committee

STATE OF ALASKA

OFFICE OF THE GOVERNOR

OFFICE OF MANAGEMENT AND BUDGET
DIVISION OF GOVERNMENTAL COORDINATION

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February 6, 1987

Mr. Robert Gilmore
Regional Director
U.S. Department of the Interior
U.S. Fish and Wildlife Service
1011 East Tudor Road
Anchorage, AK 99503

Dear Mr. Gilmore:

The state has reviewed the Draft Arctic National Wildlife Refuge (ANWR), Alaska, Coastal Plain Resource Assessment 1002(h) Report. We appreciate the additional time granted the state to review this important report. Based on our review of the substantial amount of information contained in the draft 1002(h) report, we strongly support the conclusion that oil and gas exploration be allowed in ANWR consistent with the chief purpose of the refuge to preserve its unique wildlife values.

The State of Alaska recommends that Congress immediately open the 1002 area to oil and gas leasing, with the exception of the area described by U.S. Fish and Wildlife Service (USFWS) as the "core" caribou calving area. The state strongly recommends that leasing in the "core" calving area be deferred for a ten-year period. During this ten-year period, the Department of the Interior (DOI) should establish an ANWR Caribou Impact Assessment Study Group composed of federal, state, university, and private researchers to further study the potential impacts of oil and gas activities in the calving area on the Porcupine Caribou Herd. The study should be conducted over a seven-year period following commencement of the first exploratory well and result in a report to the Secretary of the Interior and Governor of Alaska. The report would seek to document the biological importance of the core calving area, the effects of oil and gas activities in the 1002 area on the Porcupine Caribou Herd, and the effectiveness of mitigation measures employed in the 1002 area to minimize adverse impacts to caribou. Based on the report findings, the Governor and Secretary would recommend to Congress to extend the deferral or open the core calving area to oil and gas leasing. If

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1542 SCOMM 57: SENATE SPECIAL COMMITTEE ON OIL & GAS, 1987-1988 839

Congress failed to act on the recommendations within the ten-year period, the recommendation of the Secretary and Governor would be implemented.

It is imperative that the recommendations from the Governor of Alaska be included with those of the Secretary of the Interior given the significant interests of the state involved in both the leasing and protection of resources in the 1002 area. Not only is the state a sovereign steward of natural resources with regulatory responsibilities in the area, it is the principle owner of lands which any ANWR production transportation system must cross.

This recommendation is based on several salient facts. First, Congress has mandated that fish and wildlife populations in ANWR receive a very high level of protection. Because of this mandate, USFWS is required to take a conservative approach when making decisions regarding the impact of development activity on the refuge's fish and wildlife populations. Second, while a sizable amount of information has been collected on the impact of oil and gas activity on the Central Arctic Caribou Herd, questions remain regarding the potential impact of the oil and gas activity on the Porcupine Caribou Herd population because of its larger size, distribution and movement patterns, and population dynamics. Contrary to the statements made on page 112 of the draft 1002(h) report, at this point in time there is inadequate information to predict what population impacts would occur if oil and gas development were to take place in the core calving area. Third, protection of the herd and its habitat is of great concern to our Canadian neighbors, and the deferral and studies will respect those concerns.

<u>Special Values of ANWR</u>

We predicated our review on two fundamental facts inherent to ANWR. First, the fish and wildlife resources of ANWR are of significant state, national, and international importance. The Porcupine Caribou Herd, which numbers some 180,000 animals, annually migrates between Canada's Northwest Territories and Alaska's arctic coastal plain where it spends a portion of each summer. These animals are of great importance to both the people of Alaska and Canada. The Porcupine Caribou Herd and other fish and wildlife of the ANWR coastal plain are the foundation of the subsistence way of life to the residents of Kaktovik, Arctic Village, Venetie, and Fort Yukon in Alaska and Old Crow in the Yukon Territory of Canada. Furthermore, within the refuge, "The 1002 area is the most biologically productive part of the Arctic Refuge for wildlife and is the center of wildlife activity on the refuge." (Draft 1002(h) report, page 46.) The Alaska Department of Fish and Game has conducted an extensive review of ANWR fish and wildlife information which is available on request to USFWS and other interested parties. The department's data on distribution and abundance of fish and wildlife and areas of special concern confirm the great importance of ANWR's renewable resource base.

The second intrinsic feature of ANWR is that it has high oil and gas potential. The state concurs with the draft 1002(h) report findings on page 1 that the 1002 area, ". . . is clearly the most outstanding oil and gas frontier remaining in the United States, and could contribute substantially to domestic energy supplies." As you know, the Alaska Department of Natural Resources has recently made public a preliminary appraisal it conducted of petroleum resource potential in ANWR's coastal plain. Alaska's report confirms DOI's conclusion that ANWR's coastal plain has the potential for an unusually large accumulation of oil.

Past Lessons Learned from Oil and Gas Activities in Alaska

As indicated in the draft 1002(h) report, development of ANWR's coastal plain will alter the existing environment and to some degree affect the Porcupine Caribou Herd. It is critical that appropriate and effective measures be taken to minimize the potential adverse effects of oil and gas activities on ANWR's coastal plain. Alaska has nearly two decades of experience in dealing with oil exploration, and lessons of the past will serve as a guideline for development in the future. In the event Congress permits exploration, the state would encourage that the best and latest technology be used.

The state assumes the draft 1002(h) report was not intended to be all inclusive, and that more detailed performance standards would be developed in concert with the state prior to any lease sales or any transfer of subsurface rights. Clearly, additional time will be needed in order to develop an adequate set of terms and conditions designed to ensure protection of air and water quality and fish and wildlife resources. With this understanding, our general comments on the proposed mitigation measures summarized in the draft 1002(h) report are included in Enclosure A.

Federal/State Consultation and Resolution of Issues

The state is encouraged to read on page 97 of the 1002(h) report that "The FWS would emphasize early and continuous consultation and coordination with leaseholders, permittees, and state and federal agencies at the start of planning." Consistent with this federal intent, the state feels it is essential that DOI establish a formal consultation process with the state and other parties in order to clearly establish at what points in the process and what level of detail different issues and authorities will be addressed. This process would also allow the opportunity for the parties to clarify their respective authorities, permitting, and field procedures to avoid duplication or conflicting efforts. These consultations should identify or acknowledge existing regulatory requirements and authorizations at federal, state, and local levels. At a minimum, it should address different agencies' review times and public notice requirements. Issues that should be addressed are the timing of the various phases of review for specific projects; the level of detail to be addressed at each; and the coordination of permitting, review of plans of operations, field surveillance, and field approvals. Experiences associated with the development of the Trans-Alaska Pipeline System (TAPS) and the proposed Alaska Natural Gas Transportation System (ANGTS) from Prudhoe Bay to the Canadian border could provide useful models for cooperative management programs.

A coordinated interagency process for planning, design review, permitting, field surveillance, compliance and enforcement, and reclamation would serve the state, DOI, and industry well. The state's existing coastal management consistency process as well as the jurisdiction of state agencies such as the Departments of Fish and Game, Environmental Conservation, Natural Resources and the Alaska Oil and Gas Conservation Commission need to be acknowledged and effectively implemented in the review and permitting of each stage of the overall project. Lack of sufficient and effective coordination could lead to each agency dealing independently with applicants and could result in permitting inefficiencies with duplicative and inconsistent compliance and enforcement actions.

Topics Needing Further Discussion in the Final 1002(h) Report

Overall, the State finds that USFWS did an excellent job in compiling and summarizing a large amount of biological and geological information in the draft 1002(h) report. Considerably more work needs to be directed to the following eight issues of major importance to the state.

1. Standards for Air and Water Quality Protection

The draft 1002(h) document focuses primarily on a discussion of habitat and wildlife issues and petroleum potential. The document is considerably weaker with respect to air, land, and water quality issues. DOI must acknowledge and accurately reflect in the final 1002(h) report state authority in this area and the body of regulations and requirements associated with sound environmental practices. A list of pertinent state authorities is included in Enclosure B for your reference.

a) Air Quality Management

Particular attention should be paid to emissions associated with start-up and upset flaring, emissions of nitrogen oxides, and the best available technology review process associated with "prevention of significant deterioration" review.

b) Drilling Wastes and Solid Waste Management

Major waste streams include garbage, drilling wastes, metal wastes, and oily wastes. Our experiences on the north slope verify that it is very important that proper management of all these wastes be addressed from the beginning.

Drilling wastes are of particular concern. Improper management of drilling wastes can result in the contamination of adjacent habitats with potential negative effects to the vegetation and fish and wildlife species. Management of drilling wastes should involve development of best practices to minimize waste generation and to ensure total containment or injection of all produced wastes. Best practices should be based in part on a thorough evaluation of the effectiveness of past practices of drilling waste disposal in Alaska. Recent efforts by the Alaska Department of Environmental Conservation to develop a workable set of regulations governing these activities are nearing completion and should be viewed as the framework for developing specific requirements. In addition, the U.S. Environmental Protection Agency is currently studying the issue of proper drilling waste disposal and should soon have a report available.

Provisions for pickup of windblown litter and other debris must be addressed by stipulation. Early planning for sound disposal of each waste stream will lead to the best environmental results.

c) Liquid Waste Management

Possible liquid waste discharges include domestic wastewater, reserve pit fluids, produced water discharges, hydrostatic test discharges, vessel rinsates and radiographic wastes. Each needs to be identified and provisions made for proper disposal. The existing local, state and federal regulatory structure, ranging from plan review to the use of the best practicable technology, needs to be addressed. Reinjection of produced waters and non Resource Conservation and Recovery Act (RCRA) regulated liquid wastes is routinely practiced on state lands on the north slope.

d) Hazardous Waste Management

No discussion of hazardous waste management is included in the draft 1002(h) report. Hazardous waste management is governed by stringent requirements under the federal RCRA. Transportation of hazardous materials is regulated by the federal Department of Transportation. Proper management must be addressed.

e) Oil Spill Prevention and Response

The draft 1002(h) report refers to the need to address oil spill control requirements at page 84. More detailed plans will be required under the cited state and federal statutes. Provision for a coordinated response capability should be provided by stipulation.

2. Provisions for Offshore Support Facilities

It is important that the final 1002(h) report and management alternatives address the siting in ANWR of oil and gas facilities needed to support offshore oil and gas development occurring adjacent to ANWR on state-owned submerged lands and on the federal Outer Continental Shelf. As written, none of the alternatives specifically state that support facilities, if needed, would be permitted.

3. Alternative Development and Transportation Scenarios

Statements in the draft 1002(h) report refer to a transportation corridor (road and pipeline) between ANWR and TAPS Pump Station 1 in Prudhoe Bay. The state recognizes that the scenario which was analyzed is only one of many potential alternatives. The actual alignment of transportation facilities if, in fact, discoveries are made and any facilities are required, will be dependent upon many factors including the location and size of any reserves discovered, the need to accommodate delivery of any additional nearby reserves, terrain constraints, habitat considerations, and project economics. We suggest that the final report reflect the interrelationship of these factors in determing the size and location of needed transportation facilities. In addition, we suggest that the report describe the level of any review that will proceed these decisions. Interagency and public reviews of TAPS and ANGTS projects provide a good model of the scope of analysis which accompanies the review and approval of a major transportation project.

4. Subsistence ANILCA 810 Analysis

The draft 1002(h) report does not address the process by which the impacts of oil and gas development on subsistence activities will be identified and mitigated. Such an analysis is required by Section 810 of the Alaska National Interest Lands Conservation Act (ANILCA).

Impacts of oil and gas activity in the 1002 area on fish and wildlife resources can adversely affect human uses of these resources. This is true both in the 1002 area and in other Canadian and Alaskan communities that rely on wildlife which use the 1002 area, most notably the Porcupine Caribou Herd. The draft 1002(h) report does not present a complete picture of subsistence uses in the area. The discussion focuses principally on subsistence uses in the community of Kaktovik, and makes only passing reference to some but not all other communities that use the Porcupine Caribou Herd. A more comprehensive discussion of subsistence uses by communities that use Porcupine Caribou Herd is required in order to better assess the future impacts of development in the coastal plain. The potential impacts associated with oil and gas exploration and development in the 1002 area, like the siting and design of transportation facilities, cannot be addressed with certainty until exploration has confirmed the existence and location of potential oil and gas fields and some understanding of the scope of development is known. Enclosure C describes the basic requirements of ANILCA 810, and provides a recommended approach for meeting these requirements.

5. Water Availability and Use

The draft 1002(h) report correctly notes that water resources in the 1002 area are very limited and confined to the surface. Most of these water sources freeze solid by late winter. Given the paucity of fresh water for industrial use within the 1002 area, the draft report concludes that adjacent marine waters must be viewed as a water resource. Little attention is given to other alternatives used elsewhere on the north slope, such as snow melters and deep thaw lake reservoirs.

Fresh water for use in the Prudhoe Bay oilfield was taken from the Sagavanirktok River adjacent to the Deadhorse industrial area during the early years of that field's development. This removal of water from the Sagavanirktok River resulted in dewatering of fish overwintering habitats with documented mortality of large numbers of fish. As a consequence, the state no longer allows the use of water from this and similar sources. Currently, in order to provide fresh water for industrial uses in the Prudhoe Bay area, the state requires the use of several large surface water reservoirs that have been developed. The majority of these reservoir sites are depleted deep gravel mine sites that have been flooded with surface water. Other sites are shallow tundra lakes that have been deepened to provide winter water supplies. These water reservoirs are filled either passively or actively from nearby drainages during the spring breakup period and are, in general, isolated from river and stream systems during the remainder of the year. DOI should initiate a more thorough analysis of similar alternatives for industrial water use in the 1002 area.

6. Gravel Use

Gravel sites in ANWR should be sited, developed, and reclaimed in such a manner that overall impacts to water quality and fish and wildlife resources are mitigated. Plans for gravel removal should include detailed plans for the reclamation of the site to be conducted in phases concurrent with the removal of gravel. Gravel sites may also be developed in such a manner that they can be used as water sources for both exploration and development.

7. Disputed Acreage

Although the draft report references the submerged lands ownership dispute between the state and federal government regarding the coastal lagoons between the mainland and offshore barrier islands, it does not address the ownership status of the beds of nontidal navigable waters. The state asserts ownership of the submerged lands underlying the Aichilik, Jago, Okpilak, Hulahula, Salerochit, Staines, and Canning rivers within the 1002 area.

8. Decision Rules and Mitigation Policy

The terms "avoidable adverse impacts" and "unnecessary adverse effects" are not defined and do not appear in USFWS Mitigation Policy (Federal Register, Vol. 46, No. 15). Adding further to the confusion is a list of "unavoidable effects" on page 101 that includes a mix of those that are truely unavoidable (e.g., loss of habitat by gravel overlay for roads and pads) with many that are avoidable with proper design (e.g., erosion and ponding along roads, water storage pits in streambeds).

There also appear to be discrepancies between the explanation regarding Resource Category 1 and 2 in the draft 1002(h) report and the explanation for both of these categories in the federal mitigation policy regulations. Further, the draft 1002(h) report makes no mention of the requirement for "no significant adverse affect" as provided under Section 1002(h) of ANILCA. DOI should address these apparent inconsistencies with USFWS mitigation policy in the final 1002(h) report.

As discussed earlier in our comments, the Alaska Coastal Management Program standards and review procedures need to be addressed in the final 1002(h) report. In particular, reference should be made to the Habitat Standard (6 AAC 80.130) which requires habitats to be managed so as to maintain or enhance their characteristics and that uses and activities which will not conform to this standard may be allowed if there is a significant public need and there is no feasible and prudent alternative to meet the public need.

Conclusion

Recognizing the important renewable and nonrenewable resource values found in ANWR, the state fully supports the opening of the coastal plain to oil and gas leasing subject to appropriate and effective mitigation based on our firm belief that exploration, development, and production can occur in a manner consistent with the established purposes of ANWR. We look forward to reviewing the final 1002(h) report and actively pursuing a joint consultation process in the near future to resolve specific aspects of concern to the State of Alaska.

Sincerely,

Robert L. Grogan

Robert L. Grogan
Director

Enclosure

cc: Lieutenant Governor Steve McAlpine
Commissioner Don Collinsworth, DFG, Juneau
Commissioner Judy Brady, DNR, Juneau
Commissioner Dennis Kelso, DEC, Juneau
John Katz, Office of the Governor, Washington DC
Rod Swope, Office of the Governor, Juneau
Mayor George Ahmaogak, North Slope Borough, Barrow
Mayor Loren Ahlers, Kaktovik

ENCLOSURE A
State Comments on Summary of Recommended
Mitigation for the 1002 Area

The following comments are provided within the context of the federally proposed stipulation package summarized on pages 145-147 of the draft 1002(h) report. Our comments represent the state's position in response to the specific federal proposal and do not represent the state's total concern regarding mitigation requirements. The state reserves the right to comment further on stipulations not yet included or discussed with DOI. In addition to the following major comments on the specific stipulations, there are a number of terms and conditions which should be added.

First, there are mitigative measures for certain "non evaluation" species mentioned in the species discussions in the "Environmental Consequences" chapter of the draft 1002(h) report that are not contained in the summary section. These mitigative measures should be added to the summary section. Second, there are a number of factors which are either not addressed or not handled in sufficient detail in order to provide for an overall effective mitigation program. Examples include the following: coordinated state/federal process for design review, permitting, field surveillance, compliance, and enforcement; rehabilitation; maintenance of public fish and wildlife resource use; material exploration, extraction, and rehabilitation; solid waste management; timing restrictions on activities, and setbacks required for the use of explosives; liquid waste management; hazardous waste management; stream crossings and fish passage; water management; bonding and financial responsibility; right of access; erosion control; oil spill contingency planning; penalty provisions for non-compliance; definitions of key terms; identification of information needs; design criteria and compliance plans; quality assurance/quality control; air quality; and support service industries. These subjects need to be addressed in a comprehensive manner and appropriate mitigative measures described.

In addition, the DOI stipulations do not clearly differentiate between stipulations or restrictions applied to exploration versus development. The state suggests that the DOI reorganize the entire mitigation section into two distinct components: exploration, and development. Implementation of the stipulations should be tied to the type of activity proposed. Stipulations referring to area specific closures may be effective forms of mitigation during exploratory activities but may be ineffective or inappropriate during development. For example, the stipulation on no activity within 1/2 mile of a documented polar bear den could be useful and effective during exploration, but it is unclear how it would be implemented during development when facilities are fixed and certain activity levels are required. There are other stipulations that fall into a similar category and clarification is needed in order to interpret how and when they will be used and implemented.

Stipulation 1 - Sensitive Habitats and Species:

As written it is unclear how this stipulation would be enforced. DOI should define what is included in the term "non essential facilities."

Stipulation 2 - Road and Drainage Designs:

Roads and other facilities should be designed, constructed, and maintained in such a manner that the following performance standards are achieved: natural drainage is maintained; free passage of fish is provided; gravel fills are stable; upslope ponding and downslope dewatering is prevented; the number of stream crossings is minimized; natural floodplains and flow patterns are maintained; spring areas are avoided; and road alignments are perpendicular to stream flows and sited in areas of minimal floodplain width. Design criteria and specifications to satisfy these performance standards should be developed by the industry and should be approved by the appropriate federal and state agencies.

Stipulation 3 - Exploration Pad Construction:

The state strongly supports the objective of this stipulation to minimize gravel requirements for exploration activities.

Stipulation 4 - Rehabilitation Plan:

The need for rehabilitation plans is clear, but the timing of their submittal and definition of measures necessary to ensure that they will be implemented needs further consideration. Separate rehabilitation plans for exploration and development, including abandonment should be required. Also, requirements for conducting necessary research to develop techniques and measures for the rehabilitation of specific sites (e.g., gravel pads, seismic lines, material sites, etc.) should be addressed.

Stipulation 5 - Off-Road vehicles:

Should be modified to prohibit off-road vehicle use, except for travel by snowmachines, unless otherwise specifically permitted.

Stipulation 6 - Limits on Oil Exploration:

While we agree in principle with this stipulation, as written it may be too restrictive. Exploration includes both surface disturbing and non surface disturbing activities. The stipulation should limit any surface disturbance activities to the winter months and allow only non surface disturbing activities during the summer, provided there are no area or timing restrictions that would dictate otherwise.

Stipulation 7 - Gravel and Water Removal:

The state recommends that DOI address gravel removal and water removal separately. In addition, DOI should prohibit winter water removal from fish-bearing waters, springs and tributaries. We also recommend that DOI modify summer/fall water removal language to read: "During summer and fall, water removal shall be restricted to those operations that will maintain instream flows at levels necessary to provide optimum fish passage and rearing habitat, and water quality. In addition, large surface water reservoirs should be created to provide an adequate supply of fresh water for oil and gas related industrial activity." Deep pit type excavations adjacent to active channels of the streams identified as lacking suitable fish overwintering habitat could provide a winter water source and provide overwintering fish habitat. These reservoir sites should incorporate features that will enhance their value as fish and wildlife habitat (e.g., areas of shallow water, varying shoreline, provide for free movement of fish in and out of sites).

With respect to gravel removal, prohibit removal in all fall spawning fish and overwintering areas. Additionally, prohibit gravel removal from all fish-bearing rivers/streams unless approved on site-specific basis. Plans for gravel removal should include detailed plans for the rehabilitation of the site and rehabilitation must be conducted in phases concurrent with the removal of gravel. The importance of rehabilitation cannot be overemphasized. At a minimum, any gravel site, whether upland and/or floodplain, should be sited and designed to conform to the guidelines as defined in the Gravel Removal Guidelines Manual for Arctic and Subarctic Floodplains (USFWS, Woodward-Clyde Consultants, 1980).

Stipulation 8 - Pipeline Elevation:

We recommend this stipulation be modified by adding a general statement of intent and then incorporate stipulations 8 thru 11 under that statement, and add an additional item regarding traffic control. Suggested language is as follows:

(a) Include language as proposed in stipulation No. 9.

(b) Include language as proposed in stipulation No. 10 except pipelines should be buried where "feasible and prudent" not just where "possible."

(c) Roads and pipelines should be separated. Offset distances shall be optimum for preventing the synergistic effect of roads and pipelines on caribou movement, based on most current relevant research.

(d) A surface traffic control plan should be prepared, approved by the Regional Director, and implemented. The plan should consider such measures as convoying, pulsed traffic, and seasonal or daily restrictions.

Stipulation 12 - Restrict Surface Occupancy within 3 Miles of Coastline:

The blanket 3-mile buffer for facilities adjacent to the coast is too stringent as written. Provisions must be made to allow drill pads, flow stations, and other essential support facilities for offshore development, in this buffer strip. In addition, measures must be taken to ensure free passage of caribou along the coast. Criteria must be established to determine which facilities will be allowed in the buffer area.

Stipulation 13 - Monitoring and Research Requirements:

Modify to make two separate terms. One that states: "The DOI should be responsible for ensuring appropriate monitoring of populations, productivity, movements, and general health of key species in relation to overall oil and gas activities in ANWR." Then add a separate requirement to read: Where there is a possibility that an activity could adversely affect fish and wildlife, "Lessees and permittees may be required to monitor the impacts of the activity on selected species, their habitats, and human uses; to evaluate impact hypotheses and the effectiveness of specific mitigation measures employed; and to develop corrective actions, including improved mitigative techniques, as necessary."

Stipulation 14 - Watercourse Setbacks:

The blanket 3/4-mile buffer for all permanent facilities is too stringent as written. Provisions must be made to allow drill pads, flow stations, and other essential facilities within this 3/4-mile buffer. Criteria must be established to determine which facilities will be allowed in the buffer area.

Stipulation 15 thru 18 - Peregrine Falcon and other Raptors Protection:

The state concurs with the need for special protection for the peregrine falcon, however, stipulations should be modified to incorporate language developed by the federal peregrine falcon recovery team. In addition, the same level of protection provided to the endangered peregrine falcon should not be provided to all raptors.

Stipulation 19 - Polar Bears:

This stipulation should be expanded to require an annual fall monitoring program to follow bears moving ashore and identify den site locations.

Stipulation 20 - Construction Near Coastal Bluffs:

Support language as proposed.

Stipulation 21 - Discharge of Firearms:

Restrictions on the discharge of firearms in the vicinity of structures is necessary to protect human safety and oil field operations, however, the five-mile prohibition may be excessive. Further discussion is needed on the subject and the potential effects on human use of resources in the 1002 area.

Stipulation 22 - Prohibit Surface Occupancy in Sadlerochit Spring Special Area:

In addition to the Sadlerochit Spring Special Area, surface occupancy should be prohibited in the area within 1/2 mile of the Fish Hole No. 1 spring outlet located in the Hulahula River, and extend for 1/4 mile on either side of mean high water for a distance of 3 miles downstream of the outlet.

Stipulation 23 - Protection of Thaspi arcticum:

It is not known how widespread this plant is, so it is impossible to determine how large an area will be placed off limits by this stipulation. Until the plant is placed on the endangered species list and more is known regarding its areal extent, it is premature to impose such a restriction.

Stipulation 24 - Causeways:

Based on the state's case-by-case review and experience in authorizing the Westdock, Endicott and Lisburne causeways, we recommend that the proposed stipulation be revised such that the construction of docks and causeways minimize nearshore hydrographic changes and avoid significant adverse effects on fish populations and movements.

Stipulation 25 - Time and Area Closures for Wildlife:

Although the state generally supports the language as proposed, it should be made clear that the stipulation applies only to exploratory activities, vehicle movements, and other activities that can reasonably be rescheduled for another period of time.

Stipulation 26 - Overflight Restrictions:

Expand to include aircraft overflight restriction above barrier islands, lagoons, river deltas, and wetlands within one mile of coast between May 15 and September 30 (excluding take-offs and landings). Also make clear that human safety takes precedence over the restrictions.

Stipulation 27 - Reduction of Human/Bear Conflicts:

Modify to read, "Measures must be taken to minimize human/bear interaction and conflict. These measures may include, but not be limited to, the use of bear-proof fencing around certain facilities, special solid waste management plans (such as incineration of putrescible wastes), and employee education programs."

Stipulation 28 - Limit Use of Infrastructure to Official Business:

Support language as proposed.

Stipulation 29 - Inventory Areas for Cultural Resources:

Support language as proposed.

Stipulation 30 and 31 - Air and Water Quality Provisions:

As discussed in our cover letter, the proposed stipulations represent a very small step toward defining what will be needed to provide an appropriate level of air and water quality protection as leasing moves forward. Further consultation between DOI and the state is needed on this subject to jointly develop a workable package of specific measures. Such a process would better acquaint DOI with the extensive body of environmental regulation and provide appropriate forums for decisions about stipulations, plans of operations, and permits. It is crucial to ensure that exploration and development is conducted in accordance with environmental standards appropriate for the coastal plain of ANWR.

Stipulation 32 - Environmental Orientation Programs:

Support the language as proposed.

Enclosure A/kfi

ENCLOSURE B

SUMMARY OF MAJOR STATE AUTHORITIES PERTINENT TO ANWR

The State of Alaska defines and regulates the following:

	Program	Statutes	Definitions	Regulations	Definitions
1)	SOLID WASTE	AS 46.03.100-120 800-810	AS 46.03.900(24)	18 AAC 60 (draft)	18 AAC 60.910(49)
	Construction Waste				(Not defined)
	Industrial Waste		AS 46.03.900(10)		-- --
	Other Wastes		AS 46.03.900(16)		-- --
	"Drilling Wastes"		AS 46.03.900(31-32)		18 AAC 60.910(16)
	Putrescrible Waste		-- --		18 AAC 60.910(40)
	Septage, Sewage Sludge Sludge		-- --		18 AAC 60.910(46) to (48)
	Sanitary Waste		-- --		-- --
2)	LITTER	AS 46.06	AS 46.06.150(4)		
3)	HAZARDOUS	AS 46.03.296-308 830-833	AS 46.03.299(a)-(b)	18 AAC 62	

	Type of Waste	Statutes	Definitions	Regulations	Definitions
4)	OIL and HAZARDOUS SUBSTANCES*	AS 46.03.740 758-760 780-790 822-826 AS 46.04		18 AAC 20 18 AAC 75	
	Oil		AS 46.03.758(6) AS 46.03.826(4) AS 46.04-120(9) AS 46.08.900(7)		
	Hazardous Substances	AS 46.03.826(3)	AS 46.08.900(6) AS 46.09.900(4)		
5)	WASTEWATER	AS 46.03.100-120		18 AAC 72	
	Domestic Wastewater		-- --		18 AAC 72.990(16)
	Graywater		-- --		18 AAC 72.990(24)
	Non-domestic Wastewater		-- --		18 AAC 72.990(29)
	Other Wastes		-- --		18 AAC 72.990(32)
	Septage		-- --		18 AAC 72.990(44)
	Sludge		-- --		18 AAC 72.990(50)
	Spoils		-- --		18 AAC 72.990(52)

* Note new legislation adding AS 46.08, AS 46.09, and amending AS 46.03.745, 758(k), 760(a), 765, 780(a), 790(a) (b) (d) and AS 46.04.010 and 090(b).

Type of Waste	Statutes	Definitions	Regulations	Definitions
6) TOXIC MATERIALS and WASTES are a "special class regulated under the Federal Toxic Substances Control Act and National Emission Standards for Hazardous Air Pollutants.				
7) HABITAT PROTECTION				
Fish Habitat Permit	AS 16.05.840 AS 16.05.870	-- --		
8) COASTAL MANAGEMENT	AS 46.40		6 AAC 50 6 AAC 80 6 AAC 85	6 AAC 50.190 6 AAC 80.900 6 AAC 85.900
9) WATER USE	AS 46.15		11 AAC 93	
10) GRAVEL SALES			11 AAC 76	
a. Near Shore	AS 38.05.110-120			
b. Navigable Rivers	AS 38.05.110-120			
11) PIPELINE RIGHT OF WAY LEASES			11 AAC 80	
a. Near Shore	AS 38.35			
b. Navigable Rivers	AS 38.35			
12) OIL AND GAS LEASES			11 AAC 83	
a. Near Shore	AS 38.05.180			
b. Navigable Rivers	AS 38.05.180			

Enclosure B

Type of Waste	Statutes	Definitions	Regulations	Definitions
13) SURFACE LEASES			11 AAC 62	
a. Near Shore	AS 38.05.070-075			
b. Navigable Rivers	AS 38.05.070-075			
14) LAND USE PERMITS				
a. Near Shore	AS 38.05.850		11 AAC 62	
b. Navigable Rivers	AS 38.05.850			
15) CLASSIFICATION				
a. Near Shore	AS 38.04.065-900		11 AAC 55	
b. Navigable Rivers	AS 38.04.065-900			
16) ACCESS ALONG HISTORIC TRAILS	RS 2477			

Enclosure B/kfi

ENCLOSURE C

A Recommended Approach to Implementation of ANILCA §810

March 14, 1986

§810 of ANILCA requires federal agencies to consider the effects of proposed land actions upon people engaged in subsistence uses. Specifically, it requires agencies to:

1. Evaluate the effects of the proposed action on subsistence uses and needs;

2. Determine the availability of other lands for the purposes sought to be achieved and assess whether other alternatives are available which would reduce or eliminate the use, occupancy or disposition of public lands needed for subsistence purposes;

3. Determine whether the proposed action would "significantly restrict" subsistence uses;

4. If the proposed action would significantly restrict subsistence uses, to:

   a. Meet certain public notice and hearing requirements.

   b. Determine that such a restriction meets certain standards, including involving the minimum amount of public lands and minimizing adverse impacts upon subsistence uses and resources.

This paper describes the basic requirements of §810 and provides a systematic approach to meeting these requirements when making a decision on an OCS oil and gas lease sale.

Evaluating Effects on Subsistence Uses

ANILCA §810 provides, as a starting point, that "in determining whether to...lease...public lands...the head of the federal agency having primary jurisdiction over such lands...shall evaluate the effect of such use, occupancy, or disposition...on subsistence uses and needs...."

This section is clearly intended to require a specific assessment of impacts on subsistence uses. An adequate §810 evaluation must include complete and accurate information about the proposed action and about the subsistence uses of potentially affected wild resources.

Information about the wildlife populations, fish stocks, and geographic areas which could be affected by the proposed action are needed to determine the scope of potential effects on subsistence. Information about the specific subsistence uses of, and needs related to, these resources and areas is required to identify and evaluate these effects. This includes data on:

1. Who uses the resources which could be affected;

2. Where, when, and how the resources are harvested;

3. How much they use; and,

4. The significance of the harvested resources for meeting socioeconomic and cultural needs.

Maps of community subsistence use areas can provide valuable data about which communities and groups of people use fish and wildlife that could be affected. Each §810 evaluation should include a map and list of communities that use the stocks and populations of resources potentially affected by a proposed action. The Alaska Department of Fish and Game routinely develops maps of subsistence use as it conducts community subsistence studies. The state welcomes opportunities to cooperate with federal agencies in improving the subsistence data base.

Once the area and communities which could be affected by an action are identified, an assessment must be made of the potential effects of the action on uses of fish and wildlife. The potential linkages between the proposed action, fish and wildlife resources, and subsistence uses need to be clearly described. This can be accomplished through developing hypothetical scenarios, and tracing their implications out through the biological system to the people who rely on subsistence uses.

The evaluation of effects should address potential positive, neutral, and negative effects, as well as direct and indirect impacts on subsistence uses resulting from a proposed lease sale. The guidelines for implementation of §810 developed by the Alaska Land Use Council are helpful in identifying several effects which would restrict subsistence uses:

1. A reduction in subsistence uses due to direct impacts on the resource, adverse impacts on habitat, increased competition for the resources, or other factors;

2. A reduction in the subsistence uses due to changes in availability of resources caused by an alteration in their distribution, migration, or location; and

3. A reduction in subsistence uses due to limitations

on the access to harvestable resources, such as by physical or legal barriers.

An adequate §810 assessment must consider the potential effects of the proposed action in each community which would be affected. In some circumstances, however, it may be necessary to examine effects on the subsistence uses of "typical" communities or groups of people within the affected zone.

Biological and socioeconomic data need to be at a level of detail which will allow a meaningful assessment of potential impacts on the people who use resources for subsistence. These effects can occur at the individual, household, community and regional level.

A working document has been developed by the Alaska Land Use Council which identifies minimum data standards for making an adequate §810 assessment. (Alaska Land Use Council, Working Group II; November 28, 1984, Draft Standards and Guidelines for the Collection, Analysis, and Presentation of Subsistence Use Information for ANILCA §810 Determination, pp. 5-6.) In some cases existing data on subsistence uses may not be adequate to conduct a §810 analysis. Agencies must anticipate these special data needs at the earliest stages in the EIS process. Public meetings may be useful in compiling additional data on subsistence uses and needs. Additional research may also be necessary to address particular data gaps. New studies should be closely coordinated with the State of Alaska as required by ANILCA §812.

The §810 evaluation must thoroughly describe and document data about subsistence resources and uses so that all concerned parties can ascertain which resources and subsistence uses could be affected by a proposed action.

Identifying Alternatives

§810(a) also requires federal agencies to evaluate "...the availability of other lands for the purposes to be achieved, and other alternatives which would reduce or eliminate the use, occupancy, or disposition of public lands needed for subsistence purposes."

In ANILCA §802 Congress states its policy that the "...utilization of the public lands in Alaska is to cause the least adverse impact possible on rural residents who depend upon subsistence uses of the resources of such lands...." It is therefore important that §810 analyses fully identify and explore alternative areas and approaches which would minimize adverse impacts on rural residents.

Determining Whether Actions Would "Significantly Restrict" Subsistence Use

Once the potential effects of the lease sale upon subsistence uses have been described, the next step required by §810 is to determine whether these effects could "significantly restrict subsistence uses...."

The legislative history of ANILCA gives no clue to the intended meaning of "significantly restrict." The closest parallel to the "significantly restrict" standard appears to be the requirement of the National Environmental Policy Act (NEPA) to analyze actions which may "significantly affect" the environment. Regulations of the Council on Environmental Quality (CEQ) for implementing NEPA state that both the context and intensity of impacts must be considered in deciding significance.

The people who would be affected, and the roles that the particular resources play in their lives provide the obvious context for evaluating significance in relation to restrictions on subsistence uses. The "intensity" of effects also has to be evaluated in relation to use of specific resources by people.

In §810 Congress recognized that subsistence uses are essential to many rural Alaskans, and intended federal land actions to have the least adverse impact possible upon them.

When considered in relation to this mandate, a "significant" restriction to subsistence uses is an effect which imposes a meaningful burden or hardship on particular people.

A determination of "significance" therefore requires discussion of such factors as socioeconomic circumstances, the degree to which harvest of particular resources could be reduced by the proposed action, and the consequences of the frequency, timing, and location of restrictive effects. These need to be evaluated in the context of the people who actually harvest and use the potentially affected resources, and in the context of what would constitute a meaningful burden to those people.

A hypothetical example may be useful in demonstrating the approach suggested above:

During an EIS study a proposed lease sale is determined potentially to affect local salmon stocks. The studies suggest that the activity will not have a major impact on regional salmon populations or regional harvest levels, but depending on its timing and precise location, it could reduce a particular stock or run. It is impossible, given uncertainty about where or when the activity will occur, to predict exactly which salmon stock might be affected. However, the EIS has identified 20 communities and groups of people who make subsistence use of the salmon runs which migrate through the general impact area and could be affected. The §810 evaluation therefore identifies these communities and the potential risks. It then examines what effect a reduction in a local salmon run could have for households within typical communities, perhaps dividing the communities into four or five categories, based on location, degree of reliance on subsistence resources, and so forth.

In the hypothetical example, the FEIS concludes that the proposed action could substantially reduce local stocks of king salmon for one or more seasons. As subsistence uses have been shown to occur on these stocks the §810 analysis would then identify this as a potential restriction and then go on to determine whether the action would "significantly restrict" the subsistence use of king salmon. In this analysis king salmon are one of the first fresh foods available to particular households in early summer, and the loss of king salmon for one or more seasons would be a meaningful burden on families in the communities. The §810 analysis, after weighing the risks to subsistence use of king salmon against the important role of king salmon to the people, might conclude that the action could "significantly restrict" subsistence use of king salmon in several of the communities.

Meeting Notice and Hearing Requirements

§810(a) requires the head of each federal agency to meet certain notice and hearing requirements before allowing an action which would significantly restrict subsistence uses. The appropriate state agency and appropriate local committees and regional councils established under §805 must be notified, and a hearing must be held in the vicinity of the area involved.

In ANILCA §801 Congress clearly stated its intent that rural residents, who have knowledge of local conditions and subsistence requirements, should have a meaningful role in decisions affecting subsistence uses and needs. The specific requirements of §810 are intended to ensure that federal agencies have the best available information about the potential effects of proposed actions on rural residents. They also seem, when taken in conjunction with §810(a)(3), to be intended to ensure that local knowledge and experience is brought to bear on the requirement that adverse impacts on subsistence be minimized.

Again, a community focus in evaluating effects would simplify the notice and hearing requirements. Each §810 evaluation should include a map and list of the communities potentially affected, and identify those where subsistence uses could be significantly restricted. In this way §810 assessment itself would indicate many of the groups which should be notified.

It is desirable for agencies to follow the §810 procedures for public involvement in instances where a determination of significance is not clear or where there may be significant restriction even though certain data may not yet be available to support the finding.

Public notification of hearings following a determination of significant restriction should follow several avenues, including:

1. Notice published in local and regional newspapers;

2. Notice mailed to local fish and game advisory committees, regional councils, local governments, and Native organizations;

3. Notice aired on local radio and/or television broadcasts;

4. Notice posted in community halls and other local meeting places; and

5. Personal communications with individuals or groups known by the land manager to have an interest in the action.

<u>Minimizing unavoidable adverse impacts upon subsistence uses and resources</u>

§810(a)(3) requires three findings before an action which would significantly restrict subsistence uses can procede.

1. That such a significant restriction of subsistence uses is necessary, consistent with sound management principles, for the utilization of public lands.

This finding of necessity should be specific to the proposed action, and should be based upon an analysis of the potential impacts upon subsistence uses and the relative value of the proposed action in meeting the goals for the use of public lands.

2. That the proposed activity will involve the minimal amount of public land necessary to accomplish its purposes.

The finding of necessity should exclude all public lands that are not necessary to achieving the proposed purpose.

3. That reasonable steps will be taken to minimize adverse impacts upon subsistence uses and resources.

Identification and consideration of possible mitigation measures are required to minimize the adverse impacts to subsistence uses that could result from the proposal to use, occupy, or dispose public lands. These can take many forms, and as noted above, public involvement can play a key role in developing suitable mitigation measures.

The following categories represent a broad range of types of mitigation measures:

1. Alternatives for deleting public lands from the proposed action to reduce the risk of potential subsistence resource restriction.

2. Alternatives for reducing impact to seasonal camps and other harvest and use locations;

3. Alternatives for reducing habitat changes that may reduce species abundance and decrease harvest opportunity;

4. Alternatives for reducing numbers of people living in, working in, or passing through area;

5. Alternatives for reducing numbers of people competing for resources;

6. Alternatives for reducing disturbance, roads, noise, water quality degradation, etc., that may affect distribution of species;

7. Alternatives for reducing land classification and ownership changes;

8. Alternatives for reducing changes in access routes to use areas; or

9. Alternatives for compensating people for losses.

Time and area restrictions on activity may frequently be useful in mitigating effects on subsistence uses.

Summary

Federal agencies can satisfy the requirements of ANILCA §810 by following the systematic approach outlined above. An adequate §810 evaluation for an OCS oil and gas lease sale would clearly meet the following standards:

1. Identify the people who make subsistence use of all wild resources which would be affected by the proposed action;

2. Identify the nature of their subsistence uses and needs for these resources;

3. Describe the potential effects of the proposed action on wild resources and upon community subsistence uses and needs, and identify which of these effects could be restrictions;

4. Make a determination of whether potential restrictions would be "significant" in the context of the meaning of the affected resources to the people who use them, and the role the resources play in their lives;

5. Identify alternatives that would minimize adverse impacts on rural residents;

6. If the proposed action could significantly restrict particular subsistence uses:

   a. meet notice and hearing requirements;

   b. make findings that;

      1. the necessity for the proposed action outweighs the risks to subsistence;

      2. the proposed action will involve the minimal amount of public lands needed to accomplish its purpose;

      3. reasonable steps will be taken to minimize adverse impacts upon subsistence uses and needs.

7. Thoroughly document all data and findings so that concerned parties have access to them.

bs86030402kff

4-2-87

BRIEFING BY
DENNIS KELSO,
DEC

SENATE SPECIAL COMMITTEE ON
OIL AND GAS
April 2, 1987
3:40 p.m.

MEMBERS PRESENT

Senator Bettye Fahrenkamp, Chairman
Senator Jack Coghill

MEMBER ABSENT

Senator Paul Fischer

ALSO IN ATTENDANCE

Representative Mike Davis

COMMITTEE CALENDAR

Briefing by the Department of Environmental Conservation on Oil and Gas Issues

WITNESS REGISTER

Commissioner Dennis Kelso
Department of Environmental Conservation
P.O. Box O
Juneau, Alaska 99811

Larry Dietrick, Regional Supervisor
Division of Environmental Quality
Northern Region
Dept. of Environmental Conservation
P.O. Box 1601
Fairbanks, Alaska 99707

Jeff Mach
Division of Environmental Quality
Northern Region
Dept. of Environmental Conservation
P.O. Box 1601
Fairbanks, Alaska 99707

ACTION NARRATIVE

TAPE ONE SIDE ONE
April 2, 1987

Number 001

The Senate Special Committee on Oil and Gas meeting was called to order by Chairman Fahrenkamp at 3:40 p.m. She invited Commissioner Kelso to address the committee on oil and gas issues that relate to DEC.

Number 010

Commissioner Kelso noted that Larry Dietrick, Regional Supervisor for DEC in Fairbanks, was participating via the teleconference network and that he and Mr. Dietrick would follow the list of topics that the committee suggested and handle them jointly. He added that Jeff Mach of Larry's staff would also be participating.

The first topic Mr. Kelso addressed was the Oil and Hazardous Substance Release Response Fund. Originally the fund was envisioned to deal with things like marine oil spills but was broadened in order to cover other kinds of spills. Today, they find the demand for use of the fund for cleanup to be increasing in areas such as leaking underground storage tanks, leaking tanks above ground, and certain other kinds of spills that involve materials or liquids that are dangerous and which require immediate attention, but for which there may not be a responsible party available to do the cleanup.

Number 061

If there is a responsible party on hand, they expect that party to clean it up. If there is no responsible party, or the party is unable to clean it up or unwilling to, then they can draw on the fund, use the money for the cleanup effort and then they proceed to recover the costs, if possible, from the responsible party. That means the fund itself can be replenished by the money recovered from responsible parties by placing it in the mitigation account. It is not immediately part of the fund because of the constitutional prohibition on dedicated funds, but is specifically earmarked to be available to be appropriated into the fund in order to keep the fund at a strength that allows them to do the cleanup work.

Number 081

Responding to a question from Senator Fahrenkamp, Commissioner Kelso explained that the recovered monies are in a separate account within the general fund. The purpose of the mitigation account was to hold those funds so they could be appropriated into the fund, and that is done through the normal appropriation process.

Number 095

In FY '87 the legislature appropriated more than $600,000 to the fund, and they anticipate by the end of the fiscal year the full amount appropriated will have been used in cleanup efforts.

Number 108

For the coming fiscal year, they have estimated that precluding any major cataclysmic event that they don't now project, but just relying on those things that they know are going to require cleanup efforts now, about $1 million would be needed to do the work on those spills.

Number 116

Senator Fahrenkamp asked what percent of that he thought was recoverable, to which the Commissioner responded that based on past experience it would be well above 50%.

Number 143

Commissioner Kelso confirmed that in the case of a major problem, the Governor would be able to declare a disaster for some kinds of situations.

Number 184

The kinds of things they are projecting for the rest of this year and for FY '88 are continued work on the Peters Creek benzene contamination, exploratory investigative work on Anchor Point, the Irons Subdivision on the Kenai and industrial site cleanup in Kenai. They think the Crown Point work is completed, but in other parts of the state, work has only begun on some major spills. He referred to a fuel oil spill in Kotzebue which began coming to the surface because there was so much oil in the ground. He estimated there could be as much as 40,000 gallons of the fuel remaining and the source is probably leaking underground tanks.

Number 225

Commissioner Kelso said a problem he thinks they will see more and more that is going to require expenditures from the fund periodically will be spills that come from old tanks, some of which may not even be visible at the surface of the ground, or which their presence may not even be known.

Number 253

Representative Davis asked if when the government surpluses oil storage tanks, if anyone takes a look to make sure that they are safe to use and what their life expectancy is.

Number 265

Commissioner Kelso replied that the Federal Underground Storage Tank Program is in the process of developing standards, but the state does not currently have regulations that have been developed for that purpose. He thought that down the line the only way to address that will be to have standards for new tank installation and some standards that would apply also to the configuration of plumbing and materials used in the plumbing.

Number 285

Addressing a question by Representative Davis on whether there are any standards at all on tanks that have been surplused and then picked up, moved to another location and reused in the process, Larry Dietrick said there are no specific regulations. EPA is proposing regulations for old surplus tanks with their proposed LUST regulations, which are supposed to be out in the near the future. He explained that LUST is the federal acronym for leaky underground storage tanks. Although they haven't seen a draft of the regulations, they believe they deal directly with tank integrity, dying, construction, operation, installation and testing of both the tanks and the piping. He thought they would not only address new tanks, but old tanks that are going to be surplused.

Number 310

Senator Fahrenkamp said that if they find that is not so, to let the committee know so they can take a look at it, as she felt that it was an important issue.

Number 329

Commissioner Kelso spoke to a new program that is a priority to the department. After doing an inventory of existing underground storage tanks (4,600 identified statewide), they are beginning a training program on proper maintenance, testing, and monitoring of those tanks. Eventually, they hope to have a more comprehensive program. At the present time, unless the owner of a tank wants to have it tested, there is not a mechanism to require that person to have it tested. However, because there is a substantial potential liability if a leaking tank contaminates someone else's well, for example, there is an incentive to have that done and they can help people get the proper testing done.

Number 369

Senator Fahrenkamp said the homeowner could be liable just as well as anyone else and the cost to individuals for pressure testing could be very high. She wondered if there would be any way in the future where people in areas could sign up to have the testing done and have a pooling of rates. That way whole areas could be tested and it would make it easy for the homeowners.

Number 397

Larry Dietrick responded that they have discussed what they could do for the small operators and possibly including the homeowners. First of all, they would set up a seminar for the small operators to basically give them information to bring them up to speed as to the direction things are going in and encourage them to undertake a program for evaluating their own tanks and piping.

For the larger companies in the Fairbanks area, they are slowly trying to get a handle on their situations and are generally starting with the bigger facilities that have a bigger potential. They are trying to encourage them to take on their own testing programs, conduct tests as are appropriate for piping and/or storage tanks, and when they find problems to initiate corrective actions.

Number 463

Commissioner Kelso gave an overview of what possible expenditures may look like on a project basis for the next year.

Referring to the Kotzebue spill, it's thought that between 100,000 to 200,000 gallons are contaminating perhaps 10 acres. They have completed the Phase I work, which is, basically, determining the scope and assuring that it is not coming from other sources. Phase II involves the recovery and that is much more expensive and estimated to cost $130,000 a year.

In addition, underground spills at several sites in other parts of the state will require some attention. There are sites near Fairbanks that will require about $105,000 in cleanup efforts if they are undertaken.

There are also remote sites in the bush that would require about $210,000.

The Commissioner said these figures do not include the possible additional sites that they do not know about at this time, so the potential for a great deal of demand on the fund is there and they project that it is going to be a very active area for them over the foreseeable future.

Number 498

Representative Davis inquired if the state was going to be able to recover the costs of cleaning up those sites.

Number 502

Commissioner Kelso responded that it depended upon the circumstances of the particular spill. On some of them where the responsible party is readily established, after the recovery of the product, the cost of that work can be recovered directly, assuming that the responsible party is able to cover those cost. There is not a generic answer to the question, he said.

Number 517

Responding to a question from Representative Davis, the Commissioner said that all the projects he outlined are projects they think are candidates for cleanup under the response fund. They do not anticipate coming to the legislature for an appropriation for any of the cleanup projects, but it may well be that the total is much greater than what they can cover in the fund itself.

Number 562

Commissioner Kelso briefed the committee on what they had recovered in costs so far in FY '87 and then requested Mr. Dietrick to give a history of the MAPCO spill.

Number 584

Mr. Dietrick said the initial problem that was brought to light was a history of spills that resulted in significant contamination of the ground water in the immediate vicinity of the refinery. The spill history goes back to about 1977 and it's estimated that there are in excess of 100,000 gallons spilled to date.

The work towards bringing MAPCO under a compliance order that would lock in the recovery efforts and spell out what is needed to correct the situation began last summer. The compliance order was issued in December and the main feature of it requires that an environmental audit be conducted of the entire facility.

Recovery to date is approaching 90,000 gallons. Recent recovery rates remain high which causes them to be concerned about ongoing leakage.

Work on the environmental audit is scheduled to be completed in the fall.

The initial contamination of the drinking water wells on the refinery site was brought to light in November of '86 and that was a consequence of the compliance order which required them to immediately start testing their portable water wells on site. Initial results indicated that there was benzene in the water. The most serious implications of this was the extent of that contamination and what the potential threat was to the North Pole area. The City of North Pole does have their own wells and tests have revealed that they are basically in good condition.

As a result of concerns for the City of North Pole, they amended the compliance order by letter and required that they immediately retain a consultant to evaluate the ground water movement direction at the refinery, and based on that information, select an initial perimeter number of wells that would be installed and monitored for benzene. A consultant was retained, a preliminary analysis has been completed, an initial round of wells has been completed and they should get their first sampling next week. What this has done is provide the City of North Pole and DEC with an early warning detection system so that they can conclusively say, without doubt, whether or not the contamination is spreading from the facility.

TAPE ONE SIDE TWO
April 2, 1987

Number 675

Continuing, Mr. Dietrick said that the compliance order requires that all on-site monitoring and recovery wells be checked daily. The threshold is that if there is over a half inch of product upon that inspection, they have to start up pumping and recovery efforts immediately. Yields from some of the recovery wells remains very high. Mr. Dietrick said the problem definitely isn't going away and they remain very concerned.

Number 700

Senator Fahrenkamp asked, if it is determined by the amount that's in these recovery wells that there is a constant leaking and has been, rather than recovering spills that are no longer leaking, to what extent would the liability be determined to be on the present owners, past owners, etc.?

Number 717

Mr. Dietrick responded that determining the responsible party in some of these events is a matter that only an attorney can sort out in the end. The situation is somewhat complicated by virtue of the fact that the refinery is located and leased from the State of Alaska. The Department of Law will generally identify anybody that may have any kind of responsibility whatsoever, and it usually ends up that the judge sorts through who shares the responsibility and how much they may be subject to in the way of penalties or fines.

Number 748

Senator Fahrenkamp said any expense of the present owners would be passed on to the consumers, and she thought that was an important aspect to be looked at.

Number 825

Senator Fahrenkamp asked Mr. Dietrick to explain the complaint that MAPCO has be injecting hazardous materials into the pipeline.

Number 837

Mr. Dietrick said the most recent allegations were received in March from EPA. They received quite a number of allegations about activities pertaining to handling, storage and disposal of hazardous waste at the refinery. They already had an inspection scheduled for the facility and they requested it be moved up to the next day. They've completed the investigation at this point and the report is now in EPA's hands. EPA has labeled it "Enforcement Confidential" because of potential litigation and requested that the department not discuss or disclose any information until they've completed their investigation and determined what appropriate actions may be necessary.

In response to Senator Fahrenkamp's concern with the committee's inability to get the needed answers on the allegations, Commissioner Kelso directed Mr. Dietrick to relate the information that they have about pipeline integrity.

Number 887

Jeff Mach related that they did conduct an inspection at the facility on March 5 and found that the facility had accumulated over their operating history so far, a number of drums of oil samples and other wastes that were generated by some of their processes. They were taking drums that had been stored and segregating them and then emptying them back into the systems that they have at the refinery. Some of those things that are discarded chemicals that have not been used would be considered hazardous waste. Putting them back into the system for recycling, or neutralization is not illegal, but they did find a number of technical violations.

Number 927

Commissioner Kelso said that in conversations with the operators of the pipeline they've been assured by them that given the volumes that were alleged and the volume carried by the pipeline that there was not a threat to pipeline integrity, and that at the volumes being discussed, it would probably be difficult to detect these materials in the crude oil stream when it reached Valdez.

Number 974

Larry Dietrick next addressed waste water disposal. The refinery expanded production to 90,000 barrels a little over a year ago. Initially they were proposing to have a separate waste water treatment facility, but the plans were abandoned after they got started up. They changed over to a stack injection and had been doing that for sometime prior to expansion of their building. When the expansion occurred, their waste water stream expanded considerably and got ahead of the planning. They now have stock- piled on site approximately 3 million gallons of oily waste waters. They also went to the extent of using secondary containment areas for bulk fuel storage, or containment of this waste water, but these are basically maximized out. They are trying in a very short time frame to get the approvals that are necessary to transfer this material to the North Pole area lagoon system. The City of North Pole is very concerned and upset about the possibility.

The real concerns are that they have to be assured that the waste water doesn't contain anything that could be considered hazardous because of the allegations being made about hazardous wastes on the site.

A meeting was held to bring all the involved parties (City of North Pole, EPA, MAPCO, DEC) together to try to come up with a resolution. There is a game plan at this time and they are initially working under a May 1 deadline for MAPCO to try to have treatment completed, modifications to their EPA permit completed and compatibility tests completed. The testing and discussions between the consultants probably can't realistically be completed in that time frame. He thought MAPCO may have to bring in additional tankage on site to contain the water until they can get the initial batch pretreated and get the tests back to make sure it won't be a problem for North Pole and then initiate a transfer.

Number 052

Senator Fahrenkamp said, as she understood it, DEC is working to try to help relieve the problem so it can be settled with as little damage as possible to both parties.

Number 056

Mr. Dietrick said that was correct, and the real issue here is to make sure that the material that's being transferred is compatible with the North Pole treatment system and permit. The second part of the problem then is to work out the permitting and administrative things that have to be done to make it legal.

Number 078

Dietrick said this effort right now is focused on getting relief for them for their immediate storage problem and that will be followed by an effort on their part to evaluate their waste water stream and then propose a long-term solution.

Number 086

Senator Coghill wondered if it would be possible for MAPCO to put together a lagoon behind the MAPCO property and have an evaporating system there so that they don't have to use the city system.

Number 094

Mr. Dietrick agreed they could, but said that presently the evaporation is not occurring at a rate that is alleviating their problem.

Number 101

Senator Coghill referred to a pulp mill he had toured which had a lagoon with approximately 12 aireators. The water goes in and they reduce most of the water in the chemical waste, bring it back, retort, get the chemicals back out and reuse them. He suggested taking a look at that as a long-term solution for MAPCO.

Number 108

Mr. Dietrick thought it was a good suggestion and would be a option.

He said there were some other allegations dealing with buried materials behind the refinery and they will be pursuing those also. Those areas will have to be excavated and soils tested. EPA may include that aspect as part of their investigation, he said.

Number 138

Senator Fahrenkamp asked if there was any liability on the part of those who make the allegation, if the allegation turns out to be false.

Mr. Dietrick responded, not that he was aware of.

Commissioner Kelso added that what they have been doing in this situation is whenever an allegation has come to the Fairbanks staff that seems to have some basis in fact, they have systematically investigated. Simply because an allegation has been made, does not mean that MAPCO has had to do some particular thing, but the department takes it seriously and has pursued their investigation.

Number 152

There was a brief discussion on how the allegations are handled as to their validity when they come in to the department, and the possible costs to the state.

Number 256

Commissioner Kelso asked Mr. Dietrick to summarize the DEC Oil Industry Workshop which they had conducted that week.

Number 260

Mr. Dietrick said their general approach is preventive in nature. In most cases if they can work with companies up front, identify problems and design out the problems, they can completely avoid environmental problems. It can't be done in all cases, but there is a lot of room to do it.

The DEC workshop they have put together is for the oil and gas industry, primarily targeted on the North Slope operators. They plan to have them on an annual basis.

The intent in having these workshops was to provide a forum whereby they could communicate directly with the companies, let them know where they are going on certain programs, where they thought problems were and how to get them corrected, and what can be done to ease permitting requirements.

TAPE TWO SIDE ONE
April 2, 1987

Number 327

This year's workshop was a two-day session held in Anchorage. They expanded the agenda so that it wasn't just them doing the talking. They included representatives from the industry, having them give presentations on various practices they were employing. Vendors appeared on issues associated with flaring. They also gave an update on the hazardous waste program. An EPA representative was there to give them information on what direction EPA is going and there was a discussion during that session on underground injection control. Mr. Dietrick said they do have applications for a class 1 hazardous waste injection wells at Prudhoe, Kuparuk and Endicott. A session was held on liquid waste disposal. This year they provided a summary of the total values of liquid waste being created and disposed of on the North Slope. They also had a session on the oil pollution program. Standard and ARCO gave presentations on their drum processing operations that they have installed on the slope.

Number 508

Senator Fahrenkamp asked about the status of proposed drilling mud regulations.

Commissioner Kelso responded that their position is that drilling muds can be properly managed under state solid waste regulations. They worked closely with industry in developing a set of solid waste regulations specific to drilling muds that they think will do a very good job. They are in the last stages of adopting those regulations. Once those regulations are out, they will have regulations that specifically address drilling muds. It may be that these regulations will provide a model for some other agencies and some other states to look at, he stated.

Essentially what they are trying to do, the Commissioner said, is to keep the drilling muds in a disposal format that prevents water from moving through the material and leaching out material from the pit where the disposal takes place and then migrating into areas where it shouldn't be. They have tried to develop performance standards so that industry can use its ingenuity to come up with the proper design.

Number 580

Senator Fahrenkamp asked for an update on the spill danger from the All Alaska, a processor that went aground on the north shore of St. Paul Island.

Number 590

Commissioner Kelso said the processor carried 141,000 gallons of diesel fuel and 1/2 million pounds of crab. It went aground between 150 to 300 ft. offshore and rapidly silted in so it was not possible for a tug to get it off and there was no possibility of salvage.

By the time the Coast Guard was able to respond, the 141,000 gallons had been reduced by about 20,000 gallons and there was concern that the ship would break up spilling the rest of the fuel. They called in their Pacific strike team which deals with major marine spills. The regional response team, of which DEC is a participant, also responded. They are presently working on the best approach for removing the fuel.

DEC has been getting regular updates, but as of early this week, Commissioner Kelso still didn't have specific information on whether they were going to unload from the vessel without crossing the beach or whether they had now resolved the difficulties and were proceeding with the beach unloading. As of the weekend, there had been no further leaking and it was stable as of that time; however, he said he would keep Senator Fahrenkamp advised on the situation.

Senator Fahrenkamp inquired if the spill would be eligible for the 470 funds.

Commissioner Kelso said it probably wouldn't be necessary to use 470 because the Coast Guard will take responsibility. The vessel owner is responsible for the damage and cleanup costs, although he has abandoned the vessel. That means that the Coast Guard, through its strike team, will do the work, unload the vessel and salvage the cargo, if possible, however, that does not appear to be possible.

Number 706

Commissioner Kelso advised Senator Fahrenkamp that the rest of the materials that hadn't been covered during the meeting would be provided to the committee in a written summary.

Number 710

Senator Fahrenkamp thanked Commissioner Kelso, as well as Larry Dietrick and Jeff Mach in Fairbanks, for their participation.

There being no further business to come before the committee, the meeting was adjourned at 5:30 p.m.

ALASKA STATE LEGISLATURE

SENATE SPECIAL COMMITTEE ON OIL AND GAS

Senator Bettye Fahrenkamp
Chairman
Senator Jack Coghill
Senator Paul Fischer

P.O. Box V, State Capitol
Juneau, Alaska 99811
(907) 465-3834

M E M O R A N D U M

TO: Members, Senate Special Committee on Oil and Gas

FROM: Committee Staff

RE: Committee Meeting, April 2, 1987

DATE: April 1, 1987

On Thursday, April 2, at 3:30 pm in the Beltz Room, the Senate Special Committee on Oil and Gas will receive a briefing by Dennis Kelso, Commissioner of the Department of Environmental Conservation. The commissioner will address areas in which the department has oversight over the oil and gas industry. He will be joined via teleconference by Larry Dietrick, Northern Regional Supervisor of the Division of Environmental Quality. Topics expected to be discussed include:

(1) an update on the situation at the MAPCO refinery in Fairbanks,

(2) hazardous wastes,

(3) disposal of drilling muds,

(4) air quality on the North Slope, and

(5) the status of the Hazardous Substance Release Response Fund.

The commissioner and Mr. Deitrick will be available to answer any questions committee members may have on oil and gas issues.

f. Oil - Haz wastes

MAR 24 1987

STATE OF ALASKA

STEVE COWPER, GOVERNOR

DEPT. OF ENVIRONMENTAL CONSERVATION

Telephone: (907)
Address.

OFFICE OF THE COMMISSIONER
P.O. BOX O, JUNEAU, ALASKA 99811-1800 (907) 465-2600

March 18, 1987

The Honorable Bettye Fahrenkamp
Alaska State Senate
P.O. Box V
Juneau, AK 99811-3100

Dear Senator Fahrenkamp:

Enclosed is a report to the 15th Alaska Legislature on the Oil and Hazardous Substance Release Response Fund, as required by AS 46.08.060. The Fund allows the Department to investigate and clean up oil and hazardous substances spills. This report provides information on the department's spill response activities, fund expenditures, and monies recovered from spillers during the six month period from July 1, 1986 to January 1, 1987.

The department has funded several significant oil and hazardous substance spill investigations from the fund during the first six months of FY 87. These include the Kotzebue underground spill ($62,638), Peters Creek groundwater contamination ($208,415), Crown Point chemical release ($20,000), and Nome underground spill ($12,745). Total Fund expenditures and encumbrances for FY 87 to date are $402,751.

We estimate that $612,000 will be required to respond to and clean up oil and hazardous substance spills associated with continuing projects, identified in this report. Furthermore, the department will likely be called upon to initiate spill cleanup activities during the remainder of FY 87 and FY 88.

To date, the department has recovered monetary settlements from parties associated with three oil spills in FY 87. These funds are deposited to the Oil and Hazardous Substance Release Mitigation Account.

When final payments are made to the state, revenue to the Mitigation Account will be $307,299. As provided in AS 46.02.080, these funds are available for appropriation to the response fund.

If you have any questions on this report, please contact me.

Sincerely,

Dennis D. Kelso
Commissioner

Enclosure

A REPORT TO THE 15th ALASKA LEGISLATURE

ON THE OIL AND HAZARDOUS SUBSTANCE RELEASE RESPONSE FUND

by the

ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION

Dennis Kelso - Commissioner

January 30, 1987

STATE OF ALASKA

STEVE COWPER - GOVERNOR

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Section 1. INTRODUCTION

The 1986 Legislature passed HB 470, a bill relating to the release of oil and hazardous substances. This legislation, in part, established an Oil and Hazardous Substance Release Response Fund. The legislation incorporated the previously existing oil spill reserve account into the Oil and Hazardous Substances Release Response Fund. The department uses money from the Response Fund for the response and cleanup of oil and hazardous substance spills. Section 46.08.060 of the bill requires the department to submit to the Legislature an annual report summarizing information on: spill response activities during the preceding fiscal year; projected costs of cleanup for the next year; expenditures from the fund; and monies recovered from spillers. Since FY 87 is the first year of the fund's existence, this report covers the six month period from July 1, 1986 - January 1, 1987.

Section 2. EXECUTIVE SUMMARY

The Legislature appropriated $680,666 to the Response Fund for FY 87. However, monies in the Fund were subject to a 35 percent restriction on spending that was placed on all capital budget appropriations in July 1986. As a result, $451,327 was released to the department to spend for oil and hazardous spill responses in FY 87. On January 1, 1987, OMB released the remaining balance of the Oil Spill Mitigation Account ($79,338) to the department for additional spill expenditures. As of January 1, 1987, our records show FY 87 expenditures of $206,670 and encumbrances and other obligations of $196,081 (Attachment A), leaving $127,914 remaining in the unrestricted portion of the Fund.

During FY 87, the department reached settlement agreements for damages from three oil spills. These settlements are deposited to the Oil and Hazardous Substance Release Mitigation Account. When final payments are made to the state, total revenue recovered in the Mitigation Account from these three spill settlements will be $307,299. This total may increase as the department proceeds with enforcement actions on other spills in FY 87. As provided in HB 470, these funds are available for appropriation to the Response Fund.

The department has allocated monies from the Fund for several significant oil and hazardous substance spill investigations during the first six months of FY 87. These include the Kotzebue underground spill ($62,638), Nome underground spill ($12,745), West Poppy Lane gravel pit ($15,464), Iron's Subdivision groundwater contamination ($9,041), Peters Creek groundwater contamination ($208,415), Anchor Point groundwater contamination ($10,407), and Crown Point chemical release ($20,000).

The department projects that at least $612,000 will be needed to respond to and clean up existing known oil and hazardous substance spills. These are costs associated with continuing projects. In addition, we estimate that at least $350,000 will be required for new cleanup activities to be initiated during FY 88.

No funds were provided to municipalities for their involvement in oil and hazardous substance spill response activities during FY 87.

Section 3. FUND EXPENDITURES FOR FY 87

The Legislature established the Response Fund on July 1, 1986, with appropriations from three different sources as follows:

FY 86 Oil Spill Mitigation Account balance	$158,677
FY 86 Oil Spill Expense Reserve balance	221,989
FY 87 Capital Budget appropriation	300,000
Total	$680,666

In August, 1986, the Office of Management and Budget (OMB) restricted this appropriation by 35 percent. This reduction was applied to all capital appropriations.

The department responded to a rash of oil and hazardous substances spills during the summer of 1986. By the end of August we had either spent or encumbered a total of $226,669 for oil and hazardous substances spill response and cleanup activities. As a result, the department asked OMB that an exception to the spending restriction be granted.

On September 15, 1986, we were advised by OMB that they would release monies from the following Fund appropriations as follows:

50% of the Oil Spill Mitigation Account balance	$ 79,338
100% of FY 86 Oil Spill Expense Reserve balance	221,989
50% of FY 87 Capital budget appropriation	150,000
Total revised appropriation	$451,327

OMB released the remaining balance of the Oil Spill Mitigation Account ($79,338) on January 1, 1987 for additional spill expenditures. As of January 1, 1987, our records show total spill expenditures, encumbrances and other obligations of $402,751. The balance of the Fund on January 1, 1987, was:

	$530,665 ($451,327 + $79,338)
	402,751
Total	$127,914

Section 4. REVENUES AND SOURCES OF FUNDS RECOVERED in FY 87

To date, the department has recovered monies from three oil spills in FY 87. These spills are described in more detail in Section 5 of this report. All funds recovered from spillers are credited to the oil and hazardous substance release mitigation account.

I. Motor Vessel VASHON

A settlement agreement was reached with the owner of the M/V VASHON on September 8, 1986, whereby the owner agreed to reimburse the state in the amount of $3,500 for the department's expenses in responding to an oil spill. The vessel owner agreed to pay this amount over a 15-month period; $1,300 has been received to date.

II. Chevron - Peters Creek Underground Oil Spill

The state's investigation of the contamination of groundwater in the Peters Creek area north of Anchorage led to testing on the site of Peters Creek Chevron gasoline station to determine if an unreported 1984 fuel spill at the station was a source for the groundwater contamination. The Peters Creek Chevron Station was determined not to be a contributor to the groundwater contamination. The state did proceed to recover investigative costs and damages associated with the 1984 spill in the amount of $15,000. Chevron assumed the costs with the contractor for drilling test holes for soil sampling. The total settlement costs to Chevron are $28,693 with $14,999 payable to the mitigation account. Approximately $653 has been received, and the balance of $14,346 is due by February 18, 1987.

III. Nome Gasoline Spill

On November 28, 1986, a settlement agreement was announced for state expenses involved in investigating and cleaning up a major spill of gasoline from the Q-Trucking facility in Nome. The settlement is for $363,800; $75,000 will go to the federal government and $288,800 will be paid to the state. The spill of more than 50,000 gallons was first discovered in 1983, and DEC subsequently recovered more than 35,000 gallons from the ground.

Based on these settlements, total revenues to the oil and hazardous substance release mitigation account for FY 87 has amounted to $307,300 as follows:

M/V Vashon	$ 3,500
Peters Creek Chevron	14,999
Nome Gasoline Spill	288,800
Total	$307,299

Other funds may be recovered to the mitigation account as additional settlements are reached with spillers.

Section 5. Major Department Spill Response Activities for FY 87

I. Kotzebue Underground Oil Spill

In 1980, the department became aware of a problem with oil seeping into the elementary school basement in Kotzebue. After our investigation, we determined that 100,000 to 200,000 gallons of #1 fuel oil (diesel) was contaminating an underground area that was estimated at that time to be 10 acres. The fuel has been in the ground for 25 to 30 years. Possible causes of the spill include fuel storage or handling problems from a nearby oil facility in the 1950s.

In more recent years, oil has been observed leaching into Kotzebue Sound from time to time, posing a potential threat to local fisheries. The department has been involved in the recovery of the oil with the objective of mitigating potential environmental and safety problems. Problems experienced in the collection of the fuel included a seasonally frozen groundwater aquifer above the permafrost and inconsistent monitoring of the primary collection sump in the school basement. By the fall of 1984, about 40,000 gallons of fuel had been recovered using a variety of methods. While a large quantity of oil remains underground, recovery has been severely reduced because of recent funding constraints and sporadic collection conditions associated with the cold climate and permafrost.

During August 1986, a comprehensive study was conducted to identify the scope of the underground contamination problem and to determine that fuel loss is no longer continuing. Work included pressure testing existing fuel lines in the area, installing in-line flow meters within the perimeter of the spill site area, consultation with an expert hydrogeologist to identify the areal extent of the spill, installation of monitoring wells, and initiating a sampling program.

A report of this work has been completed. The cost of contracting this investigation was $49,633. Other costs total $6,682.

II. Nome Gasoline Spill

A major gasoline spill in Nome occurred on July 12, 1983. Unleaded gasoline surfaced with groundwater along the marshy grasses of Dry Creek near Nome. Results of ditching, drilling, surveying groundwater elevations, and product sampling ultimately led DEC to a suspect spill source. Because some of the gas product entered navigable waterways, the U.S. Coast Guard (USCG) intervened and assisted to keep the gasoline from entering Norton Sound. Once the USCG stopped cleanup, ADEC contracted for cleanup work and was later reimbursed with $597,896 of federal funds for the major part of this cleanup effort.

DEC continued efforts in 1984 and 1985 to identify the spiller and initiated litigation to recover the amounts of state funds expended that were not part of the federal reimbursement.

Expenditures this year have totalled $1,908. A contract remains active for an expert witness in the field of hydrogeology. The encumbered balance for the contract is $10,837, and it is expected to be closed out in the near future.

The Department of Law announced on November 28, 1986, that they had reached a settlement with the spiller over state expenses involved in DEC's investigation and cleanup of the Nome gasoline spill. This settlement is detailed in the revenue section of this report.

III. West Poppy Lane Gravel Pit

The West Poppy Lane gravel pit, located near Soldotna, is approximately 40 acres in size. Department investigation has revealed contaminated soils and groundwater. In FY 87, DEC has spent $15,464 on travel and per diem, sample analysis, and site excavation work. This is a continuing project for which additional expenses are likely.

IV. Iron's Subdivision

Another apparent underground spill has affected drinking water in Iron's Subdivision in Soldotna. A contract has been written to have test wells drilled for sampling to determine the source of contamination. Work is continuing on this spill. Expenditures this fiscal year have totalled $9,041.31.

V. Peters Creek

Contamination of drinking water in several private wells in the Peters Creek area in Chugiak was identified by DEC in April 1986. The department believes that the benzene contamination originated from a leak from an underground storage tank(s) and/or underground lines connecting the tanks at the Peters Creek Tesoro gasoline station. The spill created an emergency situation. Several contracts were written during the investigative phase to determine the source and extent of the contamination.

An emergency water supply was provided by the Municipality of Anchorage for 36 homes with contaminated wells. Due to the contamination, all of the wells will be abandoned.

Expenditures are $77,396 this fiscal year; an additional $52,019 has been encumbered. This was spent for contractual services for testing of water samples to define the contaminated area, testing of tanks and lines, and other investigatory work. A contract for $79,000 has been approved for the first phase of the cleanup since the property owner/spiller has declared that he does not have the financial resources for this work. Phase I work will involve the initial recovery and disposal of free product from the affected groundwater in the Peters Creek area. Litigation against the spiller has been intitiated. An additional $75,000 may be needed for further cleanup work which could continue for at least another year. Moreover, additional expenses will likely be incurred in conjunction with the litigation.

VI. Anchor Point

Benzene contamination of several wells in the Anchor Point Area has been identified. Investigative work has included drilling of test wells and sampling of water to determine the scope and source of the contamination. Like the

Peters Creek spill, this spill may involve considerable expenditures by the state before it is resolved. Expenditures and encumbrances for this fiscal year thus far are $10,407.

VII. Motor Vessel VASHON

The vessel VASHON grounded near Ketchikan in June 1986. The department and the Coast Guard worked with the vessel owner to keep the fuel oil from the vessel contained and recovered. The vessel was sold for salvage. Expenditures for this fiscal year amounted to $2,067. As noted earlier in this report, DEC and the Department of Law worked out a settlement agreement to recover DEC's expenses from the vessel's owner.

VIII. Moose Pass/Crown Point

In March 1986, toxic fumes were emitted from a tank car on the Alaska Railroad in the vicinity of Crown Point. This spill resulted in declaration of a state emergency. Funds were made available by the Department of Military and Veteran Affairs for assistance to affected people in the spill area. The department is managing $180,000 in funds provided by the Division of Emergency Services to contract with Dames & Moore to assess whether any environmental effects of the spill remain in the area. DEC has added $20,000 from the fund to analyze additional environmental samples. A report from the contractor is to be released in March 1987.

IX. Buckingham Well

This spill involved a drinking water well in Soldotna that was allegedly damaged by a fuel delivery truck's hitting the well casing. The contents of the fuel tank spilled on the ground around the well casing with some of the fuel's discharging into the well. The department cleaned the well and eliminated the residual hydrocarbon levels remaining in the drinking water. Expenditures are $1,881 for FY 87.

Section 6. Projected Response Activities for Balance of FY 87 and FY 88

I. Southeast Region - no known projects at this time.

II. Southcentral Region - Anchorage

A. Peters Creek

The Peters Creek spill is described in the previous section. Cleanup is now scheduled for the spill.
Cleaning groundwater is a difficult undertaking; the feasibility of a cleanup can be better assessed after experience is gained with the initial cleanup. If a second phase proves to be appropriate, it is estimated to cost about $75,000. The specific details of further actions needed under this second phase of cleanup will not be known until Phase One has been completed and additional information is gathered on the spill. Another $12,000 may be necessary to properly close out 20 monitoring wells in the area. Costs will also be associated with the litigation underway in this case.

B. Anchor Point

More exploratory and investigative work on this groundwater spill will be needed. Contracts are being prepared for drilling test wells in an attempt to locate the spill source. The estimates of costs for the investigative work is $14,000. Additional funds will be needed in the future for cleanup and potential litigation costs.

C. Iron's Subdivision

More investigative work requiring sampling and possibly some well drilling will be necessary at this spill site - estimated costs are $6,000. Additional funds may be needed for litigation and cleanup if the suspected spiller can not or will not clean up the contamination.

D. Industrial Site - Kenai

The estimated amount for the cleanup is expected to be about $60,000. At this point, it is uncertain whether it will be necessary for the state to initiate the cleanup. If so, cleanup activities as well as litigation costs would likely be needed.

E. Moose Pass/Crown Point

It is unknown at this time what funds may be needed on this project. The current cleanup contractor has not completed his work and reports. Additional funds may be required.

III. Northern Regional Office - Fairbanks

A. Kotzebue Oil Spill

Phase One consisted of determining the scope of the underground contamination and ensuring that other oil was not leaking from other sources. Phase Two cleanup activities in FY 88 would entail recovering free product from the groundwater and disposing of it. Cost estimates are based on an assumption that there is approximately 40,000 gallons of oil remaining in the ground and that 90 per cent of it can be recovered. Permafrost and frozen ground limit recovery work each year. As a result, complete product recovery may take one to three years. Following are provides annual cost estimates on Phase Two work.

Consulting and administrative costs	$ 10,000
Equipment costs (wells, pumps, etc.)	20,000
Contracted labor (4-6 weeks per yr.)	100,000
Total	$130,000

B. Potential Underground Oil Spill Cleanups - Fairbanks

Underground spills have occurred at several sites near Fairbanks and have contaminated the groundwater to some degree. These are Lucky Sourdough in Fairbanks, Stage Stop in North Pole, and Air North in Fairbanks. It is estimated that investigative costs will be about $35,000 per site for a total of $105,000. Additional spills in the Fairbanks area may also need to be addressed.

C. Potential Underground Oil Spill Cleanups - Remote Locations

There are four potential problem sites that may require cleanup funds. These are Minto School, Harold's Air Service in Galena, Wales City Building, and Manley Hot Springs. The estimated costs for cleanup are $70,000 per site for a total of $210,000. Cleanup work at remote sites are at least double the cost of local sites.

Conclusion

Total estimated costs of known required cleanup actions are $612,000. Based on past records and experience, we estimate that investigations for new spills discovered in FY 88 will require additional funds of at least $350,000.

Section 7. Municipal Participation in the Fund

No municipalities requested reimbursement for any expenses they incurred in the cleanup of oil and hazardous substance spills during the first half of FY 87.

Section 8. Hazardous Waste Sites

The state and the Environmental Protection Agency are in the process of investigating about fifty potential hazardous waste disposal sites in Alaska. The results of these investigations may reveal sites of past spills. The state will make every attempt to use federal funds for any remedial action that proves necessary at these sites. However, it is likely that some sites will require a response but not be eligible for federal dollars. This could add significantly to the need for response funds in the future.

Attachment B to this report is a list of known hazardous waste sites included on a list generated under the federal Comprehensive Environmental Response Compensation and Liability Act (CERCLA). and a schedule of task accomplishments for each site. Six site investigative reports have been completed. These reports generally describe the scope of the problem and investigative work completed at each site, and rank the relative importance of site. These reports are used by DEC and the Environmental Protection Agency in the evaluation process of determining what future course of action needs to be taken at each site.

Attachment A

Major Fund Expenditures and Encumbrances by Spill Project as of January 1, 1987:

Spill Project	Encumbered Balance	Expenditures	Total
Kotzebue	$ 6,322.50	$ 56,315.03	$ 62,637.53
Nome	10,837.00	1,908.48	12,745.48
Union Oil/Poppy Lane	0.00	15,464.43	15,464.43
Buckingham	0.00	1,880.86	1,880.86
Iron's Subdivision	0.00	9,041.31	9,041.31
Peter's Creek	131,018.90	77,395.79	208,414.69
Anchor Point	4,064.00	6,343.08	10,407.08
M/V Vashon	0.00	2,067.26	2,067.26
Moose Pass	20,000.00	0.00	20,000.00
Misc. spill expenditures	23,838.48	36,254.25	60,092.73
Total	$196,080.88	$206,670.49	$402,751.37

Attachment B

Revised Schedule of Accomplishments

ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
CERCLA ACTIVITIES UNDER EPA COOPERATIVE AGREEMENT

Table 1

Site	Submitted to EPA for State Lead	Proposed State Action	Workplan Ordered	Workplan Approved	Fieldwork Complete	Report Draft	Final
AKD980975106 Perseverance Mill-Juneau	3/85	SIF	7/86	10/86	11/86	3/87	5/87
AKD980495568 Juneau Landfill-Juneau	3/85	SI	7/86	2/87	11/86	3/87	4/87
AKD083354209 White Pass Yukon RR-Skagway	3/85	SI	7/86	10/86	11/86	3/87	5/87
AKD980664866 Old Kenai Dump-Kenai	3/85	SI	10/85	12/85	3/86	5/86	1/87
AKD092876390 Union Chemical-Kenai	3/85	SI	10/85	12/85	3/86	3/87	5/87
AK09806642924 Kenai Landfill-Kenai	3/85	SI	10/85	12/85	3/86	9/86	1/87
AKD009276619 Frontier Tanning-Anchorage	3/85	SI	8/85	10/85	11/85	1/86	3/86
AKD061673430 Alaska Pollution Control-Anchorage	3/85	SI	10/85	12/85	3/86	5/86	1/87
AKD018542969 Rogers & Babler-Anchorage	3/85	SI	10/85[1]				
AKD009246497 Alaska Husky Battery-Anch.	3/85	SIF	10/85	12/85	3/86	5/86	1/87
AKD980495618 Red Devil Mines-Bethel	3/85	SI	7/86	10/86	11/86	3/87	5/87

Table 1 (cont'd)

Site	Submitted to EPA for State Lead	Proposed State Action	Workplan Ordered	Workplan Approved	Fieldwork Complete	Report Draft	Final
AKD038526620 Alaska Gold - Nome	3/85	SI	8/85	10/85	11/86	1/86	3/86
AKD045771235 Fairbanks Borough Landfill - Fairbanks	3/85	SI	7/86	10/86	11/86	3/87	5/87
AKD046879567 University of Alaska - Fairbanks	3/85	SI	7/86	10/86	9/86	3/87	5/87
AKD0049 04215 Alaska Battery Enterprises Fbk		SI					
AKD980639751 Fort Yukon City Dump - Fort Yukon	3/85	SI[1]					
AK980978902 Alaska Auto Carriers - Anchorage	4/86	PA[2]					
AKD980975932 Bendles Road Oiling Facility - Anchorage	4/86	PA[2]					
AKD097246789 Red Samm Const. - Juneau	4/86	PA[2]					
AKD009252230 Louisiana Pacific - Ketchikan	4/86	SI[2]					
AKD009252487 Alaska Pulp Corporation - Sitka	4/86	SIF[2]					
AKD980980701 Union Oil Gravel Pit - Kenai	4/86	RI/FS[2] (PA)					
AKD980976203 Soldotna Landfill - Kenai	4/86	SI	7/86	12/86	4/87	6/87	7/87

Table 1 (cont'd)

Site	Submitted to EPA for State Lead	Proposed State Action	Workplan Ordered	Workplan Approved	Fieldwork Complete	Report Draft	Final
AKD037995404 Alaska Electro-plating-Anchorage	4/86	SI	7/86	10/86	11/87	3/87	5/87
AKD083350389 North Pole Refinery-North Pole	4/86	SI	7/86	2/87[3]			
AKD098866498 M&M Enterprises-Anchorage	4/86	SI	7/86	10/86	11/86	3/87	5/87
AKD980981930 Arness Property-Kenai	4/86	PA[2]					

1 CERCLA staff will make an on-site inspection to determine if further action is necessary.

2 Work on hold to prevent project cost overrun.

3 Revisions requested in workplan.

5

BOF
Coghill

Kelso —
DEC —

Kelso and Larry Deitrich
Jeff Mach.

HB 470 Fund —

deal w/ Marine oil spills. —

broader now —

leaking underground tanks

Responsible party is supposed to be
primary —

Recover costs later. —

Replenish funds —

separate account w/in GF

Thru normal appropriation process.

600,000 last year but 35%
> 450,000

for FY 88 — 1 million used.

CORRECTION

THIS DOCUMENT
HAS BEEN REPHOTOGRAPHED
TO ASSURE LEGIBILITY

02-576(2/77)

3:35

BOF
Coghill

Kelso —
DEC —

Kelso and Larry Deitrich
Jeff Mach.

HB 420 Fund —
deal w/ Maine oil spills. —
broader now —
leaking underground tanks

Responsible party is supposed to be primary —
Recover costs later. —
Replenish funds —
separate account w/in GF
Then normal appropriation process.
600,000 last year but 35%
> 450,000
for FY 88 — 1 million used.

high percentage (above 50) of replacement.

Disaster declarations by Gov. could be available

Crown Point. —

Targeted to clean-up.

Well contamination. -

Ketchikan fuel oil 100-200 gals of #1 fuel oil -
bubbled up into elementary school
10-20 years
refined product - probably from buried tanks

Old tanks will be problems in the future.

Davis surplus U.S. tanks? certified?

Dietrick no specific regs.

Fed regs will apply to new installations

(LUST) Leaky Underground Storage Tanks.

Davis working w/ service stations?

Kelso 14000 tanks statewide.

Kelso Training program on maintenance
testing monitoring of tanks.

Dietrick
1) Seminar for small operators who have tanks –
encourage programs for evaluating tanks
& pipes
60% of stations are owned by Oil companies
They have programs
Independents don't.

2) Fairbanks – Thaw zone –
breaks pipes. creates small leaks –
went to welded joints at Alyeska camps.
working w/ MUS, GVEA & Military.

130,000 / year in Kotzebue –
105,000 in Fbks

Lucky Sandwright –

Remote sites.
Minto School. 210,000

High Demand on Fund.

None - mercury - arsenic spill.

MAPCO -

SPILL -

Spill of HAGO

Wastewater

Deitrick

History of spills -
contaminated groundwater.
goes to 1977
100,000 gals spilled to date

compliance order. requires
environmental audit be conducted - completed this fall

90,000 have been recovered. - ongoing leakage

11/86 - drinking water contaminated -
benzene in water.

5 parts/billion is limit

75-500 at site.

Potential threat to N. Pole water system

pilot consultant – wells drilled
sampling next week.

determine whether contamination is spreading.

Recovery wells checked daily.

→ 400 gals/day!

no diminishing of rate!

who's responsible?

Judicial system sorts it out.

Monitoring wells –

deep wells. 30 – 40 ft.?

groundwater flow is toward school,
city wastewater lagoons.

Allegations from EPA –

move up RCRA ↯

DNR has

Arlen Cole –

MACT –

inspection 3/5 –

accumulated drums of wastes.

unused chemicals.

were segregating drums + emptying –

some could be considered Haz Wastes –

may not be illegal.

technical violations.

Assured by operators that there was no threat to pipe integrity.

at volumes. –

unlikely that you could detect.

Wastewater disposal –

when expanded –

now have 3 million gallons of oily wastewater in Lagoon.

2nd areas – 2 tanks. used evaporation unit to transfer to N. Pole treatment plant.

wastewater – ensure there's no haz waste

Sample sludge -

meeting last Friday

w/ N.P., EPA, Mapco, DEC -

will be in critical stage in 10 days -
bring in more tanks.

some material is compatible w/ N. Pole.

Permits from EPA needed.

have known about for a long time.

need long term solution.

evaporation has not worked - not fast enough

allegations of buried materials behind refinery

will be checking out.

MAPCO is on Superfund list.

Kelso

O&G Industry Workshop -

① QVEA - implicated in MAPCO.
adjacent to - also have problems.
ask for in-house audit.
also MUS

2 workshops last year — 1 Fairbanks & PB.

communicate directly w/ industry.
ease permitting.

coordinated schedule w/ AOGA
evaluations afterward.

Agenda —

underground injection —
subsurface better than surface —

on Slope — water is salty; so no change
to water supply.
EPA reviewing application

Haz wastes —

Liquid wastes —

total volume, how managed.

Oil pollution program.
adequate areas for disposal of
solid oily wastes.
a facility now working in N. Slope Borough
use of synthetic liners.
drum processing operation
washing
incineration
15-20,000 drums/year.

Air —
flare systems.
AOI's

drilling wastes —
Thermal destruction
concrete brick.

drilling muds regulations

followed by written comments by AOGA

Drilling Muds—

can be managed under state solid waste regs.

last stages of adopting regs.

may provide model for other states.

Keeps muds in a format that permits water from leaching water out + migrating to other areas.

— 1) requires pits to not leak
2) monitoring

Performance standards —

let industry come up w/ techniques

ALL ALASKA —
St. Paul Island
191,000 diesel

Crew walked on low tide —
sucked in — tug couldn't

20,000 gals leaked

Distribute minutes to other committee members
and Resources.

adjourned 5:30

April 2, 1987
Senate Special Committee on Oil and Gas

Briefing by DENNY KELSO, Commissioner of the Department of Environmental Conservation.

LARRY DEITRICK, Northern Regional Supervisor of the Division of Environmental Quality, will be on the TELECONFERENCE from FAIRBANKS.

Topics expected to be discussed include:

(1) an update on the situation at the MAPCO refinery in Fairbanks,

What are some of the allegations being made?

How will questions about the integrity of the pipeline be settled?

Is there a potential danger to the health and safety of Alaskans?

Is there a history of other environmental violations at the refinery?

(2) hazardous wastes,

What are "exempt wastes"? Examples?

Can Larry review the topics discussed at the oil and gas workshop held in Anchorage yesterday?

Does deep well injection work well?

Some kinds of disposal may work well in certain areas and not in others (Like North Slope and Kenai Peninsula). Are regulations flexible enough to accommodate this?

(3) disposal of drilling muds,

What is the status of proposed regulations?

(4) air quality on the North Slope

(5) the status of the Hazardous Substance Release Response Fund. (Also called the HB 470 FUND)

The fish processsor ALL ALASKA is on the rocks in Western Alaska. Has the oil spill danger been resolved? Would it be eligible for 470 funds?

OTHER QUESTIONS:

1) Valdez

a> existing air or water quality problems?

What is the status of Alyeska's ballast water discharge permit?

b> potential problems with proposed refinery?

ALASKA STATE LEGISLATURE

SENATE SPECIAL COMMITTEE ON OIL AND GAS

Senator Bettye Fahrenkamp
Chairman
Senator Jack Coghill
Senator Paul Fischer

P.O. Box V, State Capitol
Juneau, Alaska 99811
(907) 465-3834

M E M O R A N D U M

TO: Members, Senate Special Committee on Oil and Gas

FROM: Committee Staff

RE: Committee Meeting, April 2, 1987

DATE: April 1, 1987

On Thursday, April 2, at 3:30 pm in the Beltz Room, the Senate Special Committee on Oil and Gas will receive a briefing by Dennis Kelso, Commissioner of the Department of Environmental Conservation. The commissioner will address areas in which the department has oversight over the oil and gas industry. He will be joined via teleconference by Larry Dietrick, Northern Regional Supervisor of the Division of Environmental Quality. Topics expected to be discussed include:

(1) an update on the situation at the MAPCO refinery in Fairbanks,

(2) hazardous wastes,

(3) disposal of drilling muds,

(4) air quality on the North Slope, and

(5) the status of the Hazardous Substance Release Response Fund.

The commissioner and Mr. Deitrick will be available to answer any questions committee members may have on oil and gas issues.

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 8672
1543 SCOMM 57: SENATE SPECIAL COMMITTEE ON OIL & GAS, 1987-1988
1340

4-7-87

Hedging with Oil Futures & Options

ALASKA STATE LEGISLATURE

SENATE SPECIAL COMMITTEE ON OIL AND GAS

Senator Bettye Fahrenkamp
Chairman
Senator Jack Coghill
Senator Paul Fischer

P.O. Box V, State Capitol
Juneau, Alaska 99811
(907) 465-3834

M E M O R A N D U M

TO: Members, Senate and House Finance Committees

FROM: Senator Bettye Fahrenkamp, Chairman
Senate Special Committee on Oil and Gas BF

RE: Proposal for hedging oil price risks with crude futures and options.

DATE: April 6, 1987

I would like to invite you to attend tommorow's hearing of the Senate Special Committee on Oil and Gas.

On Tuesday, April 7, at 3:30 pm in the Beltz Room, the Senate Special Committee on Oil and Gas will receive a briefing on a proposal for hedging oil price risks with crude futures and options.

The continued uncertainty and volatility of oil prices have made budget planning difficult for states and private companies that are highly dependent on oil revenues. Using the crude oil futures and options market, it may be possible to reduce the risk of potential price decreases and more accurately plan future revenues.

Andy Lebow, an energy futures specialist from Shearson Lehman Brothers in New York, and Jim Colburn, from the New York Mercantile Exchange, will be speaking before the committee via the teleconference network. They will be discussing a proposed risk management strategy for the State of Alaska using options on crude oil futures. They will also present another risk management tool called "Exchange of Futures for Physicals", which would allow the state to secure prices for its royalty oil in advance of actual sales.

ALASKA STATE LEGISLATURE

SENATE SPECIAL COMMITTEE ON OIL AND GAS

Senator Bettye Fahrenkamp
Chairman
Senator Jack Coghill
Senator Paul Fischer

P.O. Box V, State Capitol
Juneau, Alaska 99811
(907) 465-3834

M E M O R A N D U M

TO: Members, Senate Special Committee on Oil and Gas

FROM: Committee Staff

RE: Committee Meeting, April 7, 1987

DATE: April 3, 1987

On Tuesday, April 7, at 3:30 pm in the Beltz Room, the Senate Special Committee on Oil and Gas will receive a briefing on a proposal for hedging oil price risks with crude futures and options.

The continued uncertainty and volatility of oil prices have made budget planning difficult for states and private companies that are highly dependent on oil revenues. Using the crude oil futures and options market, it may be possible to reduce the risk of potential price decreases and more accurately plan future revenues.

Andy Lebow, an energy futures specialist from Shearson Lehman Brothers in New York, and Jim Colburn, from the New York Mercantile Exchange, will be speaking before the committee via the teleconference network. They will be discussing a proposed risk management strategy for the State of Alaska using options on crude oil futures. They will also present another risk management tool called "Exchange of Futures for Physicals", which would allow the state to secure prices for its royalty oil in advance of actual sales.

April 7, 1987

Senate Special Committee on Oil and Gas

Briefing on a proposal for hedging oil price risks with crude futures and options.

TO TESTIFY:

ANDY LEBOW, an energy futures specialist from Shearson Lehman Brothers in New York,

JIM COLBURN, from the New York Mercantile Exchange,

Allan Hazen

ALSO LISTENING:

Johns ~~JIM~~ SHEY and JAMIE ROSENFIELD, Cambridge Energy Research Associates (in Cambridge, Massachusetts)

JOSEPH STANISLAW, Cambridge Energy Research Associates (in London, England)

JIM EASON, Division of Oil and Gas

Mary Lindquist - FbKs Archer

Mr Phillips Div of Oil + Gas

Andy we do have

Basics of ~~P~~ options on Crude Oil futures - price insurance for a fixed price out in the future

cost

Premium call hedge —

Call ~~Rate~~ Writer limited at 1⁰

buy a Put + sell a call

Key word is versitility

Out of the money calls.

Environment is more favorable for hedging

Revenue projections are inadequate. 1032 } 1.086 } 277.m.

State could loose
hedge stategy

Crude futures has breath depth + liquidity
State should reconsider

monthly evaluations are better
- in Kerry - longer term

basics risk view _

price risk is always down side

futures markets _ state long crude

Perfect hedge cash go down futures goe down - loa on daily - - 4.

state could lock into price market.

- Oil hedging -

ANS cash price -

price changes WTI + -

most waited averages -

basis risk of futures relative

In value - futures

state as a short hedger could not lock into the price.

could be workable - but risky

options on energy futures - limited risk -

failure of futures to move in tandem is problem

biggest risk is basic risk to Alaska

EFP transaction - agreement.

Recommend state putting out some of the oil for sale on the market.
1 to 6 months hedge.

Time is right now for hedging - Mary Ringall

SHEARSON LEHMAN BROTHERS

An American Express company

Swap market is beginning to become prominent.

June 17 Calgary

Louisiana - Texaco looking at it.

many trans - heating oil futures market
S. Calif. transit
N.J. Transit Buffalo transit

PROPOSAL ON HEDGING

OIL PRICE RISKS WITH CRUDE

FUTURES AND OPTIONS

3,000 lots per day
March 8,000 lots a day
underlying curve

1987 - Crude 49,000 contracts
49m bbls

38 year before
76 year

Should be altered
volumes were 57,000 bbls daily
futures & puts

Alaska's effect. market would effect very little.
2000 bbls per day

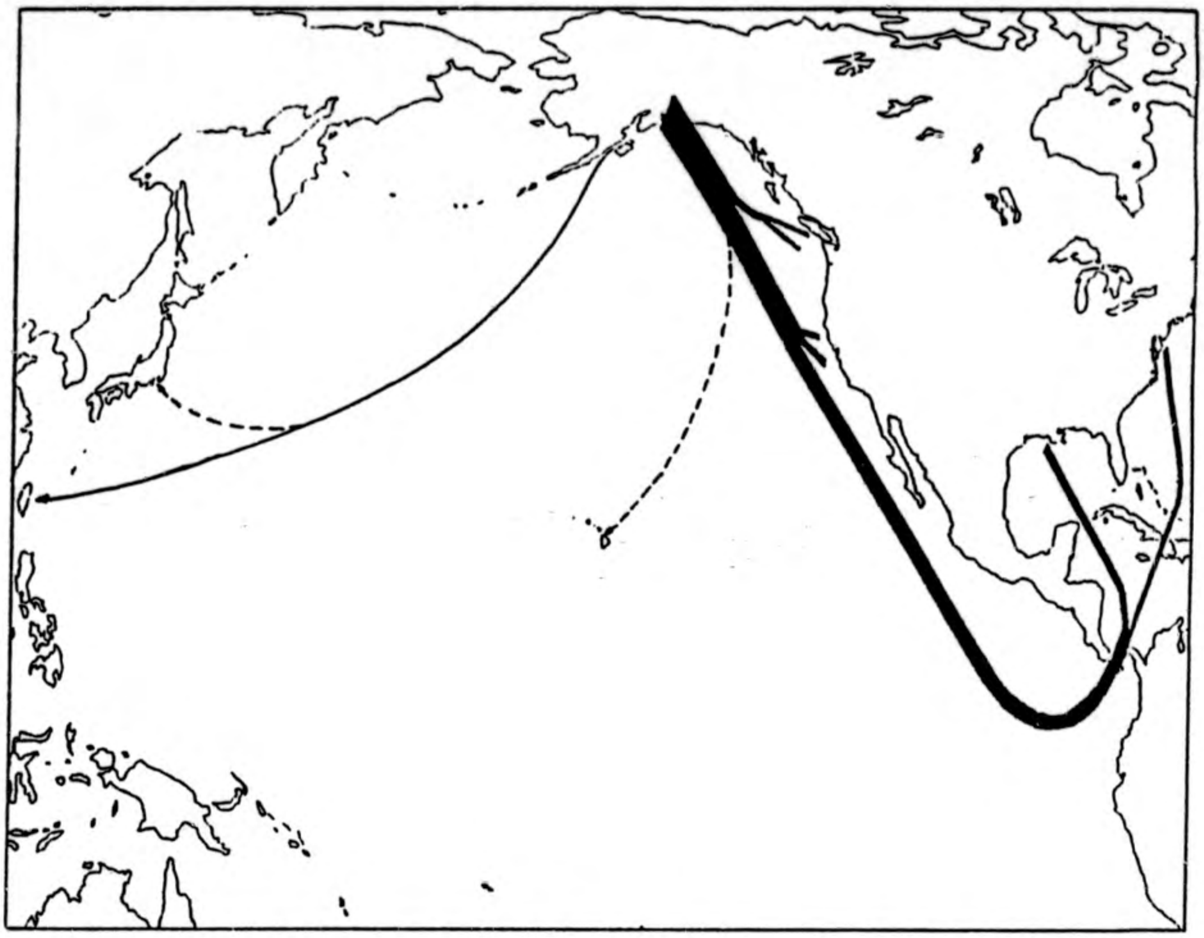
Dec '87

Andrew Lebow
VP - Energy Futures Specialist

$1,000 per contract
Commission fee
Exchange fee

opportunity cost
in placing marginal
2 to 3, or premium
in the spot market.

