

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 8672
1476 SCOM 55: JNT. SPEC. COMM. ON STATE TAX POLICY, 1986-1987 1276

System through existing pipelines serving the Kuparuk River Field. Early in 1986, Milne Point was producing about 20,000 barrels