PETROLEUM PRODUCTION REVENUE FORECAST



QUARTERLY REPORT
MARCH 1987

DEPARTMENT OF REVENUE
STATE OF ALASKA
STEVE COWPER, GOVERNOR

Table 6.
Actual and Expected Crude Oil Prices
For Alaska North Slope Crude and OPEC Marker
Monthly Data ($/bbl)

Mo/Yr	ANS West	ANS Gulf	Saudi Gulf	Mo/Yr	ANS West	ANS Gulf	Saudi Gulf
Jul 82	28.30	30.28	33.68	Jul 85	24.04	26.93	26.84
Aug	28.12	30.31	34.00	Aug	24.02	26.92	27.01
Sep	28.00	30.62	32.76	Sep	24.15	26.94	27.60
Oct	27.67	30.55	30.81	Oct	24.20	26.91	28.25
Nov	28.02	30.06	31.12	Nov	24.26	26.90	28.43
Dec	27.35	29.36	29.94	Dec	24.25	26.50	26.89
Jan 83	26.87	28.29	28.45	Jan 86	23.28	23.21	24.35
Feb	25.59	27.50	28.90	Feb	17.73	18.32	20.14
Mar	25.16	27.16	28.90	Mar	13.65	15.07	18.28
Apr	25.21	27.36	29.21	Apr	11.31	13.27	16.04
May	25.32	27.36	29.10	May	10.73	12.54	16.29
Jun	25.34	27.42	29.25	Jun	10.62	11.81	14.69
Jul	25.32	27.51	29.25	Jul	9.15	10.48	12.17
Aug	25.45	27.86	29.25	Aug	9.42	11.29	14.55
Sep	25.65	28.04	29.11	Sep	11.37	11.67	16.60
Oct	25.71	27.95	29.07	Oct	11.62	13.07	15.26
Nov	25.73	27.93	29.19	Nov	11.54	13.08	14.85
Dec	25.73	27.89	29.16	Dec	11.77	14.33	15.38
Jan 84	26.05	28.06	29.03	Jan 87	13.79	15.33	17.46
Feb	25.57	27.87	28.99	Feb	15.30	16.32	18.78
Mar	25.59	27.91	28.90	Mar	15.14	16.16	18.64
Apr	25.49	27.93	29.08	Apr	14.96	15.99	18.47
May	25.64	27.95	27.15	May	14.74	15.77	18.26
Jun	25.70	28.04	27.28	Jun	14.52	15.55	18.05
Jul	25.81	27.95	27.66	Jul	14.38	15.41	17.93
Aug	25.66	27.92	27.71	Aug	14.15	15.19	17.72
Sep	25.75	27.90	28.06	Sep	14.04	15.09	17.62
Oct	25.36	27.92	27.25	Oct	13.50	14.55	17.09
Nov	25.73	28.01	27.13	Nov	13.49	14.54	17.09
Dec	25.23	27.38	26.85	Dec	13.47	14.53	17.09
Jan 85	24.72	27.00	25.61	Jan 88	14.41	15.47	18.04
Feb	24.29	26.98	25.26	Feb	14.38	15.46	18.04
Mar	24.31	26.97	26.72	Mar	14.37	15.45	18.04
Apr	24.27	26.97	26.95	Apr	14.33	15.41	18.01
May	24.10	26.94	26.70	May	14.31	15.40	18.01
Jun	24.15	26.94	25.70	Jun	14.30	15.39	18.01

Table 7.
Actual and Expected Crude Oil Prices
For Alaska North Slope and OPEC Marker
Annual Data ($/bbl)

Year	ANS West	ANS Gulf	Saudi Gulf
1978	12.30	14.60	13.46
1979	13.70	15.50	14.41
1980	26.50	27.68	24.75

Table 7.(cont.)
Actual and Expected Crude Oil Prices
For Alaska North Slope and OPEC Marker
Annual Data ($/bbl)

Year	ANS West	ANS Gulf	Saudi Gulf
1981	31.43	33.67	29.45
1982	29.50	31.07	32.99
1983	26.75	28.86	30.51
1984	25.64	27.91	28.79
1985	24.95	27.40	26.80
1986	19.35	21.28	22.90
1987	12.78	14.09	16.54
1988	14.09	15.16	17.72
1989	14.87	16.00	18.70
1990	15.68	16.89	19.74
1991	16.81	18.11	21.15
1992	18.07	19.40	22.65
1993	19.45	20.82	24.28
1994	20.93	22.37	26.03
1995	22.65	24.25	28.11
1996	24.58	26.29	30.37
1997	26.65	28.52	32.82
1998	28.94	30.93	35.47
1999	31.24	33.59	38.34
2000	34.28	36.66	41.61
2001	37.42	39.91	45.17
2002	40.85	43.46	49.04
2003	44.59	47.33	53.25

The weighted average sales prices of ANS on the West Coast and Gulf Coast, and the weighted average wellhead prices for the last twelve months according to producer reports are shown in Table 8.

Table 8.
Average ANS Sales Prices
($/bbl)

Month	Wellhead	West Coast	Gulf/East Coast
January 1986	15.86	23.28	23.21
February	10.74	17.73	18.32
March	7.23	13.65	15.07
April	5.38	11.31	13.27
May	4.82	10.73	12.54
June	4.18	10.62	11.81
July	3.12	9.14	10.48
August	3.69	9.42	11.29
September	6.14	11.54	12.87
October	5.83	11.62	13.07
November	5.74	11.54	13.08
December	6.46	11.77	14.33

4/7/87 3:38

~~Oil Price~~
Hedging Oil Price

Andy Lebow

Jim Coldren

Options —

begin trading 11/14/86 -

(1) Flexibility —

downside price protection,

put options on futures

premium allows to sell future

buying price insurance -

premium 1.50/bbl

for right to sell at $15 —

good for 3 months.

As prices decline —

put floor at 13.50

subtract hedging costs at 1.50.

Total downside protection

The most it will cost is 1.50

will participate in market rally's -

"put" strategy.

---

call writer —

"Insurance co"

recieve premium.

recieve 1.50 as prices decline.

long position —

as price

protection is limited to $\overset{8}{1.50}$.

---

set floor -

buy "put"

sell "call" to finance 'put'

downside protection –
$0 cash outlay. –

can't participate in rallies –

has protection

oil producers like "calls"

Andy Lebow.

3/85 before Senate Finance Com.

rec. That hedge program would be difficult –

crude future options lessened problems

could protect some losses –

Exchange of Futures for Physicals.

more favorable now than 3/85

revenue projections may be
in 1989 — 86-87 1.02
projection 1.063

accurately 200 million

hedge strategy —
contribute to better forecasting —

options —

to manage prices —
buyers of ANS crude are used to

every segment of industry is using options —

hedging —
equal + opposite position in futures market.

AK always "long crude"
if prices decline, we decline.
futures follow
if "short futures" — ...

lock into market -

gains on futures = losses on crude = perfect hedge.

ANS. is lower. -
different quality, different prices.

$\boxed{\text{basis risk}}$ - correlation coefficient -

monthly is closer Than daily.

in-kind contracts

in-value - net back from -
on posted on weighted average.

WTI futures do not nec move w/ ANS price
netback in-value
could mean losses

options do not remove "basis risk"
but limited to The cost of The premium

57,000 bbls/day -

"short hedger"

3rd quarter 86

futures rise 1.6
while in-value remain another loss 11 million

Sometimes future prices fall faster
Than in-value prices —

in 1st quarter — gained.

2nd quarter. loss 29.3.
62.

future 600,000
option 1,400,000

7/85 — 6/86 —

futures 38.6 price
option 2.19/ton
40.9 mills

did provide protection for 67% of loss.

neither provided total protection —

major drawbacks — is "basis risk".

EFP

could link sales to futures —

1) protect revenue from downs or
2) lock into known prices.

based on differential above or below
futures price —

set aside % to competitive bid w/ differentials
place hedge

can place 6 mo in advance.

rec. further study.

3 - 8,000 lots / day.

1987 - 49,000 / day
49 million barrels / day

200 ea contracts / day
would not effect. market.

hedge
if 1 all of states oil flow.

Study would only want to hedge
a certain amount.

SWAP MARKET —
agreement w/ Bank.

get fixed price —
use bank in middle.

too much exposure

too much volume.

Merrill

costs —

margins, commissions & exchange fees.

opportunity costs in placing margin calls

excess margin for spot market.

There are fees —

Rhode

how far out? How many years?

April 1- open interest?
how many open contract

July

Dec 87

mostly nearby months.

Traders "stack" hedge.

T Boone Pickens - all of 87

continue to roll over from month to month.

Phade risk of not delivering? —

→ June 17, Calgary

Jim.

Other states?

Louisiana – discussed

Texas – looking at it.

Public transportation authorities.

Transit authorities –

Southern Cal Rapid Transit.

in Heating Oil to hedge diesel cost.

NJ Transit

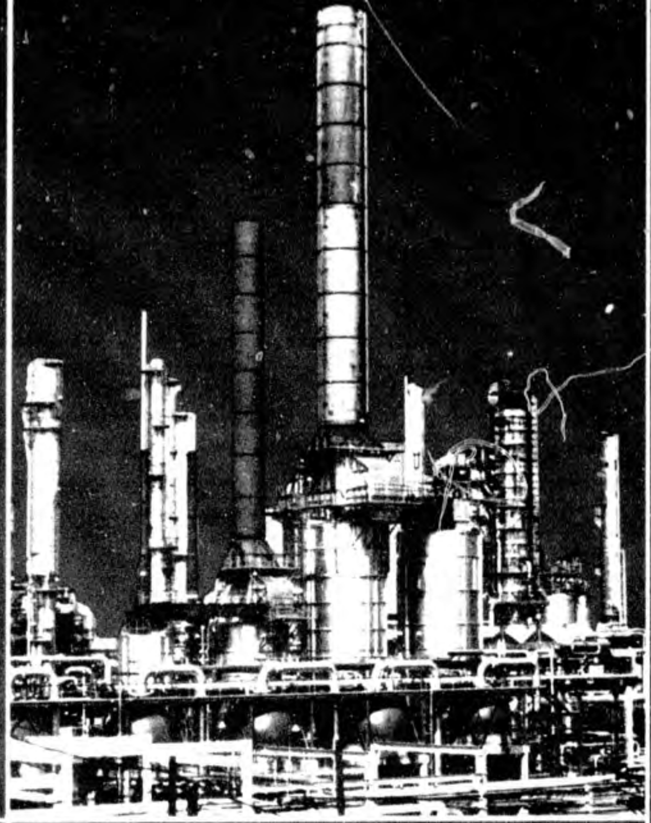
Buffalo transit.

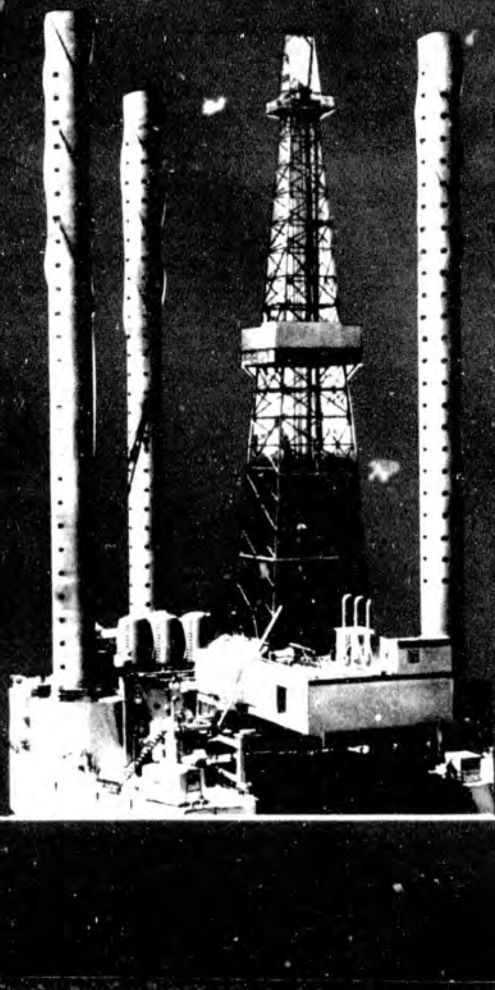
adjourned 4:42

SPECIAL SUPPLEMENT

ENERGY

Crude Oil Options





Options for Managing Volatility

ENERGY *in the news*

Since the beginning of trading crude oil options on November 14, 1986, there has been significant interest in options articles and information. Requests for recent issues of Energy in the News *have depleted our inventories. To meet current demand, this compendium of options articles was developed. Most of the following articles were taken from previous issues of* Energy in the News. *Look for future articles on options to appear in regularly scheduled quarterly issues of* Energy in the News.

3 Options for a Volatile Market — Crude Comes of Age

4 NYMEX Position Limits for Options

4 Crude Oil Option Contract Specifications

4 Crude Oil Options Vendor Symbols

5 A Promising Start for Crude Oil Options

8 The Allure of NYMEX Petroleum Options

9 Options: Hedging Alternatives for Oil Refiners

11 The Role of the Market Maker

13 Option Hedges for Oil Producers

16 Crude Oil Options: A Risk Management Tool

18 Volatility and Option Valuation

20 NYMEX Public Customer Margins

21 How to Interpret Option Deltas

24 Crude Oil Options: The Energy Speculator's New Tool

26 Time and Volatility

28 Six Basic Options Strategies

PRESS ARTICLES:

31 The Hot New Low-Stakes Play in Oil (*Business Week*)

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Vice President, Floor Operations
212/938-2249

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Product Manager, Options
212/938-2622

Paul Beenen
Gulf Coast Coordinator
713/661-0545

24-Hour Market Information

The following telephone numbers are being used to disseminate NYMEX market information:

Prices and Trading Volume	
Heating Oil Futures	212/938-8011
Gasoline Futures	212/938-8012
Crude Oil Futures	212/938-8013
Crude Oil Options	212/524-0614
Platinum, Palladium, Potatoes	212/938-8014
Open Interest	
Crude Oil, Heating Oil Futures	212/938-8016
Gasoline Futures	212/938-8017
Crude Oil Options	212/938-2625
Platinum, Palladium, Potatoes	212/938-8020
Membership	
Current Quote	212/938-2011

Options for a Volatile Market–Crude Comes of Age

The rapidly changing environment in the oil industry has created the need for more sophisticated risk management techniques. As OPEC price leadership has eroded and oil pricing has become determined by market forces, an increasing number of oil traders are using the energy futures markets to control price exposure. Crude oil futures volume on the New York Mercantile Exchange (NYMEX) totalled 8.3 million contracts (the equivalent of 8.3 billion barrels) in 1986, as compared with 3.98 million for all of 1985. This growth is a manifestation of highly volatile oil prices. Last November, NYMEX introduced yet another financial management tool to complement its energy futures complex: options on crude oil futures.

Crude oil options offer traders and risk managers more flexibility in attaining hedging goals. With options, traders can buy price insurance at a fixed cost to protect against adverse price moves without giving up the potential to profit from favorable price moves. Or, a trader might sell options against oil inventories to earn premium income. Options have the versatility to accommodate any strategy or market opinion.

Evidence of the popularity of futures options is indicated in volume performance. During 1986, over 32 million options on futures contracts were traded on metals, financials and agricultural products. And, options on futures have only been trading since 1982 (the first were on treasury bonds, sugar, and gold). If one considers just a few option strategies, the wide appeal of these instruments becomes clear.

A key feature of options is that buy option strategies have a limited, quantifiable risk regardless of where the underlying futures trade. A put buyer pays a premium for the right to sell futures at a specific price (strike price) for a specific period of time. The maximum loss for this strategy is the cost of the option, the premium.

An oil producer could purchase put options to protect a cash or futures position against a price decline below, for example, $13 per barrel. The cost of this insurance will depend on where futures are trading, the amount of time the option is valid and the level of market volatility. If prices decline below $13, the producer has already contracted to sell futures at $13; cash positions are covered. If prices rally, the put hedge can lose at most the amount of the premium, while the cash position appreciates. No additional margin is required. Downside price protection is achieved at a fixed cost, without giving up profit potential during market rallies.

Some traders may feel that premiums are too high. Selling (writing) call options against oil inventories or future production is a way to take advantage of rich premiums. A call writer, in return for the premium, is obliged to sell futures to a call buyer at a specific price for a specific period of time. For example, with futures at $15, an oil producer could sell $16 (strike price) calls for, say, $1 per barrel. As long as futures remain at or below $16, the producer earns the entire premium, $1 per barrel. An ideal outcome would be if prices rallied to $16. The producer still earns $1 from the call write, and his cash position appreciates by $1. If prices rally above $16, the producer's effective sale price remains at $17, because additional gains on the cash position are offset by losses on the written call option. This strategy earns premium income and achieves downside protection equal to the premium. However, upside profit potential is constrained if prices rally above the strike price. Unlike the purchase of options, writing options carries unlimited risk. Therefore, option writers must post margins.

A third strategy which illustrates the versatility of options is a long straddle. A long straddle is also referred to as a long volatility trade because profits are earned when the market moves dramatically in either direction. The trade involves buying a put and a call with the same expiration date and strike price. Total risk is limited to the premiums paid, while profits are unlimited if the market moves boldly up or down. A straddle could be a popular trade ahead of an OPEC meeting or before the release of new information such as an API report. Traders might buy a straddle days before an OPEC meeting with the expectation that market volatility will increase afterwards.

Options trading will add to the liquidity of the oil futures market. Because of their limited risk feature, crude oil options will be used by a much broader industry and speculative population. As market participants enter option orders, market makers and arbitrageurs taking the other side will lay off market risk by buying or selling futures contracts.

For example, if a large number of buy put orders enter the market, an arbitrageur will simultaneously sell the puts, buy calls, and sell futures. The arbitrageur takes advantage of puts being bid higher without having an exposed market position. As a result, additional liquidity in the options and futures markets is created. (Arbitrage strategies are described in "The Role of the Market Maker" on pages 11-13 in this issue.)

Option strategies can be as simple as a buy put or more complex, like straddles and spreads. The above examples illustrate only a few approaches, as option strategies are limited only by the trader's creativity. ■

NYMEX Position Limits for Options

The position limits for crude oil options are calculated on a gross, rather than a net, position basis. These limits, in all months combined, are 2,000 contracts for each of: 1) long puts, 2) long calls, 3) short puts, 4) short calls.

Speculative position limits for options may be increased to a maximum of 4,000 contracts, so long as any option contracts in excess of the 2,000-contract limit are part of a conversion, a reverse conversion, or a box spread, in which all component positions expire on the same date. Authorization from the President of the New York Mercantile Exchange is required for this. Persons must apply by filing an Options Strategy Notice within five days after assuming the above limit position. However, prior approval is required to surpass limits during a contract's last three trading days.

Speculative position limits may also be increased to a maximum of 4,000 contracts if those options in excess of 2,000 are part of a one-for-one option vs. future spread (i.e., an inter-option spread), or a one-for-one option vs. option spread (i.e., an intra-option spread). Such exemptions for inter-option spreads and intra-option spreads shall not require approval of the President.

Option position limits may also be expanded to 4,000 contracts for bona fide hedge positions, on condition that a Hedge Notice is filed within the same limits as for Options Strategy Notices, above.

A proposal to base speculative position limits on a net delta system is pending CFTC approval (contact the Exchange for further information).

Crude Oil Option Contract Specifications

CONTRACT UNIT

1,000 U.S. barrels (42,000 gallons)

TRADING HOURS

9:45 a.m.–3:10 p.m. (New York time)

TRADING MONTHS

Six consecutive futures months.

PRICE QUOTATION

Prices are quoted in dollars and cents per barrel.

MINIMUM PRICE FLUCTUATION

\$.01 (1 cent) per barrel
(\$10 per contract)

MAXIMUM DAILY LIMIT

Trading in crude oil option contracts will not be subject to price fluctuation limitations.

LAST TRADING DAY

Trading terminates at 3:10 p.m. (New York time) on the first Friday of the month preceding the delivery month. For example, options on February crude oil futures expire the first Friday in January.

STRIKE PRICES

Trading will be conducted for options with increments of \$1.00 per barrel.

EXERCISE NOTICE

Notice of exercise must be received by a Clearing Member from a customer not later than 4:30 p.m. on any business day on which an option contract is trading up to and including the date of expiration. On the same day it receives a notice of exercise from the Clearing Member, the Exchange's Clearing Department will assign the notice of exercise randomly to a seller of an option of the same series. Prior to the opening of trading on the next business day, the Exchange will notify the seller of such exercise and assignment. On the last day on which an option may be exercised, each option held by a Clearing Member having an in-the-money value of \$300 or more will be automatically exercised by the Exchange unless the Exchange receives written notification from the Clearing Member.

ASSIGNMENT

The Exchange will establish, by book entry, positions in the underlying futures contract for both the purchaser and seller of the option, the price of which will be the exercised option's strike price.

Crude Oil Options Vendor Symbols

Commodity Exchange Center	LO
ADP	
Bunker Ramo	QLO
Comtrend	QL
FIS	C1LO
Bonneville Telecomm./RDS	CL
Bridge Market Data Systems	CL
Commodity News Service	
CNS Data Quote	CL
Money Center	CL
Market Information, Inc.	CL
Market Vision Corp.	CL
Quotron Systems, Inc.	LO
Reuters U.S., Inc.	
Quote mode	LO
Full screen mode	Group 111
Standard & Poors/MWIS	CL
Telerate: access pgs.	8460–56 8470–74
Tradecenter	LO

A Promising Start For Crude Oil Options

The efforts of NYMEX members, staff, and industry advisors to launch crude oil options have paid off handsomely. Since the opening on November 14, options trading results have been excellent. Notably, open interest increased sharply to reach 54,909 on December 31. After intensive preparations, Exchange clearing and price-reporting systems functioned smoothly, while trading proceeded in an efficient manner.

On opening day, a total of 5102 contracts were traded, of which 4541 were call options and 561 put options. During the first six weeks of trading, average daily contract volume was 4,509 with 2,702 calls and 1,807 puts traded. Therefore, in 1986, during a total of 30 trading days, a total of 135,266 options contracts were traded; 81,057 calls and 54,209 puts. Each call represents an option to assume a long position in one crude oil futures contract (1,000 barrels) and each put represents an option to assume a short position in a crude oil futures contract.

Open interest in crude oil options, a measure of the market's size and liquidity, has expanded steadily. Open interest rose from 4220 at the close of trading on November 14 to reach 54,909 contracts by the end of the year. This performance indicates that new positions have continually been created, and thus the crude oil options market has broadened substantially.

Six consecutive futures months, from February to July 1987, were initially listed for the options, but the greatest trading activity has thus far occurred in the first three months. In terms of the premiums, or prices, of NYMEX crude oil options, a meaningful yardstick is the implied volatility. This can be calculated from an exact options pricing model (see box on page 7). During the first four weeks of trading, the implied volatility of at-the-money options has been 30-40 percent. These levels are at the low end of 30-day volatilities as measured earlier in 1986; i.e., a range of 30 to 100 percent.

Comparisons with the opening record of major options contracts demonstrate very favorable results. Currently, options on Treasury bonds and Deutschemark futures are among the largest such contracts. The charts on page 4 show that volume and open interest in NYMEX crude oil options has expanded quickly relative to these key contracts. Indeed, the crude oil option contract is, so far, the fastest-growing options contracts ever introduced in the futures industry.

With uncertainty virtually the only certainty in today's oil markets, this new contract can be expected to gain steadily in importance after its auspicious start.

Educational Materials From NYMEX

Educational materials explaining the NYMEX crude oil option contract and options strategies are available from the NYMEX Marketing Department. These include a crude oil options brochure, a video course with an accompanying workbook, and a slide show plus script.

The NYMEX crude oil options brochure was published in August. It defines options terms, describes the determinants of options premiums, discusses options trading and hedging applications, and lists the contract's specifications.

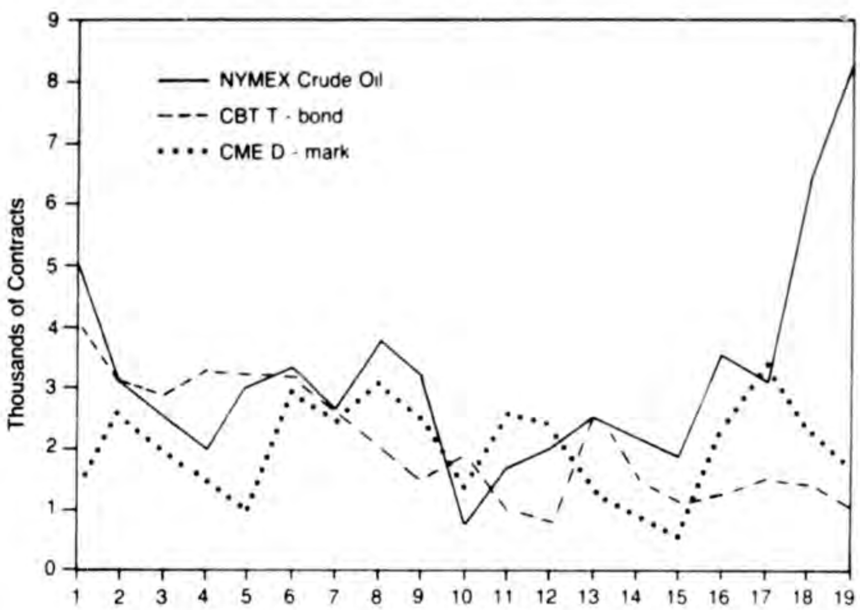
The videotape (VHS) is of lectures conducted by Joseph Sullivan, a partner of The Options Group, during a three-day seminar offered by the Exchange last June. The lectures cover the basics of options as well as advanced trading techniques such as spreads, straddles, fences, and conversions. The video is accompanied by an extensive workbook of all visuals used in the seminar.

The 48-slide presentation on crude oil options covers basic options terms and definitions, plus options pricing factors and trading strategies. The slideshow comes with a script.

The cost of the video is $100 ($50 for NYMEX members) and the cost of the slide show is $70. These prices are exclusive of taxes (applicable to New York residents) and shipping costs.

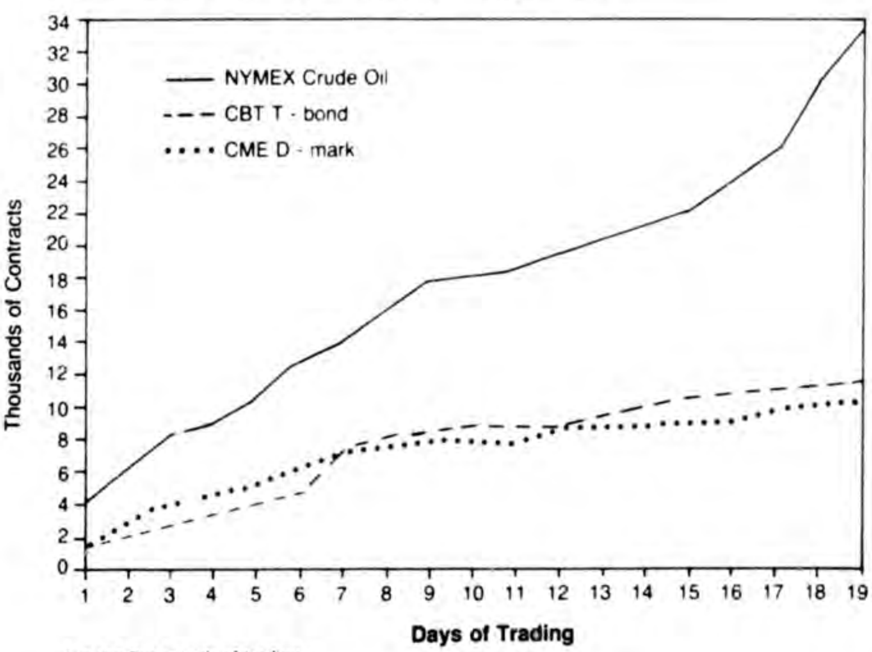
Please return the following coupon and enclose a check for these educational materials.

Crude Oil Option Volume Comparison*



* in the first month of trading

Crude Oil Option Open Interest Comparison*



* in the first month of trading

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A sample format for one contract follows:

Sample Daily Options Fact Sheet

Crude Oil Light Sweet (LO) — Calls for February 1987 (Wednesday, December 17, 1986 / Open Interest: 40,394 (R) / Volume: 6,675)

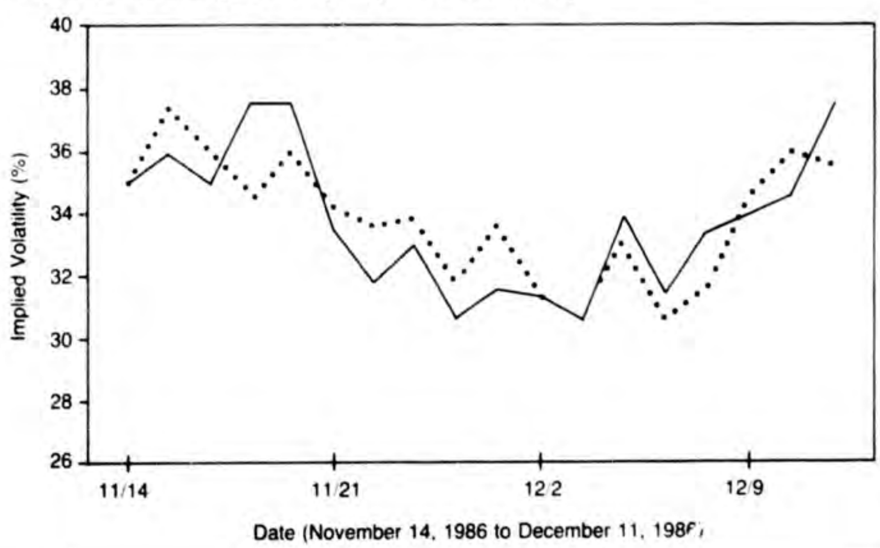
	Open Interest	*Open*	*High*	*Low*	*Last*	*Settle Price*	*Delta*	*Volume*	*Exercises*	*Contract High*	*Contract Low*
12.00	—	—	—	—	—	—	0.00	—	—	—	—
13.00	—	—	—	—	—	—	0.00	—	—	—	—
14.00	82 + 1	2.10	2.12	2.10	2.12	2.15 – .30	0.98	6	—	2.40	1.24
15.00	1,008 – 8	1.35	1.39	1.22	1.22	1.25 – .25	0.86	62	—	1.80	.51
16.00	4,295 + 160	.57	.63	.50	.56	.56 – .12	0.55	786	—	1.10	.18
17.00	4,061 + 1327	.25	.26	.19	.22	.22 – .06	0.21	1,618	—	.50	.07
18.00	1,587 – 119A	.09	.09	.07	.07	.07 – .01	0.04	40	—	.25	.04
19.00	400 + 5	.03	.03	.03	.03	.02 – .01	0.00	7	—	.15	.03
20.00	—	—	—	—	—	—	0.00	—	—	—	—
	11,433 + 1366			R = new record			Total	2,519			

A Note on Implied Volatility

Option traders look at implied volatility for an indication of the market's expectation of future price volatility. It is a derived figure, based on the market-traded option premium. Exact option pricing models calculate implied volatility from inputed data on the option premium, the time to expiration, the underlying futures price, the strike price, and the risk-free interest rate.

Computed from crude oil option premiums, the implied volatility of crude oil prices has ranged between 30 to 38 percent from November 14 to December 11 (chart). It increased ahead of the December 11 OPEC meeting, reflecting an anticipation of greater volatility in the oil markets.

NYMEX February Crude Oil Option Implied Volatility: Calls (line) and Puts (dot)



The Allure of NYMEX Petroleum Options

MICHAEL F. McDERMOTT
Vice President, Drexel Burnham Lambert

The New York Mercantile Exchange (NYMEX) introduced options on Crude Oil Futures on November 14, 1986. Options on Heating Oil Futures will commence in 1987. While the introduction of these contracts is being warmly received by many in the financial community, there are a number of questions being put forward by the petroleum industry. Namely, what is an option contract and what are the mechanics in buying and selling options? But more importantly, what is the allure of options and conversely what are the risks and costs? And finally, why should NYMEX Crude and Heating Oil options succeed?

To begin with, there are two types of options: a *Call* option and a *Put* option. A Call option gives the holder the right to purchase a futures contract at a specified price during the life of the option, while a Put option gives the holder the right to sell a futures contract at a specified price during the life of the option. Thus, an option contract is fundamentally different from a futures contract in that the holder of the option is not obligated to take or make delivery but rather has the option to buy or sell a futures contract. The price for which a futures contract can be bought (in the case of a Call option) or sold (in the case of a Put option) is referred to as the option's *Strike Price* or exercise price. The date on which an option expires — that is, the date after which it can no longer be exercised — is referred to as the option's *Expiration Date*. The market price to purchase or sell an option is its *Premium*. Finally, options are classified as either "In the Money," "At the Money," or "Out of the Money." An "At the Money" option occurs when the strike price and the futures price are equal. An option is "Out of the Money" when the strike price exceeds the futures price in a call option or is below the futures price in a put option. The opposite is the case in the "In the Money" option. Obviously, the cost or the premium to purchase the right to buy or sell a futures contract at a specified strike price is the highest when the option is "in the money" and is the lowest when an option is "out of the money."

As a way of illustration, a December $15.00 "at the money" call option gives the buyer the right (but not the obligation) to buy a December WTI futures contract at $15.00 per barrel. The premium for such an option might run $.75 per barrel. If the price of December WTI rises to $17.00, the investor would exercise the option at a net profit of $1.25 ($17.00–$15.00–$.75) per barrel. On the other hand, if December oil trades at $13.00, the investor would let the option expire worthless and only lose the initial $.75 premium. The grantor (or seller of the option), in this latter case, earns the option premium. In the opposite case, a December $15.00 put option at a premium of $.90 per barrel gives the buyer the right to sell a futures contract at $15.00 per barrel. If the price of oil falls to $13.00 a barrel, the trader would exercise the option at a net profit of $1.10 ($15.00–$13.00–$.90) per barrel. If the December WTI price rises to $17.00 per barrel, the option expires worthless and the grantor earns the initial $.90 per barrel premium.

A major appeal of buying options is that the downside risk is limited to the initial investment (the premium) while the potential gain is unlimited. Stated differently, a commercial hedger can not only fix a future price at a known cost (the premium) but also participate in a favorable price move. For example, an oil producer recognizes that the futures price of crude oil, say $15.00 per barrel, is slightly above his firm's cost of production. By purchasing the $15.00 put option, the producer is insured of a $15.00 selling price (thus preventing shutin) but can also participate in a price rally (by letting the option expire worthless). Conversely, a refiner of crude oil can also use the options market to his advantage. By purchasing a crude oil call option, the refiner is insured of a fixed price for its crude oil needs should prices move higher but is not locked into a specific price should prices move lower. Options, in these two cases, are analogous to traditional insurance premiums allowing institutional investors a mechanism to professionally manage price risk.

Another advantage of options is on the sell side (although more risky). Suppose a refiner expects prices to remain steady. By selling a call option, the refiner earns premium income or a return on his physical inventory of oil. A trader with a "short" physical position (i.e., agrees to sell crude oil at a specified price in the future) who wishes to earn a return on his "short" physical position and also perceives a steady market, could earn premium income by selling a put option.

But selling options carries with it an associated risk. Since the buyer of the option has limited risk/unlimited return, the seller assumes the other side of the equation. In the above examples, the risk occurs in the physical positions when prices move against the seller. In the first example, the refiner would incur significant losses if oil prices fell sharply. Although the option would provide some premium income, the value of the refiner's inventories would plummet with the fall in prices — i.e., the refiner is unhedged against a substantial fall in prices. In the latter case, the trader with a "short" physical position is at risk if prices rise sharply higher. Although the trader earns some offsetting premium income from the put option, he would be forced to purchase expensive oil in the physical market to meet his previously negotiated lower priced sales contract. Although there is this element of risk associated with selling options, in some respects, options writing is less risky than taking an outright futures position or holding an unhedged physical position. The reason: losses are reduced somewhat by premium income in the option position. In addition, this risk can be managed.

Besides the relatively straightforward buying and selling of "at the money" options, commercial users and producers of oil can also purchase less costly price-risk insurance by buying "out of the money" options. Also, by combining an option and a physical position with a futures contract, an offsetting option position, or a similar option position at an alternative strike price, the option mechanism can be specifically tailored to precisely reflect the individual investor's market view and needs.

It is this versatility which underscores the success of earlier options on futures. The underlying allure of the option contract is that it can be used to reduce or increase market exposure, can be profitable in any kind of market (bear, bull, or even nontrending), is relatively inexpensive, has a favorable risk-reward ratio, and can be used to lock in a profit or insure against a loss. Because of the multiple option strategies, varied investor needs, and less than certain economic environments, options will be appealing to producers, users, refiners, traders, and to the speculative community.

NYMEX will also provide other benefits to option traders. First and foremost is that NYMEX is the primary market for energy futures trading and as such will provide a structured centralized market, financially backed by the NYMEX Clearing Members. Premiums will be competitive, bids and offers will be recorded electronically and disseminated instantaneously, and transaction costs should be low. In short, it is a combination of the versatility of options, the individual risk profiles and financial objectives of investors, the less than certain business climate, and the unique situation of NYMEX which should ensure the success of the crude oil and heating oil option contracts. ■

Options: Hedging Alternatives for Oil Refiners

JOHN W. LABUSZEWSKI, Vice President, Strategic Applications, Refco, Inc.
JOHN H. O'CONNELL, Senior Metals and Energy Analyst, Refco, Inc.

Oil producers, refiners, and traders have the opportunity to learn what equity, fixed-income, and metal market investment managers already know: options represent a tremendously versatile risk-management tool for the knowledgeable professional.

Futures contracts based on crude oil and heating oil have become a well-accepted component of many oil companies' risk-management programs. The introduction of options on crude and heating oil futures promises to add flexibility, permitting energy concerns to closely tailor risk and reward to preferred levels.

Changing the Nature of Risk

From time to time, producers, refiners and traders share the risk of sharply rising or falling oil prices in volatile markets.

Futures are often thought of as tools which may be used to negate this risk. Or, more precisely, to substitute a lessor basis risk for a greater market price risk. Options offset risk as well, but also change the nature of the risk. Comparing alternative options strategies to the use of futures illustrates this.

Assumptions. A refinery borrows crude in Time Period One with the promise to replace it in Time Period Two, say January and March respectively. They now anticipate larger than previously planned for production in January. It is unclear whether their normal supply stream will be sufficient to supply the replacement in March, and spot market purchases may be necessary. While their market view remains neutral, if they are unhedged, they risk the possibility prices will rise, and cut into profit margins. Consequently, management dictates a hedged position.

Traditional Futures Hedge

By buying crude oil futures contracts to hedge this exposure, the refiner eliminates the risk of a rising market before the borrowed crude is replaced. Assuming no basis risk, a refiner who buys crude oil futures at \$16.00 per barrel, when spot oil is at \$16.00, locks in an effective purchase price of \$16.00. Thus, by buying futures, the refiner removes himself from the market and gives up the ability to profit from potentially falling prices. Futures, therefore, may be used to lock in a fixed or specific purchase price.

But many refiners might be dissatisfied with the prospect of locking-in today's price and giving up the opportunity to cover their short exposure at possibly lower oil prices. In that case, options could be used to lock-in either a minimum or a maximum price for the purchase of oil.

Buying Insurance with Long Calls

Buying a call option against the short exposure of the borrowing refinery is analogous to the purchase of a price insurance policy. The owner of a call option holds the right, but not the obligation, to buy crude oil futures at a fixed price no matter how high the market soars. In return for that privilege, the buyer pays the seller a one-time premium, which may be likened to the insurance premium. For the holder or owner of the option there are no margins calls.

EXAMPLE 1

Assume that spot and futures are trading at \$16.00 per barrel. A refiner buys a call with two months to expiration and a \$16.00 a barrel strike price for \$1.50 per barrel. The strike is the price at which the call holder may buy the futures. Assuming away basis risk, the hedger has locked in an effective maximum purchase price of \$17.50, the \$16.00 strike price, plus the \$1.50 premium.

If oil remains stable at \$16.00, the effective purchase price equals \$16.00 plus the \$1.50 premium, or \$17.50.

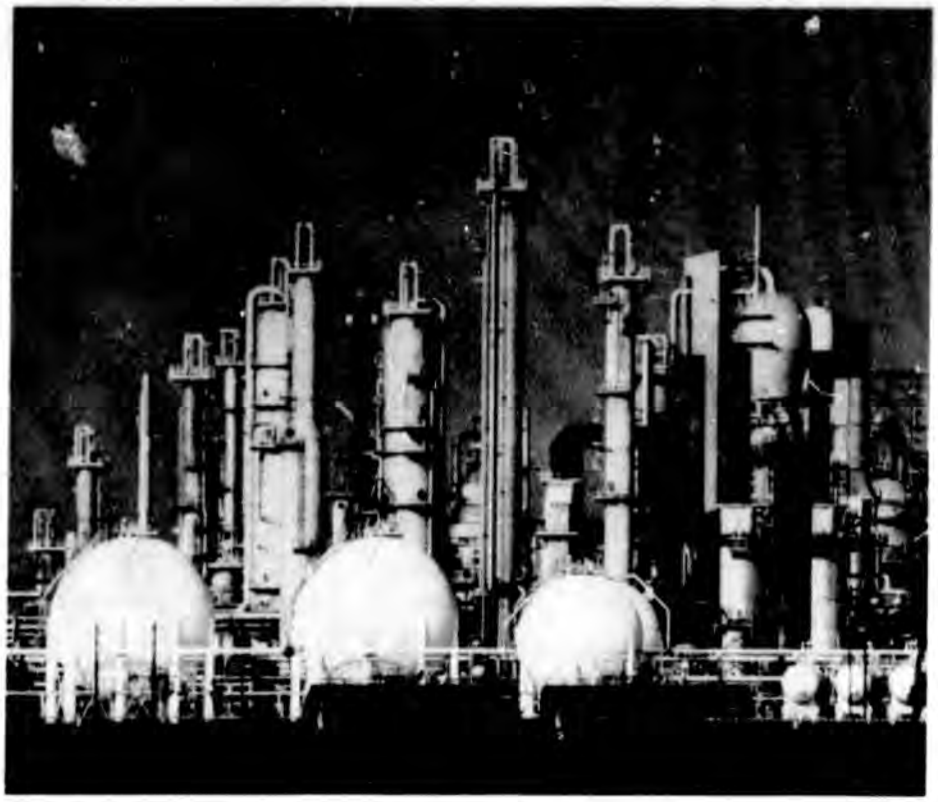
If oil rises to \$20.00, the refiner can exercise the call, buying crude oil futures at \$16.00, the strike price, when they are actually trading at \$20.00. The effective purchase price for this hedge is \$17.50, the \$16.00 strike plus the \$1.50 premium paid.

If oil falls to \$12.00, the refiner retains the ability to profit in a bear market, and this is the beauty of this option hedge. If oil drops to \$12.00, the refiner simply elects not to exercise his option. The effective purchase price for the crude equals \$13.50, \$12.00 plus the \$1.50 option premium.

The analogy between this strategy and buying insurance is strong. By paying the call premium, the refiner insures he will be able to buy oil futures at the strike price. At the same time, the refiner retains the ability to benefit substantially in a bear market.

Selling Insurance with Short Puts

Despite the merits of the long call hedge, some refiners may balk at the idea of paying \$1.50 per barrel to purchase price insur-



ance. This would be particularly true when the refinery's outlook suggests the market may remain relatively stable. Under those circumstances, a refiner may instead consider selling the insurance in the form of put options to earn the option premium.

By accepting the oil premium, the refiner augments his current income but gives up the ability to participate in price declines.

A very significant area may be identified in the immediate vicinity of the strike price. Between crude prices of \$14.50 and \$17.50, the hedged returns are positive and exceed those of an unhedged position. This suggests the short put hedge is most appropriate when the market is likely to trade within a relatively narrow range over or under the strike price.

Which Strategy is Best?

Before looking at the reward of each individual strategy it's appropriate to look at the very different risks of the two option strategies. The long call's risk is limited to the original premium payment. The short put, however, involves unlimited risk, once prices exceed \$17.50 for the refiner who has borrowed.

All three hedging strategies outlined above, long futures, long call and short put, are essentially bullish. That is, they may be used to offset, at least partially, the risk associated with a possible bullish turn in the market. Still, the reward profiles of all three strategies vary greatly.

Which strategy is preferred? That depends on the market situation. Table 1 provides the effective purchase prices for our hypothetical hedging examples under three different market scenarios.

Continuing with the original example of a refiner who borrows, but allowing for flexible hedging guidelines from management, a short put hedging strategy is somewhat more sophisticated than the straightforward long call. This strategy offers a superior hedge under certain market conditions.

EXAMPLE 2

Again, assume that spot and futures are at \$16.00 and track each other precisely. A refiner grants/sells a \$16.00 put for \$1.50 per barrel. As a writer, the refiner accepts the 1.50 premium and agrees to buy crude at \$16.00. If the option is exercised in the future this locks in a minimum price of \$14.50, the \$16.00 strike price less the \$1.50 premium earned.

If oil remains stable at \$16.00, the effective purchase price equals \$16.00 less the \$1.50 premium, or \$14.50.

If oil rises to \$20.00, the put will not be exercised, and the refiner earns the full \$1.50 premium. The refiner will have to purchase futures at \$20.00 but this higher price is cushioned by the receipt of the original option premium. Thus, the effective purchase price equals \$18.50.

If oil falls to \$12.00, the put will be exercised, obligating the refiner to buy crude futures at \$16.00 when they are actually trading at \$12.00. Thus, the effective purchase price for the crude equals \$14.50, the \$16.00 less the \$1.50 option premium.

Table 1: Effective Purchase Price

	Market Scenarios Spot Crude Prices		
Hedge Strategy	*\$12.00*	*\$16.00*	*\$20.00*
Unhedged	\$12.00	\$16.00	\$20.00
Long Futures	\$16.00	\$16.00	\$16.00
Long Call	\$13.50	\$17.50	\$17.50
Short Put	\$14.50	\$14.50	\$18.50

Most refiners will agree there is no substitute for a bearish market when you're short crude as in our time swap example. If the market falls to \$12.00, the refiner's effective purchase price is lowest when he remains unhedged. But also note that the unhedged alternative yields the highest effective purchase price when the market advances. None of the hedge alternatives produces such extreme results.

If you consider only the hedging strategies, it is clear the long call hedge dominates when the market falls, the short put hedge dominates when the market is stable, and the long futures hedge is optimal if the market should advance.

Table 2: Preferred Hedges

Ranking	*Declining Markets*	*Neutral Markets*	*Advancing Markets*
1	Long calls	Short puts	Long futures
2	Short puts	Long futures	Long calls
3	Long futures	Long calls	Short puts

Of course, it's often difficult to call the direction of the market. But if you do harbor a market view, you can put that forecast to work by implementing one or another of the hedging alternatives available.

Options open up vast new dimensions in the oil business. These are opportunities which cannot be trivialized. Granted, options are not the simplest risk-management tools to get a handle on. Like all other tools, if they are improperly used, they will produce poor results.

Still, the experience of equity, fixed income market, and metal market professionals strongly suggest energy companies will find the rewards associated with the ability to tailor the risk/reward profile vastly outweight the efforts expanded in mastering energy options. ■

The Role of the Market Maker

JAMES COLBURN
Options Product Manager, New York Mercantile Exchange

The success of any new futures or options contract depends greatly on its ability to show consistent economic relationships between the contract and the underlying instrument. Arbitrageurs and market makers constantly monitor specific relationships for profit opportunities through temporary inefficiencies. This function is crucial to an orderly market because it provides liquidity and maintains stable economic relationships between futures, options and the underlying commodity. In this article, the role of the arbitrageur, as it pertains to options, is discussed.

Futures contracts are tied to the underlying cash commodity through the delivery process. If November crude oil futures rise much above the September spot oil quote, traders can simultaneously buy spot oil and sell November futures, locking in a profit. The trader can either liquidate the trade if futures prices decline relative to spot prices or deliver the spot oil against the futures position on the delivery date. Recently, this kind of arbitrage has been widely reported as it pertains to stock index futures, i.e., program buying and selling. The overall effect is that the futures price remains within certain economic boundaries of the cash market.

Options are related to the underlying futures contract through the exercise feature. The simplest example of options arbitrage illustrates the relationship. Arbitrage opportunities exist if a September $10 strike price crude oil call option is trading at $.75 and September futures are trading at $11.00. A trader would buy the call option, sell the futures and immediately exercise for a profit of $.25:

Short futures	$11.00
Exercise option: long futures	10.00
Profit	$ 1.00
Cost of $10 call option	− .75
Net profit	$ .25

Call options will continue to be bid higher and futures offered lower until no arbitrage profits remain. This activity forces options to trade at values at least equal to their exercise values (intrinsic values). More complex arbitrage strategies are based on the following relationship:

Futures Price − Strike Price =
Call Premium − Put Premium

Options and futures must be the same month; puts and calls must have the same strike price.

This relationship is not quite an equality because it does not include financing or transaction costs (which will be excluded from the following examples).

Assume that on August 7, the following situation exists:

Oct. futures	$15.07
Oct. $16 put	1.60
Oct. $16 call	.67

The relationship holds:

$15.07 − $16.00 = − $.93
$ .67 − $ 1.60 = − $.93

What would happen if a large supply of buy put orders enters the market suddenly, bidding up put premiums to $1.70? The relationship is now:

$15.07 − $16.00 = − $ .93
$ .67 − $ 1.70 = − $1.03

Arbitrage profits would then exist. A trader could sell puts, buy calls and sell futures to lock in the following profit:

Sell futures $15.07		
Buy $16 calls	$ .67	debit
Sell $16 puts	$1.70	credit
	$1.03	net credit

Consider how this position locks in profits. If futures are trading at $15 (Case I) at the time the option expires, the futures position gains $.07, the call loses $.67, and the put gains $.70, for a total gain of $.10; if futures are trading at $16 (Case II) at option expiration, the futures loses $.93, the call loses $.67 and the put gains $1.70, for a total gain of $.10. See Table I.

Regardless of where futures trade, the value of the arbitrageur's position is $.10 at expiration. The strategy of selling futures, buying calls and selling puts is called a reversal or reverse conversion.

What happens if many buy call orders enter the market and bid premiums to $.75? Arbitrageurs will then execute conversions by selling calls, buying puts and buying futures. See Table II.

This time the market maker has locked in $.08 regardless of where futures trade. In both examples, arbitrage will continue until no profits exist. Note that conversions and reversals force the options/futures relationship to hold and increase liquidity in both the options and futures markets. Arbitrage profits are locked in without exposure to market moves. In reality, however, the arbitrageur must overcome some potential problems not addressed in our textbook examples.

Legging In And Out

Conversions and reversals have three components: two options and one futures contract. An arbitrageur must trade quickly, otherwise, the position could be exposed to a market move and expected profits could turn into losses. Many option traders address this problem by teaming up with a trader in the futures pit. However, even if the option trader does the option side of a conversion and signals to the futures trader, the market may have moved, eliminating an already slim profit margin.

Getting "Pinned"

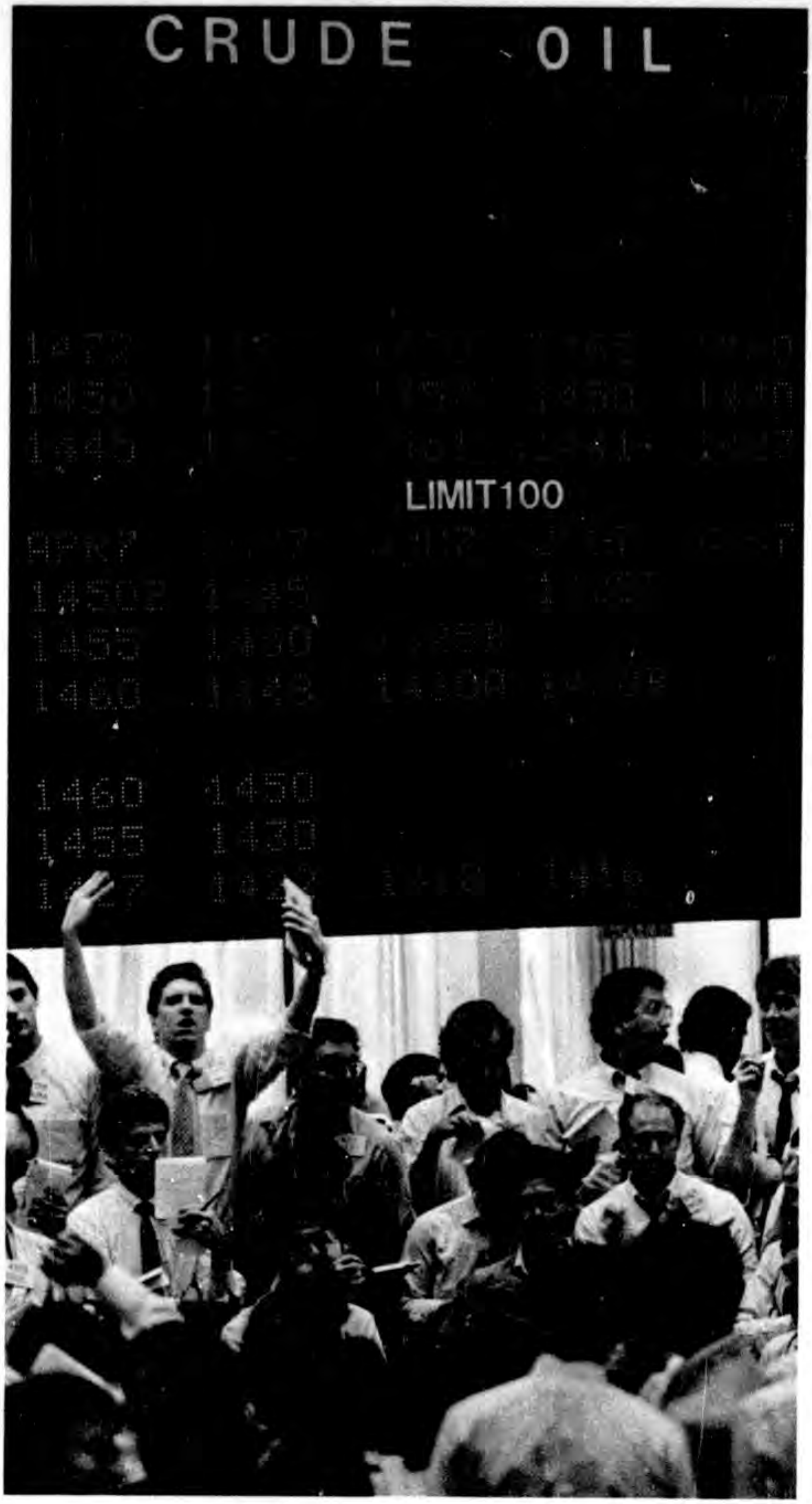
Market makers who take conversions and reversals into expiration run the risk of getting "pinned." If futures settle very close to the strike price on expiration day, a decision must be made whether to exercise the

Table I

		Case I		*Case II*	
August 7		*Expiration*	*Profit (Loss)*	*Expiration*	*Profit (Loss)*
Sell Futures	$15.07	$15.00	$.07	$16.00	($.93)
Buy $16 Calls	$ .67	0	(.67)	0	(.67)
Sell $16 Puts	$ 1.70	1.00	.70	0	1.70
Net Result	$ 1.03		$.10		$.10

Table II

		Case I		*Case II*	
August 7		*Expiration*	*Profit (Loss)*	*Expiration*	*Profit (Loss)*
Buy Futures	$15.07	$15.00	($.07)	$16.00	$.93
Sell $16 Calls	$ .75	0	.75	0	.75
Buy $16 Puts	$ 1.60	1.00	(.60)	0	(1.60)
Net Result	($ .85)		$.08		$.08



long option leg, while trying to guess what the trader holding the long side of the short option will do. A long option holder will have some time after the markets close before deciding about the exercise. If futures settle at $16, a holder of a $16 call or put might watch the cash market during that time before deciding. However, because crude oil options expire on Fridays, an exercise of options brings the risk of a substantially higher or lower opening Monday morning.

If futures settle at $16 on expiration day, traders who hold, for example, conversions (long futures, short $16 calls, long $16 puts) must guess what the other side holding the short call will do. If a trader exercises the long puts to offset the long futures, the long call may decide to exercise also. This would leave that trader with a significantly exposed market position, i.e. a short futures position, from Friday to Monday morning.

Market makers will sometimes pay a little extra to unwind conversions and reversals, so as not to get "pinned." Traders unwind by offsetting option positions in the options market and futures positions in the futures market. For example, a conversion executed with a $16 strike is liquidated by a reversal with the same $16 strike. However, not all conversions and reversals require a trader to hold the position to expiration to earn profits, nor will futures always settle on a strike price at expiration.

Margin Calls

An option position is not margined like a futures position. Unlike a futures trade, the only cash exchanging hands between a buyer and a seller of an option occurs when the trade is put on and when the trade is taken off. If a trader buys a call for $1.50 and the next day it settles at $1.75, profits of $.25 are not realized until the trade is liquidated. On the other hand, futures positions are marked to market on a daily basis — cash from market losses is transferred to those positions which have increased in value.

The problem facing an arbitrageur is that a potential negative cash flow from a futures margin is not offset by the option leg until the trade is liquidated. The arbitrageur, seeking to profit from a market inefficiency, may have to wait days or weeks before options and futures move back in line. If the market moves against the futures side of the conversion or reversal, considerable cash flow problems could develop.

Some traders simply borrow cash to pay margin and incorporate interest charges into their cost structure. Others will "tail" the conversion or reversal. The details of "tailing" are beyond the scope of this article, but the general idea is to adjust the futures position to account for the disparity in cash flows. Discounting cash flows may reveal that buying 99 futures contracts will cover 100 long puts and 100 short calls. Using slightly fewer futures contracts than options addresses the discrepancy between futures cash flow which occurs daily versus option cash flow which occurs only at execution and liquidation.

In order to circumvent potential margin calls on reversals or conversions, arbitrageurs will complete a box trade. If a conversion is held on a $16 strike, a reversal can be executed on a $15 strike or a $17 strike and the futures positions drop out. For example, a market maker is long futures, short $16 calls and long $16 puts (conversion). Selling futures, buying $15 calls and selling $15 puts removes the futures side and any corresponding margin issues.

conversion	+ reversal	= box
long futures	short futures	
sell $16 calls	buy $15 calls	
buy $16 puts	sell $15 puts	

The arbitrageur originally puts on the conversion to lock-in profits. The reversal is then executed to remove the futures side. The reversal may not necessarily earn profits, but it serves the trader by eliminating the futures leg and margin calls. The resulting position is called a box.

Arbitrageurs serve important market functions. They add liquidity to options markets and maintain economic relationships between options and futures. Futures markets also gain liquidity from risk transference of options positions. ■

Option Hedges for Oil Producers

JAMES COLBURN,
New York Mercantile Exchange

There are two kinds of options: puts and calls. A put buyer has the right, but not the obligation to sell futures at a specific price (strike price) during a specific period of time. A call buyer has the right but not the obligation to buy futures at a specific price during a specific period of time. While option buyers are buying rights, option sellers are selling rights and have obligations. A put seller (grantor, writer) has the obligation to buy futures from a put buyer at a specific period of time. A call seller has the obligation to sell futures to a call buyer at a specific price for a specific period of time.

The cost of these rights is called the premium. Option buyers pay a premium to option sellers for the right to go long futures (call) or short futures (put). The most an option buyer can lose is the premium, regardless of where futures trade. The maximum profit to an option seller is the premium, but the seller faces unlimited risk and must post margins.

Long Options	*Short Options*
(Buy calls — Buy puts)	(Sell calls — Sell puts)
Pay premium	Receive premium
Maximum loss is limited.	Maximum loss is virtually unlimited.
Maximum profit is unlimited.	Maximum profit is limited to premium.
No margin is required.	Margin is required.

Long and short options is different from long or short the market. A call buyer wants prices to go higher (long the market), but a put buyer profits when prices decline (short the market). Conversely, a call seller is short the market and a put seller is long the market. By introducing simple buy and sell option strategies, a trader will have added two more ways to go long the market and two more ways to go short the market.

Long the Market	*Short the Market*
(Bullish)	(Bearish)
Buy futures	Sell futures
Buy calls	Buy puts
Sell puts	Sell calls

Options can be disposed of in 3 ways: offset, expiration, and exercise. Most options are disposed of by offsetting, like a futures contract, which means they are traded back into the market. A long August put $10 strike, for example, can be offset by selling that same option. Options can also expire worthless. If, for example, August crude oil futures trade at $12/barrel at the time August options expire, the August put with a $10/barrel strike price would have zero value. The put holder would simply let the option expire worthless. Finally, option buyers may exercise their rights at any time before expiration. Sometimes it will be profitable for an option buyer to exercise and go long futures (call) or short futures (put) at the strike price. For example, an August put holder with a $10 strike price exercises and receives a short futures position at $10. An August put seller with a $10 strike is obliged to take the other side, i.e., a long futures position at $10.

The exercise feature in options is similar to the delivery mechanism in futures. Only a small percentage of crude oil futures volume actually results in delivery, but the possibility of delivery keeps cash and futures prices in line. Similarly, only a small percentage of option contracts are exercised, but the possibility of exercise maintains the connection between futures prices and options premiums.

Buy Put Strategy

A basic hedging strategy to protect against declining prices is to buy puts against a long cash position. Hedging losses are limited to the put premium, so that the hedger is still able to participate in market rallies. Two price scenarios are simulated: case A assumes sharply falling prices and case B assumes sharply rising prices.

On July 1st, two producers fear that oil prices will decline within the next few months and want to hedge their fourth quarter production. Each expects to produce 75,000 barrels during the fourth quarter. Producer 1 decides to hedge using November and December puts with $12 strike prices. Producer 2 decides to hedge using November and December futures.

Assumptions

- Cash prices are $1/barrel over the nearby futures price.
- Case A assumes that cash and futures prices both decline by $4/barrel, so that cash market losses are offset by futures market gains.
- Case B assumes that cash and futures prices increase by $4/barrel, so that futures losses offset cash market gains.
- Both producers lift their hedges on October 1.

Establishing the Hedges

The options premiums in the numerical examples were estimated from historical data using an exact option pricing model, courtesy of The Options Group.

Per barrel prices on July 1:

Cash		*Futures*	*$12 puts*
$14.00	Nov.	$13.00	$0.82
	Dec.	$13.00	$1.02

Producer 1

Buys 37 November puts at $0.82	
37 × 1,000 barrels × $0.82	= $30,340
Buys 38 December puts at $1.02	
38 × 1,000 barrels × $1.02	= $38,760
Total cash outlay for 75 contracts	= $69,100

Producer 2

Sells 37 November futures at $13.00
Sells 38 December futures at $13.00
Total futures sold = 75 contracts

Outcomes of Options and Futures Hedges

CASE A

Per barrel prices on October 1, when the producers lift their hedges:

Cash		*Futures*	*$12 puts*
$10.00	Nov.	$9.00	$3.00
	Dec.	$9.00	$3.01

Producer 1

Liquidates the option hedge:	
Sells 37 November $12 puts at $3.00	
37 × 1,000 barrels × $3.00 =	**$111,000**
Sells 38 December $12 puts at $3.01	
38 × 1,000 barrels × $3.01 =	**$114,380**
Total option receipts	**$225,380**
Total option cost (July 1)	**$ 69,100**
Total profit on options hedge	**$156,280**
(Loss) on 75,000 barrel production =	**$(300,000)**
Net (Loss) =	**$(143,720)**

Producer 2

Liquidates the futures hedge:	
Buys 37 November futures at $9.00	
37 × 1,000 × ($13 − 9) =	**$148,000**
Buys 38 December futures at $9.00	
38 × 1,000 × ($13 − 9) =	**$152,000**
Total futures bought = 75 contracts	
Total profit on futures hedge	**$300,000**
(Loss) on 75,000 barrels production	**$(300,000)**
Net (Loss) =	**0**

CASE B

Situation on October 1, when the producers lift their hedges:

Cash		*Futures*	*$12 Puts*
$18.00	Nov.	$17.00	$.00
	Dec.	$17.00	$.01

Producer 1

Liquidates the option hedge:	
November puts expire worthless	
37 × 1,000 × 0 =	**0**
Sell 38 December puts at $.01	
38 × 1,000 × $.01 ×	**$ 380**
Total option receipts	**$ 380**
Total options cost (July 1)	**$ 69,100**
Total (loss) on options hedge	**$(68,720)**
Gain on 75,000 barrels production	**$300,000**
Net profit	**$231,280**

Producer 2

Liquidates the futures hedge:	
Buy 37 November futures at $17.00	
37 × 1,000 barrels × ($13 − $17) =	**($148,000)**
Buy 38 December futures at $17.00	
38 × 1,000 barrels × ($13 − $17) =	**$(152,000)**
Total futures bought = 75	
Total (loss) on futures hedge =	**$(300,000)**
Gain on production =	**$300,000**
Net profit =	**0**

Summary of Results

CASE A

1. Both futures and options strategies offer downside price protection to producers.
   Producer 1 has protected 52% ($156,280 ÷ $300,000) of the decline in cash prices with the long put hedge strategy. The put premiums did not rise in value by the full amount of the decline in cash and futures market prices because the options were purchased "out-of-the-money." That is, oil prices were above the options strike price at the time the hedge was established.
   Producer 2 has protected 100% of the decline in cash prices with the short futures strategy.
2. Buying puts does not offer dollar for dollar protection like a futures hedge until oil prices move below the strike price and cover the premium. At that point, options become "in-the-money" and premiums vary close in line with the change in the underlying futures prices.
3. Long options strategies require a cash outlay; futures strategies require margin deposits.

CASE B

1. A major advantage of buying puts to hedge a long cash position is that puts offer the hedger downside protection (Case A) but allow participation in profits when prices rise (Case B).
2. The maximum cost of the buy put hedge is known when the hedge is implemented ($69,100) regardless of how cash prices move. There are no margin calls.
3. The futures hedge requires additional margin as prices increase.

Conclusions

The availability of crude oil options will give hedgers a wider array of risk management strategies. This will raise many questions that the hedger must answer to determine the best way to control price risk:

- How much price risk can I live with?
- What is my opinion of the market?
- What protection do I need?
- What should I pay for that protection?
- What strike price should I use?
- What is the best way to meet my goals?

Selling futures contracts insulates cash positions against declining prices by effectively fixing sales prices. If an oil producer wanted downside price protection without

Covered Call Strategy

Covered call strategies enable a hedger to take advantage of high option premiums. A covered call is a short call option covered by a long position in either the cash or futures markets. If prices decline, the hedger will have downside protection equal to the premium. If prices rally, the hedger's cash position will appreciate up to the call's strike price. After that, losses on the short call offset any cash market gains. Covered call strategies work best in markets which move sideways to slightly higher. Unlike buying puts, margins must be posted for covered call strategies.

In this example, two producers are slightly bullish and feel that crude oil option premiums are extremely high. They decide to write calls against fourth-quarter production of 75,000 barrels. Producer 1 sells $14 calls. Producer 2 sells $15 calls.

Assumptions

- Cash prices are $1/barrel over the nearby futures price.
- Case A assumes that cash and futures prices both decline by $4/barrel, so that cash market losses are offset by futures market gains.
- Case B assumes that cash and futures prices increase by $4/barrel, so that futures losses offset cash market gains.
- Both producers lift their hedges on October 1.

Establishing the Hedges

Per barrel prices on July 1:

Cash	*Futures*	*$14 Calls*	*$15 Calls*
$14	Nov. $13.00	$ .92	$ .63
	Dec. $13.00	$1.13	$ .83

Producer 1

Sells 37 November $14 calls at $0.92	
37 × 1,000 barrels × $.92	= $34,040
Sells 38 December $14 calls at $1.13	
38 × 1,000 barrels × $1.13	= $42,940
Total Options Sold = 75 contracts	
Total Premium Received	= $76,980

Producer 2

Sells 37 November $15 calls at $.63	
37 × 1,000 barrels × $.63	= $23,310
Sells 38 December $15 calls at $.83	
38 × 1,000 barrels × $.83	= $31,540
Total Options Sold = 75 contracts	
Total Premium Received	= $54,850

Outcome of Covered Call Strategies

CASE A

Per barrel prices on October 1:

Cash	*Futures*	*$14 Calls*	*$15 Calls*
$10.00	Nov. $9.00	0	0
	Dec. $9.00	0	0

Producer 1

Total option premium received (July 1)	$ 76,980
Value of options on October 1	0
Total profit on options trade	$ 76,980
Loss on production	($300,000)
Net (Loss)	$(223,020)

Producer 2

Total option premium received (July 1)	$ 54,850
Value of options on October 1	0
Total profit on options trade	$ 54,850
Loss on production	$(300,000)
Net (Loss)	$(245,150)

CASE B

Situation on October 1:

Cash	*Futures*	*$14 Calls*	*$15 Calls*
$18.00	Nov. $17.00	$3.00	$2.00
	Dec. $17.00	3.09	2.26

Producer 1

Liquidates the options:	
Buy 37 November $14 calls at $3.00	
37 × 1,000 × $3.00 =	$111,000
Buy 38 December $14 calls at $3.09	
38 × 1,000 × $3.09 =	$117,420
Total outlay on option	$228,420
Total premium received	$ 76,980
Total (Loss) on options	$(151,440)
Gain on production	$300,000
Net profit	$148,560

Producer 2

Liquidates the options side:	
Buy 37 November $15 calls at $2.00	
37 × 1,000 × $2.00 =	$ 74,000
Buy 38 December $15 calls at $2.26	
38 × 1,000 × $2.26 =	$ 85,880
Total outlay on options	$159,880
Total premium received	$ 54,850
Total (Loss) on options	($105,030)
Gain on production	$300,000
Net profit	$194,970

Summary of Results

CASE A

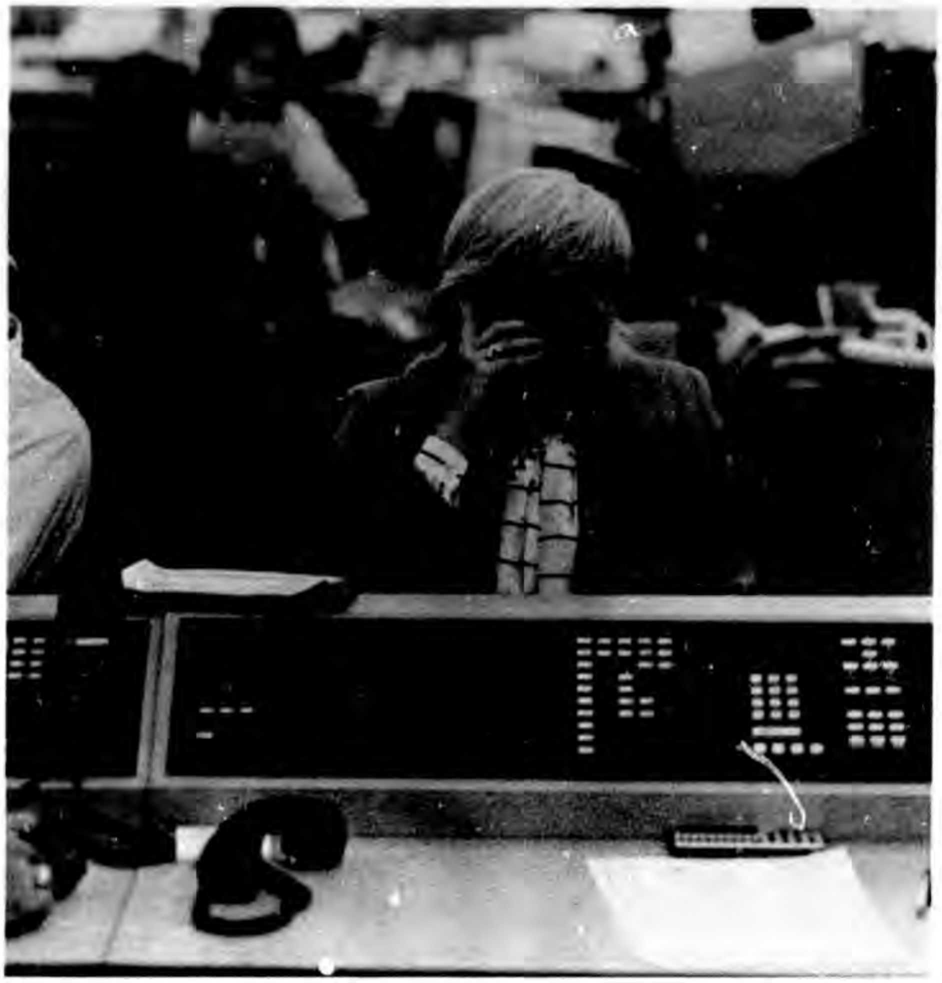
1. Both producers earn the entire option premium as prices decline.
2. Producer 1 has protected only 26% ($76,980 ÷ $300,000) of the decline in cash prices and Producer 2 has protected 18%. The maximum protection received from a short call position is the premium.
3. In a declining market, writing a call option with a lower strike price offers greater protection since it carries a higher premium.

CASE B

1. Covered call writing limits participation in a bull market because any gains on the cash or futures position are offset by losses on the written call positions. Short calls will begin to lose tick for tick with futures if prices continue to rise above the strike price.
2. Producer 2's strategy of writing $15 calls is a better position than Producer 1's strategy of writing $14 calls because prices must rally higher to reach the $15 strike. Producer 2's cash position can appreciate up to $15 whereas Producer 1's cash position is neutralized after prices reach $14.

giving up upside profit potential, buy-put strategies would be appropriate. Various strike prices will be available to give risk managers flexibility as to levels of protection and option costs. Buy-put strategies are most effective in markets that gain in volatility during the hedge period.

Short calls are least effective for downside protection because option profits are limited to the premium. Short option strategies take advantage of high premiums and work best when markets move sideways. Producers can sell call options to earn premium income, and still participate in market rallies up to the strike price. ■



Crude Oil Options: A Risk Management Tool for Financial Institutions and Independent Petroleum Companies

R.A. WALKER
Vice President, The First National Bank and Trust Company of Tulsa

Following the initial downturn in oil prices in 1982 and the introduction of crude oil futures in early 1983, The First National Bank and Trust Company of Tulsa (First Tulsa) began evaluating the use of the futures market to reduce the risk associated with reserve-based oil and gas lending. The bank began to model the concept of independent oil companies hedging the oil reserves they pledge as collateral. After considerable review it was concluded that the hedging of reserve-based loans was possible, though certain problems were identified.

First, the maintenance of the hedge or mark-to-market costs could be considerable if a rising price environment occurred during the hedge period. Second, by hedging with a futures contract an independent was limiting, or locking in, the profit margin. Third, most independent firms were not staffed with individuals proficient in the futures market. And fourth, the use of the futures market at that time was not acceptable to those independents who were comfortable with the arrangements they had with first purchasers.

Based on discussions with customers and industry experts, it was concluded that the independent was more likely to use the futures market once options for crude oil futures were introduced. There were several reasons for this. First, the cost of price insurance could be less with a put option than with a futures short hedge. Second, options are philosophically more compatible with the independent's risk-taking nature as they allow for participation in an upward price move but limit downside exposure. Third, with options, the independent does not need to be an expert in futures trading, nor require a buildup in staff and overhead to effect transactions.

Independents, in contrast to majors, multinationals and other vertically integrated companies, must make their profit at the wellhead through exploration and production efforts. Any price decline in the crude oil market cannot be passed along and made up through downstream operations.

Historically, independents have used their oil and gas reserves as collateral to finance the development of leasehold interests. The collateral value of these reserves is in large part a function of the current price being received and the expectation of what prices will be over the economic life of the reserves. As prices declined, the independents' ability to borrow deteriorated along with their ability to meet debt service requirements. Most recently, as prices dropped to levels of $10-12 per barrel, some wells were deemed uneconomical. With operating expenses exceeding operating revenues, these wells were plugged. Against this backdrop, options may provide a risk management tool which allows financial institutions to continue providing capital to the energy industry under acceptable risk-return parameters.

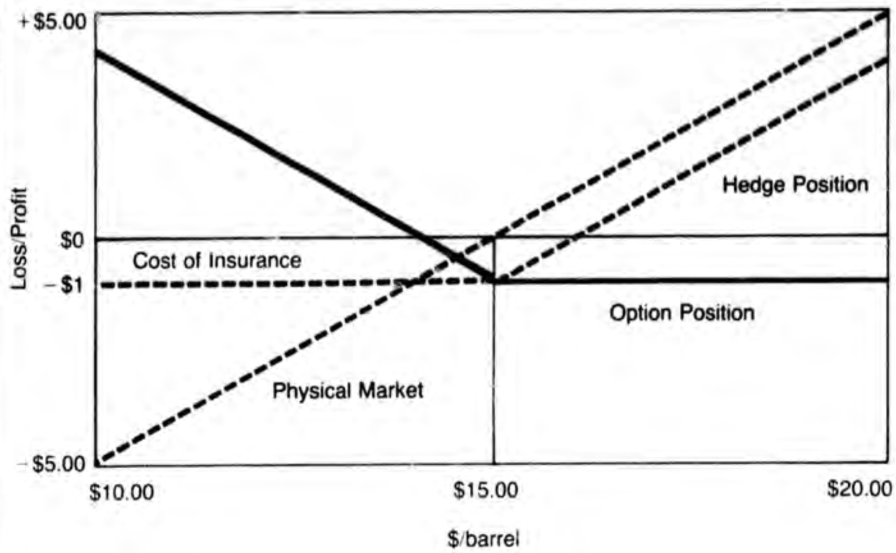
The Concept of Hedging

Last fall, The New York Mercantile Exchange (NYMEX) introduced options on crude oil futures. The reason this instrument is of interest to producers is that the downside risk is limited to the option premium while the prospective gain is unlimited. Chart I illustrates how a put option provides a price floor. A put option is the right, not the obligation, to sell an underlying future, at a pre-determined strike price, for a specific period of time.

The line defined as physical position refers to the market most producers use to sell their production under a traditional first purchaser arrangement. The price range in this diagram is from $10 to $20 and is represented on the horizontal axis. The vertical axis represents the profit/loss range. This example assumes a current price of $15 in the spot month futures price (the spot month futures price is the nearest trading month and generally correlates with the physical market spot price). The option with a strike price of $15 is considered an "at the money" option because the strike price is equal to the futures price. The shaded area defined as "cost of insurance" is the $1 per barrel premium paid at the time the put option is purchased. If prices go below $15 the producer pays nothing in addition but retains a price floor of $14 per barrel ($15 strike price − $1 premium).

CHART I

Price Floor of Put Option



Applications

Options cannot cure the problems being experienced by independents and their banks but they can provide a support mechanism. Current prices are causing the oil and gas industry to contract and restructure. The following describes one use of options by independents — to hedge revenues from acquired properties.

Energy banks base their evaluations of the borrowing base, or loan value support, of oil and gas properties on many factors. But no factor is more volatile than the prices used to evaluate the collateral value of the reserves and the future cash flow stream to be realized for debt service.

If an independent is successful in the acquisition of reserves, it may ask its bank or bank group to assess the loan value of the acquired reserves in order to obtain financing. In conjunction with the engineering evaluation, software can be adopted to evaluate the use of an option price floor.

Consider the acquisition of $100 million of oil reserves by an independent oil producer. Its bank group determines that these reserves have a borrowing base of $75 million due to the structure of the facility and the nature of the properties. The facility stipulates that the principal be amortized under a 48-month schedule.

The bank group can evaluate the need of the option strike price through two means.

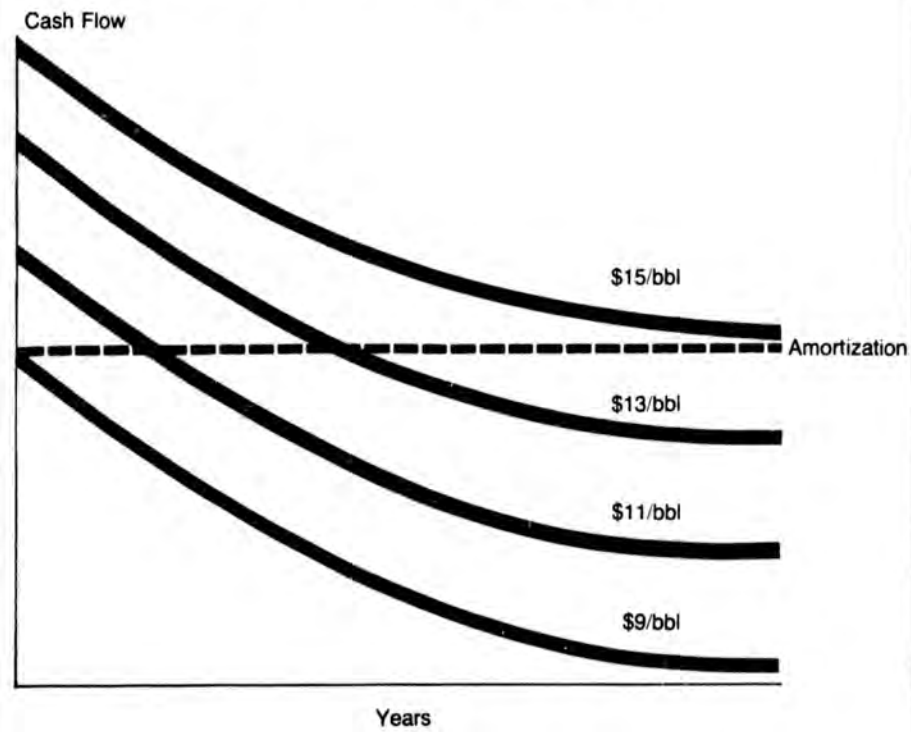
The first constructs a series of declining cash flow curves. Each curve is based on a different fixed oil price assumption and its shape reflects declining production. See Chart II.

Cash flow curves are net of overhead and discounted based on an interest rate factor held constant so as to best measure amortization capability. For purposes of illustration, a constant 48-month repayment schedule is assumed. In actuality, if debt service was as sensitive to repayment capacity under the $15 base case, a greater degree of amortization would be imposed in years 1 and 2 under a sliding amortization schedule or a smaller loan amount would be provided.

In this framework, the independent can make a decision on what strike price to use in order to maintain debt service capacity, relative to his expectation or sensitivity to price declines. For example, the independent may initially establish a cash flow floor with slightly out-of-the-money options and

CHART II

Cash Flow Curves and Amortization (dashed line)



then purchase a one-time put to protect the net present value of future cash flows in the sixth month.

A second method estimates how many option contracts will be required at various strike prices to ensure debt service. Under this evaluation, the engineered production profile is used as a benchmark for determining the contract barrels hedged. The multiplication of these engineered barrels to be produced by the various strike prices determines debt service capacity.

The strike price will vary monthly as the properties reflect their decline curves relative to debt service. Using this concept, a floor is created using monthly put options. Because options initially will only be available 6 months in advance, the hedging of the remaining loan term takes some thought. Under an inventory hedge versus a 6-month cash flow hedge, the customer can purchase options to cover the net present value of future cash flows or future debt service requirements. The details of this concept have only been modeled and to a large extent are proprietary for use by First Tulsa. However, other banks are reviewing the use of options and may have different concepts.

Current regulatory guidelines prohibit banks from acting as principals in crude oil futures transactions. Hedges are structured with banks mantaining an agency role and with the customers executing covered put option strategies. This means the option positions are only taken when an underlying cash market position is maintained, in order to avoid speculative investment.

Conclusion

The examples and concepts described here are still theoretical in nature until options trading begins. Many of the fundamental aspects of hedging energy loans, however, are no different than those developed a long time ago by major Midwest banks for hedging agricultural loans. The idea of basis risk has not been mentioned in this article, but is present in all futures transactions. Since crude oil on the NYMEX is delivered through Cushing, Oklahoma, based on a specific grade of crude, any crude grade difference or location variance to Cushing will create some basis risk. In the case of hedging with options, basis risk is generally not a tremendous problem, but it is one that cannot be eliminated.

Options should bring new participants to the NYMEX markets. Price volatility in the near future will require both independents and banks to continue to evaluate methods to reduce price risk. Options on crude oil futures could allow independents to continue to look to banks as a source of capital with acceptable levels of risk. ■

Volatility and Option Valuation

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The value of an option premium has four primary determinants: 1) time remaining until expiration; 2) the differential between the market price and the strike price; 3) prevailing risk-free interest rate (T-Bill rate), and 4) volatility of the underlying instrument. Mathematical models are available and commonly used to determine the premium using these four factors. Although the first three factors are easily quantifiable and objective, the fourth factor, volatility, has an element of subjectivity. Volatility in any option pricing model must represent future volatility of the underlying instrument. Since future volatility depends on future price action, choosing an appropriate volatility is akin to market forecasting.

Volatility of a commodity is a measure of price dispersion. The greater the price dispersion over a given period of time, the greater the volatility. Volatility can be related to a statistical measure called standard deviation. The standard deviation measures the variability of data from the mean of the distribution. It encompasses approximately two-thirds of all data over a specific period of time. The calculated standard deviation is an estimate of price volatility.

One way to interpret volatility is shown in the following example:

A 50% volatility estimate on $20.00 crude would mean that crude oil can be expected to trade 50% over or under $20.00, two-thirds of the time, over a year's period. In this example this would be a $10-30 range. If volatility was only 25% then the expected range would be $15-25. However, a more technical measure of volatility is used industry-wide. It involves determining the standard deviation of the logs of percent changes in daily prices:

$$\text{Volatility} = \sqrt{\frac{A}{n-1}\sum_{t-1}^{n}(x_t - \bar{x})^2}$$

A = number of trading days in a year

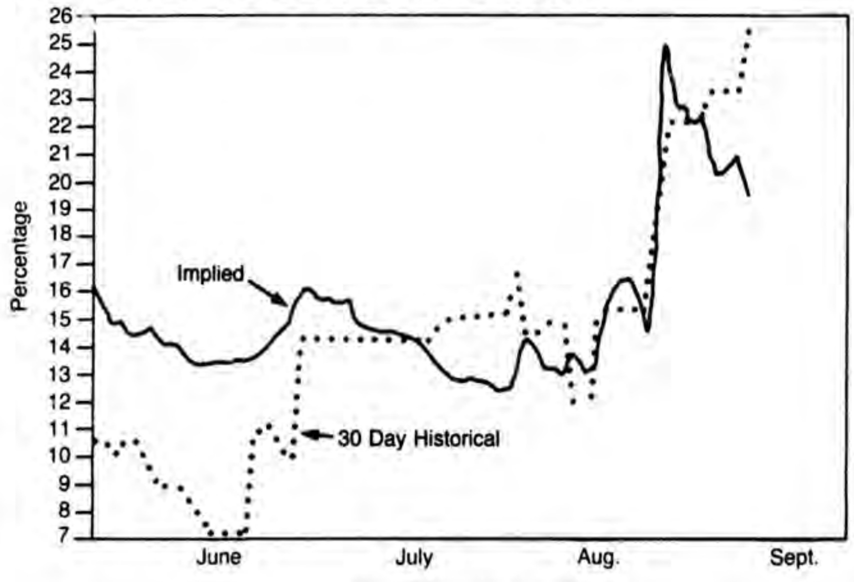
n = number of observations

$x_t = \text{Ln}\left(\frac{P_t}{P_{t}-1}\right)$ where p_t = price at time t

$\bar{x}$ = arithmetic mean of x_t's

Volatility is defined on an annualized basis but it can be easily interpreted for a shorter period. This is more appropriate in the development of a specific crude option trading strategy. The first step in determining a standard deviation is to choose a time period and determine what yearly multiple

Comparison of Historical and Implied Volatilities
The December, 1986 Gold Futures Contract



May 13 through Aug. 22

that period represents. For a weekly standard deviation, the multiple is 52 because there are 52 weeks in a year. The next step is to take the square root of the yearly multiple ($\sqrt{52} = 7.2$). Next, divide the square root of the yearly multiple into the annual volatility. Thus if the volatility is 50%, the weekly standard deviation in percentage terms would be ($50/7.2 = 7.08\%$). This is the expected range within which prices are expected to trade two-thirds of the time. For \$20.00, this would translate to a range of \$1.41 above or below \$20.00.

The same can be done with monthly, daily, or other time increments. (Note: with daily data use 256 trading days in a year. In our example, one daily standard deviation would be $50/\sqrt{256} = 3.125\%$.)

There are two types of volatility that concern the options trader. The most easily understood volatility is historical. Historical volatility is an annualized measure of how active a market has been over a past period. It is calculated from the movement of the underlying futures prices over a specified period. The shorter the time period, the more emphasis or bias that is placed on recent price action. Common periods are 10, 30, and 60 days, but there can be many others. Many traders prefer monthly volatility because it represents a time period that is neither too long nor too short.

The second type of volatility that the options trader should be aware of is implied volatility. This is the expected future volatility that is reflected or implied in an option premium. It can be calculated indirectly by solving for volatility as the unknown and using current premium, distance from the strike, risk-free interest rate, and time to maturity as knowns. There are numerous software packages that allow traders to calculate implied and historical volatility. Some brokerage houses also provide daily volatility information.

The relationship between implied and historical volatilities can vary significantly under certain market situations. The gold volatility chart (on page 14) shows how a monthly historical and implied volatility relate to each other. With crude oil it will also be possible to have considerable divergence between implied and historical volatilities. Such a situation could appear prior to an API report or an OPEC meeting. The futures market could be very quiet, but implied volatility would start to rise because premiums are being bid up in nervous anticipation of a potential sharp reaction.

Forecasting implied volatility encompasses many of the same factors and complexities as price forecasting. Numerous techniques are used to forecast implied volatility. Many traders watch volatility patterns over time and look for extreme levels relative to the current market situation. Others feel that implied should not diverge from historical by more than a certain percentage. Still other mathematical forecasting systems use various weightings of historical and expected volatilities.

How much effort should a trader put forth to monitor and forecast volatility? The floor trader and scalper needs to be constantly aware of volatility because small changes in volatility often determine if a short-term trade will be successful. The hedger or position trader who relies more on major market moves and trades less frequently should be aware of volatility and how it affects premiums, but normally does not try to forecast or monitor volatility. It is important that the hedger or position trader justify the premium expenditure for the amount of protection or profit objective. If the premium is too "expensive" for a particular hedge objective, then the trader can conclude that the current level of implied volatility is too high. Options are insurance instruments that constantly fluctuate in value. ■

NYMEX Public Customer Margins

Below is a fact sheet on public customer original margin requirements for basic option strategies.

Long Call or Long Put

The purchaser of an option pays the full premium. No margin is required.

Naked Short Call or Put

The seller of an option posts the premium for the option plus the original margin on the underlying futures contract less one-half the amount by which the option is out-of-the-money. The total margin must not be less than the sum of the option premium and one-half the original futures margin. If either the short put of the short call is a spot-month option, then the original futures margin is equal to the spot-month futures margin.

Short Call, Long Futures

A call option seller who also holds a long futures contract posts margin as follows:

- For an in-the-money call option: the premium for the option plus the original margin on the futures contract less one-half the in-the-money value of the option. This amount must not be less than the sum of the premium plus the spread margin for the futures contracts.
- For an at-the-money or out-of-the-money call option: the premium plus the original margin on the futures contract. These margin calculations also apply to short put, short futures combinations.

Long Call, Short Futures

The purchaser of an in-the-money or at-the-money call option who also holds a short futures contract posts the premium plus:

- The spread margin on the underlying futures contract, if the delivery months of the futures and option contract are different.
- The greater of the spread margin on the underlying futures contract less the in-the-money value of the option, or zero, if the delivery months of the futures and option contract are the same.

These margin calculations also apply to combined long put, long futures positions.

Short Call, Short Put

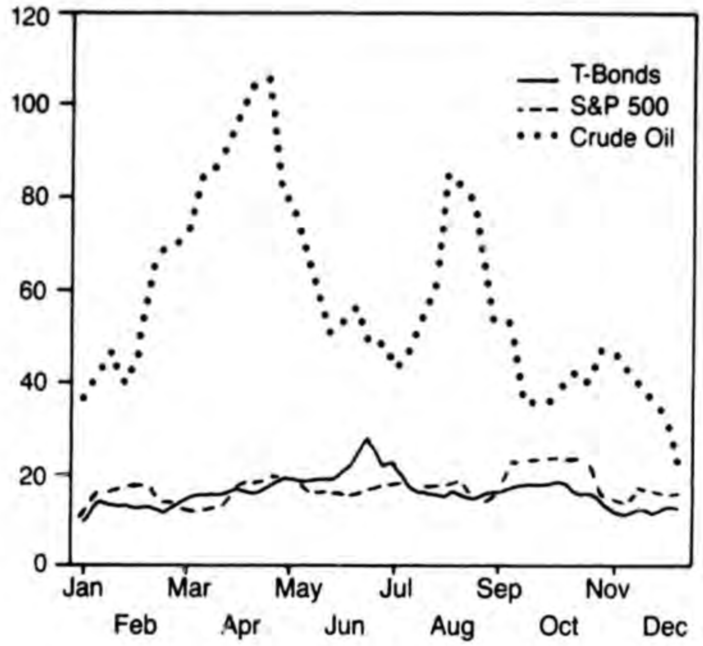
The seller of both a put option and a call option posts the premiums for both options plus:

- If the original margin of both the underlying futures are the same, an amount equal to one original margin.
- If the original margin of both the underlying futures are different, an amount equal to the greater original margin.

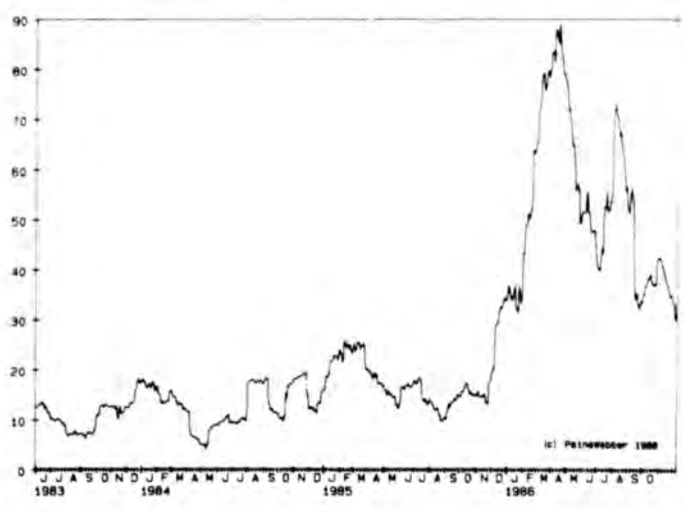
Vertical Spreads

Buying a call (put) and selling a call (put) with different strike prices but with the

Volatility Comparison (1986)
30-Day Volatility (%)



NYMEX Crude Oil 30-Day Volatility
Percentages



same expiration date is called a vertical spread.

- The margin of a net credit spread (that is, the long call strike is greater than the short call strike or the long put strike is less than the short put strike) is the difference between strike prices.
- The margin of a net debit spread (that is, the long call strike is less than the short call strike or the long put strike is greater than the short put strike) is zero.

Calendar Spreads

Buying a call (put) and selling a call (put) with different expiration dates is called a calendar spread.

- If the calendar spread is a net credit spread the margin is equal to the amount by which short option premium exceeds long option premium, plus the difference between the two strike prices. The margin cannot be less than the underlying futures spread margin nor greater than the underlying futures original margin.
- If the calendar spread is a net debit spread the margin required is equal to the underlying futures spread margin.

Conversion

A conversion consists of a long futures, long put and short call. All positions are in the same contract month and both option positions have the same strike price.

- The margin required for a conversion is equal to the amount by which the short option premium exceeds the long option premium.

Reverse Conversion

A reverse conversion consists of a short futures, short put and long call. All positions are in the same contract month and both option positions have the same strike price.

- The margin required for a reverse conversion is equal to the amount by which the short option premium exceeds the long option premium.

Butterfly Spreads

- A long butterfly (that is, long the options at the low and high strike prices and short two options at the middle strike) requires zero margin.
- Margin for a short butterfly (that is, short the options at the low and high strike prices and long two options at the middle strike) is equal to the greatest difference between two adjacent strike prices, not to exceed the original futures margin plus the amount by which the short option premiums exceed the long option premiums.

The NYMEX option contract specifications are detailed in the document, NYMEX Options Contracts, General Provisions, available from the NYMEX Marketing Department, tel. 212/938-2879.

Floor Member Margins

An Exchange Floor Member shall pay original margin on NYMEX options positions carried in his/her account as follows:

Step 1

Apply the appropriate futures spread margin rate to all futures contract spread positions.

Step 2

Determine the number of all long options and the number of all short options. For all short options in excess of long options, apply a margin surcharge of $250 per contract.

Step 3

For all other positions in NYMEX futures contracts and options on such contracts:

a. Assign a risk factor of −1.0 (negative one) to each remaining long futures contract and a risk factor of +1.0 (positive one) to each remaining short futures contract in the account.

b. Assign a negative NYMEX Risk Factor to each long call option and each short put option in the account, and a positive NYMEX Risk Factor to each short call option and each long put option in the account.

c. Determine the sum of the risk factors and the NYMEX Risk Factors described in (a) and (b).

d. Multiply the resultant sum by the margin required for the NYMEX futures contract, disregarding any negative sign in the product.

e. Determine the sum of spot-month futures' risk factors and spot-month options' NYMEX Risk Factors and multiply the resultant sum by the additional spot-month margin required for the underlying NYMEX futures contract as published by the Exchange, disregarding any negative sign in the product.

Step 4

Calculate the margin requirements for all other NYMEX contracts in the account.

Step 5

Determine the sum of the amounts computed pursuant to steps 1, 2, 3 and 4.

Step 6

Subtract the option equity in the account from the value determined in step 5.

Step 7

A positive number determined in step 6 represents the minimum margin required. A negative number determined in step 6 indicates no margin payment required. ■

How to Interpret Option Deltas

JAMES COLBURN
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An important concept in option theory is the sensitivity of option premiums to changes in futures prices, better known as the *delta*. How much can a call option premium be expected to increase if futures prices move $.50/barrel higher? How much may a put decline if futures prices rally $.30/bbl? Knowledge of deltas will help hedgers fine tune desired crude oil price exposure. Hedgers must determine how many options to trade, and at what strike price, to establish the desired protection. Option deltas will be an important factor in determining an optimal option hedge.

Option premiums can be separated into two components: *intrinsic (or exercise)* value and *time (or extrinsic)* value. On November 25, February futures prices settled at $15.04/bbl. The $14 February call must be worth at least $1.04 ($15.04-$14). Otherwise, a strategy of buy calls, sell futures and exercise calls would yield a risk free profit.[1] This $1.04 is the option's intrinsic value. However, on November 25, the February $14 call settled at $1.37, $.33 more than the intrinsic value. This additional value of $.33/bbl. is the time value:

Premium	=	Intrinsic Value	+	Time Value
$1.37	=	$1.04	+	$.33

In Table I, February premiums are separated into intrinsic and time value (note that intrinsic value is either positive or zero, but never negative).

Using the example in Table I, when the futures price is trading at $15.04/bbl, options with intrinsic value (the $14 and $15 calls and the $16, $17 and $18 puts) are said to be *in-the-money*. Options with zero intrinsic value (the $16, $17, $18, and $19 calls and the $13, $14 and $15 puts) are termed *out-of-the-money*. An option with a strike price close to the futures price is *at-the-money*. These classifications will help in our discussion of how option premiums react to changes in futures prices.

Time value is greatest for at-the-money options. On November 25, when February futures were at $15.04, the maximum time value was for the $15 put and call. Time value approaches zero as options become further in-the-money or out-of-the-money.

A graph of time value (Figure I for calls, Figure II for puts) looks like a probability distribution. Figure I shows that the market has attached a relatively low probability that futures prices will move above $19/bbl level by January 2, 1987 (the February option's expiration date). If trading had occurred in the $13 or $12 calls, time value would also approach zero, as the market attaches diminishing probabilities that futures will trade below those strike prices. There is usually a slight upward price bias expectation because crude prices at $15.04 are more likely to increase by that amount than to decline by that amount. Figure II reveals a similar probability distribution for puts.

Option Deltas Defined

Option deltas are defined as the change in the option value divided by the change in the underlying futures price. They measure how sensitive option premiums are to moves in futures prices.[2] For example, a call option with a delta of 0.5 would be expected to increase in value by $0.25/bbl, if futures rallied by $0.50/bbl.

Deep in-the-money options trade almost tick for tick with futures contracts. Consider the $18 put in Table I. With zero time value, the market is pricing the put with a high probability that it will expire in-the-money. This option trades primarily on intrinsic value and has a delta of approximately 1. If futures decrease by $0.25/bbl the option will increase by $0.25.

Deep out-of-the-money options are less sensitive to moves in futures prices. Deltas of these options approach zero, as the market attaches very low probabilities that deep out-of-the-money options will expire in the money. The $19 call, trading at $.04, may not change at all if futures prices move slightly in either direction.

At-the-money options will exhibit deltas of approximately 0.5. A futures move of $.25/bbl would indicate a $.12 to $.13 move in the option premium. At-the-money calls actually have deltas around 0.53 and puts around 0.47 because of a slightly upward

Table I

February Calls (November 25, 1986)

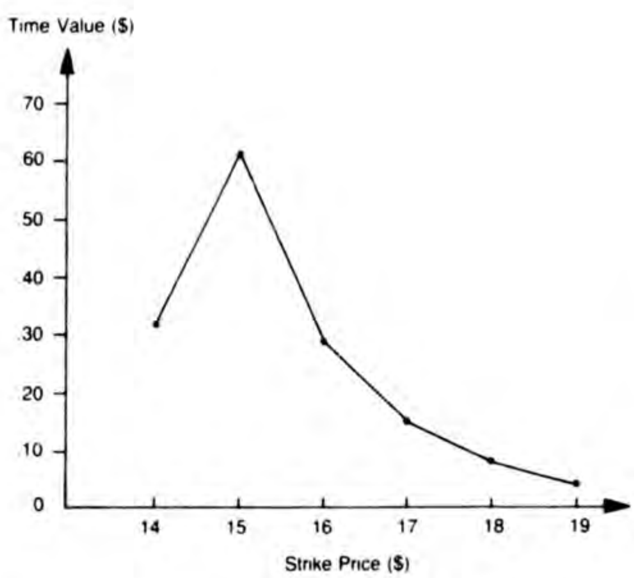
Strike	*Premium*	*Intrinsic*	*Time*	*Classification*
February Futures = $15.04				
$14	$1.37	$1.04	.33	In
15	.65	.04	.61	At
16	.29	.00	.29	Out
17	.15	.00	.15	Out
18	.07	.00	.07	Out
19	.04	.00	.04	Out

February Puts (November 25, 1986)

Strike	*Premium*	*Intrinsic*	*Time*	*Classification*
February Futures = $15.04				
$13	$ .12	$ .00	.12	Out
14	.32	.00	.32	Out
15	.63	.00	.63	At
16	1.25	.96	.29	In
17	2.10	1.96	.14	In
18	2.96	2.96	.0	In

Figure I

February Calls (November 25, 1986)

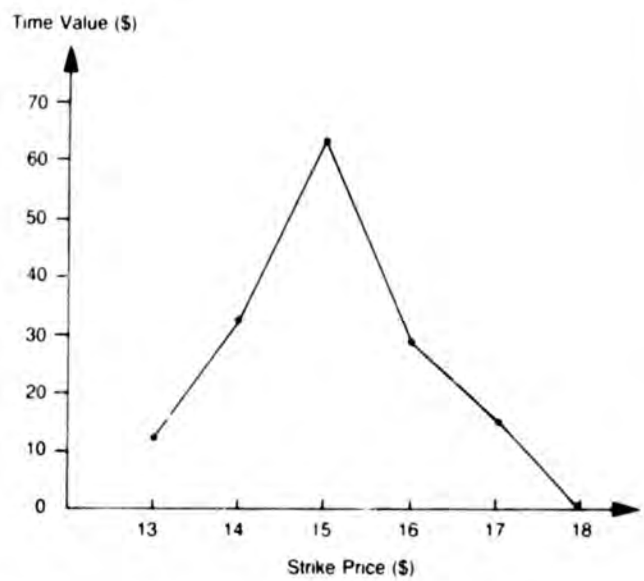


Option Classification: IN AT OUT OUT OUT OUT

Deltas 1 ← .53 → 0

Figure II

February Puts (November 25, 1986)



Option Classification: OUT OUT AT IN IN IN

Deltas 0 ← .47 → 1

bias in the expected price structure.

Applications to Hedging

Knowledge of option deltas is important in implementing and managing an option hedge. For example, if a trader is long 500,000 barrels of crude in the cash market and long 500 $15 February puts, what is the total market exposure? Using plus signs for bullish positions and minus signs for bearish positions, and assuming that cash prices are perfectly correlated with futures, an overall position delta can be calculated. To do so, all positions are converted into futures equivalents. The long cash position is equivalent to +500 deltas, or 500 long futures equivalent positions. The long put position is equivalent to −235 deltas: a 0.47 delta (Figure II) multiplied by 500 contracts with a minus sign (because buy put strategies are bearish). Summing the deltas reveals an overall position delta of +265 deltas, a 265 long futures equivalent position. While this position is still exposed to a downward price move, the exposure is not as great as the cash position without the long puts.

Traders could establish a *delta neutral* position by buying a total of 1,064 puts:

1,064	contracts
× −0.47	delta
−500	futures equivalent positions

The long cash position, + 500 futures equivalents, is now totally covered by 1,064 long $15 puts. To determine how many options per 1,000 barrels are required to totally cover a cash or futures position, calculate the reciprocal of the delta, or in this example, 2.128. (1 ÷ 0.47). Multiply this number by 500 (the futures equivalent position being hedged) to obtain the 1,064 options contracts required to establish a delta neutral position.

Option deltas are dynamic because they vary as futures prices, time to expiration and volatility change. What is a delta neutral position when futures are trading at $15.04/bbl is no longer delta neutral at, say $14.80. If February futures fell to $14.80/bbl, the option delta for the $15 put would increase to 0.53. If the hedger is long 1,064 puts, the futures equivalent position is now −564 (1,064 × 0.53). The overall position becomes −64 [500(cash) −564(puts)] or equivalent to being short 64 futures. To maintain a delta neutral position at the new price, a hedger needs to be long only 943 $15 put options (500 × (1 ÷ 0.53)). He would sell 121 puts to maintain delta neutrality. Long put options deltas become more negative as prices decline and less negative as prices rally. This means that price protection increases as futures prices decline (as a put goes deeper in-the-money, its delta approaches minus one).

Why can't a trader use futures contracts to fine tune? If a delta of an option is 0.53 and a trader is long the equivalent of 500 deltas in the cash market, why not just sell 265 (500 × 0.53) futures to simulate a purchase of 500 puts? Or, if the trader desires a delta neutral position, why not just sell 500 futures? There may be several reasons why the optimal hedge would include options. Option deltas adjust automatically. If a trader is long puts with a delta of 0.47 and prices decline, the position gets shorter and shorter the market. If prices rally, the position gets longer and longer the market. The hedger receives more protection as prices decline, and less protection as prices rally. This occurs without adjusting the option position. A futures position would require constant adjustment to simulate an option hedge. This would be difficult in periods when prices are volatile or if markets open significantly higher or lower than the previous day's close. Also, futures prices aren't affected by changes in volatility and time.

As a measure of market risk, option deltas can help hedgers closely manage price exposure. But it is important to recognize that deltas are always changing. Caution when using delta measures is especially advised when the option is close to expiration. If time left to expiration is near zero, in-the-money options will exhibit deltas of close to one while deltas of out-of-the-money options will approach zero. The sensitivity of option deltas at expiration can be appreciated if one considers a futures price trading near a call options strike price. If prices rally slightly above the strike price, the option is in-the-money; the delta quickly approaches one. If prices trade below the strike price, the call option's delta quickly approaches zero. Rapidly changing deltas can confound a hedger's attempt to manage price risk. The need to monitor deltas at option expiration time is crucial. ■

1. See "The Role of the Market Maker."

2. Deltas can be calculated from exact option pricing models. For example, the Black model gives the value of a call option as:

$$C = e^{-rt}\,[f\,N(q_1) - s\,N(q_2)]$$

and the call option's delta is:

$$\frac{\partial C}{\partial f} = e^{-rt}\,N(q_1)$$

where

$$q_1 = \frac{\ln(f/s) + (6^2/2)\,t}{6\sqrt{t}}$$

$$q_2 = q_1 - 6\sqrt{t}$$

C = value of the call
r = short-term interest rate
t = time to expiration
f = futures price
s = option strike price
6 = volatility measure
e = base of natural logarithm
N( ) = cumulative normal density function
ln = natural logarithm

Crude Oil Options: The Energy Speculator's New Tool

BERT BECKMAN
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Crude oil options bring the highly volatile crude oil market within reach of the smaller speculator, and open new trading strategies for the experienced professional. Options on futures are relatively new to the market. Banned by Congress in 1936, the first pilot programs initiated options on futures trading in 1982 and have enjoyed tremendous success. Futures options are most successful when their limited-risk nature is applied to volatile, uncertain markets. The crude oil futures market is an example of a market ripe for the flexibility of options while providing the liquidity necessary for success.

Crude Oil Options

Crude oil options are limited-risk trading instruments that convey the holder of the option the right to buy (if a call) or sell (if a put) crude oil futures at a specified strike price up until the expiration date of the option contract. Buy call strategies, similar to long futures, are bullish positions while buy put strategies and short futures are bearish positions. The purchaser of the option pays a premium to the writer of the option contract for this right. The option buyer's risk is limited to the premium paid, and the buyer is not subject to margin calls. The option seller risks market losses and can earn, at most, the premium received. At expiration, the call option is worthless if the crude oil futures trade for less than the strike price of the call and a put option is worthless if the futures trade for more than the strike price of the put.

The option premium generally fluctuates less than the underlying futures price. In options terminology, the absolute value of an option's *delta* is usually less than one. The *delta* measures the amount by which a premium changes with respect to a change in the futures price. The deeper in-the-money an option is, the higher its delta, and the more the option position will resemble an outright futures position. A call option is termed *in-the-money* if the futures price is above the strike price and in the case of a put, if the futures price is below the put's strike price.

A crude oil option contract gives the holder the right to buy/sell a crude oil futures contract, representing 1,000 barrels. If a crude oil option increases in value by $1/barrel the option will increase in equity by $1,000. A crude oil option priced at $3.50/barrel carries a premium of $3,500. Options premiums can be estimated by mathematical models such as the Black model. In the examples that follow, option premiums were simulated for historical trading opportunities to examine how crude oil options might have performed.

Market Outlook: Bullish

Following several unsuccessful and uneventful OPEC meetings during the first half of 1986, the late July conference was widely expected to end without any substantive agreement. In anticipation of the meetings, the crude oil market generally traded sideways to lower in a volatile fashion. However, to the surprise of most observers, an agreement to curtail output was reached. This development quickly translated into a dramatic crude oil price advance from around $11.50/bbl to the $15-$16 range within a matter of a few days — a move of $4,500-5,500 per futures contract.

Before crude oil options were launched on November 14, the only strategy available was a long position in crude oil futures (or possibly a spread position). For public customers, $2,000 in original margin deposit must be put up on a futures contract and variation margin must be posted if losses are incurred. The risk is "unlimited" because the investor can lose more than the initial equity required for the trade. The trader profits by $1,000 for each $1/barrel rise in the price of crude and loses $1,000 for each $1/barrel drop.

As discussed above, buy call options yield profits on bullish moves while limiting the trader's risk to the initial premium paid. Many call options are available at various strike prices above and below "the at-the-money". As shown in Table 1, the lower the strike price, the higher the premium of the option, because lower strike prices give the trader the option to buy crude oil futures at a lower price. Conversely, the higher the strike price, the cheaper the option.

Which strike price is best? This depends on the particular investment objective. Table 1 includes three different call options, with various strikes, along with the performance of each over the investment period. The more expensive, in-the-money calls, earn more in terms of dollars than the cheaper, less-in-the-money calls. In the case of the $12/bbl call, the dollar profit is almost identical to the futures position but the risk is limited. In comparing the performance of the options, note that the rate of return is greatest on the out-of-the-money call. Of course, the risk of the option expiring worthless is also greatest for an out-of-the-money call.

Market Outlook: Bearish

The first three quarters of 1985 proved to be a frustrating period for bearishly inclined traders of crude oil. Worldwide consumption was declining after a brief improvement in 1984 and output was being maintained at a relatively high level. The price picture changed dramatically during the fourth quarter as Saudi Arabia shifted its pricing and production strategies. Market share was suddenly given priority over official prices. The price impact was substantial as crude oil futures collapsed from over $31/bbl at the end of November to as low as $10/bbl by early April 1986.

To take advantage of a potential break in crude prices, the bearish trader could have shorted the futures market or bought put options (had they been available). The trader would have had to make a similar choice as in the preceding bullish example: determining which strike to choose.

Once again, there is a risk-return tradeoff.

The in-the-money option has the greatest dollar cost but returns the highest dollar profit. The deep-out-of-the-money put has the greatest risk of expiring worthless and is the least expensive. But it shows the best rate of return.

Market Outlook: Bullish and Bearish

A unique aspect of crude oil options is the straddle position, consisting of the purchase of both a put and a call. If a put and call with the same strike price are purchased, the position is called a *straddle* while a position with different strikes is known as a *strangle* or *combo* position. Both allow the buyer to profit on swings in the price of crude oil without having to predict market direction. In order for the straddle position to make a profit, the futures price must move up or down by a 'breakeven' amount. A straddle is considered a 'volatility' trade which profits from price movement in any direction, and incurs losses in stable markets. The maximum loss is limited to the total of the call and put premiums paid for the position. However, the profit potential of the put and call is unlimited. As the price of crude increases, the call increases in value. As crude oil prices decline, the put increases in value. Important industry news regarding, for example, OPEC meetings or weekly API statistics, may present opportunities for profitable straddles by allowing the trader to profit on market volatility without calling market direction.

In the simulations, volatility was assumed to be constant throughout the period for illustrative purposes only. In fact, volatility levels increased during both sample periods. By February 5, 1986 the 30 day historical volatility had risen to 43% from 30% in mid-December 1985 and by August 5, 1986 it had risen to 70%. It is reasonable to assume that in both examples, returns to the investor would have been even greater than was simulated since option premium levels increase as volatility increases. This added benefit was deleted from calculations to simplify the examples and to focus on price objectives.

In conclusion, options are most effective when sharp moves are expected, or unlimited margin risk cannot be tolerated by the trader. As time passes, options lose time premium and their effectiveness. The staying power that they provide can, however, keep the trader in the market when adverse losses might close out a futures trade. The key to successful options trading is understanding the factors that determine their profitability and affect their performance. ■

TABLE 1

Simulation of October Futures and Call Options

	Futures	*$12-call*	*$13-call*	*$14-call*
6/27/86	$12.28	$ .86	$ .44	$ .20
7/14/86	10.58	.14	.04	.01
8/5/86	15.91	3.90	2.90	1.94
Max Cost	$3,700.00*	$860.00	$440.00	$200.00
Profit	$3,630.00	$3,040.00	$2,460.00	$1,740.00
% Return	N.C.	353%	559%	870%
Max % Loss	N.C.	83%	91%	95%

TABLE 2

Simulation of April Futures and Put Options

	Futures	*$26-put*	*$22-put*	*$20-put*
12/17/85	$23.87	$2.88	$ .74	$ .26
12/30/85	25.17	1.97	.36	.09
02/05/86	16.50	9.45	5.47	3.50
Max Cost	$3,300.00*	$2,880.00	$740.00	$260.00
Profit	$7,370.00	$6,570.00	$4,730.00	$3,240.00
% Return	N.C.	228%	639%	1246%
Max % Loss	N.C.	31%	51%	65%

TABLE 3

Simulation of October Futures and Options

		Straddle	*Strangle*	*Strangle*
	Futures	*12C, 12P*	*13C, 11P*	*14C, 10P*
7/1/86	$12.28	$1.57	$ .78	$ .34
7/14/86	10.58	1.76	.91	.37
8/5/86	15.91	3.90	2.91	1.95
Max Cost	$3,700.00*	$1,570.00	$780.00	$340.00
Profit	$3,630.00	$2,330.00	$2,130.00	$1,610.00
% Return	N.C.	148%	273%	473%

TABLE 4

Simulation of April Futures and Options

		Straddle	*Strangle*	*Strangle*
	Futures	*24C, 24P*	*22P, 26C*	*20P, 28C*
12/17/85	$23.70	$3.10	$1.51	$ .62
12/30/85	25.15	3.12	1.55	.68
02/05/86	16.33	7.63	5.64	3.67
Max Cost	$3,450.00*	$3,100.00	$1,510.00	$620.00
Profit	$7,370.00	$4,530.00	$4,130.00	$3,050.00
% Return	N.C.	146%	273%	491%

* Maximum cash for initial and variation margins. (Margins would be higher for spot-month contracts.)

N.C. — not comparable to option profit/loss.

Time and Volatility

Option premiums are determined by several factors. Market, prices, strike prices, expected volatility, time left to expiration and interest rates combine, as in a kaleidoscope, to determine option premiums. Not only do these many factors determine premium levels, but these factors are also always changing. Isolating the effects of each variable requires the use of an exact option pricing model. In this article the Black model[1] is used to focus on two option pricing factors: volatility and time.

The effect of changing futures prices on option premiums is straightforward. Call premiums increase as prices rally and decrease as prices decline. Conversely, put premiums increase with declining prices and decrease with increasing prices.[2] Changes in expected volatility or changes in time until expiration, however, will sometimes influence option premiums more than a move in the underlying futures price.

Time

The less time remaining in an option's life (that is, the less time an option buyer has the right to exercise), the less value an option will have. More time remaining implies that an option has a higher probability of becoming in-the-money. The market charges a higher premium for this extra time.

The rate of premium decay changes in relation to diminishing time remaining until option contract expiration. Premium decay per day is much more rapid on an option with two weeks left to expiration than the daily decay of an option with two months left. Figure I illustrates this phenomenon.

Let's examine the time effects on the $17 (in-the-money), $18 (at-the-money) and $19 (out-of-the-money) call options assuming that futures prices are $18, volatility is 35%, and interest rates are 6%. By plugging these assumptions into the option model and then changing the time to expiration, a premium decay curve is outlined.

The $17 and $19 call options illustrate flatter decay curves than the $18 call because the out-of-the-money and the in-the-money options have less time value. Note that the $17 call has $1 of intrinsic value at expiration, while the $18 and $19 calls expire worthless. The $18 call shows how much more rapidly premium decays with, for example, one month left than with two or three months left. Premiums decline most rapidly within the last two weeks of an option's life.

An option trade which takes advantage of the rapid time decay in the nearby option is called a calendar or time spread. Selling nearby options and buying further-out options of the same type is an attempt to remove any effect of a price change while isolating and taking advantage of the rapid decay of the nearby premium. In early February, for example, a trader could sell $18 April calls and buy May or June $18 calls. This strategy, however, is confounded in crude oil markets because the underlying futures spreads are volatile. Adverse movement in the futures spreads could cause both option legs to show losses.

Time works against long option positions and works in favor of short option positions. Traders who are excessively long premium need to monitor time decay in order to effectively lift or roll positions into deferred months.

Volatility

An important piece of information extracted from options markets is the market's expectation of future volatility. If futures prices are a "best" guess of future spot prices, option premiums are a "best" guess of the standard deviation of the expected price changes. If the market expects high price volatility, option premiums will be high. If the market expects low price movement, option premiums will be low.

Using our option pricing model, let's now isolate the volatility effects on option premiums. Assuming futures prices are at $18, interest rates 6% and time to expiration is 90 days, an $18 call with three expected volatility scenarios are examined: 30%, 35% and 40%.[3] Figure II clearly shows the effect of changes in expected volatility on option premiums (intrinsic value was removed from option premiums, leaving only time value for illustrative purposes).

Volatility expectations are always changing. Before OPEC meetings, option premiums will tend to inflate as the market builds into premiums higher volatility expectations. If the market moves sideways for a period of time, declining expected volatility might deflate option premiums. However, option premiums will be determined by market expectations of future volatility, not necessarily by historic patterns or measures of volatility. Thus changes in volatility expectations may affect option premiums even without a move in the underlying futures price.

Increasing volatility works in favor of long option positions while decreasing volatility favors short option positions. A trader who is excessively short options must be wary of "pops" in volatility. And a trader might not wish to buy options when the market has high volatility expectations built into the premiums.

Summary

The constant tug-of-war between volatility and time can have dramatic effects on option premiums. Time always wins out: an option's time value is zero at expiration. But changes in the market's expectation of future volatility will change option premiums over the life of an option. The trader who understands the relationships among option variables will be better equipped to identify optimal hedging strategies. ■

[1] See Fischer Black, "The Pricing of Commodity Contracts," *Journal of Financial Economics*, 3 (January-March 1976), 167-179.

[2] A more precise measure of how a particular option will react to a move in futures price is called an option's delta. See "How to Interpret Option Deltas," pages 21-23.

[3] See "Volatility and Option Valuation," pages 18-19, for a more detailed discussion on interpreting volatility measures.

Figure 1

Time Decay

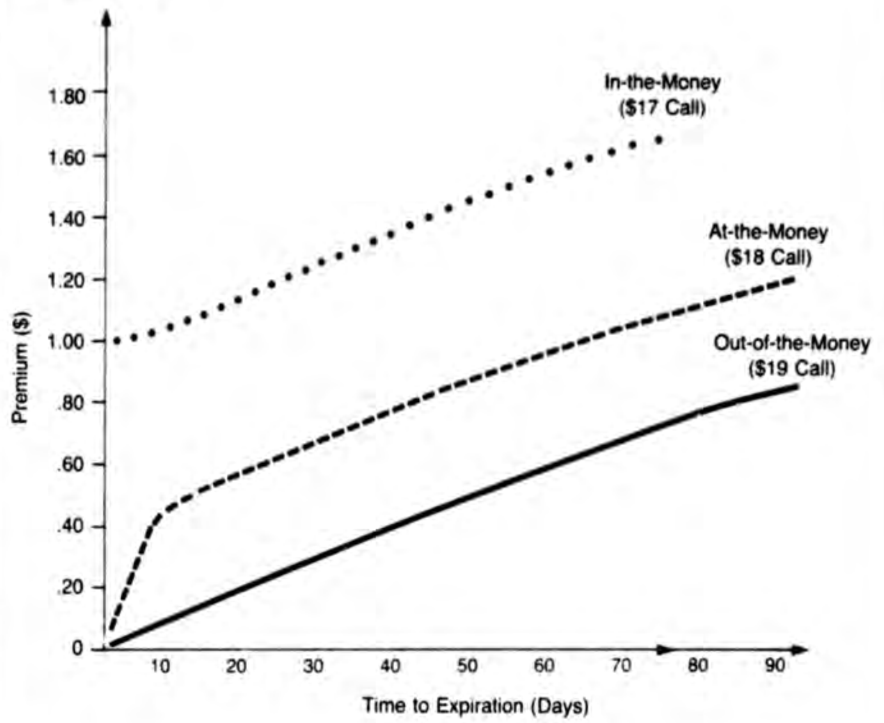
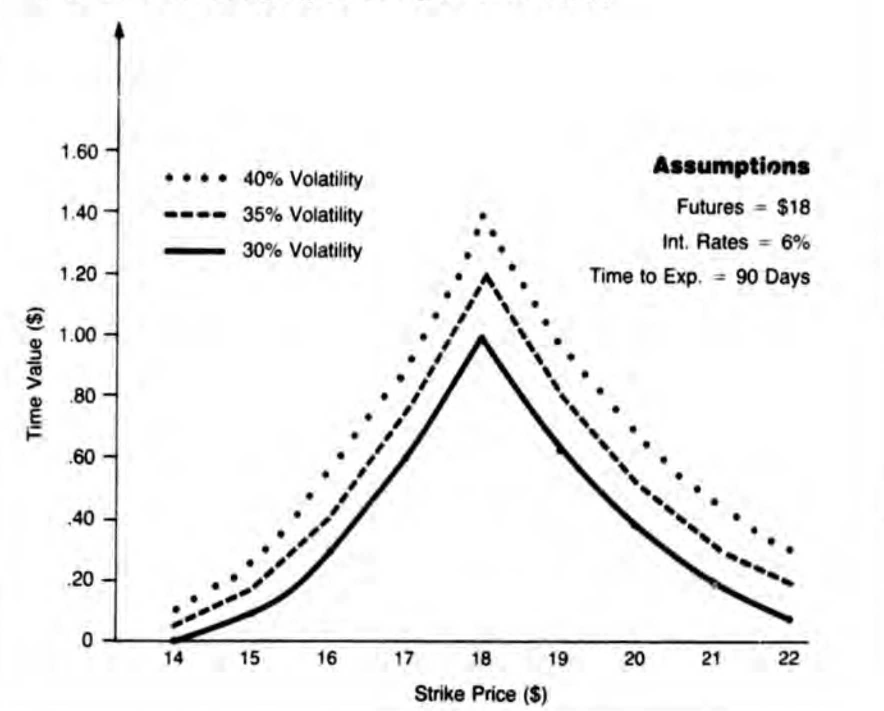


Figure 2

The Effect of Changing Volatility on Time Value



Six Basic Options Strategies

Options on crude oil futures have experienced rapid growth in terms of volume and open interest since their introduction on the NYMEX trading floor on November 14. This popularity reflects the great versatility of these instruments. Options permit traders to construct positions to suit virtually any view about market direction, timing and volatility, while tailoring the level of risk.

Presented here are six basic strategies along with their profit and loss profiles. Time is a critical factor in option valuation. This is illustrated in the accompanying charts which show the profit/loss profiles both at expiration and with 90 days remaining to expiration. These assumptions were entered into the "Black" model to calculate theoretical option premiums:

- Futures price of $16 per barrel (when position established)
- Volatility of 35 percent
- Interest rate of 6 percent

In each example, *debits* are monies paid out by the buyer of the position and *credits* are cash funds received by the seller (or writer) of the option position. The *delta* is the amount by which an option premium will change relative to a change in the underlying futures price.

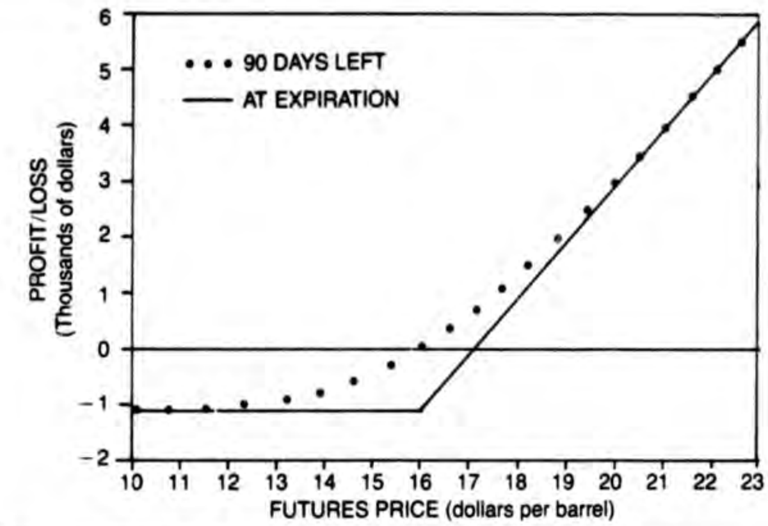
Long Call:
A long call strategy gives the holder the right, but not the obligation, to buy futures at $16 per barrel for a specific period of time. This position profits if prices rally. Profits are unlimited on the upside; total risk is limited to the premium paid regardless of where futures trade. This trade is helped by increasing volatility, while the passage of time works against it. Hedgers can use buy call strategies to lock in purchase prices and still benefit from market declines.

Short Call:
In exchange for the premium received, the writer of a call option is obligated to sell the underlying futures at $17 per barrel, any time prior to expiration, if assigned. This position maximizes profits if prices are at $17 or lower at expiration. Profits are limited to the premium received, while risk is unlimited on the upside. Declining volatility is favorable to the trade, as is the passage of time.

Long Call

Position	*Premium*	*Dollar Premium*	*Delta*
Buy 1 $16 Call	$1.09	$1,090	+.53

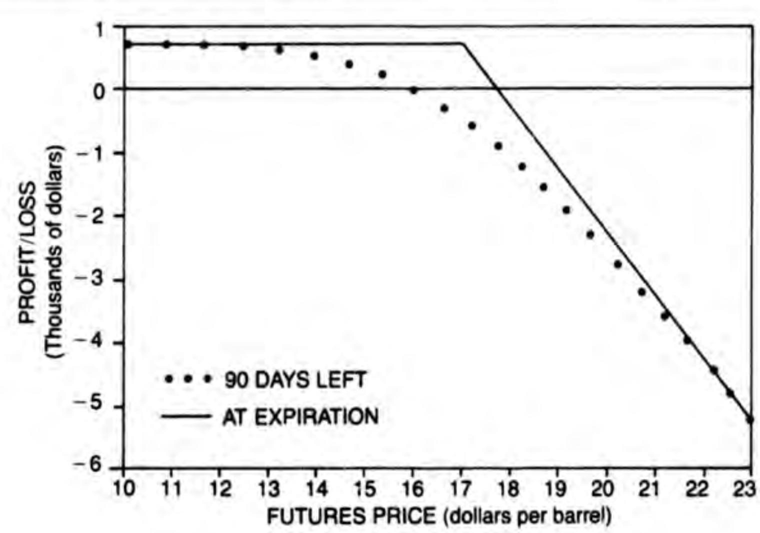
Maximum Risk:	$1.09 per barrel or $1,090 per contract
Maximum Profit:	Unlimited on the upside
Breakeven Futures Price:	$17.09



Short Call

Position	*Premium*	*Dollar Premium*	*Delta*
Sell 1 $17 Call	$0.70	$700	−.53

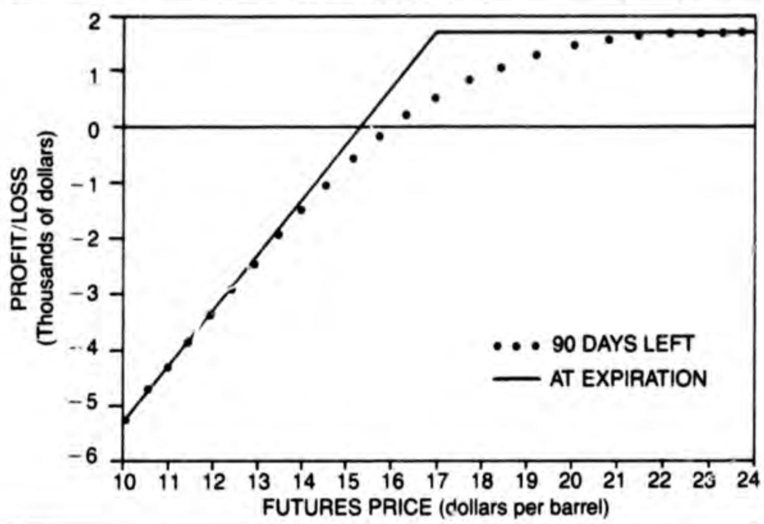
Maximum Risk:	Unlimited on the upside
Maximum Profit:	$0.70 per barrel or $700 per contract
Breakeven Futures Price:	$17.70



Covered Call

Position	Premium	Dollar Premium	Delta
Buy 1 $16 Futures			+1.00
Sell 1 $17 Call	$0.70	$700	− .40
Net Credit	$0.70	$700	
Net Delta			+ .60

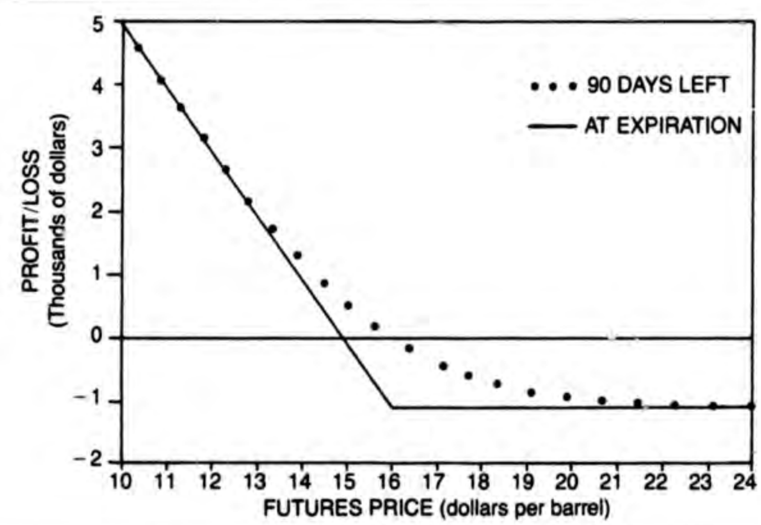
Maximum Risk:	Unlimited on downside
Maximum Profit:	$1.70 per barrel or $1700 per covered call
Breakeven Futures Price:	$15.30



Long Put

Position	Premium	Dollar Premium	Delta
Buy 1 $16 Put	$1.09	$1,090	−.47

Maximum Risk:	$1.09 per barrel or $1,090 per contract
Maximum Profit:	Unlimited on the downside
Breakeven Futures Price:	$14.91



Covered Call:
Calls are sold against a long futures position. Premium income is earned if futures move sideways to slightly higher or lower. This position is bullish (note the +.60 delta) and is helped by lower volatility and the passage of time. Profits are limited on the upside; losses are unlimited as prices decline. The premium received from the sale of the put acts as a hedge for the futures position as prices decline.

Long Put:
This position gives the holder the right but not the obligation to sell futures at $16 per barrel for a specific period of time. This position profits if prices decline. Profits are unlimited on the downside; total risk is limited to the premium paid. Increasing volatility favors this position while the passage of time works against this trade. Hedgers can use buy-put strategies for unlimited downside protection, yet still participate in market rallies.

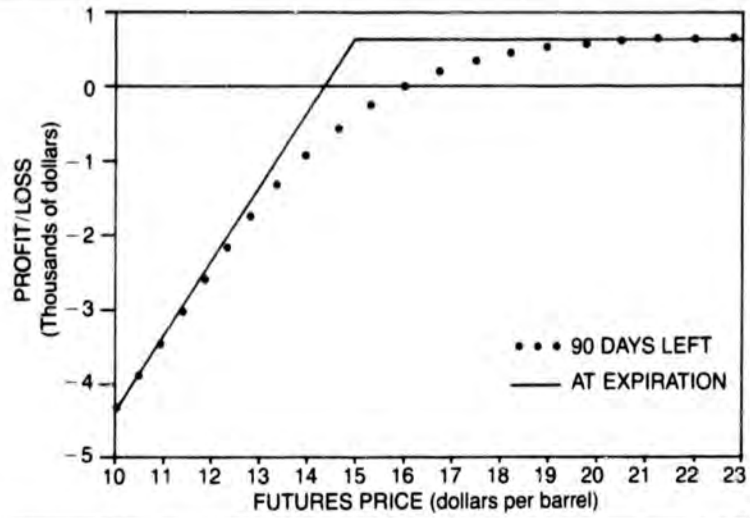
Short Put:
In exchange for the premium received, the writer of a put option is obligated to buy the underlying futures at $15 per barrel, any time prior to expiration, if assigned. This position realizes maximum profits if futures are trading at $15 or above at expiration. Profits are limited to the premium received, while risk is unlimited on the downside. Declining volatility is favorable to this trade, as is the passage of time.

Long Straddle:
A long straddle is a combination of long puts and long calls with the same strike price and same expiration date. Long straddles are also called long volatility trades because the position profits when the market moves sharply in either direction. Profits are unlimited in either direction. Losses are limited to the total premium paid. Maximum risk is $2,180 and occurs if futures are at $16 per barrel at expiration. This trade might be established ahead of a scheduled release of economic information or before an OPEC meeting, in anticipation of increased market volatility.

Short Put

Position	*Premium*	*Dollar Premium*	*Delta*
Sell 1 $15 Put	$0.64	$640	+.32

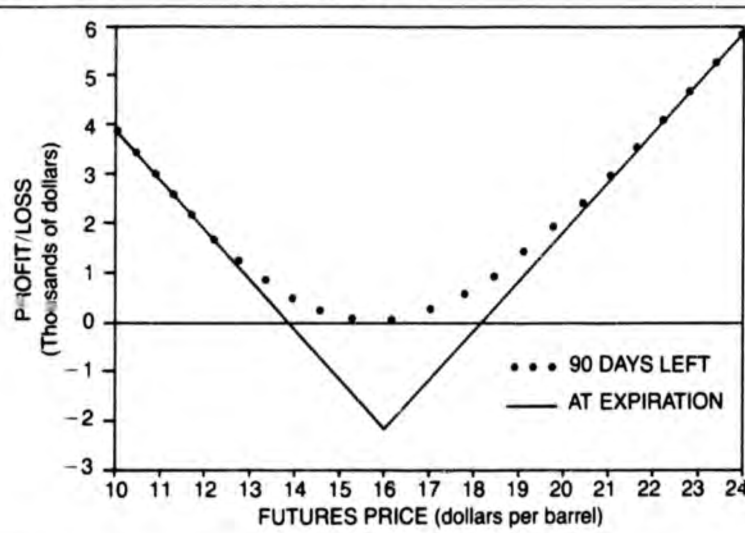
Maximum Risk:	Unlimited on the downside
Maximum Profit:	0.64 per barrel or $640 per contract
Breakeven Futures Price:	$14.36



Long Straddle

Position	*Premium*	*Dollar Premium*	*Delta*
Buy 1 $16 Call	$1.09	$1,090	+.53
Buy 1 $16 Put	$1.09	$1,090	−.47
Net Debit	$2.18	$2,180	
Net Delta			+.06

Maximum Risk:	$2.18 per barrel or $2,180 per straddle
Maximum Profit:	Unlimited in either direction
Breakeven Futures Prices:	$18.18 and $13.82

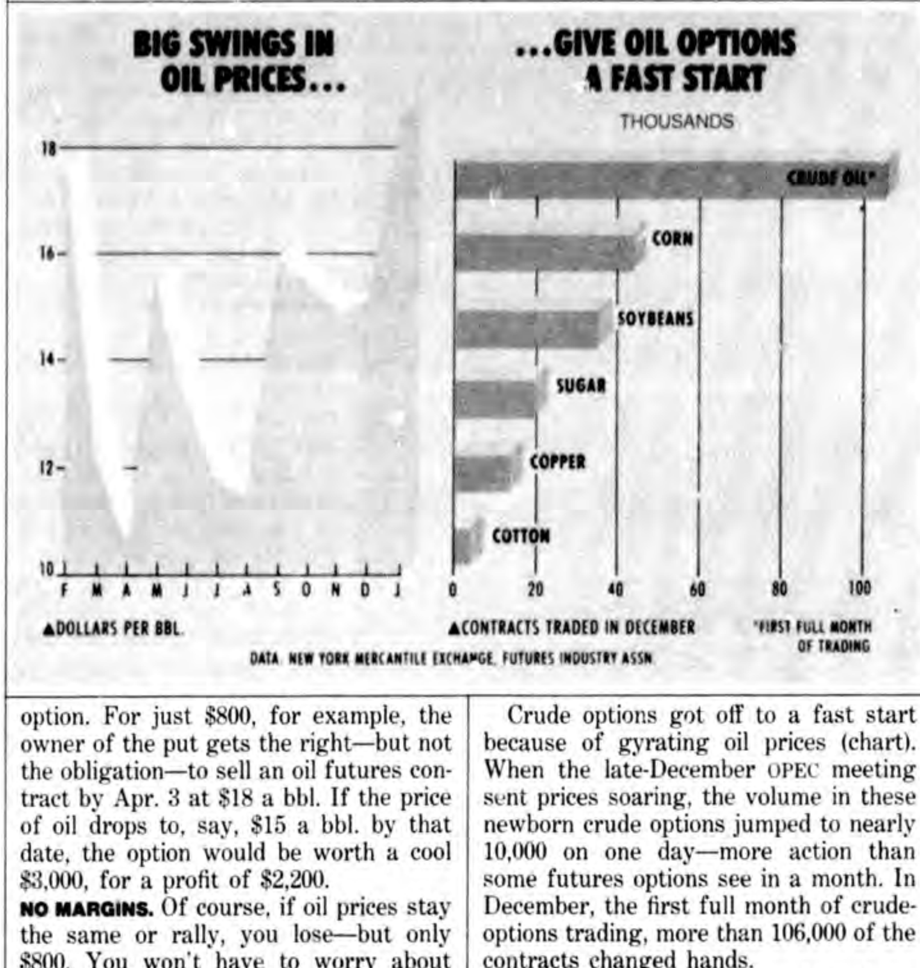


THE HOT NEW LOW-STAKES PLAY IN OIL

CRUDE OPTIONS, WHICH JUST ARRIVED ON NYMEX, ARE CHEAPER, LESS RISKY, AND MORE FLEXIBLE THAN FUTURES

The conventional wisdom has it that OPEC is back in the driver's seat and oil prices are firming for the long, cold winter. But if you don't buy that line and you've got some spare cash for a roll of the dice, you can play the hottest game in town. It's options on crude-oil futures, and for the stout-hearted it could produce some nifty returns for little money and not much risk.

Here's how it works. If you think oil prices will tumble from the current \$19 a bbl. in the next few months, buy a put option. For just \$800, for example, the owner of the put gets the right—but not the obligation—to sell an oil futures contract by Apr. 3 at \$18 a bbl. If the price of oil drops to, say, \$15 a bbl. by that date, the option would be worth a cool \$3,000, for a profit of \$2,200.



NO MARGINS. Of course, if oil prices stay the same or rally, you lose—but only \$800. You won't have to worry about paying margin charges as the market moves against you. Unlike futures, options aren't margined. Suppose the price of the oil were to go to \$22 a bbl. Selling the actual futures would result in a loss of about \$4,000. The potential loss could be greater if oil prices rocketed higher.

The new oil game has caught the speculators' fancy. In the two months since crude options began trading on the New York Mercantile Exchange, volume has averaged about 5,000 contracts a day. That's peanuts compared with the 33,000 oil futures contracts that trade on NYMEX in the average day, but one day crude options may be just as popular as the underlying futures. "I've been astounded at the acceptance so far," says Randall K. Rothenberg, vice-president for options at Preston Head Ltd. "Crude options could trade as heavily as futures within three to five years."

Crude options got off to a fast start because of gyrating oil prices (chart). When the late-December OPEC meeting sent prices soaring, the volume in these newborn crude options jumped to nearly 10,000 on one day—more action than some futures options see in a month. In December, the first full month of crude-options trading, more than 106,000 of the contracts changed hands.

Options on other futures have been trading only since 1982. The first were Treasury bonds, sugar, and gold, and there are now 34 listed contracts for options on futures. A few have generated little interest. But generally they're popular. By 1985 more than 20 million contracts were traded; last year total volume jumped 58.5%, to nearly 32 million.

Oil traders are quickly discovering that trading options can be not only cheaper and less risky than trading futures but also more flexible. With options, for instance, traders can buy price insurance at a fixed cost to protect against adverse price moves without giving up the potential profits of favorable price moves. A trader with inventory buys put options to protect against a slide in oil prices. Or he sells call options—the right to buy futures—against inventories to earn premium income.

STILL STUNNED. Trading in crude options will be fueled even more as the oil industry begins to use these instruments. It was the industry's participation in oil futures that finally put those futures on the map. Indeed, when NYMEX listed its crude-oil futures barely four years ago, most experts said the contracts were doomed. After all, they had been tried earlier in London and Chicago and failed miserably. By 1985 professional traders had pushed volume up to nearly 16,000 contracts a day, but it doubled in 1986 when energy companies became the dominant players in crude futures.

Still stunned by last year's plummeting crude prices, oil producers are desperate for new ways to protect themselves. As a result, BP and a number of oil-producing companies are looking at crude options, says Robert G. Gunnin, manager of hedging for BP North America Petroleum Inc. in Houston. Now that oil prices appear to be rising, the company is using a strategy of writing covered calls: The company sells call options, which are backed by physical inventory. The value of the crude is protected somewhat by the premium the company takes in. "That strategy," says Gunnin, "has been very profitable for us."

Refiners and oil-consuming companies, and even oil-producing states, could be major users of options. In the simplest hedging programs, producers can protect their inventories against drops in crude-oil prices by buying puts. Refiners, on the other hand, can buy calls to protect against higher oil prices that would erode profits. Oil-dependent states such as Texas, Louisiana, or Oklahoma may choose to use crude options to hedge against unanticipated declines in oil production tax revenues.

Energy banks and other financial institutions in the Southwest are showing their customers how to use options to lock in prices that will guarantee a certain level of revenues or help protect the value of oil reserves. Of course, it will take a couple of years before all these trends take hold. But when they do, crude-oil options may become the star of the options exchanges.

By Terri Thompson in New York

ROB DOYLE/BW

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Financial Instruments For Today's Oil Industry

Price volatility is changing today's oil industry. Financial planning is now more art than science. Competition is intense. And all segments of the business—producers, refiners, marketers, end-users—are responding to market forces as never before.

In this dynamic environment, managing price risk is a top priority. That's why companies throughout the oil industry are using financial instruments like NYMEX futures and options contracts to reduce the effect of price changes on operating results.

NYMEX futures contracts allow these companies to fix oil prices in advance of actual purchase or sale. NYMEX options contracts permit them to insure against adverse price fluctuations and still capture some benefit from favorable moves.

Both help companies manage risk by minimizing the uncertainty of future oil prices.

Energy futures and options. Two ways to cushion the impact of oil price volatility. From NYMEX—a leader in financial instruments for today's oil industry.

NYMEX—The Energy Exchange

FOUR WORLD TRADE CENTER, NEW YORK, NY 10048
212/938-2879

212-938-2622
Telex 12491

James T. Colburn
Product Manager — Options

NEW YORK MERCANTILE EXCHANGE
Four World Trade Center, New York, N.Y. 10048

NEW YORK MERCANTILE EXCHANGE

Crude Oil Options

NEW YORK MERCANTILE EXCHANGE FOUR WORLD TRADE CENTER NEW YORK, N.Y 10048 212-938-2222

Option Terms

- Put / Call
- Buy / Write
- Exercise (Striking) Price
- Expiration
- Premium
- Intrinsic Value
- Time Value

Long/Short Options

Long (Buy)	*Short (Sell)*
Pay Premium	Receive Premium
Have Rights	Have Obligations
Risk Limited to Premium	Risk Unlimited
Profit Unlimited	Profit Limited to Premium
	Require Margin

Long/Short The Market

Long (Buy)	*Short (Sell)*
Buy Futures	Sell Futures
Sell Puts	Buy Puts
Buy Calls	Sell Calls

Option Description

Option	*Future*
Buy/Sell	Buy/Sell
Quantity	Quantity
Premium	Price
Month (Expiration)	Month
Strike Price	
Put/Call	

Disposition of Option

1. Close Out
2. Exercise
3. Lapse

Option Pricing Factors

1. Volatility
2. Time
3. Interest Rates
4. Market Price Relative to Exercise Price

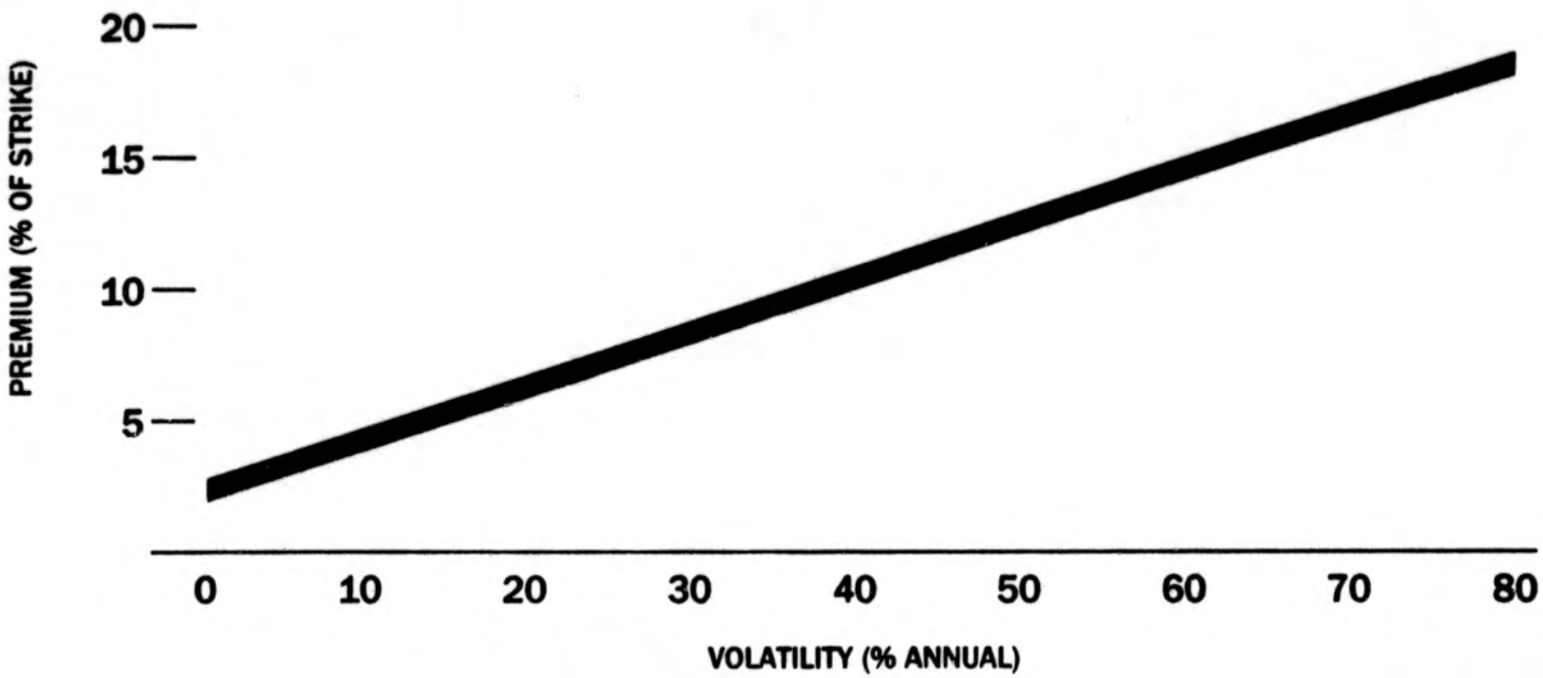
NEW YORK MERCANTILE EXCHANGE: CRUDE OIL OPTIONS

Premiums for Three-Month Options — Futures at $15

Exercise Price	Call Premium	Put Premium
$14	$2.05	$1.05
15	1.50	1.50 per barrell
16	1.10	2.10

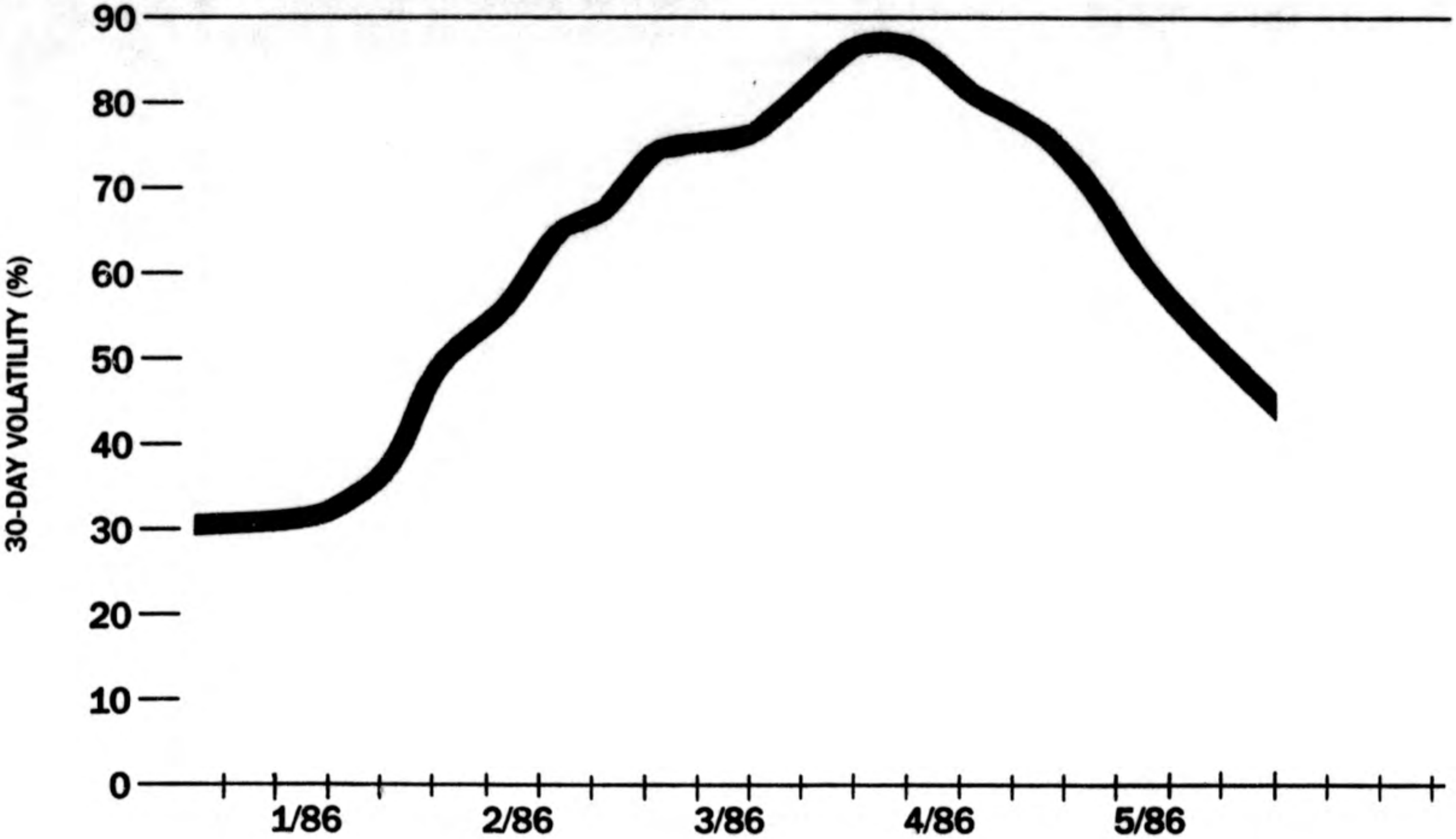
Estimated buyer traded options

Volatility


20
15
10
5
PREMIUM (% OF STRIKE)
0
10
20
30
40
50
60
70
80
VOLATILITY (% ANNUAL)

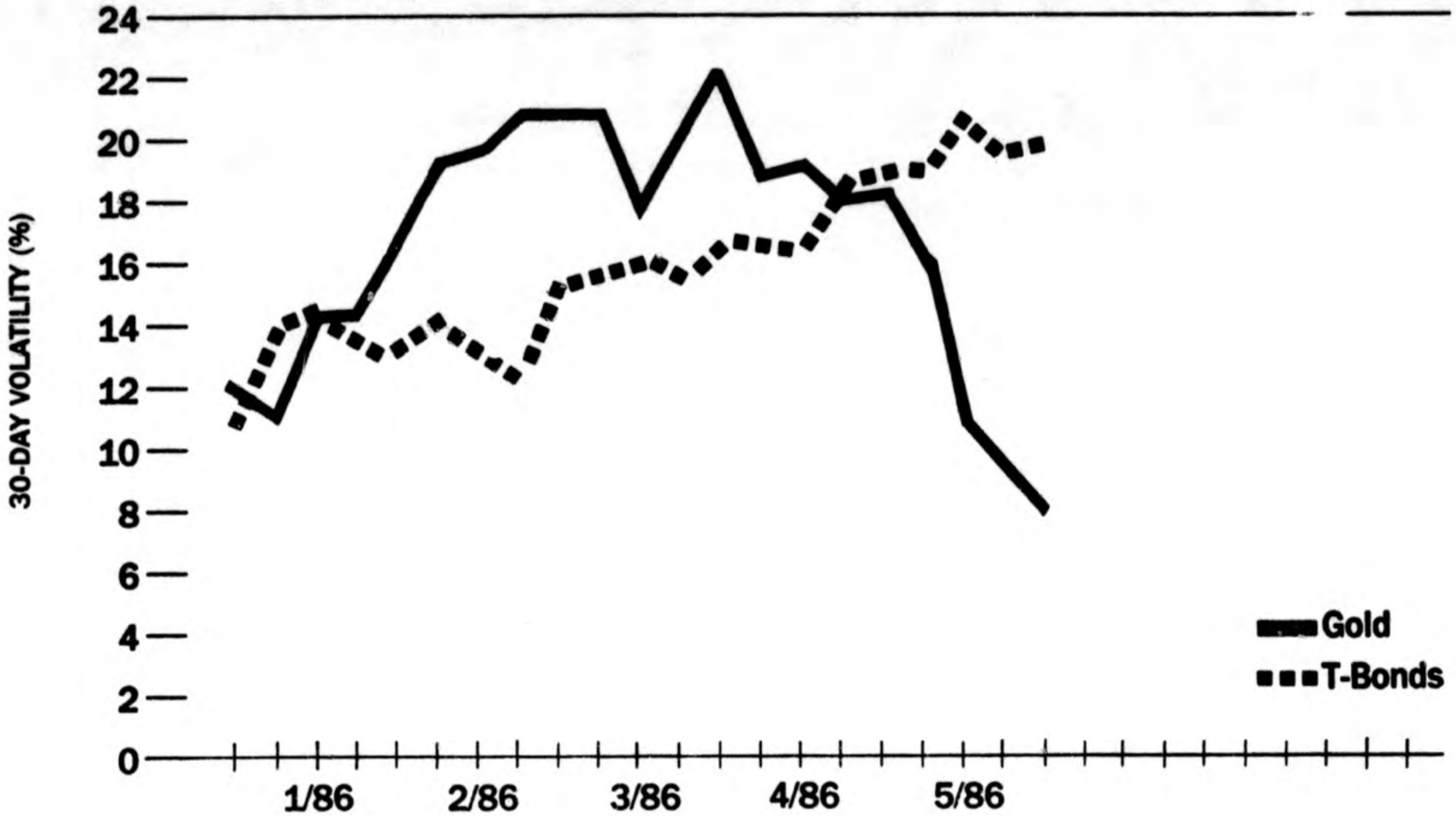
NEW YORK MERCANTILE EXCHANGE: CRUDE OIL OPTIONS

Crude Oil Volatility

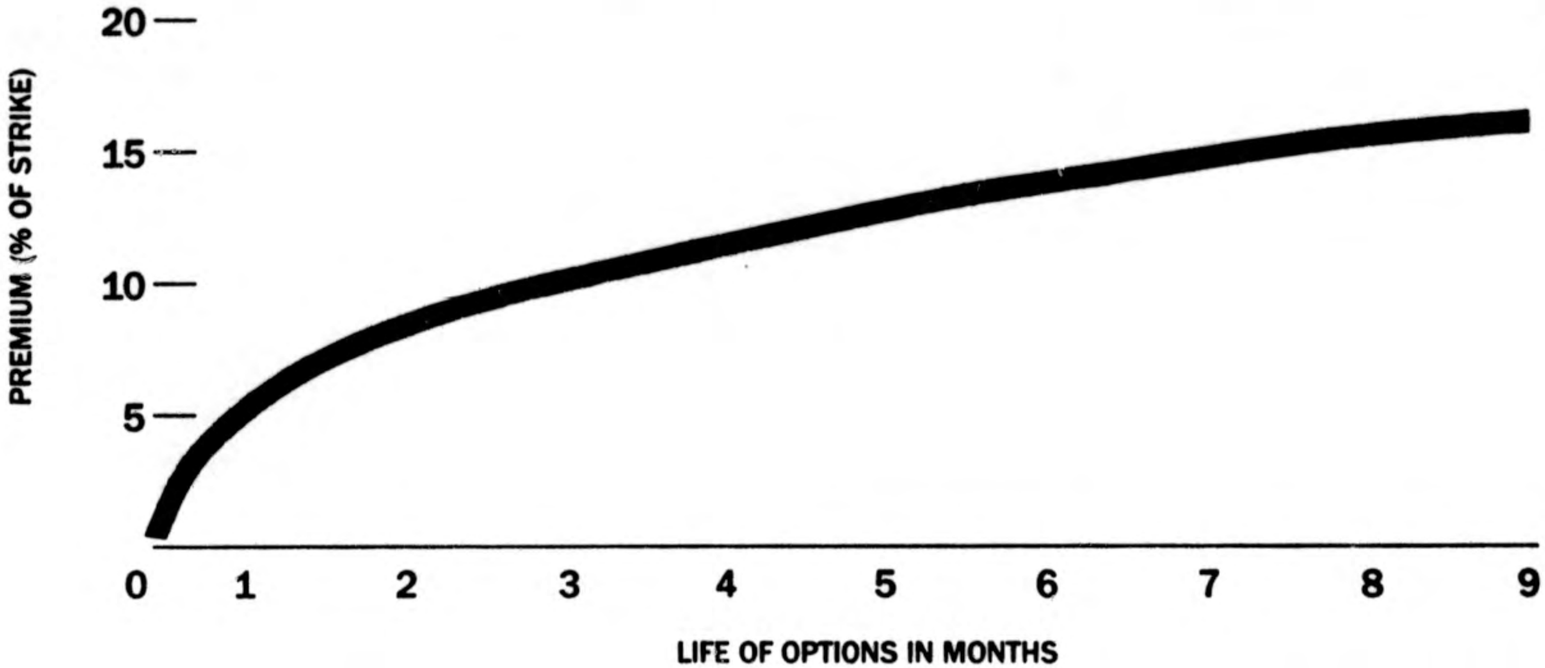


NEW YORK MERCANTILE EXCHANGE: CRUDE OIL OPTIONS

Volatility Comparison



Time



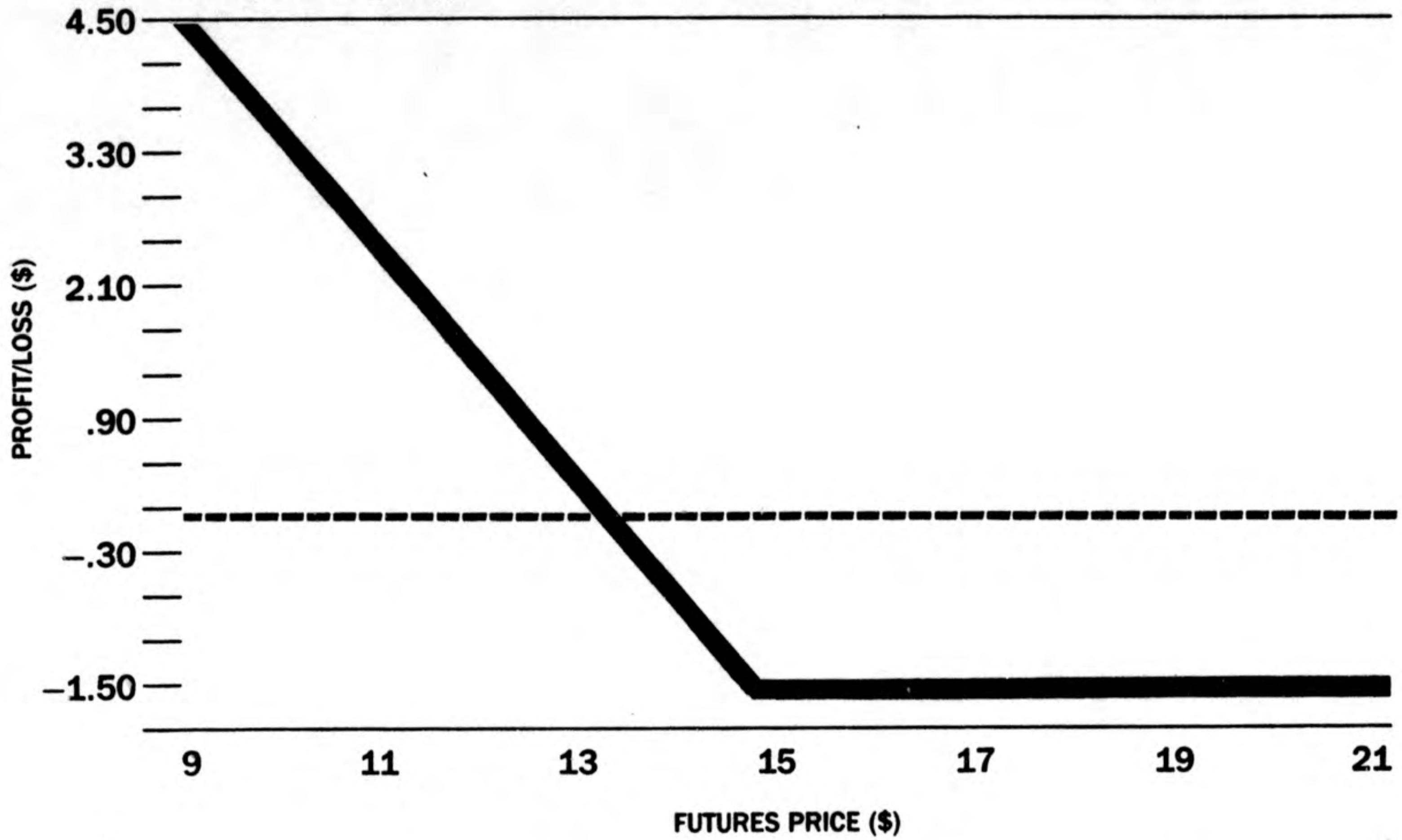
20
15
10
5
PREMIUM (% OF STRIKE)
0
1
2
3
4
5
6
7
8
9
LIFE OF OPTIONS IN MONTHS

Premiums for Three-Month Options Futures at $15

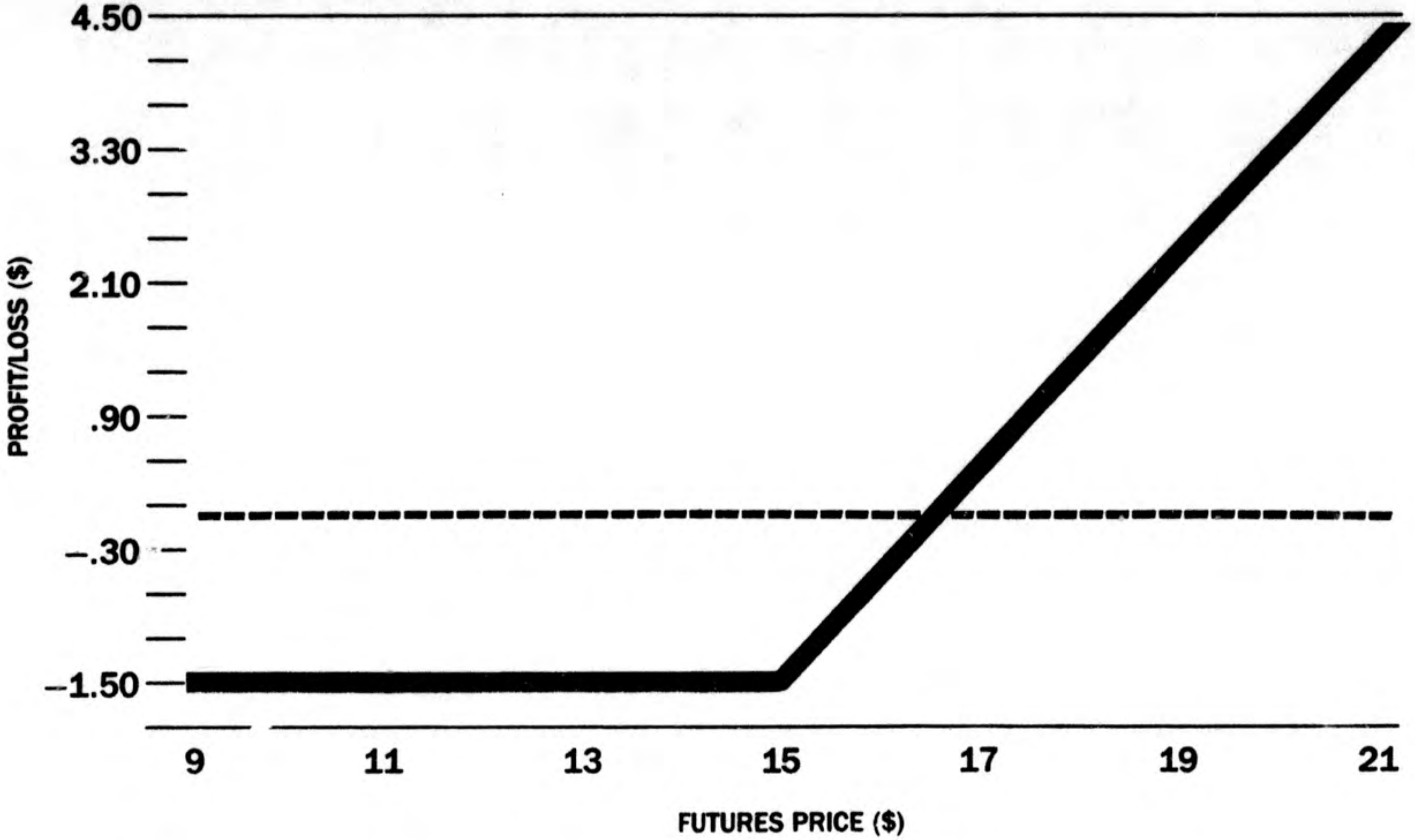
Exercise Price	Call Premium	Put Premium
$14	$2.05	$1.05
15	1.50	1.50
16	1.10	2.10

NEW YORK MERCANTILE EXCHANGE: CRUDE OIL OPTIONS

Put Buyer

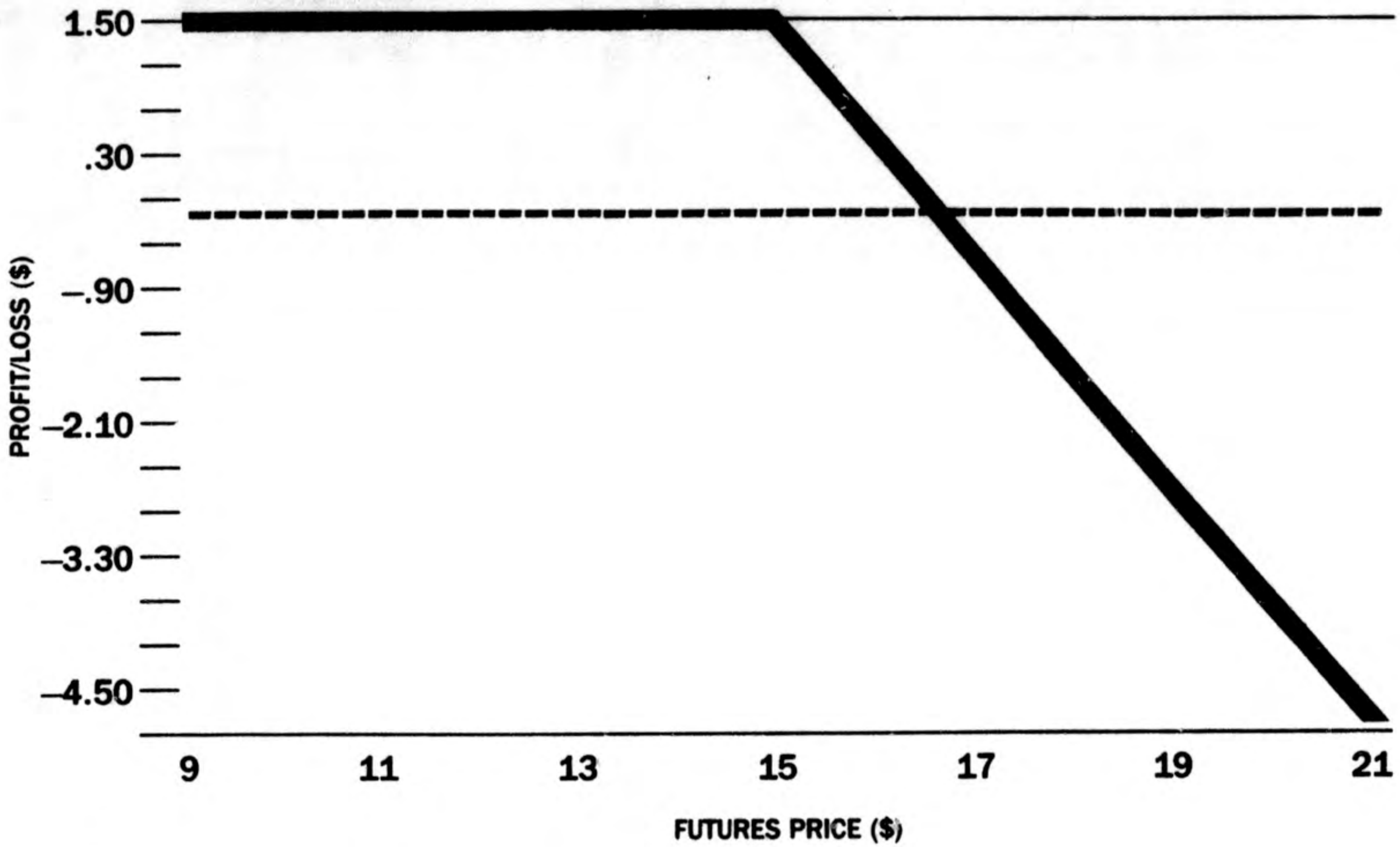


Call Buyer


4.50
3.30
2.10
.90
–.30
–1.50
PROFIT/LOSS ($)
9
11
13
15
17
19
21
FUTURES PRICE ($)

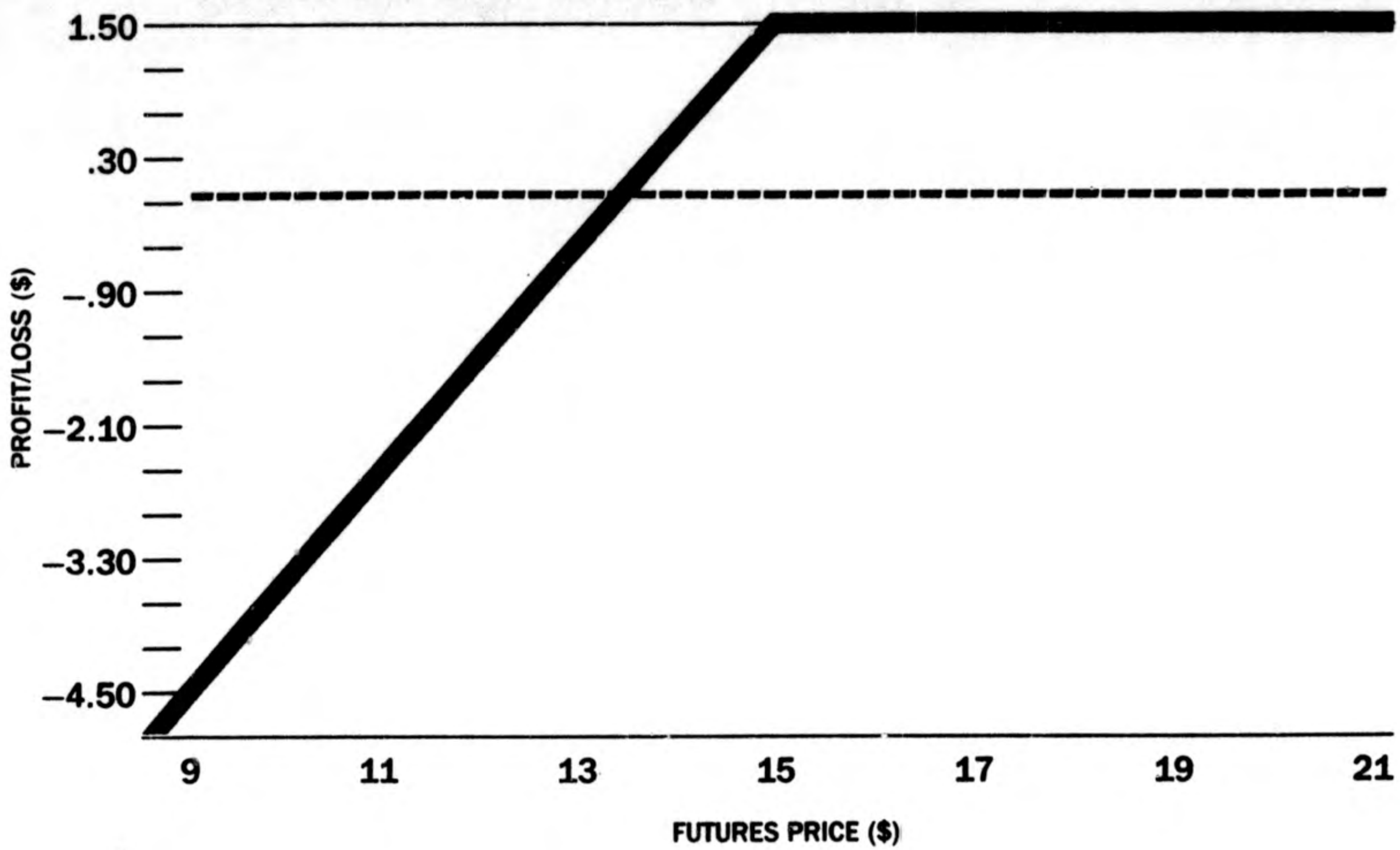
NEW YORK MERCANTILE EXCHANGE: CRUDE OIL OPTIONS

Call Writer



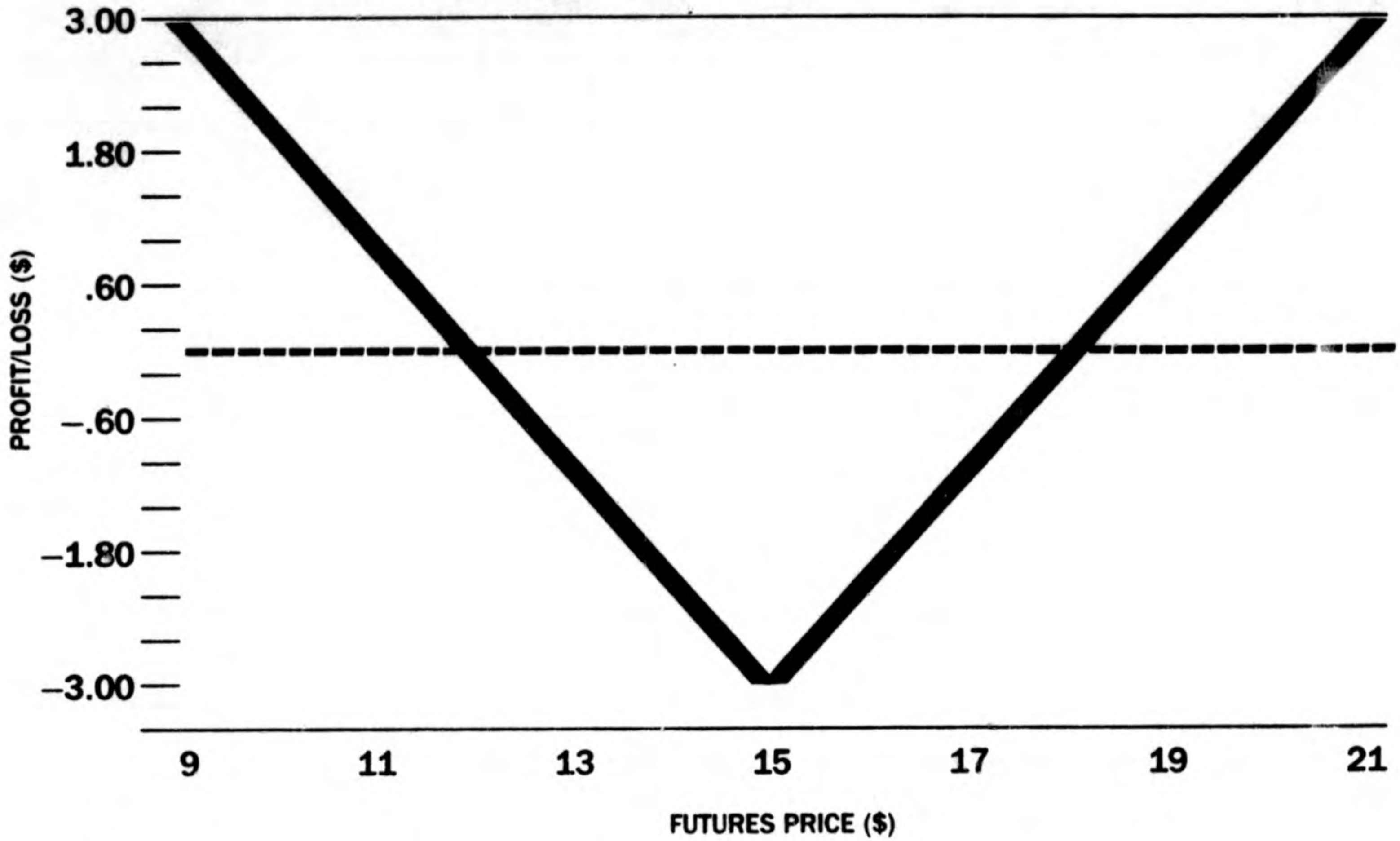
NEW YORK MERCANTILE EXCHANGE: CRUDE OIL OPTIONS

Covered Call Writer

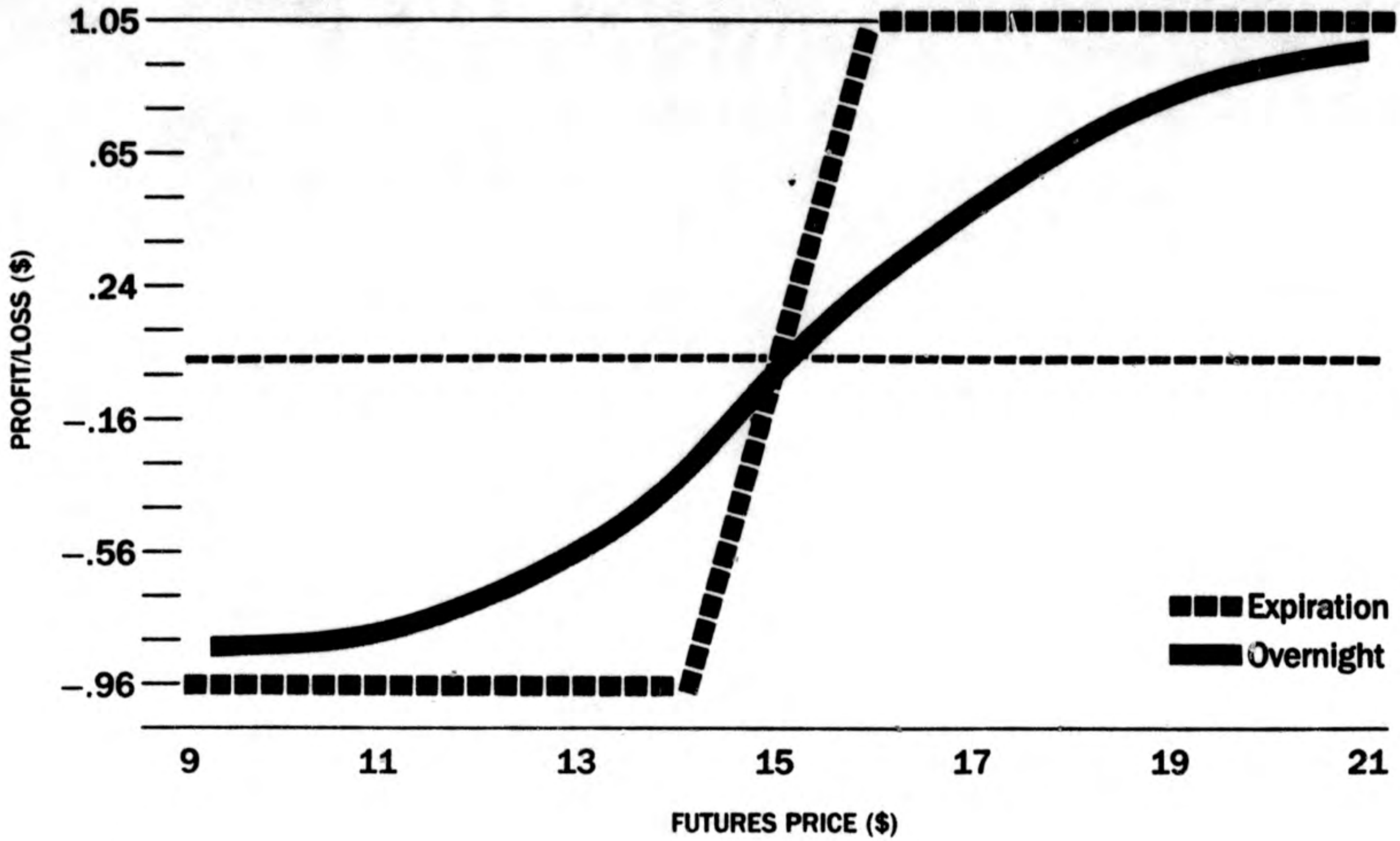


NEW YORK MERCANTILE EXCHANGE: CRUDE OIL OPTIONS

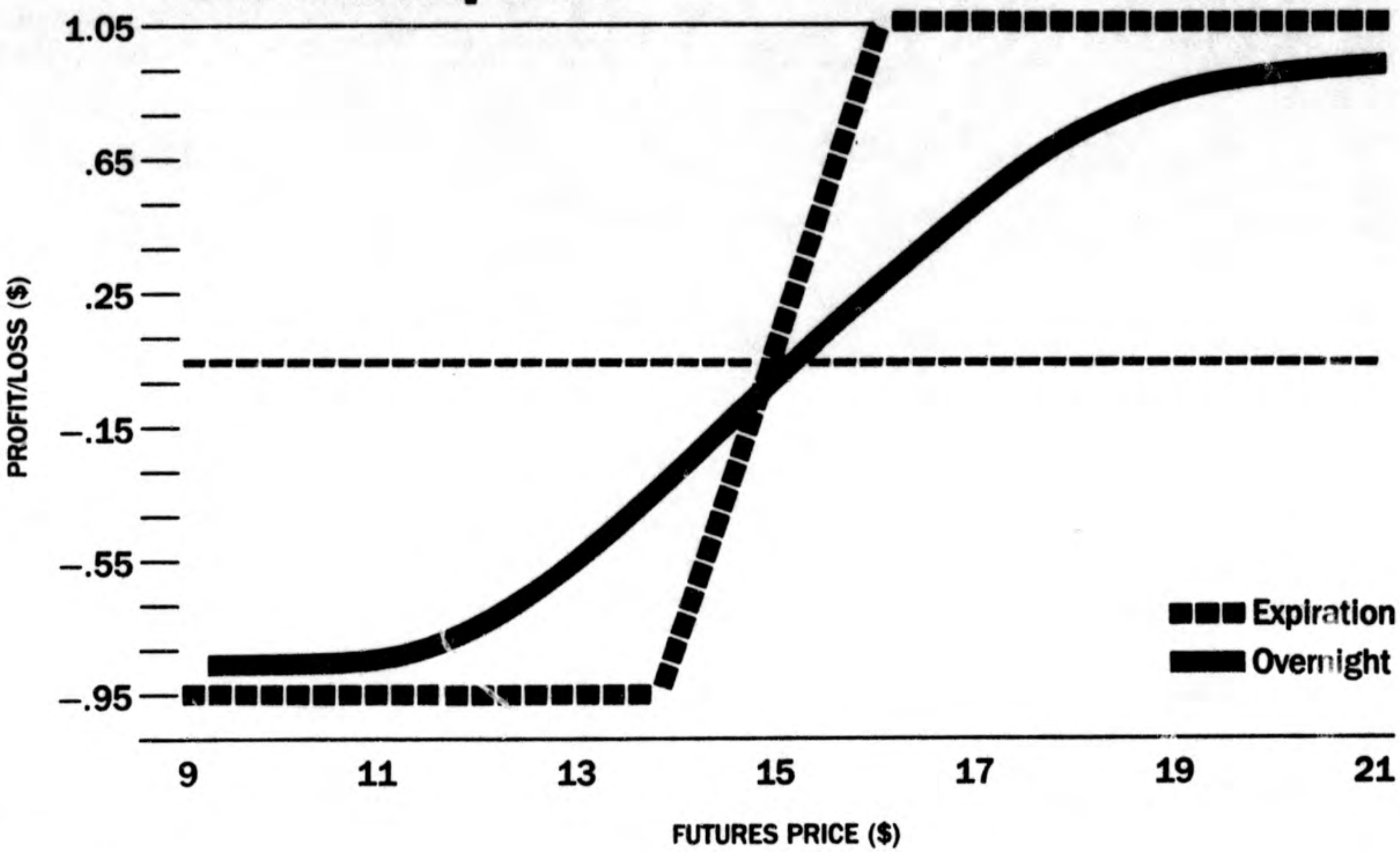
Straddle: Long Volatility



Fence


1.05
.65
.24
-.16
-.56
-.96
PROFIT/LOSS ($)
Expiration
Overnight
9
11
13
15
17
19
21
FUTURES PRICE ($)

Call Bull Spread



(NW¼) of Section Twenty-
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Judicial District, State of
more particularly described
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et;
e North 89 degrees 58' East,
to the true point of begin-

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e North 89 degrees 55'
.34 feet to a point;
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eet to a point that is North
es 58' East from the true
beginning;
e South 89 degrees 58' West,
eet to the true point of
.

rising 2.998 acres, more or

whereas, a breach of the
secured by said deed of
occurred in that payment
been made in accordance
terms thereof and there is
and owing the principal
$5,328.18, plus interest
t the rate of 12% per annum
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administration not yet
beneficiary.
therefore, Safeco Title
Inc., an Alaska corporation,
rbanks Title Agency, acting
the undersigned attorney,
he real property described
: public auction to the
d best bidder to satisfy the
then secured by the deed
The sale will be conducted
nt door of the State Court
604 Barnette Street, Fair-
aska, at 1:00 o'clock, P.M.,
24, 1987. Beneficiary
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amount equal to the obliga-
ed by the deed of trust at
le.
this 20th day of March,

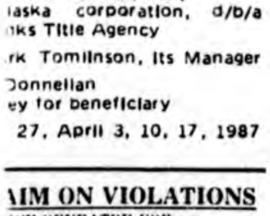
Title Agency, Inc.,
laska corporation, d/b/a
nks Title Agency

rk Tomlinson, its Manager

Donnellan
ey for beneficiary

27, April 3, 10, 17, 1987

AIM ON VIOLATIONS
ASK OPERATOR FOR
ENITH 3377



A FISH & WILDLIFE
AFEGUARD

HB200 which requires persons appointed to the Boards of

budget address.

The original suggestions for cuts were sensible in his address

V, Juneau, AK 99811, or call 465-4940.

Bits From Betteye

Option Contracts Could Help Cushion Oil Price Swings

By Sen. Bettye Fahrenkamp

What will the price of oil be next year? Who can predict next month's or even next week's oil price?

The oil market is now being dscribed as "volatile" and "unstable." How can Alaska, with our overwhelming dependence on this price, deal with this uncertainty?

At a recent hearing before the Senate Special Committee on Oil and Gas, a proposal for reducing that risk was discussed.

In an effort to plan our future revenues, the state now gazes into its computer crystal ball and predicts what the price of oil will be during upcoming years.

Four times a year the Department of Revenue updates the "Petroleum Production Revenue Forecast." They use a sophisticated computer model and consider all the current trends in the world oil market.

But in today's volatile oil market, planning next year's budget is like shooting at a moving target.

Many companies in the oil industry are using the oil futures and options market to reduce the effect of price changes.

Futures contracts allow companies to fix oil prices in advance of actual sales. Using option contracts, companies can in effect buy an insurance policy against oil price declines.

It may be possible for the state to use these financial instruments to manage risk by minimizing the uncertainty of future oil prices. But isn't playing the commodities market a dangerous and risky game?

It is if you're using it to speculate. It's not so much if it's used as a hedge.

In a sense, the state's current budgeting process can be viewed as speculation on the price of oil. The state benefits from unanticipated increases in the price of oil and suffers when the price falls below the forecast price.

A hedging strategy may help cushion oil price swings. We may not make as much if prices rise, but we may protect our oil revenues when prices fall.

By using oil futures and options, or through negotiated long term agreements with oil users, it may now be possible to lock in a guaranteed future price for our oil.

On April 7, the Senate Special Committee on Oil and Gas heard from two New York energy market experts on how the state may use oil futures and options to hedge against oil price risks. Legislators have expressed interest in learning more about this and our committee is continuing to investigate different techniques for managing future oil revenues.

This is not a new idea, but may be the time for policy makers to re-evaluate our overall goals for royalty oil disposal.

When oil prices were high and the state budget was bloated by petrodollars, we were most concerned with determining the best use of it.

Today, we should be more concerned with ensuring that our oil revenues are protected and we are receiving the best possible price for our royalty oil.

Managing our royalty oil should be like managing personal finances. What kind of bank account is best? A checking account with unlimited check-writing but no earned interest? A savings account with a guaranteed rate of return? A high risk mutual fund with potential for high returns? A combination of all three?

This kind of planning does not eliminate the problem of coping with reduced revenues due to oil price declines. If prices don't rebound, state spending must be cut and new sources of revenue found. However, there may be other ways to soften the effects of volatile oil prices on our budget planning process.

Take stock in America.
United States Savings Bonds

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 8672
1544 SCOMM 57: SENATE SPECIAL COMMITTEE ON OIL & GAS, 1987-1988 1341

1-21-88

AMERADA
HESS

BRIEFING (JOINT
with SENATE Jud)

Alaska State Legislature

SENATE SPECIAL COMMITTEE ON OIL AND GAS

SENATOR BETTYE FAHRENKAMP
CHAIRMAN
SENATOR JACK COGHILL
SENATOR PAUL FISCHER

P.O. BOX V
JUNEAU, AK 99811
(907) 465-3834

MEMORANDUM

TO: Members, Senate Special Committee on Oil and Gas
Senate Judiciary Committee

FROM: Committee staff
Senate Special Committee on Oil and Gas

RE: Committee hearing, January 21, 1988

DATE: January 20, 1988

On Thursday, January 21 at 1:30 in the Butrovich Room, the Senate Special Committee on Oil and Gas will hold a joint hearing with the Senate Judiciary Committee for a briefing on the Amerada Hess royalty litigation by Wil Condon, the state's lead counsel.

The Amerada Hess case is the state's largest royalty oil case, with potential recovery estimated to be between $300 million and $2 billion. At issue is the value of Alaska North Slope oil at the wellhead.

In the summer of 1977, when the Trans Alaska Pipeline System commenced operations, there was no consensus among the oil producers and the state as to how to implement the lease form provisions that give the state its 12.5% royalty share. The governor applied to the Alaska Superior Court for a judgement on the proper way to determine wellhead value. Some portions of the case (field costs) were settled in 1980. In November, 1987, a scheduling order was issued setting a trial date for October 2, 1989. Also in November, three producers, Standard Alaska, Exxon, and Chevron, filed suit in U.S. District Court against the state, contending that they could not get a fair trial in any court in Alaska because every resident had a pecuniary interest in the outcome. The state is moving to dismiss the case.

Wil Condon will make a detailed presentation using a sample month of oil production to illustrate the state's approach to the case. This could take up to four hours. The case involves some highly sensitive information, much of which is confidential by law, and whose disclosure could adversely affect the business interests of various parties. In order to protect the confidentiality of this information, the court has entered a protective order. This allows only certain classes of individuals to have access to this information and prevents them from sharing it with others who do not have the right to see it. For purposes of this briefing, we must comply with the court's protective order. Legislators may have access under Paragraph 5(i) of the order. A copy is attached for your review. Certain information in the case has been classified "Confidential" and "Highly Confidential". Only "Confidential" information will be disclosed at the briefing. However, the briefing will be conducted in Executive Session and legislators will be required to sign a statement agreeing to comply with the order.

HUGHES THORSNESS GANTZ POWELL & BRUNDIN

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JAMES F. KLASEN

OF COUNSEL
JOHN C. HUGHES
RICHARD O. GANTZ

ANCHORAGE

VIA DHL

January 12, 1988

Senator Bettye Fahrenkamp
Senate Special Committee on Oil and Gas
P.O. Box V
Juneau, Alaska 99811

Dear Senator Fahrenkamp:

Your letter of December 17, 1987, to Mr. Rozell and me as Alaska counsel for the energy company defendants in the Amerada Hess royalty case was referred to the appropriate representatives of each of our respective clients. To be effective for your purposes each of the defendants would have to waive the "confidentiality agreement," which is in the form of a protective order. This letter is intended to explain why the defendants politely and respectfully decline your request.

A protective order was initially proposed by the defendants to facilitate compliance with discovery requests in Amerada Hess. The protective order eventually entered by Judge Carpeneti in Amerada Hess reflected extensive briefing and compromise by both sides. It was designed to protect the confidentiality of both business and governmental records. It provides for two tiers of confidentiality, with carefully constructed limits as to who can see each tier within the individual defendant companies as well as within the State. That Order also provides in paragraph 9 that:

> The provisions of this Protective Order shall not apply (a) if the party asserting confidentiality specifically waives in writing the protective

> conditions set forth in this Order with respect to the use of any information, whether generally or for a specified purpose . . . .

Therefore, if a defendant were to waive the confidentiality protections as you have requested, that waiver would eliminate the protective provisions of the Protective Order for all purposes as to that information.

Unfortunately, the scope of your request is not limited to the July 1984 transactional data. Having heard Wil Condon's presentation, we believe that authorizing a similar presentation to your committee would entail waiving the Protective Order as to much more commercially sensitive and confidential information than just the various prices at which oil was transacted in July 1984. The State's presentation included discussion of individual company marketing and valuation methodologies, some of which reflected information on documents designated Highly Confidential under the Protective Order. Thus, the scope of any waiver would be difficult to delineate and the protections of the Protective Order would be jeopardized as to many of the Confidential and Highly Confidential documents produced by individual defendants beyond those dealing solely with July 1984 transactional data.

Given the spirit of such Sunshine laws as AS 09.25.110 and AS 09.25.120 and Uniform Rule 22(a) of the Alaska State Legislature, and given ¶ 9 of the Protective Order, it would be difficult to confine any Confidential or Highly Confidential information to the legislators on your committee and their staff. Even if the Protective Order were amended to confine the effect of the waiver you request just to your committee, and even if the Sunshine laws would not compel disclosure of that information, the Alaska Legislature has involved itself directly in the marketing of Alaska's royalty oil by retaining authority to review and approve amendments of royalty-in-kind oil sales contracts, such as in AS 38.05.183(f). Accordingly, it would be inappropriate for the details of commercially sensitive marketing strategy information to be made available to the Legislature, when the Legislature effectively functions as a competitor for marketing oil.

Finally, our evaluation of the State's chances of success in Amerada Hess is markedly different from that reflected in Wil Condon's presentation, both as to whether the State is entitled to any additional royalty payments from any defendant, and, whether the State's latest theory of lease interpretation is valid. It is not our intention to denigrate the State's counsel or consultants in any way with respect to their handling, evaluation, or attempts to develop a theory of the case. Our point is simply that there are many disputed legal and factual issues in the case, some of which are complex, and that our views of the case differ substantiality from those advanced by the State.

For these reasons, the defendants respectfully decline to waive the protections of Judge Carpeneti's Protective Order.

HUGHES, THORSNESS, GANTZ,
POWELL & BRUNDIN
Attorneys for defendants other than ARCO Alaska Inc. and Atlantic Richfield Company

By: Carl J. D. Bauman
Carl J. D. Bauman

cc: Wilson L. Condon, Esq.
Amerada Hess Royalty Litigation Committee

LAW OFFICES OF

FAULKNER, BANFIELD, DOOGAN & HOLMES

A PROFESSIONAL CORPORATION

JAN 19 1988

MICHAEL M. HOLMES**
RANDALL J. WEDDLE
WILLIAM B. ROZELL
CHARLES N. DRENNAN
ANTHONY M. SHOLTY
JAMES R. WEBB
MICHAEL A. BARCOTT**
RICHARD B. BROWN
TIMOTHY A. McKEEVER
JOHN F. CLOUGH, III
LEON T. VANCE
DIANE L. DALEY**

JAMES E. HUTCHINS
JULIE E. BRYANT
JOHN E. CASPERSON**
ANN GIFFORD VANCE
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JEROME H. JUDAY
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SUSAN RANDALL POLLARD
ROBERT J. McLAUGHLIN
DEBORAH E. BEHR
CHERYL M. JONES

OF COUNSEL

NORMAN C. BANFIELD
LAWRENCE T. FEENEY
LEE S. GLASS, M.D.**

HERBERT L. FAULKNER (1882 - 1972)
FRANK M. DOOGAN (1923 - 1977)

**ADMITTED IN WASHINGTON & ALASKA
OTHERS NOT ADMITTED IN WASHINGTON

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SEATTLE, WASHINGTON 98104
(206) 292-8008

January 15, 1988

Senator Bettye Fahrenkamp
Alaska State Legislature
P.O. Box V, Mail Stop 3100
Juneau, AK 99811

RE: State v. Amerada Hess
6-1547

Dear Senator Fahrenkamp:

As I have explained to Daniel Consenstein by telephone and in a meeting at your office, ARCO is unable to provide you with the waiver of the court order requested in your letter of December 17, 1987. Our reasons are similar in most respects to those outlined by Carl Bauman in his letter to you of January 12. As I indicated to Mr. Consenstein, I am also available to talk with you further about questions you may have on this subject if you think it would be helpful to do so.

Very truly yours,

Bart Rozell

William B. Rozell

WBR:pb/1309q
cc: Wilson Condon
Royalty Litigation Committee

Alaska State Legislature

SENATE SPECIAL COMMITTEE ON OIL AND GAS

SENATOR BETTYE FAHRENKAMP
CHAIRMAN
SENATOR JACK COGHILL
SENATOR PAUL FISCHER

P.O. BOX V
JUNEAU, AK 99811
(907) 465-3834

December 17, 1987

Carl J.D. Bauman, Esq.
Hughes, Thorness, Gantz,
Powell and Brundin
509 West Third Avenue
Anchorage, AK 99501

William B. Rozell, Esq.
Faulkner, Banfield, Doogan and Holmes
302 Gold Street
Juneau, AK 99801

Dear Mssrs. Bauman and Rozell:

The Senate Special Committee on Oil and Gas and the Senate Judiciary Committee are preparing hearing schedules for the first part of the 1988 Legislative Session. Of particular interest to both committees is the Amerada Hess royalty case.

We have requested that attorneys for the state brief the legislature on their theory of the case and the manner in which they expect to establish liability. They have informed me that they recently made such a presentation to the defendants, using a sample month, July, 1984, to illustrate their approach to the case. They noted, however, that confidentiality agreements prevent them from sharing this presentation with the legislature unless a specific waiver is granted by all defendants.

I would appreciate your efforts in securing from your respective clients a waiver in order that the legislature and its staff, in one or more meetings, could be provided a breifing using the July, 1984 illustration.

I look forward to receiving your positive response at your earliest convenience. Please contact my committee staff, Danny Consenstein at 465-3834, for additional information.

Sincerely,

Bettye

Bettye Fahrenkamp
Chairman

BF:dc/og
cc: Senator J. Kerttula, Chairman
Senate Judiciary Committee

January 21, 1988

Joint Meeting of Senate Special Committee on Oil and Gas and Senate Judiciary Meeting

Briefing by Wil Condon on the Amerada Hess Royalty Litigation

TO TESTIFY:

BRUCE BOTHELO or BOB MAYNARD, Attorney General's office

Will review the progess of the interagency working group.

WIL CONDON, Lead Counsel for the state.

Make sure Wil explains in detail the implications of signing the confidentiality waiver. Can you take notes?

QUESTIONS:

1) On November 2, 1987, three producers, Standard Alaska, Exxon, and Chevron, filed suit in U.S. District Court in Anchorage against the state, contending that they could not get a fair trial in any court in Alaska because every resident of the state had a pecuniary interest in the outcome.

How has this affected the state's position or strategy?

Were you prepared for this development?

2) The exchange transactions that some producers, mostly Standard, negotiated resulted in substantial profits to the producer. Is the state entitled to share in those profits?

3) Is there any indication that ARCO manipulated tanker charges? That high priced tankers were put on runs designed to reduce royalty liability?

4) Have the individual producers maintained consistency in presenting their pricing methodology? If not, was the state informed when a change in methodology occured?

5) Some have suggested that even if these issues are resolved in court, wellhead pricing is inherently complex to administer and prone to abuses. Shouldn't the state be looking for alternative pricing methodologies to avoid future disputes over value on both the royalty and the tax side?

STATE OF ALASKA

DEPARTMENT OF LAW

OFFICE OF THE ATTORNEY GENERAL

STEVE COWPER, GOVERNOR

REPLY TO:

☐ *1031 W 4th AVENUE*
SUITE 200
ANCHORAGE, ALASKA 99501-1994
PHONE: (907) 276-3550

☐ *1st NATIONAL CENTER*
1"" CUSHMAN ST.
SUITE 400
FAIRBANKS, ALASKA 99701-4679

☑ *P.O. BOX K—STATE CAPITOL*
JUNEAU, ALASKA 99811-0300
PHONE: (907) 465-3600

January 21, 1988

TO WHOM IT MAY CONCERN:

Re: Section 5(i) of the Protective Order in State v. Amerada Hess, et al.

I hereby determine that the disclosure to certain members of the Legislature of certain confidential information contained in a proposed presentation by Mr. Wilson Condon is necessary pursuant to Section 5(i) of the Protective Order in State v. Amerada Hess, et al.

I have had the opportunity to review this material when it was presented to me last July. Given the Legislature's expressed desire to exercise its oversight responsibility with respect to the conduct of this executive branch activity, I believe it is necessary to make a presentation such as this to give them the understanding I believe they need to effectively exercise that responsibility. The only way we can inform the Legislature about any of the precise details of this litigation is by resort to information which has been classified by the defendants as confidential pursuant to the Protective Order. I believe the Legislature needs to develop an appreciation for some of these precise details to effectively fulfill its role with respect to this litigation.

Sincerely,

Grace Berg Schaible

Grace Berg Schaible
Attorney General

GBS:jf

SUBSCRIBED AND SWORN TO before me this 21st day of January, 1988 at Juneau, Alaska.

Notary Public, State of Alaska
My commission expires: 1-29-90

03-C5LH

January 21, 1988

Joint Meeting of Senate Special Committee on Oil and Gas and Senate Judiciary Meeting

Briefing by Wil Condon on the Amerada Hess Royalty Litigation

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EXHIBIT A

AGREEMENT TO BE BOUND BY

PROTECTIVE ORDER

I, ______________________________ (print or type name), am employed by ______________________________.

I hereby acknowledge that I have received and read a copy of the Protective Order entered in the action pending in the Superior Court for the State of Alaska, First Judicial District of Juneau, entitled STATE OF ALASKA, et al. v. AMERADA HESS CORPORATION, et al. (No. 1 JU 77-847 Civil), and understand the limitations it imposes on the use and disclosure of information designated as "CONFIDENTIAL" or "HIGHLY CONFIDENTIAL." I agree to be bound by all of the terms of such Protective order.

____

DATED:

IN THE SUPERIOR COURT FOR THE STATE OF ALASKA

FIRST JUDICIAL DISTRICT AT JUNEAU

STATE OF ALASKA,

Plaintiff,

COMMISSIONERS OF NATURAL RESOURCES, STATE OF ALASKA, and DIRECTOR OF THE DIVISION OF LANDS, STATE OF ALASKA

Involuntary Plaintiffs,

vs.

AMERADA HESS CORPORATION; ATLANTIC RICHFIELD COMPANY; BP ALASKA INC.; BP ALASKA EXPLORATION, INC.; EXXON CORPORATION; GETTY OIL COMPANY; HUNT INDUSTRIES; CAROLINE HUNT TRUST ESTATE; LAMAR HUNT TRUST ESTATE; WILLIAM HERBERT HUNT TRUST ESTATE; N.B. HUNT; THE LOUISIANA LAND AND EXPLORATION COMPANY; MARATHON OIL COMPANY; MOBIL OIL CORPORATION; SOHIO PETROLEUM COMPANY; CHEVRON U.S.A., INC.; PLACID OIL COMPANY; and PHILLIPS PETROLEUM COMPANY, PARTNERSHIP PROPERTIES, CO., a Colorado general partnership; PETRO-LEWIS CORPORATION, and AMOCO PRODUCTION COMPANY,

Defendants.

Hellen, Partnow & Condon
SEP 14 1984
RECEIVED

FILED IN THE TRIAL COURTS
STATE OF ALASKA, FIRST DISTRICT
AT JUNEAU
SEP 11 1984
Clerk of Court
By PB Deputy

No. 1JU-77-847 Civil

PROTECTIVE ORDER

In order to facilitate expeditious discovery while protecting the confidentiality of business and governmental records, the following Protective Order is entered:

1. (a) Any party may designate as "CONFIDENTIAL" any information produced, filed, or otherwise disclosed by it in this action. The designation shall be based on a good faith belief that the designated information consists of proprietary business information or sensitive governmental information not normally available to the public or to persons or entities outside the party and its affiliates (or nonparty source as defined in

paragraph 2). Information so designated may be disclosed only to the extent set forth below. A party may at any time serve a written notice of objection to the designation of information as "CONFIDENTIAL". The notice shall identify specifically the information from which the objecting party wishes to have the designation removed and specify the reasons for wishing to do so. Within 30 days of actual receipt of such notice, the designating party or nonparty source shall notify the objecting party in writing whether the designating party or nonparty source will agree to remove the designation as requested. Absent such agreement, the objecting party may move for an Order declassifying the specified information.

(b) Any party may designate as "HIGHLY CONFIDENTIAL" information produced or disclosed which the party determines in good faith is of such a high level of sensitivity that its disclosure to current employees of one or more parties could result in material competitive prejudice to the party or nonparty source disclosing such information; provided, however, that any such information more than one year old shall not be designated "HIGHLY CONFIDENTIAL" in the absence of an accompanying statement of the reasons therefor. Any party may, within 30 days after receipt of such "HIGHLY CONFIDENTIAL" information more than one year old and accompanying statement of reasons, object to the designation, in which event the party so designating the information shall be required, within 30 days after receipt of any such objection, to move for an order of the court confirming said designation. The information shall be treated as "HIGHLY CONFIDENTIAL" unless and until the designation is modified by court order, or the designating party has failed to move as required hereinabove. If information is properly designated as "HIGHLY CONFIDENTIAL" at the time of its production, the fact that it becomes more than one year old shall not affect its designation.

(c) Except as expressly provided herein, no person or entity who is not persently a party to this action shall be afforded access to any information designated as "CONFIDENTIAL" or as "HIGHLY CONFIDENTIAL" without further order of the court.

2. The provisions of this Protective Order apply equally to any person or entity not a party ("nonparty source") who provides information in the form of documents, testimony, or otherwise in this action.

3. (a) The designation of information as "CONFIDENTIAL" or "HIGHLY CONFIDENTIAL" shall be made by placing or affixing on it a legend reading as follows:

> CONFIDENTIAL MATERIAL [or HIGHLY CONFIDENTIAL]. Not to be used, copied, or disclosed except in accordance with Protective order, State of Alaska, et al., v. Amerada Hess Corporation, et al., Superior Court for the State of Alaska, No. 1JU-77-847 Civil.

(b) A party to this action or nonparty source may designate any part of deposition testimony in which its own information is disclosed, directly or indirectly, as "CONFIDENTIAL" or as "HIGHLY CONFIDENTIAL" by advising the reporter at the time of the deposition or within ten days of receiving a copy of any transcript ordered on an expedited basis. The reporter shall annotate the transcript accordingly and, if such transcript is required to be filed with the court, shall file the transcript under seal with the clerk. If information in the transcript is not designated as "CONFIDENTIAL" or as "HIGHLY CONFIDENTIAL" until after the reporter has disseminated copies thereof, the reporter shall notify each recipient of the designation, and such recipient shall apply the legend required by subparagraph 3(a).

(c) During the period between the date of the deposition testimony and the tenth day after receipt of the transcript thereof, all deposition transcripts and exhibits marked therein shall be treated as "CONFIDENTIAL," except that any portions designated as "HIGHLY CONFIDENTIAL" shall be treated as provided in paragraph 7.

4. Information designated "CONFIDENTIAL" or "HIGHLY CONFIDENTIAL" under this Protective Order shall be used solely for matters relating to royalties or taxes pursuant to AS 43.21 or AS 43.55 claimed to be due to the State of Alaska, and shall not be used or disclosed for any other governmental, business, competitive, or other purpose whatsoever, unless the party or nonparty source furnishing such information consents in writing to such other uses. Such information shall be kept in secure, limited-access facilities and may be disclosed only as set forth below. Until further order of the court, counsel for each party shall retain the originals of each Agreement in the form attached hereto as Exhibit A. With respect to information designated "HIGHLY CONFIDENTIAL," counsel for each party shall also maintain until further order of the court a list of any persons given access to such information by that counsel, and a description of the information disclosed.

5. Counsel for a party who obtains from any source information designated as "CONFIDENTIAL" under this Protective Order may disclose or permit disclosure of such information only to the following:

(a) Outside counsel for any party working on matters relating to royalties or taxes pursuant to AS 43.21 or AS 43.55 claimed to be due to the State of Alaska, and paralegal and clerical employees of law firms which serve as outside counsel;

(b) Corporate attorneys, regularly employed by a corporate party or its parent or subsidiaries, working on matters relating to royalties or taxes pursuant to AS 43.21 or AS 43.55 claimed to be due to the State of Alaska, and paralegal and clerical employees assisting them;

(c) The Attorney General, the Department of Law attorneys working on matters relating to royalties or taxes pursuant to AS 43.21 or as 43.55 claimed to be due to the State of Alaska, and paralegal and clerical employees assisting them;

(d) Personnel of the Alaska Court System;

(e) Court reporters in any jurisdiction, who are engaged in proceedings relating to royalties or taxes pursuant to AS 43.21 or AS 43.55 claimed to be due to the State of Alaska, and who, prior to disclosure, have agreed to be bound by this Protective Order by executing an Agreement in the form attached hereto as Exhibit A;

(f) Outside consultants or experts, and their employees and assistants, retained to assist counsel with respect to matters relating to royalties or taxes pursuant to AS 43.21 or AS 43.55 claimed to be due to the State of Alaska, and who, prior to disclosure, have agreed to be bound by the terms of this Protective Order by executing an Agreement in the form attached hereto as Exhibit A. The term "outside", as used in this subparagraph and elsewhere in this Protective Order, refers to a person who is not an officer or employee of a party to this action;

(g) Employees of the Departments of Natural Resources or Revenue assisting counsel for the State of Alaska on matters relating to royalties or taxes pursuant to AS 43.21 or AS 43.55 claimed to be due to the State of Alaska, and who, prior to disclosure, have agreed to be bound by the terms of this Protective Order by executing an Agreement in the form attached hereto as Exhibit A;

(h) Any witness, who, prior to disclosure, has agreed to be bound by the terms of this Protective Order by executing an Agreement in the form attached hereto as Exhibit A. In connection with issuance of process to compel attendance of a witness at a deposition or other proceeding the parties agree that such process may include a notice specifying that information disclosed at such deposition or other proceeding shall be disclosed and is protected pursuant to the terms of this Protective Order, in which event the witness, who shall be served with a copy of this Protective Order, shall not be required to sign the Agreement in the form attached hereto as Exhibit A. Any witness to whom such information is disclosed may not retain such information, or any notes, compilations, or other materials derived from such information, after the conclusion of his or her testimony, unless such witness is a person to whom counsel is otherwise entitled to disclose such information under subparagraphs (a) through (g) hereinabove or such witness is itself the source of such information; and

(i) Any present or former officer, director, or employee of a party whose participation is determined to be necessary by counsel of record for that party and who, prior to disclosure, has agreed to be bound by the terms of this Protective Order by executing an Agreement in the form attached hereto as Exhibit A.

6. Information produced under this Protective Order disclosed to employees of the Department of Revenue shall be deemed to be data obtained from a taxpayer in a report or return made under AS 43.21 or AS 43.55 and shall, in addition to the protection afforded by this Protective Order, have the confidentiality provided by AS 43.05.230 and applicable regulations thereunder; provided, however, that transactional

data more than one year old consisting of sales price, volume, gravity (API°), date of shipment, transportation costs, delivery point, and date of delivery in the sale, exchange, or other disposition of Alaska North Slope Crude Oil or gas which is provided to the Department of Revenue for use in a tax proceeding, shall be kept confidential as provided by AS 43.05.230 and the applicable Department of Revenue Regulations, and the Department of Revenue shall not be subject to the other provisions of this protective order with respect to such data which is more than one year old.

7. (a) Disclosure of information designated as "HIGHLY CONFIDENTIAL" shall be limited to those persons described in subparagraphs 5(a) through 5(h).

(b) Persons described in subparagraph 5(f) and 5(h), who are officers or employees of any company or entity, or affiliate or subsidiary thereof, engaged in the exploration, production, trading, transportation, refining or marketing of oil or gas:

(i) shall not be provided with any "HIGHLY CONFIDENTIAL" information except upon actual notice to the party or nonparty source furnishing such information five business days in advance of disclosure; provided that if such notice is given no party or person acting on behalf of or at the instance of a party, other than the party providing such notice shall contact the expert, consultant, or witness nor subject such person to discovery to inquire into matters arising within such person's consultation with the notifying party, except as provided in Rule 26(b)(4); and

(ii) shall not disclose any information subject to this Protective Order to his employer or any representative thereof or utilize this information as the basis for gaining any competitive advantage over any party or nonparty source.

(c) Persons described in subparagraph 5(g) shall not be permitted to use any information subject to this Protective Order as the basis for gaining any competitive advantage over any party or nonparty source furnishing information in connection with the disposition by the State of Alaska of royalty oil and gas.

(d) Information designated as "HIGHLY CONFIDENTIAL" may be disclosed to persons described in subparagraph 5(h), provided that (unless such witness is a person to whom counsel is otherwise entitled to disclose such information under subparagraphs 5(a) through 5(g) hereinabove) no such person is permitted to retain such information, or any notes, compilations or other materials derived from such information;

8. Except with the written consent of the party or nonparty source who furnished such information, counsel for any party or any other person who obtains access to information designated as "CONFIDENTIAL" or "HIGHLY CONFIDENTIAL" under this Protective Order shall not use or make copies, duplicates, extracts, summaries, or descriptions of the information or any portion thereof except as may be reasonably necessary in connection with preparation for and trial or hearing of matters relating to royalties or taxes pursuant to AS 43.21 or AS 43.55 claimed to be due to the State of Alaska, and any appeals therefrom. Any such copies, duplicates, extracts, summaries, or descriptions shall be marked with the appropriate legend as set forth in subparagraph 3(a) and accordingly be treated as "CONFIDENTIAL" or as "HIGHLY CONFIDENTIAL", under this Protective Order.

9. The provisions of this Protective Order shall not apply (a) if the party asserting confidentiality specifically

waives in writing the protective conditions set forth in this Order with respect to the use of any information, whether generally or for a specified purpose, or (b) if information is lawfully acquired by a party or its counsel, without use of or reliance upon any information designated by the other party or any nonparty source as "CONFIDENTIAL" or "HIGHLY CONFIDENTIAL." Under either circumstance the information may be disclosed by the State or any defendant without regard to the provisions of this Protective Order.

10. All depositions in this action shall be held in the presence only of the deponent, officers of the court (including the reporter), and persons described in paragraph 5. Persons not permitted, pursuant to paragraph 7, to have access to information designated as "HIGHLY CONFIDENTIAL" may be excluded from any depositions during such times as information designated as "HIGHLY CONFIDENTIAL" is being disclosed.

11. (a) To the extent that a document to be filed with the court may reveal information designated as "CONFIDENTIAL" or "HIGHLY CONFIDENTIAL", any portion of the document containing designated information shall be marked as set forth in subparagraph 3(a) and filed in a sealed envelope. The service copies shall also be so marked. All copies shall be withheld from public disclosure as provided herein, except upon order of the court.

(b) The use of any information designated as "CONFIDENTIAL" or "HIGHLY CONFIDENTIAL" in any court proceeding shall not cause it to lose its designated status, and the parties shall take all steps reasonably required to protect its confidentiality during such use. The parties should cooperate in advance of trial or hearing to minimize the need for continuing the protected status of such information.

12. (a) The provisions of this Protective Order shall

survive after termination of this action. All parties and persons subject to this Protective Order shall take reasonable precautions to maintain the information in accordance with the terms of this Protective Order.

(b) The clerk shall maintain under seal all papers filed under seal with the court as to which a claim of confidentiality was made.

13. The court may modify this Protective Order at any time for good cause shown and upon notice to the affected parties.

14. Nothing in this Protective Order limits in any way the authority of the Department of Revenue to conduct tax audits or investigations or to independently obtain or use information in the conduct of such tax audits or investigations.

IT IS SO ORDERED this 11th day of September, 1984.

Walter L. Carpeneti
WALTER L. CARPENETI
SUPERIOR COURT JUDGE

CERTIFICATION

The undersigned certifies that on the 12 day of September, 19 84, a true copy of this document was served on the following attorneys: Robert Maynard; Wilson Condon; Carl Bauman; David Nelson; Wm. Rozell; John Norman; Arden Page; Clerk of Court (Juneau).
by P.M. [illegible]

CORRECTION

THIS DOCUMENT
HAS BEEN REPHOTOGRAPHED
TO ASSURE LEGIBILITY

02-576(2/77)

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by P.K. Lock

1/21/80 BE Coghill Fischer | Sturg Joe Kertulla Halford | Menard Miller Pierce Martin Hurley

Amerada Hess Briefing

Bob Maynard

Leg needs to know info.
1) large amounts $ - company 300 - 2 billion
2) Policy decisions on how O+G should be valued
3) cannot make decision w/o

4) Leg must appropriate $ for litigation

Protective order -
2 levels - 1) confidential — can be if "need to know" AG
2) highly confidential

AG memo - is leg pursuant to 5(1) of protective effectively exercise oversight responsibility

Originally asked for waiver -
Now "highly confidential" is deleted.

Joe what is prejudice ?

Protective order doesn't include legislators

Kirk companies know AG knows but leg doesn't

Maynard

Tapes on but marked as "confidential"

Administration — working group —

valuation of state's royalty share 1977-86

cleaning costs resolved in 1980-1

Internal working group —
meet regular basis —
DNR, Rev, OMB, AG schaible, Maynard, Bartelo
Eason DNR, Fleischinger DOR.
Policies + goals.

BF "void" — ~~L~~ legislature missing.

Condon Value of oil at PS#1
Kuparuk + PB — on state land.
Selected in 1963 — Statehood Act.
Some submerged land at Statehood.
1st Lease sale Dec. 1964 — (most of Kuparuk
Offered in July 1965 — (most of PB)
in 1967 — offshore — gas cap discovered
Reoffered Sept 1969 = 900 million

Lease Form — drafted by Territorial.
Royalty provisions
several Cl's together.

State & producers disagree on some parts —

Can take in value or in kind —
Since 1979 — 1/2 in kind, 1/2 in value.

Tied most sales to 4H outcome.
Some not — (2 competitive sales)
ALPETCO

Lease Form —

¶ 11 12.5% amount or value

¶ 14 Royalty in kind

¶ 15 Value ¶

"the field market value at the well"

¶ 16 Price ¶

shall not be less than the highest of:
2) Posted
3) prevailing price rec'd by other producers

Establish minimum —

might be higher than price rec'd.
mechanically tied to specific transaction

Agree — minimum is set —
could be more

Lessee's ~~agree~~ —
no sale at well —
none else either

State —
No transmutations at Christmas tree —
should count if sale to 3rd party —
wherever they occur, not back to well
if #1, Valdez, cont'd. use sales at those points

3) Look at others's deals.

Hal — other interpretation

Cond — Companies — done the best job marketing — them — don't apply other's deals

Burden on state to prove other's are higher —
Some companies don't sell —

Steng — Different approaches —

Cond — ~~T~~

Faiks — is part of case determining intent of original lease drafters?

Con — yes — Defendants not together.

6

Curl In 1964 - used standard form -
no deliberations on how should apply to ANS.

Statehood approaching.

Everett Brown. from BLM
collected lease forms from the states OK, Texas, LA.
WestO&GA
hired BILL DYER Dept of Int.

Draft at public hearing in Dec.
During 1st session Land Act revised.
from Boards & Commission to Exec

4/15
DNR Commissioner Phil Holdsworth - used special approp
hired consultant - draft new
WOGA - comments on draft. - hired
WANVIK. depositions taken.

Martin why does it take so long.

Condon Co's different #'s - not all right.
State look at it all.
need to look at market facts -
trial 10/89 appeal 1 1/2 after 1992
can't decide in a vacuum.

Martin change lease form?

Condon Endicott - 1/2 old
1/2 new 1979 form
39. Kuparuk 1982 form - different

Maynard body of expertise to find new solutions.

Joe Range of $ - ?

Con have claimed refunds

Joe interpret against drafter (State)

May Count did not apply against state.

Joe ~~State~~ ~~[illegible]~~ - Suit in Federal Court.

Fisher stop spending $

May costs drop after trial -

Now - experts - acct's
$ 6 million

Cond

Need, accurate, reliable data -
match production to disposition -
complicated -
Jan oil delivered in April at Gulf
Royalty obligations are monthly -
Some co's kept good records -
Exxon good. - others know tankers but not feed
Million pages of documents - most expensive
25,000 tanker loads
100,000 deliveries 5 billion barrels.

May/ Side benefits - data base useful for tax audits

2) Require reporting in future.

Fitz

JO Legislation Continuing expenditures?

Mng Costs but not as much

BF look at statutory changes to require reporting.

Condn. ·Average Month.

can't use prices rec'd

Disposition Breakdown -

None sold — ALL EXCHANGED →

put value on Exchanges.

2-5-88

BRIEFING ON
Oil & GAS
(JOINT with
SENATE RES.)

JOINT SENATE RESOURCES COMMITTEE AND SENATE OIL AND GAS
February 5, 1988
1:38 p.m.

MEMBERS PRESENT

Senator Jack Coghill, Chairman
Senator Bettye Fahrenkamp, Chairman
Senator Paul Fischer
Senator Jim Duncan
Senator Fred Zharoff
Senator Arliss Sturgulewski
Senator Dick Eliason
Senator Fanning

COMMITTEE CALENDAR

SENATE BILL NO. 304
"An Act relating to filing and recording, recordable documents, conveyances, plats, and platting authorities; and providing for an effective date."

Overview of the oil and gas policy management accounting practices

WITNESS REGISTER

Hugh Malone, Commissioner
Department of Revenue
P.O. Box S
Juneau, Alaska 99811

Bill Van Dyke
Petroleum Manager
Division of Oil and Gas
Dept. of Natural Resources

Chat Chatterton, Chairman
Oil and Gas Conservation Committee
Department of Commerce and Economic Development
3001 Porcupine Drive
Anchorage, Alaska 99501
(Testified via teleconference)

Bob Maynard
Assistant Attorney General
P.O. Box K
Juneau, Alaska 99811

PREVIOUS ACTION

SB 304 - See Resource Committee minutes dated 1/20/88, and 1/27/88.

ACTION NARRATIVE
TAPE 1, SIDE 1
Number 001

Senator Coghill called the Senate Resources meeting to order at 1:38 p.m.

Number 014
#SB304
The first measure to come before the committee was Senate Bill 304. Senator Coghill noted there was an amendment on the second page of the bill. He said section 5 was added which read, "(5) instructions that explain to the public the formal requirements that a document must satisfy to be recorded."

Number 33

Senator Sturgulewski moved for the adoption of the committee substitute for Senate Bill 304, Resources and asked unanimous consent. Senator Coghill asked if there were any objections. Hearing none, it was so ordered.

Senator Coghill informed the members the committee substitute for Senate Bill was before the committee. Senator Sturgulewski made a motion to move the bill with individual recommendations. Senator Coghill asked if there were any objections. Hearing no objections, the motion passed.
#
Number 091

Senator Coghill announced the next item on the agenda would be an overview of the oil and gas policy management accounting practices. Mr. Bill Van Dyke, Petroleum Manager for the Division of Oil and Gas within Department of Natural Resources was first to testify before the committee.

Mr. Van Dyke said he would be giving a brief overview of the royalty accounting and management of oil and gas. He said the oil is made pipeline quality, then it flows to pump station one where there is a royalty meter. From the meters there are meter tickets produced. He said that is the official spot where royalty is measured and volume is accounted for. Mr. Van Dyke informed the members that Standard Oil is the oil movements coordinator at Prudhoe Bay.

Mr. Van Dyke said they receive meter tickets, operative reports and a monthly royalty report which is filed by each of the lessees. They then cross check what comes in on the royalty reports to make sure it matches up with meter tickets, operative reports and numbers that the Alaska Oil and Gas Conservation Commission (AOGCC) has provided.

Number 190

Senator Eliason asked why a bank in Pennsylvania is used. Commissioner Hugh Malone said the First Pennsylvania Bank is a clearing bank and they are capable of providing services at a national level.

Mr. Van Dyke said as oil is produced at Prudhoe Bay it goes through cleaning and separation facilities. Some of that gas produced is burned as fuel to run equipment and provide heating. He said there is no royalty due on that gas.

He said there is a certain amount of oil that goes through the crude oil topping plant. Mr. Van Dyke noted there is a small refinery which makes diesel. He informed the committee members diesel is used mostly for well operations.

Number 260

Senator Sturgulewski asked how gas liquids are handled. Mr. Van Dyke said the gas liquids are blended with the crude oil, then the combined mixture goes through pump one and is metered. Senator Sturgulewski asked if there is a royalty determination on the combined mixture and asked what the value of product is. Mr. Van Dyke said they are presently having a disagreement determining what type of processing fee should be deducted. He said the disagreement is determining whether it should be the Prudhoe Bay field cost that was agreed on or a different number.

Number 284

Senator Sturgulewski asked if it is recorded separately so a value can be established. Mr. Van Dyke said the natural gas liquids are produced at a natural gas facility in Prudhoe Bay and that volume coming out is metered.

Senator Coghill noted there are four meters that are being tracked. One is for the liquids, one off the diesel plant, one from the Kuparuk oil field and the main meter at pump one.

Number 306

Mr. Van Dyke said the main meter for Prudhoe Bay is at pump one. He noted Kuparuk, Lisbourne and Endicott have separate meters and they all feed into pump one.

Senator Fahrenkamp asked if the figure of 40,000 is a correct figure for natural gas liquids. Mr. Van Dyke said some days there are 50,000 to 55,000 barrels output per day and there are hopes the plant could output more. Mr. Van Dyke said they receive the volume numbers on the royalty tickets and royalty returns. They then prepare bills for inkind purchasers such as Mapco, Petrostar, Chevron, etc. for the volumes taken.

Senator Fahrenkamp asked if the state gets royalty on all the natural gas the companies burn. Mr. Van Dyke said not on the gas burned in the field. He said they receive royalty on the gas that is sold to Alyeska. He informed the members the first four pump stations use natural gas for fuel. Senator Fahrenkamp asked Mr. Van Dyke how he thinks the accounting procedure is working.

Mr. Van Dyke said he believes the system is working very well. He also noted there has been an independent petroleum accounting firm that has looked at the system and indicated they felt comfortable with it. He noted Legislative Audit looks at the records every other year.

Number 408

Senator Coghill asked if the gas, which is used to run the camps, is metered. Mr. Van Dyke said the gas used by Arco and Standard is used for free and the gas sold by a third party is metered. He also said 1/8 of the gas they burn, if sold somewhere else, would have a 1/8 royalty.

Mr. Van Dyke said when the central gas facility at Prudhoe Bay came on line, natural gas liquids were produced and shipped down the pipeline, the producers filed their monthly royalty return including their share of the natural gas liquids. They deducted a processing fee from the reported value.

Number 450

Senator Coghill asked how the volume is tied through the meters, to a price, when there isn't an established price. Mr. Van Dyke said the producers report a price.

Number 471

Mr. Robert Maynard, Assistant Attorney General came before the committee. He said the companies pay a royalty on all oil taken out of the system that is used by the pump stations below pump four. He said they report a number and the state can disagree with the number. Mr. Maynard said they do record and pay a royalty on those amounts. He referred to the natural gas used for field fuel and noted there is not a royalty obligation on that. Mr. Maynard stated the royalty question arises only when gas is removed from the unit.

Number 493

Senator Eliason asked at what point, certainly not at the well head, certainly not a pump station one where they have the count, is it at the market place on that particular day, that the oil is being delivered to that market. Is that where the final figures come from or how do you work that. Mr. Maynard said some of the companies accounted for the price of the oil as it value day it was removed from the field, the day it actually entered pump station one. Some of the companies value the oil on the day it actually arrived in the lower 48.

Number 509

Senator Coghill referred to the product going through pump one and the meter, it is laced with gas liquids, it goes into their system, they take their cut and put the balance back into the line and send it down through. Senator Coghill asked how value is determined for the product that is going to the refineries. Mr. Maynard said they are taking the position that once the gas liquid is butted with the oil stream, it becomes oil. He said the companies are taking the position that the gas liquids are not oil and should be treated as something different. Senator Coghill asked if the value of the oil is increased because it is being laced with gas.

Number 534

Mr. Maynard said the companies are trying to charge $4 to $7 as a processing fee for every barrel treated as gas liquids. Mr. Maynard said the oil companies are trying to say that every barrel they treat as gas liquids, are entitled to a processing fee of $4 to $7 per barrel. If it is treated as oil they only get $.70. He said once it goes into pump one, the whole stream value is raised.

Number 568

Mr. Maynard told committee members there is a fairly complex accounting system used by the TAPS System called "quality bank" which charges or penalizes individual shippers, depending on whether it is crude or gas liquids, that are being injected into the system. If higher gravity crudes are being injected, there will be a credit. If lower crudes are being injected a company would have to pay more into the quality bank. He said the quality bank is supposed to equalize the cost of transporting crude oil of different grades

Number 602

Senator Fahrenkamp referred to unitization and how its done. She asked Mr. Van Dyke to explain how it works.

Mr. Van Dyke said they offer individual oil and gas leases for sale and administer those leases. People go onto those leases and drill exploratory wells. If they are successful and the surrounding lessees are successful, they would unitize, they join together and through a written agreement. They operate that field as if it were one big oil and gas lease.

Senator Fahrenkamp asked what the criteria is to determine who participates in the unit. Mr. Van Dyke said the people who have leases over that common oil and gas pool are the ones who are entitled to participate in that unit agreement.

Number 633

Senator Fahrenkamp asked if there is specific criteria of who makes the bottom line decision and what is the system of appeal.

TAPE 1, SIDE 2
Number 001

Mr. Van Dyke said they petition the commissioner and ask to come into the unit. The commissioner decides based on the technical information that is presented. He noted there are appeal rights. Mr. Van Dyke stated the Conservation Commission has that same authority on all leases in the state.

Number 041

Senator Fahrenkamp referred to not having a set criteria and asked if it is determined by each unit. Mr. Van Dyke told her it is determined by each application.

Number 105

Senator Coghill asked if the state has a formula to add acreage that has been dropped. Mr. Van Dyke said if someone goes outside an existing unit and drills, finds oil and gas, that is clear evidence of a find. He said he couldn't see how it could be denied to bring that lease in.

Senator Fahrenkamp referred to Sale 54 and asked who bid, what was taken in on it and what method was used. Mr. Van Dyke showed a map with some summary information on it. He stated there was a lot of competition for those tracts. Senator Fahrenkamp asked how people are notified of a sale. Mr. Van Dyke noted there is a mailing list and, as people call in, they are added. He noted they send notices to trade journals such as the Oil and Gas Journal and publish notices in local papers.

Senator Fahrenkamp asked what the incentives were on the sale. Mr. Van Dyke said they offered exploration incentive credit. Someone bids and wins a lease, they drill an exploratory well, they are allowed to credit 15% of that well cost or so many dollars per foot, against rents and royalties due the state.

Number 207

Mr. Van Dyke said the commissioner and Governor wanted to know what Canada and other states were doing as far as incentives. He said they then compiled a comprehensive report of a listing and analysis of what laws other states actually put on the books. He said they discussed, with the commissioner, which of those laws might or might not make sense for Alaska. He said they are presently under advisement. Senator Fahrenkamp asked that the committee be kept informed as to the status regarding the advisements.

Number 236

Senator Fahrenkamp referred to legislation passed, last year, regarding exempt sales. She asked if there has been any exempt sales held. Mr. Van Dyke said there was an amendment to statute number 38.05.035. He said those provisions will be used in a sale this coming June.

Number 256

Senator Coghill referred to lease sales and asked if all lease holders, in a particular lease sale, would have the same terms and conditions when they are issued. Mr. Van Dyke said in the most part all the terms and conditions for a lease sale are identical.

Number 321

Senator Fahrenkamp referred to Dr. Stansilaw from Cambridge Energy testifying before the Finance Committee. Dr. Stansilaw had said prices could go to $12 and even lower. She asked if there is any kind of a provision in any policies of the department where the state, on their royalty part, could decrease production or have any control of what is produced.

Number 363

Mr. Maynard said this was looked at during the end of the Sheffield Administration. He said there are potential options but if the state went in and tried to close out Prudhoe Bay, lateral consequences occur elsewhere. He said there is a concept of economic waste which is sometimes used, as a basis, for regulating production. He said the Texas Railroad used this concept to cut production in Texas when the prices dropped. Mr. Maynard said there is nothing in the state's leases which would allow that particular concept. He said the concept primarily used by the Oil and Gas Commission deals with physical waste in which economic considerations are a secondary consideration.

Number 390

Senator Fahrenkamp asked Mr. Maynard if there is a need for a statutory change? Mr. Chatterton said there are four oil producing states which have language in their statutes that deal with economic waste. He said the the U.S. can't do much to control the world price of crude even with our eight million barrels per day production. He said he didn't know what could be done to prevent this.

Number 434

Mr. Maynard said that preventing negative well head values and the possibility raising an already adequate price to a higher level are two different things. He said the only way the state would be able, under present law, to cut back production would be under the rubric or an announced goal of preventing waste of the resource.

Number 480

Senator Coghill referred to the lease and production contracts the state presently has in place. He asked if the state couldn't go to a statutory authority saying that economic waste, of our resource, is when oil is being pumped out at a negative return to the state. Mr. Maynard said theoretically the lease is still subject to exercise of governmental powers over conservation.

Number 494

Senator Fahrenkamp asked if we couldn't take our oil and put it into a holding tank. Mr. Chatterton said we could have our own Alaska strategic petroleum reserve and put royalty oil into it. He noted that we don't get any royalty until the environmental oil is captured and then we get 1/8 of the barrel. He said we could take all the 1/8 of the barrels and reinject it into a subsurface reservoir and bank roll it. Mr. Chatterton noted the only problem is we may not get all the oil back.

Number 529

Senator Fahrenkamp referred to under lifted provisions in cases of emergencies and asked if under lifting can go into effect in the case of waste and, if it could it be changed statutorily. Mr. Maynard told her the answer was no to both questions.

Number 538

Senator Fahrenkamp asked Mr. Chatterton if he believes the accounting system is working. Mr. Chatterton said their part is to try and assure the people of Alaska that the oil is being produced at "severed them from the property," and is accounted for, measured properly and honestly, and the quality of the oil is recorded and reported. He said there is not a question in his mind that a top notch job is being done.

Number 568

Senator Coghill asked Commissioner Malone to come before the committee. Senator Coghill asked if Mr. Malone feels the accounting procedures are satisfactory and protect the public's interest.

Number 583

Commissioner Malone said in as far the accounting and physical production of oil and gas leases in the state goes, he believes the information is adequate. It is basically the same system the producers are using. He said the real problem comes in when the engineers leave and the accountants take over.

Commissioner Malone referred to the zero well head value as it affects the tax area and said there is a legal way for the state to protect itself. That is to put a floor on severance tax. He said there is a way to do this on the tax side but royalty is more complicated because it is a contract.

TAPE 2, SIDE 1
Number 001

Mr. Malone noted he believes the state needs to make efforts in making sure they have information, on a current basis, that is in much greater detail than is being received at the present time. He indicated this problem could be brought up to date.

He said what can't be fixed are the complexity of the transactions that are inherent in national and international businesses.

Number 061

Senator Coghill asked if there isn't a way that certain reporting structures would be required.

Mr. Malone said the state does need to make more of an effort, on a current basis rather than a project basis, to get data. The executive and legislative branches should be reviewing the data to make sure the tax and royalty laws are being administered. He suggested the legislature look at the structure of the laws to see if there are ways that the law could be made more simple. He said it would be best to do it through the legislative process.

Number 102

Senator Fahrenkamp asked in the event of oil spills, hazardous waste cleanups or bankruptcy, are their bonds sufficient to cover the cost.

Mr. Van Dyke referred to the oil and gas leases at Prudhoe and Kuparuk. The operators are required to post a bond to cover those lease operations and activities. Senator Fahrenkamp asked if the bonds are sufficiently covering spill areas? Mr. Van Dyke said as far as oil and gas operations and leases go, the bonds are sufficient.

Number 170

Mr. Chatterton said by regulation, the commission requires a $100 thousand bond as a condition for issuing a permit for drilling a single well. A $200 thousand bond is required for two or more wells. He said the $100 thousand would be insufficient if the operator walked away. He also noted if the bonds were raised to a higher amount, it would be bad for independent operators as it is more difficult for them to obtain bonds.

Number 225

Senator Coghill told the committee these issues would be scheduled, before the Senate Resources Committee, at a later date. He adjourned the meeting at 3:23 p.m.

2/5/88

Cog Fanning
BF Eliason
Fischer Sturgulewski
Duncan

JOINT w/ Senate Resources
+ Senate Special Committee on
Oil + Gas.

BILL VAN DYKE — Div. Oil and Gas. →
Petroleum Manager -

Royalty Acct. Rpt and Management.

North Slope -
made pipeline quality → P.S. #1 .
royalty meter - meter tickets - volume
and Standard responsible -
also meter for Kuparuk + monthly royalty reports
Royalty payments were transferred to Bank in
Pennsylvania 1st Penn Bank

Topping plant - diesel - reported seperately

Sturg NGL - seperate accounting or value

blended upstream - go through PS #1
value -

processing fee - Prudhoe Bay field costs
or others.

Royalty

VanDyke Independent Petroleum
+ leg Audit - OK.

Sturg Current?

Van Dyke yes. w/in a month.

Eliason meters other place on line —

Van Dyke Yes. in Valdez

Arco + Standard use gas for free.

Quality Bank —

injecting higher gravity — credit.
lower — penal. -

differential payments — contribution to stream

relate to tariffs

for equalizing costs —

Unitization —

1) leases —
2) - fields cover

unit agreement to operate as one lease.
operated by one operator.

use well data, seismic, results from development wells. — amended over time —

on state leases — commissioner makes final determination

on all leases ~ AOGCC

looked at circle target - methods —

2 circles wouldn't overlap

Sale 54 —

happy w # of companies —

dollar per acre not that good —

majors bidd against each other.
maintain mailing list. —

Notify —

Early exploration — offered ex incentive credit.

allowed to credit up to 15% of well costs
total % of well or $ ~~ft~~ per foot.

Other incentives —

listing + analysis of other states —

Exempt sales —

will use in June —
useful in North Slope —
later in Cook Inlet.

Coy Lease terms + sales?

VanDyke mostly identical — environmental stips
royalty

Zero-wellhead — protect royalties?

not aware –

truly to prevent waste of resource.

reinject royalty oil —

underlifting — for emergency —

triggered by lifting provisions.

Chat

measurements are being done —

meters checked daily.

any oil severed is accounted for accurately.

Malone

information adequate.

same systems that producers use.

floor on severance tax —

but ELF

80 ¢ / barrel.

4.50 ¢.

difficulty w/ netback —

accounting

① better detail from co's.
②. Gather own empirical data.

Dugr

look at simplifying tax laws.

Bonds — are They high enough

Chat - commission requires 100,000 bond. - single
200,000 - 2 or more.

would be insufficient for state to cover down-hole abandonment.

large operators have no problem getting bond.
independents can't get underwriting -

adjourned. 3:20 —

JOINT MEETING OF SENATE SPECIAL COMMITTEE ON OIL AND GAS AND SENATE RESOURCES COMMITTEE

February 5, 1988

Briefing on State oil and gas management, policies, and accounting.

TO TESTIFY:

BILL VAN DYKE, Division of Oil and Gas, DNR

CHAT CHATTERTON, Alaska Oil and Gas Conservation Commission (on teleconference)

ALSO ATTENDING:

DEBRA VOGT, Department of Revenue,

RICHARD FINEBERG, Division of Policy , OMB

BOB MAYNARD, Attorney General's Office

1. Ask for an overview of the division's role in implementing oil and gas policies.
   A. How do other agencies, Revenue, Law, DEC, Fish and Game, OMB work with you?

2. Recent Oil and Gas Activity
   A. What's been happening around the state in the oil and gas industry?
   B. I've heard that the industry is expecting to increase drilling and exploration activity next year. Standard Alaska said it will spend about $400 million and ARCO indicates it will spend about $300 million.
      1) How does this compare to last year?
         a) It's about double.
3. Review Five Year Plan
   A. What lease sales are planned for the next year?

4. Results of Sale #54, Kuparuk Uplands
   A. Who bid?
   B. Who is notified of our lease sales?
      1) We were told by Japanese oil industry executive at a recent conference that they were eager to integrate into upstream activities, like exploration and production. Should the state make an effort to actively solicit more interest in our lease sales?
   C. The state offered incentive credits to companies willing to explore within five years. Can you explain how that works? Do you expect to offer these in the future?
      1) The division did some research this fall on other tax incentives. Can you comment on the results? Can you explain:
         a) Discovery Royalties, or
         b) Royalty Holidays

5. Exempt Sales
   A. Last year the oil and gas committee sponsored legislation that would help to streamline the exempt sales procedures. We hoped this would allow the division to hold exempt sales in areas of interest to industry in less time. Has this worked? Have you had any or planning any exempt sales?

B. Any other suggestions for legislation?

6. Tracking and accounting for state oil and gas
   A. How is throughput determined?
      1) Is there a meter somewhere? Where?
         a) Yes. In Prudhoe Bay. But after the topping plant takes out what it needs. How much is that?
      2) Who checks it? How often?
         a) DNR checks it every other week. Is that enough?
      3) Have you noticed any relationship between oil prices and throughput? When prices were at their lowest in 1986, what was the throughput?
         a) It was high because high profits were being made in the refinery runs.
      4) Do the other agencies, Revenue and the Oil and Gas Conservation Commission, use the same numbers?
         a) No. They each have different figures. Why?
         b) The most glaring example is that the throughput numbers being used for Revenue projections have been low and were recently revised upwards by 50,000 barrels per day to account for the NGL's produced.
      5) Ask Chat Chatterton how he feels the accounting procedure is working.
         a) He admits there are problems.

   B. Protection of state resources in low or zero wellhead prices.
      1) Dr. Stanislaw told us yesterday that prices could go to $12 in the short term. Or even lower. He said there is nothing to stop it from going lower.
      2) What can the state do in the event that oil prices drop to a level where the netback value is close to zero as it did in 1986? Do we have the authority to restrict production? Underlift?

7. Bonds required for oil and gas leases.
   A. How much is required? In the event of an oil spill or hazardous waste clean-up, and a company declares bankruptcy, are they sufficient to cover costs? Should they be increased?

8. NGL field costs negotiations.
   A. Can you review the background, discuss some of the disputed

issues and bring us up to date on the status of the negotiations?

9. Unitization
   A. Can you explain the procedures the division uses for unitizing oil and gas fields?
   B. What are the criteria for determining participating areas?
   C. How often are they reviewed?
   D. Other states use the "circle tangent method". Wouldn't that be simpler and lead to less controversy?
   E. Ask Chat Chatterton to explain how the Oil and Gas Conservation Commission handles unitization.
   F. Is it consisitent with the Division of Oil and Gas? Is there a unified state policy?
   G. Are state resources and state revenues being drained as a result of unitization policies?

[illegible]
(907) 452-[illegible]

April 7, 1987

Katherine Fortney
State Division of Oil and Gas
Pouch 7-034
Anchorage, Alaska 99510-0734

Dear Kate:

Burglin et al (Burglin) is requesting a written policy from the Division of Oil and Gas regarding PA (participating area) review. It is clear under II AAC 83.351 (c) "A participating area must be expanded to include acreage reasonably estimated through use of geological, geophysical, and engineering data to be capable of producing or contributing to the production of hydrocarbons in paying quantities, and must be contracted to exclude acreage reasonably proven through use of geological, geophysical or engineering data to be incapable of producing hydrocarbons in paying quantities, subject to approval by the commissioner. A revised division of interest or formula allocating production and costs must be submitted for approval under II AAC 83.371 at the time of expansion or contraction of a participating area."

The Division of Oil and Gas staff has emphasized initial P.A.'s in their recent decisions concerning P.A.'s. Burglin is requesting the division address Burglin's following concerns:

(1) How often are P.A.'s reviewed by division staff?
(2) When does an initial P.A. become a final P.A.
(3) How are initial P.A.'s [illegible] delineated?
(4) Does the division staff take any initiative to expand or contract P.A.'s based on additional information?
(5) Does the unit operator have any obligation to expand or contract a P.A. when additional information dictates a P.A. expansion or contraction?

If you have any questions concerning Burglin's request, please feel free to contact Brian at 452-5149.

Sincerely,

Brian

Brian Burglin

BB/mbg

cc: James Eason
Bill Van Dyke
Comm. Judy Brady
Senator Bettye Fahrenkamp
Senator Jack Coghill
Senator Don Bennett

DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL AND GAS
P.O. BOX 7034
ANCHORAGE, ALASKA 99510-7034

April 17, 1987

(907) 762-4241

Mr. Brian Burglin
P. O. Box 131
Fairbanks, AK 99707

Dear Mr. Burglin:

I have reviewed your April 7, 1987 request to Ms. Catherine Fortney for a written policy regarding the Division of Oil and Gas's review and determination of participating areas (PAs) for oil and gas units.

In brief, the division agrees with you that the determination of participating areas is governed by 11 AAC 83.351, and that the configuration of participating areas, both initial and subsequent, must be determined on the basis of all geological and engineering data available at the time the PA is established or expanded/contracted. It is almost inevitable that some technical information pertaining to the establishment of participating areas will be proprietary, and not available to all parties within or adjacent to the unit; however, the division must, by the terms of 11 AAC 83.351, take all available information into account when approving a participating area.

The answers to your specific questions are as follows:

(1) Reviews of participating areas are generally triggered by internal unit action such as planned expansions or contractions of the unit area, or a request by one or more of the unit working interest owners for expansion or contraction of the participating area. However, the division may initiate a review and revision to an approved participating area on its own volition or at the request of others when new data are presented indicating that such a revision is necessary to protect the state's interest or the correlative rights of others. By who?

STATES INTERESTS ?

(2) ~~Generally, there is no~~ such thing as a "final" participating area until unit reserves are depleted. Participating areas are continually subject to review and expansion or contraction based on new technical data. For most oil and gas units, contraction of the unit area to exclude all lands outside of an approved participating area is tied to the date of establishment of the "initial" participating area (the first participating area within the unit). There may be no practical difference between "initial" participating areas and subsequent participating areas if sufficient data are available at the time the initial participating area is approved to confirm the distribution of reserves within the unit area.

HOW OFTEN IS CONTINUALLY ?

2

(3) Initial participating areas are delineated on the basis of all geological, geophysical, and engineering data available to the division at the time the participating area is established. Data may be available from more than one source, and the separate parties, which may not have access to all information regarding the participating area limits, may not agree with one another's interpretations. In the case of conflicting technical data, the division reviews all information available, and makes an independent determination of an appropriate participating area based on the terms of 11 AAC 83.351.

WHAT SPECIFIC CRITERIA IS USED ?

WHAT SPECIFIC [illegible]

(4) Under certain circumstances, the division has initiated action for expansion or contraction of a participating area, particularly in those instances where data indicate that an existing participating area does not adequately and equitably represent the interests of all parties involved. However, normal practice is for one or more of the working interest owners of a unit to initiate action for expansion or contraction of a participating area. A lessee adjacent to the unit may also initiate expansion or contraction if that lessee possesses technical information showing that such action is warranted.

WHAT SPECIFIC TECHNICAL INFORMATION ?

(5) In general, under the terms of 11 AAC 83.351, the unit operator, representing the working interest owners of a unit, is obligated to expand or contract when additional information indicates that such an expansion or contraction is appropriate. This obligation is also usually reflected in the provisions of the various unit agreements.

I hope this is responsive to your questions regarding the division's policy on the establishment and expansion/contraction of participating areas. If you have any additional questions on the above, please feel free to contact me.

Sincerely,

James E. Eason

James E. Eason
Director

cc: Judith M. Brady, Commissioner
Catherine Fortney, DNR/DO&G
Bill Van Dyke, DNR/DO&G
Cass Ariey, DNR/DO&G

Senator Bettye Fahrenkamp
Senator Jack Coghill
Senator Don Bennett

April 28, 1987

James Eason
Division of Oil and Gas
P. O. Box 7034
Anchorage, Alaska 99510-7034

Dear Jim:

As Burglin et al, (Burglin) understands your 4/17/87 letter, the division generally does not review participating areas unless requested to do so by an interested party.

Burglin's concern with this policy is that in undefined gas fields there can be many years and substantial drilling activity which change initial geological interpretation before a participating area is reviewed by the division.

For example, the last participating area review and revision for the Beluga River Unit was made in 1977. From [illegible] thru 1977 six (6) gas wells were drilled within the Beluga River Unit, during which time there were five participating area revisions of the Beluga River Field. From 1978 to 1987 twelve (12) gas wells have been drilled with no participating area review by the Division of Oil and Gas. Mr. Bill Van Dyke confirmed that the Beluga River Unit participating areas had not been reviewed by the division staff in over [illegible] 1/2 years, and was unaware of any Beluga River Unit participating area review since 1978. From 1985 thru 1986 eight (8) additional wells have been drilled in the Beluga River Unit. There is no economic incentive for a unit operator to initiate a participating area expansion or contraction when additional well data confirms, modifies, or rejects initial structural interpretation and estimated productive limits, once the original Working Interest Owners have lost their interest in the surrounding acreage, through unit contraction. Well data is usually confidential to adjacent lease holders or interested parties for at least two years after wells have been drilled.

Burglin feels the State's interest would be better protected if participating areas were reviewed on an annual basis and this review incorporated into unit plans of a development and operation, especially in undefined gas pools.

Sincerely,

Brian Burglin

BB/kd

cc: Commissioner Brady
Bill Van Dyke
Senator Fahrenkamp
Senator Coghill
Senator Bennett
Commissioner C. Chatterton

[illegible] rements directly asso[illegible] operations, including [illegible] n and design of well [illegible] pplies, solid waste [illegible], airstrips, and all [illegible] pment necessary to con[illegible] operations;

[illegible] ans for rehabilitation of the affected unit area after completion of operations or phases of those operations; and

(4) a description of operating procedures designed to prevent or minimize adverse effects on other natural resources and other uses of the unit area and adjacent areas, including fish and wildlife habitats, historic and archeological sites, and public use areas.

(e) In approving a unit plan of operations or an amendment of a plan, the commissioner will require amendments he determines necessary to protect the state's interest. The commissioner will not require any amendment that would be inconsistent with the terms of sale under which the lease was obtained, or with the terms of the lease itself, or which would deprive the lessee of reasonable use of the leasehold interest.

(f) The unit operator may, with the approval of the commissioner, amend an approved plan of operations.

(g) Upon completion of operations, the unit operator shall inspect the area of operations and submit a report indicating the completion date of operations and stating any noncompliance of which the unit operator knows, or should reasonably know, with requirements imposed as a condition of approval of the plan. (Eff. 6/28/81, Reg. 78; am 3/15/82, Reg. 83; am 3/18/83, Reg. 85)

Authority: AS 38.05.020 AS 38.05.145
AS 38.05.130 AS 38.05.180

11 AAC 83.350. APPROVAL OF FEDERAL UNITS. Repealed 6/28/81.

11 AAC 83.351. PARTICIPATING AREA. (a) At least 90 days before sustained unit production from a reservoir, the unit operator shall submit to the commissioner for approval a description, based on subdivisions of the public land or its aliquot parts, of the proposed participating area. The participating area may include only the land reasonably known to be underlain by hydrocarbons and known or reasonably estimated through use of geological, geophysical, and engineering data to be capable of producing or contributing to production of hydrocarbons in paying quantities. Under 11 AAC 83.371(a), the unit operator also shall submit to the commissioner for approval a proposed division of interest or formula setting out the percentage of production and costs to be allocated to each lease and portion of lease within the participating area. Upon approval by the commissioner, the area of productivity [illegible] participating area.

(b) A sep[illegible] participating area [illegible] be established as provided [illegible] section for each reservoir [illegible] With the [illegible] of the commissioner [illegible] all working interest owners [illegible] participating areas within the unit may be combined into one participating area. [illegible] participating area [illegible] within the same reservoir.

(c) [illegible] participating area [illegible] be expanded to include [illegible] through use of g[illegible] and engineering data to be [illegible] contributing to the production of [illegible] in paying quantities, and [illegible] to exclude acreage [illegible] through use of geological, geophysical [illegible] engineering data to be incapable of producing [illegible] in paying quantities, subject to approval by the commissioner. A revised division of interest, or formula allocating production [illegible] must be submitted for approval under 11 AAC 83.371 at the time of expansion or contraction of a participating area. (Eff. 6/28/81, Reg. 78; am 3/18/83, Reg. 85; am 3/20/84, Reg. 89)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.355. APPLICATIONS. Repealed 6/28/81.

11 AAC 83.356. UNIT AREA: CONTRACTION AND EXPANSION. (a) A unit must encompass the minimum area required to include all or part of one or more oil or gas reservoirs, or all or part of one or more potential hydrocarbon accumulations.

(6)

CORRECTION

THIS DOCUMENT
HAS BEEN REPHOTOGRAPHED
TO ASSURE LEGIBILITY

02-576(2/77)

[illegible] requirements directly associated with the proposed operations, including but not limited to the location and design of well sites, material sites, water supplies, solid waste sites, buildings, roads, utilities, airstrips, and all other facilities and equipment necessary to conduct the proposed operations;

(3) plans for rehabilitation of the affected unit area after completion of operations or phases of those operations; and

(4) a description of operating procedures designed to prevent or minimize adverse effects on other natural resources and other uses of the unit area and adjacent areas, including fish and wildlife habitats, historic and archeological sites, and public use areas.

(e) In approving a unit plan of operations or an amendment of a plan, the commissioner will require amendments he determines necessary to protect the state's interest. The commissioner will not require any amendment that would be inconsistent with the terms of sale under which the lease was obtained, or with the terms of the lease itself, or which would deprive the lessee of reasonable use of the leasehold interest.

(f) The unit operator may, with the approval of the commissioner, amend an approved plan of operations.

(g) Upon completion of operations, the unit operator shall inspect the area of operations and submit a report indicating the completion date of operations and stating any noncompliance of which the unit operator knows, or should reasonably know, with requirements imposed as a condition of approval of the plan. (Eff. 6/28/81, Reg. 78; am 8/15/82, Reg. 83; am 3/18/83, Reg. 85)

Authority: AS 38.05.020 AS 38.05.145
AS 38.05.130 AS 38.05.180

11 AAC 83.350. APPROVAL OF FEDERAL UNITS. Repealed 6/28/81.

11 AAC 83.351. PARTICIPATING AREA. (a) At least 90 days before sustained unit production from a reservoir, the unit operator shall submit to the commissioner for approval a description, based on subdivisions of the public land or its aliquot parts, of the proposed participating area. The participating area may include only the land reasonably known to be underlain by hydrocarbons and known or reasonably estimated through use of geological, geophysical, and engineering data to be capable of producing or contributing to production of hydrocarbons in paying quantities. Under 11 AAC 83.371(a), the unit operator also shall submit to the commissioner for approval a proposed division of interest or formula setting out the percentage of production and costs to be allocated to each lease and portion of lease within the participating area. Upon approval by the commissioner, the area of productivity constitutes a participating area.

(b) A separate participating area must be established as provided in (a) of this section for each reservoir delineated, except that with the consent of the commissioner and all working interest owners, any two or more reservoirs or participating areas within the unit may be combined into one participating area. Separate participating areas may be established to distinguish between an oil rim and a gas cap within the same reservoir.

(c) A participating area must be expanded to include acreage reasonably estimated through use of geological, geophysical, and engineering data to be capable of producing or contributing to the production of hydrocarbons in paying quantities, and must be contracted to exclude acreage reasonably proven through use of geological, geophysical, or engineering data to be incapable of producing hydrocarbons in paying quantities, subject to approval by the commissioner. A revised division of interest or formula allocating production and costs must be submitted for approval under 11 AAC 83.371 at the time of expansion or contraction of a participating area. (Eff. 6/28/81, Reg. 78; am 3/18/83, Reg. 85; am 3/30/84, Reg. 89)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.355. APPLICATIONS. Repealed 6/28/81.

11 AAC 83.356. UNIT AREA; CONTRACTION AND EXPANSION. (a) A unit must encompass the minimum area required to include all or part of one or more oil or gas reservoirs, or all or part of one or more potential hydrocarbon accumulations.

[illegible] unit area [illegible] include only those lands then included in an approved participating area and lands that facilitate production including the immediately adjacent lands necessary for secondary or tertiary recovery, pressure maintenance, reinjection, or cycling operations. The commissioner will, in his discretion, after considering provisions of 11 AAC 83.303, delay contraction of the unit area if the circumstances of a particular unit warrant. If any portion of a lease is included in the participating area, the entire lease will remain committed to the unit.

(c) Any expansion or contraction of the unit area must be based on legal subdivisions of land as defined in 11 AAC 88.185.

(d) No land will be excluded from a unit area due to the depletion of hydrocarbons.

(e) Not sooner than 10 years from the effective date of the unit agreement, the commissioner will, in his discretion, contract the unit area to include only that land covered by an approved unit plan of exploration or development, or that area underlain by one or more oil or gas reservoirs or one or more potential hydrocarbon accumulations and lands that facilitate production as set out in (b) of this section. Before any contraction of the unit area under this subsection, the commissioner will give the unit operator, the working-interest owners, and royalty owners of the leases or portions of leases being excluded reasonable notice and an opportunity to be heard. (Eff. 6/28/81, Reg. 78; am 3/18/83, Reg. 85)

Authority: AS 31.05.110 AS 38.05.145
AS 38.05.020 AS 38.05.180

11 AAC 83.360. NOTATION OF APPROVAL. Repealed 6/28/81.

11 AAC 83.361. CERTIFICATION OF WELL TEST RESULTS. For the purposes of 11 AAC 83.301 — 11 AAC 83.395, a well will be considered capable of producing hydrocarbons in paying quantities, as defined in 11 AAC 83.395, when so certified by the commissioner following application by the lessee or unit operator. The commissioner will require the submission of data necessary to make the certification, including all results of the flow test or tests, supporting geological data, and cost data reasonably necessary to show that the production capability of the well satisfies the economic requirements of the paying quantities definition. (Eff. 6/28/81, Reg. 78; am 8/15/82, Reg. 83; am 3/18/83, Reg. 85)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.365. UNIT BONDS. Repealed 6/28/81.

11 AAC 83.366. UNIT OPERATING AGREEMENT. Any revision of the unit operating agreement must be submitted to the commissioner before it takes effect. The unit agreement controls the respective rights and obligations of the unit operator, the working interest owners, the State of Alaska, and royalty interest owners other than the State of Alaska in case of conflict between the unit agreement and the unit operating agreement. Where conflicts exist solely between working interest owners, the unit operating agreement [illegible]. (Eff. 6/28/81, Reg. 78; am 8/15/82, Reg. 83)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.370. [illegible] Repealed 6/28/81.

11 AAC 83.371. ALLOCATION OF PRODUCTION AND COSTS. (a) The proposed or revised division of interest or formula allocating hydrocarbon production and unit operating costs among the leases in the unit area may not take effect until approved by the commissioner in writing. When requested by the commissioner, the lessees or unit operator shall promptly file with the commissioner all data that relates to the proposed or revised division of interest or allocation formula for all leases in the participating area. Before any disapproval of the proposed or revised division of interest or allocation formula, the commissioner will give the working interest and royalty owners reasonable notice and an opportunity to be heard. After the

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[illegible] the commissioner will approve the proposed or revised division of interest or allocation formula as submitted unless he finds in writing that the formula does not equitably allocate production and costs among the leases.

(b) If there is a separate division of interest or allocation formula among any of the parties holding an interest in the unit that is different from the division of interest or allocation formula approved by the commissioner, the parties to the separate division of interest or allocation formula not approved by the commissioner shall submit a copy of that formula to the commissioner and a statement explaining the reasons for the difference. (Eff. 6/28/81, Reg. 78; am 3/18/83, Reg. 85)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.373. SEVERANCE. (a) Except as otherwise provided in this section and 11 AAC 83.356, where only a portion of a lease is committed to a unit agreement approved or prescribed by the commissioner, the commitment constitutes a severance of the lease as to the unitized and nonunitized portions of the lease. The portion of the lease not committed to the unit will be treated as a separate and distinct lease having the same effective date and term as the original lease and may be maintained thereafter only in accordance with the terms and conditions of the original lease, statutes and regulations. Any portion of the lease not committed to the unit agreement will not be affected by the unitization or pooling of any other portion of the lease by operations in the unit, or by suspension approved or ordered for the unit under 11 AAC 83.336(b).

(b) The commissioner will, in his discretion, grant up to a two-year extension of the lease term for that portion of a lease not committed to the unit agreement under this section.

(c) A lease having a well certified as capable of production in paying quantities before commitment to the unit agreement will not be severed. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71; am 6/28/81, Reg. 78; am 8/15/82, Reg. 83)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

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

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

(c) If a default occurs with respect to a unit in which there is no well capable of producing oil or gas in paying quantities and the default is not cured by the date indicated in the demand, the commissioner will, in his discretion, and after giving the unit operator and defaulting party (if other than the unit operator) reasonable notice and opportunity to be heard, terminate the unit agreement by mailing notice of the termination to the unit operator and defaulting party. Termination is effective upon mailing the notice.

(d) If a default occurs with respect to a unit in which there is a well capable of producing oil or gas in paying quantities and the default is not cured by the date indicated in the demand, the commissioner [illegible] to terminate the unit agreement by judicial proceedings. (Eff. 6/28/81, Reg. 78)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.378. CONFIDENTIALITY OF DATA. Repealed 3/18/83.

11 AAC 83.379. SIGNATURES. Each signature on the unit agreement must be notarized or attested by at least two witnesses. Corporate or other signatures made in a representative capacity must be accompanied by evidence of the authority of the signatory to act on behalf of the principal or by a reference to such evidence previously filed. The printed or typed name and address of each signatory to the unit agreement must be set out below the signature.

For the purpose of this section, an affected owner is an owner of a quarter section directly or diagonally offsetting any quarter section upon which the operation is proposed to be conducted. In areas where irregular-shaped properties are to be drilled, the commission will determine who is an affected owner.

(i) A directional survey report, required by (a)(3) or (e) of this section, must contain the following:

(1) name of surveying company;

(2) name, title, and signature of person actually performing the survey;

(3) the date on which the survey was performed;

(4) type of survey conducted;

(5) method used in calculating survey;

(6) a complete identification of the well so as to indicate the name of the operator, the property name, the well number, and field name;

(7) the depth interval over which the survey was conducted; and

(8) a plat showing the surface location, the plotted well course, and the nearest property lines or unit lines.

(j) An inclination survey report, required by (a)(2) of this section, must contain a tabulation of the depth and drift angles for all inclination survey points.

(k) The commission will, in its discretion, require the submittal of the original film, time sheets, charts, graphs, discs, and other data used to compile the survey required by (a)(3) or (e) of this section.

(l) Upon application, the commission will, in its discretion, waive all or part of the directional survey requirements of this section, or approve alternate means for determining the location of a bore hole. (Eff. 4/13/80, Reg. 74; am 4/2/86, Reg. 97)

Authority: AS 31.05.030

20 AAC 25.055. DRILLING UNITS AND WELL SPACING. (a) In proven oil and gas fields, the establishment of drilling units and a spacing pattern may be governed by special pool rules adopted in accordance with 20 AAC 25.520. In the absence of an order by the commission establishing drilling units or prescribing a spacing pattern for a pool, the following apply:

(1) a governmental quarter section constitutes the drilling unit for oil exploration; the surface location for a well exploring for oil must be at least 500 feet from the drilling unit boundary;

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(2) a governmental section constitutes the drilling unit for gas exploration; the surface location for a well exploring for gas must be at least 1500 feet from the drilling unit boundary;

(3) where oil has been discovered, not more than one well may be drilled to that pool on any governmental quarter section, nor may any oil pool be opened to the well bore closer than 500 feet to any quarter section line, nor closer than 1,000 feet to any well drilling to or capable of producing from the same pool; and

(4) where gas has been discovered, not more than one well may be drilled to that pool on any governmental section, nor may any gas pool be opened to the well bore closer than 1,500 feet to any section line, nor closer than 3,000 feet to any well drilling to or capable of producing from the same pool.

(b) An application for exception to the provisions of this section must set out the names of all owners and of all operators of governmental quarter sections directly and diagonally offsetting the quarter section where the oil well is located, or the names of all owners and of all operators of governmental sections directly or diagonally offsetting the section where the gas well is located. A plat must be attached, drawn to a scale of one inch equaling 2,640 feet or larger, showing the location of the well for which the exception is sought, all other completed and drilling wells on the property, and all adjoining properties and wells. The application must be verified by a person acquainted with the facts, stating that all facts are true and that the plat correctly portrays pertinent and required data. The applicant for exception must send notice of the application by registered mail to all owners and to all operators noted above, and furnish the commission with a copy of the notice, date of mailing, and the addresses to which the notices were sent. The application for exception will be handled in accordance with 20 AAC 25.540.

(c) A well may not be re-entered for the purpose of producing oil on a property that is smaller than the governmental quarter section upon which the well is located or for the purpose of producing gas on a property that is smaller than the governmental section upon which the well is located.

(d) If two or more separately owned properties are embraced within a governmental quarter section to be drilled, or a well re-entered for oil, or a governmental section to be drilled, or a well re-entered for gas, persons owning the oil or gas rights may voluntarily pool their separate interests to form a drilling unit. A copy of the pooling agreement must be submitted to the commission. If one or more persons owning oil and gas rights fail to voluntarily pool their interests, the commission, upon petition or its own motion, and after public hearing, will, in its discretion, issue an order pooling the owner's interests for the development of their land as a drilling unit. (Eff. 4/13/80, Reg. 74; am 4/2/86, Reg. 97)

Authority: AS 31.05.030
AS 31.05.100

20 AAC 25.061. WELL SITE SURVEYS. (a) Near surface strata to a depth of 2000 feet in the well site area for all exploratory and stratigraphic test wells must be evaluated seismically by common depth point refraction or reflection profile analysis to identify anomalous velocity variations indicative of potential shallow gas sources. Analysis results must be included with the application for the Permit to Drill (Form 10-401).

(b) The well site area must be evaluated by sidescan sonar and other pertinent surveys to determine whether potential seabed hazards to drilling operations are present for each type of well listed in 20 AAC 25.005 to be drilled offshore from a mobile bottom-founded, jack-up or floating unit. Survey results must be included with the application for Permit to Drill (Form 10-401).

(c) Upon request by the operator, the commission, in its discretion, will waive the requirements of this section. (Eff. 4/13/80, Reg. 74, am 4/2/86, Reg. 97)

Authority: AS 31.05.030

20 AAC 25.065. HYDROGEN SULFIDE. (a) When hydrogen sulfide gas is encountered, the operator shall notify the commission within 24 hours.

(b) If a well is to be drilled in an area where a formation to be penetrated is known to contain hydrogen sulfide gas, or if hydrogen sulfide is encountered while drilling, each operator shall meet the requirements of API RP 49, "Recommended Practices for Safe Drilling of Wells Containing Hydrogen Sulfide."

(c) If there is an insufficient history of drilling in an area to know whether hydrogen sulfide exists, the commission will specify on the drilling permit that the operator shall comply with the minimum requirements for detection, monitoring, contingency and control, and training as follows:

(1) detection and monitoring:

(A) an automatic hydrogen sulfide monitor must be installed and must have a combination visual and audible alarm system located where it can be seen or heard from all parts of the location;

(B) the automatic hydrogen sulfide monitor must have a minimum of two probes, one at the shale shaker and one on the bell nipple; and

(C) in addition to the automatic hydrogen sulfide monitor, at least three manual detectors with an adequate supply of extra detector tubes, must be available at the drill site;

(2) contingency and control

November 11, 1986

James Eason
State of Alaska
Division of Oil and Gas
Pouch 7-034
Anchorage, Alaska 99510

Re: Pretty Creek Unit Establishment of Initial Participating Area

Dear Mr. Eason:

Thank you for your prompt response to Burglin et al (Burglin's) October 22, 1986 letter.

Burglin does agree that the criteria for establishment of participating areas is set forth in 11 AAC 83.351, however, Burglin does not agree that the Division has consistently followed 11 AAC 83.351. At this time Burglin is unable to discern what methodology, if any, is used by the Division for the establishment of participating areas. When Burglin specifically demonstrates that the Division has not followed the criteria as set forth in 11 AAC 83.351 based on submitted data, the Division informs Burglin that the Division has the authority to "geologically compromise" the data submitted. This was acknowledged by Ms. Fortney's letter of 2/20/86 in which she states: " it is our belief that your contention that 11 AAC 83.351 does not give the Division of Oil and Gas the power to accept a compromise PA is without merit. 11 AAC 83.351, attached to this letter as Part II of Attachment 1, is completely silent as to the methodology by which the extent of a participating area is determined. All it requires is that the participating area include only the 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 production of hydrocarbons in paying quantities.

In any unit with more than one working interest owner, there are bound to be differing technical interpretations of the available data. In that sense, each and every unit area and participating area application that comes into this office for approval is a "compromise" application. Not only is the State not explicitly prohibited from considering and approving such "compromise" applications, we are required to consider all interpretations submitted, including the "compromise" interpretations, and, if necessary, decide which interpretation best fits the available data.

In this case, where the working interest owners have not agreed on a consensus or compromise geologic interpretation of the area, any approved participating area will by necessity be a "compromise" for at least some of the parties involved. However, any initial participating area is subject to further revision in the future as newly acquired data indicate the need for such revision."

11 AAC 83.351 does not explicitly give the Commissioner of the Division their

(907) 452-5180

November 11, 1986
James Eason
P. 2

assumed authority to compromise geological data. If the Division had the authority to "geologically compromise" participating areas, then 11 AAC 83.351 would not be needed. In Ms. Brown's decision letter of January 7, 1986 she states: "The regulation governing the establishment of participating areas (11 AAC 83.351) states that a participating area may include only the land reasonably known to be underlain by hydrocarbons or reasonably estimated through use of geological, geophysical and engineering data to be capable of producing or contributing to production of hydrocarbons in paying quantities, and that a participating area must be expanded to include acreage reasonably estimated through use of geological, geophysical or engineering data to be capable of producing or contributing to production of hydrocarbons in paying quantities. The division interprets this regulation to mean that all lands included within a defined hydrocarbon accumulation must be included within the participating area of a producing unit."

To allow the Division to "compromise" a party out of a PA when that party has met and followed the criteria of 11 AAC 83.351 is definitely not in the compromised parties' best interest. Further, the Commissioner is required under 11 AAC 83.303 to "(3) provide for the protection of all parties of interest, including the state."

In conclusion, Burglin still feels that a hearing is needed to discuss the Division's "methodology" for the establishment of participating areas, whether the Division is willing to discuss it or not.

Sincerely,

Brian Burglin

Brian Burglin

BB/mbg

cc: Governor Steve Cowper
Senator Bettye Fahrenkamp
Senator Don Bennett
Rep. Mike Davis
Rep. Mike Miller
Rep. Niilo Koponen
Rep. Mark Boyer
Rep. Steve Frank
Commissioner Chatterton, AOGCC

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May 27, 1986

Lonnie C. Smith
Commissioner
Alaska Oil and Gas Conservation Commission
3001 Porcupine Dr.
Anchorage, Alaska 99501-3192

Re: The application of CHEVRON U.S.A., INC. for an exception to 20 AAC 25.055 to permit the drilling of a well in Pretty Creek Unit.

Dear Commissioner Smith:

Burglin et al (Burglin) is filing written protest against any well location exceptions requested by Chevron on behalf of the Working Interest Owners of the Pretty Creek Unit.

Burglin does not feel any proposed well location exceptions should be granted in an approved unit in which no underlying [illegible] been clearly delineated. The productive limits of the Beluga and Sterling formations within the Pretty Creek Unit have not been clearly delineated at this time.

Chevron has not submitted a complete Unit Plan of Development [illegible] 11 AAC 83.343 which must include: "(1) long-range proposed [illegible] activities for the unit, including plans to delineate all underlying oil or gas reservoirs, bring the reservoirs into production, and maintain and enhance production once established;
(2) plans for the exploration or delineation of any land in the unit not included in a participating area;".

The Division of Oil and Gas admittedly uses "compromised" geology for the establishment of initial PA's (Participating Areas). To allow well spacing exceptions in conjunction with "compromised" geology prior to clear delineation of all underlying reservoirs is not in the best interest of the State of Alaska.

Compromised initial PA's (allocation of production) and liberal well-spacing exceptions are two of the primary reasons why Burglin has recommended the State of Alaska adopt the circle-tangent method for determining a PA.

Adoption of the circle-tangent method would greatly restrict the use of compromise PA's and well-spacing exceptions.

If you have any questions, please call Brian at 452-3118.

Regards,

Brian Burglin

Brian Burglin

cc: Rep. Mike Davis
Rep. John Ringstad
Rep. Steve Frank
Rep. Mike W. Miller
Sen. Don Bennett
Sen. Bettye Fahrenkamp
Kate Eortney, DNR

BB/plb

enclosures

3-7-88

Oil & Gas

Hearing

(Joint with

Senate Res.)

JOINT SENATE RESOURCES COMMITTEE AND OIL AND GAS
March 7, 1988
1:39 p.m.

MEMBERS PRESENT

Senator Jack Coghill, Chairman
Senator Bettye Fahrenkamp, Chairman
Senator Paul Fischer
Senator Jim Duncan
Senator Fred Zharoff
Senator Arliss Sturgulewski
Senator Dick Eliason
Senator Ken Fanning

COMMITTEE CALENDAR

Overview of Oil and Gas matters

WITNESS REGISTER

Bill Van Dyke
Petroleum Manager
Dept. of Natural Resources
P.O. Box 107034
Anchorage, Alaska 99510
(907) 762-2547

Cliff Burglin
Land Consultant & Independent
Oil Leaser
Fairbanks, Alaska

ACTION NARRATIVE
TAPE 1, SIDE 1
Number 001

Senator Coghill called the Senate Resources meeting to order at 1:39 p.m. Senator Coghill announced the schedule for the meeting.

Number 045

Mr. Bill Van Dyke, Petroleum Manager for the Division of Oil and Gas within the Department of Natural Resources, was first to come before the committee members. He continued to explain some information which was in the committee member's packets. He also passed, to the members, a general summary of the unitization process. Mr. Van Dyke noted the bulk of the handouts were unitization regulations. He also noted there were regulations from the Gas Conservation Commission on well spacing also included.

Mr. Van Dyke referred to exempt lease sales and noted there is one planed for September, 1988, in addition to one scheduled for June, 1988. He said they have requested comments to see how much interest there is. If there is good interest for the North Slope sale, it will be held in September.

Number 106

Senator Coghill asked which areas would be up for lease. Mr. Van Dyke told Senator Coghill the areas are all onshore. The sale proposed for September is south of Prudhoe Bay in Kuparuk.

Mr. Van Dyke referred to the handout on unitization and said Department of Natural Resources has never been the ones instigating unitization, it has been lessees that have decided they want to unitize. Mr. Van Dyke said the lessees present geological and geophysical information to support why the areas should be unitized.

Number 151

Senator Fahrenkamp asked if there is a disagreement between the geologists and the people of the state, what method of appeal is there. Mr. Van Dyke said if the commissioner approved a unit boundary which someone disagreed with, they could appeal the commissioner's position and ask her to reconsider. If they still felt strong about it, they could go to court and have a judge make a ruling. He also said they could go to the Conservation Commission. Mr. Van Dyke noted there are regulations in 11 AAC 88 regarding appeals. Senator Coghill noted he would like a copy of these regulations.

Number 188

Mr. Van Dyke said a participating area is a subset of the unit area and is formed over one particular oil and gas pool. He said at Prudhoe Bay there are a number of different oil and gas pools within the Prudhoe Bay unit boundary. Mr. Van Dyke said a participating area is a means of allocating ownership within the oil and gas pools.

Number 215

Senator Coghill asked if the applicants seismic and geologic data is relied on to make the unitization decisions. Mr. Van Dyke said the data is used it is very seldom that there is only one set of information. There is information from several companies and the Department of Natural Resources. All information is considered, he stated.

Number 235

Mr. Van Dyke referred to information the legislators had and said it shows well spacings and a map field limit. He continued to present visual information, maps, and illustrations to the committee members while explaining them.

Number 312

Mr. Van Dyke referred to the well logs and said this information is submitted to the Conservation Commission for every well drilled in the state and then becomes public information after two years. Senator Coghill referred to the information submitted and asked if it is kept confidential and if Department of Natural Resources uses it to determine their position as far as unitization is concerned. Mr. Van Dyke said they get copies of the seismic information if it is gathered on state land it is used in the determination. Senator Coghill asked if Department of Natural Resources goes out and does seismic work. Mr. Van Dyke said the information they receive is either from the oil companies or from a seismic companies. He said the seismic companies gather the information and then they sell it to anyone who wants to buy it. The state is entitled to a copy and pays the copying charges.

Number 370

The next person to testify before the committee was Mr. Cliff Burglin, Land Consultant and Independent Oil Leaser. He said he believes the state is painting itself into a corner and there are two ways it will loose a tremendous amount of revenue. Alaska has approximately a billion acres of potential oil and gas exploration lands onshore and offshore. He noted Russia is the largest oil producer in the world and Canada is also one of the largest.

Mr. Burglin said the state has to fight for it's share of the market. He said major oil companies can go to Canada, Russia or federal lands. He continued, by explaining different maps. He said you can have a lot of federal oil put into a state pipeline in which you get much less revenue. Senator Coghill referred to the Prudhoe field as being big, that there are federal leases offshore to the north. He also noted there are onshore state leases that, because of the differences in the return due to royalties, oil companies would then extract it out of the federal leases and take away the royalty revenue stream into the state treasury. Mr. Burglin said this is correct.

Number 428

Mr. Burglin referred to oil companies trying to make money and asked why would they pay the state 93% net profits when they could pay the federal government 16 and 2/3% royalty.

They will drill the oil from the federal land which can then drain the oil from Alaskan acreage.

Number 454

Mr. Burglin referred to there always being a glut of oil and said when people won't face the economic facts, the state will and is getting to be in very dire trouble.

Mr. Burglin said the state has maybe 300 million acres onshore and offshore they could develop and noted there is not a shortage of places to drill, develop and explore for oil. He said the companies are there to make money for their stock holders and will go where they can make the best field. He said there are some concerns that need to be dealt with right now. Mr. Burglin referred to the Seal Island field and said there are at least six different potential producing zones. The chance of finding commercial oil fields is very good but not necessarily on state land. He continued to explain a state petroleum map to the members.

Mr. Burglin referred to Guidered Bay and Milne Point and said the state needs to make the leasing terms all the same. It needs to be 12.5% plus severance tax. He said there is a very serious problem brewing.

Number 516

Senator Fischer asked Mr. Burglin if Milne Point is considered a marginal field. Mr. Burglin said yes. Senator Fischer asked if it is considered marginal because the state is getting too much of a percentage. Mr. Burglin said yes.

Number 524

Senator Coghill asked Mr. Burglin if he is suggesting the state make a reform in their leasing policy to have all leases equal and on the same return base.

Mr. Burglin indicated this should be done. He said the major oil companies have the ability to move around and will drain oil where they make the most dollars.

Number 526

Senator Fischer referred to Amerada Hess and said they offered the state royalty. He asked Mr. Burglin if the state reduced the amount of royalty, how would the competitor feel. Senator Fischer asked Mr. Burglin how he would justify it.

Mr. Burglin said they wouldn't care because they could drain oil from the federal tracks and leave Alaska with nothing.

Mr. Burglin stated the State of Alaska has to fight to keep its share of the market. He said Mexico, Iran, Iraq, Saudi Arabia, Nigeria, Algeria, Venezuela and Canada could get Alaska's two million barrels just like that.

Number 566

Senator Fahrenkamp referred to the time when there was high royalty parts of the contract sales. She said she didn't believe this was done by legislation but rather by the agreements of the sale.

Mr. Van Dyke said the statutes were amended to allow a number of different options but the commissioner, by region, picks a bidding method.

Number 575

Mr. Burglin said people are hung up on the big bonus bids. He referred to Prudhoe Bay and said the high bonus bids were $1,471,000. He said the state has gotten billions in royalties and severance taxes from Prudhoe Bay. He noted the money doesn't come from the bonus bids but rather from production. He stated that Alaska is going to have to fight for production.

Number 587

Senator Coghill asked Mr. Burglin if he is saying that there should be a formula to add acreage to unitization and get as much land as possible, as soon as possible, under exploration. Mr. Burglin said yes and continued to show examples of areas, on a map, which should be opened.

Senator Eliason asked if the lands are not put up for bid what will happen to the oil under them. Mr. Burglin said it will get drained from other adjacent lands.

Mr. Burglin referred to Sale 54 and said seventy-five days before the sale he wrote a letter to the commissioner and requested some acreage to be put up for bid. He said about thirty days before the sale he got an answer saying the state couldn't honor the request. Mr. Burglin said by not doing this, the state lost about $5 million in bonus bids.

Number 624

Mr. Burglin noted in Texas 15,000 wells are drilled in their worst economic times. He noted Alaska has to be aggressive in it's leasing policies.

Senator Eliason asked how the oil was being siphoned off of Alaska's land. Mr. Burglin said it isn't being done yet. Senator Eliason asked why should the state produce more wells when the price of oil may drop to $10. Mr. Burglin said because Alaska needs to keep it's share of the world market.

TAPE 1, SIDE 2
Number 003

Senator Fahrenkamp asked if we need to encourage oil exploration and get leases bid out so Alaska can keep producing at the present level as we approach production declining. Mr. Burglin said yes.

Number 031

Senator Sturgulewski said Mr. Burglin is asking two things and that is to take existing leases and put them back to 12.5%. He is also requesting lands that are not presently leased onshore be added to lease sales coming up. Mr. Burglin suggested this be done as quickly as possible.

Senator Sturgulewski asked what would happen if the state did what he is suggesting. Mr. Burglin said there may be a lot more competition for state acreage. This would allow independents to come in who can operate cheaper. Senator Sturgulewski said he is talking about a substantial number of leases which exist. She asked what the affect would be. Mr. Burglin said there would be development in some areas that you would not see. He said and he continued to show the committee members examples by showing them different areas on the map.

Number 083

Senator Eliason referred to Mr. Burglin saying the bonus on bids is not the main point of lessors but is a small part. He said he fails to see how there will be more production if the line is running at capacity now and there is no oil from the federal leases going into the pipeline. He asked how will the production be increased.

Mr. Burglin said if the state's production tappers off, oil from the federal leases can go into the pipeline. Senator Eliason said none of the federal oil has gone into the line and asked how has the state lost so much money. Mr. Burglin said we haven't yet but there are a lot of things that need correcting.

Number 114

Senator Fischer asked if there are fields in production, at the present time, that are yielding the state greater than

12.5%. Mr. Burglin said he didn't believe so. Senator Fischer said if the state does reduce all leases to 12.5% we could loose revenue.

Number 138

Senator Coghill referred to conditions put on all the lessees with all the variances and said we're competing. What we want to do is standardize drilling/exploration which would create a lot more activity. Mr. Burglin said he believes it would create more activity but if it wasn't done you wouldn't loose what you've presently got.

Senator Coghill asked Mr. Burglin if he is saying that now is the time to correct this because the federal and native leases are in competition with the state. The federal and native leases will be bid out next to our fields and would be drain Alaska's field. Mr. Burglin said it could easily be done.

Mr. Burglin said the feds are in the process of hurting themselves because they have a high minimum bonus bid. He said he believes they are putting up 40 million acres and their minimum bonus bid is $150 per acre or, rounded off, $1 million per track.

Number 194

Mr. Burglin referred to levels of stature in the oil business. He said the highest level is Exxon, Shell and BP. Next there is Chevron, Mobile than the Unions, Philips which are not in the ball park of the top three. Mr. Burglin said the state should want these companies involved. They're important to the state as producers.

Number 216

Senator Fahrenkamp referred back to about eight years ago to a question as to why the state couldn't interest independents. She said the answer is because it is so expensive the independents won't come. She said Mr. Burglin is bringing in the aspect that part of the leasing policy has as much to do with it as the expense. Mr. Burglin said it does and also the environmental issues. He said the the insinuation is that every developer is going to destroy the land. He gave examples of places that have been mined and noted there isn't any environmental damage.

Number 257

Senator Fahrenkamp said a push is on in Congress for the drilling muds, etc., to be classified as hazardous waste. She said drilling lead is hazardous waste and asked Mr. Burglin how this would effect the chances of getting into development with independents. Mr. Burglin said it would make it more costly.

Senator Fanning said if we were to change the leasing structure to ensure and allow that independents and others were able to cross the board and lease more acreages of land, the tendency wouldn't be for the royalty and severance tax percentages to decrease from 12.5% to 8%, it could probably be done in a way where they would increase as long as the entry fee was decreased. He said there is such a high entry fee it prohibits anyone else from getting involved in the current competitive leases.

Mr. Burglin said the state doesn't need $20 or $15 dollar oil, it needs $3 dollar oil. That way the state will always sell oil. He referred to when Prudhoe Bay was discovered and the price was $3 per barrel at the wellhead and the majors determined Prudhoe was economic at that price.

Number 307

Senator Fanning said, from a state standpoint, the legislature would like to see why there is an advantage to decreasing fees, to open up more country and to increase the percentages in the event that there is a climb.

Mr. Burglin said you have to get costs as low as you possibly can where oil is back a $3 per barrel again, you can still be competitive. He said you can land a barrel of Saudi Arabian oil in New York harbor for about $1.25 per barrel and state oil has got to compete with this.

Number 324

Senator Fanning asked how much money would the state make if there were noncompetitive leasing in other fields. He asked if money would be made from leasing and would we discover new discoveries that weren't discovered because of our procedure. He asked would we make more money. Mr. Burglin answered yes to all the questions. Senator Fanning asked why we would make more money.

Number 328

Mr. Burglin said because there would be more drilling, more activity, more people working. He referred to activity in the Copper River Basin. He said the more you have the more it generates and the less costly the power and fuel is, the better the economy is going to be. Mr. Burglin said it decreases costs to miners, agriculture, fishing, etc.

Number 340

Senator Eliason said he has been told that a lot of activities have been curtailed on the North Slope because the price of oil dropped below a certain level. He asked why would someone go and drill a well at the high costs and with no return.

Mr. Burglin said there is a point where it is uneconomical. He noted he didn't know what the point was but with some of the major producers on the North Slope it is about $7.50 per barrel.

Number 382

Senator Fanning asked what the average royalty was in private land stakes. Mr. Burglin said it is between 12.5% and 20%. He said you would always be competitive at 12.5% and noted the severance tax which could be moved up or down.

Number 392

Senator Fanning said if there was an annual lease payment for tracks on a per acre basis, what figure would make it so independents and others could compete. Mr. Burglin said $1.00 per acre would get a lot of people involved. Senator Fanning said at $1.00 an acre how many million acres are we talking about and what type of annual revenue would there be on the lease payments. Mr. Burglin said between $20 million and $50 million.

Number 416

Mr. Burglin stated he hopes the oil and gas land in the state wasn't set aside for the major oil companies to explore and produce.

Senator Eliason referred to fluctuating the severance tax to fit the criteria after wells go into production and asked how would it be decided when to do this. Mr. Burglin said there needs to be people in the state government who study these things.

Number 450

Mr. Burglin noted all his leases are state leases. Senator Eliason asked Mr. Burglin if he was producing any oil at the present time. Mr. Burglin said no.

Number 456

Mr. Burglin referred to a bulletin put out the the Alaska Oil and Gas Conservation Commission dated 2/19/88. He said it shows all the undefined fields. He also noted he had asked the Governor how he knows where the reserves are if the fields are mostly undefined. Mr. Burglin referred to the Kuparuk River field and said it is undefined.

Number 487

Senator Sturgulewski asked Mr. Burglin what he proposes needs to be done with unitization. Mr. Burglin said the fields need to be defined. He said more wells have to be drilled. Senator Sturgulewski asked by whom. Mr. Burglin said by the operators.

Mr. Burglin said when they present good data and ask the state for something, it is very difficult to deal with someone that says, "no you can't do it." He said the state doesn't even have to say why, they use the excuse that some of their data is confidential.

Number 522

Senator Coghill asked Mr. Burglin if he thinks there should be a step policy on unitization so the geological data that is brought to the table, and if the unitization does or doesn't move forward, it should be based on that data. Mr. Burglin said this is right.

Number 529

Senator Fanning said if the companies could see the state's data what policy would take place in the way things are developed. Mr. Burglin said the companies would show their data and give testimony and the state just says no your picture is inaccurate and, therefore, the companies cannot become part of the unit or create a new unit. The state says they disagree with the companies information and the companies ask why. The state responds by saying it is proprietary and confidential.

Number 569

Senator Coghill asked Mr. Burglin if he is suggesting to the committee is that only the seismic information that is brought to the table for unitization of a field should be considered at the meeting, by expert witnesses, which would include the state. The state would have to make their presentation also.

Senator Coghill asked if this would be before the Oil and Gas Conservation Commission. Mr. Burglin said yes.

Number 600

Mr. Burglin noted there are exploration units and producing units. Mr. Burglin referred to the Kemmy Springs unit and said it is an exploration unit of 110 thousand acres. He noted if his company applies for a unit that is 40 thousand acres and wanted to drill a well and spend $5 or $10 million, why does the state say no - we're not going to let you do that.

Senator Coghill said units allow lease holders to share costs. He referred to companies wanting to unitize to get into a better position to drill a well and asked what was the state's rational to saying no.

Senator Fischer said he thought when companies have leased land they could drill as many wells as they want.

TAPE 2, SIDE 1
Number 001

Mr. Burglin referred to the Department of Natural Resources and said they have geologists and petroleum engineers that should be generating data for the legislature. Senator Coghill asked if it would be an advantage for the state to identify fields by keeping track of oil and by having unitization.

Mr. Burglin said if the fields are defined by drilling, but according to the state's data they have not defined most of the fields including Prudhoe Bay.

Number 093

Mr. Bill Van Dyke came before the committee members once again. Senator Coghill asked if the ultimate goal to solve this type of dilemma is to give the commission the power on unitization?

Mr. Van Dyke said there has never been an order or demand that someone cannot drill on their own lease. He said whether it is a situation where there is a lease holder outside a unit boundary that feels they should be in the unit, they are entitled to go drill that lease and prove that they are entitled to be in that unit. Mr. Van Dyke said if it is inside a unit boundary but not within a participating area, they are entitled to drill that track and prove that there is oil in that pool and then include it in a participating area.

Senator Fahrenkamp asked if this was the only way they can drill a hole. Mr. Van Dyke said they can present geophysical or information which supports that they should be there. He said if it is sound information they'll be included in the participating area.

Number 162

Senator Fanning said he thought the situation was where Chevron and Mr. Burglin has specifically applied to drill on a lease that they held and was denied. He asked Mr. Van Dyke if a lease holder wanted to drill the department wouldn't deny them.

Mr. Van Dyke said if a lease holder wants to drill they can. They may ask to unitize and that request may be denied but they can still go and drill on their own lease.

Senator Fahrenkamp asked if they both couldn't drill and share expenses. Mr. Van Dyke said they could drill and share the expenses. Senator Fahrenkamp asked what was denied. Mr. Van Dyke said the request to unitize was denied as the department didn't feel there was a prospect there.

Number 188

Mr. Van Dyke said if the companies believed there is a prospect, he assumed they would have drilled it anyway as they still own the leases. The state just denied the request to unitize. He noted unitization also extends leases. He said a company gets to the 9th year and 364th day of the lease and decides to submit a unit application so they can get a five or ten year extension on their leases. Mr. Van Dyke said the state doesn't believe this is good policy.

Number 197

Senator Fanning said to Mr. Burglin they were denied unitization but still could have drilled. Senator Fanning asked why they didn't. Mr. Burglin said the rest of the leases around the well would have expired.

Mr. Burglin noted these leases were 20% and 30% net profit leases which would've meant the state would have made 40% or 45% of production.

Senator Fanning referred to the wells which would have been drilled, unitization would've been denied, and asked if is there is an opportunity, upon discovery, to reapply for unitization and would an extension on surrounding leases be granted.

Number 242

Mr. Van Dyke said all the options are open at that point. Senator Fanning asked if there are any guarantees or assurances. Mr. Van Dyke said if someone discovers a oil and gas pool, the area should be unitized.

Senator Fanning said if there is a guarantee of a discovery would the state reconsider its inappropriate actions of not to unitize. He also asked if the state would, after a discovery and based on new information, unitize. Mr. Van Dyke said he isn't aware of any unit applications, meeting those conditions, that has ever been denied.

Number 266

Senator Fanning said in the event the department denies unitization and in the event any company wants to precede with drilling and asked if there is currently a mechanism that would mandate an automatic extension of the unitization leases or leases under potential unitization until completion of the well. Mr. Van Dyke said there are no provisions in the statutory regulations which allows lease extensions under the assumption that it is going to be a productive well. He said only the lease where the well is being drilled can be extended but surrounding leases would expire.

Senator Fanning asked Mr. Van Dyke if he would oppose mandating a regulation. Mr. Van Dyke said it would be hard to administer if one persons extenuating circumstances is going to be someone else's tough luck.

Number 301

There was a short discussion between committee members regarding this matter.

Number 323

Mr. Burglin said these leases were ten year work commitment leases and between the time the companies got them and the time when they were beginning to expire the price of oil had dropped substantially.

Number 330

Senator Coghill asked what happened to those leases. Mr. Burglin said they went back to the state have been put up for competitive bid. Mr. Burglin said instead of letting them get developed for 20% royalty and 30% net profits, they took them away and put them up for bid for 12.5%. Senator Coghill asked if these leases are available for exploration. Mr. Burglin indicated they are. Senator Coghill asked if they could apply for unitization now. Mr. Burglin said possibly.

Number 346

Senator Fanning said if there is production in those specific areas, the bid used to be a 30% net profit and 20%

royalty and they are bid out now at 12.5%, he asked Mr. Van Dyke how this makes sense to the state.

Mr. Van Dyke said if there is oil and gas under those leases, it didn't make sense. He said it does make sense to apply rules equally regardless of who the lessee is and regardless of whether it is a state lease involved or federal lands.

Number 402

Senator Coghill adjourned the Senate Resources meeting at 3:35 p.m.

Bettye Fahrenkamp

1. What is the purpose of establishing a P.A. (participating area) (-11 AAC 83.351)?

2. How does determination of a P.A. effect state revenues?

3. Why is it necessary to compromise P.A.'s?

4. Who determines whether or not a P.A. compromise (revenue compromise) [illegible] parties [illegible] interest?

5. What state [illegible] regulatory [illegible]

[illegible]

[illegible]

10. [illegible]

[illegible]

13. [illegible]

[illegible]

17. [illegible] reasonably known that at least [illegible] around the well bore is contributing to the gas being produced from a producing gas well?

Alaska State Legislature

Senate Resources Committee

Sen. John B. (Jack) Coghill, Chairman
Sen. Paul Fischer, Vice-Chairman
Sen. Lloyd Jones
Sen. Arliss Sturgulewski
Sen. Jim Duncan
Sen. Fred Zharoff
Sen. Dick Eliason

Box V
Juneau, Alaska 99811
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M E M O R A N D U M

To: Senate Resource Committee Members

From: Senator Coghill

Subj: Todays Meeting on Oil & Gas Management

Date: March 7, 1988

The focus of this committee meeting is on the unitization aspect of state petroleum resources management. We will have a short briefing by the Division of Oil and Gas and we'll follow that up with a presentation by Mr. Cliff Burglin.

Attached to this memorandum is a March 17, 1983 list of qualifications of Division of Oil and Gas personnel. This is for your information since Bill Van Dyke and Catherine (Cass) Ariey will be making the divisions presentation today.

This should be an interesting meeting.

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 8672
1545 SCOMM 57: SENATE SPECIAL COMMITTEE ON OIL & GAS, 1987-1988 1342

March 17, 1983

QUALIFICATIONS -- DMEM PROFESSIONAL AND TECHNICAL STAFF

Following are the qualifications and credentials of professional and managerial staff at the Division of Minerals and Energy Management (DMEM), Department of Natural Resources. For purposes of this compilation, qualifications of those individuals at and above the section chief level as well as those with professional or technical responsibilities have been listed. These individuals represent all top management positions within the division.

OIL & GAS

Kay Brown, Director: Holds a bachelors degree in journalism from Baylor University. Served as energy policy analyst for the Alaska Legislative Research Agency; served as special assistant to the Commissioner of Natural Resources for oil and gas policy development and implementation. Was promoted to Deputy Director of DMEM for Oil and Gas in July, 1980 because of previous key role in assuring that the 1979 Joint Federal/State Beaufort Sea Sale was held on schedule and in a legally defensible manner, and because of outstanding managerial abilities. Was promoted to Director of DMEM in January, 1982 for continuing excellence as a manager. Brown has successfully implemented the state's five-year oil and gas leasing program; she is the first director to solicit broad public involvement in the leasing program.

Jim Eason, Deputy Director for Oil and Gas: Petroleum Geologist with a masters degree in geology. Prior industry experience with Amoco Production Company and the Atlantic Richfield Company. Prior government experience included performing oil and gas evaluations for the U.S. Geological Survey. Promoted to Deputy Director because of technical expertise and outstanding administrative capability.

Bill Van Dyke, Petroleum Manager and Chief of the Lease Administration Section: Petroleum Engineer. Prior industry experience with Gulf Oil Company. and Chevron Served as a petroleum reservoir engineer with DMEM until promotion to Petroleum Manager because of technical expertise and knowledge. Responsible for oversight of exploration and development plans and operations on all state leases, as well as negotiation of unitization agreements. Prepares reserve estimates and production forecasts. Expertise in petroleum reservoir management and engineering.

WVD

Donna Wood, Royalty Manager and Chief of the Royalty Section: Has extensive experience in performing complex audits, including the management of full-scale audits of multi-national oil companies for compliance with state corporate income tax, severance tax and royalty payment requirements while with the Alaska Department of Revenue, Division of Petroleum Revenue. Private industry experience includes management, tax and audit responsibilities with Arthur Young Company, one of the "big eight" CPA firms in the country.

Pamela Rogers, Leasing Manager and Chief of the Lease Sales Section: Has extensive experience in the field of journalism; specialized in covering land use and economic issues. Began employment with the Department of Natural Resources in 1977 as a Research Analyst. Was transferred to DMEM in 1979 by the Deputy Commissioner because of outstanding organizational abilities needed by DMEM in carrying out responsibilities related to the 1979 Joint Federal/State Beaufort Sea Sale. Was promoted to Leasing Manager for DMEM in 1980 because of continued excellence as an organizer and manager. Manages the state's five-year oil and gas leasing program.

Catherine Ariey, Petroleum Geologist: Works in the division's Lease Sales Section. Responsible for prospect evaluation and geologic evaluation of unitization proposals. Prior industry experience with Atlantic Richfield Company; prior government experience with the U.S. Geological Survey. Has oil and gas operational experience ranging from geologic analysis to well site evaluation.

Ed Phillips, Petroleum Economist: Works in DMEM's Lease Sales Section. Performs prospect analyses for all oil and gas lease sales. Holds masters degree in economics. As a senior economist with private business prior to his employment with DMEM in 1977, he served as a consultant developing socio-economic impact studies for oil companies operating in the Gulf of Alaska .

Ted Bond, Petroleum Engineer: Supervises the Plans of Operation Unit in the Lease Administration Section, which approves oil and gas development plans on all state leases. Is a graduate petroleum engineer whose industry experience includes employment with Getty Oil Company, Tenneco Oil Company, and Dresser Magcobar. Previous government experience included work for the Texas Railroad Commission, which is the agency that regulates oil and gas development in Texas.

Catherine Fortney, Petroleum Engineer: Supervises the Unitization Unit in the Lease Administration Section. Is a graduate chemical engineer, and registered professional engineer in California and Alaska. Prior industry experience with Atlantic Richfield Company in Alaska, Phillips Petroleum, and the Bechtel Corporation. Her experience in private industry includes facility design, operation and improvement as well as design of oil and gas handling, processing and transportation systems.

Sam Murray, Petroleum Economist: Holds a masters degree in economics, which he received at age 21. Works for the Lease Administration Section evaluating the economic implications of unitization proposals. Previous experience includes three years with the U.S. Army Corps of Engineers preparing economic feasibility analyses of energy facilities and evaluating alternative energy sources.

STATE OF ALASKA
OIL AND GAS LEASE UNITIZATION PROCESS

Unitization of State of Alaska Oil and Gas leases is governed by Title 11, Chapter 83, Article 3 of the Alaska Administrative Code (AAC). The following is a brief summary of the steps necessary to form an Alaskan Oil and Gas Unit:

1. The lessees of the leases overlying a reservoir or a potential hydrocarbon accumulation as those terms are defined in 11 AAC 83.395 must determine an prospective area to be unitized. For units which intend to commence production immediately, an appropriate participating area must also be determined in accordance with 11 AAC 83.351. We strongly recommend that the prospective lessees to be included within the unit area (the "working interest owners") meet with Division of Oil and Gas staff to review the technical data supporting the proposed unit prior to any submittal of an application for unitization.

2. The working interest owners must select a unit operator, which must be qualified to act as unit operator under 11 AAC 83.331.

3. The unit operator, acting on behalf of all of the working interest owners, must submit an application for unitization. The application must include the following items:

   A. A Unit Agreement based on the State of Alaska Standard Unit Agreement Form (DNR Form 10-1128), executed by all of the working interest owners, including all exhibits required under 11 AAC 83.341, 11 AAC 83.343, 11 AAC 83.346, 11 AAC 83.351, and 11 AAC 83.371, as applicable.

   B. A Unit Operating Agreement executed by all working interest owners, which is submitted for information only, and does not require the commissioner's approval for adoption or amendment. Most Unit Operating Agreements for State of Alaska oil and gas units are executed on the Rocky Mountain Unit Operating Agreement Form 2 (Divided Interest)[1], but this is not required.

   C. Evidence of reasonable effort made to obtain joinder of any proper party who has refused to execute the Unit Agreement and commit its interests within the unit area to the unit[2]. A proper party is defined in 11 AAC 83.328.

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1. Model Rocky Mountain Unit Operating Agreement forms are available from the Rocky Mountain Mineral Law Foundation, University of Colorado, Fleming Law Bldg., Boulder, Colorado 80309.

2. The State requires that at least 70% of the acreage within the proposed unit area commit to the Unit Agreement to ensure "reasonably effective control of operations" as required by 11 AAC 83.316(c). Unit applications with less than 70% of the acreage committed will not be accepted by the division as complete.

D. If any modifications or changes to the State of Alaska's Standard Unit Agreement Form are proposed, an explanation of why such changes should be accepted by the State.

E. All pertinent geological, geophysical, engineering, and well data, and interpretations of those data, directly supporting the application.

3. All signatures on the application must meet the provisions of 11 AAC 83.379; that is they must have the signator's name and title typed or printed underneath, and must be notarized or attested by two separate individuals. All persons signing on behalf of a corporation must be qualified to sign for that corporation, and their signatures must be on file with the division as evidenced by the qualification files for that corporation.

4. An application fee of $1000.00 for a new unitization application must accompany the above application for unitization [11 AAC 05.010 (10) (D)]. The check should be made out to the State of Alaska, Department of Revenue.

5. One copy of items A through D above should be forwarded to the Commissioner of the Department of Natural Resources, P. O. Box "M", Juneau, AK 99811; the original application plus three additional copies of items A through D, two copies of item E, and the application fee should be forwarded to the Unit Manager, Department of Natural Resources, Division of Oil and Gas, P. O. Box 7034, Anchorage, AK 99510. Upon written request by the submittor, any technical data submitted will be kept confidential in accordance with the terms of Alaska Statute 38.05.035(9)(C).

6. Within 10 days of the determination by the Division of Oil and Gas that the application as submitted is appropriate and complete, the division will publish notice of receipt of the application in both State-wide and local newspapers. In addition, notice of receipt of the application will be forwarded to certain parties as set out in 11 AAC 83.311. Public comments will be accepted by the division concerning the proposed unit for 30 days after the first publication of the public notice.

7. The division will issue a written decision approving or denying the application based on the criteria in 11 AAC 83.303 within 60 days of the close of the public comment period. In general, the division will <u>not</u> make a conditional or partial approval of a unitization application; this is why we strongly recommend meeting with the division staff prior to submitting a unitization application.

Prior to making an application for unitization of State of Alaska lands, it is recommended that applicants familiarize themselves with the contents of the unitization regulations (11 AAC 83.301 - 11 AAC 83.395) and the terms and provisions of the State's Standard Unit Agreement Form (form DNR 10-1128). If you have any questions relating to the process of unitization, please contact the Unit Manager, Division of Oil and Gas, (907) 762-4241.

2739A

ALASKA ADMINISTRATIVE CODE
TITLE 11, CHAPTER 83, ARTICLE 3

UNITIZATION REGULATIONS

Last Amended 3/30/84, Register 89

Section

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UNITIZATION REGULATIONS

Alaska Administrative Code
Title 11, Chapter 83, Article 3

Last Amended 3/30/84, Register 89

11 AAC 83.301. PURPOSE. (a) 11 AAC 83.301 - 11 AAC 83.395 establish standards and procedures governing the submission of applications to the commissioner and criteria for approval of unit agreements for state oil and gas leases, and standards to be followed by a state lessee in conducting lease operations under an oil and gas unit agreement approved by the commissioner.

(b) 11 AAC 83.301 - 11 AAC 83.395 apply to an existing oil and gas lease or approved unit agreement where not inconsistent with the lease or unit agreement or regulations in effect on the effective date of the lease or unit agreement. (Effective 6/28/81, Register 78; amended 3/18/83, Register 85.)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.303. CRITERIA. (a) The commissioner will approve a proposed unit agreement for state oil and gas leases if he makes a written decision that the decision is necessary or advisable to protect the public interest considering the provisions of AS 38.05.180(p) and this section. The commissioner will approve a proposed unit agreement upon a written finding that it will

(1) promote conservation of all natural resources, including all or part of an oil or gas pool, field, or like area;

(2) promote the prevention of economic and physical waste; and

(3) provide for the protection of all parties of interest, including the state,

(b) In evaluating the above criteria, the commissioner will consider:

(1) the environmental costs and benefits of unitized exploration or development;

(2) the geological and engineering characteristics of the potential hydrocarbon accumulation or reservoir proposed for unitization;

(3) prior exploration activities in the proposed unit area;

(4) the applicant's plans for exploration or development of the unit area;

(5) the economic costs and benefits to the state; and

(6) any other relevant factors, including measure to mitigate impacts identified above, the commissioner determines necessary or advisable to protect the public interest.

(c) The commissioner will consider the criteria in (a) and (b) of this section when evaluating each requested authorization or approval under 11 AAC 83.301 - 11 AAC 83.395, including

(1) approval of a unit agreement;

(2) an extension or amendment of a unit agreement;

(3) a plan or amendment of a plan of exploration, development, or operations;

(4) a participating area; or

(5) a proposed or revised production or cost allocation formula. (Effective 9/5/74, Register 51; amended 7/22/79, Register 78; amended 3/18/83, Register 85.)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.306. APPLICATION FOR UNIT APPROVAL. Any person owning an interest in a lease which is proposed to be committed to a unit which would include a state oil and gas lease may propose a unit agreement by applying to the commissioner for approval of the agreement. The following items constitute a complete application for approval:

(1) the unit agreement, including exhibits required under 11 AAC 83.341 or 11 AAC 83.343, executed by the proper parties;

(2) the unit operating agreement executed by the working interest owners, which is submitted for information only and does not require the commissioner's approval for adoption or amendment;

(3) evidence of reasonable effort made to obtain joinder of any proper party who has refused to join the unit agreement;

(4) all pertinent geological, geophysical, engineering, and well data, and interpretations of those data, directly supporting the application; and

(5) an explanation of proposed modifications, if any, of the standard state unit agreement form. (Effective 6/28/81, Register 78; amended 8/15/82, Register 83; amended 3/18/83, Register 85.)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.311. PUBLIC NOTICE. Within 10 days after receipt of a complete application for approval of a unit agreement under 11 AAC 83.356, or extension of the unit term under 11 AAC 83.336(a)(2), the commissioner will publish notice of the application in a newspaper of general statewide circulation and in a newspaper serving the locality in which the unit or proposed unit is located. In addition, the commissioner will, in his discretion, publish notice by radio, television, or other electronic media. If the unit or proposed unit is within the boundary of an organized borough, municipality, regional corporation, or village corporation organized under Section 8(a) of the Alaska Native Claims Settlement Act, the notice will be mailed to the chief executive officer of the borough or municipality, or designated representative of the corporate entity. The notice will also be mailed to the postmaster of each permanent settlement of more than 25 persons located within six miles of the proposed unit area. In the case of a proposed unit expansion, a copy of the notice will be mailed to the unit operator. The notice will include

(1) the name and address of the applicant, and the location of the unit or proposed unit;

(2) a statement explaining the nature of the approval sought;

(3) a statement indicating where copies of the nonconfidential portions of the application may be obtained; and

(4) a statement that any person may file written comments on the application with the commissioner within 30 days after publication of the notice. (Effective 6/28/81, Register 78; amended 3/18/83, Register 85.)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.316. UNIT APPROVAL. (a) Within 60 days after the close of the public comment period required by 11 AAC 83.311, the commissioner will issue a written decision approving or disapproving the unit agreement, in which he states the basis for his decision after considering the provisions of 11 AAC 83.303.

(b) If the commissioner determines that the provisions of 11 AAC 83.303 are not met, the commissioner will, in his discretion, propose modifications which, if accepted by the parties to the proposed unit agreement, would qualify the agreement for approval.

(c) No unit will be approved unless parties to the unit agreement hold sufficient interest in the unit area to give reasonably effective control of operations and at least one lease or portion of a lease in the unit area is a state lease. (Effective 9/5/74, Register 51; amended 7/22/79, Register 71; amended 6/28/81, Register 78; amended 3/18/83, Register 85.)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.321. COPIES OF APPLICATION REQUIRED. In submitting an application under 11 AAC 83.301 - 11 AAC 83.395, the applicant must provide five copies of the nonconfidential portions of the pertinent agreement, plan, modification, or other instrument or document for which approval is sought and two copies of any confidential material submitted. Ten copies of unit plans of operations are required for activities within the coastal zone. (Effective 9/5/74, Register 51; amended 7/22/79, Register 71; amended 6/28/81, Register 78.)

Authority: AS 38.05.020
AS 38.05.145

11 AAC 83.326. STANDARD UNIT AGREEMENT. (a) Except as provided in 11 AAC 83.393, and as otherwise provided in this section, a unit agreement must be executed on, or in a manner consistent with, a standard state unit agreement form.

(b) The commissioner will allow a modification of the standard state unit agreement form, upon request by the unit applicant, when the commissioner determines that the modification is reasonably required to meet the needs and requirements of the particular unit considering the facts and conditions found to exist with respect to that unit, and the proposed modification meets the provisions of 11 AAC 83.303. The commissioner will require a modification of the standard state unit agreement form if required to meet the provisions of 11 AAC 83.303. Any request by the unit applicant for modification of the standard state unit agreement form must be made in writing not later than the time an application is submitted for approval under 11 AAC 83.306 and must include an explanation of proposed modifications. (Effective 6/28/81, Register 78; amended 3/18/83, Register 85.)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.328. PARTIES. (a) The record owners of any right, title or interest in the oil or gas reservoirs or potential hydrocarbon accumulations to be included in a unit are the proper parties to the unit agreement. All proper parties must be invited to join the unit agreement.

(b) Where authorized by lease, the commissioner will, in his discretion, require a state lessee or any assignee of interest in a state lease to subscribe to a unit agreement. (Effective 9/5/74, Register 51, amended 6/28/81, Register 78.)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.331. UNIT OPERATOR. (a) A unit operator must be qualified to hold a lease as provided in 11 AAC 82.200 - 11 AAC 82.205, and must be qualified to fulfill the duties and obligations prescribed in the unit agreement.

(b) The unit operator may be a working interest owner in the unit area or may be a party selected by the working interest owners.

(c) No designation or change of the unit operator becomes effective until approved by the commissioner. The commissioner will approve or disapprove a proposed change of the unit operator within 30 days after receipt of request, and will explain in writing his basis for disapproval. (Effective 9/5/74, Register 51; amended 6/28/81, Register 78.)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.336. EFFECTIVE DATE AND TERM OF UNIT AGREEMENT. (a) A unit agreement becomes effective upon approval by the commissioner and automatically terminates five years from the effective date unless

(1) a unit well in the unit area has been certified as capable of producing hydrocarbons in paying quantities, in which case the unit agreement will remain in effect for so long as hydrocarbons are produced in paying quantities from the unit area, or for so long as hydrocarbons can be produced in paying quantities and unit operations are being conducted in accordance with an approved unit plan of exploration or development, or, should production cease, for so long after that as diligent operations are in progress to restore production and then so long after that as unitized substances are produced in paying quantities; or

(2) exploration activities have been conducted in accordance with an approved unit plan of exploration, and the commissioner, after issuing written notice under 11 AAC 83.311, issues a written decision extending the unit term in which he states the basis for his decision, considering the provisions of 11 AAC 83.303; no single extension will exceed five years.

(b) If a suspension of unit operations or production on all or part of the unit area has been ordered or approved under federal, state, or local law, or, if the commissioner determines that the unit operator has been prevented, despite good-faith efforts, from complying with any express or implied promise, term, condition, or covenant of the unit agreement, or from conducting exploration, development, production, transportation, or marketing operations or or from the unitized area by reason of force majeure, the unit operator's obligation to comply with the provision will be held in abeyance, but not voided, and the commissioner will extend the term of the unit agreement for a period of time equal to the time lost under the unit term due to the suspension or prevention by force majeure. If unit operations or production are suspended or prevented under this subsection and the continuance of those operations or production without suspension or prevention would have had the effect of extending the unit agreement, the unit agreement does not terminate during the period in which operations or production are suspended or prevented plus a reasonable time after that, which will not be less than six months, for the unit operator to resume operations or production. Nothing in this subsection holds in abeyance the obligation to pay rentals, royalties, or other production or profit-based payments to the State of Alaska from operations or production in the unitized area which are not suspended or prevented, or from operations or production which are unrelated to any suspension or prevention. For the purposes of this subsection, any seasonal restriction on operations or production or other conditions specifically required or imposed as a term of sale of an original lease, or as a condition required for unit agreement approval, will not be considered a suspension of operations or production ordered under law, or prevention due to force majeure. However, upon application to the commissioner, seasonal restrictions on operations or production imposed subsequent to approval of a unit agreement will be considered a suspension of operations or production ordered under law.

(c) A unit agreement may be terminated at any time with the approval of the commissioner.

(d) Upon termination of a unit, each lease or portion of a lease committed to the unit may be continued in effect only in accordance with the terms and conditions of the lease, statutes, and regulations, or as provided in the unit agreement. (Effective 6/28/81, Register 78; amended 8/15/82, Register 83; amended 3/18/83, Register 85.)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.341. UNIT PLAN OF EXPLORATION. (a) Unless a unit plan of development is filed under 11 AAC 83.343, a unit plan of exploration must be filed for approval by the commissioner as an exhibit to the unit agreement under 11 AAC 83.306. The plan must describe the applicant's proposed exploration activities, including the bottom-hole locations and depths of proposed wells, and the estimated date drilling will commence. All exploration operations must be conducted under an approved plan of exploration. The commissioner will approve a unit plan of exploration if it complies with the provisions of 11 AAC 83.303. If the proposed unit plan of exploration is disapproved, the commissioner will, in his discretion, proposed modifications which, if accepted by the unit operator, would qualify the plan for approval.

(b) The unit plan of exploration must be updated and submitted to the commissioner for approval at least 60 days before the expiration date of the previously approved plan, as set out in that plan. The update must describe the extent to which requirements of the previously approved plan were achieved; if actual operations deviated from or did not comply with the previously approved plan, an explanation of the deviation or noncompliance must be included in the update. Within 10 days after receipt of an updated plan of exploration, the commissioner will inform the unit operator as to whether a proposed unit plan of exploration is complete. After the commissioner has determined that a unit plan of exploration is complete, as submitted or modified by the unit operator following the commissioner's suggestions, the commissioner will have an additional 30 days in which to approve or disapprove the plan; if no action is taken by the commissioner, the unit plan of exploration is approved.

(c) The commissioner will approve an update of the unit plan of exploration if it complies with the provisions of 11 AAC 83.303. If the proposed update of a unit plan of exploration is disapproved, the commissioner will, in his discretion, propose modifications which, if accepted by the unit operator, would qualify the plan for approval.

(d) The unit operator shall submit an annual report to the commissioner describing the operations conducted under the unit plan of exploration during the preceding year.

(e) The unit operator may, with the approval of the commissioner, amend an approved plan of exploration. (Effective 6/28/81, Register 78, amended 3/18/83; Register 85.)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.343. UNIT PLAN OF DEVELOPMENT. (a) A unit plan of development must be filed for approval as an exhibit to the unit agreement if a participating area is proposed for the unit area under 11 AAC 83.351, or when a reservoir has become sufficiently delineated so that a prudent operator would initiate development activities in that reservoir. All development operations must be conducted under an approved plan of development. A unit plan of development must contain sufficient information for the commissioner to determine whether the plan is consistent with the provisions of 11 AAC 83.303. The plan must include a description of the proposed development activities based on data reasonably available at the time the plan is submitted for approval as well as plans for

the exploration or delineation of any land in the unit not included in the participating area. The plan must include, to the extent available information exists

(1) long-range proposed development activities for the unit, including plans to delineate all underlying oil or gas reservoirs, bring the reservoirs into production, and maintain and enhance production once established;

(2) plans for the exploration or delineation of any land in the unit not included in a participating area;

(3) details of the proposed operations for at least one year following submission of the plan; and

(4) the surface location of proposed facilities, drill pads, roads, docks, causeways, material sites, base camps, waste disposal sites, water supplies, airstrips, and any other operation or facility necessary for unit operations.

(b) The commissioner will approve the unit plan of development if it complies with the provisions of 11 AAC 83.303. If the proposed unit plan of development is disapproved, the commissioner will, in his discretion, ~~proposed~~ propose modifications which, if accepted by the unit operator, would qualify the plan for approval.

(c) The unit plan of development must be updated and submitted to the commissioner for approval at least 90 days before the expiration date of the previously approved plan, as set out in that plan. The update must describe the extent to which the requirements of the previously approved plan were achieved; if actual operations deviated from or did not comply with the previously approved plan, an explanation of the deviation or noncompliance must be included in the update. The commissioner will approve the updated unit plan of development if it complies with the provisions of 11 AAC 83.303. If the proposed update of a unit plan of development is disapproved, the commissioner will, in his discretion, propose modifications which, if accepted by the unit operator, would qualify the plan for approval. Within 10 days after receipt of an updated plan of development, the commissioner will inform the unit operator as to whether the proposed unit plan of development is complete. After the commissioner has determined that an updated unit plan of development is complete as submitted, or as modified by the unit operator following the commissioner's suggestions, the commissioner will have an additional 60 days in which to approve or disapprove the plan; if no action is taken by the commissioner, the update of the unit plan of development is approved.

(d) The unit operator shall submit an annual report to the commissioner describing the operations conducted under the unit plan of development during the preceding year.

(e) The unit operator may, with the approval of the commissioner, amend an approved plan of development. (Effective 6/28/81, Register 78; amended 3/18/83, Register 85.)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.346. UNIT PLAN OF OPERATIONS. (a) Except as provided in (b) of this section, a unit plan of operations for all or part of the unit area must be approved by the commissioner before any operations may be undertaken on the unit area if

(1) the state owns all or part of the surface estate of the unit area;

(2) the unit includes a lease that reserves a net profit share to the state; or

(3) the state owns all or part of the mineral estate, but the entire surface estate of the unit area is owned by a party other than the state, and a surface owner requests that a unit plan of operations be required by the commissioner for the portion of the unit area owned by that surface owner.

(b) A unit plan of operations will not be required by the commissioner for activities that would not require a land use permit under this title.

(c) Before undertaking operations on the unit area, the unit operator shall provide for full payment of all damages sustained by the owner of the surface estate as well as by the surface owner's lessees and permittees, by reason of entering the land. If the surface estate is owned by a party other than the state, the unit operator shall also notify the surface owner of his opportunity to request that the commissioner require a plan of operations before allowing operations to be undertaken on the unit area owned by the requesting surface owner.

(d) An application for approval of a plan of operations must contain sufficient information, based on data reasonably available at the time the plan is submitted for approval, for the commissioner to determine the surface use requirements and impacts directly associated with the proposed operations. An application must include statements and maps or drawings setting out the following:

(1) the sequence and schedule of the operations to be conducted in the unit area, including the date operations are proposed to begin and their proposed duration;

(2) projected use requirements directly associated with the proposed operations, including but not limited to the location and design of well sites, material sites, water supplies, solid waste sites, buildings, roads, utilities, airstrips, and all other facilities and equipment necessary to conduct the proposed operations;

(3) plans for rehabilitation of the affected unit area after completion of operations or phases of those operations; and

(4) a description of operating procedures designed to prevent or minimize adverse effects on other natural resources and other uses of the unit area and adjacent areas, including fish and wildlife habitats, historic and archeological sites, and public use areas.

(e) In approving a unit plan of operations or an amendment of a plan, the commissioner will require amendments he determines necessary to protect the state's interest. The commissioner will not require any amendment that would be inconsistent with the terms of sale under which the lease was obtained, or with the terms of the lease itself, or which would deprive the lessee of reasonable use of the leasehold interest.

(f) The unit operator may, with the approval of the commissioner, amend an approved plan of operations.

(g) Upon completion of operations, the unit operator shall inspect the area of operations and submit a report indicating the completion date of operations and stating any known noncompliance of which the unit operator knows, or should reasonably know, with requirements imposed as a condition of approval of the plan. (Effective 6/28/81, Register 78; amended 8/15/82, Register 83; amended 3/18/83, Register 85.)

Authority: AS 38.05.020
AS 38.05.130
AS 38.05.145
AS 38.05.180

11 AAC 83.351. PARTICIPATING AREA. (a) At least 90 days before sustained unit production from a reservoir, the unit operator shall submit to the commissioner for approval a description, based on subdivisions of the public land or its aliquot parts, of the proposed participating area. The participating area may include

only the land reasonably known to be underlain by hydrocarbons and known or reasonably estimated through use of geological, geophysical, and engineering data to be capable of producing or contributing to production of hydrocarbons in paying quantities. Under 11 AAC 83.371(a), the unit operator shall also submit to the commissioner for approval a proposed division of interest or formula setting out the percentage of production and costs to be allocated to each lease and portion of lease within the participating area. Upon approval by the commissioner, the area of productivity constitutes a participating area.

(b) A separate participating area must be established as provided in (a) of this section for each reservoir delineated, except that with the consent of the commissioner and all working interest owners, any two or more reservoirs or participating areas within the unit may be combined into one participating area. Separate participating areas may be established to distinguish between an oil rim and a gas cap within the same reservoir.

(c) A participating area must be expanded to include acreage reasonably estimated through use of geological, geophysical, and engineering data to be capable of producing or contributing to the production of hydrocarbons in paying quantities, and must be contracted to exclude acreage reasonably proven through use of geological, geophysical, or engineering data to be incapable of producing hydrocarbons in paying quantities, subject to approval by the commissioner. A revised division of interest or formula allocating production and costs must be submitted under 11 AAC 83.371 at the time of expansion or contraction of a participating area. (Effective 6/28/81, Register 78; amended 3/18/83, Register 85; amended 3/30/84, Register 89.)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.356. UNIT AREA; CONTRACTION AND EXPANSION. (a) A unit must encompass the minimum area required to include all or part of one or more oil or gas reservoirs, or all or part of one or more potential hydrocarbon accumulations.

(b) Ten years after sustained unit production begins, the unit area must be contracted to include only those lands then included in an approved participating area and lands that facilitate production including the immediately adjacent lands necessary for secondary or tertiary recovery, pressure maintenance, reinjection, or cycling operations. The commissioner will, in his discretion, after considering the provisions of 11 AAC 83.303, delay contraction of the unit area if the circumstances of a particular unit warrant. If any portion of a lease is included in the participating area, the entire lease will remain committed to the unit.

(c) Any expansion or contraction of the unit area must be based on legal subdivisions of land as defined in 11 AAC 88.185.

(d) No land will be excluded from a participating area due to the depletion of hydrocarbons.

(e) Not sooner than 10 years from the effective date of the unit agreement, the commissioner will, in his discretion, contract the unit area to include only that land covered by an approved unit plan of exploration or development, or that area underlain by one or more potential hydrocarbon accumulations and lands that facilitate production as set out in (b) of this section. Before any contraction of the unit area under this subsection, the commissioner will give the unit operator, the working interest owners, and the royalty owners of the leases or portions of leases being excluded reasonable notice and an opportunity to be heard. (Effective 6/28/81, Register 78; amended 3/18/83, Register 85.)

Authority: AS 31.05.110
AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.361. CERTIFICATION OF WELL TEST RESULTS. For the purposes of 11 AAC 83.301 - 11 AAC 83.395, a well will be considered capable of producing hydrocarbons on paying quantities, as defined in 11 AAC 83.395, when so certified by the commissioner following application by the lessee or unit operator. The commissioner will require the submission of data necessary to make the certification, including all results of the flow test or tests, supporting geological data, and cost data reasonably necessary to show that the production capability of the well satisfies the economic requirements of the paying quantities definition. (Effective 6/28/81, Register 78; amended 8/15/82, Register 82; amended 3/18/83, Register 85.)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.366. UNIT OPERATING AGREEMENT. Any revision of the unit operating agreement must be submitted to the commissioner before it takes effect. The unit agreement controls the respective rights and obligations of the unit operator, the working interest owners, the State of Alaska, and royalty owners other than the State of Alaska in case of conflict between the unit agreement and the unit operating agreement. Where conflicts exist solely between working interest owners, the unit operating agreement shall control. (Effective 6/28/81, Register 78; amended 8/15/82, Register 83.)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.371. ALLOCATION OF PRODUCTION AND COSTS. (a) The proposed or revised division of interest or formula allocating hydrocarbon production and unit operating costs among the leases in the unit area may not take effect until approved by the commissioner in writing. WHen requested by the commissioner, the lessees or unit operator shall promptly file with the commissioner all data that relate to the proposed or revised division of interest or allocation formula for all leases in the participating area. Before any disapproval of the proposed or revised division of interest or allocation formula, the commissioner will give the working interest and royalty owners reasonable notice and an opportunity to be heard. After the hearing, the commissioner will approve the proposed or revised division of interest or allocation formula as submitted unless he finds in writing that the formula does not equitably allocate production and costs among the leases.

(b) If there is a separate division of interest or allocation formula among any of the parties holding an interest in the unit that is different from the division of interest or allocation formula approved by the commissioner, the parties to the separate division of interest or allocation formula not approved by the commissioner shall submit a copy of that formula to the commissioner and a statement explaining the reasons for the difference. (Effective 6/28/81, Register 78; amended 3/18/83, Register 85.)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.373. SEVERANCE. (a) Except as otherwise provided in this section and 11 AAC 83.356, where only a portion of a lease is committed to a unit agreement

approved or prescribed by the commissioner, the commitment constitutes a severance of the lease as to the unitized and nonunitized portions of the lease. The portion of the lease not committed to the unit will be treated as a separate and distinct lease having the same effective date and term as the original lease and may be maintained thereafter only in accordance with the terms of the original lease, statutes, and regulations. Any portion of the lease not committed to the unit agreement will not be affected by the unitization or pooling of any other portion of the lease by operations in the unit, or by suspension approved or ordered for the unit under 11 AAC 83.336(b).

(b) The commissioner will, in his discretion, grant up to a two-year extension of the lease term for that portion of a lease not committed to the unit agreement under this section.

(c) A lease having a well certified as capable of production in paying quantities before commitment to the unit agreement will not be severed. (Effective 9/5/74, Register 51; amended 7/22/79, Register 71; amended 6/28/81, Register 78; amended 8/15/82, Register 83.)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

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

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

(c) If a default occurs with respect to a unit in which there is no well capable of producing oil or gas in paying quantities and the default is not cured by the date indicated in the demand, the commissioner will, in his discretion, and after giving the unit operator and defaulting party (if other than the unit operator) reasonable notice and an opportunity to be heard, terminate the unit agreement by mailing notice of the termination to the unit operator and defaulting party. Termination is effective upon mailing the notice.

(d) If a default occurs with respect to a unit in which there is a well capable of producing oil or gas in paying quantities and the default is not cured by the date indicated in the demand, the commissioner will, in his discretion, seek to terminate the unit agreement by judicial proceedings. (Effective 6/28/81, Register 78.)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.379. SIGNATURES. Each signature on the unit agreement must be notarized or attested by at least two witnesses. Corporate of other signatures made in a representative capacity must be accompanied by evidence of the authority of the signatory to act on behalf of the principal or by a reference to such evidence previously filed. The printed or typed name and address of each signatory to the unit agreement must be set out below the signature. (Effective 9/5/74, Register 51; amended 7/22/79, Register 71; amended 6/28/81, Register 78.)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.380. COUNTERPARTS. The parties may execute any number of counterparts of a unit agreement or may execute a ratification, joinder, or consent in a separate instrument. These documents have the same effect as if all parties signed the same instrument. (Effective 9/5/74, Register 51; amended 6/28/81, Register 78.)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.383. NOTATION OF APPROVAL. If approved by the commissioner, the counterparts of each instrument submitted for approval will be returned to the applicant with the commissioner's approval noted on the approved counterparts. (Effective 9/5/74, Register 51; amended 7/22/79, Register 71; amended 6/28/81, Register 78.)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.385. MODIFICATION OF UNIT AGREEMENT. Any modification of an approved unit agreement is subject to the commissioner's approval. (Effective 9/5/74, Register 51; amended 7/22/79, Register 71; amended 6/28/81, Register 78.)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.390. UNIT BONDS. In place of separate bonds required for each lease committed to a unit agreement, the unit operator shall furnish and maintain a statewide oil and gas lease bond under 11 AAC 83.160. (Effective 9/5/74, Register 51; amended 7/22/79, Register 71; amended 6/28/81, Register 78.)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.393. APPROVAL OF FEDERAL AND PRIVATE PARTY UNITS. (a) If the State of Alaska selects or otherwise acquires any federal land which, at the effective date of selection or acquisition, is subject to a federal oil and gas lease which is committed to a unit agreement that has been approved in accordance with federal laws and regulations, the unit agreement will be considered to have been approved by the commissioner for all the purposes of AS 38.05 and 11 AAC 83.301 - 11 AAC 83.395.

(b) The commissioner will, in his discretion, enter into agreements with the federal government to provide for the unitization of state and federal oil and gas leases overlying a common reservoir. If the agreement permits or requires the commissioner to take any action or enter into any unit agreement which is contrary to or inconsistent with 11 AAC 83.301 - 11 AAC 83.395, the commissioner will, in his discretion, do so after making a written finding that his action or the unit agreement is necessary or advisable to protect the public interest, and will, in all cases, comply with the requirements of 11 AAC 83.303 and 11 AAC 83.311.

(c) Any person owning an interest in a state oil and gas lease who has been asked to join a unit in which all state leases proposed to be committed to the unit constitute not more than 10 percent of the surface acreage of the unit or not more than five percent of the initial participation in the unit may request approval of the commissioner to join the unit as a working interest owner and may also request that the commissioner join the unit as a royalty owner. The commissioner will, in his discretion, approve and join the unit agreement as a royalty owner if, after giving public notice in accordance with 11 AAC 83.311, he makes a written finding that the proposed unit is necessary or advisable to protect the public interest considering the criteria in 11 AAC 83.303. A unit agreement entered into under this section need not comply with the requirements of this chapter. (Effective 9/5/74, Register 51; amended 7/22/79, Register 71; amended 6/28/81, Register 78.)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.395. DEFINITIONS. Unless the context clearly requires a different meaning, in 11 AAC 83.301 - 11 AAC 83.395 and in the applicable unit agreements

(1) "conservation of the natural resources of all or parts of an oil or gas pool, field, or like area" means maximizing the efficient recovery of oil and gas and minimizing the adverse impacts on the surface and other resources;

(2) "commissioner" means the commissioner of the state Department of Natural Resources or his designee;

(3) "force majeure" means war, riots, acts of God, unusually severe weather, or any other cause beyond the unit operator's reasonable ability to foresee or control and includes operational failure to existing transportation facilities and delays caused by judicial decisions or lack of them;

(4) "paying quantities" means quantities sufficient to yield a return in excess of operating costs, even if drilling and equipment costs may never be repaid and the undertaking considered 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;

(5) "potential hydrocarbon accumulation" means any structural or stratigraphic entrapping mechanism which has been reasonably defined and delineated through geophysical, geological, or other means and which contains one or more intervals, zones, strata, or formations having the necessary physical characteristics to accumulate and prevent the escape of oil and gas;

(6) "reservoir" means an oil or gas accumulation which has been discovered by drilling and evaluated by testing and which is separate from any other accumulation of oil and gas;

(7) "unit" means a group of leases covering all or part of one or more potential hydrocarbon accumulations, or all or part of one or more adjacent or vertically separate oil or gas reservoirs, which are subject to a unit agreement;

(8) "unit agreement" means the agreement executed by the State of Alaska, working interest owners, and royalty owners creating the unit; and

(9) "sustained unit production" means continuing production of oil or gas from a reservoir in the unit area into a pipeline or other means of transportation to market, but does not include testing, evaluation, or pilot production. (Effective 6/28/81, Register 78; amended 3/18/83, Register 85.)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

- END OF TITLE 11, CHAPTER 83, ARTICLE 3 -

of this section, or approve alternate means for determining the location of a bore hole. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97)

Authority: AS 31.05.030

20 AAC 25.055. DRILLING UNITS AND WELL SPACING. (a). In proven oil and gas fields, the establishment of drilling units and a spacing pattern may be governed by special pool rules adopted in accordance with 20 AAC 25.520. In the absence of an order by the commission establishing drilling units or prescribing a spacing pattern for a pool, the following apply:

(1) a governmental quarter section constitutes the drilling unit for oil exploration; the surface location for a well exploring for oil must be at least 500 feet from the drilling unit boundary;

(2) a governmental section constitutes the drilling unit for gas exploration; the surface location for a well exploring for gas must be at least 1500 feet from the drilling unit boundary;

(3) where oil has been discovered, not more than one well may be drilled to that pool on any governmental quarter section, nor may any oil pool be opened to the well bore closer than 500 feet to any quarter section line, nor closer than 1,000 feet to any well drilling to or capable of producing from the same pool; and

(4) where gas has been discovered, not more than one well may be drilled to that pool on any governmental section, nor may any gas pool be opened to the well bore closer than 1,500 feet to any section line, nor closer than 3,000 feet to any well drilling to or capable of producing from the same pool.

(b) An application for exception to the provisions of this section must set out the names of all owners and of all operators of governmental quarter sections directly and diagonally offsetting the quarter section where the oil well is located, or the names of all owners and of all operators of governmental sections directly or diagonally offsetting the section where the gas well is located. A plat must be attached, drawn to a scale of one inch equaling 2,640 feet or larger, showing the location of the well for which the exception is sought, all other completed and drilling wells on the property, and all adjoining properties and wells. The application must be verified by a person acquainted with the facts, stating that all facts are true and that the plat correctly portrays pertinent and required data. The applicant for exception must send notice of the application by registered mail to all owners and to all operators noted above, and furnish the commission with a copy of the notice, date of mailing, and the addresses to which the notices were sent. The application for exception will be handled in accordance with 20 AAC 25.540.

(c) A well may not be re-entered for the purpose of producing oil on a property that is smaller than the governmental quarter section upon which the well is located or for the purpose of producing gas on a property that is smaller than the governmental section upon which the well is located.

(d) If two or more separately owned properties are embraced within a governmental quarter section to be drilled, or a well re-entered for oil, or a governmental section to be drilled, or a well re-entered for gas, persons owning the oil or gas rights may voluntarily pool their separate interests to form a drilling unit. A copy of the pooling agreement must be submitted to the commission. If one or more persons owning oil and gas rights fail to voluntarily pool their interests, the commission, upon petition or its own motion, and after public hearing, will, in its discretion, issue an order pooling the owner's interests for the development of their land as a drilling unit. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97)

Authority: AS 31.05.030
AS 31.05.100

20 AAC 25.061. WELL SITE SURVEYS. (a) Near surface strata to a depth of 2000 feet in the well site area for all exploratory and stratigraphic test wells must be evaluated seismically by common depth point refraction or reflection profile analysis to identify anomalous velocity variations indicative of potential shallow gas sources. Analysis results must be included with the application for the Permit to Drill (Form 10-401).

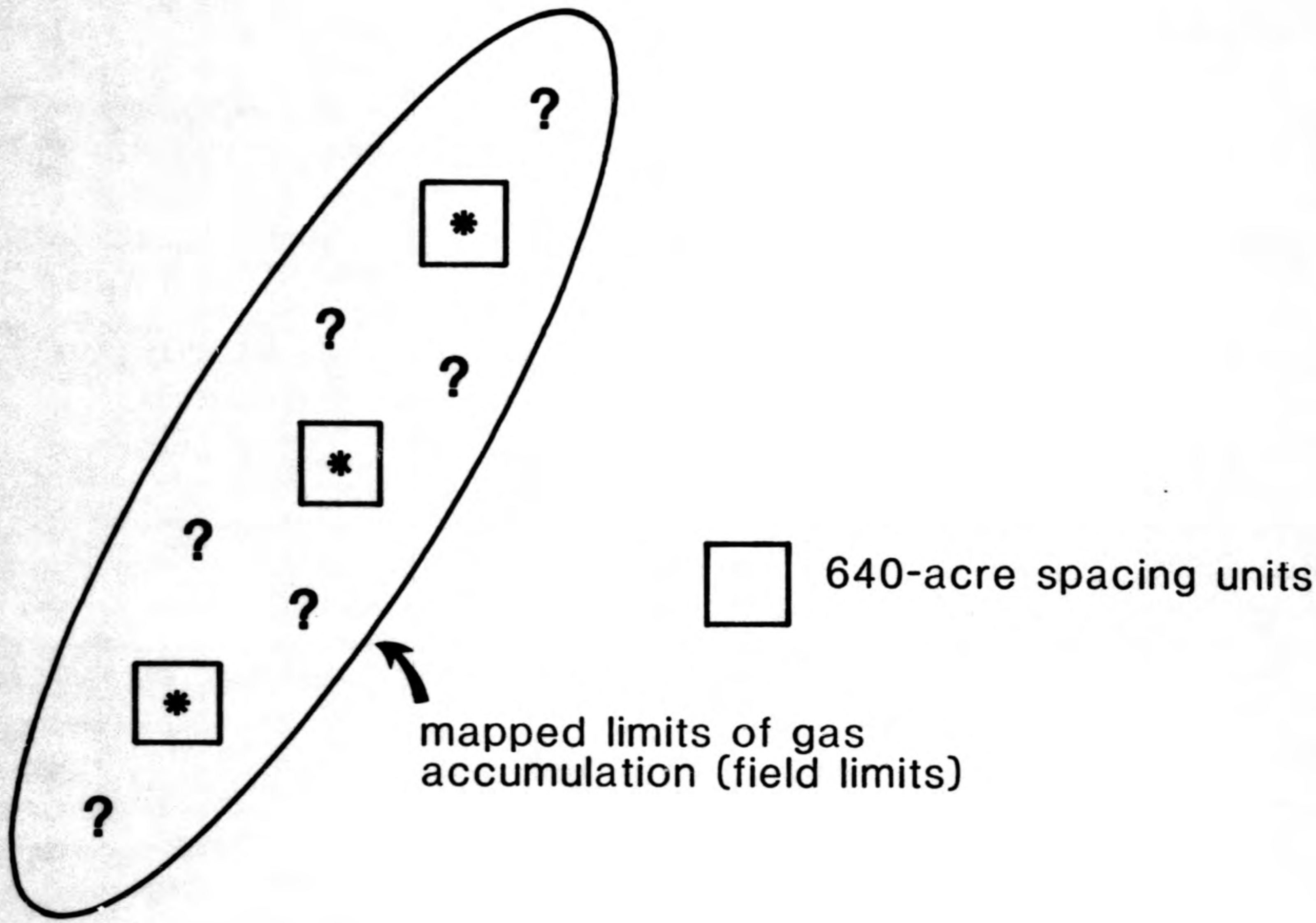
(b) The well site area must be evaluated by sidescan sonar and other pertinent surveys to determine whether potential seabed hazards to drilling operations are present for each type of well listed in 20 AAC 25.005 to be drilled offshore from a mobile bottom-founded, jack-up or floating unit. Survey results must be included with the application for Permit to Drill (Form 10-401).

(c) Upon request by the operator, the commission, in its discretion, will waive the requirements of this section. (Eff. 4/13/80, Register 74; am 4/2/86, Register 97)

Authority: AS 31.05.030

20 AAC 25.065. HYDROGEN SULFIDE. (a) When hydrogen sulfide gas is encountered, the operator shall notify the commission within 24 hours.

Hypothetical Field Drilled on 640-acre Spacing Units

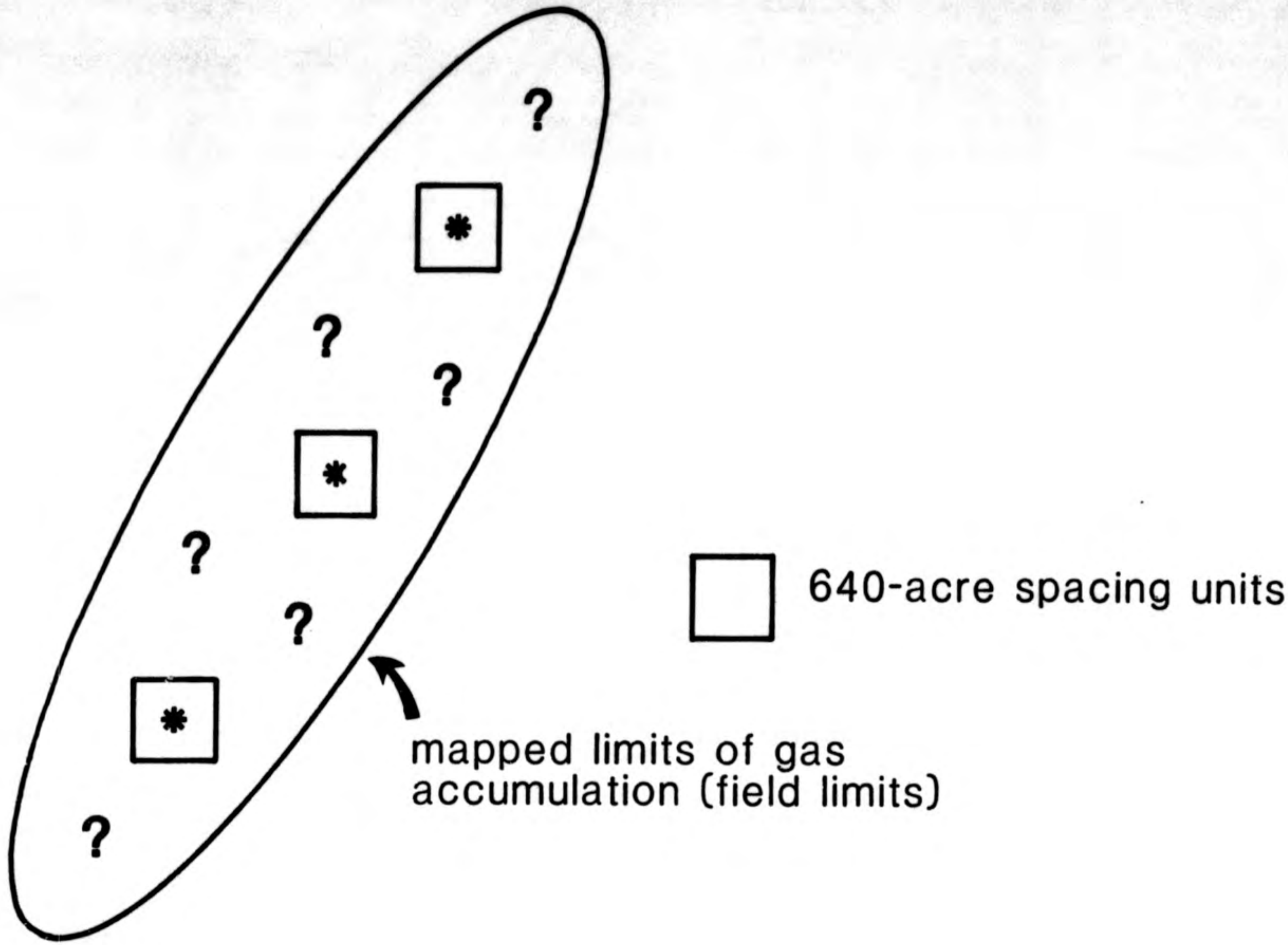


CORRECTION

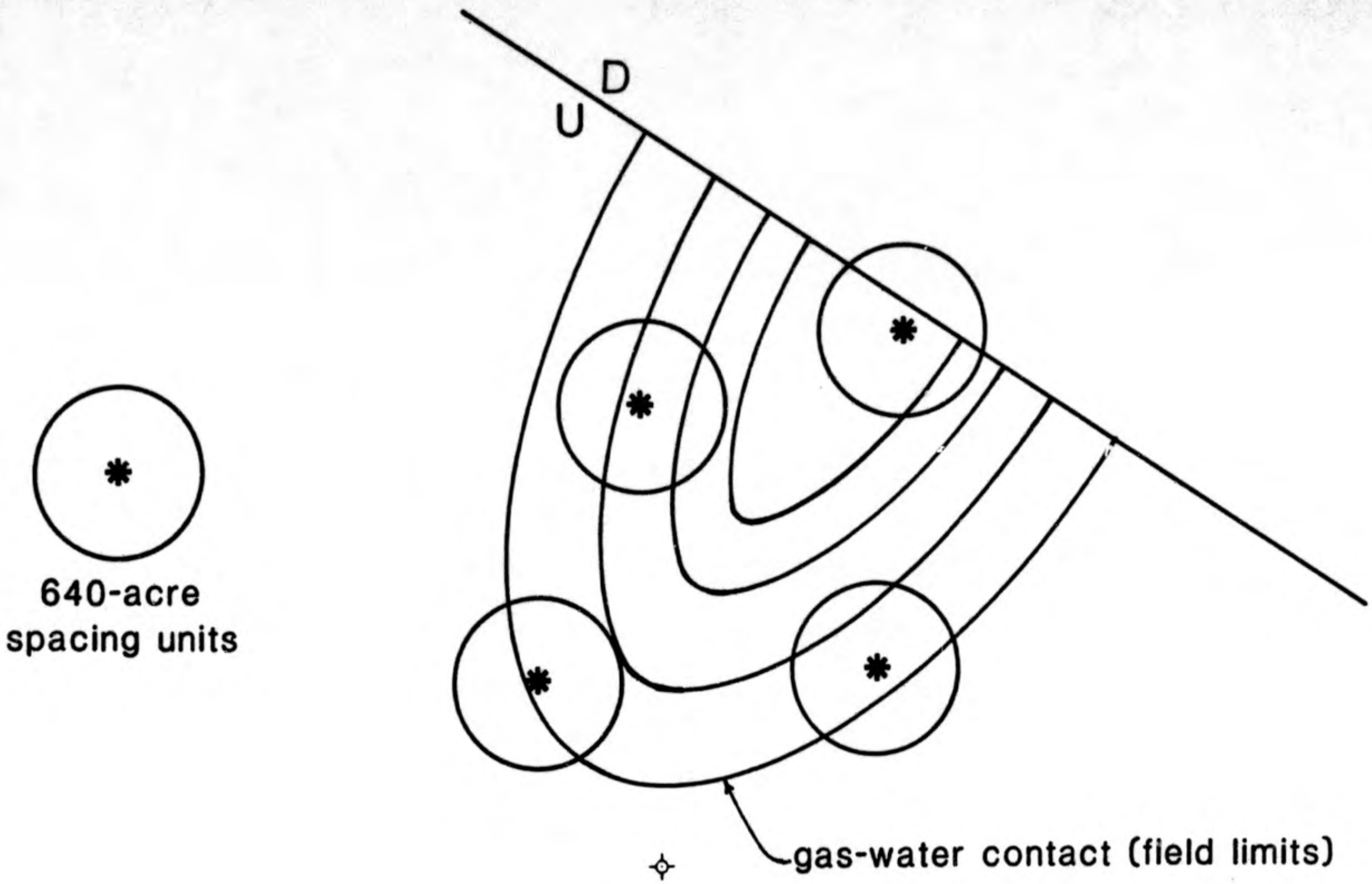
THIS DOCUMENT
HAS BEEN REPHOTOGRAPHED
TO ASSURE LEGIBILITY

02-576(2/77)

Hypothetical Field Drilled on 640-acre Spacing Units

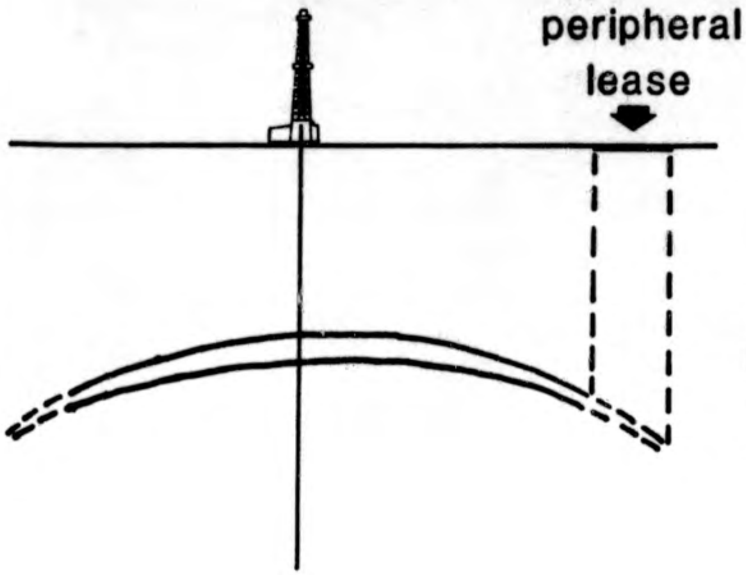


Hypothetical Field Drilled on 640-acre Spacing Units

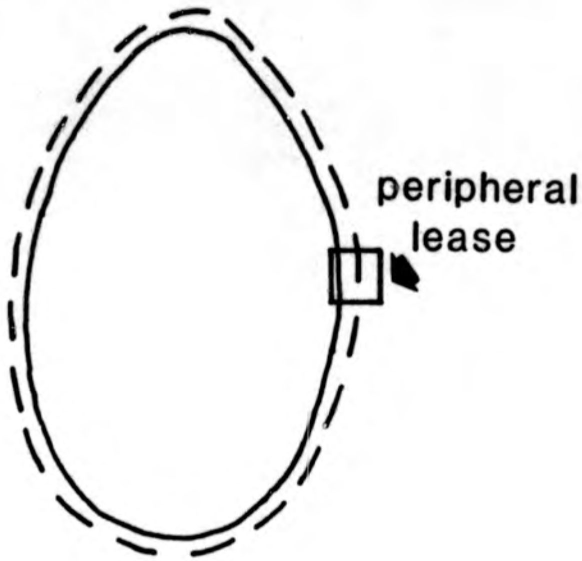


Determining Field Limits

Cross Section



Map View

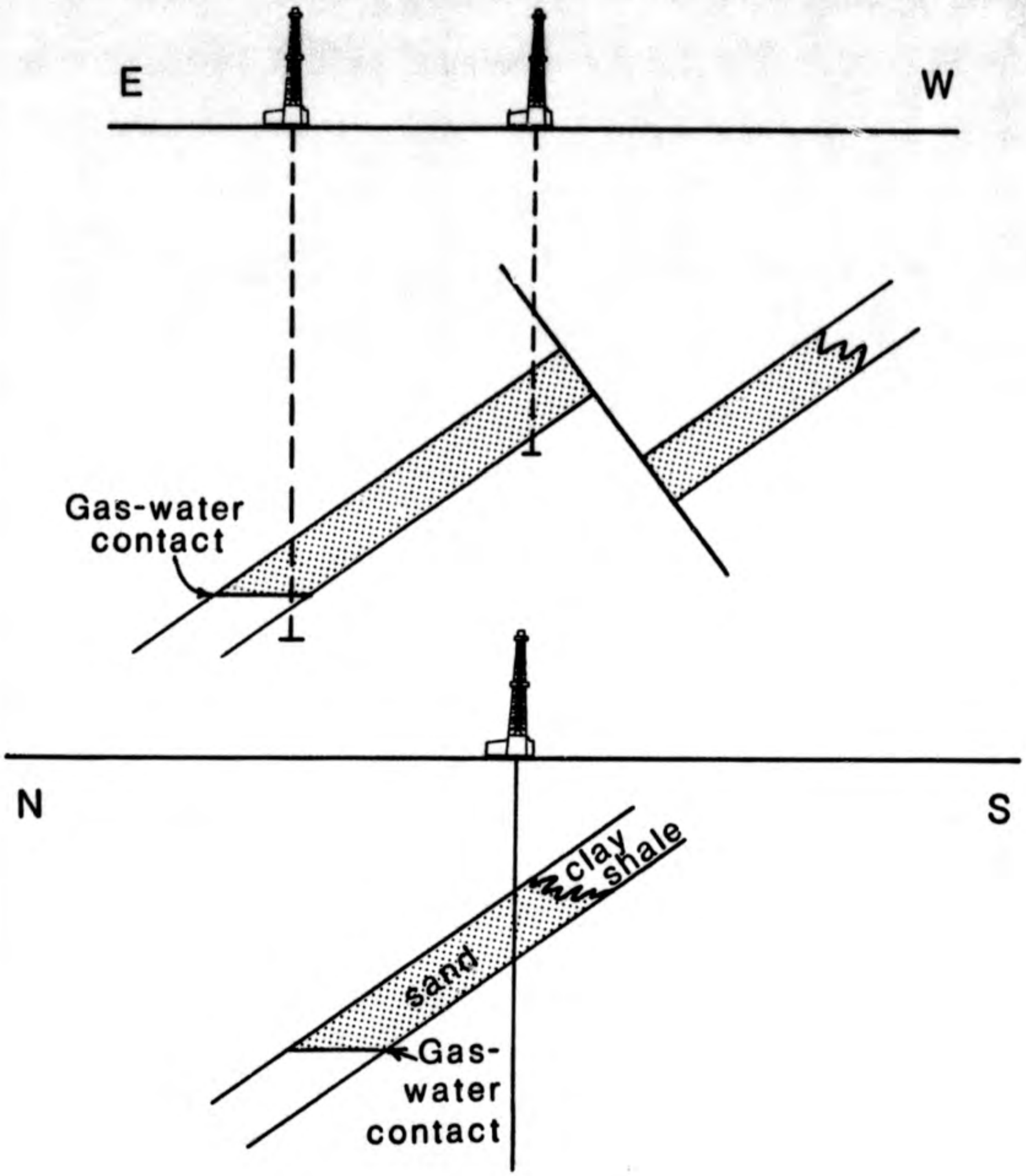


Useful Information

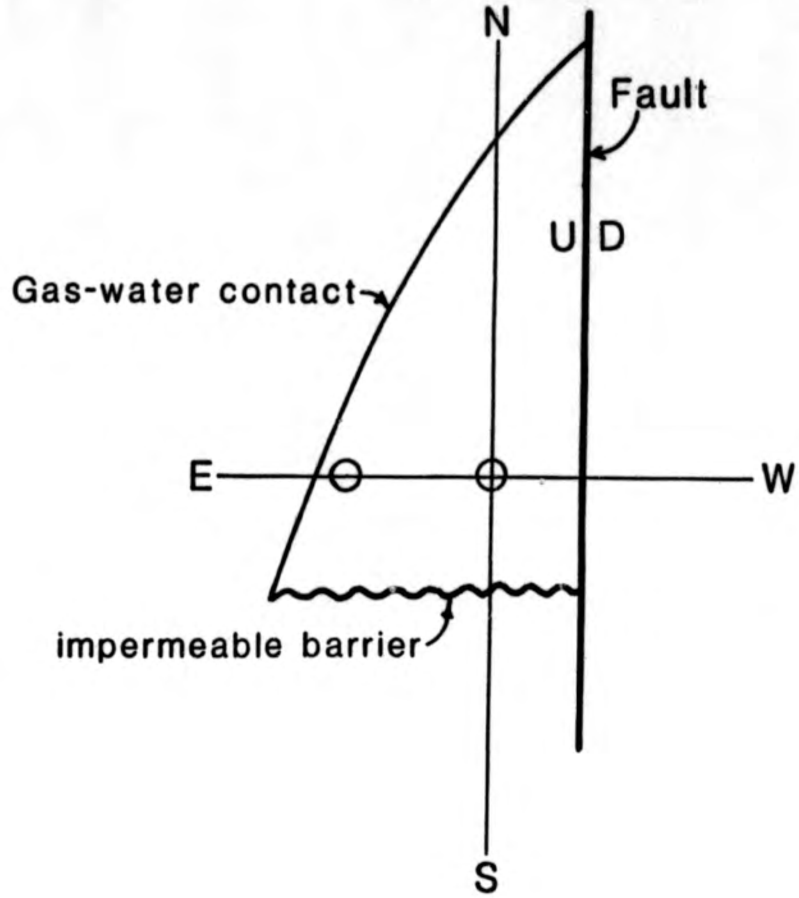
1) Seismic data
2) Reservoir type
   (homogeneous?)
3) Other fields in basin
4) Well data
   oil-water,
   gas-water contacts
   other log information
5) Production data
   pressure draw-down etc.

Combination Structural-Stratigraphic Trap
Hypothetical Asymmetrical Gas Field

Cross Sections:

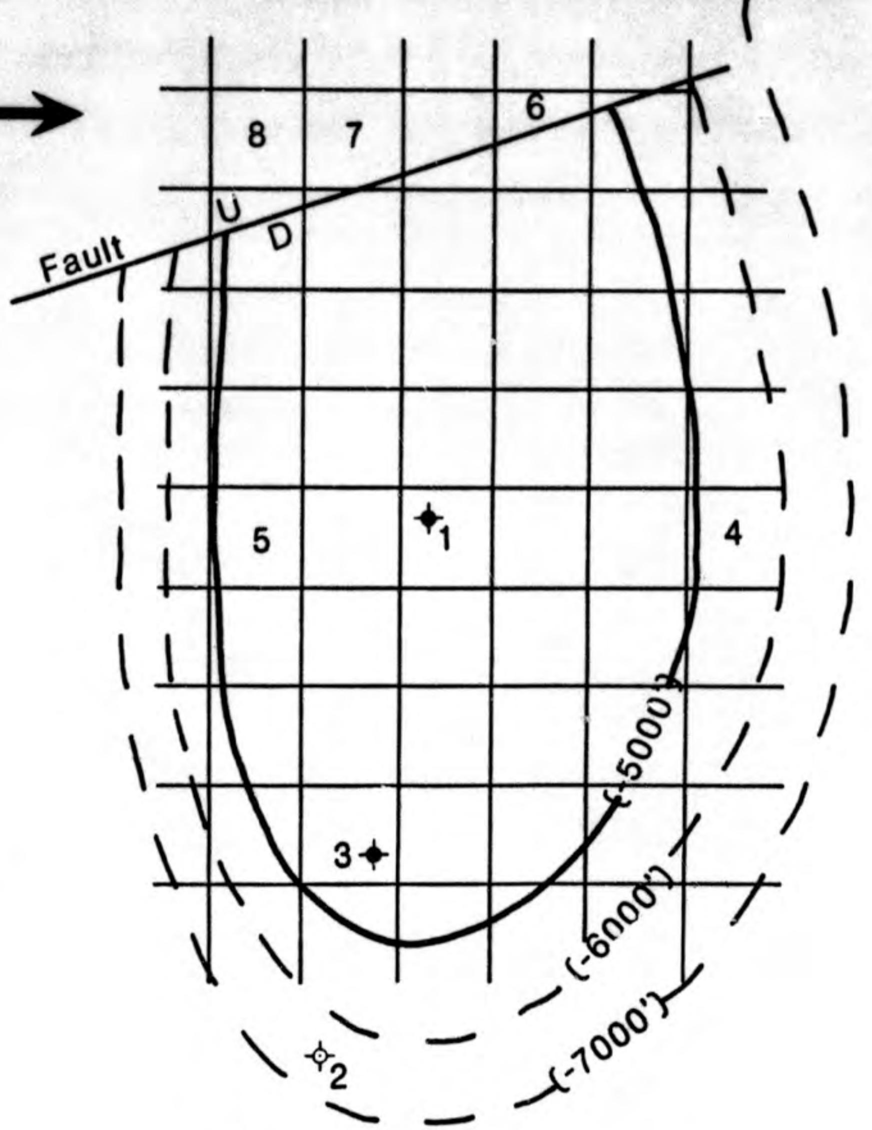


Map View:

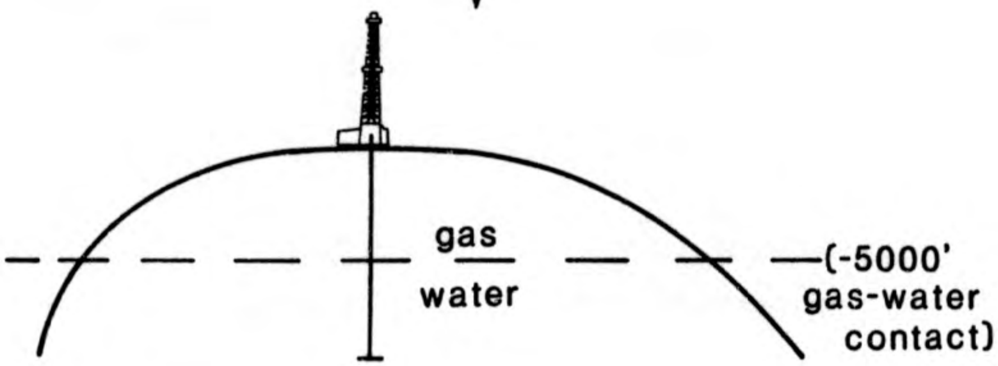


Hypothetical Gas Field
showing possible well locations and field (lease) equity

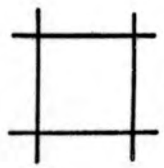
Map View



Cross Section



1. Discovery well
2. Dry hole
3. Confirmation well
4. Lease with minor amount of hydrocarbons
5. Lease with substantial hydrocarbons
6. Hydrocarbons limited by fault
7. Minor hydrocarbons due to fault
8. No hydrocarbons



shows leases based on 4 640-acre sections each

MAR 23 1988

STATE OF ALASKA

STEVE COWPER, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

P.O. BOX 7034
ANCHORAGE, ALASKA 99510-7034

(907)762-2550

March 18, 1988

The Honorable Jack Coghill
The Honorable Bettye Fahrenkamp
Alaska State Legislature
P. O. Box V
Juneau, Alaska 99811

Dear Senators Coghill and Fahrenkamp:

Thank you for the opportunity to present testimony at the March 7, 1988 Joint Senate Resources/Senate Special Oil and Gas Committee hearings on unitization policy and procedures.

Because my final testimony was cut short due to the required 3:30 adjournment time, I would like to provide the committees with my answers and views to the points raised by Mr. Cliff Burglin in his testimony. I have addressed the points in the order that Mr. Burglin discussed them.

1. Are state oil and gas leases competitive relative to other private lands and government leases?

   The Division clearly recognizes that the state must compete in a worldwide market when it offers oil and gas leases for sale. We take into account the size and location of the lease, the primary term of the lease, required minimum bonus bid, the royalty terms, estimated hydrocarbon potential, and possible exploration incentives. Unitization and permitting policy, though not a direct lease-sale consideration, also are important because they both affect the costs of exploration and development on the leases. Oil prices began to slide in 1982, and crashed in 1986. Since 1984 the division has conducted 10 lease sales. All 10 sales were bonus bid with a fixed royalty rate. A net profit share was not included in any of the leases, nor was an explicit work commitment required. The minimum bonus bid varied from $1.00 to $5.00 per acre, and the primary term of the leases was for 10 years. The royalty rate varied from 12.5 to 16.67 percent in those sales. A total of 5.4 million acres were offered for lease in those 10 sales. In our most recent sale (Sale 54), 80 percent of the acreage offered was leased. The royalty rate was 12.5 percent, and the minimum bid was $5.00 per acre. For the 72 tracts bid on (89 tracts were offered), 164 bids were received. Sale 54 also included an exploration incentive provision. At Sale 50 held last June, 100 percent of the tracts offered were leased. Federal OCS acreage offered in recent years carried a minimum bonus bid ranging between $25 and $150 per acre. I believe that state leases are very competitive relative to other leases available worldwide. The division will continue to monitor worldwide events to assure that our leasing program remains competitive.

2. Are state oil and gas resources being drained by wells on federal or private lands?

   On the North Slope, there currently is no production from federal or fee lands. In addition, I am not aware of any development activities underway or soon-to-be underway on North Slope federal or fee lands. There are a number of safeguards in our oil and gas leases (and, in fact, in state and federal law) to prevent the type of situation that Mr. Burglin postulated. The state has access to the geological, geophysical and well data from federal OCS lands that are adjacent to our three-mile territorial waters. These adjacent OCS lands are commonly referred to as the 8(g) zone [taken from section 8(g) of the Federal OCS Lands Act]. The state would be aware well in advance of any potential drainage situation. Our own oil and gas leases contain provisions to require offset wells, compensatory royalty payments and required development of a state leasehold in threat of drainage. Contrary to Mr. Burglin's claim, drainage of oil and gas from state lands to federal or private lands is not, and will not be, a problem.

3. Should the state correct a "mistake" it made in setting the lease terms of the Seal Island/North Star Island area of the Beaufort Sea?

   The state leased the Seal Island/North Star area in 1979. Amerada Hess and Texas Eastern each acquired two state leases overlying that prospect. All four leases have a fixed 20 percent royalty rate. The net profit share was the bid variable for those specific leases, and the rates bid were 91.2 percent and 93.2 percent (Amerada Hess), and 85.26 percent and 85.26 percent (Texas Eastern). A total of 25 bids were received for the four leases. For these tracts, the cash bonus bid was fixed at $875.00 per acre. On other state acreage in that sale the high bonus bid (where the bonus was the bid variable) was $15,170 per acre. Since that sale, the lessees have built two artificial gravel islands and drilled a total of six exploratory wells to evaluate the prospect. A relatively large new oil and gas field was discovered as a result of those wells. However, due to the water depth (about 40 feet), remote offshore location (about seven miles from shore and 18 miles from pump station number 1), and current oil prices, the field does not appear economic to develop at this time.

   I am convinced that current and anticipated oil prices, not lease terms, are the primary factor in the decision to not develop the leases at this time. But as history has shown, oil prices and future expectations can change almost overnight.

4. Could the state be earning millions more dollars and creating thousands more jobs by immediately offering all its acreage for lease?

While we do have a few very promising areas left, the majority of the remaining unleased state acreage has only moderate to low oil and gas potential. Initially, only modest additional revenue will be generated from the bonus and rental monies as these low potential lands are leased, and very little, if any, money will be received if these lands are leased noncompetitively. As Mr. Burglin stated, in relative terms the vast majority of oil and gas revenues come from royalty and tax payments associated with production activities, and not at the time of a lease sale. That is why the division is attempting to lease the most prospective acreage over the next five years; hopefully, royalty and production tax payments will follow. As I stated at the hearing, of the 3.8 million state acres currently under lease, only 0.5 million acres are classified as producing. There are 3.3 million acres of state land under lease and ready to be drilled; I do not believe that the current lull in drilling activity is due to the unavailability of state leases. Again, current and forecasted oil prices are the culprit.

5. Should the state convert all its existing leases to 12 1/2 percent royalty rates and offer all future leases at 12 1/2 percent royalty?

   Our experience to date with other than 12 1/2 percent royalty leases has not been disappointing. The Endicott field includes one lease which is allocated 26 percent of the total field oil and gas production where the royalty rate is 20 percent and the net profit share rate on the lease is 79 percent. About 80 percent of the Milne Point field is comprised of 20 percent royalty rate leases. The Kuparuk field has two net profit share leases included in the producing area and, as stated earlier, the North Star/Seal Island area leases are at 20 percent royalty and include a net profit share. I believe that oil prices (both current and projected) are the driving force behind development decisions. While royalty rate is a consideration at the time of proposed development, I do not believe it is the only or primary deciding factor.

6. Why aren't more "independents" operating in Alaska?

   Quite a few independents have purchased oil and gas leases at state lease sales. Our low minimum bid requirements and generous 10 year lease terms provide ample opportunity for independents to become active in Alaska <u>if</u> they want to. However, the cost of exploration and development in the state, for the most part, prevents most of those parties from actively participating in the drilling of wells. By definition, independents have limited monies available for exploration on an annual basis. It would not be a wise business decision for an independent to gamble all its annual exploration budget on drilling one well in Alaska when it could drill 10 wells elsewhere for the same total cost. Fundamental laws of risk analysis dictate that you spread your risk to maximize your profits (or, conversely, to minimize your losses). Until costs of exploration in Alaska come down, there will be few independents actively drilling wells in our state, though independents still seem interested in acquiring leases here.

7. Are Alaska's oil and gas fields currently "undefined"?

   Mr. Burglin stated that the administration was remiss in not knowing what the oil and gas reserves were in each recognized field and in not knowing the field limits for each accumulation. The document Mr. Burglin used as an example was a monthly bulletin printed by the Alaska Oil and Gas Conservation Commission (AOGCC). Unfortunately, Mr. Burglin misinterpreted the term "undefined" as used by the AOGCC. The AOGCC uses the term undefined to classify oil and gas produced from pools (reservoirs) where specific ~~specific~~ field rules have yet to be established. The absence of field rules for a given pool in no way implies that reserve estimates or accumulation limits are not known. It is unfortunate that Mr. Burglin chose to use this specific example out of context. If you have any further questions on this issue, I suggest that you contact the AOGCC directly for a full explanation of how it estimates reserves and employs field rules.

8. Why doesn't the state reveal its proprietary oil and gas data to Mr. Burglin prior to issuing certain unitization decisions?

   Two points need to be addressed concerning this issue. First, by law (AS 38.05.035(a)(c)), the state is prohibited from releasing proprietary information to third parties without the written consent of the "owner" of the proprietary data. Since almost all of the state's proprietary data are supplied by third parties, we cannot release the data to Mr. Burglin without prior approval. The second point concerns the state's unitization decision process. Even if Mr. Burglin was given access to the state's data, I doubt that the state's final decision would be different. Our decision is based upon all the available information in the record regardless of whether or not Mr. Burglin agrees with the interpretation of all that data. As was discussed on March 7, the parties seldom disagree with the basic geological, geophysical and well data; however, interpretation of the data does, on occasion, bring about disagreements. And as also was stated at the March 7 hearing, all lessees, including Mr. Burglin, have the option to drill on their leases to prove the existence of hydrocarbons if there are insufficient data to prove or disprove conclusively whether the acreage is productive. A unit does not have to be approved prior to drilling a well on a lease.

9. If unitization is beneficial, why doesn't the state approve any and all applications for units?

   Commitment of a lease to a unit agreement extends that lease for the life of the unit. Commitment of a lease to a unit agreement also satisfies any work commitment stipulation that is made part of that lease. In addition, a unit area is intended to cover a defined potential hydrocarbon accumulation or a known reservoir. Unless the affected lessees have a sound geological and geophysical basis for an exploratory unit or well data to confirm the need for a development unit (i.e., a seismically or geologically defined subsurface "prospect"), the approval of a unit application to explore the area is not warranted. The lessees must also commit to an exploration plan or development plan at the time the unit is formed. Units will not be approved for areas where no prospect is defined for which an adequate work plan is not a part of the proposal. Again, the lessee(s) can always drill a well to prove its point. Unitization should not be used to arbitrarily extend the primary term of unproven leases.

10. Should the state institute a noncompetitive leasing system?

With the 1987 amendment to 38.05.035(e)(7), the division now can reoffer acreage on a more regular basis. In addition, the division has 12 "regular" lease sales already scheduled over the next five years. In recent years both the State of Alaska and the federal government have experienced a number of fraud and consumer "rip-offs" through lower 48 boiler-room, high-pressure telephone sales schemes involving resale of predominantly noncompetitive leases to unsuspecting individuals. Unfortunately, these few illegal schemes have seriously jeopardized the future of all noncompetitive leasing. In 1987 the Alaska State Legislature abolished noncompetitive leasing of state lands in 1978. The United States Congress completely overhauled the federal noncompetitive leasing program in to require that all lands first be offered competitively for lease. Federal acreage that is offered competitively, but that receives no bids, can then be offered noncompetitively over the next two-year period. Minimum bonus bid is $2.00 per acre, and the first year annual rental is $1.50 per acre.

I believe that a dependable lease sale schedule, combined with regular competitive reofferings of expired or previously unpurchased leases, best accomplishes the goal of making acreage available for exploration and, at the same time, protects the state's interests. I do not believe that a state noncompetitive leasing program is needed, nor would it provide all the benefits described by Mr. Burglin in his testimony.

11. Is there a consensus that unitization policy or leasing policy needs change?

Prior to considering changes to the statutes, I recommend that the committee hear from such parties as the Alaska Oil and Gas Conservation Commission, other independents active in leasing in the state, in-state and out-of-state oil and gas consultants, and representatives from the major oil and gas companies active in Alaska. Because of the varied nature and objectives of the parties active in oil and gas leasing in Alaska, it is seldom that all parties will totally agree with each policy or statute currently in place. However, if there is a consensus that change is needed, then ways to bring about that change should be investigated.

12. Are changes necessary in the state oil and gas permitting process?

Over the last five years, considerable improvements have been made in the oil and gas permit processing and decision-making procedures for both individual agency permits and coastal zone management act consistency determinations. The outcome of recent major project reviews such as Lisburne, Endicott, and Steelhead illustrate this fact. The state and the respective local governments have been out front in these permitting actions. Complications involving required federal permits or disputes with fee owners of the surface estate have slowed down some applications after state permits for the proposed projects were already approved. However, I do not believe that the state permitting process is hindering or prohibiting exploration or development in Alaska.

As you requested, enclosed is a copy of the departmental regulations (11 AAC 88) governing appeal of Director or Commissioner decisions.

Again, thank you for the opportunity to present testimony to the committees on March 7. I would be happy to discuss the points outlined in this letter with the committees or with individual committee members as your interests and time constraints dictate. Please contact me if you need further clarification on any of these issues or want to discuss the issues in further detail.

Sincerely,

William Van Dyke

William Van Dyke
Petroleum Manager

Enclosure

cc: Senate Resource Committee Members:
Senator Paul Fischer
Senator Arliss Sturgulewski
Senator Jim Duncan
Senator Fred Zharoff
Senator Dick Eliason
Senator Ken Fanning
Senate Special Oil and Gas Committee Members:
Senator Jack Coghill
Senator Paul Fischer
Judith M. Brady, Commissioner, DNP
Cliff Burglin, Land Consultant
Chat Chatterton, Chairman, AOGCC
Cass Ariey, Petroleum Geologist, Division of Oil and Gas
Mike Kotowski, Petroleum Engineer, Division of Oil and Gas

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CHAPTER 88.
PRACTICE AND PROCEDURE

Section
100. Applicability
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110. Withdrawal of applications
115. Additional information
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150. Mailing list
151. Notice required by AS 38.05.945(c)
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180. Notice of decision
185. Definitions

Editor's Note: The mineral-leasing regulations in 11 AAC 82, 11 AAC 83, 11 AAC 84, 11 AAC 86 and 11 AAC 88, effective September 5, 1974, and distributed in Alaska Administrative Register 51, constitute a comprehensive reorganization and revision of this material, and thus a history line at the end of each section does not reflect the history of the provision before September 5, 1974, and the section numbering may or may not be related to the numbering before that date.

11 AAC 88.100. APPLICABILITY. This chapter applies to 11 AAC 82 – 11 AAC 86 unless specifically provided otherwise by the sections dealing with the subject of the application, filing or payment. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020(b)(1)

11 AAC 88.105. APPLICATIONS. All applications filed under 11 AAC 82 – 11 AAC 86 must comply with any requirements imposed by the regulations dealing with the subject of the applications, and must

(1) be typewritten or printed in ink;

(2) be signed by the applicant;

(3) be filed by mail or personal delivery at any filing office of the division;

(4) identify any affected lease, permit, or application by serial number or date of filing;

(5) describe the land affected by the application;

(6) state the address to which any notice concerning the application may be mailed; and

(7) be accompanied by the fee or fees prescribed by 11 AAC 05.010. (Eff. 9/5/74, Reg. 51; am 1/1/86, Reg. 96)

Authority: AS 38.05.020(b)(1)

11 AAC 88.110. WITHDRAWAL OF APPLICATIONS. At any time before a lease or permit is issued, the application may be withdrawn in whole or in part. If withdrawn in part, the application as modified must meet all the requirements of the applicable laws and regulations. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020(b)(1)

11 AAC 88.115. ADDITIONAL INFORMATION. The director may require any additional information regarding an applicant's, claimant's, permittee's or lessee's compliance with the statutes and regulations except proprietary data not specifically authorized by other regulation or statute. Failure to comply results in rejection of the application and is a default under the terms of the permit or lease and the regulations applicable to it. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020(b)(1)
AS 38.05.035(a)(4)

11 AAC 88.120. DEFICIENT FILINGS. (a) Applications and documents filed with omissions or errors give the applicant no priority if

(1) the land description is insufficient to identify the land or the description does not comply with the compactness requirements;

(2) the total acreage exceeds the maximum established by law or regulation, except where the rule of approximation applies;

(3) the total acreage is less than the minimum established by law or regulation;

(4) the full filing fee and the first year's rental, where required, is not filed; and

(5) the application is not signed by or on behalf of each person having an interest in the application whether by written or oral agreement or contract.

(b) Applications with the defects listed in (a) of this section may be corrected without loss of filing fee if done within 15 days of receipt of notice of the defect, but the time of filing is the date of the receipt of the correct information.

(c) The director may allow the correction of any other omission or error in an application or document other than those listed in (a) of this section without affecting the original filing time if he determines that the omission or error is immaterial or due to excusable inadvertance. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020(b)(1)

11 AAC 88.125. TIME FOR FILING. (a) Filing hours for payments and applications are from 10:00 a.m. to the end of posted office hours on business days, which are Mondays through Fridays, holidays excepted.

(b) Filing hours for all documents to be filed for record in the recording district in which the claim or site is located are from 8:30 a.m. to the end of posted office hours from Monday through Friday, holidays excepted.

(c) All documents, including payments and applications, received during filing hours on business days are stamped with the exact date and time of filing.

(d) Payments and applications received at any other time are filed at 10:00 a.m. on the next business day.

(e) Documents to be filed under (b) of this section received at any other time are considered to be filed at 8:30 a.m. on the next business day.

(f) Applications and documents showing the same time stamp are considered to have been filed simultaneously. (Eff. 9/5/74, Reg. 51; am 12/31/82, Reg. 84)

Authority: AS 38.05.020

11 AAC 88.130. TIMELY FILING. (a) Payments are timely if an affected lease or permit is identified by an Alaska Division of Lands' serial number, and is either (1) delivered at any of the division offices designated by the director as "filing offices" during filing hours within the time allowed by any notice, decision, regulation or law, or (2) mailed on or before the due date provided by any notice, decision, regulation or law and the mailing date can be verified by postmark or other post office record or notation.

(b) If the serial number is not identified, as required in (a) of this section, the time of filing is the time of receipt of correct information unless the director determines that the lack of such information is immaterial or due to excusable inadvertance.

(c) All other documents are timely filed if received during filing hours within the time allowed by any notice, decision, regulation, or law at any office designated by the director and posted in the office as a filing office.

(d) When the last day of the time for filing or payment falls on a day the designated filing office is officially closed, the time for filing is extended to the next day the office is open to the public. (Eff. 9/5/74, Reg. 51; am 12/31/82, Reg. 84)

Authority: AS 38.05.020(b)(1)

11 AAC 88.135. MEANS OF FILING. Filings and payments may be made by mail or personal delivery, unless provided otherwise by the section dealing with the subject of the filing or payment. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020(b)(1)

11 AAC 88.140. NOTICES. (a) Any notice which the director gives to any person must be in writing and must be delivered in person or mailed by registered or certified mail, return receipt requested, to the person at his current address of record with the division.

(b) Any person may file his current mailing address with the division in writing and may change his address of record by written notice filed with the division at any time. "Current mailing address" is the most recent or permanent legal address of an applicant, permittee, lessee or claimant. It is the responsibility of any person doing business with the division to notify the division of his most recent or permanent legal address.

(c) A notice is considered to be given and received on the date delivered to the current address of record.

(d) Whenever any notice is required to be given to a lessee, permittee or claimant, copies of the notice shall also be given, in the manner provided by (a) of this section, to any assignee whose assignment has been filed for approval. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020(b)(1)

11 AAC 88.145. REFUNDS. (a) If an application on which rental has been submitted is rejected or withdrawn in whole or in part, the first year's rental will be refunded in whole or in pro rata part on an acreage basis.

(b) Notwithstanding any other provision of 11 AAC 82 – 11 AAC 88, no refund will be made for less than $2.00. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020(b)(1)

11 AAC 88.150. MAILING LIST. The division shall maintain a mailing list for the purpose of sending general notices, orders and other information which the director determines to be of public interest regarding mineral activities of the division to persons who file a written request to be put on a list. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020(b)(1)

11 AAC 88.151. NOTICE REQUIRED BY AS 38.05.945(c). (a) A village corporation will be given notice under AS 38.05.945(c)(3) if it owns or has selected land within six miles of the state land proposed for disposal.

(b) A community will be given notice under AS 38.05.945(c)(4) if land within its boundaries is no more than six miles from the state land proposed for disposal. A community is an incorporated or unincorporated place with 25 or more inhabitants, according to the most recent census of the U.S. Census Bureau. An incorporated community's boundaries will be those reported to the department by the Local Boundary Commission. An unincorporated community's boundaries will be those delineated by the U.S. Census Bureau in the most recent census. (Eff. 6/28/81, Reg. 78; am 12/31/82, Reg. 84)

Authority: AS 38.05.020
AS 38.05.945

11 AAC 88.155. RECONSIDERATION. (a) An order, decision or other action of the director or the division which may be made or taken without the advance approval, consent or concurrence of the commissioner is subject to reconsideration by the director. After reconsideration by the director, any person aggrieved by the decision of the director may appeal the decision to the commissioner.

(b) An order, decision or other action of the commissioner, or of the director with the advance approval, consent, or concurrence of the commissioner, is subject to reconsideration only by the commissioner. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020(b)(1)

11 AAC 88.160. JUDICIAL APPEALS. A decision or other action of the division, the director or the commissioner becomes final for purposes of an appeal to the superior court 30 days after delivery as provided in 11 AAC 88.140 or as provided by applicable provisions of the Administrative Procedure Act, including AS 44.62.540, 44.62.560 and 44.62.570, and the Rules of Appellate Procedure of the State of Alaska, including Rule 44. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020(b)(1)

11 AAC 88.165. APPLICATIONS FOR RECONSIDERATION AND APPEAL. An application for reconsideration or an appeal must

(1) be filed within 30 days after receipt of notice of the action;

(2) be filed at the principal office of the director;

(3) comply with 11 AAC 88.105 except that there is no filing fee;

(4) specify the action to be reconsidered or appealed; and

(5) specify the grounds on which the reversal or modification of the action is urged. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020(b)(1)

11 AAC 88.170. BRIEFS. Written briefs in support of an application for reconsideration or an appeal may be filed with the division within 20 days after the filing of the application. The intention to file a brief must be specified in the application for reconsideration or appeal. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020(b)(1)

11 AAC 88.175. ORAL ARGUMENT. Oral argument may be allowed at the discretion of the officer who is to reconsider the action if written request for it is filed with the division within the time allowed for filing written briefs. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020(b)(1)

11 AAC 88.180. NOTICE OF DECISION. Following reconsideration of any action or final decision on appeal, the applicant will be given notice of the decision reached, specifying whether the action is affirmed, reversed, or modified, and, if the last, the details of the action as modified. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020(b)(1)

11 AAC 88.185. DEFINITIONS. As used in 11 AAC 82 – 11 AAC 88 and unless the context clearly requires a different meaning or unless otherwise defined in these chapters

(1) "adjacent" means touching or lying in close proximity, as opposed to "contiguous" which requires a common boundary;

(2) "cash" means cashier's or certified checks drawn on any solvent bank in the United States, postal or telegraphic money orders or legal tender of the United States of America, or any combination of these;

(3) "commissioner" means the Commissioner of the Department of Natural Resources;

(4) "cooperative agreement" means an agreement or plan of development and operation for the recovery of oil and gas from any pool, field, or like area or any part thereof in which separate ownership units are independently operated pursuant to the agreement without allocation of production;

(5) "director" means the Director of the Division of Lands;

(6) "division" means the Division of Lands, Department of Natural Resources;

(7) "filing office" means any place designated by the director as a filing office for applications, payments and filings under 11 AAC 82 – 11 AAC 88;

(8) "gas" means all natural gas and all hydrocarbons produced at a well not defined herein as oil;

(9) "gas well" means (A) a well which produces natural gas only; (B) that part of a well where the gas producing stratum has been successfully cased off from the oil, and the gas and oil being produced through separate casing or tubing; (C) any well classed as a gas well by the Alaska Oil and Gas Conservation Commission in the administration of the Alaska Oil and Gas Conservation Act;

(10) "leasehold location" or "mining leasehold location" means the interests in land subject to a location under AS 38.05.205 before a lease has been issued;

(11) "legal subdivision" means an aliquot part of a section of land according to the public land rectangular survey system, not smaller than one-quarter of one-quarter of one section of land, containing approximately 40 acres; where a section of land contains section lots, "legal subdivision" also means those section lots; "legal subdivision" also means a protracted legal subdivision according to any protracted public land rectangular survey prepared by the division or Bureau of Land Management of the Department of the Interior, and made available to prospective applicants for leases;

(12) "lessee or permittee of record" means the original lessee or permittee under any lease or permit or, if an assignment has been approved at any time, the latest assignee whose assignment has been approved;

(13) "locatable minerals" means those minerals which, on January 3, 1959, were subject to location under the United States mining laws (Title 30, USC);

(14) "Mineral Leasing Act" means the Act of Congress of February 25, 1920 (41 Stat. 437, 30 USC § 181, et seq.), as amended;

(15) "offshore" means tide and submerged lands, that is, those lands lying seaward from the line of mean high tide;

(16) "oil" means crude petroleum oil and other hydrocarbons regardless of gravity which are produced and saved in liquid form at the well by ordinary production methods;

(17) "oil well" means any well operated for the primary purpose of producing oil and which by the nature of its production cannot be classed as a gas well as defined in paragraph (6) of this section;

(18) "operating agreement" means an agreement giving the operator the right to carry on operations authorized by a lease or leases and to share in production obtained from the leased lands;

(19) "option" means an option to obtain an assignment of or an operating agreement covering a lease or portion of one;

(20) "order" means a determination made by the director or the commissioner in accordance with authority lawfully vested in him, issued in writing, filed in the permanent files of the division, posted in a conspicuous place in the offices of the division and made continuously available for inspection by the public;

(21) "participating area" means that part of an oil and gas lease unit area to which production is allocated in the manner described in a unit agreement;

(22) "person" includes a corporation and an association of persons;

(23) "pool" means an underground reservoir containing or appearing to contain a common accumulation of oil or gas or both; each zone of a general structure which is completely separated from any other zone in the structure is a pool;

(24) "primary term" means the initial term of an oil and gas lease and any extension of it;

(25) "smallest legal subdivision" means one-quarter of one-quarter of one section of land, containing 40 acres more or less, except where a section contains smaller section lots according to the public land rectangular survey or a protracted public land rectangular survey prepared by the division or by the Bureau of Land Management of the Department of the Interior, and made available to prospective applicants for leases, in which case "smallest legal subdivision" means those smaller section lots; as to unsurveyed land not covered by such

a protracted survey, it means a square containing 40 acres, more or less;

(26) "status record" means the basic record maintained by the division to show the status of every tract of land and of leases and applications for leases on them;

(27) "unit agreement" means an agreement or plan of development and operation for the recovery of oil and gas from a pool, field or like area, or any part of one, as a single consolidated unit without regard to separate ownerships, and for the allocation of costs and benefits on a basis as defined in the agreement or plan; "unit agreement" also includes "cooperative agreement" unless the context clearly requires the more restricted meaning;

(28) "unit area" means the area described in a unit agreement as constituting the land logically subject to development under the agreement;

(29) "unit operator" means the person, corporation or association designated under a unit agreement to conduct operations on unitized lands as specified in the agreement;

(30) "unitized land" means the part of a unit area committed to a unit agreement;

(31) "unitized substance" means deposits of oil, gas and associated substances produced with them recoverable by operations pursuant to a unit agreement;

(32) "working interest" means the interest held in lands by virtue of a lease, operating agreement, fee title or otherwise, under which the owner of the interest is vested with the right to explore for, develop and produce minerals; the right delegated to a unit operator by a unit agreement is not a working interest;

(33) "qualified to do business in Alaska" means holding the state certificates necessary to lawfully conduct business within the state;

(34) "leasehold," "mining lease," or "upland mining lease" means the interests in land subject to a mining lease issued in accordance with AS 38.05.205;

(35) "location" or "mining location" means a mining claim made under AS 38.05.195, a leasehold location made under AS 38.05.205, or a prospecting site location made under AS 38.05.245. (Eff 9/5/74, Reg. 51; am 3/27/82, Reg. 81; am 5/30/85, Reg. 94)

Authority: AS 38.05.020

DMEM Form No. 18-83 (UNIT AGREEMENT)
DNR Form No. 10-1128
(Revised June, 1983)

UNIT AGREEMENT
FOR THE EXPLORATION, DEVELOPMENT, AND OPERATION
OF THE KEY UNIT

STATE OF ALASKA
THIRD JUDICIAL DISTRICT

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UNIT AGREEMENT
FOR THE EXPLORATION, DEVELOPMENT, AND OPERATION
OF THE KEY UNIT

STATE OF ALASKA
THIRD JUDICIAL DISTRICT

THIS AGREEMENT is entered into as of the ___________ day of _________, 19__ by the parties who have signed this Agreement, and with the approval of the State of Alaska.

WHEREAS, the parties to this Agreement are the owners of Working, Royalty, or other oil and gas interests in the Unit Area subject to this Agreement; and

WHEREAS, Section 31.05.110(a) of the Alaska Statutes (Oil and Gas Conservation) provides that to prevent, or to assist in preventing waste, to insure a greater ultimate recovery of oil and gas, and to protect the correlative rights of owners of interests in the tracts of land affected, these owners may validly integrate their interests to provide for the unitized development and operation of such tracts of land as a unit; and

WHEREAS, the Commissioner of the Department of Natural Resources, State of Alaska, is authorized by Alaska Statute 38.05.180 and regulations adopted under that statute to consent to and approve oil and gas unit agreements containing oil and gas leases for which the State of Alaska is the lessor; and

WHEREAS, the parties to this Agreement have complied with the Alaska Statutes and regulations prescribing the standards and procedures governing the submission of applications and criteria for approval of oil and gas unit agreements containing oil and gas leases for which the State of Alaska is the lessor; and

WHEREAS, the Commissioner of the Department of Natural Resources has found that this Agreement is necessary or advisable to protect the public interest;

NOW THEREFORE, in consideration of the provisions contained in this Agreement, it is agreed as follows:

ARTICLE 1

DEFINITIONS

1.1 Commissioner means the Commissioner of the Department of Natural Resources, State of Alaska, or his duly authorized representative, who is authorized and has been delegated the authority to act for and on behalf of the Commissioner of the Department of Natural Resources.

1.2 Effective Date means the time and date this Agreement becomes effective as provided in Article 13.1.

1.3 Force Majeure means war, riots, acts of God, unusually severe weather, or any other cause beyond the Unit Operator's reasonable ability to foresee or control (including delays caused by operational failure of existing transportation facilities and judicial decisions or lack of them), whether similar to those enumerated or not.

1.4 Oil and Gas Rights means the rights to explore, develop, and operate on lands within the Unit Area for the production of Unitized Substances, or to share in the production, the proceeds, or the value of the Unitized Substances.

1.5 Outside Substances means substances purchased or otherwise obtained by the Working Interest Owners and injected into a Reservoir in the Unit Area.

1.6 Participating Area means a Tract or group of Tracts described and designated as a Participating Area under this Agreement for the purposes of developing, producing, or allocating one or more Unitized Substances from all or part of a Reservoir.

1.7 Participating Area Expense means all cost, expense, or indebtedness incurred by the Working Interest Owners or Unit Operator under this Agreement or the Unit Operating Agreement for or on account of production from or operations in a Participating Area, and allocated solely to the Tracts in that Participating Area and not to any other Tracts in the Unit.

1.8 Paying Quantities means quantities sufficient to yield a return in excess of operating costs, even if drilling and equipment costs may never be repaid and the undertaking considered 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. A well will be considered capable of producing Unitized Substances in Paying Quantities when so certified by the Commissioner following application by the Unit Operator.

1.9 Reservoir means an accumulation of Unitized Substances which has been discovered by drilling and evaluated by testing and which is separate from any other accumulation of Unitized Substances.

1.10 Royalty Interest means a right to or interest in any portion of, or the proceeds or value of the Unitized Substances other than a Working Interest.

1.11 Royalty Owner means the State of Alaska and any other party that owns a Royalty Interest.

1.12 State means the State of Alaska acting in this Agreement by and through the Commissioner of the Department of Natural Resources or his authorized representative.

1.13 Sustained Unit Production means continuing production of Unitized Substances from a Reservoir in the Unit Area into a pipeline or other means of transportation to market, but does not include testing, evaluation, or pilot production.

1.14 Tract means the land which is described in Exhibit A and given a Tract number.

1.15 Tract Participation means the percentage assigned to a Tract in a Participating Area for allocating Unitized Substances to that Tract.

1.16 Unit Area means the land identified by Tracts in Exhibit A and shown on Exhibit B to which this Agreement applies or to which it may be extended as provided in this Agreement.

1.17 Unit Expense means all cost, expense, or indebtedness incurred by the Working Interest Owners or the Unit Operator under this Agreement and the Unit Operating Agreement for or on account of Unit Operations, except for Participating Area Expense.

1.18 Unit Operating Agreement means the agreement entered into by the Working Interest Owners, having the same Effective Date as this Agreement, entitled "Unit Operating Agreement, KEY Unit, State of Alaska," as amended or supplemented from time to time.

1.19 Unit Operations means all operations conducted under this Agreement and the Unit Operating Agreement.

1.20 Unit Operator means the Working Interest Owner or other party designated by the Working Interest Owners under the Unit Operating Agreement to conduct Unit Operations, acting as operator and not as a Working Interest Owner.

1.21 Unitized Substances means all oil, gas, and associated substances other than Outside Substances within or produced from the Unit Area.

1.22 Working Interest means an interest in Unitized Substances by virtue of a lease, operating agreement, fee title, or otherwise, including a carried interest, under which the owner of that interest has the right to drill, develop, and produce, or cause to be drilled for, developed, or produced, oil and gas, and the owner of which interest is obligated to pay, either in cash or out of production or otherwise, a portion of the Unit Expense or the Participating Area Expense. A Royalty Interest created out of a Working Interest subsequent to the execution of this Agreement by the owner of that Working Interest shall continue to be subject to those Working Interest burdens and obligations that are stated in this Agreement and the Unit Operating Agreement.

1.23 Working Interest Owner means a party to this Agreement owning a Working Interest.

ARTICLE 2

EXHIBITS

2.1 Exhibits. The following exhibits which are attached to this Agreement are incorporated into this Agreement by reference:

2.1.1* Exhibit A is a schedule that identifies and describes each Tract in the Unit Area, and shows the Working Interest Ownership of Oil and Gas Rights in each Tract and a schedule of the Royalty and Net Profit Share rates applicable to each Tract in the Unit Area.

2.1.2 Exhibit B is a map depicting the boundaries of the Unit Area and the Tracts.

2.1.3** Exhibit C is a description of the Participating Areas formed under this Agreement, including general geologic descriptions and schedules showing Tract Numbers, Legal Descriptions, Alaska Lease Numbers (ADLs), and Tract Participations.

2.1.4** Exhibit D is a map depicting the boundary lines of the Participating Areas and the Tracts formed under this Agreement.

2.1.5** Exhibit E is a schedule that describes the allocation of Participating Area Expense to each Tract in the Participating Areas formed under this Agreement.

2.1.6 Exhibit F is a schedule that describes the allocation of the Unit Expense to each Tract in the Unit Area.

2.1.7*** Exhibit G is the plan of exploration or development for the Unit Area.

2.2 Reference to Exhibits. When reference is made to an exhibit, it is to the exhibit as originally attached or, if revised, to the latest approved revision.

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*Exhibit A will reflect the royalty rate from the leases; if a royalty rate is renegotiated at the time of unitization, Exhibit A will reflect this modification.

**If there is more than one Participating Area when the Unit is initially created, these areas should be described in Exhibits C-1, C-2, etc., D-1, D-2, etc., and E-1, E-2, etc.

***If no Participating Areas are established at the time this unit is approved, Exhibit G should be a plan of exploration. If a Participating Area is established at the time of unitization, Exhibit G should be a plan of development.

2.3 Exhibits Considered Correct. Exhibits A, B, C, D, E, F, and G have been established using the best information available and shall be considered to be correct until revised.

2.4 Correcting Errors. If subsequent to the date of this Agreement it appears that any Tract should be divided into more than one Tract because of diverse Royalty or Working Interest Ownership, or that any mechanical miscalculation or clerical error has been made, the Unit Operator, with the approval of the Working Interest Owners and the Commissioner, shall correct the mistake by revising the exhibits to conform to the facts. The revision shall not include any reevaluation of engineering or geological interpretations used in determining Tract Participation. Each revision of an exhibit made less than 30 days after the Effective Date shall be effective as of the Effective Date. Each revision made 30 days or more after the Effective Date shall be effective at 12:01 a.m. on the first day of the next calendar month following the filing of the revised exhibit with the Commissioner for his approval or on any other date as may be agreed upon by the Working Interest Owners and the Commissioner and set forth in the revised exhibit.

2.5 Filing Revised Exhibits. If an exhibit is revised, the Unit Operator shall execute an appropriate instrument with the revised exhibit attached and file the same for record in the filing office of the Department of Natural Resources, Anchorage, Alaska.

2.6 Exhibits for New Participating Areas. The Unit Operator shall prepare Exhibits C, D, and E for each new Participating Area created under Article 6 of this Agreement, and shall submit these exhibits to the Working Interest Owners and, after approval by them, to the Commissioner for approval. The Working Interest Owners also shall submit revisions to Exhibit F at the same time for approval by the Commissioner.

ARTICLE 3

CREATION AND EFFECT OF UNIT

3.1 Oil and Gas Rights Unitized. All Oil and Gas Rights in and to the lands described in Exhibit A are unitized so that Unit Operations may be conducted as if the Unit Area had been included in a single lease executed by the State of Alaska and any other party who has authority to execute oil and gas leases, as lessor, in favor of all Working Interest Owners, as lessees.

3.2 Amendment of Leases and Other Agreements. The provisions of the various leases, agreements, division and transfer orders, or other instruments pertaining to the respective Tracts or the production from those Tracts, are amended to the extent necessary to make them conform to the provisions of this Agreement, but otherwise shall remain in effect.

3.3 Continuation of Leases and Term Interests. Except for the purpose of determining payments to the State of Alaska and other Royalty Owners, production from any part of a Participating Area shall be considered as production from each Tract in the Participating Area and shall continue each lease in the Participating Area in effect just as if a well were producing from each Tract, so long as that Tract remains committed to the Unit. Unit Operations, if conducted under and in compliance with an approved plan of exploration or development, shall continue each lease in the Unit Area in effect as if Unit Operations were conducted on each Tract, so long as that Tract remains committed to the Unit.

3.4 Rental Settlement. Rental due on leases committed to this Agreement shall be paid by the Working Interest Owners who are lessees of the leases. The lessee shall pay annual rental to the State in accordance with the following rental schedule:

(1) For the first year of the term of the lease, $1.00 per acre or fraction of an acre;

(2) For the second year of the term of the lease, $1.50 per acre or fraction of an acre;

(3) For the third year of the term of the lease, $2.00 per acre or fraction of an acre;

(4) For the fourth year of the term of the lease, $2.50 per acre or fraction of an acre;

(5) For the fifth year of the term of the lease, and all following years, $3.00 per acre or fraction of an acre. Rental may be waived or suspended by the Commissioner.

3.4.1 Annual rental paid in advance on a lease, any portion of which is committed to a Participating Area, is a credit on the royalty or net profit share due under the lease for that year.

3.4.2 The lessee shall pay the annual rental to the State of Alaska (or any depository designated by the State with at least 60 days notice to the lessee) in advance, on or before the annual anniversary date of the lease. The State is not required to give notice that rentals are due by billing the lessee. If the State's (or depository's) office is not open for business on the annual anniversary date of the lease, the time for payment is extended to include the next day on which that office is open for business. If the annual rental is not paid timely, this lease automatically terminates as to both parties at 11:59 p.m., Alaska Standard Time, on the date by which the rental payment was to have been made. Rental may be waived or suspended by the Commissioner.

3.5 Minimum Royalty. If any State oil and gas lease committed to this Agreement requires the payment of minimum royalty, that lease is amended to delete that minimum royalty obligation. Rental, at the rate specified in Alaska Statute 38.05.180(n), shall be paid in lieu of minimum royalty.

3.6 Injection Rights. Under the plan of development attached as Exhibit G, the Working Interest Owners may inject substances into the Unit Area for Unit Operations, may drill, use, and maintain injection wells in the Unit Area, and may use for injection purposes any nonproducing or abandoned wells or dry holes, and any producing wells completed in the Unit Area.

3.7 Surface and Subsurface Operating Rights. Except to the extent modified in this Agreement, the Working Interest Owners, and the Unit Operator in their behalf, shall have the same rights to use of the surface and subsurface and use of water and any other rights as are granted in the leases. Except to the extent modified in this Agreement, any stipulations or operating conditions attached to a lease at the time of sale remain applicable to the lease. The State of Alaska retains all rights reserved it to explore, use, dispose of, or otherwise act upon or with respect to the surface and subsurface to the same extent as those rights are reserved in the oil and gas leases. The Working Interest Owners and the Unit Operator will, to the extent possible, minimize and consolidate surface facilities in order to minimize surface impacts.

3.8 Personal Property Excepted. All lease and well equipment, materials, and other facilities placed by any of the Working Interest Owners in the Unit Area are and shall remain personal property belonging to and removable by the Working Interest Owners. The rights and interests in that property as among the Working Interest Owners are set out in the Unit Operating Agreement.

3.9 Titles Unaffected by Unitization. Nothing in this Agreement shall be construed to result in the transfer of title to Oil and Gas Rights by any party to any other party or to the Unit Operator.

ARTICLE 4

UNIT OPERATOR

4.1 Unit Operator. The Working Interest Owners are concurrently entering into the KEY Unit Operating Agreement. The Working Interest Owners by the Unit Operating Agreement designate BURGLIN as the Unit Operator, which the Commissioner, by his signature to this Agreement, approves as the Unit Operator. By signature to this Agreement, BURGLIN affirms that it is qualified under Alaska law to be a Unit Operator and accepts the duties and obligations of the Unit Operator for the KEY Unit. A change of the Unit Operator may be made in accordance with the Unit Operating Agreement, but no change shall become effective until approved by the Commissioner, who shall not be required to grant approval unless he determines that the new Unit Operator is qualified under Alaska law to be a Unit Operator. Except as otherwise provided in this Agreement or in the Unit Operating Agreement, the Unit Operator shall have the exclusive right to conduct Unit Operations, which shall conform to the provisions of this Agreement and the Unit Operating Agreement. In the event of any change of Operator, the Unit Operator designated in this Agreement shall continue in its capacity as Unit Operator until a qualified successor has been selected by the Working Interest Owners and approved by the Commissioner, and the successor has assumed its duties as Unit Operator.

ARTICLE 5

PLANS OF EXPLORATION, DEVELOPMENT, AND OPERATIONS

5.1 Unit Plan of Exploration. If, upon the Effective Date of this Agreement, a Unit Plan of Development is not in effect as described in Article 5.2 of this Agreement, the Unit Operator, on behalf of the Working Interest Owners, with diligence and in accordance with good engineering practice, shall explore the Unit Area as described in the Unit Plan of Exploration attached to this Agreement as Exhibit G. The Unit Plan of Exploration shall conform to the provisions of 11 AAC 83.341, and may be amended or modified from time to time by the Unit Operator with the approval of the Commissioner.

5.2 Unit Plan of Development. If, upon the Effective Date of this Agreement, or at any time thereafter, a Reservoir in the Unit Area has been sufficiently delineated such that a prudent operator would initiate development activities in that Reservoir, the Unit Operator, on behalf of the Working Interest Owners, with diligence and in accordance with good engineering and production practice, shall explore, develop, and produce from the Unit Area in accordance with the Unit Plan of Development attached to this Agreement as Exhibit G. The Unit Plan of Development shall conform to the provisions of 11 AAC 83.343, and may be amended or modified from time to time by the Unit Operator with the approval of the Commissioner.

5.3 Unit Plan of Operations. A Unit Plan of Operations approved by the Commissioner is required before any operations may be undertaken on the Unit Area. The Unit Plan of Operations shall conform to the provisions of 11 AAC 83.346, and may be amended or modified from time to time by the Unit Operator with the approval of the Commissioner.

5.4 Rate of Exploration, Development, and Production. The Commissioner, after giving the Unit Operator written notice and an opportunity to be heard, may require the Unit Operator to modify the rate of exploration of, development of, or production from the Unit Area. Any modification required by the Commissioner shall not be contrary to any state or federal law or regulation or require the Unit Operator to violate a valid order or rule of the Alaska Oil and Gas Conservation Commission; shall not require any increase in the rate of exploration or development of, or production from the Unit Area that would be in excess of that permitted under prudent oil and gas engineering and production practices; shall not require the Unit Operator to alter or modify the rates of exploration or development of, or production from the Unit Area from those provided in the Unit Plan of Exploration or Development then in effect; or, in any case, shall not curtail rates of production to an unreasonable extent, considering Unit productive capacity, transportation facilities available, and conservation objectives. Nothing in this section is intended to preclude the enforcement by the Commissioner of any law or regulation which, by its terms, is required to be enforced by the Commissioner.

5.5 Drilling by Working Interest Owners. Any Working Interest Owner shall be entitled to drill wells on its lease under circumstances and limitations prescribed in the Unit Operating Agreement. Subject to the provisions of the Unit Operating Agreement, and with the approval of the Commissioner, a plan of testing, evaluation, and pilot production may be carried out by such Working Interest Owner or the Unit Operator to determine if such wells are capable of sustained production of Unitized Substances in sufficient quantities to justify the Working Interest Owners in developing and producing the Reservoir into which such well is completed; provided, however, that any such wells which are determined to be capable of production in Paying Quantities must thereafter be operated by the Unit Operator. Production of Unitized Substances resulting from testing, evaluation, or pilot plant operations saved, removed, or sold from the Unit Area shall be allocated to the lease from which such production occurred, and royalties paid on such production in accordance with Articles 7 and 8 of this Agreement.

ARTICLE 6

PARTICIPATING AREAS

6.1 Participating Areas Established. Participating Areas established under this Agreement are described in Exhibits C, D, and E.

6.1.1 At least 90 days before commencement of Sustained Unit Production from a Reservoir, the Unit Operator, on behalf of the Working Interest Owners, shall submit to the Commissioner for approval (1) proposed Exhibits C, D, and E describing a Participating Area for the Reservoir; (2) a proposed division of interest or formula allocating Tract Participation and Participating Area Expense as described in proposed Exhibits C and E; (3) if needed, a proposed modification of Exhibit F allocating Unit Expense to each Tract; (4) a proposed plan of development for the Unit Area (Exhibit G); and (5) a proposed plan of operations for the Unit Area. A Participating Area becomes effective on the day Sustained Unit Production commences.

6.1.2 A Participating Area may, but need not, encompass the entire Unit Area. A Participating Area shall include only the land reasonably known to be underlain by hydrocarbons and known or reasonably estimated through use of geological, geophysical, and engineering data to be capable of producing or contributing to production of Unitized Substances in Paying Quantities. A separate Participating Area shall be established for each separate Reservoir delineated in or partially in the Unit Area. Any two or more Participating Areas may be combined into one with the consent of the Commissioner and all Working Interest Owners in the Participating Areas to be combined.

6.2 Expansion and Contraction of Participating Area. A Participating Area shall be expanded or contracted from time to time by the Unit Operator with the approval of the Working Interest Owners and the Commissioner, whenever expansion or contraction is warranted on the basis of further drilling or otherwise. A Participating Area shall be expanded to include acreage reasonably proven through use of geological, geophysical, and engineering data to be capable of producing or contributing to production of Unitized Substances in Paying Quantities, or contracted to exclude acreage reasonably proven through use of geological, geophysical, and engineering data to be incapable of producing or contributing to production of Unitized Substances in Paying Quantities, subject to the approval of the Commissioner. A revised division of interest or formula allocating production and costs must be submitted for approval by the Commissioner at the time of application for expansion or contraction of a Participating Area. No land in a Participating Area shall be excluded from the Participating Area due to the depletion of Unitized Substances.

ARTICLE 7

ALLOCATION OF UNITIZED SUBSTANCES AND EXPENSES; PAYMENT OF ROYALTY

7.1 Allocation of Production and Costs. The division of interest or the formula which allocates the Tract participations of production, Unit Expense, and Participating Area Expense among the leases within the Unit Area shall not take effect until approved by the Commissioner in writing. Any proposed revision of an approved division of interest or allocation formula shall not take effect until approved by the Commissioner in writing. When requested by the Commissioner, the lessees or Unit Operator shall promptly file with the Commissioner all data that relates to the proposed or revised division of interest or the allocation formula.

7.2 Allocation of Unitized Substances Produced From Participating Areas. All Unitized Substances produced and saved or sold from the Unit Area shall be allocated to the Participating Area established for the Reservoir from which the Unitized Substances were produced. Unitized Substances allocated to a Participating Area shall be allocated to each Tract within the Participating Area in accordance with each Tract's Tract Participation and among each Working Interest Owner in accordance with each Working Interest Owner's ownership in the Oil and Gas Rights in the Tract. The amount of Unitized Substances allocated to each Tract, regardless of whether the amount is more or less than the actual production of Unitized Substances from the wells, if any, on a Tract, shall be considered for all purposes to have been produced from that Tract.

7.3 Provisions Common to All Reservoirs. For all Participating Areas, the Working Interest Owners and the Royalty Owners other than the State may allocate Unitized Substances, Participating Area Expense, and Unit Expense in amounts other than those set out in Exhibits C, E, and F, provided that any allocation which is different from the allocations required by Exhibits C, E, and F shall be submitted to the Commissioner for his information with a statement explaining the reasons for the different allocations.

7.4 Royalty Reports. Each month, the Unit Operator shall furnish to the Commissioner a schedule which shall specify, for the previous month, the total amount of Unitized Substances produced, the amount of Unitized Substances used for Unit Operations or unavoidably lost as provided in Article 8 of this Agreement, the amount of Unitized Substances allocated to each Tract as royalty delivered in kind to the Commissioner, and the amount of Unitized Substances allocated to each Tract as royalty production to be settled in value.

7.5 Royalty in Value. Each Working Interest Owner shall make settlement for its share of royalty on Unitized Substances taken in value by the State as follows:

7.5.1 Royalty paid in value shall be free and clear of all lease expense, Unit Expense, and Participating Area Expense (and any portion of those expenses that is incurred away from the Unit Area), including, but not limited to, expenses for separating, cleaning, dehydration, gathering, salt water disposal, and preparing the Unitized Substances for transportation off the Unit Area, and free from any lien for them. All royalty that may become payable in money to the State shall be paid on or before the last day of the calendar month following the month in which the Unitized Substances are produced. The amount of all royalty in value payments which are not paid when due under this Agreement or which are subsequently determined to be due as a result of a redetermination will bear interest from the date the obligation accrued until it is paid in full, at a variable annual rate equal to 1.25 percent plus the prime rate as announced from time to time by the Bank of America, San Francisco, California. Royalty payments shall be accompanied by copies of run tickets or other information relating to the valuation of royalty as the State may require, which may include, but is not limited to, evidence of sales and shipments of Unitized Substances produced from the Unit Area.

7.5.2 For purposes of computing royalties due under this Agreement, the value of Unitized Substances payable to the State as Royalty Owner shall not be less than the highest of:

(1) the field price received by the Working Interest Owner for the Unitized Substances;

(2) the volume-weighted average of the three highest field prices received by other producers in the same field or area for Unitized Substances of like kind, character, and quality at the time the Unitized Substances are sold or removed from the Unit Area or, in the case of gas, at the time that gas is delivered to an extraction plant if that plant is located on the Unit Area. If there are less than three prices reported by other producers, the volume-weighted average shall be calculated by using the lesser number of prices received by other producers in the field or area;

(3) the Working Interest Owner's posted price in the field or area for Unitized Substances; or

(4) the volume-weighted average of the three highest posted prices in the same field or area of the other producers in the same field or area for Unitized Substances of like kind, character, and quality at the time the Unitized Substances are sold or removed from the Unit Area, or, in the case of gas, at the time that gas is delivered to an extraction plant if that plant is located on the Unit Area. If there are less than three prices posted by other producers, the volume-weighted average shall be calculated using the lesser number of prices posted by other producers in the field or area.

7.5.3 If Unitized Substances are sold away from the Unit Area, the term "field price" in 7.5.2 of this Article shall be the cash value of all consideration received by the Working Interest Owner from the purchaser of the Unitized Substances, less the reasonable costs of transportation away from the Unit Area to the point of sale. The "reasonable costs of transportation" as used in this Article shall be those costs as defined in 11 AAC 83.228 -- 11 AAC 83.229 as those regulations exist on the Effective Date of this Agreement.

7.5.4 In the event the Working Interest Owner does not sell in an arm's-length transaction the Unitized Substances after removal from the Unit Area, the term "field price" in 7.5.2 and 7.5.3 of this Article shall mean the price on the Unit Area the Working Interest Owner would expect to receive for the Unitized Substances if the Working Interest Owner did sell the Unitized Substances in a arm's-length transaction. The Working Interest Owner shall determine this price in a consistent and logical manner using information available to the Working Interest Owner and report this price to the Commissioner.

7.5.5 The Commissioner may establish minimum values for purposes of computing royalties on Unitized Substances obtained from this Unit, with consideration being given to the price actually received by the Working Interest Owner, to the price or prices paid in the same field or area for production of like quality, to posted prices, to prices received by the Working Interest Owner and other producers from sales occurring away from the Unit Area, and to other relevant matters. In establishing minimum values, the Commissioner may use, but is not limited to, the Department of Revenue's methodology for determining "prevailing value" for purposes of the oil and gas property production tax, AS 43.55 et seq., or the methodology for determining "prevailing value" as defined in 11 AAC 83.227, in circumstances where terms of a contract set a single price for Unitized Substances without adjustments tied to market conditions for periods of longer than six years, or where the terms of a contract set prices which do not reasonably reflect market conditions for production from that field or area prevailing at the time the contract is executed or renegotiated, or where fraud or an intent to evade payment is demonstrated. Each minimum value determination shall be made only after the Working Interest Owner has been given reasonable notice and an opportunity to be heard. Under this provision, it is expressly agreed that the minimum value of royalty on Unitized Substances under this Agreement may not necessarily equal the price of such Unitized Substances.

7.5.6 The Commissioner may determine which of the methods contained in this Article shall be used to establish the minimum value of royalty for the purposes of royalties payable under this Agreement.

7.6 Payment of Royalty in Value. All payment to the State shall be made payable to the State in the manner directed by the Commissioner and, unless otherwise specified, must be tendered at

Department of Natural Resources
Pouch 7-034
Anchorage, Alaska 99510
Attention: Accounting

or to any depository designated by the Commissioner with at least 60 days notice to Unit Operator and the Working Interest Owners.

7.7 Failure to Pay Royalty. In the event of the failure of any Working Interest Owner to make proper settlement of any royalty due, the Commissioner shall have all rights and remedies available to him under law, the lease, and this Agreement, including any rights of cancellation and termination of the lease. If there is any conflict between a lease provision and the provisions of this Agreement, this Agreement shall govern.

7.8 Royalty In Kind. As close as practicable to 12 months before the commencement of Sustained Unit Production from a Participating Area, the Unit Operator shall give the Commissioner notice of the anticipated date for commencement of production. Within six months of receipt of that notice, the Commissioner shall give written notice to the Unit Operator of the State's election to take in kind all, none, a specified percentage, or a specified quantity of its royalty on any Unitized Substances produced from the Participating Area.

7.8.1 Anytime after the commencement of Sustained Unit Production from a Participating Area, the Commissioner, upon six months advance written notice to the Unit Operator, may elect to take in kind all, none, a specified percentage, or a specified quantity of the State's royalty on any Unitized Substance produced from the Participating Area. Upon six months advance written notice to the Unit Operator, the Commissioner may increase or decrease (including ceasing to take royalty in kind) the amount of royalty on any Unitized Substances the State takes in kind, except that this provision does not authorize the State to receive a royalty percentage on any Unitized Substances greater than the royalty percentage set out in Exhibit A of this Agreement.

7.8.2 In the written notices given under this Article, the Commissioner may elect to specify the Tracts from which royalty taken in kind by the State is to be allocated. If the Commissioner does not specify any Tracts in the notice, the royalty taken in kind shall be allocated to all Tracts in accordance with the Tract Participation.

7.8.3 The royalty taken in kind by the State shall be delivered to the Commissioner, or his designee, at the Unit Area boundary and in a pipeline or other facility capable of carrying the State's royalty share with the Unitized Substances of the Working Interest Owners, or at any other place mutually agreed upon by the Commissioner and the Unit Operator, and shall be delivered to the State or to any individual, firm, or corporation designated by the Commissioner.

7.8.4 The State's royalty Unitized Substances delivered in kind shall be delivered in good and merchantable condition and be of pipeline quality. Royalty delivered in kind shall be free and clear of all lease expenses, Unit Expense, and Participating Area Expense (including any portion of those expenses which is incurred away from the Unit Area), including but not limited to expenses for separating, cleaning, dehydration, gathering, salt water disposal, and preparing the Unitized Substances for transportation off the Unit Area.

7.8.5 Each Working Interest Owner shall furnish storage for royalty oil and natural gas liquids produced from the Unit Area to the same extent that Working Interest Owner provides storage for its own share of oil and natural gas liquids. The Working Interest Owner shall not be liable for the loss or destruction of stored royalty oil and natural gas liquids from causes beyond the Unit Operator's or the Working Interest Owner's reasonable control.

7.8.6 If a State royalty purchaser refuses or for any reason fails to take delivery of Unitized Substances, or in an emergency, and with as much notice to the Unit Operator as practical or reasonable under the circumstances, the Commissioner may elect without penalty to underlift for up to six months all or a portion of the State's royalty on Unitized Substances produced from the Unit or from any Tract and taken in kind. The State's right to underlift is limited to the portion of royalty Unitized Substances that the royalty purchaser refused or failed to take delivery of, or the portion necessary to meet the emergency condition. Underlifted Unitized Substances may be recovered by the State at a daily rate not to exceed 10 percent of its Royalty Interest share of daily production at the time of the underlift recovery. Recovery of underlifted Unitized Substances will be completed within two years of the date such underlift commences.

7.9 Royalty on Outside Substances. If any Outside Substance consisting of natural gases is injected into any Reservoir in the Unit Area, _____ percent of any like substance contained in the Unitized Substances subsequently produced from that Reservoir and allocated to the Participating Area for that Reservoir and sold, or used for other than Unit Operations, shall be considered to be a part of the Outside Substance injected until the total volume considered to be those Outside Substances equals the total volume of the Outside Substances injected. If liquefied petroleum gas or other liquid hydrocarbons which are Outside Substances are injected into the Reservoir,
____ percent of all those Unitized Substances produced and sold after one year from the time the injection of those Outside Substances was commenced shall be considered to be a part of the Outside Substances until the total value of the production considered to be those Outside Substances equals the total cost of the Outside Substances so injected. ____ percent of the Unitized Substances considered to be Outside Substances will be in addition to that which is being recovered for natural gases as provided in this Article if both liquefied petroleum gas or other liquid hydrocarbons and natural gases are injected. No payment shall be due or payable to the Royalty Owners on substances produced from any Reservoir in the Unit Area that are considered to be Outside Substances.

7.10 Records. The Unit Operator and the Working Interest Owners shall keep and have in their possession books and records showing the development and production (including records of development and production expenses) and disposition (including records of sales prices, volumes, and purchasers) of all Unitized Substances produced from the Unit Area. The Unit Operator and the Working Interest Owners shall permit the Commissioner to examine those books and records at all reasonable times. These books and records of development, production, and disposition shall employ methods and techniques that shall ensure the most accurate figures reasonably available without requiring separate tankage or meters for each well. The Working Interest Owners shall use generally accepted and internally consistent accounting procedures.

ARTICLE 8

USE OR LOSS OF UNITIZED SUBSTANCES

8.1 Use of Unitized Substances. Working Interest Owners may use or consume Unitized Substances for Unit Operations, including but not limited to the injection of Unitized Substances into any Reservoir underlying the Unit Area, provided the injection is made under an approved Plan of Development.

8.2 Royalty Payments. No royalty, overriding royalty, production, or other profit-based payments shall be payable on account of Unitized Substances used, unavoidably lost, stored, or consumed in Unit Operations. Royalty, overriding royalty, production, or other profit-based payments on Unitized Substances reinjected into the Unit Area will not be payable until those Unitized Substances are finally produced and transported off the Unit Area or used for other than Unit Operations. If Unitized Substances are consumed in the operation of any facility which is not exclusively devoted to Unit Operations, royalty, overriding royalty, production, or profit-based payments shall not be payable on the Unitized Substances consumed by that facility which are allocatable to Unit Operations.

ARTICLE 9

EXPANSION AND CONTRACTION OF UNIT AREA

9.1 Expansion of Unit Area. The Unit Area may be expanded from time to time to include any additional lands determined to overlie any Reservoir all or part of which is within the Unit Area, or any additional lands regarded as reasonably necessary to facilitate production of hydrocarbons or for any other purpose of this Agreement. Any expansion shall not be effective until approved by the Commissioner. The lands to be included shall be based on subdivisions of the public land surveys as may be approved by the Commissioner. Expansion shall be effected in the following manner:

9.1.1 Unit Operator, acting under the terms of the Unit Operating Agreement or on demand of the Commissioner, shall prepare a notice of the proposed expansion describing the contemplated additions to the Unit Area, the reasons for expansion, and the proposed Effective Date.

9.1.2 The notice shall be delivered to the Commissioner and a copy mailed to each Working Interest Owner and Royalty Interest Owner at its last known address, and to any other party believed by the Unit Operator to own any Oil and Gas Rights in any lands proposed to be added. The notice shall state a definite period, which shall not end earlier than 30 days after the mailing of the last notice to be mailed, during which time any interested party may file with the Unit Operator written objections to the proposed expansion.

9.1.3 Upon expiration of the period stated in the notice, the Unit Operator shall file with the Commissioner evidence of mailing of the notice of expansion, copies of all objections which have been submitted to the Unit Operator, and applications for joinder executed by those owning Oil and Gas Rights in any land sought to be added as have been submitted to the Unit Operator.

9.1.4 After consideration of all pertinent information, the Commissioner shall approve or disapprove the expansion as to each lease or lands submitted for commitment. Unless the Commissioner's decision states to the contrary, that decision shall become effective as of the time specified in the notice. The Commissioner will notify Working Interest and Royalty Owners and all other parties who have requested notification upon approval or disapproval of a proposed expansion.

9.1.5. If permitted by a lease issued by the State, the Commissioner may compel joinder to this Agreement by any lessee, or any assignee of an interest in a State lease. The parties to this Agreement agree to accept that joinder upon reasonable terms and conditions. Before compelling joinder under this Article, the Commissioner will give all affected parties reasonable notice and an opportunity to be heard.

9.2. Contraction of Unit Area Ten Years After Sustained Unit Production. Any lease, a part of which is neither included in a Participating Area nor which facilitates production of hydrocarbons in Paying Quantities on the tenth anniversary of the commencement of Sustained Unit Production from the initial Participating Area formed under this Agreement, shall be excluded from the Unit Area and from this Agreement. If any portion of a lease is included in a Participating Area or facilitates production of hydrocarbons in Paying Quantities, the entire lease will remain commited to the Unit. Nothing in this Agreement shall operate to excuse further development on the portion of any lease lying outside the Unit Area where the circumstances would require a prudent lessee to further develop.

9.3 Contraction for Failure to Drill Second Well pursuant to Exhibit G. Unless a well has been commenced on or before March 31, 1987 which will have a bottomhole location in Block B, which Block is shown in Exhibits A and B, or such drilling obligation has been suspended in accordance with the provisions of 11 AAC.83.336(b), the Unit Area shall be contracted to exclude all of the Tracts in Block B, except those Tracts included in an established Participating Area or a Participating Area for which an application is pending.

9.3.1 Effect of Contraction. Upon contraction of the Unit Area as provided in Article 9.3 of this Agreement, operations on any Tract excluded from the Unit Area may be continued. Each oil and gas lease covering lands within Block B excluded from the Unit Area shall remain in force for at least one year after the date on which such a contraction is made, and for a further period, if any, as provided by the lease. The salvaging of any equipment or the need for rehabilitation of lands excluded from the Unit Area shall be as provided for in Article 14.4.

9.3.2 If any lease within Block A of the Unit Area as set out in Exhibits A and B of this Agreement includes a work commitment pursuant to Stipulation #5 of such lease, that work commitment will be satisfied by the drilling of the first well with a bottom hole location under a lease contained in Block A of the Unit Area. If any lease within Block B of the Unit Area as set out in Exhibits A and B of this Agreement includes a work commitment pursuant to Stipulation #5 of such lease, that work commitment will be satisfied by the drilling of the first well with a bottom hole location under a lease contained in Block B of the Unit Area. Any well with a bottom hole location under a lease contained in Block A of the Unit Area will not satisfy a work commitment for any lease contained in Block B of the Unit Area and vice versa.

9.3.3 If any lease commited to this Agreement is eliminated from the Unit Area in accordance with the provisions of Artictle 9.3 of this Agreement, and that lease contains a work commitment pursuant to Stipulation #5 of such lease, that work commitment will reattach to such lease at the time of its contraction out of the Unit Area. The time period allowed for the lessee to commence the drilling of a well as required by the work commitment shall be the period of time that remained for the completion of the work commitment at the time such lease was commited to Unit Area but in no event shall that period be less than one year from the date such work commitment reattaches.

ARTICLE 10
TITLES

10.1 Removal of Tract form Unit Agreement. If a Working Interest Owner or a Royalty Owner ceases to have any of its Tracts committed to theis Agreement because of failure of title, those Tracts shall be removed from this Agreement effective as of 12:01 a.m. on the first day in the calendar month in which the failure ot title is finally determined unless within 90 days after the date of its final determination of the failure of title, the true Working Interest Owner and Royalty Owner of the Tract execute this Agreement and, if a Working Interest Owner, the Unit Operating Agreement.

10.2 Revision of Exhibits. If a Tract in a Participating Area is removed from this Agreement because of failure of title, the Unit Operator shall recompute the Tract Participation of each of the Tracts remaining in the

Participating Area and shall revise the exhibits to this Agreement accordingly; provided, however, that the revised Tract Participations of the Tracts remaining in the Participating Area shall remain in the same ratio one to another. The revised exhibits shall be effective as of 12:01 a.m. on the first day of the calendar month in which the failure of title is finally determined.

10.3 Failure of Title of Part of Tract. In the event of the failure of title of any party to this Agreement as to a divided portion of any Tract, the Unit Operator, with the approval of the Working Interest Owners and the Commissioner, shall divide that Tract into separate Tracts, and if that Tract is in a Participating Area, shall recompute the Tract Participation of each of the resulting Tracts (the sum of which shall equal the Tract Participation of the original Tract) and revise the Exhibits to this Agreement accordingly. After that revision, that resulting Tract in which title was not affected shall remain in this Agreement, and the resulting Tract in which title failed shall be subject to the provisions of Articles 10.1 and 10.2 of this Agreement.

10.4 Working Interest Titles. If title to a Working Interest fails, the rights and obligations of the Working Interest Owners by reason of the failure of title shall be governed by the Unit Operating Agreement.

10.5 Royalty Interest Titles. If title to a Royalty Interest fails, but the Tract to which it relates is not removed from this Agreement, the party whose title failed shall not be entitled to royalty.

10.6 Production Where Title is in Dispute. If the title or right of any party claiming the right to receive all or any portion of the Unitized Substances allocated to a Tract is in dispute, the Unit Operator, at its discretion, shall either

(1) require that the party to whom Unitized Substances are delivered or to whom the proceeds or value are paid furnish security for the proper accounting to the rightful owner if the title or right of that party fails in whole or in part; or

(2) withhold and market the portion of Unitized Substances with respect to which title or right is in dispute, and impound the proceeds until the title or right is established by a final judgment of a court of competent jurisdiction or otherwise to the satisfaction of Working Interest Owners, whereupon the proceeds impounded shall be paid to the party rightfully entitled to them.

10.7 Definition of "In Dispute." For purposes of Article 10.6 of this Agreement, the State of Alaska's title shall not be deemed "in dispute" until a court with initial jurisdiction to adjudicate title has entered a judgment that the State does not have title to the lands.

10.8 Payment of Taxes to Protect Title. The owner of surface rights to lands within the Unit Area, or severed mineral interests or Royalty Interest in those lands or lands outside the Unit Area on which personal property, lease and well equipment, plants, and other facilities and equipment used, taken over, or otherwise acquired by the Working Interest Owners for use in Unit Operations are located, is responsible for the payment of any ad valorem taxes on all those rights, interests, or property, unless that owner and the Working Interest Owners otherwise agree. If any ad valorem taxes are not paid by or for that owner when due, the Unit Operator may, with approval of the Working Interest Owners, at any time prior to tax sale, or prior to expiration of the period of redemption after tax sale, pay the tax lien. Any payment shall be an item of Unit Expense or Participating Area Expense. Unit Operator shall, if possible, withhold from any proceeds derived from the sale of Unitized Substances otherwise due any delinquent taxpayer an amount sufficient to defray the costs of payment or redemption, and credit the withholding to the Working Interest Owners. Withholding shall be without prejudice to any other remedy available to Unit Operator or Working Interest Owners.

10.9 Transfer of Title. Any conveyance of all or any part of any interest owned by any party with respect to any Tract shall be made expressly subject to this Agreement.

10.10 Successors and Assigns. This Agreement shall extend to, be binding upon, and inure to the benefit of the parties and their respective heirs, devisees, legal representatives, successors, and assigns and shall constitute a covenant and equitable servitude running with the land, leases, and interest covered by them.

ARTICLE 11

RELATIONSHIP OF PARTIES

11.1 No Partnership. The duties, obligations, and liabilities of the parties are intended to be several and not joint or collective. This Agreement is not intended to create, and shall not be construed to create, an association or trust, or to impose a partnership duty, obligation, or liability with regard to any one or more of the parties to this Agreement. Each party shall be individually responsible for its own obligations.

11.2 No Joint Refining or Marketing. This Agreement is not intended to provide, and shall not be construed to provide, directly or indirectly, for any joint refining or marketing of Unitized Substances.

11.3 Royalty Owners Free of Costs. This Agreement is not intended to impose, and shall not be construed to impose upon the State of Alaska or any other Royalty Owner any obligation to pay Unit Expense or Participating Area Expense.

11.4 Confidentiality of Information. Upon the request of the Unit Operator or the Working Interest Owners, the Commissioner shall hold as confidential to the extent authorized by statute any engineering, geophysical, or geological data, well data, daily drilling reports, or any other data or information of a similar nature which may be required by the State for any purpose of this Agreement.

ARTICLE 12

FORCE MAJEURE AND
SUSPENSION OF OPERATIONS

12.1 Force Majeure and Suspension of Operations. If a suspension of Unit Operations or production on all or part of the Unit Area has been ordered under federal, state, or local law, or if the Commissioner determines that the Unit Operator has been prevented, after efforts made in good faith, from complying with any express or implied promise, term, condition, or covenant of this Agreement, from conducting drilling operations, or from producing or marketing Unitized Substances from the Unit Area by reason of Force Majeure, the Unit Operator's obligation to comply with that provision will be held in abeyance, but not voided, and the Commissioner will extend the term of the Unit Agreement for a period of time equal to the time lost under the unit term due to the suspension or prevention by Force Majeure. If Unit Operations or production are suspended or prevented under this Article and the continuation of those operations or production without suspension or prevention would have had the effect of extending the Unit Agreement, the Unit Agreement does not terminate during the period in which operations or production are suspended or prevented plus a reasonable time after that period, which shall not be less than six months, for the Unit Operator to resume operations or production. Nothing in this Article holds in abeyance the obligation to pay rentals, royalties, or other production or profit-based payments to the State of Alaska from operations or production in the Unit Area which are not suspended or prevented, or from operations or production which are unrelated to any suspension or prevention. For the purposes of this Article, any seasonal restriction on operations or production or other conditions specifically required or imposed as a term of sale of an original lease, or as a condition imposed under this Agreement, will not be considered a suspension of operations or production ordered pursuant to law, or prevention due to Force Majeure. However, upon application to the Commissioner, seasonal restrictions on operations or production imposed subsequent to approval of a Unit Agreement will be considered a suspension of operations or production ordered under law.

ARTICLE 13

EFFECTIVE DATE

13.1 Effective Date. This Agreement shall become binding upon each party as of the date each party signs the instrument by which it becomes a party, and shall become effective as of 12:01 a.m. on the day following approval by the Commissioner. At least one counterpart of this Agreement shall be filed for record by the Unit Operator in the filing office of the Department of Natural Resources, Anchorage, Alaska.

ARTICLE 14

TERM

14.1 Term. This Agreement terminates five years from the Effective Date unless

(1) a unit well in the Unit Area has been certified as capable of producing Unitized Substances in Paying Quantities, in which case this Agreement shall remain in effect for so long as Unitized Substances are produced in Paying Quantities from the Unit Area, or for so long as Unitized Substances can be produced in Paying Quantities and Unit Operations are being conducted in accordance with an approved Unit Plan of Exploration or Development, or, should production cease, for so long thereafter as diligent operations are in progress to restore production and then so long thereafter as Unitized Substances are produced in Paying Quantities; or

(2) the unit term is extended by the Commissioner in accordance with applicable regulations.

14.2 Termination by Working Interest Owners. This Agreement may be terminated at any time by the Working Interest Owners with the approval of the Commissioner.

14.3 Effect of Termination. Upon termination of this Agreement, the further development and operation of the Unit Area as a unit shall be abandoned, and Unit Operations shall cease. Each oil and gas lease or other agreement covering lands within the Unit Area shall remain in force for at least one year after the date on which this Agreement terminates, and for a further period, if any, as provided by the lease.

14.4 Salvaging Equipment and Rehabilitation Upon Termination. The Unit Operator and the Working Interest Owners shall have the right for a period of 3 years after the date of termination of this Agreement in which to salvage and remove all personal property, lease and well equipment, plants, and other facilities and equipment used, taken over, or otherwise acquired by the Working Interest Owners for use in Unit Operations. The Unit Operator shall rehabilitate the Unit Area to the satisfaction of the Commissioner within 3 years after the date of termination of this Agreement. The Commissioner may extend the period for salvage and removal of equipment and rehabilitation of the Unit Area. Upon the expiration of this period, and at the discretion of the Commissioner, any equipment not removed from the Unit Area becomes the property of the State of Alaska or may be removed by the State at the expense of the Working Interest Owners. All other improvements, such as roads, well pads, water reservoirs, landing strips, and material sites either shall be abandoned and the sites rehabilitated to the satisfaction of the Commissioner or shall be left intact and the Unit Operator and the Working Interest Owners absolved of all further responsibility or liability as to their maintenance, repair, and eventual abandonment and rehabilitation.

ARTICLE 15

EXECUTION

15.1 Original, Counterpart, or Other Instrument. An owner of Oil and Gas Rights may become a party to this Agreement by signing the original of this instrument, a counterpart, or other instrument agreeing to become a party. The signing of these instruments shall have the same effect as if all parties had signed this Agreement.

15.2 Joinder in Dual Capacity. Execution of this Agreement by any party as either a Working Interest Owner or a Royalty Owner shall commit all interests owned or controlled by that party in the Unit Area to this Agreement.

ARTICLE 16

RELATIONSHIP OF AGREEMENTS

16.1 Unit Agreement and Unit Operating Agreement. This Unit Agreement shall control the respective rights and obligations of the Unit Operator, the Working Interest Owners, the State of Alaska, and Royalty Interest Owners other than the State of Alaska in case of any conflict between this Agreement and the Unit Operating Agreement. However, where conflicts exist solely between Working Interest Owners, the Unit Operating Agreement shall prevail.

ARTICLE 17

LAWS AND REGULATIONS

17.1 Laws and Regulations. This Agreement shall be subject to all applicable federal, state, and local laws, rules, regulations, and orders in effect on the Effective Date and, insofar as is constitutionally permissible, to all laws, rules, regulations, and orders subsequently enacted or adopted after the Effective Date of this Agreement.

17.2 Construction. This agreement shall be construed according to the laws of the State of Alaska.

ARTICLE 18

GENERAL

18.1 Amendments. Except as otherwise provided in this Agreement, this Agreement may be amended by the parties. Except as otherwise provided in this Agreement, an amendment becomes effective upon approval by the Commissioner.

18.2 Action by Working Interest Owners. Except as otherwise provided in this Agreement, any action or approval required by the Working Interest Owners under this Agreement shall be in accordance with the provisions of the Unit Operating Agreement.

ARTICLE 19

DEFAULT

19.1 Default. Failure to comply substantially with any of the terms of this Agreement, including any Plans of Exploration, Development, or Operations which are a part of this Agreement, is a default under this Agreement.

19.1.1 The Commissioner will give notice to the Unit Operator and defaulting party (if other than the Unit Operator) of the default. The notice will state the nature of the default and include a demand to cure the default within a reasonable time, which, in the case of failure to pay rentals or royalties, will be a date determined by the Commissioner, and the case of any other default will be a date not less than 90 days after the date of the Commissioner's notice of default.

19.1.2 If there is no well certified as capable of producing Unitized Substances in Paying Quantities at the time a default occurs under this Agreement and the default is not cured by the date indicated in the demand, the Commissioner will, in his discretion, and after giving the Unit Operator and defaulting party (if other than the Unit Operator) reasonable notice and an opportunity to be heard, terminate this Agreement by mailing notice of the termination to the Unit Operator and defaulting party. Termination is effective upon mailing the notice.

19.1.3 If there is a well capable of producing Unitized Substances in Paying Quantities at the time a default occurs under this Agreement and the default is not cured by the date indicated in the demand, the Commissioner will, in his discretion, seek to terminate this Agreement by judicial proceedings.

IN WITNESS OF THE FOREGOING, the parties have executed this Unit Agreement on the dates opposite their respective signatures.

Party: ______________________ Date: ______________

By: ______________________

Title: ______________________

Address: ______________________

____

____

Party: ______________________ Date: ______________

By: ______________________

Title: ______________________

Address: ______________________

____

____

EXHIBIT A
OWNERSHIP INFORMATION
KEY UNIT "A" BLOCK

Tract No..	Legal Description	No. of Acres	ADL#	Lessee of Record Ownership	Working Interest	State Royalty	NPSI.
1			318601	CHEVRON			
2			318615	CHEVRON			
3	T10N-R17E-UM	2501	318618	KELLEY EVERETTE	5%	20%	30%
	Sec. 5, 6, 7, 8			C. BURGLIN	15%		
				R. WAGNER	15%		
				W. COURTNEY	15%		
				R. GREGORY	15%		
				DAVID BURGLIN	35%		
4	T10N-R18E-UM	2512	318626	KELLEY EVERETTE	5%	20%	30%
	Sec. 17, 18, 19, 20			C. BURGLIN	15%		
				A. GRIEG	20%		
				J. DIERINGER	20%		
				R. WAGNER	20%		
				BRIAN BURGLIN	20%		
5				UNLEASED			
6	T10N-R17E-UM	2560	318621	KELLEY EVERETTE	5%	20%	30%
	Sec. 15, 16, 21, 22			C. BURGLIN	15%		
				W. WAUGAMAN	205		
				J. RIBAR	20%		
				V. GAVORA	20%		
				MARY GUSTAFSON	20%		

EXHIBIT A
OWNERSHIP INFORMATION
KEY UNIT "A" BLOCK

Tract No.	Legal Description	No. of Acres	ADL#	Lessee of Record Ownership	Working Interest	State Royalty	NPSL
7	T10N-R17E-UM Sec. 17, 18, 19, 20	2512	318620	KELLEY EVERETTE	5%	20%	30%
				C. BURGLIN	15%		
				J. THURMAN	20%		
				R. GREGORY	20%		
				C. COLE	20%		
				MARY GUSTAFSON	20%		
8			318616	CHEVRON			
9			318617	CHEVRON			
10			318622	CHEVRON			
11	T10N-R17E-UM Sec. 27, 28, 33, 34	2560	318623	KELLEY EVERETTE	5%	20%	30%
				C. BURGLIN	15%		
				A. GRANT	20%		
				BOB GROSECLOSE	20%		
				M. MILLER	20%		
				BRIAN BURGLIN	20%		
12	T10N-R17E-UM Sec. 25, 26, 35, 36	2560	318624	KELLEY EVERETTE	5%	20%	30%
				C. BURGLIN	15%		
				L. SANDERS	20%		
				E. COOK	20%		
				E. BIVENS	20%		
				MARY GUSTAFSON	20%		
13			318627	AMOCO			

EXHIBIT A
OWNERSHIP INFORMATION
KEY UNIT "B" BLOCK

Tract No..	Legal Description	No. of Acres	ADL#	Lessee of Record Ownership	Working Interest	State Royalty	NPSL
14			318673	AMOCO			
15				UNLEASED			
16	T9N-R17E-UM						
	Sec. 1, 2, 11, 12	2560	318667	KELLEY EVERETTE	5%	20%	30%
				C. BURGLIN	15%		
				C. COLE	20%		
				W. BOGGESS	20%		
				D. MORRISON	20%		
				DAVID BURGLIN	20%		
17	T9N-R17E-UM						
	Sec. 3, 4, 9, 10	2560	318666	KELLEY EVERETTE	5%	20%	30%
				C. BURGLIN	15%		
				R. WAGNER	20%		
				J. ARSENAULT	20%		
				M.MILLER	20%		
				MARY GUSTAFSON	20%		
18	T9N-R16E-UM						
	Sec. 5, 6, 7, 8	2533	318665	KELLEY EVERETTE	5%	20%	30%
				C. BURGLIN	15%		
				C. COLE	20%		
				W. BOGGESS	20%		
				D. LARSON	20%		
				BRIAN BURGLIN	20%		

EXHIBIT A
OWNERSHIP INFORMATION
KEY UNIT "B" BLOCK

Tract No.	Legal Description	No. of Acres	ADL#	Lessee of Record Ownership	Working Interest	State Royalty	NPSL
19	T9N-R17E-UM Sec. 17, 18, 19, 20	2544	318668	K. EVERETTE	5%	20%	30%
				C. BURGLIN	15%		
				R. WAGNER	20%		
				J. ARSENAULT	20%		
				O. DROZ	20%		
				BRIAN BURGLIN	20%		
20				UNLEASED			
21	T9N-R17E-UM Sec. 13, 14, 23, 24	2560	318669	K. EVERETTE	5%	20%	30%
				C. BURGLIN	15%		
				C. COLE	20%		
				R. SPAKE	20%		
				J. JOHNSON	20%		
				MARY GUSTAFSON	20%		
22	T9N-R18E-UM Sec. 17, 18, 19, 20	2544	318674	K. EVERETTE	5%	20%	30%
				C. BURGLIN	15%		
				R. WAGNER	20%		
				J. DIERINGER	20%		
				R. SPAKE	20%		
				BARBARA BURGLIN	20%		
23			318675	AMOCO			
24			318676	AMOCO			
25				AMOCO			
26				UNLEASED			
27				UNLEASED			

EXHIBIT A
OWNERSHIP INFORMATION
KEY UNIT "B" BLOCK

Tract No.	Legal Description	No. of Acres	ADL#	Lessee of Record Ownership	Working Interest	State Royalty	NPSL
28	T9N-R20E-UM						
	Sec. 29, 30, 31, 32	2555	318682	K. EVERETTE	5%	20%	30%
				C. BURGLIN	15%		
				R. GREGORY	20%		
				J. THURMAN	20%		
				J. MURPHY	20%		
				BRUCE BURGLIN	20%		
29	T9N-R19E-UM						
	Sec. 25, 26, 35, 36	2560	318681	K. EVERETTE	5%	20%	30%
				C. BURGLIN	15%		
				J. ARSENAULT	20%		
				J. THURMAN	20%		
				C. COLE	20%		
				BRUCE BURGLIN	20%		
30				UNLEASED			
31	T9N-R19E-UM						
	Sec. 29, 30, 31, 32	2555	318680	K. EVERETTE	5%	20%	30%
				C. BURGLIN	15%		
				R. GREGORY	20%		
				J. THURMAN	20%		
				R. GOMEZ	20%		
				BARBARA BURGLIN	20%		
32				MOBIL/PHILLIPS			

EXHIBIT A
OWNERSHIP INFORMATION
KEY UNIT "B" BLOCK

Tract No.	Legal Description	No. of Acres	ADL#	Lessee of Record Ownership	Working Interest	State Royalty	NPSI
33	T9N-R18E-UM						
	Sec. 27, 28, 33, 34	2560	318678	K. EVERETTE	5%	20%	30%
				C. BURGLIN	15%		
				R. GREGORY	20%		
				J. THURMAN	20%		
				R. WAGNER	20%		
				BARBARA BURGLIN	20%		
34	T9N-R18E-UM						
	Sec. 29, 30, 31, 32	2555	318677	K. EVERETTE	5%	20%	30%
				C. BURGLIN	15%		
				J. THURMAN	20%		
				J. ARSENAULT	20%		
				R. WAGNER	20%		
				BARBARA BURGLIN	20%		
35	T9N-R17E-UM						
	Sec. 25, 26, 35, 36	2560	318671	K. EVERETTE	5%	20%	30%
				C. BURGLIN	15%		
				R. GREGORY	20%		
				J. THURMAN	20%		
				C. COLE	20%		
				BARBARA BURGLIN	20%		
36				UNLEASED			
37	T9N-R17E-UM						
	Sec. 29, 30, 31, 32	2555	318670	K. EVERETTE	5%	20%	30%
				C. BURGLIN	15%		
				R. GREGORY	20%		
				J. THURMAN	20%		
				R. SPAKE	20%		
				MARY GUSTAFSON	20%		

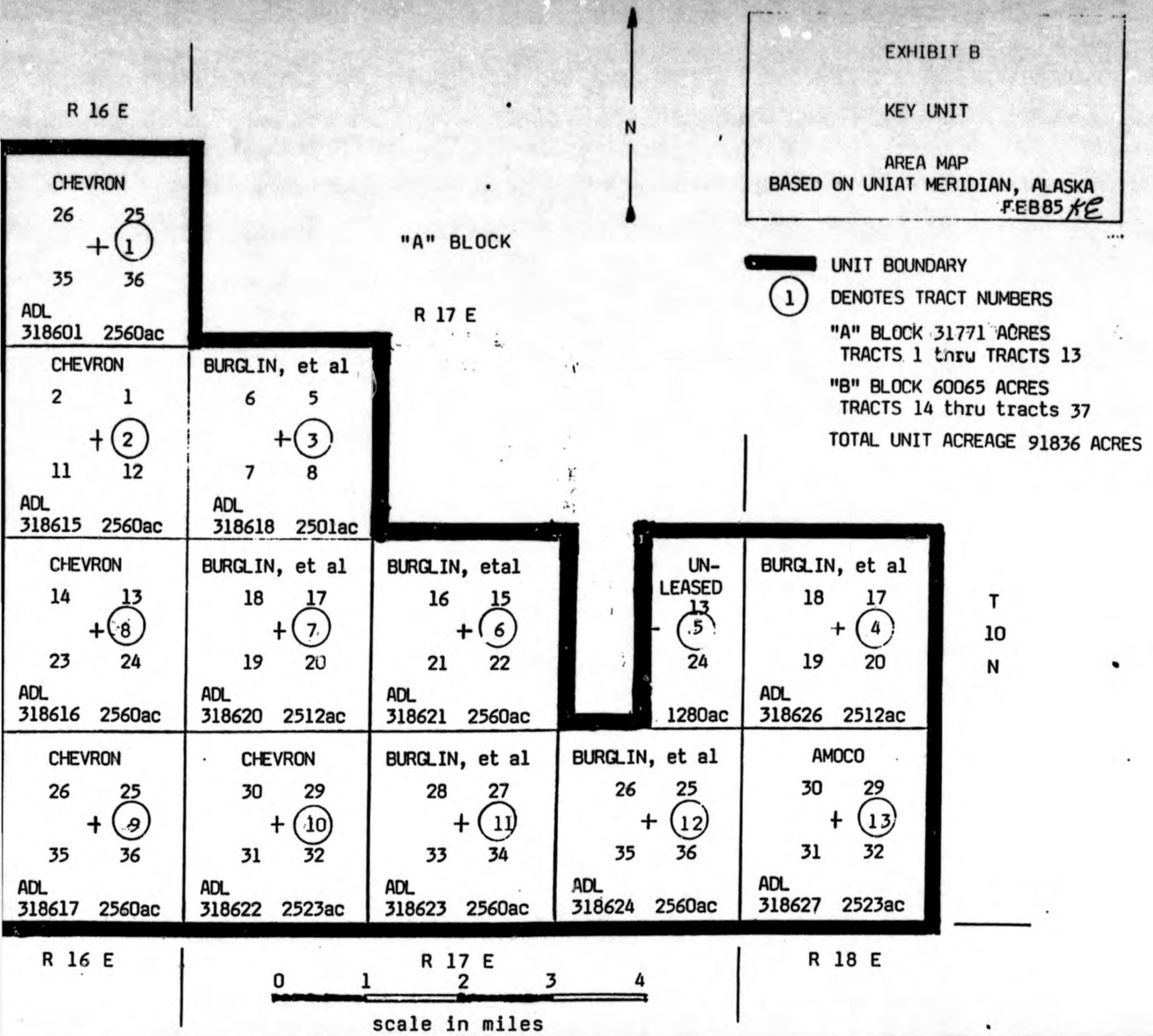

EXHIBIT B
KEY UNIT
AREA MAP
BASED ON UNIAT MERIDIAN, ALASKA
FEB85 KE
UNIT BOUNDARY
1 DENOTES TRACT NUMBERS
"A" BLOCK 31771 ACRES
TRACTS 1 thru TRACTS 13
"B" BLOCK 60065 ACRES
TRACTS 14 thru tracts 37
TOTAL UNIT ACREAGE 91836 ACRES
N
R 16 E
"A" BLOCK
R 17 E
T 10 N
CHEVRON 26 25 1 35 36 ADL 318601 2560ac
CHEVRON 2 1 2 11 12 ADL 318615 2560ac
BURGLIN, et al 6 5 3 7 8 ADL 318618 2501ac
CHEVRON 14 13 8 23 24 ADL 318616 2560ac
BURGLIN, et al 18 17 7 19 20 ADL 318620 2512ac
BURGLIN, etal 16 15 6 21 22 ADL 318621 2560ac
UN-LEASED 13 5 24 1280ac
BURGLIN, et al 18 17 4 19 20 ADL 318626 2512ac
CHEVRON 26 25 9 35 36 ADL 318617 2560ac
CHEVRON 30 29 10 31 32 ADL 318622 2523ac
BURGLIN, et al 28 27 11 33 34 ADL 318623 2560ac
BURGLIN, et al 26 25 12 35 36 ADL 318624 2560ac
AMOCO 30 29 13 31 32 ADL 318627 2523ac
R 16 E
R 17 E
R 18 E
0 1 2 3 4
scale in miles

EXHIBIT B

KEY UNIT
"B" BLOCK

R 17 E			R 18 E		
BURGLIN, et al 6 5 + 18 7 8 ADL 318665 2533ac.	BURGLIN, et al 4 3 + 17 9 10 ADL 318666 2560ac.	BURGLIN, et al 2 1 + 16 11 12 ADL 318667 2560ac.	UNLEASED 6 5 + 15 7 8 2560ac.	AMOCO 4 3 + 14 9 10 ADL 318673 2560ac.	
BURGLIN, et al 18 17 + 19 19 20 ADL 318668 2544ac.	UNLEASED 16 15 + 20 21 22 2560ac.	BURGLIN, et al 14 13 + 21 23 24 ADL 318669 2560ac.	BURGLIN, et al 18 17 + 22 19 20 ADL 318674 2544ac.	AMOCO 16 15 + 23 21 22 ADL 318675 2560ac.	AMOCO 14 13 + 24 23 24 ADL 318676 2560ac.
BURGLIN, et al 30 29 + 37 31 32 ADL 318670 2555ac.	UNLEASED 28 27 + 36 33 34 2560ac.	BURGLIN, et al 26 25 + 35 35 36 ADL 318671 2560ac.	BURGLIN, et al 30 29 + 34 31 32 ADL 318677 2555ac.	BURGLIN, et al 28 27 + 33 33 34 ADL 318678 2560ac.	MOBIL/PHILLIPS 26 25 + 32 35 36 2560ac.

T 9 N

CONTINUED ON PAGE 3

R 17 E R 18 E

EXHIBIT B

KEY UNIT

"B" BLOCK

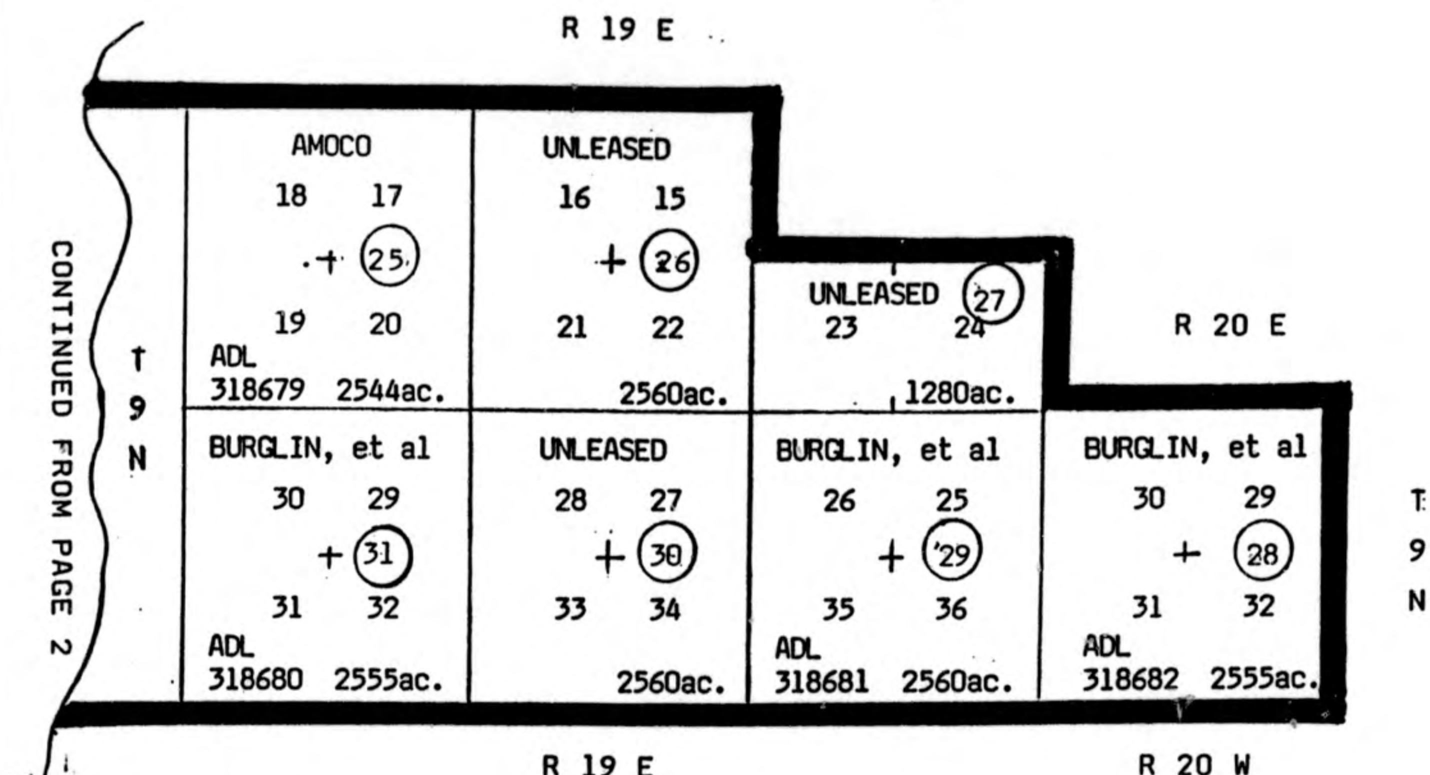

EXHIBIT A
Ownership Information

Tract No.	Description (Township, Range, Sec., Lot)	No. of Acres	ADL No.	Lessee of Record Ownership	Working Interest	Royalty Percentage and Owner	NPSL

EXHIBIT B
Map of Unit Area and Tracts

EXHIBIT C
________ Participating Area
(General Geologic Description)

Tract No.	Legal Description (Township, Range, Sec., Lot)	ADL No.	Tract Participation

EXHIBIT D
Map of ______________ Participating Area

EXHIBIT E
Allocation of Participating Area Expense

Tract No.	Allocation of ________________ Participating Area Expense (%)

EXHIBIT F
Allocation of Unit Expense

Tract No.	Allocation of Unit Expense

EXHIBIT G
Plan of Development or Exploration

KEY TO ABBREVIATIONS:

ACC	-	Alaskan Crude Corporation
BURGLIN	-	Burglin, et al

EXHIBIT G

UNIT PLAN OF EXPLORATION

Attached to and made a part of
the Key Unit Agreement

For the period starting with the Effective Date of this Agreement and continuing for five (5) years thereafter, the Working Interest Owners intend to proceed with the following Unit Plan of Exploration.

1. Exploratory Wells

   a. The first well will have a bottomhole location in the northeast quarter (NE¼) of Section 5 of T10N-R17E on Lease ADL 318618 drilled to a depth sufficient to test the hydrocarbon potential of the Lisburne Group. The Lisburne Group is that interval (or stratigraphic equivalent) which was encountered between 9353 and 9655 feet measured depth in the ARCO Delta State No. 1. (Section 10-T10N-R16E). This well is planned to commenced prior to March 31, 1987.

   b. A second exploratory well is planned to be commenced prior to March 31, 1989. The bottomhole location of the second well will be in Block B of the Unit as described in Exhibits A and B and will take into account information obtained from all previous wells and the studies mentioned below. The geological justification for the well bottomhole location will be provided to the State.

2. Studies

   Geological, geophysical and engineering studies based on available information and integrated with new data will continue to be carried out by the Working Interest Owners in order to evaluate the hydrocarbon potential of the leases within the Unit boundary.

The terms of the Unit Plan of Exploration shall cover the time period from Effective Date of this Agreement through a period of five (5) years.

The Unit Operator will continue to obtain applications and permits for Unit Operations as required by State laws, regulations and/or State Oil and Gas Lease Stipulations. Commencing in 1986, The Unit Operator will file annual progress reports describing operations and results to date under the Unit Plan of Exploration.

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 8672
1546 SCOMM 57: SENATE SPECIAL COMMITTEE ON OIL & GAS, 1987-1988 1343

provision is in the lease or in the regulations dealing with the products to be taken, all or any portion of the state's share will, at the option of the commissioner, be taken in kind in accordance with the following:

(1) 90 days written notice will be given to each lessee of the state's election to take the royalty products in kind; however, if the portion of the state's share to be taken in kind exceeds 50 percent of the state's share, 180 days notice will be given;

(2) after taking has actually commenced, the amount to be taken in kind will, in the commissioner's discretion, be increased or decreased from time to time by

(A) not more than 10 percent, upon 30 days written notice to each lessee of record;

(B) from 10 percent to 50 percent, upon 90 days written notice; and

(C) more than 50 percent, upon 180 days written notice; and

(3) the products must be delivered to the state or its designated purchaser free of charge at the point specified in the lease for determination of the value of the royalty product as if the product to be taken were to be paid in money rather than taken in kind; the condition of the product must be the same as the non-royalty share at the point of taking; the lessee shall, if necessary, furnish safe storage for the royalty share free of charge for the same duration and in the same manner as storage is provided for the non-royalty share. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71; am 7/19/86, Reg. 99)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.182

11 AAC 82.705. BIDDING METHOD FOR ROYALTY PRODUCTS OTHER THAN OIL, GAS, OR GAS LIQUIDS. Royalty products, other than oil, gas, or gas liquids, which the commissioner determines are to be sold by competitive bid will be offered for sale by sealed bid or at public auction. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71; am 7/19/86, Reg. 99)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.183

11 AAC 82.710. NOTICE OF SALE FOR ROYALTY PRODUCTS OTHER THAN OIL, GAS, OR GAS LIQUIDS. If the commissioner determines that royalty products other than oil, gas, or gas liquids will be offered for competitive sale, notice of the sale will be given as provided by AS 38.05.945. The notice must specify all the terms and conditions of the sale including the royalty products to be sold, bidding method, bond requirements, sale place and time, minimum bid, if prescribed, and any other term or condition that the commissioner determines necessary to carry out the purposes of AS 38.05.183. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71; am 3/18/83, Reg. 85; am 3/30/83, Reg. 85; am 7/19/86, Reg. 99)

Authority: AS 38.05.020 AS 38.05.180
AS 38.05.135(b) AS 38.05.183
AS 38.05.145

11 AAC 82.715. QUALIFICATIONS FOR ROYALTY PRODUCTS OTHER THAN OIL, GAS, OR GAS LIQUIDS. A purchaser of the state royalty products other than oil, gas, or gas liquids must comply with the qualification requirements of 11 AAC 82.200 and must supply the showing of qualification required of mineral permittees and lessees by 11 AAC 82.205. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71; am 7/19/86, Reg. 99)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.183

ARTICLE 8.
RECORDS AND REPORTS

Section
800. Production records
805. Test results
810. Confidentiality of data
815. Cross-referencing

11 AAC 82.800. PRODUCTION RECORDS. (a) Mineral lessees of state land shall keep in their possession accurate books and records showing the production and disposition of all minerals produced from the leased land and shall permit the commissioner or his agents at all reasonable hours to examine them.

(b) The commissioner will, in his discretion, require copies of sales contracts and other agreements with the first bona fide purchaser affecting produced minerals which are subject to royalties. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71)

Authority: AS 38.05.020(b)(1)
AS 38.05.145(a)

11 AAC 82.805. TEST RESULTS. The lessee of a state-issued mineral lease shall furnish, upon request of the commissioner, a copy of all geological, geophysical, engineering, and other factual data obtained from the lease, including all pertinent tests, records, surveys, and analyses conducted on or pertaining to the leased land or products from it, but not including interpretations of these items or proprietary research data or techniques. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71; am 3/18/83, Reg. 85)

Authority: AS 38.05.020(b)(1)
AS 38.05.145(a)

11 AAC 82.810. CONFIDENTIALITY OF DATA. (a) Geological, geophysical, and engineering data, including well and bore hole data, and interpretations of those data, will be kept confidential at the written request of the person supplying the information. Cost data and financial information submitted in support of applications, bonds, leases, and similar items will be kept confidential at the written request of the person supplying the information except as provided in AS 38.05.036.

(b) Information for which confidentiality is requested must be identified as "confidential" on the outer envelope and on each page, and must be submitted separately from information not entitled to confidential status. (Eff. 3/18/83, Reg. 85)

Authority: AS 38.05.020
AS 38.05.035
AS 38.05.145

11 AAC 82.815. CROSS-REFERENCING. A party who is required to submit information to the commissioner under this title may cross-reference information which it or other parties, including agencies of state or federal government, have previously filed with the commissioner. A party making a cross-reference shall precisely identify the referenced information, the approximate date, and the office with which it was filed. If the information cannot be located in departmental files, or if inaccessibility of the information would delay processing of the application, the commissioner will, in his discretion, require that the information be submitted. (Eff. 3/18/83, Reg. 85)

Authority: AS 38.05.020
AS 38.05.035
AS 38.05.145

CHAPTER 83. OIL AND GAS LEASING

Article

1. General Oil and Gas Lease Provisions (11 AAC 83.100–11 AAC 83.190)
2. Net Profit Share Leasing (11 AAC 83.201–11 AAC 83.295)
3. Unitization (11 AAC 83.300–11 AAC 83.395)
4. Communitization and Drilling and Development Contracts (11 AAC 83.400)
5. Underground Storage (11 AAC 83.500–11 AAC 83.520)
6. Federal Leases and Preference Rights on Alaska Lands (11 AAC 83.600–11 AAC 83.630)
7. Work Commitment (11 AAC 83.700–11 AAC 83.705)
8. Exploration Incentive Credit (11 AAC 83.800–11 AAC 83.820)
9. Exempt Lease Sales (11 AAC 83.900–11 AAC 83.910)

Editor's Note: The mineral-leasing regulations in 11 AAC 82, 11 AAC 83, 11 AAC 84, 11 AAC 86 and 11 AAC 88, effective September 5, 1974, and distributed in Alaska Administrative Register 51, constitute a comprehensive reorganization and revision of this material, and thus the history line at the end of each section does not reflect the history of the provisions before September 5, 1974, and the section numbering may or may not be related to the numbering before that date.

ARTICLE 1. GENERAL OIL AND GAS LEASE PROVISIONS

Section

100. Leasing method
105. "Paying quantities" defined
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115. (Repealed)
120. (Repealed)
125. Extension by drilling
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182. Royalty bidding
183. Sliding scale royalty
185. Royalty reduction
190. Extension by commitment to an approved unit

11 AAC 83.100. LEASING METHOD. All land is competitive for oil and gas leasing purposes and may only be leased under competitive procedures provided in 11 AAC 82. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71)

Authority: AS 38.05.020 AS 38.05.145(a)
AS 38.05.135 AS 38.05.180

11 AAC 83.105. "PAYING QUANTITIES" DEFINED. "Production in paying quantities," as used in 11 AAC 83.100 – 11 AAC 83.295 and 11 AAC 83.400 – 11 AAC 83.910, means production in such quantity as to enable the operator to realize a profit. For purposes of the habendum clause of a lease, that is, for the purpose of keeping the lease in force after the expiration of the primary term, "paying quantities" means production in quantities sufficient to yield a return in excess of operating costs, even though drilling and equipment costs may never be repaid and the undertaking considered as a whole may ultimately result in a loss. (Eff. 9/5/74, Reg. 51; am 6/28/81, Reg. 78)

Authority: AS 38.05.020
AS 38.05.145(a)
AS 38.05.180

11 AAC 83.110. RENTAL. (a) All oil and gas leases are conditioned upon payment of the annual rental in advance on or before the beginning of each lease year before completion of a well capable of producing oil and gas in paying quantities on these leased lands.

(b) After a well has been plugged and abandoned and there is no other well on the lease capable of production, the commissioner will, in his discretion, allow the rental rate effective during the year of the abandonment to be the rate for the remainder of the term of the lease, or, if production is achieved from a subsequent well, until the royalty or net profit share to the state exceeds the rental for that year. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71)

Authority: AS 38.05.020
AS 38.05.145(a)
AS 38.05.180(n)

11 AAC 83.115. MINIMUM ROYALTY. Repealed 6/28/81.

11 AAC 83.120. EXTENSION FOR EXTENUATING CIRCUMSTANCES. Repealed 6/28/81.

11 AAC 83.125. EXTENSION BY DRILLING. (a) If drilling, including redrilling, sidetracking, or other means necessary to reach the originally proposed bottom hole location, has commenced on or before the expiration date of the primary term of the lease and is continued through that date with reasonable diligence, the lease will continue in full force until 90 days after the drilling has ceased and for so long after that date as oil or gas is produced in paying quantities.

(b) In (a) of this section, "drilling" means operations necessary or convenient to drilling a well in the ground with equipment of sufficient size and capacity to drill to the total depth proposed for the well. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71)

Authority: AS 38.05.020
AS 38.05.145(a)
AS 38.05.180

11 AAC 83.130. EXTENSION AFTER PRODUCTION. If production occurs in paying quantities during the primary term of any lease, and if at the end of the primary term or at any time prior to the end of the primary term that production has ceased, or if production ceases at any time after the expiration of the primary term, then the lease does not terminate if the lessee commences drilling or reworking operations (either in a well from which the production has ceased or in a new well) within 60 days after the cessation of production; and the lease remains in full force and effect so long as operations are prosecuted with reasonable diligence; and, if the drilling or reworking operations result in the production of oil or gas, the lease remains in full force and effect so long as oil or gas is produced from it in paying quantities. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020
AS 38.05.145(a)
AS 38.05.180(b)

11 AAC 83.135. SHUT-IN PRODUCTION. No lease covering land on which there is a well capable of producing oil or gas in paying quantities will expire because the lessee fails to produce oil or gas, unless the commissioner gives notice to the lessee or operator allowing a reasonable time, which will not be less than 60 days after receipt of notice, to place the well on a producing status and the lessee or operator fails to do so. After producing status is established, production must continue on the leased land until suspension of production is allowed by the commissioner. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71)

Authority: AS 38.05.020
AS 38.05.140(d)
AS 38.05.180

11 AAC 83.140. EXTENSION BY ELIMINATION FROM A UNIT. If any lease or a portion of one is eliminated from the unit plan or recovery program, or if the unit plan or recovery program is terminated, then the lease or portion of it so eliminated continues in full force and effect as may be provided in the unit or cooperative agreement, but for not less than 90 days from the date of the elimination or termination and so long thereafter as drilling or redrilling operations are being conducted on it and so long thereafter as oil or gas is produced in paying quantities. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020
AS 38.05.145(a)
AS 38.05.180(d)

11 AAC 83.145. DIRECTIONAL DRILLING CLAUSE. The commissioner will include a directional drilling clause in all oil and gas leases that have been issued or that may be subsequently issued by the state. The clause will provide that actual drilling from a well located off the leased premises, but to be completed or bottomed on leased premises, will be considered as actual drilling under the lease terms. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71)

Authority: AS 38.05.020
AS 38.05.145(a)
AS 38.05.180

11 AAC 83.150. RESERVATIONS. (a) Every oil and gas lease must reserve to Alaska the right to dispose of to others the surface of the leased land subject to the lease, and the right to authorize others by grant, lease, or permit, subject to the lease and under such conditions as will prevent unnecessary or unreasonable interference with the rights and operations under the lease, to enter upon and use the leased land

(1) to explore for oil or gas by geological or geophysical means including the drilling of shallow core holes or stratigraphic tests to a depth of not more than 1,000 feet;

(2) to explore for, develop and remove natural resources other than oil, gas, and associated substances on or from the leased land;

(3) for non-exclusive easements and rights-of-way for any lawful purpose, including shafts and tunnels necessary or appropriate for working of the leased land or other land for natural resources other than oil, gas, or associated substances;

(4) for well sites and well bores of wells drilled from or through the leased land to explore for or produce oil, gas, and associated substances in and from other land; and

(5) for any other purpose now or after September 4, 1974 authorized by law and not inconsistent with the rights under the lease.

(b) The subsurface storage of oil or gas is not authorized except as a necessary incident to recycling, pressure maintenance, repressuring, or other similar operations designed to increase the ultimate recovery of oil or gas or prevent the waste of oil or gas produced from the leased land or from any unit area of which the leased land is a part. Every lease must reserve to Alaska the right to authorize the subsurface storage of oil, gas or associated hydrocarbons in the leased land by the lessee or by others in order to avoid waste or to promote conservation of natural resources in accordance with 11 AAC 83.500 – 11 AAC 83.520, and upon conditions that will prevent unnecessary or unreasonable interference with the rights and operations under the lease, including conditions prohibiting the storage of oil or gas in any reservoir capable of producing oil and gas in paying quantities without the consent of the holder of any lease covering the reservoir. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71)

Authority: AS 38.05.020 AS 38.05.145(a)
AS 38.05.125 AS 38.05.180(u)

11 AAC 83.153. CONFIDENTIAL REPORTS. (a) If the commissioner finds that reports or information required under AS 31.05.035(a) contain significant information relating to the valuation of unleased land within a three-mile radius of the well from which these reports or information were obtained, the commissioner will, upon the written request of the owner of the well, keep the reports or information confidential for a reasonable time not to exceed 90 days after disposal of the unleased land, unless the owner of the well gives written permission to release the reports and information at an earlier date. The commissioner will, in his or her discretion, extend confidentiality to reports or information required under AS 31.05.035 from a well located more than three miles from any unleased land if the owner of the well from which these reports or information are derived makes a sufficient showing that the reports or information contain significant information relating to the valuation of unleased land beyond the three-mile radius.

(b) Reports or information for which extended confidentiality is requested or has been granted under AS 31.05.035 will not be eligible for extended confidentiality when

(1) the lease on which the well is drilled has expired; or

(2) the unleased land within a three-mile radius of the well from which the reports or information are obtained is offered in a competitive lease sale, but receives no bids greater than or equal to any minimum bid established for that sale.

(c) As used in this section, "mile" means a statute mile or 5,280 feet.

(d) As used in this section, "disposal" means the grant or issuance of an oil and gas lease. (Eff. 3/30/84, Reg. 89)

Authority: AS 31.05.035(c)
AS 38.05.020
AS 38.05.180

11 AAC 83.155. DAMAGES. Each lessee or permittee is required to pay any damage that becomes payable under AS 38.05.130 and shall indemnify Alaska and hold it harmless from and against any claims, demands, liabilities and expenses arising from or in connection with the damage. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020
AS 38.05.130
AS 38.05.145(a)

11 AAC 83.158. PLAN OF OPERATIONS. (a) Except as provided in (b) of this section, a plan of operations for all or part of the leased area must be approved by the commissioner before any operations may be undertaken on the leased area if

(1) the state owns all or part of the surface estate of the leased area;

(2) the lease reserves a net profit share to the state; or

(3) the state owns all or part of the mineral estate, but the entire surface estate is owned by a party other than the state, and a surface owner requests that a plan of operations be required by the commissioner for the portion of the leased area owned by that surface owner.

(b) A lease plan of operations is not required for

(1) activities that would not require a land use permit under this title; or

(2) operations undertaken under an approved unit plan of operations in accordance with this title.

(c) Before undertaking operations on the leased area, the lessee shall provide for full payment of all damages sustained by the owner of the surface estate as well as by the surface owner's lessees and permittees, by reason of entering the land. If the surface estate is owned by a party other than the state, the lessee shall also notify the surface owner of his opportunity to request that the commissioner require a plan of operations before allowing operations to be undertaken on the portion of the leased area owned by the requesting surface owner.

(d) An application for approval of a plan of operations must contain sufficient information, based on data reasonably available at the time the plan is submitted for approval, for the commissioner to determine the surface use requirements and impacts directly associated with the proposed operations. An application must include statements and maps or drawings setting out the following:

(1) the sequence and schedule of the operations to be conducted on the leased area, including the date operations are proposed to begin and their proposed duration;

(2) projected use requirements directly associated with the proposed operations, including but not limited to the location and design of well sites, material sites, water supplies, solid waste sites, buildings, roads, utilities, airstrips, and all other facilities and equipment necessary to conduct the proposed operations;

(3) plans for rehabilitation of the affected leased area after completion of operations or phases of those operations; and

(4) a description of operating procedures designed to prevent or minimize adverse effects on other natural resources and other uses of the leased area and adjacent areas, including fish and wildlife habitats, historic and archeological sites, and public use areas.

(e) In approving a lease plan of operations or an amendment of a plan, the commissioner will require amendments he determines necessary to protect the state's interest. The commissioner will not require any amendment that would be inconsistent with the terms of sale under which the lease was obtained, or with the terms of the lease itself, or which would deprive the lessee of reasonable use of the leasehold interest.

(f) The lessee may, with approval of the commissioner, amend an approved plan of operations.

(g) Upon completion of operations, the lessee shall inspect the area of operations and submit a report indicating the completion date of operations and stating any noncompliance of which the lessee knows, or should reasonably know, with requirements imposed as a condition of approval of the plan.

(h) In submitting a proposed plan of operations for approval, the lessee shall provide 10 copies of the plan if activities proposed are within the coastal zone, and five copies if activities proposed are not within the coastal zone. (Eff. 6/28/81, Reg. 78; am 8/15/82, Reg. 83; am 3/18/83, Reg. 85)

Authority: AS 38.05.020 AS 38.05.145
AS 38.05.130 AS 38.05.180

11 AAC 83.160. OIL AND GAS LEASE BOND. (a) Before operations commence on a state oil and gas lease, a bond in the amount of at least $10,000 must be furnished to the department.

(b) The commissioner will, in his discretion, after notice and an opportunity to be heard, require a bond in a reasonable amount greater than the amount specified in (a) of this section where a greater amount is justified by the nature of the surface, the uses and improvements on or in the vicinity of the leased land, and the degree of risk involved in the types of operations proposed or being conducted on the lease. A statewide bond furnished under (c) of this section will not satisfy any requirement of a bond imposed under this provision but will be considered by the commissioner in determining the need for and the amount of any additional bond under this subsection.

(c) Any person holding any interest in any lease may furnish a statewide bond in the amount of $500,000. A statewide bond satisfies all the bond requirements to which an oil or gas lease is subject under the Department of Natural Resources except that the commissioner will, in his discretion, require an additional unusual risk bond under (b) of this section or specific lease provisions.

(d) All oil and gas lease bonds must comply with 11 AAC 82.600. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71; am 6/29/80, Reg. 74)

Authority: AS 38.05.020(b)
AS 38.05.145(a)

11 AAC 83.165. CONDITIONAL LEASES. (a) If all or any part, as shown on the division leasing plats when the lease was issued, of the land covered by a lease is land that has been selected by Alaska under laws of the United States granting land to Alaska but the land has not been patented to Alaska by the United States, then the lease shall be a conditional lease as provided by law with respect to the land until a patent becomes effective. If for any reason a selection is disapproved or patent is denied as to all or any part of the land, no rentals, royalties or minimum royalties paid to Alaska under the lease will be refunded. Any bonus paid for a competitive lease will be refunded in full if the entire lease fails or if the lease fails in part and the lessee elects to surrender the remaining part. If the lessee elects to retain a remaining part, the bonus will be refunded in pro rata part on an acreage basis.

(b) To be considered a conditional lease under this section, the lease must contain at least a legal subdivision or 40 acres in the aggregate of land which has not been patented to Alaska by the United States. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020
AS 38.05.145(a)
AS 38.05.180(a)

11 AAC 83.170. FAILURE TO PAY RENTAL. (a) Any lease on which there is no well capable of producing oil or gas in paying quantities terminates by operation of law if any rental due is not timely paid on or before each anniversary date of the lease, except where the provisions of 11 AAC 83.620 are applicable.

(b) For purpose of this section, and notwithstanding 11 AAC 88.130(a)(2), rental is timely if it is received in the designated office by the anniversary date. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71; am 6/29/81, Reg. 78)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.175. REINSTATEMENT. (a) The commissioner will reinstate a lease automatically terminated under 11 AAC 83.170 if he finds that the failure to pay rental was justifiable and not due to lack of reasonable diligence by the lessee and the rental is paid within 15 days after receipt of notice of the termination, along with a statement and supporting evidence of the reasons for the failure. The burden of showing that he qualifies for reinstatement under this subsection is on the lessee and only those cases will be considered where the circumstances can be verified by independent evidence other than lessee's statements. The failure to pay rental will not be considered justifiable unless payment was prevented or delayed by unforeseen circumstances beyond the lessee's reasonable control. Situations such as ignorance of the lease, law, or regulations, inability to pay, error or oversight of the lessee's employees or agents, forgetfulness, and failure to receive a billing are not grounds for reinstatement. Situations caused by major sickness, accidents, death, acts of God, and errors of departmental employees, the U.S. Postal Service, or a commercial delivery service may be considered as grounds for reinstatement.

(b) If the rental payment due under a lease is timely paid but the amount of the payment is deficient, and the commissioner believes the payment was determined in accordance with the rental or acreage figure stated in the lease or in a bill, decision, notice, or letter by the department and the figure is found to be in error, or if the commissioner finds that the deficiency was otherwise justifiable and not due to a lack of reasonable diligence on the part of the lessee, the lease will be reinstated if the lessee corrects the deficiency within 15 days after receipt of notice of the deficiency. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg 71; am 6/28/81, Reg. 78)

Authority: AS 38.05.020
AS 38.05.145

11 AAC 83.180. DEFAULT. (a) Whenever the lessee of a lease on which there is no well capable of producing oil or gas in paying quantities fails to comply with any provision of the lease or applicable regulations other than the payment of rental and the failure to comply continues for 60 days after receipt of notice to the lessee of the failure to comply, the director may terminate the lease by mailing notice of the termination to the lessee. Termination is effective upon giving the notice.

(b) Whenever the lessee of a lease on which there is a well capable of producing oil or gas in paying quantities fails to comply with any of the provisions of the lease or applicable regulations and the failure continues for a period of 60 days following notice to the lessee of the failure to comply, the lease may be cancelled by judicial proceedings instituted for that purpose in any court of competent jurisdiction having jurisdiction over the land covered by the lease or any part of it. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020
AS 38.05.035
AS 38.05.145(a)

11 AAC 83.182. ROYALTY BIDDING. If the commissioner selects a method of bidding in which the royalty share reserved to the state is the bid variable, the commissioner will set a minimum fixed cash bonus in an amount to be announced no later than the date of the notice of sale. (Eff. 11/9/79, Reg. 72)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.183. SLIDING SCALE ROYALTY. If the commissioner selects a method of bidding which sets a royalty reserved to the state, either fixed or as the bid variable, based on a sliding scale, the sliding scale will be determined, according to a method chosen at the commissioner's discretion which will be based on volume of production or other factors. The method chosen by the commissioner will consider the prolongation of the economic life of the oil and gas reservoir or reservoirs underlying the sale area or lease to which the sliding scale is to be applied. (Eff. 11/9/79, Reg. 72)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.185. ROYALTY REDUCTION. (a) An application for a reduction of royalty on leases under AS 38.05.180(j) must comply with 11 AAC 88.105 and

(1) state all the facts entitling the applicant to relief;

(2) state location and status of all past and present activities on the lease;

(3) include a detailed report of all production during the six months preceding the filing of the application;

(4) contain a detailed statement covering the entire life of the lease showing all expenses and costs of operating the lease, including all royalties and overriding royalties and all income from all produced minerals from the lease; and

(5) include an agreement by the applicant to defray the cost of publishing a notice as provided by (b) of this section.

(b) Upon receipt of an application complying with (a) of this section, the commissioner will cause to be published a notice of public hearing as required on the application. The notice will

(1) state the time and place of hearing;

(2) describe the land involved; and

(3) state the name of the applicant and the nature of the relief applied for.

(c) The notice will be published at least once a week for at least two consecutive weeks in advance of the hearing date, which must be at least 15 days after the last date of publication, in at least one newspaper of general circulation in the vicinity of the principal office of the department, and must be posted at the principal office for the same period.

(d) At the time and place specified in the published notice, the commissioner will hear evidence offered by the applicant and any other interested party.

(e) Within a reasonable time following the hearing or any continuation of it, the commissioner will make written findings together with his determination as to the relief that should be granted.

(f) The commissioner will give notice of the findings and determination to the lessee and to any other person who has filed a written request for it. The action taken is effective on the date specified in the notice. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71)

Authority: AS 38.05.020(b)
AS 38.05.145(a)
AS 38.05.180(j)

11 AAC 83.190. EXTENSION BY COMMITMENT TO AN APPROVED UNIT. If, on or before the expiration date of the primary term of a lease, the lease is committed to a unit agreement approved by the state, the lease will be extended for so long as it remains subject to the unit agreement. (Eff. 7/22/79, Reg. 71)

Authority: AS 38.05.020(b)

ARTICLE 2.
NET PROFIT SHARE LEASING

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Editor's Note: The former Article 2, relating to oil and gas leases discovery royalty, consisting of 11 AAC 83.200, 11 AAC 83.205, 11 AAC 83.210, 11 AAC 83.215, 11 AAC 83.220, 11 AAC 83.225 and 11 AAC 83.230, was repealed effective November 9, 1979.

11 AAC 83.201. PURPOSE. 11 AAC 83.201 – 11 AAC 83.295 establish procedures to be used by the lessee in calculating net profit share payments due the state for the production of oil and gas from any state net profit share lease (NPSL) issued by the department. The purpose of 11 AAC 83.201 – 11 AAC 83.295 is to allow a lessee to recover development costs, with interest, and operating costs, for each NPSL from production revenue for each NPSL before any net profit share payments become due the state from the lessee. (Eff. 11/9/79, Reg. 72)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.202. PAYMENT DUE STATE. The net profit share payment due the state each month under a NPSL equals the balance in the net profit payment account for that month, defined in 11 AAC 83.214, multiplied by the net profit share rate, defined in 11 AAC 83.204. (Eff. 11/9/79, Reg. 72; am 8/15/82, Reg. 83)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.204. NET PROFIT SHARE RATE. The net profit share rate is the fixed percentage share of the net profit payment account, defined in 11 AAC 83.214, payable to the state. The net profit share rate is determined through competitive bidding or by the commissioner as a condition of sale. (Eff. 11/9/79, Reg. 72)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.207. ACCOUNTING SYSTEM. (a) The lessee of a NPSL shall establish and maintain on a monthly, accrual basis, in addition to its own standard accounting system for itself or joint operators, an accounting system for that NPSL in accordance with 11 AAC 83.201 – 11 AAC 83.295 for the purpose of the reporting and payment requirements established in 11 AAC 83.245. The accounting system consists of three accounts: the development account, the production revenue account and the net profit payment account. These accounts allow a lessee to accumulate and recover development costs under 11 AAC 83.219, with interest compounded monthly, and to apply it against the NPSL production revenue account under 11 AAC 83.209 from which direct operating expenses, and royalties under 11 AAC 83.240 and 11 AAC 83.242, respectively, are deducted before any net profit share payments under 11 AAC 83.202 become due to the state from the lessee.

(b) The lessee's books and records relating to the NPSL accounting system and the financial accounting system for itself or joint operators must be available for inspection and copying by representatives and agents of the state during normal business hours. (Eff. 11/9/79, Reg. 72)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.209. PRODUCTION REVENUE ACCOUNT. (a) The production revenue under 11 AAC 83.222 for the NPSL during a month is credited to the NPSL's production revenue account for that month.

(b) Debited to the NPSL's production revenue account for a month are

(1) the NPSL's direct operating costs under 11 AAC 83.240 for that month; and

(2) the NPSL's royalty payments, as specified in 11 AAC 83.242, for that month.

(c) If the credits to the production revenue account for a NPSL during a month equal or exceed the debits that month to that account, an amount equal to that excess, (if any) is to be credited that month to the development account of that NPSL and the same amount debited to the NPSL's production revenue account so the ending balance in the production revenue account that month is zero. If the debits to the production revenue account for a NPSL during a month exceed the credits that month to that account, an amount equal to that excess is to be carried forward as a debit to the production revenue account of the NPSL for the following month. (Eff. 11/9/79, Reg. 72)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.212. DEVELOPMENT ACCOUNT. (a) The beginning balance in the development account for a NPSL at the time the NPSL is issued by the state is zero. For each month thereafter the beginning balance in the development account for the NPSL equals the ending balance in that account for the previous month.

(b) The NPSL's development costs under 11 AAC 83.219 during a month, less any exploration incentive credits which are applied against oil and gas royalties payable in value, rental payments to the state or taxes payable under AS 43.55, are debited to the NPSL's development account for that month.

(c) If a credit to the NPSL's development account arises under 11 AAC 83.209(c) from the NPSL's production revenue account, that credit is entered in the development account in the same month as the month in which it arises from the production revenue account.

(d) If a month's preliminary ending balance in the NPSL's development account is a debit balance, interest accrues and the amount of that interest is debited that month to the NPSL's development account. A month's preliminary ending balance in the NPSL's development account equals the beginning balance that month in that account together with the debits under (b) of this section and the balance transferred under (c) of this section that are booked to the NPSL's development account for that month. The amount of interest is to be calculated on the basis of the annual rate prescribed by the commissioner in the terms of the sale for the NPSL, using as the principal an amount equal to one half of the absolute value of the sum of the beginning balance and the preliminary ending balance in the NPSL's development account for that month.

(e) Each month the ending balance in the development account for a NPSL equals the preliminary ending balance in that account for the month together with the amount of interest, if any, debited to that account for that month under (d) of this section, provided the ending balance in the NPSL's development account is not a credit balance. If the month's ending balance in the NPSL's development account is a credit balance, then that balance is transferred to the NPSL's net profit payment account for that month so that the ending balance that month in the NPSL's development account is zero. (Eff. 11/9/79, Reg. 72)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.214. NET PROFIT PAYMENT ACCOUNT. The net profit payment account for a NPSL in any month equals the amount, if any, transferred for that month from the NPSL's development account under 11 AAC 83.212(e). Each amount so transferred is a credit in the net profit payment account. If for a month no transfer is made from the NPSL's development account under 11 AAC 83.212(e), the balance in the NPSL's net profit payment account for that month is zero. (Eff. 11/9/79, Reg. 72)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.217. EXCLUSIONS FROM ACCOUNTS. The following costs will be excluded in determining net profit share payments due the state:

(1) lease acquisition costs in the form of a cash bonus;

(2) expense of handling, investigating and settling litigation or claims against the state, discharging liens held by the state, paying judgments and amounts for settlement of claims against the state incurred in or resulting from a net profit share lease operation or necessary to protect or recover the net profit share lease property;

(3) any franchise tax, value added tax or any tax based on or measured by net income imposed upon the lessee;

(4) expenses incurred in the preparation and audit of a net profit share payment to the state;

(5) any expense incurred before the effective date of the NPSL; and

(6) net profit share payments to the state. (Eff. 11/9/79, Reg. 72; am 11/19/79, Reg. 72; am 3/27/82, Reg. 81)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.219. DEVELOPMENT COSTS. (a) The development costs that are incurred by or for a lessee for a NPSL are a debit to the lessee's NPSL development account.

(b) The lessee's development costs for a NPSL equal direct charges, as defined in 11 AAC 83.243, that are not excluded under 11 AAC 83.217 and that are directly attributable to a NPSL for

(1) geological, geophysical, geotechnical and geochemical examinations and other investigations on or adjacent to the NPSL relating to pre and post drilling operations on the NPSL;

(2) cost of design of construction projects, as defined in the approved "Plan of Operation";

(3) accumulated cost of capital work in progress, on or adjacent to the NPSL or on a contractor's premises;

(4) rentals and other payments directly attributable to the NPSL such as lease rental, licenses or permits, renewal or extension fees, and other similar payments required and made to maintain the interest of the lessee in the NPSL;

(5) drilling costs for wells bottomed on the NPSL;

(6) costs to acquire, construct and/or install facilities and equipment on or in support of the NPSL that directly result in or are necessary for continued or enhanced production from the NPSL;

(7) that portion of the full consideration given by the lessee in acquiring a production interest in the NPSL that is properly attributable to the wells, facilities and equipment on or in support of the NPSL which directly result in or are necessary for continued or enhanced production from the NPSL, as opposed to the consideration given for the lease itself; the lessee transferring the production interest must credit his development account for a like amount;

(8) before the commencement of commercial production, ad valorem tax paid to the state (net of all credits and refunds for municipal ad valorem taxes on the same property) for property used in the drilling described in (5) of this subsection or for property described in (6) of this subsection, that is installed or constructed before the commencement of commercial production and ad valorem and other taxes paid to one or more municipalities that were incurred directly as the result of, and in the course of, the drilling described in (5) of this subsection and/or the acquisition, installation or construction of property described in (6) of this subsection before the commencement of commercial production but excluding any windfall profits, franchise or income taxes.

(c) Costs that are "directly attributable" within the meaning of this section are only those direct charges incurred for activities occurring on or in support of the NPSL premises which are necessary for production or support of production from the lease. For NPSL's included in a unit, "directly attributable" costs are direct charges incurred for activities occurring on or in support of the unit premises and allocated to that lease. Any costs debited as direct operating costs under 11 AAC 83.240 are specifically excluded from "directly attributable" costs.

(d) If the NPSL is subject to an operating agreement in which at least one working-interest owner is a third party to the operator, then a non-operator may include as a development cost for that NPSL the direct charges allowed in (b), (c), and (f) of this section that are incurred by the operator in developing that NPSL, if they are reimbursable to the operator by the non-operator under the terms of that operating agreement.

(e) Repealed 8/15/82.

(f) General overhead and administrative expenses for a month may be included as a direct development cost at the rate of three precent of the development costs as defined in (b)(1), (2), (3), (5), and (6) of this section. If the NPSL is subject to a unit operating agreement in which at least one working interest owner is a third party to the operator, the commissioner will, in his discretion, require use of the overhead rate applicable to development costs specified in the unit operating agreement. (Eff. 11/9/79, Reg. 72; am 8/15/82, Reg. 83)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.222. PRODUCTION REVENUE. A lessee's production revenue during a month from each NPSL is

(1) the value at the point of production of the lessee's gross share of the oil and gas produced from that lease; however, oil or gas that is used, flared or unavoidably lost in the production operations for the NPSL or that is injected into a reservoir in the course of the operations for the same field for purposes of repressuring or conservation, (if any) may not be included in determining the lessee's production revenue from that NPSL; and

(2) all extraordinary production revenue or loss as defined in 11 AAC 83.231. (Eff. 11/9/79, Reg. 72)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.223. UNITIZATION. If all or part of a NPSL is included within a participating area of a unit, a cooperative drilling agreement, or other similar arrangement, such that production (in kind or in value) or expenses are attributed to the NPSL for activities of the unit, any formula or method of allocation governing the attribution of that production or expenses must be approved by the commissioner before it may take effect, unless that formula or other method of allocation is imposed and mandated by the Oil and Gas Conservation Commission under AS 31. (Eff. 11/9/79, Reg. 72)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.224. VALUATION OF OIL OR GAS. (a) Except as provided in (e) of this section, this section applies to all oil and gas produced on a NPSL whether or not the oil or gas is removed from the NPSL.

(b) Except when (c) of this section applies, the gross value at the point of production for all oil and gas is the sales price under 11 AAC 83.226 less the reasonable costs of transportation under 11 AAC 83.228 and 11 AAC 83.229 from the point of production to the sales delivery point. When (c) of this section applies, the gross value at the point of production is the prevailing value as determined under 11 AAC 83.227 less the reasonable costs of transportation under 11 AAC 83.228 and 11 AAC 83.229 from the point of production to the sales delivery point.

(c) Prevailing value must be used if the oil or gas is sold or exchanged under circumstances where the sales price is substantially lower than the prevailing value for oil or gas of like kind, character and quality being sold at sales delivery points in the same market or in a comparable market if there are no sales of significant quantities in the same market; for the purposes of this subsection

(1) "circumstances" refers to instances where terms of a contract set a single price for oil or gas without adjustments tied to market conditions for periods of longer than six years, or where the terms of a contract set prices which do not reasonably reflect market conditions for that field or area prevailing at the time the contract is executed or renegotiated, or where fraud or an intent to evade the net profit share payment is demonstrated; and

(2) the determination of a "substantially lower" price is to be made by analyzing the cash value of consideration received for oil or gas and taking into account any asserted difference between sales price and prevailing value, the quantity of oil or gas involved in the transaction, and the duration of the contract giving rise to the claim.

(d) For valuation purposes, production of oil or gas does not include oil or gas

(1) used, flared, or unavoidably lost in production operations on the NPSL; or

(2) injected into a reservoir in the course of operations in the same field for purposes of repressuring or conservation.

(e) Notwithstanding anything to the contrary in (a) – (d) of this section, where a lessee's gas from a NPSL is run through a gas processing plant and part or all of the residue gas and extracted liquids are returned to that lessee, the "value at the point of production" for that gas is the total value of that residue gas and extracted liquids as they come out of the plant, less

(1) a reasonable allowance (either withheld in kind by the plant operator or paid in cash to the plant operator) for the cost of processing that gas through the plant;

(2) the reasonable cost of transportation, under 11 AAC 83.228 and 11 AAC 83.229, if any, from the point of production for that gas to the intake into the plant; and

(3) the value of any residue gas returned to the lessee that is used, flared or unavoidably lost in the production operations for the lease or property or is injected into a reservoir in the course of operations for the same field. (Eff. 11/9/79, Reg. 72; am 3/27/82, Reg. 81; am 8/15/82, Reg. 83)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.226. SALES PRICE. (a) Sales price under this chapter for the first bona fide, arm's-length sales to a third party is the cash value of the full consideration given in receipt for the lessee's oil or gas so sold.

(b) Sales price under this chapter for all transactions other than those set forth in (a) of this section is the greater of

(1) the cash value of the full consideration given in receipt for the lessee's oil or gas used, exchanged, or otherwise transferred to another party; or

(2) the sales price attributable to that transaction entered on a lessee's books in accordance with the generally accepted accounting principles, consistently applied. (Eff. 11/9/79, Reg. 72)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.227. PREVAILING VALUE. (a) For a lessee's oil, the prevailing value is the arithmetic average acquisition cost CIF (at the refinery inlet in the same market in which the lessee's Alaska oil is refined) based on the sales price of like oil sold in up to three third-party, arm's-length transactions selected by the department, if disclosure of the sales price information is permitted by the parties to those transactions at the time of an audit of the lessee. In this subsection, "like oil" means an oil of substantially similar quality produced in the same general area of the state and subject to the same federal price controls, if any, as the oil for which the prevailing value is to be determined.

(b) If the information under (a) of this section may not be disclosed or is unavailable, then the prevailing value for purposes of this chapter equals the arithmetic average acquisition cost CIF, (at the refinery inlet in the same market in which the lessee's Alaska oil is refined) of up to six oils selected by the department, including

(1) up to three domestic oils of substantially similar quality which are sold in significant quantities in the same market or near the same market; and

(2) up to three imported oils of substantially similar quality which are sold in significant quantities in the same market or near the same market.

(c) The respective acquisition cost CIF at the refinery inlet in a market for each of the oils used in this section equals the sum of

(1) the respective official government sales price or posted price of the oil (with adjustments for differentials and surcharges) appearing in the latest Platt's Oilgram Price Report published on or before the last day of the month of sale; and

(2) the respective tanker transportation cost of the oil from its port of origin to ship's rail in the same market as that in which the lessee's Alaska oil is refined; this cost is calculated by

(A) multiplying the London Tanker Broker's average freight rate assessment ("AFRA") applicable to that voyage during that month for AFRA LR 2 (Long range 2) oil tankers, by the most recently published worldscale rate for that voyage; or

(B) applying another applicable freight rate if foreign flag vessels are prohibited from transporting that oil; and

(3) any canal tolls and expenses not included in the applicable freight rate for that voyage; and

(4) pipeline or other carrying charges.

(d) Prevailing value for gas is

(1) the volume-weighted average of the prices received by the lessee in arm's-length sales transactions which have been entered into or whose pricing provisions have been amended during the calendar year or the two preceding years for significant quantities at the sales delivery points within the same market for that production for Alaska gas of like kind, character and quality produced during the month of sale; or

(2) if the lessee makes no arm's-length sales of significant quantities at the sales delivery points within the same market for Alaska gas of like kind, character and quality produced during the month, the volume-weighted average of the prices being given and received under the terms of arm's-length sales contracts (whether between third parties or not) which have been entered into or whose pricing provisions have been amended during the calendar year or the two preceding years for significant quantities of gas from the same field as the lessee's gas (or if there are no such contracts for that field, the counterparts of those contracts in the nearest field), with appropriate adjustments for differences (if any) in kind, character, and quality between gas sold under the reference sales contracts and the lessee's gas.

(e) For purposes of this section, "same market" means

(1) with respect to a lessee's oil refined in Alaska, the Alaska market;

(2) with respect to a lessee's oil landed on the U.S. West Coast (including Hawaii), the West Coast market or, if appropriate, the submarkets on the West Coast (i.e., Puget Sound, San Francisco Bay, the Long Beach and Los Angeles area, and Hawaii);

(3) with respect to a lessee's oil landed on the U.S. Gulf Coast, the Gulf Coast market;

(4) with respect to a lessee's oil landed on the U.S. East Coast, the East Coast market;

(5) with respect to a lessee's oil landed in Puerto Rico or the U.S. Virgin Islands, the Puerto Rico and Virgin Islands market;

(6) with respect to a lessee's gas marketed in Alaska, the Alaskan market or portion of it served by gas from the same field or area as the lessee's gas;

(7) with respect to a lessee's gas marketed in the continental United States, the continental United States market;

(8) with respect to a lessee's gas marketed in a foreign country, the market in that foreign country. (Eff. 11/9/79, Reg. 72; am 3/27/82, Reg. 81)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.228. CHOICE OF METHODS FOR DETERMINING REASONABLE COSTS OF TRANSPORTATION. (a) Except as provided in (b) of this section, the reasonable cost of transportation is the actual cost of transportation as determined in 11 AAC 83.229.

(b) The reasonable cost of transportation is the fair market value as defined in 11 AAC 83.229, when all of the following conditions exist:

(1) the parties to the transportation of oil or gas are affiliated;

(2) the contract for the transportation of oil or gas is not an arm's-length transaction or is not representative of the market value of the transportation; and

(3) the method of transportation of oil or gas is not reasonable in view of existing alternative methods of transportation. (Eff. 11/9/79, Reg. 72)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.229. CALCULATION OF REASONABLE COSTS OF TRANSPORTATION. (a) Reasonable costs of transportation shall be calculated from the point of production to the sales delivery point.

(b) Reasonable costs of transportation under 11 AAC 83.228(a) are actual costs of transportation. The actual costs of transportation are

(1) in the case of transportation of oil or gas by a regulated carrier, the tariff on file with the FERC or other regulatory agency having jurisdiction that is applicable to that transportation of the oil or gas by the carrier, from the point where that oil or gas is tendered into the facilities of the carrier to the point where it is delivered from the facilities of the carrier;

(2) in the case of transportation of oil by a tanker or other vessel that is not owned or effectively owned by the lessee

(A) for a single voyage charter, the reasonable cost for that transportation is, for purposes of this chapter, the charter fee for that vessel, plus any voyage and port costs not included in that fee that are incurred with respect to that transportation during the term of the charter and that are borne by the lessee plus the positioning cost, if any, borne by the lessee for that vessel;

(B) for a consecutive voyage charter or a time charter, the reasonable cost for that transportation is, for purposes of this chapter, the charter fee for that vessel, plus any voyage and port costs not included in that fee that are incurred with respect to that transportation during the term of the charter and that are borne by the lessee, plus the positioning cost (amortized over the lesser of 36 months or the term of the charter in the case of a time charter, and amortized on the basis of the number of voyages in the case of a consecutive voyage charter), if any, borne by the lessee for that vessel;

(C) for a contract of affreightment, the reasonable cost for that transportation is, for purposes of this chapter, the affreightment fee specified in that contract, plus any voyage and port costs and any positioning costs not included in that fee that are incurred with respect to that transportation during the term of the contract of affreightment and that are borne by the lessee.

(c) In the case of transportation of oil by a tanker or other vessel that is owned or effectively owned by the lessee, the department will, in its discretion, authorize the lessee to use the fair market value of like transportation as the reasonable cost for the transportation in question. The department, and not the lessee, will determine the fair market value of like transportation, on the basis of third-party time charters (that is, time charters in which the lessee does not own or effectively own the vessel) of one year or more that are reported to the department for like vessels; and when it makes its determination, the department will notify the lessee. Two vessels will be considered like vessels for purposes of this chapter if the difference between them in deadweight tonnage is less than

10,000 deadweight tons and if they are both Jones Act vessels, or are both CDS vessels, or are both ODS vessels, or are both CDS/ODS vessels. If the department does not authorize the lessee to use fair market value of like transportation (as described in this subsection) as the reasonable cost for the transportation in question, then the reasonable cost for that transportation is, for purposes of this chapter, the lessee's actual cost for that transportation. This actual cost equals the sum of

(1) the voyage and port costs incurred with respect to that transportation;

(2) the positioning cost, amortized over 36 months, for that vessel, but only for placing that vessel into position before its employment in the Alaska trade and not for placing it into position after its employment in the Alaska trade for employment in another trade;

(3) depreciation of the vessel; if the vessel is actually owned by the lessee, depreciation must be calculated in accordance with the applicable FASB Financial Accounting Standards for such owned assets; if the vessel is effectively owned by the lessee, depreciation must be calculated in accordance with FASB-13 from the standpoint of a lessee under a capital lease; and

(4) an amount which, when taken together with depreciation under (3) of this subsection, will provide a reasonable return on the acquisition cost of the vessel over its expected life; for purposes of this paragraph

(A) "acquisition cost" means the cost of the vessel which may be capitalized by its actual owner under generally accepted accounting principles, but not including costs of improvements made after the date the vessel is placed in service by or on behalf of the lessee, and

(B) "expected life" means the period of the time used to calculate depreciation under (3) of this subsection.

(d) In the case of transportation of gas as LNG where not all of the LNG transportation facilities are subject to tariff regulation (by FERC or another agency of the United States, a state, territory or possession of the United States or a foreign nation)

(1) when the lessee does not have or effectively have an ownership interest in the LNG transportation facility, the reasonable cost of transportation for that LNG transportation facility is, for purposes of this chapter, the amount charged to the lessee for that LNG transportation; or

(2) when the lessee has or effectively has an ownership interest in the LNG transportation facility, the department will, in its discretion, authorize the lessee to use the fair market value of like transportation as the reasonable cost for the transportation in question; the department, and not the lessee, will determine the fair market value of like transportation, on the basis of third-party charters or leases (that is, charters or leases in which the lessee does not own or effectively own the LNG transportation facility in question) of three years or more that are reported to the department for like LNG transportation facilities; and if it makes such a determination, the department will notify the lessee of its determination; if the department does not authorize or require the lessee to use fair market value of like transportation (as described in this paragraph) as the reasonable cost for the transportation in question, then the reasonable cost for that transportation is, for purposes of this chapter, the lessee's actual cost for that transportation; this actual cost equals the sum of

(A) the direct operating costs of the LNG transportation facility (in the case of an LNG tanker, its respective voyage and port costs) incurred with respect to the lessee's gas;

(B) depreciation of the LNG transportation facility (if the facility is actually owned by the lessee, depreciation must be calculated in accordance with the applicable FASB Financial Accounting Standards for the owner of such assets; if the LNG transportation facility is effectively owned by the lessee, depreciation must be calculated in accordance with FASB-13 from the standpoint of a lessee under a capital lease); and

(C) an amount that, when taken together with depreciation under (B) of this paragraph, will provide a reasonable return on the acquisition cost of the LNG transportation facility over its expected life; for the purposes of this subparagraph

(i) "acquisition cost" means the cost of the LNG transportation facility which may be capitalized by its actual owner under generally accepted accounting principles, and

(ii) "expected life" means the period of time used to calculate depreciation under (B) of this paragraph.

(e) Reasonable cost of transportation under sec. 228(b) of this chapter is fair market value. Fair market value of transportation is to be determined

(1) for shipments of oil, on the basis of third party charters (that is, time charters in which the lessee does not own or effectively own the vessel) of one year or more, plus regulated transportation costs determined under (a) of this section; two vessels will be considered like vessels for purposes of comparing like transportation under this chapter if the difference between them in deadweight tonnage is less than 10,000 deadweight tons and if they are both Jones Act vessels, or are both CDS vessels, or are both ODS vessels or are both CDS/ODS vessels; or

(2) for shipments of gas as LNG, on the basis of third party charters or leases (that is, charters or leases in which the lessee does not own or effectively own the LNG transportation facility in question) of three years or more which are reported to the department for like LNG transportation facilities, plus regulated transportation costs determined under (b)(1) of this section.

(f) If a lessee sells its oil or gas to a third party in what would otherwise be a bona fide, arm's-length sale but at the time of this particular sale the lessee expects to repurchase that oil or gas at a subsequent time and place, then that sale to the third party and the repurchase from the third party, when it occurs, must be disregarded and the oil or gas subject to that sale must be regarded as if it had remained the lessee's own oil or gas throughout the time between that sale and repurchase. In determining the value at the point of production in such a case, the reasonable cost of transportation between the point of sale for that sale and the point of repurchase must be determined as if the lessee were the shipper. This subsection does not apply if the lessee's expected repurchase does not in fact occur.

(g) For the purposes of this chapter, "voyage and port costs" for a vessel are

(1) costs actually incurred for fuel for the vessel while in port and at sea, stores and provisions for the vessel and for her captain and crew, wages and benefits of the vessel's captain and crew, routine maintenance, port and dock fees, storage costs, demurrage, tug and pilotage fees, marine agents' fees in port, lightering, transshipment charges, customs fees and duties, regular and customary gratuities that are also legal, insurance premiums actually paid to third party insurers, minor cargo losses or measuring differentials, loading and unloading inspection fees, Panama Canal transit fees, a reasonable management fee (to be prorated equally among vessels) for coordinating arrivals and departures into and out of ports for vessels owned, effectively owned or chartered by the shipper and other reasonable costs associated with the operation or maintenance (or both) of the vessel; and

(2) in addition to the costs listed in (1) of this subsection, in the case of catastrophic loss or damage of a vessel transporting oil or LNG from Alaska or en route to Alaska to take on oil or LNG, a portion of the loss (for loss or damage of the ship, for injury or loss of her captain or crew and for damage and cleanup due to spillage of part or all of her cargo, but not for the loss of the cargo itself) that is borne by the lessee as the result of that catastrophic loss or damage and that is not reimbursed by insurance or by a third party but excluding any civil and criminal penalties and civil punitive damages which may be assessed as a result of this loss or damage; a lessee's portion of the loss is determined by dividing the unreimbursed liability on the basis of deadweight tonnage among the vessels owned, effectively owned or chartered by the lessee to transport oil or LNG (whichever was lost) from Alaska.

(h) A lessee "effectively owns," "has effective ownership of" or "effectively has an ownership interest in" a vessel or LNG transportation facility for purposes of this section if

(1) the vessel or LNG transportation facility is owned by another person comprising part of a consolidated business in which the lessee is also a part;

(2) the vessel or LNG transportation facility is the subject of a capital lease on which the lessee or another person comprising part of a consolidated business in which the lessee is also a part, is the lessee under that capital lease;

(3) the vessel or LNG transportation facility was built to the account of the lessee (or another person comprising part of the consolidated business in which the lessee is also a part), was sold and was chartered back by the lessee (or another person comprising part of the consolidated business in which the lessee is also a part) all in a simultaneous transaction and the vessel or LNG transportation facility is on a term charter or lease to the lessee (or another person comprising part of the consolidated business in which the lessee is also a part) for a period of 15 years or longer.

(i) For purposes of this chapter, the "positioning cost" for a vessel includes the costs not included in the charter for that vessel that are borne by the lessee for placing that vessel into position before the first voyage under that charter or the estimated costs to be borne by the lessee for delivering it up at a specified location after the last voyage under that charter, or both if the lessee is obligated under the terms of the charter or contract of affreightment to bear them both.

(j) A reasonable return under (c)(4) or (d)(2)(C) of this section is presumed to be that internal rate of return (after federal income tax) on the amount which yields an investment that equals two percent plus the average annual national inflation rate (measured by the GNP deflator) during

(1) the period between the time the commitment is made to construct or acquire the vessel or LNG transportation facility and the time when the vessel or LNG transportation facility has been received (or delivered) and is ready to be placed into service, or

(2) if the period in (1) of this subsection falls entirely within a calendar year, that entire calendar year.

(k) At the request of the lessee, the department will in its discretion, or, on its own motion, the department will replace the presumed return under (j) of this section with one based on the rate of return imputed to that investment or similar ones by the person owning or effectively owning the vessel or LNG transportation facility.

(l) The third-party nature of an agreement between a shipper and a third-party carrier regarding transportation costs is not affected during the term of that agreement by a subsequent consolidation of that lessee and carrier into a consolidated business, if, at the time they entered that agreement, neither the lessee nor the carrier exercised, directly or indirectly, any control over the business affairs of the other in anticipation of their subsequent consolidation into the same consolidated business. (Eff. 11/9/79, Reg. 72)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.231. EXTRAORDINARY PRODUCTION REVENUE OR LOSS. (a) A lessee's extraordinary production revenue or loss for a lease is fully recognized for purposes of this chapter in the month in which it is realized. Multiple realizations of extraordinary production revenue or loss by a lessee during a single month are cumulative, with revenues added to revenues and losses to losses, and with revenues and losses offset against each other.

(b) A retroactive decrease or increase in the tariff or fee allowed to be charged by a regulated carrier for transporting a lessee's oil and gas produced from the lease results in extraordinary production revenue or loss, respectively, for that NPSL, which is realized for purposes of this chapter at the time the retroactive change takes effect.

(c) A retroactive increase or decrease in the sales price in a bona fide, arm's-length sale of a lessee's oil and gas produced from the lease results in extraordinary production revenue or loss, respectively, for that lessee, which is realized for purposes of this chapter at the time the retroactive change takes effect.

(d) The amount of a lessee's extraordinary production revenue or loss under (b) or (c) of this section for the NPSL is the amount of the increase or decrease, respectively, in the value at the point of production for the lessee's oil and gas from that lease to which the retroactive tariff change or change in sales price applies, offset by any corresponding increase or decrease in costs or expenses under 11 AAC 83.219 – 11 AC 83.242 that change as the result of changing the value at the point of production for that oil and gas. (Eff. 11/9/79, Reg. 72)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.232. DEVELOPMENT ACCOUNT AND PRODUCTION REVENUE ACCOUNT – IN GENERAL. (a) Unless otherwise specified, a lessee's costs under this chapter are regarded as being incurred on an accrual basis.

(b) When a lessee incurs costs under this chapter and part or all of those costs are reimbursable to the lessee from one or more third parties, only the unreimbursed portion of those costs of the lessee may be used in calculating that debit. (Eff. 11/9/79, Reg. 72)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.240. DIRECT OPERATING COSTS. (a) The direct operating costs during a month that are incurred by or for a lessee for the NPSL are a debit to the production revenue account.

(b) After commencement of commercial production from the NPSL, the direct operating costs for that NPSL are

(1) the direct charges under 11 AAC 83.243 that are not excluded under 11 AAC 83.217, that have not been charged as a development cost under 11 AAC 83.219, and that are incurred for the operation of the wells and equipment on or in support of the NPSL which directly result in or are necessary for continued production from the NPSL;

(2) general overhead and administrative expenses in the manner and amount provided in (d) of this section;

(3) abandonment costs in the manner and amount provided in (e) of this section;

(4) the amount of liability for taxes imposed on the value of production or on sales from a NPSL that are incurred by, or on behalf of, a lessee during a month; the amount of tax liability imposed on the value of production includes Early Development Incentive Credits applied against that tax;

(5) the amount of tax paid during a month to the state (net of credits or refunds made that month for municipal ad valorem taxes on the same properties) and the total amount paid that month for municipal ad valorem taxes which are based on the value of a lessee's properties used directly in the production, gathering, treatment or preparation for pipeline shipment of oil and gas from a NPSL that is in commercial production before those payments to the state or any municipality are made.

(c) If the NPSL is subject to an operating agreement in which at least one working-interest owner is a third party to the operator, then a non-operator may include as a direct operating cost for that NPSL the direct charges allowed in (b) of this section that are incurred by the operator in operating that NPSL if they are reimbursable to the operator by the non-operator under the terms of that operating agreement.

(d) General overhead and administrative expenses for a month may be included as a direct operating cost at the rate of nine percent of the allowable direct operating costs defined in (b)(1) of this section. If the NPSL is subject to a unit operating agreement in which at least one working-interest owner is a third party to the operator, the commissioner will, in his or her discretion, require use of the overhead rate applicable to direct operating costs specified in the unit operating agreement.

(e) Following commencement of commercial production, abandonment costs of wells and facilities on or in support of the NPSL may be included as a direct operating cost, and, if included, must be amortized on a unit-of-production basis. The initial amount amortized per Btu equivalent equals the estimated real cost (i.e., without regard to inflation) as of the commencement of commercial production for abandonment of the wells and facilities on or in support of the NPSL, divided by the number of Btu equivalents represented by the proved reserves of the NPSL as of that time. The amount amortized per Btu equivalent may be redetermined, not more often than once every two years at the commencement of the operator's fiscal year, by dividing the number of Btu equivalents represented by the proved reserves of the NPSL as of the time of redetermination into the difference between the then-estimated real cost for abandonment of the wells and facilities on or in support of the NPSL and the cumulative amortization already allowed as of that time for the NPSL. If, upon abandonment of all wells and facilities on or in support of the NPSL, the actual abandonment costs, less salvage value (if any) are less than the total amount amortized for abandonment on or in support of that NPSL, the excess amortization must be included as extraordinary production revenue under 11 AAC 83.231 for the purposes of determining a lessee's net profit share payment due the state. If, upon abandonment of all wells and facilities on or in support of the NPSL, the actual abandonment costs, less salvage value (if any), are greater than the total amount amortized for abandonment on or in support of that NPSL, the difference may be included as extraordinary production loss for the purpose of determining a lessee's net profit share payment due the state.

(f) For purposes of this section

(1) a "development cost" is the cost of

(A) the acquisition of equipment, other than a well, and the extension, alteration or expansion of that equipment, or the replacement of it, where the intended purpose of the replacement includes extension, alteration or expansion; included are all costs and related indirect costs, associated with the design, procurement, construction, transportation, installation and commissioning of such equipment; and

(B) the drilling and completion of a well and the initial installation of artificial-lift equipment and the extension, alteration or expansion of a well or the replacement of equipment in it where the intended purpose of the extension, alteration, expansion or replacement is to increase the capacity or improve the operating characteristics of the well over a level that could be realized if the equipment in the well prior to replacement were in new condition; included are all costs, both tangible and intangible, and related indirect costs associated with them including the design, procurement and transportation of the equipment in the well;

(2) A "direct operating cost" is a cost incurred for normal ongoing operating and maintenance activities that cannot be defined as a development cost. (Eff. 11/9/79, Reg. 72; am 3/27/82, Reg. 81; am 8/15/82, Reg. 83)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.242. ROYALTY. (a) The amount of royalty in value to the state, if any, for each NPSL that is accrued during a month by or for a lessee, including a shut-in or minimum royalty, is a debit to the lessee's production revenue account.

(b) The value at the point of production (determined on the basis of the value at the point of production for the lessee's production interest at the time the royalty is delivered) of royalty to the state for a NPSL that is delivered in kind by or for a lessee during a month is a debit to the lessee's production revenue account.

(c) For purposes of this section, "royalty" does not include the lessee's net profit share payment due the state. (Eff. 11/9/79, Reg. 72)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.243. DIRECT CHARGES. For the purposes of this chapter, direct charges are

(1) lease rentals paid by lessee to the state for the operations of the NPSL, but excluding net profit share payments to the state;

(2) labor, which includes (A) salaries and wages of lessee's employees including supervisors and technical employees such as geologists, geophysicists, engineers, and drilling and construction supervisors directly employed on, or in transit to or from, the NPSL in lease operations, including earned or compensatory time off; and (B) salaries and wages of technical employees including engineers, technologists, draftsmen, engineering clerks, landmen, and other personnel performing technical services within the technical organizations who are

either temporarily or permanently assigned to, and directly employed in NPSL operations; charges for these technical personnel must be limited to that portion of the salaries and wages attributable to the time actually devoted to the NPSL operations; these charges may be made on a per diem basis as approved by the parties;

(3) lessee's cost of holiday, vacation, sickness, and disability benefits and other customary allowances paid to the employees whose salaries and wages are chargeable to the appropriate NPSL account under (2) of this section; costs under this paragraph may be charged on a "when and as-paid basis" or by "percentage assessment" on the amount of salaries and wages chargeable to the appropriate NPSL account under this paragraph; if percentage assessment is used, the rate must be based on the lessee's cost experience;

(4) expenditures or contributions made under assessments imposed by governmental authority which are applicable to the lessee's labor cost of salaries and wages chargeable to the appropriate NPSL account under (2) and (3) of this section;

(5) reasonable personal expenses of those employees whose salaries and wages are chargeable to the appropriate NPSL account under (2) and (3) of this section and for which expenses the employees are reimbursed under lessee's usual practice;

(6) the lessee's current costs for established plans for employee group life insurance, hospitalization, pension, retirement, stock purchase, thrift, bonus, and other similar benefit plans, applicable to the lessee's labor costs chargeable to the NPSL account under (2) and (3) of this section, provided that these costs do not exceed the percent most recently recommended by the Council of Petroleum Accountants Societies of North America;

(7) material purchased or furnished by lessee for use on the NPSL as provided under 11 AAC 83.244 so far as it is reasonably practical and consistent with efficient and economical operation; however, only such material as may be required for immediate use may be purchased for or transferred to the NPSL, and the accumulation of surplus stocks must be avoided;

(8) transportation of employees and material necessary for operations on the NPSL with the following limitations:

(A) if material is moved to the NPSL from the lessee's warehouse or other properties, no charge may be made to the appropriate NPSL account for a distance greater than the distance from the nearest reliable supply store, recognized barge terminal, railway or air cargo receiving point where like material is normally available, unless that charge is provided for by 11 AAC 83.244(3);

(B) if surplus material is moved to lessee's warehouse or other storage point, no charge may be made to the appropriate NPSL account for a distance greater than the distance to the nearest reliable supply store, recognized barge terminal, railway or air cargo receiving point; no charge may be made to the appropriate NPSL account for moving material to other properties belonging to lessee;

(C) however, under (A) and (B) of this paragraph there may be no equalization of actual gross trucking cost of $400 or less, excluding accessorial charges;

(9) the lessee's cost of contract services, equipment and utilities provided by outside sources, except the cost and expense of services provided by outside sources in connection with matters of taxation, traffic, accounting, or matters before or involving governmental agencies and those services excluded by (12) of this section; the cost of professional consultant services or contract services of technical personnel not directly engaged on the NPSL must be limited to that portion of the cost attributable to the time actually devoted to the NPSL;

(10) the lessee's cost of using lessee-owned equipment and facilities, including shore base and offshore facilities, based on rates commensurate with costs of ownership and operation; those rates may include labor, maintenance, repairs, other operating expense, insurance, taxes, depreciation, and interest on depreciated investment not to exceed a percentage to be determined by the commissioner; in addition, the rate may include an element for the estimated cost of abandonment, reclamation, and

restoration; these rates may not exceed average commercial rates currently prevailing in the immediate area of the NPSL; in place of charges in this paragraph, the lessee may elect to use average commercial rates prevailing in the immediate area of the NPSL less 20 percent; for automotive equipment, the lessee may elect to use rates published by the Petroleum Motor Transport Association;

(11) all costs or expenses necessary to repair or replace property due to damage or loss caused by fire, flood, storm, theft, accident, or other causes, less reimbursements and contributions made to a reserve account by a self-insurer, except those costs resulting from the lessee's gross negligence or willful misconduct; however, the lessee shall furnish the lessor written notice of damage or loss as soon as practicable after the lessee receives a report of them;

(12) expense of handling, investigating, and settling litigation or claims, discharging liens, paying judgments, and settling of claims incurred in or resulting from operations or necessary to protect or recover property, less any reimbursements and contributions made to a reserve account by a self-insurer; except that no charge for services of the lessee's legal staff or fees or expense of outside attorneys may be made;

(13) net premiums paid for insurance required to be carried for the operations for the protection of the parties; if operations are conducted at offshore locations in which lessee may act as self-insurer for workmen's compensation and employers' liability, lessee may include the risk under its self-insurance program in providing coverage under state and federal laws and charge the appropriate NPSL account at lessee's cost not to exceed manual rates;

(14) costs of acquiring, leasing, installing, operating, repairing, and maintaining communication systems including radio and microwave facilities between the NPSL and the lessee's nearest base facility; if communication facilities/systems serving the NPSL are lessee-owned, charges to the appropriate NPSL account must be made as provided in (10) of this section;

(15) costs incurred on the NPSL for archaeological and geophysical surveys relative to identification and protection of cultural resources and/or other environmental or ecological surveys as may be required by applicable laws and regulations plus costs to provide or have available pollution containment and removal equipment plus costs of actual control and cleanup and resulting responsibilities of oil spills as required by applicable laws and regulations, but excluding any civil and criminal penalties and civil punitive damages which may be assessed as a result of this loss or damage and excluding any costs under 11 AAC 83.229(g)(2);

(16) all proper costs and expenditures relative to the NPSL operations incurred under a contract other than the NPSL;

(17) costs of environmental impact statements and cleanup contingency plans;

(18) costs of preliminary platforms, feasibility, and design studies, or similar marine projects, incurred in compliance with applicable laws and regulations;

(19) contributions or advances to others if based on the lessee's working-interest participation;

(20) standby costs incurred while working-interest operations are deferred, suspended or curtailed by reason of force majeure;

(21) cost of compliance with applicable laws and regulations directly related to the lessee's working-interest participation in effect at the date of agreement or later enacted or adopted;

(22) dry or bottom hole contributions for information relative to the exploration or development of the working-interest participation;

(23) costs of permits and licenses for the operation of the area;

(24) costs of required well work commitment;

(25) costs of purchased substances, less cost recoveries, used as injection for repressuring, pressure maintenance, cycling or other secondary or tertiary recovery purposes;

(26) adjustments paid or received for investment costs and expenses resulting from changing

participations, unitization, or equity adjustments in the operating area according to the applicable operating agreements;

(27) charges for cleaning, dehydration, desulphurization, etc., for making the production of the royalty, overriding royalty and other nonoperating interest share of production marketable, offset by reimbursements (if any) from the royalty owner;

(28) charges for losses for lease fuel, vapor losses, drilling, etc., which are borne by working-interest participation according to applicable laws and regulations. (Eff. 11/9/79, Reg. 72; am 6/28/81, Reg. 78; am 3/27/82, Reg. 81; am 8/15/82, Reg. 83; am 4/14/84, Reg. 90)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.244. PRICING OF MATERIALS AND SUPPLIES. Material purchases, transfers and dispositions by a lessee for use on a NPSL must be priced according to the following standards:

(1) Material purchased must be charged at the price paid by lessee after deduction of all discounts received. In case of material found to be defective or returned to a vendor for any other reason, credit must be passed to the appropriate account when adjustment has been received by the lessee.

(2) Material transferred within the NPSL operations and material transferred from the NPSL operations or disposed of by the lessee must be priced at average warehouse stock prices. Transfers will be priced at current-condition value using average warehouse stock prices if they are available and reasonably representative of current market price. If they are not available or are not reasonably representative of current market price, the following applies. Material transferred must be priced at current-condition value replacement cost effective at date of transfer as specified in paragraph (3) of this section which must include material invoice cost, labor supplies, transportation, and material handling charges associated with getting material FOB to the NPSL property.

(3) Material required for operation must be purchased for direct charge to the NPSL account whenever practical. However, under circumstances where it is most practical for lessee to furnish materials from lessee's storehouse or other properties located in Canada, Alaska, or the continental United States, those material movements are subject to the following:

(A) New material is classified as Condition "A" and must be priced as follows:

(i) Tubular goods, except line pipe involving movements for less than 30,000 pounds, must be priced at the current price in effect on date of movement on a maximum carload or barge load weight basis, regardless of quantity transferred, equalized to the lowest published price FOB railway receiving point, recognized barge terminal, or air cargo receiving point nearest the NPSL where that material is normally available.

(ii) Line pipe involving movement of less than 30,000 pounds must be priced at the current price in effect at date of movement, as listed by a reliable supply store nearest the NPSL where such material is normally available. Movement of 30,000 pounds or more must be priced under provisions of tubular goods pricing in (i) of this subparagraph.

(iii) Other material must be priced at the current new price in effect at the date of movement, listed by a reliable supply store or FOB railway or air cargo receiving point nearest the NPSL where that material is normally available.

(iv) The NPSL account will not be credited with cash discounts applicable to prices provided for in paragraph (3) of this section.

(B) Used material is classified as either Condition "B" or "C" and must be priced as follows:

(i) Material in sound and serviceable condition and suitable for reuse without reconditioning moved to the NPSL, must be classified as Condition "B" and priced at 75 percent of the current price of new material.

(ii) Material in sound and serviceable condition and suitable for reuse without reconditioning moved from the NPSL must be classified as Condition "B" and priced at 75 percent of current new price if material was originally charged to NPSL account as new material, cr at 65 percent of current new price if material was originally charged to the NPSL account as used material at 75 percent of current new price.

(iii) Material which is not in sound and serviceable condition and not suitable for its original function until after reconditioning must be either classified as Condition "B" and priced at 75 percent of the current price of new material when the cost of reconditioning is to be absorbed by the transferor or classified as Condition "C" and priced at 50 percent of current price of new material when the cost of reconditioning is to be charged to the transferee, provided Condition "C" value, plus cost of reconditioning, does not exceed Condition "B" value.

(iv) Obsolete material or material which cannot be classified as Condition "B" or Condition "C" must be priced at a value commensurate with its use or at prevailing prices. Material no longer suitable for its original purpose but usable for some other purpose must be priced on a basis comparable with that of items normally used for those other purposes.

(C) Loading and unloading costs may be charged to the appropriate NPSL account only at the rate of 25 cents per hundred weight on all tubular goods movements, in place of loading and unloading costs sustained when actual hauling costs of those tubular goods are equalized under 11 AAC 83.243(8).

(D) Material involving erection costs must be charged at applicable percentage of the current knocked-down price of new material.

(E) The pricing and origination point of that material must be FOB a reliable supply store or railway, barge terminal, or air cargo receiving point nearest that lessee's storehouse from which the material is furnished.

(4) Whenever material is not readily obtainable at published or listed prices because of national emergencies, strikes or other unusual causes over which the lessee has no control, the lessee may charge the appropriate NPSL account for the required material at the lessee's actual cost incurred in providing that material, in making it suitable for use, and in moving it to the NPSL.

(5) In case of defective material, credit may not be passed to the appropriate NPSL account until adjustment has been received by the lessee from the manufacturers or their agents. (Eff. 11/9/79, Reg. 72; am 3/27/82, Reg. 81; am 8/15/82, Reg. 83)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.245. REPORTING AND PAYMENT REQUIREMENTS. (a) For each NPSL not in commercial production, each lessee shall file an annual report within 90 days following the end of each calendar year on forms prescribed by the department. Where two or more lessees hold a working interest in the same NPSL, they may, with the consent of the commissioner, appoint a designated operator of that NPSL to be responsible for the above reporting requirements.

(b) Once commercial production commences, each lessee shall file a report on forms prescribed by the department, together with the appropriate payment due the state on each NPSL, not later than 60 days following the end of each month during production. If the due date falls on a Saturday, Sunday or holiday, the report is due on the next business day. The report must contain the following information:

(1) the volume and dispositions of all oil and gas production saved, removed or sold for the production period;

(2) the value of oil or gas removed or sold;

(3) the amount and description of items in the NPSL accounts as defined in 11 AAC 83.209 – 11 AAC 83.214 and the balance of the accounts for the month; and

(4) the monthly profit share of the lessee and the monthly net profit payment due the state.

(c) Repealed 8/15/82.

(d) Interest will be charged at a variable rate per year equal to the prime rate as announced from time to time by the Bank of America, San Francisco, California, plus 1.25 percent a year on the amount of the net profit share payment due the state from the due date of the net profit share payment until the payment is received by the state.

(e) Records pertaining to development costs incurred before the start of commercial production, which are not included in reports filed under (b) of this section, must be kept and maintained for four years after the expiration of the calendar year in which commercial production begins or until abandonment of the lease if no commercial production begins. Records of the information required in (b) of this section, including a lessee's standard or joint accounting system records, must be kept and maintained for six years after the expiration of the calendar year in which the reports were filed with the state under (b) of this section. However, records of information required in (b) of this section, including standard or joint accounting system records, relating to abandonment cost amortization, must be kept and maintained from the date of issuance of the lease until three years following abandonment of the lease. Upon request by the state, the lessee shall make all records required by this section available for inspection and copying by authorized representatives of the state during normal business hours.

(f) Upon notice to the lessee, the state has the authority to audit the lessee's records of financial transactions, including the lessee's standard or joint accounting system records, inventories and other records pertaining to net profit share leasing operations. The audit period will remain open for the same period of time as specified in (e) of this section for record retention. If the commissioner determines there has been a showing of fraud or misrepresentation, then the audit period will remain open. Where possible, the auditor for the state will coordinate audit efforts with any other non-operators. (Eff. 11/9/79, Reg. 72; am 8/15/82, Reg. 83)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.247. REDETERMINATION. (a) If, as a result of an inspection of records under 11 AAC 83.245(e) or an audit under 11 AAC 83.245(f), the commissioner determines that (1) the method of allocating costs and production to a NPSL within a unit is improper, (2) there is an error or an improper cost claimed in a net profit share lease account, or (3) there is an error in the net profit share payment due the state, the commissioner will redetermine the net profit, recalculate the net profit share payment due the state, and notify the lessee of the redetermination.

(b) In the event of an underpayment, the lessee shall pay any additional amount of net profit share payment due the state plus interest at a variable rate per year equal to the prime rate prevailing during the month of the underpayment, as announced from time to time by the Bank of America, San Francisco, California, plus 1.25 percent a year. In the event of an overpayment, the state will return the overage to the lessee plus interest at a variable rate per year equal to the prime rate prevailing during the month of the overpayment, as announced from time to time by the Bank of America, San Francisco, California, plus 1.25 percent a year, or the lessee may claim a credit in the same amount to be applied to the next profit share payment. (Eff. 11/9/79, Reg. 72; am 8/15/82, Reg. 83)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.250. LESSEE PROTESTS. (a) A lessee who disagrees with and wishes to protest the commissioner's redetermination issued under 11 AAC 83.247, shall file a written protest with the department. To preserve the lessee's rights and to receive consideration by the department, this written protest must

(1) be filed within 60 days after the mailing date of the department's notice of redetermination with which the lessee disagrees or is aggrieved;

(2) be mailed or personally delivered to: Office of the Commissioner, Alaska Department of Natural Resources, Pouch M, Juneau, Alaska 99811;

(3) state what action by the department it is that the lessee is protesting and what relief the lessee seeks;

(4) state the grounds for the lessee's protest, including the facts (if any) at issue, the legal authority (statutes, regulations and case law), and any generally accepted accounting principles that support the lessee's protest;

(5) state whether the lessee wants an informal conference or waives its right to an informal conference in favor of a formal hearing.

(b) All sums declared to be owing for the net profit share payment due the state must be paid in full no later than 60 days following the mailing date of the department's notice of redetermination in accordance with 11 AAC 83.245(c). Payment under this subsection is subject to refund if, when and to the extent a refund is finally determined to be warranted. Failure to make timely payment of those sums forfeits the lessee's rights to pursue its protest before the department.

(c) A lessee may be represented or assisted by an attorney, certified public accountant or other authorized representative at the informal conference and the formal hearing. Proof of that authorization must be submitted for each representative at the conference or formal hearing. (Eff. 11/9/79, Reg. 72)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.252. INFORMAL CONFERENCES. (a) Upon receipt of the lessee's written protest, the department will designate a conference officer who will promptly schedule the informal conference with the lessee. A lessee wishing to present facts and financial information regarding its NPSL in support of its position must bring all pertinent books, records and other documents to the conference or must make them readily available for examination by the conference officer. The conference officer may copy any of the books, records and other documents brought to the conference or made available for the conference officer's examination.

(b) A lessee whose protest turns solely on one or more findings of material fact and who has waived its right to an informal conference in favor of a formal hearing, may be required to attend an informal conference prior to going to a formal hearing if the department believes the disagreement over material facts can be resolved at the conference level.

(c) After considering the facts, financial information and arguments presented by the lessee at the informal conference, the conference officer will make a recommendation. The conference officer is not authorized to compromise or waive the net profit share payment that is protested by the lessee; however, upon a conference officer's recommendation that a correction of the department's original action is warranted, the department will make the recommended correction and promptly notify the lessee in writing of the correction.

(d) A lessee dissatisfied with the conference officer's recommendation and wishing to continue its protest in the matter, shall, within 30 days after the date of the department's notice of its action on the conference officer's recommendation, file a written request for a formal hearing before the department. Failure to file a timely request waives the lessee's right to further consideration of its protest before the department.

(e) A conference officer's recommendation is not a final administrative determination of the lessee's protest by the department. (Eff. 11/9/79, Reg. 72)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.255. FORMAL HEARINGS. (a) The department will hold a formal hearing for a lessee

(1) when the lessee files a timely protest fulfilling the requirements of 11 AAC 83.250 (a) and (b), waiving the right to an informal conference in favor of a formal hearing;

(2) when the lessee files a request for a formal hearing within 30 days after the date of the conference officer's recommendation regarding that lessee's protest, if the request for a formal hearing fulfills the requirements of (b) of this section; or

(3) when, under the facts and circumstances

of a particular case, it appears appropriate to the department to conduct a formal hearing.

(b) A lessee's request to continue its protest at a formal hearing after the department has acted on the conference officer's recommendation regarding that protest must

(1) be mailed to: Office of the Commissioner, Alaska Department of Natural Resources, Pouch M, Juneau, Alaska 99811;

(2) state the nature of the lessee's continuing protest and the relief sought;

(3) state the grounds for the lessee's protest, including the facts (if any) remaining at issue, the legal authority (statutes, regulations, or case law) and any generally accepted accounting principles that support the lessee's protest.

(c) Upon receipt of the lessee's request for formal hearing, the department will promptly appoint a hearing officer to preside over that hearing.

(d) On the hearing officer's own motion or at the request of the lessee or of a representative of the appropriate division of the department, the hearing officer may order that a prehearing conference be scheduled for the purpose of narrowing issues or establishing a schedule for the discovery or production of evidence, for submission of briefs or for stipulation of facts.

(e) The formal hearing will be scheduled as early as possible at an office of the department nearest the lessee's place of business or at another time and place acceptable to the department and the lessee.

(f) At the hearing, the lessee has the burden of proving its protest by a preponderance of the evidence. At the hearing both the lessee and the department's representative may introduce into evidence any materials relevant to a determination of the merit of the protest.

(g) After the hearing, the hearing officer shall prepare a written decision, specifying the hearing officer's findings of fact and conclusions of law. Upon approval by the commissioner, the written decision of the hearing officer becomes the final decision of the department. (Eff. 11/9/79, Reg. 72)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.257. APPEALS. A lessee disagreeing with the decision of the department under 11 AAC 83.255 may appeal the decision to a court having jurisdiction to hear such appeals as provided in AS 44.62.560 and AS 44.62.570. (Eff. 11/9/79, Reg. 72)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.295. DEFINITIONS. Unless the context clearly requires a different meaning, in 11 AAC 83.201 – 11 AAC 83.295

(1) "abandonment cost" means those costs that will be incurred by the lessee to meet state and/or federal requirements to satisfactorily restore the lease, to plug and abandon the well and remove personal property within a reasonable time;

(2) "Btu-equivalent" means a barrel of oil or six Mcf of gas; except if the Btu-equivalents of the proved reserves of oil originally in place in the field that includes a particular NPSL, do not exceed 20 percent of the Btu-equivalents of the proved reserves of gas originally in place in that field, or vice versa, then "Btu-equivalent" will be understood to refer to the unit of production (barrel or oil or Mcf of gas) of the dominant reserve of that field for purposes of this chapter; however, if a lessee uses a similar but different unit of production for its unit-of-production amortization or depreciation for financial accounting purposes, the "Btu-equivalent" will be understood to refer to the unit of production used in that amortization or depreciation;

(3) "capital lease" means a lease classified as a capital lease from the standpoint of the lessee under FASB-13;

(4) "CDS vessel" means a United States flag vessel built for use in foreign trade which receives (while it is so used) a subsidy for the differential in construction costs between building it in the United States and building it elsewhere;

(5) "CDS/ODS vessel" means a United States flag vessel built for use in foreign trade which

receives (while it is so used) both the subsidy for a CDS vessel and the subsidy for an ODS vessel;

(6) "commissioner" means the commissioner of the Department of Natural Resources, State of Alaska, or his designee;

(7) "commercial production" means the production of oil and gas for purposes of sale or other beneficial use, except when the sale or beneficial use is incidental to the testing of an unproved well or unproved completion interval;

(8) "credit" means an entry used within the context of generally accepted accounting procedures;

(9) "debit" means an entry used within the context of generally accepted accounting procedures;

(10) "department" means the Department of Natural Resources, State of Alaska;

(11) "entitlements treatment" refers to the issuance, purchase, sale or use of whole and/or fractional entitlements associated with refining a particular run of oil pursuant to 10 CFR §§ 211 and 212, or to the treatment of that oil under any other program having a similar effect that the United States Department of Energy may adopt or administer as a replacement or continuation of the present entitlements program;

(12) "FASB" means the Financial Accounting Standards Board;

(13) "FASB 13" means FASB's Statement of Financial Accounting Standards No. 13, "Accounting for Leases" (November 1976), as amended or interpreted by FASB's Statement of Financial Accounting Standards No. 17, "Accounting for Leases – Initial Direct Costs" (November 1977); FASB's Statement of Financial Accounting Standards No. 22, "Changes in the Provisions of Lease Agreements Resulting from Refundings of Tax-Exempt Debt" (June 1978); FASB's Statement of Financial Accounting Standards No. 23, "Inception of the Lease" (August 1978); FASB Interpretation No. 19, "Lessee Guarantee of the Residual Value of Leased Property" (October 1977); and FASB Interpretation No. 21, "Accounting for Leases in a Business Combination" (April 1978);

(14) "FERC" means the Federal Energy Regulatory Commission of the United States Department of Energy, or the agency succeeding to its regulatory functions;

(15) "gross share" means the volume of production attributable to a production interest before any deductions for royalty in-value and royalty in-kind due the state that may be chargeable to that production interest.

(16) "Jones Act vessel" means a United States flag vessel built for use in domestic trade;

(17) "lessee" means an individual or individuals, a corporation, or, collectively, two or more corporations or individuals, that hold a working interest in a NPSL;

(18) "LNG" means a cryogenic liquid formed from normally gaseous hydrocarbons, chiefly methane;

(19) "LNG transportation facility" means any or all of the following when they are parts of a system to transport LNG: the LNG liquefaction plant, gathering lines to that plant, loading and unloading facilities for LNG tankers, LNG tankers themselves and facilities to regasify the LNG;

(20) "Mcf" or "Mcf of gas" means one thousand cubic feet of gas measured at 60 degrees Fahrenheit and 14.65 pounds per square inch (absolute);

(21) "ODS vessel" means a United States flag vessel built for use in foreign trade, that receives (while it is so used) a subsidy for the differential in operating costs between being manned by United States crews and being manned by foreign crews;

(22) "oil and gas" may, if appropriate, refer to either oil or gas, as well as meaning both of them in other contexts;

(23) "point of production" means

(A) for oil, the automatic custody transfer meter or unit through which the oil enters into the facilities of a carrier pipeline or other transportation carrier; and, in the absence of an automatic custody transfer meter or unit, the "point of production" for oil is the outlet flange of the tank gauge (or, in the absence of an automatic transfer meter or a tank gauge, another mechanism or device to measure the quantity of oil that has been approved by the department for this purpose) through which the oil is tendered and accepted into the facilities of a carrier pipeline or other transportation carrier;

(B) for gas recovered in association with oil, the meter on or nearest (measured along the course taken by the gas) to the NPSL from which the gas is recovered, at which meter the sales stream of gas is measured with sufficient accuracy and at appropriate temperature, pressure and other condition for purposes of sale, regardless of whether the particular gas in question is actually sold at that meter;

(C) for gas not recovered from or in association with oil, the point where it is accurately metered or measured, or if the gas is sold on the NPSL premises from which it is recovered, then the point of such sale;

(24) "positioning costs" is defined in 11 AAC 83.229(i);

(25) "produced," in the sense of oil and gas produced from a NPSL, includes oil and gas attributed (pursuant to the terms of a pooling agreement, unit agreement, lease-line well agreement, drainage agreement or other similar agreement between the production-interest owner(s) of the lease and the production-interest owner(s) of an adjacent lease, or pursuant to the terms of an order or decision by an appropriate regulatory agency or by a court) to that NPSL from one or more wells bottomed on the adjacent lease, as well as oil and gas from wells bottomed on the NPSL itself;

(26) "production interest" means a royalty interest or a working interest;

(27) "royalty" or "royalty interest" means a basic royalty or overriding royalty in the production of oil and gas;

(28) "sales delivery point" means

(A) for a lessee's oil and gas sold in a bona fide arm's-length sale to a third party, the point of delivery specified under the terms of the contract or agreement for that sale;

(B) for a lessee's oil not sold in a bona fide, arm's-length sale to a third party, the inlet of the refinery or comparable facility to which that oil is ultimately transported; and

(C) for a lessee's gas not sold in a bona fide, arm's-length sale to a third party, the point of delivery under the terms of the sales contract being used as the reference for the calculation of sales price of the lessee's gas under 11 AAC 83.226;

(29) "voyage and port costs" are defined in 11 AAC 83.229(g);

(30) "working interest" means any interest (including fee title) in the production of oil and gas that is not a royalty interest;

(31) "NPSL" is defined in 11 AAC 83.201. (Eff. 11/9/79, Reg. 72; am 8/15/82, Reg. 83)

Authority: AS 38.05.020
AS 38.05.180

ARTICLE 3.
UNITIZATION

Section
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395. Definitions

Editor's Note: 11 AAC 83, Article 3, relating to the unitization of oil and gas leases, is repealed in its entirety. Many of the provisions are readopted with minor changes under new section numbers. Where possible, the previous history of those sections is shown in the history note following the corresponding regulation.

11 AAC 83.300. APPLICATION FOR DESIGNATION OF AREA. Repealed 6/28/81.

11 AAC 83.301. PURPOSE. (a) 11 AAC 83.301 – 11 AAC 83.395 establish standards and procedures governing the submission of applications to the commissioner and criteria for approval of unit agreements for state oil and gas leases, and standards to be followed by a state lessee in conducting lease operations under an oil and gas unit agreement approved by the commissioner.

(b) 11 AAC 83.301 – 11 AAC 83.395 apply to an existing oil and gas lease or approved unit agreement where not inconsistent with the lease or unit agreement or regulations in effect on the effective date of the lease or unit agreement. (Eff. 6/28/81, Reg. 78; am 3/18/83, Reg. 85)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.303. CRITERIA. (a) The commissioner will approve a proposed unit agreement for state oil and gas leases if he makes a written finding that the agreement is necessary or advisable to protect the public interest considering the provisions of AS 38.05.180(p) and this section. The commissioner will approve a proposed unit agreement upon a written finding that it will

(1) promote conservation of all natural resources, including all or part of an oil or gas pool, field, or like area;

(2) promote the prevention of economic and physical waste; and

(3) provide for the protection of all parties of interest, including the state.

(b) In evaluating the above criteria, the commissioner will consider

(1) the environmental costs and benefits of unitized exploration or development;

(2) the geological and engineering characteristics of the potential hydrocarbon accumulation or reservoir proposed for unitization;

(3) prior exploration activities in the proposed unit area;

(4) the applicant's plans for exploration or development of the unit area;

(5) the economic costs and benefits to the state; and

(6) any other relevant factors, including measures to mitigate impacts identified above, the commissioner determines necessary or advisable to protect the public interest.

(c) The commissioner will consider the criteria in (a) and (b) of this section when evaluating each requested authorization or approval under 11 AAC 83.301 – 11 AAC 83.395, including

(1) an approval of a unit agreement;

(2) an extension or amendment of a unit agreement;

(3) a plan or amendment of a plan of exploration, development or operations;

(4) a participating area; or

(5) a proposed or revised production or cost allocation formula. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71; am 6/28/81, Reg. 78; am 3/18/83, Reg. 85)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.305. DESIGNATION; EFFECT. Repealed 6/28/81.

11 AAC 83.306. APPLICATION FOR UNIT APPROVAL. Any person owning an interest in a lease which is proposed to be committed to a unit which would include a state oil and gas lease may propose a unit agreement by applying to the commissioner for approval of the agreement. The following items constitute a complete application for approval:

(1) the unit agreement, including exhibits required under 11 AAC 83.341 or 11 AAC 83.343, executed by the proper parties;

(2) the unit operating agreement executed by the working-interest owners, which is submitted for information only and does not require the commissioner's approval for adoption or amendment;

(3) evidence of reasonable effort made to obtain joinder of any proper party who has refused to join the unit agreement;

(4) all pertinent geological, geophysical, engineering, and well data, and interpretations of those data, directly supporting the application;

(5) an explanation of proposed modifications, if any, of the standard state unit agreement form; and

(6) the application fee prescribed by 11 AAC 05.010. (Eff. 6/28/81, Reg. 78; am 8/15/82, Reg. 83; am 3/18/83, Reg. 85; am 1/1/86, Reg. 96)

Authority: AS 38.05.020 AS 38.05.145
AS 38.05.035 AS 38.05.180

11 AAC 83.310. DRAFT OF AGREEMENT. Repealed 6/28/81.

11 AAC 83.311. PUBLIC NOTICE. Within 10 days after receipt of a complete application for approval of a unit agreement, expansion of an approved unit under 11 AAC 83.356, or extension of the unit term under 11 AAC 83.336(a)(2), the commissioner will publish notice of the application in a newspaper of general statewide circulation and in a newspaper serving the locality in which the unit or proposed unit is located. In addition, the commissioner will, in his discretion, publish notice by radio, television, or other electronic media. If the unit or proposed unit is within the boundary of an organized borough, municipality, regional corporation, or village corporation organized under Section 8(a) of the Alaska Native Claims Settlement Act, the notice will be mailed to the chief executive officer of the borough or municipality, or designated representative of the corporate entity. The notice also will be mailed to the postmaster of each permanent settlement of more than 25 persons located within six miles of the proposed unit area. In the case of a proposed unit expansion, a copy of the notice will be mailed to the unit operator. The notice will include

(1) the name and address of the applicant, and the location of the unit or proposed unit;

(2) a statement explaining the nature of the approval sought;

(3) a statement indicating where copies of the non-confidential portions of the application may be obtained; and

(4) a statement that any person may file written comments on the application with the commissioner within 30 days after publication of the notice. (Eff. 6/28/81, Reg. 78; am 3/18/83, Reg. 85)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.315. RATES OF PROSPECTING AND PRODUCTION. Repealed 6/28/81.

11 AAC 83.316. UNIT APPROVAL. (a) Within 60 days after the close of the public comment period required by 11 AAC 83.311, the commissioner will issue a written decision approving or disapproving the unit agreement, in which he states the basis for his decision after considering the provisions of 11 AAC 83.303.

(b) If the commissioner determines that the provisions of 11 AAC 83.303 are not met, the commissioner will, in his discretion, propose modifications which, if accepted by the parties to the proposed unit agreement, would qualify the agreement for approval.

(c) No unit will be approved unless parties to the unit agreement hold sufficient interest in the unit area to give reasonably effective control of operations and at least one lease or portion of a lease in the unit area is a state lease. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71; am 6/28/81, Reg. 78; am 3/18/83, Reg. 85)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.320. PARTIES Repealed 6/28/81.

11 AAC 83.321. COPIES OF APPLICATION REQUIRED. In submitting an application under 11 AAC 83.301 – 11 AAC 83.395, the applicant must provide five copies of the non-confidential portions of the pertinent agreement, plan, modification, or other instrument or document for which approval is sought and two copies of any confidential material submitted. 10 copies of unit plans of operations are required for activities within the coastal zone. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71; am 6/28/81, Reg. 78)

Authority: AS 38.05.020
AS 38.05.145

11 AAC 83.325. SIGNATURES. Repealed 6/28/81.

11 AAC 83.326. STANDARD UNIT AGREEMENT. (a) Except as provided in 11 AAC 83.393, and as otherwise provided in this section, a unit agreement must be executed on, or in a manner consistent with, a standard state unit agreement form.

(b) The commissioner will allow a modification of the standard state unit agreement form, upon request by the unit applicant, when the commissioner determines that the modification is reasonably required to meet the needs and requirements of the particular unit considering the facts and conditions found to exist with respect to that unit, and the proposed modification meets the provisions of 11 AAC 83.303. The commissioner will require a modification of the standard state unit agreement form if required to meet the provisions of 11 AAC 83.303. Any request by the unit applicant for modification of the standard state unit agreement form must be made in writing not later than the time an application is submitted for approval under 11 AAC 83.306 and must include an explanation of proposed modifications. (Eff. 6/28/81, Reg. 78; am 3/18/83, Reg. 85)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.328. PARTIES. (a) The record owners of any right, title or interest in the oil or gas reservoirs or potential hydrocarbon accumulations to be included in a unit are the proper parties to the unit agreement. All proper parties must be invited to join the unit agreement.

(b) Where authorized by lease, the commissioner will, in his discretion, require a state lessee or any assignee of interest in a state lease to subscribe to a unit agreement. (Eff. 9/5/74, Reg. 51; am 6/28/81, Reg. 78)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.330. COUNTERPARTS. Repealed 6/28/81.

11 AAC 83.331. UNIT OPERATOR. (a) A unit operator must be qualified to hold a lease as provided in 11 AAC 82.200 – 11 AAC 82.205, and must be qualified to fulfill the duties and obligations prescribed in the unit agreement.

(b) The unit operator may be a working-interest owner in the unit area or may be a party selected by the working-interest owners.

(c) No designation or change of the unit operator becomes effective until approved by the commissioner. The commissioner will approve or disapprove a proposed change of the unit operator within 30 days after receipt of request and will explain in writing his basis for disapproval. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71; am 6/28/81, Reg. 78)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.335. UNIT OPERATORS. Repealed 6/28/81.

11 AAC 83.336. EFFECTIVE DATE AND TERM OF UNIT AGREEMENT. (a) A unit agreement becomes effective upon approval by the commissioner and automatically terminates five years from the effective date unless

(1) a unit well in the unit area has been certified as capable of producing hydrocarbons in paying quantities, in which case the unit agreement will remain in effect for so long as hydrocarbons are produced in paying quantities from the unit area, or for so long as hydrocarbons can be produced in paying quantities and unit operations are being conducted in accordance with an approved unit plan of exploration or development, or, should production cease, for so long after that as diligent operations are in progress to restore production and then so long after that as unitized substances are produced in paying quantities; or

(2) exploration operations have been conducted in accordance with an approved unit plan of exploration, and the commissioner, after issuing written notice under 11 AAC 83.311, issues a written decision extending the unit term in which he states the basis for his decision, considering the provisions of 11 AAC 83.303; no single extension will exceed five years.

(b) If a suspension of unit operations or production on all or part of the unit area has been ordered or approved under federal, state, or local law, or, if the commissioner determines that the unit operator has been prevented, despite good-faith efforts, from complying with any express or implied promise, term, condition, or covenant of the unit agreement, or from conducting exploration, development, production, transportation, or marketing operations on or from the unitized area by reason of force majeure, the unit operator's obligation to comply with the provision will be held in abeyance, but not voided, and the commissioner will extend the term of the unit agreement for a period of time equal to the time lost under the unit term due to the suspension or prevention by force majeure. If unit operations or production are suspended or prevented under this subsection and the continuation of those operations or production without suspension or prevention would have had the effect of extending the unit agreement, the unit agreement does not terminate during the period in which operations or production are suspended or prevented plus a reasonable time after that, which will not be less than six months, for the unit operator to resume operations or production. Nothing in this subsection holds in abeyance the obligation to pay rentals, royalties, or other production or profit-based payments to the State of Alaska from operations or production in the unitized area which are not suspended or prevented, or from operations or production which are unrelated to any suspension or prevention. For the purposes of this subsection, any seasonal restriction on operations or production or other conditions specifically required or imposed as a term of sale of an original lease, or as a condition required for unit agreement approval, will not be considered a suspension of operations or production ordered under law, or prevention due to force majeure. However, upon application to the commissioner, seasonal restrictions on operations or production imposed subsequent to approval of a unit agreement will be considered a suspension of operations or production ordered under law.

(c) A unit agreement may be terminated at any time with the approval of the commissioner.

(d) Upon termination of a unit, each lease or portion of a lease committed to the unit may be continued in effect only in accordance with the terms and conditions of the lease, statutes and regulations, or as provided in the unit agreement. (Eff. 6/28/81, Reg. 78; am 8/15/82, Reg. 83; am 3/18/83, Reg. 85)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.340. APPROVAL OF UNIT AGREEMENT. Repealed 6/28/81.

11 AAC 83.341. UNIT PLAN OF EXPLORATION. (a) Unless a unit plan of development is filed under 11 AAC 83.343, a unit plan of exploration must be filed for approval by the commissioner as an exhibit to the unit agreement under 11 AAC 83.306. The plan must describe the applicant's proposed exploration activities, including the bottom-hole locations and depths of proposed wells, and the estimated date drilling will commence. All exploration operations must be conducted under an approved plan of exploration. The commissioner will approve a unit plan of exploration if it complies with the provisions of 11 AAC 83.303. If the proposed unit plan of exploration is disapproved, the commissioner will, in his discretion, propose modifications which, if accepted by the unit operator, would qualify the plan for approval.

(b) The unit plan of exploration must be updated and submitted to the commissioner for approval at least 60 days before the expiration date of the previously approved plan, as set out in that plan. The update must describe the extent to which requirements of the previously approved plan were achieved; if actual operations deviated from or did not comply with the previously approved plan, an explanation of the deviation or noncompliance must be included in the update. Within 10 days after receipt of an updated plan of exploration, the commissioner will inform the unit operator as to whether a proposed unit plan of exploration is complete. After the commissioner has determined that a unit plan of exploration is complete, as submitted or modified by the unit operator following the commissioner's suggestions, the commissioner will have an additional 30 days in which to approve or disapprove the plan; if no action is taken by the commissioner, the unit plan of exploration is approved.

(c) The commissioner will approve an update of the unit plan of exploration if it complies with the provisions of 11 AAC 83.303. If the proposed update of a unit plan of exploration is disapproved, the commissioner will, in his discretion, propose modifications which, if accepted by the unit operator, would qualify the plan for approval.

(d) The unit operator shall submit an annual report to the commissioner describing the operations conducted under the unit plan of exploration during the preceding year.

(e) The unit operator may, with the approval of the commissioner, amend an approved plan of exploration. (Eff. 6/28/81, Reg. 78; am 3/18/83, Reg. 85)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.343. UNIT PLAN OF DEVELOPMENT. (a) A unit plan of development must be filed for approval as an exhibit to the unit agreement if a participating area is proposed for the unit area under 11 AAC 83.351, or when a reservoir has become sufficiently delineated so that a prudent operator would initiate development activities in that reservoir. All development operations must be conducted under an approved plan of development. A unit plan of development must contain sufficient information for the commissioner to determine whether the plan is consistent with the provisions of 11 AAC 83.303. The plan must include a description of the proposed development activities based on data reasonably available at the time the plan is submitted for approval as well as plans for the exploration or delineation of any land in the unit not included in a participating area. The plan must include, to the extent available information exists

(1) long-range proposed development activities for the unit, including plans to delineate all underlying oil or gas reservoirs, bring the reservoirs into production, and maintain and enhance production once established;

(2) plans for the exploration or delineation of any land in the unit not included in a participating area;

(3) details of the proposed operations for at least one year following submission of the plan; and

(4) the surface location of proposed facilities, drill pads, roads, docks, causeways, material sites, base camps, waste disposal sites, water supplies, airstrips, and any other operation or facility necessary for unit operations.

(b) The commissioner will approve the unit plan of development if it complies with the provisions of 11 AAC 83.303. If the proposed unit plan of development is disapproved, the commissioner will, in his discretion, propose modifications which, if accepted by the unit operator, would qualify the plan for approval.

(c) The unit plan of development must be updated and submitted to the commissioner for approval at least 90 days before the expiration date of the previously approved plan, as set out in that plan. The update must describe the extent to which the requirements of the previously approved plan were achieved; if actual operations deviated from or did not comply with the previously approved plan, an explanation of the deviation or noncompliance must be included in the update. The commissioner will approve the updated unit plan of development if it complies with the provisions of 11 AAC 83.303. If the proposed update of a unit plan of development is disapproved, the commissioner will, in his discretion, propose modifications which, if accepted by the unit operator, would qualify the plan for approval. Within 10 days after receipt of an updated unit plan of development, the commissioner will inform the unit operator as to whether the proposed unit plan of development is complete. After the commissioner has determined that an updated unit plan of development is complete as submitted, or as modified by the unit operator following the commissioner's suggestions, the commissioner will have an additional 60 days in which to approve or disapprove the plan; if no action is taken by the commissioner, the update of the unit plan of development is approved.

(d) The unit operator shall submit an annual report to the commissioner describing the operations conducted under the unit plan of development during the preceding year.

(e) The unit operator may, with the approval of the commissioner, amend an approved plan of development. (Eff. 6/28/81, Reg. 78; am 3/18/83, Reg. 85)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.345. MODIFICATION OF UNIT AGREEMENTS. Repealed 6/28/81.

11 AAC 83.346. UNIT PLAN OF OPERATIONS. (a) Except as provided in (b) of this section, a unit plan of operations for all or part of the unit area must be approved by the commissioner before any operations may be undertaken on the unit area if

(1) the state owns all or part of the surface estate of the unit area;

(2) the unit includes a lease that reserves a net profit share to the state; or

(3) the state owns all or part of the mineral estate, but the entire surface estate of the unit area is owned by a party other than the state, and a surface owner requests that a unit plan of operations be required by the commissioner for the portion of the unit area owned by that surface owner.

(b) A unit plan of operations will not be required by the commissioner for activities that would not require a land use permit under this title.

(c) Before undertaking operations of the unit area, the unit operator shall provide for full payment of all damages sustained by the owner of the surface estate as well as by the surface owner's lessees and permittees, by reason of entering the land. If the surface estate is owned by a party other than the state, the unit operator shall also notify the surface owner of his opportunity to request that the commissioner require a plan of operations before allowing operations to be undertaken on the unit area owned by the requesting surface owner.

(d) An application for approval of a plan of operations must contain sufficient information, based on data reasonably available at the time the plan is submitted for approval, for the commissioner to determine the surface use requirements and impacts directly associated with the proposed operations. An application must include statements, and maps or drawings, setting out the following:

(1) the sequence and schedule of the operations to be conducted in the unit area, including the date operations are proposed to begin and their proposed duration;

(2) projected use requirements directly associated with the proposed operations, including but not limited to the location and design of well sites, material sites, water supplies, solid waste sites, buildings, roads, utilities, airstrips, and all other facilities and equipment necessary to conduct the proposed operations;

(3) plans for rehabilitation of the affected unit area after completion of operations or phases of those operations; and

(4) a description of operating procedures designed to prevent or minimize adverse effects on other natural resources and other uses of the unit area and adjacent areas, including fish and wildlife habitats, historic and archeological sites, and public use areas.

(e) In approving a unit plan of operations or an amendment of a plan, the commissioner will require amendments he determines necessary to protect the state's interest. The commissioner will not require any amendment that would be inconsistent with the terms of sale under which the lease was obtained, or with the terms of the lease itself, or which would deprive the lessee of reasonable use of the leasehold interest.

(f) The unit operator may, with the approval of the commissioner, amend an approved plan of operations.

(g) Upon completion of operations, the unit operator shall inspect the area of operations and submit a report indicating the completion date of operations and stating any noncompliance of which the unit operator knows, or should reasonably know, with requirements imposed as a condition of approval of the plan. (Eff. 6/28/81, Reg. 78; am 8/15/82, Reg. 83; am 3/18/83, Reg. 85)
Authority: AS 38.05.020 AS 38.05.145
AS 38.05.130 AS 38.05.180

11 AAC 83.350. APPROVAL OF FEDERAL UNITS. Repealed 6/28/81.

11 AAC 83.351. PARTICIPATING AREA. (a) At least 90 days before sustained unit production from a reservoir, the unit operator shall submit to the commissioner for approval a description, based on subdivisions of the public land or its aliquot parts, of the proposed participating area. The participating area may include only the land reasonably known to be underlain by hydrocarbons and known or reasonably estimated through use of geological, geophysical, and engineering data to be capable of producing or contributing to production of hydrocarbons in paying quantities. Under 11 AAC 83.371(a), the unit operator also shall submit to the commissioner for approval a proposed division of interest or formula setting out the percentage of production and costs to be allocated to each lease and portion of lease within the participating area. Upon approval by the commissioner, the area of productivity constitutes a participating area.

(b) A separate participating area must be established as provided in (a) of this section for each reservoir delineated, except that with the consent of the commissioner and all working interest owners, any two or more reservoirs or participating areas within the unit may be combined into one participating area. Separate participating areas may be established to distinguish between an oil rim and a gas cap within the same reservoir.

(c) A participating area must be expanded to include acreage reasonably estimated through use of geological, geophysical, and engineering data to be capable of producing or contributing to the production of hydrocarbons in paying quantities, and must be contracted to exclude acreage reasonably proven through use of geological, geophysical, or engineering data to be incapable of producing hydrocarbons in paying quantities, subject to approval by the commissioner. A revised division of interest or formula allocating production and costs must be submitted for approval under 11 AAC 83.371 at the time of expansion or contraction of a participating area. (Eff. 6/28/81, Reg. 78; am 3/18/83, Reg. 85; am 3/30/84, Reg. 89)
Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.355. APPLICATIONS. Repealed 6/28/81.

11 AAC 83.356. UNIT AREA; CONTRACTION AND EXPANSION. (a) A unit must encompass the minimum area required to include all or part of one or more oil or gas reservoirs, or all or part of one or more potential hydrocarbon accumulations.

(b) 10 years after sustained unit production begins, the unit area must be contracted to include only those lands then included in an approved participating area and lands that facilitate production including the immediately adjacent lands necessary for secondary or tertiary recovery, pressure maintenance, reinjection, or cycling operations. The commissioner will, in his discretion, after considering provisions of 11 AAC 83.303, delay contraction of the unit area if the circumstances of a particular unit warrant. If any portion of a lease is included in the participating area, the entire lease will remain committed to the unit.

(c) Any expansion or contraction of the unit area must be based on legal subdivisions of land as defined in 11 AAC 88.185.

(d) No land will be excluded from a unit area due to the depletion of hydrocarbons.

(e) Not sooner than 10 years from the effective date of the unit agreement, the commissioner will, in his discretion, contract the unit area to include only that land covered by an approved unit plan of exploration or development, or that area underlain by one or more oil or gas reservoirs or one or more potential hydrocarbon accumulations and lands that facilitate production as set out in (b) of this section. Before any contraction of the unit area under this subsection, the commissioner will give the unit operator, the working-interest owners, and royalty owners of the leases or portions of leases being excluded reasonable notice and an opportunity to be heard. (Eff. 6/28/81, Reg. 78; am 3/18/83, Reg. 85)

Authority: AS 31.05.110 AS 38.05.145
AS 38.05.020 AS 38.05.180

11 AAC 83.360. NOTATION OF APPROVAL. Repealed 6/28/81.

11 AAC 83.361. CERTIFICATION OF WELL TEST RESULTS. For the purposes of 11 AAC 83.301 — 11 AAC 83.395, a well will be considered capable of producing hydrocarbons in paying quantities, as defined in 11 AAC 83.395, when so certified by the commissioner following application by the lessee or unit operator. The commissioner will require the submission of data necessary to make the certification, including all results of the flow test or tests, supporting geological data, and cost data reasonably necessary to show that the production capability of the well satisifies the economic requirements of the paying quantities definition. (Eff. 6/28/81, Reg. 78; am 8/15/82, Reg. 83; am 3/18/83, Reg. 85)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.365. UNIT BONDS. Repealed 6/28/81.

11 AAC 83.366. UNIT OPERATING AGREEMENT. Any revision of the unit operating agreement must be submitted to the commissioner before it takes effect. The unit agreement controls the respective rights and obligations of the unit operator, the working-interest owners, the State of Alaska, and royalty interest owners other than the State of Alaska in case of conflict between the unit agreement and the unit operating agreement. Where conflicts exist solely between working-interest owners, the unit operating agreement shall control. (Eff. 6/28/81, Reg. 78; am 8/15/82, Reg. 83)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.370. SEGREGATED LEASES. Repealed 6/28/81.

11 AAC 83.371. ALLOCATION OF PRODUCTION AND COSTS. (a) The proposed or revised division of interest or formula allocating hydrocarbon production and unit operating costs among the leases in the unit area may not take effect until approved by the commissioner in writing. When requested by the commissioner, the lessees or unit operator shall promptly file with the commissioner all data that relates to the proposed or revised division of interest or allocation formula for all leases in the participating area. Before any disapproval of the proposed or revised division of interest or allocation formula, the commissioner will give the working interest and royalty owners reasonable notice and an opportunity to be heard. After the hearing, the commissioner will approve the proposed or revised division of interest or allocation formula as submitted unless he finds in writing that the formula does not equitably allocate production and costs among the leases.

(b) If there is a separate division of interest or allocation formula among any of the parties holding an interest in the unit that is different from the division of interest or allocation formula approved by the commissioner, the parties to the separate division of interest or allocation formula not approved by the commissioner shall submit a copy of that formula to the commissioner and a statement explaining the reasons for the difference. (Eff. 6/28/81, Reg. 78; am 3/18/83, Reg. 85)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.373. SEVERANCE. (a) Except as otherwise provided in this section and 11 AAC 83.356, where only a portion of a lease is committed to a unit agreement approved or prescribed by the commissioner, the commitment constitutes a severance of the lease as to the unitized and nonunitized portions of the lease. The portion of the lease not committed to the unit will be treated as a separate and distinct lease having the same effective date and term as the original lease and may be maintained thereafter only in accordance with the terms and conditions of the original lease, statutes, and regulations. Any portion of the lease not committed to the unit agreement will not be affected by the unitization or pooling of any other portion of the lease by operations in the unit, or by suspension approved or ordered for the unit under 11 AAC 83.336(b).

(b) The commissioner will, in his discretion, grant up to a two-year extension of the lease term for that portion of a lease not committed to the unit agreement under this section.

(c) A lease having a well certified as capable of production in paying quantities before commitment to the unit agreement will not be severed. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71; am 6/28/81, Reg. 78; am 8/15/82, Reg. 83)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

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

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

(c) If a default occurs with respect to a unit in which there is no well capable of producing oil or gas in paying quantities and the default is not cured by the date indicated in the demand, the commissioner will, in his discretion, and after giving the unit operator and defaulting party (if other than the unit operator) reasonable notice and opportunity to be heard, terminate the unit agreement by mailing notice of the termination to the unit operator and defaulting party. Termination is effective upon mailing the notice.

(d) If a default occurs with respect to a unit in which there is a well capable of producing oil or gas in paying quantities and the default is not cured by the date indicated in the demand, the commissioner will, in his discretion, seek to terminate the unit agreement by judicial proceedings. (Eff. 6/28/81, Reg. 78)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.375. CONFIDENTIALITY OF DATA. Repealed 3/18/83.

11 AAC 83.379. SIGNATURES. Each signature on the unit agreement must be notarized or attested by at least two witnesses. Corporate or other signatures made in a representative capacity must be accompanied by evidence of the authority of the signatory to act on behalf of the principal or by a reference to such evidence previously filed. The printed or typed name and address of each signatory to the unit agreement must be set out below the signature.

(Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71; am 6/28/81, Reg. 78)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.380. COUNTERPARTS. The parties may execute any number of counterparts of a unit agreement or may execute a ratification, joinder, or consent in a separate instrument. These documents have the same effect as if all parties signed the same instrument. (Eff. 9/5/74, Reg. 51; am 6/28/81, Reg. 78)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.383. NOTATION OF APPROVAL. If approved by the commissioner, the counterparts of each instrument or document submitted for approval will be returned to the applicant with the commissioner's approval noted on the approved counterparts. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71; am 6/28/81, Reg. 78)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.385. MODIFICATION OF UNIT AGREEMENT. Any modification of an approved unit agreement is subject to the commissioner's approval. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71; am 6/28/81, Reg. 78)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.390. UNIT BONDS. In place of separate bonds required for each lease committed to a unit agreement, the unit operator shall furnish and maintain a statewide oil and gas lease bond under 11 AAC 83.160. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71; am 6/28/81, Reg. 78)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.393. APPROVAL OF FEDERAL AND PRIVATE PARTY UNITS. (a) If the State of Alaska selects or otherwise acquires any federal land which, at the effective date of selection or acquisition, is subject to a federal oil and gas lease which is committed to a unit agreement that has been approved in accordance with federal laws and regulations, the unit agreement will be considered to have been approved by the commissioner for all the purposes of AS 38.05 and 11 AAC 83.301 – 11 AAC 83.395.

(b) The commissioner will, in his discretion, enter into agreements with the federal government to provide for unitization of state and federal oil and gas leases overlying a common reservoir. If the agreement permits or requires the commissioner to take any action or enter into any unit agreement which is contrary to or inconsistent with 11 AAC 83.301 – 11 AAC 83.395, the commissioner will, in his discretion, do so after making a written finding that his action or the unit agreement is necessary or advisable to protect the public interest, and will, in all cases, comply with the requirements of 11 AAC 83.303 and 11 AAC 83.311.

(c) Any person owning an interest in a state oil and gas lease who has been asked to join a unit in which all state leases proposed to be committed to the unit constitute not more than 10 percent of the surface acreage of the unit or not more than five percent of the initial participation in the unit may request approval of the commissioner to join the unit as a working interest owner and may also request that the commissioner join the unit as a royalty owner. The commissioner will, in his discretion, approve and join the unit agreement as a royalty owner if, after giving public notice in accordance with 11 AAC 83.311, he makes written finding that the proposed unit is necessary or advisable to protect the public interest considering the criteria in 11 AAC 83.303. A unit agreement entered into under this section need not comply with the requirements of this chapter. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71; am 6/28/81, Reg. 78)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.395. DEFINITIONS. Unless the context clearly requires a different meaning, in 11 AAC 83.301 – 11 AAC 83.395 and in the applicable unit agreements

(1) "conservation of the natural resources of all or part of an oil or gas pool, field or like area" means maximizing the efficient recovery

of oil and gas and minimizing the adverse impacts on the surface and other resources;

(2) "commissioner" means the commissioner of the state Department of Natural Resources or his designee;

(3) "force majeure" means war, riots, acts of God, unusually severe weather, or any other cause beyond the unit operator's reasonable ability to foresee or control and includes operational failure to existing transportation facilities and delays caused by judicial decisions or lack of them;

(4) "paying quantities" means quantities sufficient to yield a return in excess of operating costs, even if drilling and equipment costs may never be repaid and the undertaking considered 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;

(5) "potential hydrocarbon accumulation" means any structural or stratigraphic entrapping mechanism which has been reasonably defined and delineated through geophysical, geological, or other means and which contains one or more intervals, zones, strata, or formations having the necessary physical characteristics to accumulate and prevent the escape of oil and gas;

(6) "reservoir" means an oil or gas accumulation which has been discovered by drilling and evaluated by testing and which is separate from any other accumulation of oil and gas;

(7) "unit" means a group of leases covering all or part of one or more potential hydrocarbon accumulations, or all or part of one or more adjacent or vertically separate oil or gas reservoirs, which are subject to a unit agreement;

(8) "unit agreement" means the agreement executed by the State of Alaska, working-interest owners, and royalty owners creating the unit; and

(9) "sustained unit production" means continuing production of oil or gas from a reservoir in the unit area into a pipeline or other means of transportation to market, but does not include testing, evaluation, or pilot production. (Eff. 6/28/81, Reg. 78; am 3/18/83, Reg. 85)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

ARTICLE 4.
COMMUNITIZATION AND DRILLING AND DEVELOPMENT CONTRACTS

Section
400. Applications

11 AAC 83.400. APPLICATIONS. Applications for approval of a communitization or drilling agreement under AS 38.05.180(s) or drilling or development contracts under AS 38.05.180(t) must comply with 11 AAC 85.105 and must be accompanied by three signed copies of the proposed agreement. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71)

Authority: AS 38.05.020
AS 38.05.145(a)
AS 38.05.180

ARTICLE 5.
UNDERGROUND STORAGE

Section
500. Qualifications to hold storage lease
505. Storage lease restrictions
510. Lieu royalty
515. Term of affected oil and gas leases
520. Applications for storage lease

11 AAC 83.500. QUALIFICATIONS TO HOLD STORAGE LEASE. A storage lease authorized by AS 38.05.180(u) may be issued to any person qualified to hold an oil and gas lease, whether or not the person holds an oil and gas lease on all or part of the land covered by the storage lease. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71)

Authority: AS 38.05.020
AS 38.05.145(a)
AS 38.05.180(u)

11 AAC 83.505. STORAGE LEASE RESTRICTIONS. A storage lease issued under AS 38.05.180(u)

(1) does not give the storage lessee any right to drill for, develop, produce, extract, remove, or market oil, gas or other natural resources in and from the land covered by the storage lease other than oil or gas or both in an amount not greater than the amount of oil or gas or both introduced into that land for storage;

(2) does not prohibit the state from issuing oil and gas leases to others covering all or portions of the land covered by the storage lease;

(3) must contain conditions that will prevent unnecessary or unreasonable interference with the rights and operations under any oil and gas lease, including conditions prohibiting the storage of oil or gas in any reservoir capable of producing oil or gas in paying quantities without the consent of the holder of any oil and gas lease covering the reservoir;

(4) must contain a damage provision as stated in sec. 160 of this chapter and the reservations provided for in sec. 155 of this chapter;

(5) must provide for a storage fee or rental on stored oil or gas or both, as determined by the commissioner;

(6) must specify its terms; and

(7) must contain any other provision that the commissioner considers reasonable and necessary to protect the interests of Alaska. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71)

Authority: AS 38.05.020
AS 38.05.145(a)
AS 38.05.180(u)

11 AAC 83.510. LIEU ROYALTY. In cases where the storage lessee also holds the right to produce oil or gas not previously produced in conjunction with stored oil or gas, the storage lease may, in place of the fee or rental provided for under sec. 505(5) of this chapter, provide for a royalty upon stored oil or gas when produced. The royalty rate may be the same as or different from the royalty rate or rates provided for in any oil and gas leases involved. If the rate is different from the rate or rates in the oil and gas lease or leases, the storage lease must specify whether or not that different rate applies to oil or gas not previously produced and thereafter produced in conjunction with stored oil or gas. If the different rate is to apply, the royalty rate or rates under the oil and gas lease or leases must be modified with respect to oil or gas so produced. If the different rate is not to apply, the storage lease must specify a reasonable method for determining respective portions of production to which the different royalty rates apply. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71)

Authority: AS 38.05.020
AS 38.05.145(a)
AS 38.05.180

11 AAC 83.515. TERM OF AFFECTED OIL AND GAS LEASES. Where the storage lessee also holds the right to produce oil or gas not previously produced in conjunction with stored oil or gas, any lease covering the oil or gas not previously produced shall be extended for the period of storage and so long thereafter as oil or gas is produced in paying quantities from the zones or geologic horizons used for that storage. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020
AS 38.05.180(r)

11 AAC 83.520. APPLICATIONS FOR STORAGE LEASE. Applications for storage leases must comply with 11 AAC 88.105 and be accompanied by

(1) three copies of a proposed form of storage lease; and

(2) supporting data demonstrating the feasibility of the proposed storage project. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020
AS 38.05.145(a)

ARTICLE 6.
FEDERAL LEASES AND PREFERENCE RIGHTS ON ALASKA LANDS

Section

600. **Date of transfer – Uplands and shorelands**
605. **Notice of patent**
610. **(Repealed)**
615. **Substitution of lessor**
620. **Rental payment**
625. **Shorelands preference rights: general**
630. **Shorelands preference rights: lease application**

11 AAC 83.600. DATE OF TRANSFER – UPLANDS AND SHORELANDS. The effective date of the transfer of the lessor's interest under leases transferred from the United States to Alaska is the effective date of patent, or the date on which the land subject to the leases is transferred from the United States to Alaska, whichever is applicable. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71)

Authority: AS 38.05.020
AS 38.05.145(a)
AS 38.05.180(o)

11 AAC 83.605. NOTICE OF PATENT. Promptly upon receipt of a lease from the federal government, the commissioner will mail notice to the lessee of record and to any operator whose operating agreement has been approved, stating the effective date of the patent and that all payments accruing after that effective date must be made as directed by the commissioner. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71)

Authority: AS 38.05.020
AS 38.05.145(a)

11 AAC 83.610. EXCHANGE. Repealed 7/22/79.

11 AAC 83.615. SUBSTITUTION OF LESSOR. Upon the transfer of a federal lease to the state, Alaska succeeds as the lessor, and all obligations accruing after that date are owed to Alaska, and all payments, reports, notices, applications, and similar matters required or permitted under the lease must, after that date, be addressed as directed by the commissioner. The commissioner is authorized to enforce all obligations, give all notices, make all determinations and do all other things that any officer or representative of the United States could do if the lease remained a federal lease. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71)

Authority: AS 38.05.020
AS 38.05.145(a)
AS 38.05.180(o)

11 AAC 83.620. RENTAL PAYMENT. The failure to timely pay rental to Alaska for the first and second lease years commencing after the effective date of the transfer of the lease to Alaska does not terminate the lease if the rental payment was made to the United States within the time allowed, and either the payment is transmitted to Alaska by the United States or the lessee makes payment to Alaska within 30 days after receiving written notice demanding the payment. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020
AS 38.05.145(a)

11 AAC 83.625. SHORELANDS PREFERENCE RIGHTS: GENERAL. For the purposes of AS 38.05, "shorelands" means that land belonging to the State of Alaska which is covered by nontidal waters that are navigable under the laws of the United States up to the ordinary high water mark, as modified by accretion, erosion, or reliction before September 5, 1974 or after September 4, 1974. This land does not include tideland which is periodically covered by tidal waters between the elevation of mean high and mean low tides, nor does it include submerged land, bays, or estuaries that are subject to the ebb and flow of the tide. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71)

Authority: AS 38.05.020
AS 38.05.145(a)
AS 38.05.180(o)

11 AAC 83.630. SHORELANDS PREFERENCE RIGHTS: LEASE APPLICATION. (a) After determination of navigability, the holder of a federal or private upland lease, on his own motion or within 30 days from receipt of notice from the commissioner, may apply for and will be issued a State of Alaska lease covering any land within the exterior boundaries of the federal or private lease which has been excluded from the lease on the basis of navigability. The term of the State of Alaska lease will conform to the primary term of the federal or private lease giving rise to the preference right, including any extended term of it.

(b) No attempt to segregate the shoreland preference right from the federal or private lease by assignment will be approved by the commissioner. If a partial assignment of the federal or private lease is made, the shoreland within the section or aliquot part of the section is subject to the assignment. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71)

Authority: AS 38.05.020
AS 38.05.145(a)
AS 38.05.180(o)

ARTICLE 7.
WORK COMMITMENT

Section

700. Work commitment
705. Work commitment modification

11 AAC 83.700. WORK COMMITMENT. (a) If a work commitment is a condition of a lease, the terms of the work commitment will be specified in the notice of sale. The work commitment will state the minimum requirement for exploration and development on each lease. The lessee shall file reports with the commissioner substantiating adherence to the work commitment terms.

(b) The commissioner will, in his or her discretion, alter or abrogate the terms of the work commitment if the lessee demonstrates to the satisfaction of the commissioner that the lease will be unproductive or uneconomic under the terms of the work commitment.

(c) The commissioner will abrogate a work commitment if the lessee relinquishes the lease.

(d) The commissioner will, in his or her discretion, grant a single waiver of any term of a work commitment imposed on a lease under (a) of this section for a period not to exceed two years if the commissioner makes a written finding that conditions preventing fulfillment of the work commitment were beyond the lessee's reasonable ability to foresee or control. The commissioner will consider the following factors when determining whether the conditions preventing fulfillment of the work commitment were beyond the lessee's reasonable ability to foresee or control:

(1) the lessee's statement of the conditions that prevented fulfillment of the work commitment;

(2) the lessee's explanation of how those conditions prevented fulfillment of the work commitment;

(3) the lessee's explanation of how and why the lessee did not foresee or failed to avoid the conditions that prevented fulfillment of the work commitment;

(4) the lessee's explanation of why the conditions that prevented fulfillment of the work commitment were beyond the lessee's reasonable control;

(5) the lessee's plans to remedy the conditions that prevented fulfillment of the work commitment during the initial term of the work commitment;

(6) the lessee's plans to fulfill the terms of the work commitment during the term of the waiver; and

(7) other relevant information.

(e) The commissioner will, in his or her discretion, grant a single waiver of any term of a work commitment imposed on a lease under (a) of this section for a period not to exceed two years if the commissioner makes a written finding that the lessee has demonstrated, through good faith efforts, the intent and ability to fulfill the terms of the work commitment during the term of the waiver. The commissioner will consider the following factors when determining whether a lessee has demonstrated the intent and ability to fulfill the terms of a work commitment during the term of any waiver that may be granted:

(1) whether the lessee has undertaken appropriate actions to fulfill the work commitment, including but not limited to having acquired permits, materials, and financing necessary to fulfill the work commitment;

(2) reasons why fulfillment of the work commitment during the term of any waiver that may be granted is more likely than it was during the initial term of the work commitment;

(3) the lessee's specific plans and actions to be taken to fulfill the work commitment during the term of the waiver; and

(4) other relevant information.

(f) The length of time for a waiver granted under (e) of this section will be based on the time determined by the commissioner to be needed for the lessee to take the specific actions planned by the lessee to fulfill the work commitment during the term of the waiver.

(g) If a lessee fails to meet any term of a work commitment by its due date, the lease will automatically terminate. In addition, any penalty provisions established by the commissioner in the work commitment stipulation or as a condition to any extension, alteration, or waiver will take effect immediately if the work commitment is not completed by its due date. For purposes of this subsection, the due date for a work commitment is its original due date under the work commitment stipulation to the lease, plus any additional time granted by extension, alteration, or waiver of the work commitment.

(h) As a condition of waiver of any term of a minimum work commitment under (e) of this section, the commissioner will, in his or her discretion, require the lessee to post a performance bond or other security acceptable to the commissioner. The amount of the performance bond or other security, if required, will be set by the commissioner in an amount not to exceed $100,000 for each lease. The bond or other security will be released to the lessee upon fulfillment of the work commitment. If, before the end of the waiver period granted under (e) of this section, the commissioner agrees to alter or abrogate the terms of the work commitment under (b) or (c) of this section, part of the bond or other acceptable security will forfeit automatically to the state in proportion to the portion of the waiver period that has elapsed, unless forfeiture is waived by the commissioner. If the work commitment is not fulfilled by the end of the waiver period, the performance bond or other security will forfeit automatically to the state. The commissioner will, in his or her discretion, establish additional terms or penalties as a condition of waiver of a work commitment. (Eff. 11/9/79, Reg. 72; am 9/25/85, Reg. 95)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.705. WORK COMMITMENT MODIFICATION. Application for modification of a work commitment under AS 38.05.180(h) must comply with 11 AAC 88.105 and must

(1) state all the facts that may entitle the applicant to a modification of the work commitment;

(2) state the location and status of all past and present activities on the lease;

(3) contain a detailed report of all activity on the lease preceding the filing of the application and must include an accounting for all expenses and costs of operating the lease;

(4) be filed not later than 30 days before the existing deadline for the fulfillment of the term of the work commitment the lessee wishes to be modified;

(5) address all pertinent factors listed in 11 AAC 83.700(b), (c), (d) and (e), as appropriate; and

(6) in connection with an application for a waiver under 11 AAC 83.700(e), affirm the lessee's readiness and ability to post a performance bond or to provide other security acceptable to the commissioner to assure fulfillment of the work commitment. (Eff. 11/9/79, Reg. 72; am 9/25/85, Reg. 95)

Authority: AS 38.05.020
AS 38.05.180

ARTICLE 8.
EXPLORATION INCENTIVE CREDIT

Section

800. Exploration incentive credits
805. Credit for exploratory wells
810. Credit for geophysical work
815. Filing of statements
820. Definitions

11 AAC 83.800. EXPLORATION INCENTIVE CREDITS. (a) If the commissioner receives a request for exploration incentive credit, the commissioner will, in his discretion, allow credits for expenditures for both exploratory wells and geophysical work against

(1) oil and gas royalty payable in-value and rental payments payable to the state; or

(2) taxes payable under AS 43.55.

(b) The period during which exploration incentive credits may be earned and used and the percent of the exploration expenditures that will be allowed for credits in a particular region will be established by the commissioner and will be announced no sooner than two years before the sale but in no event later than the date of the notice of sale. The period during which exploration incentive credits may be earned and used may be extended at the discretion of the commissioner. Exploration incentive credits may be assigned. A notice of assignment must be filed with the commissioner on forms prescribed by the department. (Eff. 11/9/79, Reg. 72; am 8/15/82, Reg. 83)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.805. CREDIT FOR EXPLORATORY WELLS. Credits may be earned only for one well per sale tract as that tract is defined on the day of a competitive oil and gas lease sale. Actual footage drilled in exploratory wells may earn exploration incentive credits at a rate established by the commissioner. In place of credit for actual footage drilled, expenditures for other operations related to the well will be considered for credit in the following manner:

(1) The cost of constructing and preparing the drilling location will be credited on a case-by-case basis at the discretion of the commissioner, who will determine the specific costs applicable to the exploratory well.

(2) Credits for other costs incurred by the lessee when drilling the exploratory well will also be considered on a case-by-case basis.

(3) At the request of the commissioner, the lessee shall submit all cost information necessary to determine the accuracy of the requested credits. If more than one company participates in drilling the exploratory well, then credit will be allowed in proportion to the participation in the drilling cost of the well. (Eff. 11/9/79, Reg. 72; am 3/30/84, Reg. 89)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.810. CREDIT FOR GEOPHYSICAL WORK. (a) Geophysical exploration costs may be credited at a rate approved by the commissioner in the following manner:

(1) If the applicant desires credits for geophysical work, copies of the geophysical data

obtained during the credit time period must be submitted to the commissioner within 90 days after completion of collection and processing of data.

(2) The commissioner will inspect the information submitted to ensure that the geophysical work was conducted according to accepted standards of geophysical practice before granting credits.

(3) The applicant is responsible for submitting correct information, for advising the state of any erroneous data previously submitted, and for correcting all errors in the geophysical information.

(b) Credits may be considered for geophysical work performed during the two seasons before the scheduled sale date.

(c) Geophysical information which accompanies an application under 11 AAC 83.815 for geophysical exploration incentive credits, including information submitted under (a)(1) – (3) of this section, will be made public 30 days after the lease sale date. (Eff. 11/9/79, Reg. 72; am 3/18/83, Reg. 85)

Authority: AS 38.05.022
AS 38.05.180

11 AAC 83.815. FILING OF STATEMENTS. (a) Applications for determinations of total exploration incentive credits must be signed and notarized by the lessee or its authorized representative and contain a statement attesting to the truth and accuracy of the information submitted. Applications must be submitted in triplicate to the commissioner and must include an accounting of expenditures and the date the expenditure was made.

(b) Applications for geophysical work credits must be signed and notarized by the person performing the work or his authorized representative and contain a statement attesting to the truth and accuracy of the information submitted. Applications must be submitted in triplicate to the commissioner and contain copies of the required geophysical information.

(c) The commissioner will, in his discretion, request additional information if an application contains insufficient information to determine the accuracy of the request for credit.

(d) Once exploration incentive credit is granted by the commissioner, the commissioner will certify to the grantee the amount of the credit, the work for which the credit was given, the period during which it may be (or has been) earned, and the period during which it may be applied.

(e) Approved credits, when used, must be reported on the monthly royalty or tax payment statement or on the yearly rental payment statement against which they are being applied. (Eff. 11/9/79, Reg. 72)

Authority: AS 38.05.030
AS 38.05.180

11 AAC 83.820. DEFINITIONS. Unless the context clearly requires a different meaning, as used in 11 AAC 83.800 – 11 AAC 83.820

(1) "commissioner" means the commissioner of the Department of Natural Resources, State of Alaska;

(2) "exploratory well" means a well drilled for the purpose of oil and gas exploration that

(A) is located three miles or more from any other well drilled for oil and gas with all distances measured as the horizontal distance between exploration targets, or

(B) is within three miles from a well drilled for oil and gas, but tests potential hydrocarbon traps that the commissioner, after analyzing evidence submitted by the lessee and other information, determines constitute a distinctly separate exploration target;

(3) "geophysical exploration season" means one year;

(4) "geophysical information" means the raw field data and all information necessary to compute, process, and prepare the field data for geological interpretation; for seismic work, this data includes the standard processed sections that are stacked after filtering and correction for statics and normal moveout;

(5) "geophysical work" means all geophysical methods used in hydrocarbon exploration and for the determination of geologic hazards, including but not limited to seismic, gravity, magnetic and electromagnetic measurements;

(6) "tax" means payments due under AS 43.55 or its successor tax.

(7) "actual footage drilled" means the well's measured depth, and may include sidetracking or redrilling necessary to reach the originally proposed bottom-hole location. (Eff. 11/9/79, Reg. 72; am 3/30/84, Reg. 89)

Authority: AS 38.05.020
AS 38.05.180

ARTICLE 9.
EXEMPT LEASE SALES

Section
900. Previously offered land
901. Exempt lease sales
910. Land contiguous to leased land

11 AAC 83.900. PREVIOUSLY OFFERED LAND. The commissioner will adopt a leasing method under AS 38.05.180(f) for exempt lease sales of land previously offered for oil and gas lease. (Eff. 7/22/79, Reg. 71; am 6/28/81, Reg. 78)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180(w)

11 AAC 83.901. EXEMPT LEASE SALES. An "exempt lease sale" or "exempt sale" is a lease sale excepted from the five-year oil and gas lease program requirement by AS 38.05.180(d) (1) – (4) or AS 38.05.180(w). (Eff. 6/28/81, Reg. 78)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.910. LAND CONTIGUOUS TO LEASED LAND. As used in AS 38.05.180(d)(2), and notwithstanding 11 AAC 88.185(1), "contiguous" means sharing a common boundary or a common corner. (Eff. 3/26/81, Reg. 77)

Authority: AS 38.05.020(b)(1)

CHAPTER 84.
OTHER LEASABLE MINERALS

Article
1. **Coal (Repealed)**
2. **Phosphates (11 AAC 84.200)**
3. **Oil Shale (11 AAC 84.300)**
4. **Sodium (11 AAC 84.400)**
5. **Sulphur (11 AAC 84.500)**
6. **Potassium (11 AAC 84.600)**
7. **Geothermal Leasing (11 AAC 84.700–11 AAC 84.790)**
8. **Geothermal Unitization (11 AAC 84.810–11 AAC 84.950)**

Editor's Note: The mineral-leasing regulations in 11 AAC 82, 11 AAC 83, 11 AAC 84, 11 AAC 86 and 11 AAC 88, effective September 5, 1974, and distributed in Alaska Administrative Register 51, constitute a comprehensive reorganization and revision of this material, and thus the history line at the end of each section does not reflect the history of the provision before September 5, 1974, and the section numbering may or may not be related to the numbering before that date.

ARTICLE 1.
COAL

Repealed 6/18/82.

Editor's Note: The former Article 1 relating to coal leasing was replaced by 11 AAC 85, effective 6/18/82 and distributed in Register 82.

ARTICLE 2.
PHOSPHATES

Section
200. Phosphate leasing method

11 AAC 84.200. PHOSPHATE LEASING METHOD. Phosphate leases authorized by AS 38.05.155 are subject to disposition under 11 AAC 82. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020
AS 38.05.145(a)

ARTICLE 3.
OIL SHALE

Section
300. Oil shale leasing method

11 AAC 84.300. OIL SHALE LEASING METHOD. Oil shale leases authorized by AS 38.05.160 are subject to disposition under 11 AAC 82. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020
AS 38.05.145(a)

divided into two categories, those within the city boundaries of Fairbanks and North Pole, and those outside those boundaries. A certain number of signatures of each category of citizen is needed on the petitions, and then, a majority of votes in each category is needed when the unification issue is finally put on the bal-

candidates. In fact, several league members later said that their participation in the gathering of signatures is not assured at this point and will be decided in a membership meeting March 5.

Whoever attempts to gather the needed signatures will certainly face an uphill battle in convincing rural residents that

studying unification?" To which a fair reply would be: If someone is determined to drown you in deep water, would you like to go for a little swim with him?

If this is on the fall ballot, we will also be asked to elect members of the charter commission. Rest assured that these folks will be advocates of one larger unified

clerk's office, voters who have previously signed the petition, but who now would like their name removed from it, may give a signed statement to that effect to that office. Possibly, as the true ramifications of a unification move sink in, the petitions will shrink in length rather than expand, and we can continue under our three smaller, more responsive local governments.

All Alaska Weekly Feb 26, 1988

Governor promises economic cures and big deals

by Cliff Burglin

Governor Cowper is turning into a carrot dangler. A carrot dangler could be defined as someone who is going to cure all of the state's economic ills with a big deal that is right around the corner. Like the proverbial rabbit, for the people of Alaska, the carrot is always two strides out of reach.

Among the governor's carrots are making the state a financial power in the Western Hemisphere. Another is a gas line from the North Slope that will soak up all of Alaska's unemployed at high wages. Still another is having foreign nations come in and invest a lot of money in the development of Alaska's timber, mining, agricultural, etc. resources. Notwithstanding the fact that every one of these resources can be developed more profitably and with more encouragement in other states and other nations.

It is relatively easy for the governor to meet and associate with the top people in other nations and other states. It is quite another thing for these people to invest hard dollars in Alaska's resources where state government with its regulations and restrictions prohibits any development from being profitable.

The governor and legislature could at least insure that our most profitable and viable industry is encouraged. The best way to do this is to amend and extend all of the oil and gas leases that were issued when oil was in excess of $30 a barrel.

The leases that were issued for shorter periods than 10 years should have their terms extended for the additional years up to 10 years. The terms of all leases should be the same: 12-1/2 percent royalty plus severance tax. This would bring state leases in line and competitive with adjacent federal and Native lands within the state.

For instance at 12-1/2 percent royalty plus severance tax, Conoco's Milne Point and Gwyder Bay fields would be economic and competitive. With the severance tax the state's take equals about 25 percent. Not too bad for putting forth very little positive effort.

It would also mean that the Texas Eastern, Amerada Hess, etc. tracts adjacent to Seal Island would be bringing in a great deal of money to the state when that field is put on line. As of now these leases carry between 85 and 93 percent net profits.

If the terms of these leases are not amended to be competitive, they will be drained by the adjacent federal tracts and rather than the state earning 25 percent of a couple hundred million barrels of oil plus any gas, it will earn 85 to 93 percent of nothing.

Out of the hundreds of state leases, fewer than 50 would have to be amended. If these leases are not amended, this acreage will probably never be developed.

Another advantage to amending the terms and the other provisions would be that it would not take an army of state accountants, lawyers and assorted bureaucrats to litigate the definition of net profits.

It would also be a good idea if the state adhered to the same leasing procedures and conditions for every sale.

If these suggestions are followed it might not be too late for the State of Alaska to continue to be a world class oil producer. Make no mistake, oil will be produced in Alaska, but certainly not on state lands with the current eccentric and inconsistent state policies.

Despite the fact that the majors have announced that they plan to spend $25 billion in Alaska, it is certainly not all going to be spent developing oil and gas reserves on state acreage. This is yet another reason for the state to get its policies, regulations and terms in line with their two major competitors within the state — the Native corporations and the federal government.

If the state does not change its practices, less than one half of this money will be spent on state lands which means eventually, less than one half of the oil flowing through the pipeline will be state oil.

Catastrophic illness insurance for all Alaskans

by Rep. Niilo Koponen
House District 21

The United States is the only major

The current proposals include SSHB 410 which provides for affordable catastrophic illness insurance automatically extended to all state residents. There is a

to go through the hearing process and be made both affordable and reasonable for the people of the state. Alternatives include lowering the benefit cost by raising

Like anything else, the bill would require continuing effort to lower costs and extend benefits as Alaska changes. One

PARTICIPATING AREAS

Study shows as much as 25% error

by Ruth A. Maurer and Bruce C. Kirchhoff

Millions of dollars are invested in scientific exploration and development in federal oil and gas units. Yet participating area determinations are often made by simple observation.

And those determinations can be wrong.

Those are among the conclusions of a sample study of 30 successful exploratory wells in Colorado and Wyoming conducted at the Colorado School of Mines. Using a precise, computer-generated determination of the participating areas, the study showed 16 of the 30 improperly included or excluded acreage.

Even state-of-the-art technology cannot pinpoint the optimal well location within a reservoir.

Geophysical and geological information can only suggest, within a section or quarter-section of the public land survey, the well location having the greatest potential.

Geological data is of limited use or accuracy in determining, upon completion of a well, which lands are reasonably proved productive of unitized substances in paying quantities, such that certain lands should or should not be included in a participating area. Therefore, a technologically sound proxy must be developed to determine the boundaries from within which oil and gas are actually produced.

Several methods of allocation are used in the region, the study revealed. New Mexico uses a drilling block system, defined by a state well-spacing statute. Montana attempts, optimistically, to use only geological information in its determination of participating areas. Utah has reportedly processed relatively few operating federal units, but uses the circle-tangent method.

Colorado and Wyoming are the only Rocky Mountain states surveyed that extensively use the circle-tangent method. This method reasonably assumes that the fluid flow from the reservoir into the wellbore is in the radial direction.

The radius of this drainage boundary is determined primarily by geologic and engineering information. Consideration is also given to the depth of the productive zone and whether oil or gas is the primary substance produced. Only after a well is determined to be productive in paying quantities is the circle-tangent method applied.

According to the circle-tangent method, 40- or 10-acre tracts entirely within the drainage boundary are included in the participating area. Tracts

Summary of working interest changes

Calculated from precise participating area determinations

Well No.	Errors	Working Interest As Approved	Working Interest Actual	Change	Comment
1	No	14/14	14/14		Operator holds no tracts
2	No	15/15	15/15		
3	No	10/17	10/17		
4	Yes	1/13	1/16	0.014423	Operator's benefit
5	Yes	8/8	6/8	0.250000	Operator's benefit
6	Yes	16/16	15/15		Operator's benefit subsequent well
7	Yes	8/14	8/15	0.038095	Operator's benefit
8	No	8/8	8/8		
9	Yes	8/8	8/8		Operator's benefit if drilled to southwest
10	No	13/15	13/15		
11	No	11/15	11/15		
12	No	8/17	8/17		
13	No	10	0		
14	No	9/14	9/14		
15	Yes	15/16	14/15	0.004167	Operator's benefit
16	Yes	4/8	4/7	0.071429	Not operator's benefit
17	Yes	14/14	15/15		No consequence
18	No	11/15	11/15		
19	No	17/17	17/17		
20	Yes	15/17	14/16	0.007353	Operator's benefit
21	Yes	8/8	7/7		No consequence
22	No	16/16	16/16		
23	Yes	10/16	1/17	0.053824	Not operator's benefit
24	No	16/16	16/16		
25	Yes	14/15	13/14	0.052381	Not operator's benefit
26	Yes	15/15	16/16		Operator's benefit when P.A. enlarged
27	No	16/16	16/16		
28	Yes	8/8	8/8		No consequence
29	Yes	16/16	15/15		Operator's benefit, subsequent well
30	Yes	13/14	13/15	0.014286	Operator's benefit

Source: Ruth A. Maurer & Bruce C. Kirchhoff

Off target

This chart shows both the working interest for each participating area as approved by working interest owners and accepted by the BLM, and as precisely determined by the software used in the study. Errors ranged up to 25%.

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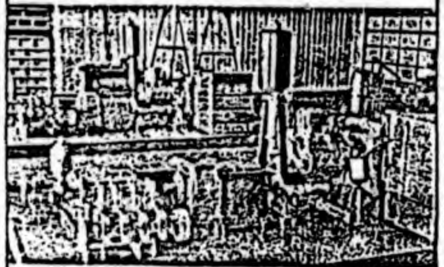

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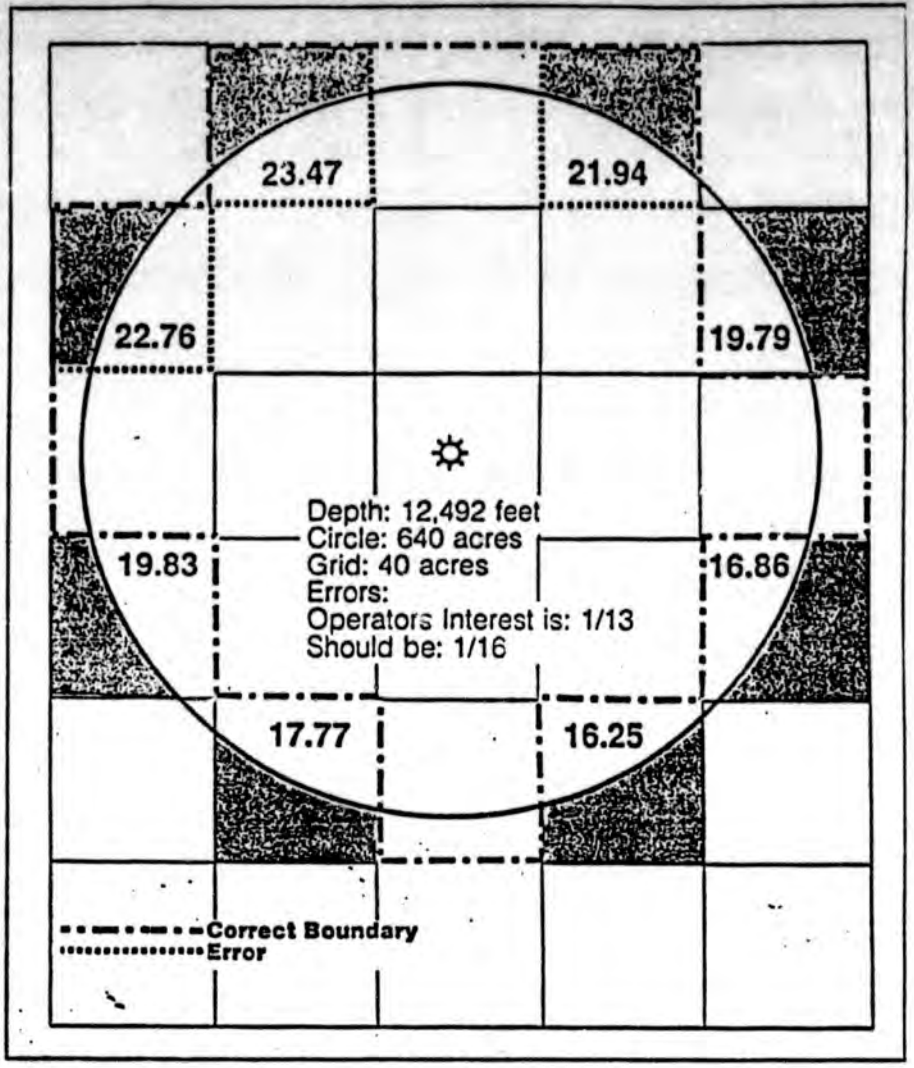

Human error

One of the incorrectly determined participating areas. Computer-generated determinations showed that 16 out of 30 areas improperly included or excluded acreage. Most often operators benefited from the errors.

cut half or more by the boundary are also included.

When subsequent wells are drilled and determined to be productive from a common pool, the participating area is often enlarged. The revised participating area now includes all lands within each separate participating area by virtue of the common acreage drained.

An individual working interest within the participating area is determined by the proportion of acreage contributed by that working interest owner to the total acreage in the participating area.

Critical to this study is the rule that all acreage proved reasonably productive by this method shall be included in the participating area and will share in its expense and revenue.

Tools implementing the circle-tangent method today are basic. Wells are located on a scaled map by ruler and pencil. Circles are drawn by compass. The "eyeball technique" determines whether, in a questionable situation, a given tract is cut half or more by the drainage boundary.

A second technique attempts to be more accurate. A scaled grid system is employed to determine whether a given tract is cut half or more by the drainage boundary. For example, the number of grids in a questionable tract contained within the drainage boundary are counted and converted to an acreage figure. Such a tedious technique must assume the accuracy of the graph paper, the ruler and the compass.

Clearly, a problem exists where millions of dollars are invested in scientific exploration and development, but the participative determinations are made by simple observation. In order to determine the problem's magnitude, a study was conducted at Colorado School of Mines.

A sample of 30 successful exploratory wells was studied to determine whether the corresponding participating areas were correctly determined. Data was obtained from several Bureau of Land Management (BLM) offices in Colorado and Wyoming. The information requested included the unitized substance produced, productive zone depths, well location coordinates and land maps showing participating area boundaries.

Using a newly available software package by Precision Units Inc., the participating area for each well was precisely determined, based on the circle-tangent method and the following assumptions:

• Unless otherwise noted on state well completion forms, surface well location coordinates indicate the bottomhole location, the true predicate for participating area determination.

• All information received concerned participating areas determined by the circle-tangent method, rather than by an exception to the method.

Of the 30 participating areas, 16 were in error. Of the 16 errors made by operators and approved by other working interest owners, 10 accrued, or likely would accrue to the operator's benefit. Of the remaining six errors, three were neutral and three decreased the operator's working interest.

In the study, differences between correct operator's working interests and working interests as approved ranged from 0.4167% to 25%.

Three of the errors deserve special mention. In one application, interest owners approved a participating area based on a well location established in the wrong 40-acre tract.

In another application, the operator submitted a completed well drilled in SW NW 17 and incorrectly determined the participating area to include all of the section. The operator omitted the acreage reasonably proved productive in Section 18. Incredibly, no acreage in Section 17 was leased by the operator, who held all of Section 18 under lease. The participating area was modified to include some of the operator's acreage in Section 18, but one 40-acre tract too many was included.

In a third case, an operator submitted a participating area which could only have been determined from a state regulatory commission spacing order. But no such order was issued for the acreage in question. The adjoining interest owners approved an 8/8 working interest in favor of a single party. That party's correct interest was 6/8. In this case, a single working interest owner lost the 1/4 interest in the well. □

About the authors

Ruth A. Maurer, Ph.D., is associate professor of mineral economics at the Colorado School of Mines, Golden, Colo. She has served as a consultant for several firms.

Bruce C. Kirchhoff will graduate this month from the Colorado School of Mines with a master of science degree in mineral economics. He completed his law degree at the University of Denver and is employed by a Denver law firm. He is also founder and president of Precision Units Inc., Denver, consultants in unitization.

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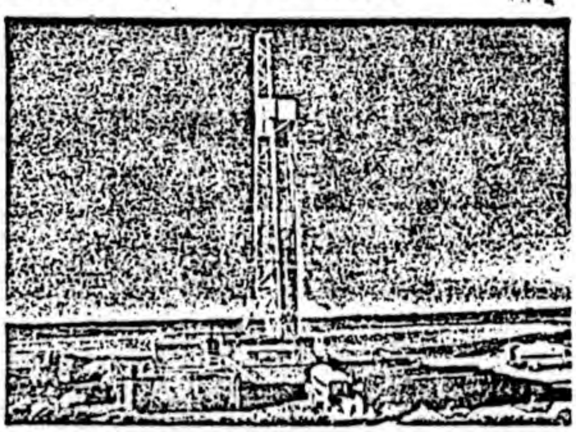

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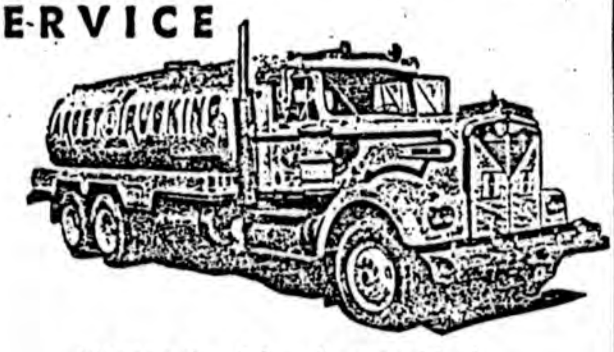

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1. What is the purpose of establishing a P.A. (participating area) (-11AAC 83.351)?

2. How does determination of a P.A. effect state revenues?

3. Why is it necessary to compromise P.A. s?

4. Who determines whether or not a P.A. compromise (revenue compromise) is in the State of Alaska or any other parties' best interest?

5. What state agency has statutory or regulatory authority to "compromise" geological, geophysical and engineering data used to establish an initial P.A.?

6. How many gas fields have been clearly delineated (defined) in the State of Alaska?

7. Is the drilling of delineation wells the most accurate method of determining the productive limits of a gas field?

8. Is there any consistent procedure or common industry knowledge (i.e. basic engineering principles used by the DO&G (Division of Oil & Gas) to "compromise" data used to determine P.A. s?

9. In general would a single gas pool with one producing well estimated to contain 50 BCF of gas reserves have a larger or smaller initial P.A. than one producing well in a single gas pool estimated to contain 400 BCF of gas reserves?

10. Does the DO&G feel it should have to comply with statutes and regulations adopted by the AOGCC?

11. Does the AOGCC feel it should have to comply and abide by the statutes and regulations adopted by the DO&G?

12. According to state regulation 20 AAC 25.055 Drilling Units and Well Spacing, what is the minimum area (acres) drained by a productive gas well as determined by the AOGGC (ALASKA OIL AND GAS CONSERVATION COMMISSION)?

13. When a gas well has been certified by the DO&G as capable of producing in paying quantities (11 AAC 83.105) is it reasonably known that at least 640 acres around the well bore is contributing to the gas being produced from a producing gas well?

C. Burglin
Land Consultant
P.O. Box 131
Fairbanks, Alaska 99707
(907) 452-5149

April 7, 1987

Katherine Fortney
State Division of Oil and Gas
Pouch 7-034
Anchorage, Alaska 99510-0734

Dear Kate:

Burglin et al (Burglin) is requesting a written policy from the Division of Oil and Gas regarding PA (participating area) review. It is clear under II AAC 83.351 (c) "A participating area must be expanded to include acreage reasonably estimated through use of geological, geophysical, and engineering data to be capable of producing or contributing to the production of hydrocarbons in paying quantities, and must be contracted to exclude acreage reasonably proven through use of geological, geophysical or engineering data to be incapable of producing hydrocarbons in paying quantities, subject to approval by the commissioner. A revised division of interest or formula allocating production and costs must be submitted for approval under II AAC 83.371 at the time of expansion or contraction of a participating area."

The Division of Oil and Gas staff has emphasized initial P.A.'s in their recent decisions concerning P.A.'s. Burglin is requesting the division address Burglin's following conerns:

(1) How often are P.A.'s reviewed by division staff?
(2) When does an initial P.A. become a final P.A?
(3) How are initial P.A.'s clearly delineated?
(4) Does the division staff take any initiative to expand or contract P.A.'s based on additional information?
(5) Does the unit operator have any obligation to expand or contract a P.A. when additional information dictates a P.A. expansion or contraction?

If you have any questions concerning Burglin's request you may contact Brian at 452-5149.

Sincerely,

Brian

Brian Burglin

PB/mbg
cc: James Eason
Bill Van Dyke
Comm. Judy Brady
Senator Bettye Fahrenkamp
Senator Jack Coghill
Senator Don Bennett

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

STEVE COWPER, GOVERNOR

P.O. BOX 7034
ANCHORAGE, ALASKA 99510-7034

April 17, 1987

(907) 762-4241

Mr. Brian Burglin
P. O. Box 131
Fairbanks, AK 99707

Dear Mr. Burglin:

I have reviewed your April 7, 1987 request to Ms. Catherine Fortney for a written policy regarding the Division of Oil and Gas's review and determination of participating areas (PAs) for oil and gas units.

In brief, the division agrees with you that the determination of participating areas is governed by 11 AAC 83.351, and that the configuration of participating areas, both initial and subsequent, must be determined on the basis of all geological and engineering data available at the time the PA is established or expanded/contracted. It is almost inevitable that some technical information pertaining to the establishment of participating areas will be proprietary, and not available to all parties within or adjacent to the unit; however, the division must, by the terms of 11 AAC 83.351, take all available information into account when approving a participating area.

The answers to your specific questions are as follows:

(1) Reviews of participating areas are generally triggered by internal unit action such as planned expansions or contractions of the unit area, or a request by one or more of the unit working interest owners for expansion or contraction of the participating area. However, the division may initiate a review and revision to an approved participating area on its own volition or at the request of others when new data are presented indicating that such a revision is necessary to protect the state's interest or the correlative rights of others.

(2) Generally there is no such thing as a "final" participating area until unit reserves are depleted. Participating areas are continually subject to review and expansion or contraction based on new technical data. For most oil and gas units, contraction of the unit area to exclude all lands outside of an approved participating area is tied to the date of establishment of the "initial" participating area (the first participating area within the unit). There may be no practical difference between "initial" participating areas and subsequent participating areas if sufficient data are available at the time the initial participating area is approved to confirm the distribution of reserves within the unit area.

(3) Initial participating areas are delineated on the basis of all geological, geophysical, and engineering data available to the division at the time the participating area is established. Data may be available from more than one source, and the separate parties, which may not have access to all information regarding the participating area limits, may not agree with one another's interpretations. In the case of conflicting technical data, the division reviews all information available, and makes an independent determination of an appropriate participating area based on the terms of 11 AAC 83.351.

(4) Under certain circumstances, the division has initiated action for expansion or contraction of a participating area, particularly in those instances where data indicate that an existing participating area does not adequately and equitably represent the interests of all parties involved. However, normal practice is for one or more of the working interest owners of a unit to initiate action for expansion or contraction of a participating area. A lessee adjacent to the unit may also initiate expansion or contraction if that lessee possesses technical information showing that such action is warranted.

(5) In general, under the terms of 11 AAC 83.351, the unit operator, representing the working interest owners of a unit, is obligated to expand or contract when additional information indicates that such an expansion or contraction is appropriate. This obligation is also usually reflected in the provisions of the various unit agreements.

I hope this is responsive to your questions regarding the division's policy on the establishment and expansion/contraction of participating areas. If you have any additional questions on the above, please feel free to contact me.

Sincerely,

James E. Eason

James E. Eason
Director

cc: Judith M. Brady, Commissioner
Catherine Fortney, DNR/DO&G
Bill Van Dyke, DNR/DO&G
Cass Ariey, DNR/DO&G
Senator Bettye Fahrenkamp
Senator Jack Coghill
Senator Don Bennett

C Burglin
Land Consultant
P.O. Box 131
Fairbanks, Alaska 99707
(907) 452-5149

April 28, 1987

James Eason
Division of Oil and Gas
P. O. Box 7034
Anchorage, Alaska 99510-7034

Dear Jim:

As Burglin et al. (Burglin) understands your 4/17/87 letter. the division generally does not review participating areas unless requested to do so by an interested party.

Burglin's concern with this policy is that in undefined gas fields there can be many years and substantial drilling activity which change initial geological interpretation before a participating area is reviewed by the division.

For example, the last participating area review and revison for the Beluga River Unit was made in 1977. From 1968 thru 1977 six (6) gas wells were drilled within the Beluga River Unit, during which time there were five participating area revisions of the Beluga River Field. From 1978 to 1987 twelve (12) gas wells have been drilled with no participating area review by the Division of Oil and Gas. Mr. Bill Van Dyke confirmed that the Beluga River Unit participating areas had not been reviewed by the division staff in over 2 1/2 years, and was unaware of any Beluga River Unit participating area review since 1978. From 1985 thru 1986 eight (8) additional wells have been drilled in the Beluga River Unit. There is no economic incentive for a unit operator to initiate a participating area expansion or contraction when additional well data confirms, modifies, or rejects initial structural interpretation and estimated productive limits, once the original Working Interest Owners have lost their interest in the surrounding acreage, through unit contraction. Well data is usually confidential to adjacent lease holders or interested parties for at least two years after wells have been drilled.

Burglin feels the State's interest would be better protected if participating areas were reviewed on an annual basis and

C. Burglin
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this review incorporated into unit plans of a development and operation, especially in undefined gas pools.

Sincerely,

Brian Burglin

Brian Burglin

BB/kd

cc: Commissioner Brady
Bill Van Dyke
Senator Fahrenkamp
Senator Coghill
Senator Bennett
Commissioner C. Chatterton

CHAPTER 83.
OIL AND GAS LEASING

Article
1. General Oil and Gas Lease Provisions (11 AAC 83.100–11 AAC 83.190)
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Editor's Note: The mineral-leasing regulations in 11 AAC 82, 11 AAC 83, 11 AAC 84, 11 AAC 86 and 11 AAC 88, effective September 5, 1974, and distributed in Alaska Administrative Register 51, constitute a comprehensive reorganization and revision of this material, and thus the history line at the end of each section does not reflect the history of the provisions before September 5, 1974, and the section numbering may or may not be related to the numbering before that date.

ARTICLE 1.
GENERAL OIL AND GAS LEASE PROVISIONS

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11 AAC 83.100. LEASING METHOD. All land is competitive for oil and gas leasing purposes and may only be leased under competitive procedures provided in 11 AAC 82. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71)

Authority: AS 38.05.020 AS 38.05.145(a)
AS 38.05.135 AS 38.05.180

11 AAC 83.105. "PAYING QUANTITIES" DEFINED. "Production in paying quantities," as used in 11 AAC 83.100 – 11 AAC 83.295 and 11 AAC 83.400 – 11 AAC 83.910, means production in such quantity as to enable the operator to realize a profit. For purposes of the habendum clause of a lease, that is, for the purpose of keeping the lease in force after the expiration of the primary term, "paying quantities" means production in quantities sufficient to yield a return in excess of operating costs, even though drilling and equipment costs may never be repaid and the undertaking considered as a whole may ultimately result in a loss. (Eff. 9/5/74, Reg. 51; am 6/28/81, Reg. 78)

Authority: AS 38.05.020
AS 38.05.145(a)
AS 38.05.180

11 AAC 83.110. RENTAL. (a) All oil and gas leases are conditioned upon payment of the annual rental in advance on or before the beginning of each lease year before completion of a well capable of producing oil and gas in paying quantities on these leased lands.

(b) After a well has been plugged and abandoned and there is no other well on the lease capable of production, the commissioner will, in his discretion, allow the rental rate effective during the year of the abandonment to be the rate for the remainder of the term of the lease, or, if production is achieved from a subsequent well, until the royalty or net profit share to the state exceeds the rental for that year. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71)

Authority: AS 38.05.020
AS 38.05.145(a)
AS 38.05.180(n)

11 AAC 83.115. MINIMUM ROYALTY. Repealed 6/28/81.

11 AAC 83.120. EXTENSION FOR EXTENUATING CIRCUMSTANCES. Repealed 6/28/81.

11 AAC 83.125. EXTENSION BY DRILLING. (a) If drilling, including redrilling, sidetracking, or other means necessary to reach the originally proposed bottom hole location, has commenced on or before the expiration date of the primary term of the lease and is continued through that date with reasonable diligence, the lease will continue in full force until 90 days after the drilling has ceased and for so long after that date as oil or gas is produced in paying quantities.

(b) In (a) of this section, "drilling" means operations necessary or convenient to drilling a well in the ground with equipment of sufficient size and capacity to drill to the total depth proposed for the well. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71)

Authority: AS 38.05.020
AS 38.05.145(a)
AS 38.05.180

11 AAC 83.130. EXTENSION AFTER PRODUCTION. If production occurs in paying quantities during the primary term of any lease, and if at the end of the primary term or at any time prior to the end of the primary term that production has ceased, or if production ceases at any time after the expiration of the primary term, then the lease does not terminate if the lessee commences drilling or reworking operations (either in a well from which the production has ceased or in a new well) within 60 days after the cessation of production; and the lease remains in full force and effect so long as operations are prosecuted with reasonable diligence; and, if the drilling or reworking operations result in the production of oil or gas, the lease remains in full force and effect so long as oil or gas is produced from it in paying quantities. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020
AS 38.05.145(a)
AS 38.05.180(b)

11 AAC 83.135. SHUT-IN PRODUCTION. No lease covering land on which there is a well capable of producing oil or gas in paying quantities will expire because the lessee fails to produce oil or gas, unless the commissioner gives notice to the lessee or operator allowing a reasonable time, which will not be less than 60 days after receipt of notice, to place the well on a producing status and the lessee or operator fails to do so. After producing status is established, production must continue on the leased land until suspension of production is allowed by the commissioner. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71)

Authority: AS 38.05.020
AS 38.05.140(d)
AS 38.05.180

11 AAC 83.140. EXTENSION BY ELIMINATION FROM A UNIT. If any lease or a portion of one is eliminated from the unit plan or recovery program, or if the unit plan or recovery program is terminated, then the lease or portion of it so eliminated continues in full force and effect as may be provided in the unit or cooperative agreement, but for not less than 90 days from the date of the elimination or termination and so long thereafter as drilling or redrilling operations are being conducted on it and so long thereafter as oil or gas is produced in paying quantities. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020
AS 38.05.145(a)
AS 38.05.180(d)

11 AAC 83.145. DIRECTIONAL DRILLING CLAUSE. The commissioner will include a directional drilling clause in all oil and gas leases that have been issued or that may be subsequently issued by the state. The clause will provide that actual drilling from a well located off the leased premises, but to be completed or bottomed on leased premises, will be considered as actual drilling under the lease terms. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71)

Authority: AS 38.05.020
AS 38.05.145(a)
AS 38.05.180

11 AAC 83.150. RESERVATIONS. (a) Every oil and gas lease must reserve to Alaska the right to dispose of to others the surface of the leased land subject to the lease, and the right to authorize others by grant, lease, or permit, subject to the lease and under such conditions as will prevent unnecessary or unreasonable interference with the rights and operations under the lease, to enter upon and use the leased land

(1) to explore for oil or gas by geological or geophysical means including the drilling of shallow core holes or stratigraphic tests to a depth of not more than 1,000 feet;

(2) to explore for, develop and remove natural resources other than oil, gas, and associated substances on or from the leased land;

(3) for non-exclusive easements and rights-of-way for any lawful purpose, including shafts and tunnels necessary or appropriate for working of the leased land or other land for natural resources other than oil, gas, or associated substances;

(4) for well sites and well bores of wells drilled from or through the leased land to explore for or produce oil, gas, and associated substances in and from other land; and

(5) for any other purpose now or after September 4, 1974 authorized by law and not inconsistent with the rights under the lease.

(b) The subsurface storage of oil or gas is not authorized except as a necessary incident to recycling, pressure maintenance, repressuring, or other similar operations designed to increase the ultimate recovery of oil or gas or prevent the waste of oil or gas produced from the leased land or from any unit area of which the leased land is a part. Every lease must reserve to Alaska the right to authorize the subsurface storage of oil, gas or associated hydrocarbons in the leased land by the lessee or by others in order to avoid waste or to promote conservation of natural resources in accordance with 11 AAC 83.500 – 11 AAC 83.520, and upon conditions that will prevent unnecessary or unreasonable interference with the rights and operations under the lease, including conditions prohibiting the storage of oil or gas in any reservoir capable of producing oil and gas in paying quantities without the consent of the holder of any lease covering the reservoir. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71)

Authority: AS 38.05.020 AS 38.05.145(a)
AS 38.05.125 AS 38.05.180(u)

11 AAC 83.153. CONFIDENTIAL REPORTS. (a) If the commissioner finds that reports or information required under AS 31.05.035(a) contain significant information relating to the valuation of unleased land within a three-mile radius of the well from which these reports or information were obtained, the commissioner will, upon the written request of the owner of the well, keep the reports or information confidential for a reasonable time not to exceed 90 days after disposal of the unleased land, unless the owner of the well gives written permission to release the reports and information at an earlier date. The commissioner will, in his or her discretion, extend confidentiality to reports or information required under AS 31.05.035 from a well located more than three miles from any unleased land if the owner of the well from which these reports or information are derived makes a sufficient showing that the reports or information contain significant information relating to the valuation of unleased land beyond the three-mile radius.

(b) Reports or information for which extended confidentiality is requested or has been granted under AS 31.05.035 will not be eligible for extended confidentiality when

(1) the lease on which the well is drilled has expired; or

(2) the unleased land within a three-mile radius of the well from which the reports or information are obtained is offered in a competitive lease sale, but receives no bids greater than or equal to any minimum bid established for that sale.

(c) As used in this section, "mile" means a statute mile or 5,280 feet.

(d) As used in this section, "disposal" means the grant or issuance of an oil and gas lease. (Eff. 3/30/84, Reg. 89)

Authority: AS 31.05.035(c)
AS 38.05.020
AS 38.05.180

11 AAC 83.155. DAMAGES. Each lessee or permittee is required to pay any damage that becomes payable under AS 38.05.130 and shall indemnify Alaska and hold it harmless from and against any claims, demands, liabilities and expenses arising from or in connection with the damage. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020
AS 38.05.130
AS 38.05.145(a)

11 AAC 83.158. PLAN OF OPERATIONS. (a) Except as provided in (b) of this section, a plan of operations for all or part of the leased area must be approved by the commissioner before any operations may be undertaken on the leased area if

(1) the state owns all or part of the surface estate of the leased area;

(2) the lease reserves a net profit share to the state; or

(3) the state owns all or part of the mineral estate, but the entire surface estate is owned by a party other than the state, and a surface owner requests that a plan of operations be required by the commissioner for the portion of the leased area owned by that surface owner.

(b) A lease plan of operations is not required for

(1) activities that would not require a land use permit under this title; or

(2) operations undertaken under an approved unit plan of operations in accordance with this title.

(c) Before undertaking operations on the leased area, the lessee shall provide for full payment of all damages sustained by the owner of the surface estate as well as by the surface owner's lessees and permittees, by reason of entering the land. If the surface estate is owned by a party other than the state, the lessee shall also notify the surface owner of his opportunity to request that the commissioner require a plan of operations before allowing operations to be undertaken on the portion of the leased area owned by the requesting surface owner.

(d) An application for approval of a plan of operations must contain sufficient information, based on data reasonably available at the time the plan is submitted for approval, for the commissioner to determine the surface use requirements and impacts directly associated with the proposed operations. An application must include statements and maps or drawings setting out the following:

(1) the sequence and schedule of the operations to be conducted on the leased area, including the date operations are proposed to begin and their proposed duration;

(2) projected use requirements directly associated with the proposed operations, including but not limited to the location and design of well sites, material sites, water supplies, solid waste sites, buildings, roads, utilities, airstrips, and all other facilities and equipment necessary to conduct the proposed operations;

(3) plans for rehabilitation of the affected leased area after completion of operations or phases of those operations; and

(4) a description of operating procedures designed to prevent or minimize adverse effects on other natural resources and other uses of the leased area and adjacent areas, including fish and wildlife habitats, historic and archeological sites, and public use areas.

(e) In approving a lease plan of operations or an amendment of a plan, the commissioner will require amendments he determines necessary to protect the state's interest. The commissioner will not require any amendment that would be inconsistent with the terms of sale under which the lease was obtained, or with the terms of the lease itself, or which would deprive the lessee of reasonable use of the leasehold interest.

(f) The lessee may, with approval of the commissioner, amend an approved plan of operations.

(g) Upon completion of operations, the lessee shall inspect the area of operations and submit a report indicating the completion date of operations and stating any noncompliance of which the lessee knows, or should reasonably know, with requirements imposed as a condition of approval of the plan.

(h) In submitting a proposed plan of operations for approval, the lessee shall provide 10 copies of the plan if activities proposed are within the coastal zone, and five copies if activities proposed are not within the coastal zone. (Eff. 6/28/81, Reg. 78; am 8/15/82, Reg. 83; am 3/18/83, Reg. 85)

Authority: AS 38.05.020	AS 38.05.145
AS 38.05.130	AS 38.05.180

11 AAC 83.160. OIL AND GAS LEASE BOND. (a) Before operations commence on a state oil and gas lease, a bond in the amount of at least $10,000 must be furnished to the department.

(b) The commissioner will, in his discretion, after notice and an opportunity to be heard, require a bond in a reasonable amount greater than the amount specified in (a) of this section where a greater amount is justified by the nature of the surface, the uses and improvements on or in the vicinity of the leased land, and the degree of risk involved in the types of operations proposed or being conducted on the lease. A statewide bond furnished under (c) of this section will not satisfy any requirement of a bond imposed under this provision but will be considered by the commissioner in determining the need for and the amount of any additional bond under this subsection.

(c) Any person holding any interest in any lease may furnish a statewide bond in the amount of $500,000. A statewide bond satisfies all the bond requirements to which an oil or gas lease is subject under the Department of Natural Resources except that the commissioner will, in his discretion, require an additional unusual risk bond under (b) of this section or specific lease provisions.

(d) All oil and gas lease bonds must comply with 11 AAC 82.600. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71; am 6/29/80, Reg. 74)

Authority: AS 38.05.020(b)
AS 38.05.145(a)

11 AAC 83.165. CONDITIONAL LEASES. (a) If all or any part, as shown on the division leasing plats when the lease was issued, of the land covered by a lease is land that has been selected by Alaska under laws of the United States granting land to Alaska but the land has not been patented to Alaska by the United States, then the lease shall be a conditional lease as provided by law with respect to the land until a patent becomes effective. If for any reason a selection is disapproved or patent is denied as to all or any part of the land, no rentals, royalties or minimum royalties paid to Alaska under the lease will be refunded. Any bonus paid for a competitive lease will be refunded in full if the entire lease fails or if the lease fails in part and the lessee elects to surrender the remaining part. If the lessee elects to retain a remaining part, the bonus will be refunded in pro rata part on an acreage basis.

(b) To be considered a conditional lease under this section, the lease must contain at least a legal subdivision or 40 acres in the aggregate of land which has not been patented to Alaska by the United States. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020
AS 38.05.145(a)
AS 38.05.180(a)

11 AAC 83.170. FAILURE TO PAY RENTAL. (a) Any lease on which there is no well capable of producing oil or gas in paying quantities terminates by operation of law if any rental due is not timely paid on or before each anniversary date of the lease, except where the provisions of 11 AAC 83.620 are applicable.

(b) For purpose of this section, and notwithstanding 11 AAC 88.130(a)(2), rental is timely if it is received in the designated office by the anniversary date. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71; am 6/28/81, Reg. 78)

Authority: AS 38.05.020
AS 38.05.145
AS 38.05.180

11 AAC 83.175. REINSTATEMENT. (a) The commissioner will reinstate a lease automatically terminated under 11 AAC 83.170 if he finds that the failure to pay rental was justifiable and not due to lack of reasonable diligence by the lessee and the rental is paid within 15 days after receipt of notice of the termination, along with a statement and supporting evidence of the reasons for the failure. The burden of showing that he qualifies for reinstatement under this subsection is on the lessee and only those cases will be considered where the circumstances can be verified by independent evidence other than lessee's statements. The failure to pay rental will not be considered justifiable unless payment was prevented or delayed by unforeseen circumstances beyond the lessee's reasonable control. Situations such as ignorance of the lease, law, or regulations, inability to pay, error or oversight of the lessee's employees or agents, forgetfulness, and failure to receive a billing are not grounds for reinstatement. Situations caused by major sickness, accidents, death, acts of God, and errors of departmental employees, the U.S. Postal Service, or a commercial delivery service may be considered as grounds for reinstatement.

(b) If the rental payment due under a lease is timely paid but the amount of the payment is deficient, and the commissioner believes the payment was determined in accordance with the rental or acreage figure stated in the lease or in a bill, decision, notice, or letter by the department and the figure is found to be in error, or if the commissioner finds that the deficiency was otherwise justifiable and not due to a lack of reasonable diligence on the part of the lessee, the lease will be reinstated if the lessee corrects the deficiency within 15 days after receipt of notice of the deficiency. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg 71; am 6/28/81, Reg. 78)

Authority: AS 38.05.020
AS 38.05.145

11 AAC 83.180. DEFAULT. (a) Whenever the lessee of a lease on which there is no well capable of producing oil or gas in paying quantities fails to comply with any provision of the lease or applicable regulations other than the payment of rental and the failure to comply continues for 60 days after receipt of notice to the lessee of the failure to comply, the director may terminate the lease by mailing notice of the termination to the lessee. Termination is effective upon giving the notice.

(b) Whenever the lessee of a lease on which there is a well capable of producing oil or gas in paying quantities fails to comply with any of the provisions of the lease or applicable regulations and the failure continues for a period of 60 days following notice to the lessee of the failure to comply, the lease may be cancelled by judicial proceedings instituted for that purpose in any court of competent jurisdiction having jurisdiction over the land covered by the lease or any part of it. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020
AS 38.05.035
AS 38.05.145(a)

11 AAC 83.182. ROYALTY BIDDING. If the commissioner selects a method of bidding in which the royalty share reserved to the state is the bid variable, the commissioner will set a minimum fixed cash bonus in an amount to be announced no later than the date of the notice of sale. (Eff. 11/9/79, Reg. 72)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.183. SLIDING SCALE ROYALTY. If the commissioner selects a method of bidding which sets a royalty reserved to the state, either fixed or as the bid variable, based on a sliding scale, the sliding scale will be determined, according to a method chosen at the commissioner's discretion which will be based on volume of production or other factors. The method chosen by the commissioner will consider the prolongation of the economic life of the oil and gas reservoir or reservoirs underlying the sale area or lease to which the sliding scale is to be applied. (Eff. 11/9/79, Reg. 72)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.185. ROYALTY REDUCTION. (a) An application for a reduction of royalty on leases under AS 38.05.180(j) must comply with 11 AAC 88.105 and

(1) state all the facts entitling the applicant to relief;

(2) state location and status of all past and present activities on the lease;

(3) include a detailed report of all production during the six months preceding the filing of the application;

(4) contain a detailed statement covering the entire life of the lease showing all expenses and costs of operating the lease, including all royalties and overriding royalties and all income from all produced minerals from the lease; and

(5) include an agreement by the applicant to defray the cost of publishing a notice as provided by (b) of this section.

(b) Upon receipt of an application complying with (a) of this section, the commissioner will cause to be published a notice of public hearing as required on the application. The notice will

(1) state the time and place of hearing;

(2) describe the land involved; and

(3) state the name of the applicant and the nature of the relief applied for.

(c) The notice will be published at least once a week for at least two consecutive weeks in advance of the hearing date, which must be at least 15 days after the last date of publication, in at least one newspaper of general circulation in the vicinity of the principal office of the department, and must be posted at the principal office for the same period.

(d) At the time and place specified in the published notice, the commissioner will hear evidence offered by the applicant and any other interested party.

(e) Within a reasonable time following the hearing or any continuation of it, the commissioner will make written findings together with his determination as to the relief that should be granted.

(f) The commissioner will give notice of the findings and determination to the lessee and to any other person who has filed a written request for it. The action taken is effective on the date specified in the notice. (Eff. 9/5/74, Reg. 51; am 7/22/79, Reg. 71)

Authority: AS 38.05.020(b)
AS 38.05.145(a)
AS 38.05.180(j)

11 AAC 83.190. EXTENSION BY COMMITMENT TO AN APPROVED UNIT. If, on or before the expiration date of the primary term of a lease, the lease is committed to a unit agreement approved by the state, the lease will be extended for so long as it remains subject to the unit agreement. (Eff. 7/22/79, Reg. 71)

Authority: AS 38.05.020(b)

11 AAC 88.130. TIMELY FILING. (a) Payments are timely if an affected lease or permit is identified by an Alaska Division of Lands' serial number, and is either (1) delivered at any of the division offices designated by the director as "filing offices" during filing hours within the time allowed by any notice, decision, regulation or law, or (2) mailed on or before the due date provided by any notice, decision, regulation or law and the mailing date can be verified by postmark or other post office record or notation.

(b) If the serial number is not identified, as required in (a) of this section, the time of filing is the time of receipt of correct information unless the director determines that the lack of such information is immaterial or due to excusable inadvertance.

(c) All other documents are timely filed if received during filing hours within the time allowed by any notice, decision, regulation, or law at any office designated by the director and posted in the office as a filing office.

(d) When the last day of the time for filing or payment falls on a day the designated filing office is officially closed, the time for filing is extended to the next day the office is open to the public. (Eff. 9/5/74, Reg. 51; am 12/31/82, Reg. 84)

Authority: AS 38.05.020(b)(1)

11 AAC 88.135. MEANS OF FILING. Filings and payments may be made by mail or personal delivery, unless provided otherwise by the section dealing with the subject of the filing or payment. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020(b)(1)

11 AAC 88.140. NOTICES. (a) Any notice which the director gives to any person must be in writing and must be delivered in person or mailed by registered or certified mail, return receipt requested, to the person at his current address of record with the division.

(b) Any person may file his current mailing address with the division in writing and may change his address of record by written notice filed with the division at any time. "Current mailing address" is the most recent or permanent legal address of an applicant, permittee, lessee or claimant. It is the responsibility of any person doing business with the division to notify the division of his most recent or permanent legal address.

(c) A notice is considered to be given and received on the date delivered to the current address of record.

(d) Whenever any notice is required to be given to a lessee, permittee or claimant, copies of the notice shall also be given, in the manner provided by (a) of this section, to any assignee whose assignment has been filed for approval. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020(b)(1)

11 AAC 88.145. REFUNDS. (a) If an application on which rental has been submitted is rejected or withdrawn in whole or in part, the first year's rental will be refunded in whole or in pro rata part on an acreage basis.

(b) Notwithstanding any other provision of 11 AAC 82 – 11 AAC 88, no refund will be made for less than $2.00. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020(b)(1)

11 AAC 88.150. MAILING LIST. The division shall maintain a mailing list for the purpose of sending general notices, orders and other information which the director determines to be of public interest regarding mineral activities of the division to persons who file a written request to be put on a list. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020(b)(1)

11 AAC 88.151. NOTICE REQUIRED BY AS 38.05.945(c). (a) A village corporation will be given notice under AS 38.05.945(c)(3) if it owns or has selected land within six miles of the state land proposed for disposal.

(b) A community will be given notice under AS 38.05.945(c)(4) if land within its boundaries is no more than six miles from the state land proposed for disposal. A community is an incorporated or unincorporated place with 25 or more inhabitants, according to the most recent census of the U.S. Census Bureau. An incorporated community's boundaries will be those reported to the department by the Local Boundary Commission. An unincorporated community's boundaries will be those delineated, by the U.S. Census Bureau in the most recent census. (Eff. 6/28/81, Reg. 78; am 12/31/82, Reg. 84)

Authority: AS 38.05.020
AS 38.05.945

11 AAC 88.155. RECONSIDERATION. (a) An order, decision or other action of the director or the division which may be made or taken without the advance approval, consent or concurrence of the commissioner is subject to reconsideration by the director. After reconsideration by the director, any person aggrieved by the decision of the director may appeal the decision to the commissioner.

(b) An order, decision or other action of the commissioner, or of the director with the advance approval, consent, or concurrence of the commissioner, is subject to reconsideration only by the commissioner. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020(b)(1)

11 AAC 88.160. JUDICIAL APPEALS. A decision or other action of the division, the director or the commissioner becomes final for purposes of an appeal to the superior court 30 days after delivery as provided in 11 AAC 88.140 or as provided by applicable provisions of the Administrative Procedure Act, including AS 44.62.540, 44.62.560 and 44.62.570, and the Rules of Appellate Procedure of the State of Alaska, including Rule 44. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020(b)(1)

11 AAC 88.165. APPLICATIONS FOR RECONSIDERATION AND APPEAL. An application for reconsideration or an appeal must

(1) be filed within 30 days after receipt of notice of the action;

(2) be filed at the principal office of the director;

(3) comply with 11 AAC 88.105 except that there is no filing fee;

(4) specify the action to be reconsidered or appealed; and

(5) specify the grounds on which the reversal or modification of the action is urged. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020(b)(1)

11 AAC 88.170. BRIEFS. Written briefs in support of an application for reconsideration or an appeal may be filed with the division within 20 days after the filing of the application. The intention to file a brief must be specified in the application for reconsideration or appeal. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020(b)(1)

11 AAC 88.175. ORAL ARGUMENT. Oral argument may be allowed at the discretion of the officer who is to reconsider the action if written request for it is filed with the division within the time allowed for filing written briefs. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020(b)(1)

11 AAC 88.180. NOTICE OF DECISION. Following reconsideration of any action or final decision on appeal, the applicant will be given notice of the decision reached, specifying whether the action is affirmed, reversed, or modified, and, if the last, the details of the action as modified. (Eff. 9/5/74, Reg. 51)

Authority: AS 38.05.020(b)(1)

11 AAC 88.185. DEFINITIONS. As used in 11 AAC 82 – 11 AAC 88 and unless the context clearly requires a different meaning or unless otherwise defined in these chapters

(1) "adjacent" means touching or lying in close proximity, as opposed to "contiguous" which requires a common boundary;

(2) "cash" means cashier's or certified checks drawn on any solvent bank in the United States, postal or telegraphic money orders or legal tender of the United States of America, or any combination of these;

(3) "commissioner" means the Commissioner of the Department of Natural Resources;

(4) "cooperative agreement" means an agreement or plan of development and operation for the recovery of oil and gas from any pool, field, or like area or any part thereof in which separate ownership units are independently operated pursuant to the agreement without allocation of production;

(5) "director" means the Director of the Division of Lands;

(6) "division" means the Division of Lands, Department of Natural Resources;

(7) "filing office" means any place designated by the director as a filing office for applications, payments and filings under 11 AAC 82 – 11 AAC 88;

(8) "gas" means all natural gas and all hydrocarbons produced at a well not defined herein as oil;

(9) "gas well" means (A) a well which produces natural gas only; (B) that part of a well where the gas producing stratum has been successfully cased off from the oil, and the gas and oil being produced through separate casing or tubing; (C) any well classed as a gas well by the Alaska Oil and Gas Conservation Commission in the administration of the Alaska Oil and Gas Conservation Act;

(10) "leasehold location" or "mining leasehold location" means the interests in land subject to a location under AS 38.05.205 before a lease has been issued;

(11) "legal subdivision" means an aliquot part of a section of land according to the public land rectangular survey system, not smaller than one-quarter of one-quarter of one section of land, containing approximately 40 acres; where a section of land contains section lots, "legal subdivision" also means those section lots; "legal subdivision" also means a protracted legal subdivision according to any protracted public land rectangular survey prepared by the division or Bureau of Land Management of the Department of the Interior, and made available to prospective applicants for leases;

(12) "lessee or permittee of record" means the original lessee or permittee under any lease or permit or, if an assignment has been approved at any time, the latest assignee whose assignment has been approved;

(13) "locatable minerals" means those minerals which, on January 3, 1959, were subject to location under the United States mining laws (Title 30, USC);

(14) "Mineral Leasing Act" means the Act of Congress of February 25, 1920 (41 Stat. 437, 30 USC § 181, et seq.), as amended;

(15) "offshore" means tide and submerged lands, that is, those lands lying seaward from the line of mean high tide;

(16) "oil" means crude petroleum oil and other hydrocarbons regardless of gravity which are produced and saved in liquid form at the well by ordinary production methods;

(17) "oil well" means any well operated for the primary purpose of producing oil and which by the nature of its production cannot be classed as a gas well as defined in paragraph (6) of this section;

(18) "operating agreement" means an agreement giving the operator the right to carry on operations authorized by a lease or leases and to share in production obtained from the leased lands;

(19) "option" means an option to obtain an assignment of or an operating agreement covering a lease or portion of one;

(20) "order" means a determination made by the director or the commissioner in accordance with authority lawfully vested in him, issued in writing, filed in the permanent files of the division, posted in a conspicuous place in the offices of the division and made continuously available for inspection by the public;

(21) "participating area" means that part of an oil and gas lease unit area to which production is allocated in the manner described in a unit agreement;

(22) "person" includes a corporation and an association of persons;

(23) "pool" means an underground reservoir containing or appearing to contain a common accumulation of oil or gas or both; each zone of a general structure which is completely separated from any other zone in the structure is a pool;

(24) "primary term" means the initial term of an oil and gas lease and any extension of it;

(25) "smallest legal subdivision" means one-quarter of one-quarter of one section of land, containing 40 acres more or less, except where a section contains smaller section lots according to the public land rectangular survey or a protracted public land rectangular survey prepared by the division or by the Bureau of Land Management of the Department of the Interior, and made available to prospective applicants for leases, in which case "smallest legal subdivision" means those smaller section lots; as to unsurveyed land not covered by such

STATE OF ALASKA

STEVE COWPER, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

P.O. BOX 7034
ANCHORAGE, ALASKA 99510-7034

March 1, 1988

CALL FOR NOMINATIONS,
Proposed Oil and Gas Lease Sale 69A, North Slope

The Department of Natural Resources, Division of Oil and Gas, is considering adding an exempt acreage sale to the state's oil and gas leasing program. The new sale, proposed Oil and Gas Lease Sale 69A, North Slope, would be held in September 1988. The lands being considered for inclusion in the proposed sale were previously offered for leasing in Kuparuk Uplands Sales 48 or 54 or Prudhoe Bay Uplands Sale 51.

To help determine industry interest and delineate the proposed sale area, the Department of Natural Resources, Division of Oil and Gas, is requesting nominations for proposed Sale 69A. Industry is invited to nominate state-owned North Slope lands, as outlined on the attached map, for possible oil and gas leasing. Areas nominated should be defined as specifically as possible. If requested, the identity of individuals or companies making nominations will be held confidential. Nominations must be received by March 31, 1988. The department realizes that this offers relatively short notice for this sale. The sale may not be held unless significant and specific interest is received.

Proposed Sale 69A is an "exempt" acreage sale allowed under AS 38.05.180(d). This provision of the leasing statute allows the leasing of lands not on the five-year oil and gas leasing program if the lands were previously subject to valid state or federal oil and gas leases or are contiguous to land already under lease. As an "exempt" acreage sale, Sale 69A may also be subject to the provisions of AS 38.05.035(e)(7). This statute allows the department to hold an exempt acreage sale without issuing a best interest finding if one has been issued for the sale area within 36 months of the sale date. Written findings for previous oil and gas lease sales in these areas were issued within 36 months of Sale 69A's proposed sale date. However, this statute requires a best interest finding if the commissioner of Natural Resources determines that new information received justifies revision to the earlier findings.

Following analysis of industry nominations for Sale 69A and delineation of the proposed sale area, the Division of Oil and Gas will issue a call for comments requesting socioeconomic and environmental information for the proposed sale area. If no new information is received which justifies revision of the earlier findings, the proposed sale will be scheduled for September 1988. If new information is received and if the commissioner of Natural Resources determines that revision of the earlier findings is warranted, then holding the proposed sale during September 1988 may not feasible.

The area's petroleum potential is considered moderate.

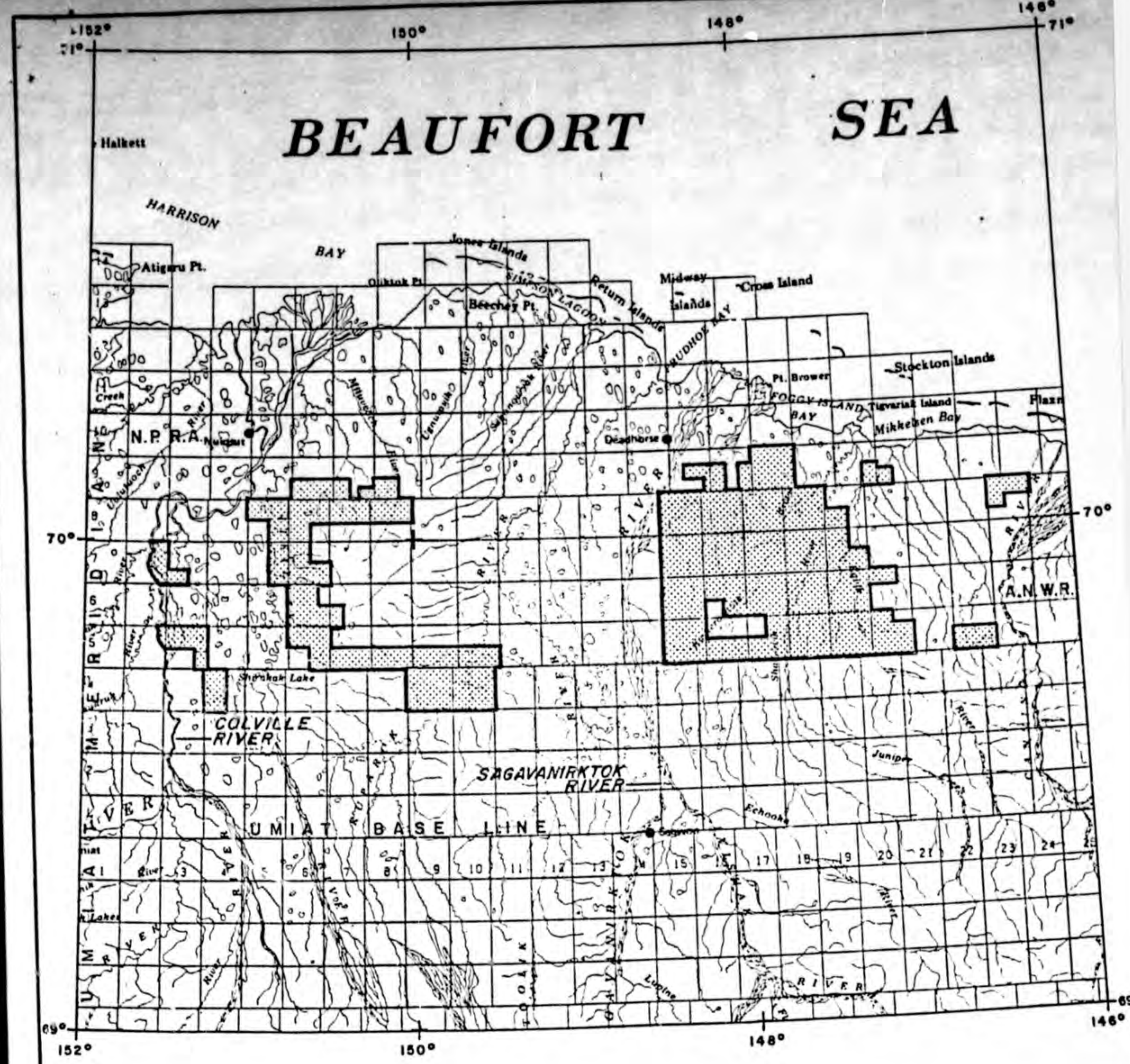
Information submitted in response to this call will be used to help determine the areas offered in proposed Sale 69A. No decision has been made on whether or not the state will hold the sale.

Please submit nominations by March 31, 1988 to:

Pamela Rogers, Leasing Manager
Division of Oil and Gas
P.O. Box 107034
Anchorage, AK 99510-7034.

Attachment

1245C

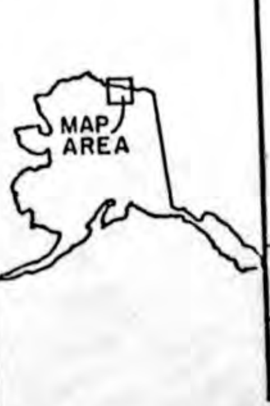


STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL & GAS

PROPOSED OIL AND GAS LEASE SALE 69A
NORTH SLOPE

SCALE 1:1,267,200 1" = 20 Mi.

MILES 10 0 10 20 30 40 50 MILES



DIRECTOR, DIV. OF OIL & GAS JIM EASON (in Pamela L. Rogers)	DRAWN BY O.D.S.	DATE APPROVED 3/1/88
LEASING MANAGER, PAMELA ROGERS	CHECKED BY: JMJ	BASE MAP: COPYRIGHT ARCTIC ENVIRONMENTAL INFORMATION & DATA CENTER, 1978 ALL RIGHTS RESERVED, INCLUDING REPRODUCTION IN WHOLE OR IN PART IN ANY FORM. UNIVERSAL TRANSVERSE MERCATOR PROJECTION ON SIX DEGREE BANDS

NOTE: NO DECISION HAS YET BEEN MADE ON WHETHER THE STATE WILL HOLD THIS LEASE SALE. THE STATE IS GATHERING SOCIAL, ENVIRONMENTAL & ECONOMIC INFORMATION ON WHICH TO BASE A DECISION.

PROPOSED SALE AREA

Sec. 38.05.180. Oil and gas leasing. (a) The legislature finds that

(1) the people of Alaska have an interest in the development of the state's oil and gas resources to

(A) maximize the economic and physical recovery of the resources;

(B) maximize competition among parties seeking to explore and develop the resources;

(C) maximize use of Alaska's human resources in the development of the resources;

(2) it is in the best interests of the state to encourage an assessment of its oil and gas resources and to allow the maximum flexibility in the methods of issuing leases to

(A) recognize the many varied geographical regions of the state and the different costs of exploring for oil and gas in these regions;

(B) minimize the adverse impact of exploration, development, production, and transportation activity.

(b) The commissioner shall annually prepare and submit to the legislature, between the first and the fifteenth day of each regular legislative session, a five-year proposed oil and gas leasing program consisting of a schedule of proposed lease sales and specifying as precisely as practicable the location of tracts proposed to be offered for oil and gas leasing during the calendar year in which the proposed program is submitted to the legislature and the following four calendar years.

(c) Except as provided in (d) and (w) of this section, an oil and gas lease sale may not be held unless it was included in the proposed leasing programs submitted to the legislature during the two calendar years preceding the year in which the sale is held. A lease sale shall be held during the calendar quarter for which it is scheduled in the proposed oil and gas leasing program but may be delayed by the commissioner for not more than 90 days after the last day of the calendar quarter for which it was scheduled if the commissioner determines that a delay is in the best interest of the state. A lease sale which is not held during the calendar quarter for which it was scheduled in the oil and gas leasing program, or in the following 90-day period authorized by this subsection, may be held only if rescheduled as provided in (b) of this section. A lease sale may not be held before the date it is scheduled in the proposed oil and gas leasing program.

(d) The commissioner may issue oil and gas leases in an area that has not been included in a leasing program submitted, in accordance with (b) of this section, to the legislature if

(1) the land to be leased was previously subject to a valid state or federal oil and gas lease; or

(2) the land to be leased is contiguous to land already under state, federal or private lease and the commissioner makes a written finding, after hearing, that leasing of the land would result in a substan-

tial probability of early evaluation and development of the land to be leased; or

(3) the land to be leased is adjacent to land owned or controlled by another party on which a discovery of commercial quantities of oil or gas has been made, and the commissioner finds, after hearing, that there is a reasonable probability that the land to be leased contains oil or gas in communication with the oil or gas discovered on the land of the other party; or

(4) the land to be leased is adjacent to land included in the federal five-year Outer Continental Shelf leasing program under 43 U.S.C. § 1344, and the commissioner makes a written finding, after hearing, that coordinated or simultaneous leasing with the federal government is in the public interest.

(e) Simultaneously with submission of the leasing program required under (b) of this section, the commissioner shall submit to the legislature a report containing the following:

(1) the schedule of all lease sales held during the preceding calendar year, the bidding method or methods utilized, and an analysis of the results of the bidding;

(2) if determined, a description of the bidding methods to be used for all lease sales to be held during the current and next two succeeding calendar years;

(3) the reasons a particular bidding method has been selected.

(f) The commissioner may issue oil and gas leases on state land to the highest responsible qualified bidder determined by competitive bidding under regulations adopted by the commissioner. Bidding may be by sealed bid or according to any other bidding procedure the commissioner determines is in the best interests of the state. Whenever, under any of the leasing methods listed in this subsection, a royalty share is reserved to the state, it shall be delivered in pipeline quality and free of all lease or unit expenses, including but not limited to separation, cleaning, dehydration, gathering, salt water disposal, and preparation for transportation off the lease or unit area. Following a pre-sale analysis, the commissioner may choose at least one of the following leasing methods:

(1) a cash bonus bid with a fixed royalty share reserved to the state of not less than 12 1/2 per cent in amount or value of the production removed or sold from the lease;

(2) a cash bonus bid with a fixed royalty share reserved to the state of not less than 12 1/2 per cent in amount or value of the production removed or sold from the lease and a fixed share of the net profit derived from the lease of not less than 30 per cent reserved to the state;

(3) a fixed cash bonus with a royalty share reserved to the state as the bid variable but no less than 12 1/2 per cent in amount or value of the production removed or sold from the lease;

(4) a fixed cash bonus with the share of the net profit derived from the lease reserved to the state as the bid variable;

(5) a fixed cash bonus with a fixed royalty share reserved to the state of not less than 12 1/2 per cent in amount or value of the production removed or sold from the lease with the share of the net profit derived from the lease reserved to the state as the bid variable;

(6) a cash bonus bid with a fixed royalty share reserved to the state based on a sliding scale according to the volume of production or other factor but in no event less than 12 1/2 per cent in amount or value of the production removed or sold from the lease;

(7) a fixed cash bonus with a royalty share reserved to the state based on a sliding scale according to the volume of production or other factor as the bid variable but not less than 12 1/2 per cent in amount or value of the production removed or sold from the lease.

(g) The share of the net profit derived from a lease reserved to the state under (f) of this section is royalty sale proceeds for the purposes of the Alaska permanent fund under AS 37.13.010.

(h) The commissioner may include terms in any oil and gas lease imposing a minimum work commitment on the lessee. These terms shall be made public before the sale, and may include appropriate penalty provisions to take effect in the event the lessee does not fulfill the minimum work commitment. If it is demonstrated that a lease has been proven unproductive by actions of adjacent lease holders, the commissioner may set aside a work commitment. The commissioner may waive for a period not to exceed one two-year period any term of a minimum work commitment if the commissioner makes a written finding either that conditions preventing drilling or exploration were beyond the lessee's reasonable ability to foresee or control or that the lessee has demonstrated through good faith efforts an intent and ability to drill or develop the lease during the term of the waiver.

(i) The commissioner may provide for the establishment of an exploration incentive credit system under which a lessee of state land drilling an exploratory well on that land may earn credits based upon the footage drilled and the region in which the well is situated. The commissioner may also provide for credits to be earned by persons performing geophysical work on state land, if that work is performed during the two seasons immediately preceding an announced lease sale and on land included within the sale area and the geophysical information is made public following the sale. Credits may not exceed 50 percent of the cost of the drilling or geophysical work. Credits may be used during a limited period established by the commissioner and may be assigned during that period. Credits may be applied against (1) oil and gas royalty and rental payments payable to the state or (2) taxes payable under AS 43.55. A credit may not exceed 50 percent of the payment toward which it is being applied. Amounts due the

Alaska permanent fund (AS 37.13.010) shall be calculated before the application of credits under this subsection.

(j) To prolong the economic life of an oil and gas field, the commissioner shall adopt regulations for all bidding methods to allow reduction of royalty on leases within the field to compensate for increasing costs in the later stages of production decline. The commissioner may not grant a reduction of royalty until two years' initial production from the field has occurred and each lessee requesting the reduction has made a clear showing that the revenue from all hydrocarbons produced from the field is insufficient to produce a reasonable rate of return with respect to that lessee's total investment in the field.

(k) The commissioner shall define all terms and adopt all regulations necessary for a reasonable understanding and evaluation of a particular bidding method before the public announcement of the terms of proposed sale employing that method.

(*l*) Subject to the provisions of AS 31.05, the commissioner has discretion to enter into an agreement whereby, with the consent of the lessee, the state's royalty share of oil and gas production may be stored or retained in storage by the lessee, or the commissioner may enter into an agreement with one or more of the affected field lease holders to trade current royalty production from a field for a like amount, kind, and quality of future production, on the condition that the state receives back its stored or traded royalty share during the first half of the estimated field life or no later than 15 years after start of production, whichever is sooner.

(m) An oil and gas lease must cover a reasonably compact area not exceeding 5,760 acres, and may be for a maximum period of 10 years, except that the commissioner may issue a lease for a period not less than five years upon a finding that it is in the best interests of the state. An oil and gas lease shall be automatically extended if and for so long thereafter as oil or gas is produced in paying quantities from the lease or if the lease is committed to a unit approved by the commissioner. A lease issued under this section covering land on which there is a well capable of producing oil or gas in paying quantities does not expire because the lessee fails to produce oil or gas unless the lessee is allowed reasonable time to place the well on a producing status. Upon extension, the commissioner may increase lease rentals so long as the increased rental rate does not exceed 150 per cent of the rate for the preceding year. If drilling has commenced on the expiration date of the primary term of the lease and is continued with reasonable diligence, including such operations as redrilling, sidetracking, or other means necessary to reach the originally proposed bottom hole location, the lease continues in effect until 90 days after drilling has ceased and for so long thereafter as oil or gas is produced in paying quantities. An oil and gas lease issued under this section which is subject to termination by reason of cessation of production does not terminate if, within 60 days after production ceases, reworking or drilling operations are commenced on the land under lease and are thereafter conducted with reasonable diligence during the period of nonproduction.

(n) The commissioner may establish by regulation that after a well has been plugged and abandoned, the rental rate which was in effect during the year of abandonment is maintained for the remainder of the term. Rental is payable in advance and continues until income to the state from royalty or net profit share exceeds rental income to the state for that year. Oil and gas leases shall provide for payment to the state of rental on the following basis:

(1) for the first year, $1.00 per acre;
(2) for the second year, $1.50 per acre;
(3) for the third year, $2.00 per acre;
(4) for the fourth year, $2.50 per acre;
(5) for the fifth and following years, $3.00 per acre.

(o) Upon timely application as provided by regulation, the state may issue to the holder of a federal or private lease, a state shoreland lease covering land within the exterior boundaries of the federal or private lease which has been excluded on the basis of navigability or which is later administratively or judicially determined to be shoreland. The term of such a state shoreland lease shall be the same as the term of the federal or private lease.

(p) To conserve the natural resources of all or a part of an oil or gas pool, field, or like area, the lessees and their representatives may unite with each other, or jointly or separately with others, in collectively adopting or operating under a cooperative or a unit plan of development or operation of the pool, field, or like area, or a part of it, when determined and certified by the commissioner to be necessary or advisable in the public interest. The commissioner may, with the consent of the holders of leases involved, establish, change, or revoke drilling, producing, and royalty requirements of the leases and adopt regulations with reference to the leases, with like consent on the part of the lessees, in connection with the institution and operation of a cooperative or unit plan as the commissioner determines necessary or proper to secure the proper protection of the public interest. The commissioner may require oil and gas leases issued under this section to contain a provision requiring the lessee to operate under a reasonable cooperative or unit plan, and may prescribe a plan under which the lessee must operate. The plan must adequately protect all parties in interest, including the state.

(q) A plan authorized by (p) of this section, which includes land owned by the state, may contain a provision vesting the commissioner, or a person, committee, or state agency, with authority to modify from time to time the rate of prospecting and development and the quantity and rate of production under the plan. All leases operated under a plan approved or prescribed by the commissioner are excepted in determining holdings or control under AS 38.05.140. The provisions of this section concerning cooperative or unit plans are in addition to and do not affect AS 31.05.

(r) Producing acreage on a known geologic structure of a producing oil or gas field is excluded from chargeability as against the acreage limitation provisions of AS 38.05.140.

(s) When separate tracts cannot be individually developed and operated in conformity with an established well-spacing or development program, a lease, or a portion of a lease, may be pooled with other land, whether or not owned by the state, under a communization or drilling agreement providing for an apportionment of production or royalties among the separate tracts of land comprising the drilling or spacing unit when determined by the commissioner to be in the public interest. Operations or production under the agreement are considered as operations or production as to each lease committed to the agreement.

(t) The commissioner may prescribe conditions and approve, on conditions, drilling, or development contracts made by one or more lessees of oil or gas leases, with one or more persons, when, in the discretion of the commissioner, the conservation of natural resources or the public convenience or necessity requires it or the interests of the state are best served. All leases operated under approved drilling or development contracts and interests under them, are excepted in determining holding or control under AS 38.05.140.

(u) To avoid waste or to promote conservation of natural resources, the commissioner may authorize the subsurface storage of oil or gas whether or not produced from state land, in land leased or subject to lease under this section. This authorization may provide for the payment of a storage fee or rental on the stored oil or gas, or, instead of the fee or rental, for a royalty other than that prescribed in the lease when the stored oil or gas is produced in conjunction with oil or gas not previously produced. A lease on which storage is so authorized shall be extended at least for the period of storage and so long thereafter as oil or gas not previously produced is produced in paying quantities.

(v) *[Repealed, § 36 ch 94 SLA 1980.]*

(w) Notwithstanding any other provisions of this section, land which has been offered for lease within the previous five years and which received no bids at competitive sale or for which no bid was accepted may be, at the discretion of the commissioner, immediately offered for lease, under regulations adopted by the commissioner, upon terms appearing most advantageous to the state; however, noncompetitive leasing is prohibited. The commissioner shall establish a royalty determined to be in the public interest but not less than 12 1/2 percent. A lease must provide for payment to the state or rental but need not adhere to the rental schedule in (n) of this section nor to the 5,760-acres-per-lease limitation in (m) of this section. The lease term may not exceed five years except as provided in (m) and (o) of this section.

(x) A lessee conducting or permitting any exploration for, or development or production of, oil or gas on state land shall provide the commissioner access to all noninterpretive data obtained from that lease and shall provide copies of that data, as the commissioner may request. The confidentiality provisions of AS 38.05.035 apply to the information obtained under this subsection.

(y) A noncompetitive lease existing at October 10, 1978 shall be extended for a period of two years and so long thereafter as oil and gas is produced in paying quantities. A noncompetitive lease extended under this subsection is subject to the regulations in force at the expiration of the initial five-year term of the lease. No extension may be granted, however, unless within a period of 90 days before the expiration date an application for extension is filed by the record title holder or an assignee whose assignment has been filed for approval, or an operator whose operating agreement has been filed for approval.

(z) No leases may be issued under this section without the inclusion of the following language: "The landowners' royalty share 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 landowners, free and clear of all unit expense and free of any lien for it." Leases issued in violation of this subsection shall, for all purposes, be construed as containing the language required by this subsection.

(aa) Within 90 days after the written request of a lessee of a lease issued under this section, the commissioner shall enter into an agreement with the lessee to use the price for the gas established in the contract between the lessee and a gas or electric utility as the value of the state's royalty share of gas production sold by the lessee under the contract unless the commissioner makes a written finding, based on clear and convincing evidence, that

(1) the contract price is unreasonably low;

(2) the prospective reduction in royalty receipts would not be balanced by increased benefits to in-state gas and electric consumers;

(3) the lessee and the utility are related in management, ownership, or other aspect; and

(4) the contract price is not in the best interest of the state.

(bb) In (aa) of this section

(1) "gas or electric utility" includes an electric cooperative organized under AS 10.25, a municipal utility, and a gas or electric utility regulated under AS 42.05; provided that if the contract gas is transmitted to consumers through a pipeline and the gas utility either owns the pipeline or is related in ownership to the owner of the pipe-

line, then the gas utility qualifies as a "gas or electric utility" within the meaning of this paragraph only if it is bound or agrees to be bound by the covenants set out in AS 38.35.120;

(2) "price for the gas established in the contract" includes tax reimbursement amounts, deliverability and other charges, and other forms of consideration paid by the gas or electric utility under the contract;

(3) "state's royalty share of gas production" does not include the state's royalty share of gas production from land patented to the state under

(A) P.L. 84-830, 70 Stat. 709 (Alaska Mental Health Enabling Act);

(B) 38 Stat. 1214 (Act of March 4, 1915); or

(C) 43 U.S.C. 1635 in settlement of the claims of the state under 38 Stat. 1214. (§ 3(7) art VIII ch 169 SLA 1959; am § 18 ch 61 SLA 1960; am § 1 ch 124 SLA 1962; am §§ 4 — 7 ch 30 SLA 1964; am § 20 ch 70 SLA 1964; am § 2 ch 91 SLA 1967; am § 1 ch 65 SLA 1969; am § 1 ch 86 SLA 1970; am § 1 ch 155 SLA 1978; am § 16 ch 160 SLA 1978; am §§ 3, 4 ch 65 SLA 1979; am § 6 ch 18 SLA 1980; am § 36 ch 94 SLA 1980; am §§ 1 — 5 ch 111 SLA 1980; am §§ 11, 12 ch 161 SLA 1984; am § 1 ch 89 SLA 1985; am § 2 ch 55 SLA 1986)

Cross references. — For legislative findings in connection with the 1986 amendment to this section, see § 1, ch. 55, SLA 1986, in the Temporary and Special Acts.

Effect of amendments. — The 1985 amendment in subsection (h) substituted "If it is" for "Should it be" at the beginning of the third sentence and added the last sentence.

The 1986 amendment added subsections (aa) and (bb).

Editor's notes. — Section 5, ch. 55, SLA 1986 provides that subsection (aa) of this section "applies to agreements to establish for a lease issued under AS 38.05.180 the in-value royalties on gas production that is sold under a contract entered into on or after May 30, 1986, between the state's lessee and a gas or electric utility."

Sec. 38.05.183. Sale of royalty. (a) The sale, exchange or other disposal of a mineral obtained by the state as a royalty under AS 38.05.182, or the sale, exchange or other disposal in whole or in part of a right to receive future mineral production under a state lease under this chapter, shall be by competitive bid and the sale, exchange or other disposal made to the highest responsible bidder, except that competitive bidding is not required when the commissioner, after prior written notice to the Alaska Royalty Oil and Gas Development Advisory Board under AS 38.06.050, determines that the best interest of the state does not require it or that no competition exists.

(b) When competitive bids are required, the commissioner, after prior written notice to the Alaska Royalty Oil and Gas Development Advisory Board, may reject all bids on a determination that because of the amount of the bids, the lack of responsibility on the part of the bidders, or for reasons consistent with the criteria set out in AS 38.06.070, the acceptance of the bids would not be in the best interest of the state.

FIVE-YEAR OIL AND GAS LEASING PROGRAM

JANUARY 1988

AS 38.05.180

Alaska Department of
NATURAL RESOURCES
DIVISION OF OIL & GAS

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 8672
1547 SCOMM 57: SENATE SPECIAL COMMITTEE ON OIL & GAS, 1987-1988/344

FIVE-YEAR OIL & GAS LEASING PROGRAM

ALASKA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL & GAS

Proposed Area & Date	1987							1988												1989												1990												1991												1992								
	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S
54 Kuparuk Upl. 1·88			P		M	F		S																																																								
55 Demarcation Pt. 6·88								P		M	F		S																																																			
66A N.S. Exempt* 6·88	N		C[1]				C[2]	A	P		F		S																																																			
52 Beaufort Sea 1·89			C[3]												P		M	F		S																																												
56 Alaska Peninsula 6·89						L		C[3]												P		M	F		S																																							
67A Cook Inlet Exempt* 6·89	N		C[1]				L	A		C[2]										P		M	F		S																																							
59 Cook Inlet 1·90					C[2]								L		C[3]												P		M	F		S																																
57 N.S. Foothills 6·90			C[2]															L		C[3]												P		M	F		S																												
64 Kavik 1·91					C[2]																				L		C[3]												P		M	F		S																				
65 Beaufort Sea 6·91								C[2]																						L														P		M	F		S															
61 White Hills 1·92	N		C[1]					A							C[2]																							L		C[3]											P		M	F		S								
68 Beaufort Sea 6·92	N		C[1]					A												C[2]																						L		C[3]												P		M	F		S			

N = Nominations Requested
A = Proposed Sale Area Added to 5-Year Leasing Schedule
C = Call for Comments:
New Sales and 5-Year Schedule Revisions [1]
Request for General Information [2]
Request for Socioeconomic and Environmental Information [3]

L = Preliminary Land Status Check
P = Preliminary Finding/Preliminary Notice [AS 38.05.945(a)(3)]
M = Public Meetings or Teleconference

F = Final Finding/Final Notice of Sale and Terms [AS 38.05.945(a)(4)] and Alaska Coastal Management = Program Consistency Determination, if Required
S = Sale
* = A Best Interest Finding May not be Required [AS 38.05.035(e)(7)]

Proven and Probable Oil Reserves on Currently Leased State Lands
North Slope, Alaska [1]

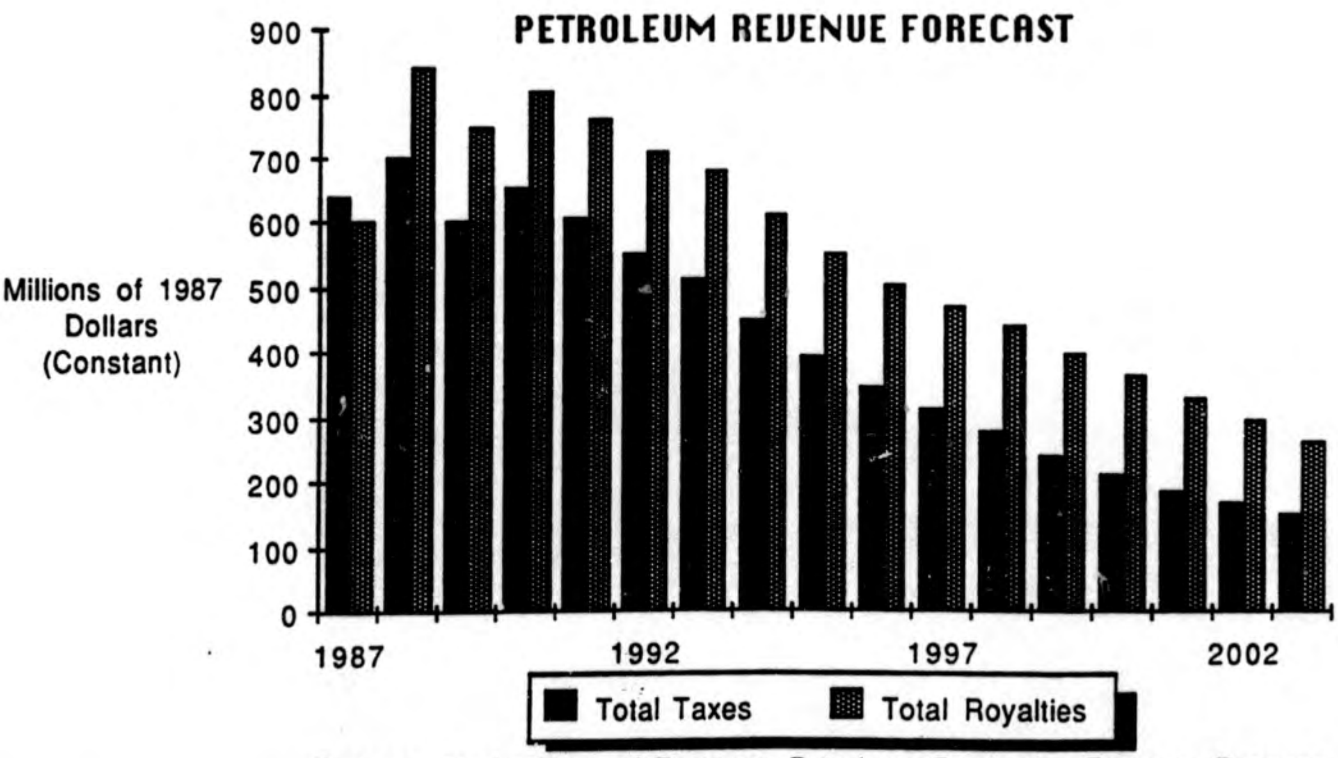
AREA	Range of Reserves (millions of barrels) low	most probable	high
Prudhoe Bay Unit	4100	4800	6000
Kuparuk River Unit	600	900	1100
Milne Point Area	0	60	95
Gwydyr Bay Area	0	0	10
Shallow Cretaceous Sands	0	1500	3000
Prudhoe Bay Lisburne Reservoir	280	380	580
Endicott	270	370	445
Point Thomson Area and Flaxman Island Area [2]	0	0	350
Beaufort Sea	0	0	300
Totals	5250	8010	11880
Totals (minus Prudhoe Bay)	1150	3210	5880

[1] As of 1/88, estimates by W. Van Dyke, Department of Natural Resources Division of Oil & Gas.

[2] Oil and gas condensate.

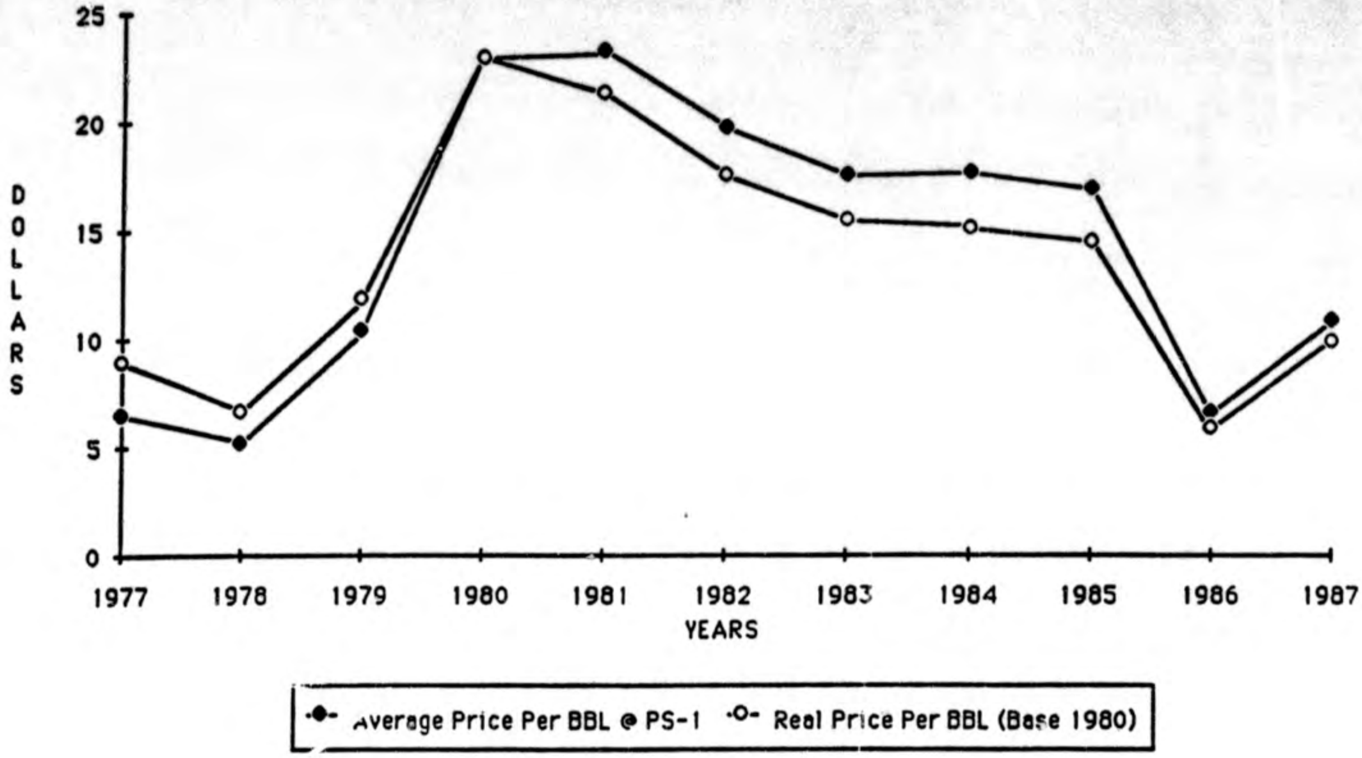
Constant Dollar
Petroleum Production Revenue Forecast
(Values In Millions of 1987 Dollars)

Fiscal Year	Total Severance and Conservation Taxes	Total Royalties	Total Petroleum Revenues
1987	642.86	604.06	1246.92
1988	700.81	843.40	1544.22
1989	604.13	748.08	1352.21
1990	655.63	803.20	1458.83
1991	606.79	760.50	1367.29
1992	551.96	710.97	1262.93
1993	512.47	679.20	1191.67
1994	451.00	613.87	1064.87
1995	394.82	552.95	947.77
1996	349.44	507.44	856.88
1997	315.59	473.25	788.85
1998	278.82	440.27	719.08
1999	241.53	399.50	641.03
2000	213.35	363.64	576.99
2001	187.45	331.06	518.51
2002	168.26	296.55	464.81
2003	149.86	264.10	413.96

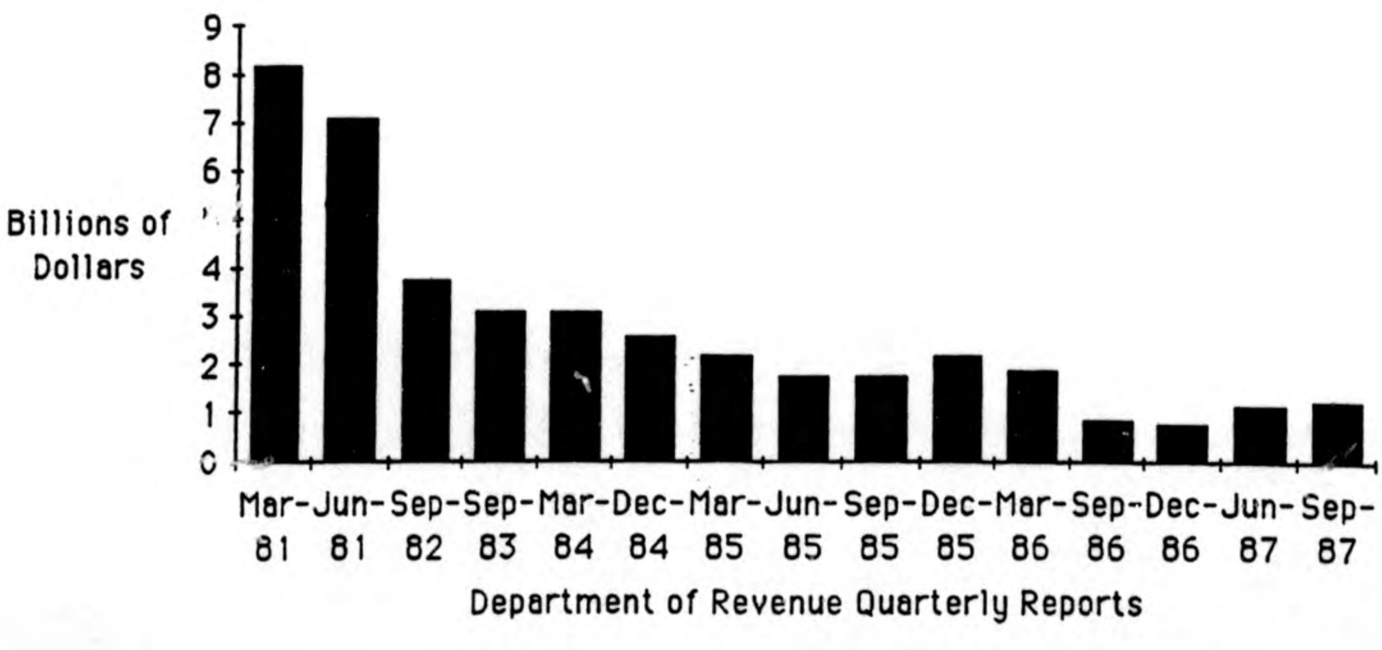


Source: Alaska Dept. of Revenue, Petroleum Production Revenue Forecast, Quarterly Report, Sept. 1987

Average Price Per Barrel at Pump Station No. 1



State Revenue Forecasts for Fiscal '87



North Slope Petroleum Development Summary (as of October 1987)

FIELD NAME	Prudhoe Bay	Lisburne	Kuparuk	Milne Point	Endicott
Discovery Date	12/67	12/67	4/69	10/69	3/78
Size of Oil Pool (sq. mi.)	400	125	400	45	40
Production Start-up Date	6/77	12/86	12/81	11/85	10/87
Production to Date (mill. bbls)	4,918	5	292	5 (1)	(2)
1986 Average Production Rate (barrels/day)	1,554,000	40,000	257,000	12,900	100,000
Remaining Reserves:					
million barrels	4,672	395	1,308	55	375
billion cubic feet	26,000	625	565	0	730
Existing Wells	828	37	505	29	4 (3)
Drill Sites/Pads	38	5	34	4	2
Production Centers	6	1	3	1	1
Base Camps	2	1	1	1	1
Construction Camps	2	0	1	1	1
Power Plants	1	1	1	1	1
Topping Plants	1	0	1	0	0
Gas Compression Plants	1	1	1	1	1
Sea Water Treatment Plants	1	0	1	0	1
Enhanced Oil Recovery Plants	1	0	1	0	0
Docks	1	0	1	0	1
Causeways	1	0	0	0	1
Water Injection Centers	2	0	(4)	(4)	0
Associated Support and Industrial Sites	1	0	1	0	0
Airports and Company Operated Airstrips	2	0	1	0	0
Pipelines (miles)	63 (5)	(5)	418	15	28
Roads (miles)	218 (5)	(5)	94	19	15
Acreage Filled (acres)	5374 (5)	(5)	1409	54	198
River Crossings (number)	3 (5)	(5)	5	1	1

(1) Field shut in January 1987
(2) Production commenced October 1987
(3) 80-100 wells planned
(4) Water injection system included in production centers
(5) Lisburne numbers included with Prudhoe Bay

Standard Alaska Production Company has recently applied for discovery royalty for a new field, Niakuk, located offshore between the Lisburne and Endicott fields. Standard currently is considering various development plans. No estimate of reserves is available at this time.

Camp Lonely, located 80 miles west of Oliktok Point and the Kuparuk field, has served as a staging area for western Beaufort Sea activities. The camp was constructed by the federal government for exploration activities in the National Petroleum Reserve Alaska. The Cook Inlet Region, Incorporated (CIRI) bought the camp in 1982. CIRI plans to operate the facility as a joint venture with Arctic Slope Regional Corporation. Infrastructure includes a 100 person camp, offices, carpentry shop, communications shop, sewage treatment plant, generating system, vehicle maintenance shop, a large tank farm, and warm and cold storage warehouses. Inventory on hand consists of drill pipe, casing and drilling mud.

In addition to these areas, future development is possible from the West Sak Reservoir in the Prudhoe Bay Unit, Seal Island, Tern Island, Sandpiper Island, Colville Delta, Flaxman Island/Point Thomson, Hemi Springs Unit, ARCO Alaska's K-10 and Bullen Point Staging Area.

EXPLORATION INCENTIVE CREDITS
Report Month: October 1987

ADL	WELL	COMPANY	CERTIFICATION DATE	TOTAL AMOUNT
343109	G-2 Well	Exxon	10/5/83	$6,197,625.00
		Standard Alaska	12/27/83	$4,152,408.75
		BPAE	10/5/83	$2,045,216.25
344010	Leffingwell	Arco	10/2/84	$3,706,000.00
		Union	10/2/84	$3,706,000.00
344033	J-1 Well	Exxon	10/31/84	$5,119,500.00
355005	Long Island Well	Exxon	11/14/84	$1,378,076.00
		Standard Alaska	11/14/84	$1,378,076.00
345126	Totek Hills	Arco Alaska	8/02/85	$715,530.81
355037	Colville Delta #1	Texaco	07/09/86	$637,500.00
		Amerada Hess	07/09/86	$888,594.00
		Diamond Shamrock(A)	07/09/86	$100,128.00
		Mobil	02/05/87	$432,511.00
		Placid Oil (C)	07/09/86	$314,679.00
		Union Texas (B)	07/09/86	$475,631.00
		Rosewood Resources	07/09/86	$12,662.00
		Hunt Pet Co.	07/09/86	$11,213.00
364478	Colville Delta Area AHC 25-13-6 #1 well	Amerada Hess	10/12/87	$677,853.00
		Union Texas	10/12/87	$508,390.00
		Texaco	10/12/87	$225,951.00
		Maxus Expl.	10/12/87	$225,951.00
		Placid Oil	10/12/87	$129,115.00
		Rosewood Res.	10/12/87	$21,360.00
		Hunt Pet Co.	10/12/87	$18,987.00
355038	Colville Delta #2	Amerada Hess	10/28/87	$757,731.46
		Union Texas	10/28/87	$205,106.95
		Texaco	10/28/87	$273.475.93
		Maxus Expl.	10/28/87	$273,475.93
		Placid Oil	10/28/87	$423,982.26
		Rosewood Res.	10/28/87	$77,561.49
		Hunt Pet Co.	10/28/87	$68,943.50
355039	Colville Delta #3	Amerada Hess	10/28/87	$364,048.13
		Union Texas	10/28/87	$91,012.03
		Texaco	10/28/87	$364,048.13
		Maxus Expl.	10/28/87	$364,048.13
		Placid Oil	10/28/87	$178,918.37
		Rosewood Res.	10/28/87	$34,416.31
		Hunt Pet Co.	10/28/87	$30,592.28
GRAND TOTAL				$36,575,980.71

(A) Assigned $432,511 of EIC to Mobil Oil Corp. effective 02/05/87
(B) Assigned entire EIC to BP Alaska effective 02/03/87
(C) Assigned entire EIC to Texaco Inc. effective 03/31/87

Source: Alaska Department of Natural Resources, Division of Oil and Gas

SUMMARY OF PAST COMPETITIVE LEASE SALES

Sale No.	Acres Offered	Percent Leased	Acres Leased	Average $/Acre	Tracts Offered	Tracts Leased	Bonus Received
1.	88,055.00	87.66	77,191.00	52.08	37	31	$4,020,342.43
2.	17,567.51	93.96	16,505.57	24.70	27	26	407,654.54
3.	73,047.70	31.30	22,866.70	1.55	26	9	35,325.31
4.	400.00	100.00	400.00	679.04	3	3	271,614.40
5.	97,876.00	98.06	95,980.00	74.71	102	99	7,170,464.88
6.	13,257.00	100.00	13,257.00	8.35	5	6	110,671.55
7.	255,708.44	73.14	187,025.40	79.47	68	53	14,863,049.33
8.	1,061.70	100.00	1,061.70	4.80	8	8	5,097.00
9.	315,668.93	87.77	264,437.13	59.43	89	76	15,714,112.60
10.	167,583.06	84.43	141,490.51	29.23	200	158	4,136,224.92
11.		C A N C E L L E D					
12.	346,782.40	71.25	247,089.00	12.31	309	207	3,042,680.74
13.	1,194,373.00	60.51	722,659.00	7.66	610	341	5,537,100.94
14.	754,033.00	53.45	403,000.00	15.25	297	159	6,145,472.59
15.	403,042.06	74.87	301,751.28	15.49	293	216	4,674,343.74
16.	184,410.05	72.66	133,987.29	52.55	205	153	7,040,880.17
17.	19,229.70	96.67	18,589.70	7.33	36	35	136,279.67
18.	47,729.00	88.82	42,397.00	34.88	23	19	1,478,777.23
19.	2,560.00	R E J E C T E D 12/9/74					
20.	311,249.89	82.39	256,447.31	73.14	295	220	18,757,340.88
21.	346,623.00	47.59	164,961.00	18.24	308	147	3,009,224.00
22.	111,199.48	54.20	60,272.15	17.29	230	125	1,042,219.90
23.	450,858.47	91.50	412,548.47	2,181.66	179	164	900,041,605.34
24.	196,635.07	47.10	92,617.97	4.92	244	106	455,640.57
25.	325,401.42	54.78	178,244.71	7.43	259	152	1,324,673.40
26.	399,920.96	44.50	177,972.56	8.75	218	105	1,557,848.84
27.	308,400.81	36.93	113,891.71	9.93	210	96	1,130,324.51
28.	166,648.04	58.69	97,803.69	253.77	98	62	24,819,189.91
29.	278,269.43	50.00	127,119.65	8.19	164	82	1,040,909.98
29A.		C A N C E L L E D					
29B.	34,678.04	100.00	34,678.04	4.56	20	20	158,041.78
30.	341,140.18	86.80	296,307.65	1,914.87	71	62	567,391,497.48
31.	196,268.00	100.00	196,268.00	63.12	78	78	12,387,469.60
33.	815,000.00	50.99	429,978.16	10.00	202	103	4,299,781.60
32.	202,836.74	75.15	152,428.22	10.00	78	59	1,524,282.20
35.	601,171.50	21.82	131,190.69	10.00	149	31	1,311,906.90
36.	56,862.41	100.00	56,862.41	573.02	13	13	32,583,451.87
37.	852,603.08	19.80	168,849.00	3.33	217	33	562,943.90
37A.	1,874.60	100.00	1,874.60	52.00	1	1	97,479.20
34.	1,231,517.00	46.44	571,954.00	46.71	261	119	26,713,018.17
38.		C A N C E L L E D					
39.	211,988.08	100.00	211,988.08	99.05	42	42	20,998,100.98
40.	1,044,745.02	42.44	443,354.88	7.17	284	140	3,177,178.26
43&43A.	374,152.89	95.64	357,863.02	94.53	84	81	33,827,377.15
41.	1,437,930.46	19.39	278,938.96	3.03	308	63	843,964.92
46A.	248,584.64	76.45	190,041.54	13.28	65	50	2,523,333.71
45A.	606,385.00	27.19	164,885.00	28.25	113	32	4,657,478.08
47.	192,568.81	94.80	182,559.81	63.79	50	48	11,645,003.26
48.	526,101.00	50.70	266,736.00	9.16	104	54	2,444,341.85
48A.	42,053.00	100.00	42,053.00	12.13	11	11	510,255.16
49.	1 189,099.61	33.21	394,880.74	2.40	260	98	947,171.27
51.	592,142.00	17.99	100,632.00	2.88	119	26	289,624.90
50.	118,147.31	100.00	118,147.31	56.05	35	35	6,621,722.81
	17,797,475.92	52.63	9,165,038.61	189.54	7,108	4,057	1,763,484,494.32

STATE COMPETITIVE SALE AREAS

	SALE	DATE	DESCRIPTION	BIDDING METHOD
1.	Wide Bay; offshore Kenai to Ninilchik; Kachemak Bay	12/10/59	Offshore	Cash Bonus Bid with fixed Royalty
2.	Kenai Peninsula; West Forelands; Nushagak Bay	7/13/60	Offshore/Uplands	Cash Bonus Bid with fixed Royalty
3.	Katalla; Kalifonsky Beach; Herendeen Bay; offsh. Kodiak	12/7/60	Offshore	Cash Bonus Bid with fixed Royalty
4.	Uplands Ninilchik	1/25/61	Uplands	Cash Bonus Bid with fixed Royalty
5.	Tyonek; Controller Bay; Pavlov Bay	5/23/61	Offshore/Uplands	Cash Bonus Bid with fixed Royalty
6.	Controller Bay (Special Sale)	8/4/61	Tidelands	Cash Bonus Bid with fixed Royalty
7.	Icy, Yakutat & Kachemak Bays; So. Kenai Penin.; N. Cook Inlet	12/19/61	Offshore/Uplands	Cash Bonus Bid with fixed Royalty
8.	Big Lake	4/24/62	Uplands	Cash Bonus Bid with fixed Royalty
9.	Tyonek; W. Forelands; Knik Arm/Kalgin Island; Chisik Island; So. Kenai Penin.; Wide Bay	7/11/62	Offshore/Uplands	Cash Bonus Bid with fixed Royalty
10.	Tyonek; Kenai Offshore & Uplands	5/8/63	Offshore/Uplands	Cash Bonus Bid with fixed Royalty
11.	Yakutat Bay	CANCELLED		
12.	S. of Forelands; Knik & Turnagain Arms; Upper Cook Inlet; Kenai Pen.; Tyonek to Katunu River	12/11/63	Offshore/Uplands	Cash Bonus Bid with fixed Royalty
13.	Fire Island; W. Forelands; Trinity Islands; Prudhoe West	12/9/64	Offshore/Uplands	Cash Bonus Bid with fixed Royalty
14.	Prudhoe West to Canning River	7/14/65	Offshore/Uplands	Cash Bonus Bid with fixed Royalty
15.	Fire Island & N. Cook Inlet; Kalgin Island & Redoubt Bay; Knik; S. Kenai Peninsula	9/28/65	Offshore/Uplands	Cash Bonus Bid with fixed Royalty
16.	Kenai Penin. & Knik; Middleton Island; Fire Island, Redoubt Bay; Kalgin Island, Iliamna Mt.; N. Cook Inlet	7/19/66	Offshore/Uplands	Cash Bonus Bid with fixed Royalty
17.	Big Lake; Kenai	11/22/66	Offshore/Uplands	Cash Bonus Bid with fixed Royalty
18.	Katalla; Prudhoe	1/24/67	Offshore/Uplands	Cash Bonus Bid with fixed Royalty
19.	Lower Cook Inlet	3/28/67	Offshore/Uplands	Cash Bonus Bid with fixed Royalty
20.	Big Lake; Knik; Iliamna Mt.; Belukha; N. Cook Inlet; Kalgin Island; Ninilchik	7/25/67	Offshore/Uplands	Cash Bonus Bid with fixed Royalty
21.	Port Heiden & Port Moller	3/26/68	Offshore	Cash Bonus Bid with fixed Royalty
22.	Big Lake; Knik; Belukha; West Forelands; Ninilchik; Kachemak & Kenai	10/29/68	Uplands	Cash Bonus Bid with fixed Royalty

STATE COMPETITIVE SALE AREAS

	SALE	DATE	DESCRIPTION	BIDDING METHOD
23.	Colville to Canning River	9/10/69	Offshore/Uplands	Cash Bonus Bid with fixed Royalty
24.	Big Lake; Knik; Kenai; West Forelands	5/12/71	Uplands	Cash Bonus Bid with fixed Royalty
25.	Big Lake; Knik; Belukha; North Cook Inlet	9/26/72	Offshore/Uplands	Cash Bonus Bid with fixed Royalty
26.	Cook Inlet (Between Forelands & Turnagain Arm)	12/11/72	Offshore/Uplands	Cash Bonus Bid with fixed Royalty
27.	Tuxedni; Ninilchik; Kenai; Kalgin	5/9/73	Offshore/Uplands	Cash Bonus Bid with fixed Royalty
28.	Ninilchik; Kachemak Bay; Belukha	12/13/73	Offshore/Uplands	Cash Bonus Bid with fixed Royalty
29.	Kalgin & West Forelands; Chisik; Ninilchik N. Cook Inlet; Turnagain; Big Lake	10/23/74	Offshore Uplands	Cash Bonus Bid with fixed Royalty
29A.	Point Thomson	CANCELLED		
29B.	Copper River Basin	7/24/79	Uplands	Cash Bonus Bid with fixed Royalty
30.	Beaufort Sea (Joint Federal & State Sale)	12/12/79	Offshore	Cash Bonus w/fixed Sliding Scale Royalty; Net Profit Share (NPS) Bid w/fixed Royalty and fixed Cash Bonus
31.	Prudhoe Uplands	9/16/80	Uplands	Cash Bonus Bid with fixed Royalty and fixed NPS
32.	Lower Cook Inlet	8/25/81	Offshore/Uplands	Royalty Bid with fixed Cash Bonus
33.	Upper Cook Inlet	5/13/81	Offshore/Uplands	Royalty Bid with fixed Cash Bonus
35.	Lower Cook Inlet	2/2/82	Offshore/Uplands	Royalty Bid with fixed Cash Bonus
36.	Beaufort Sea	5/26/82	Offshore/Uplands	Cash Bonus Bid with fixed Royalty and fixed NPS
37.	Middle Tanana & Copper River Basins	8/24/82	Uplands	Cash Bonus Bid with fixed Royalty and fixed NPS
37A.	Chakok River, Exempt	8/24/82	Uplands	Cash Bonus Bid with fixed Royalty
34.	Prudhoe Uplands	9/28/82	Uplands	Cash Bonus Bid with fixed Royalty and fixed NPS
38.	Norton Basin	CANCELLED		

STATE COMPETITIVE SALE AREAS

SALE	DATE	DESCRIPTION	BIDDING METHOD
39. Beaufort Sea	5/17/83	Offshore/Uplands	Cash Bonus Bid with fixed Royalty and fixed NPS
40. Upper Cook Inlet	9/28/83	Offshore/Uplands	Cash Bonus Bid with fixed Royalty
43. Beaufort Sea	5/22/84	Offshore	Cash Bonus Bid with fixed Royalty
43A. Colville River Delta/Prudhoe Bay Uplands	5/22/84	Offshore/Uplands	Cash Bonus Bid with fixed Royalty and fixed NPS
41. Bristol Bay Uplands	9/18/84	Uplands	Cash Bonus Bid with fixed Royalty
46A. Cook Inlet Exempt	2/26/85	Offshore/Uplands	Cash Bonus Bid with fixed Royalty
45A. North Slope Exempt	9/24/85	Uplands	Cash Bonus Bid with fixed Royalty
47. Kuparuk Uplands	9/24/85	Uplands	Cash Bonus Bid with fixed Royalty
48. Kuparuk Uplands	2/25/86	Uplands	Cash Bonus Bid with fixed Royalty
48A. Mikkelson	2/25/86	Offshore/Uplands	Cash Bonus Bid with fixed Royalty
49. Cook Inlet	6/24/86	Offshore/Uplands	Cash Bonus Bid with fixed Royalty
51. Prudhoe Bay Uplands	[illegible]/27/87	Uplands	Cash Bonus Bid with fixed Royalty
50. Camden Bay	6/30/87	Offshore	Cash Bonus Bid with fixed Royalty

CURRENT STATE OIL & GAS LEASE INVENTORY
(December 1987)

CATEGORY	NO. OF LEASES	NO. OF ACRES
ACTIVE LEASES	1155	3,843,827
OFFSHORE		1,629,247
ONSHORE		2,214,580
TOTAL PRODUCING LEASES	278	548,719
UNITIZED LEASES	436	957,078
COMPETITIVE LEASES	1125	3,820,104
OFFSHORE		1,629,247
ONSHORE		2,190,857
NONCOMPETITIVE LEASES	12	8,890
OFFSHORE		-0-
ONSHORE		8,890
NET PROFIT SHARE LEASES	141	620,414
OFFSHORE		290,795
ONSHORE		329,620
CONDITIONAL LEASES (1)	84	176,950
OFFSHORE		17,382
ONSHORE		159,567
TRANSFERRED FEDERAL LEASES (2)	15	14,181
OFFSHORE		-0-
ONSHORE		14,180
SHORELAND PREFERENCE LEASES (3)	3	651

(1) State leases issued prior to May 6, 1969 on lands which the state has not yet received patent.

(2) Federal leases which have since been transferred to state ownership.

(3) State leases for the bottoms of navigable waterbodies issued to federal leaseholders whose tracts surround those waterbodies.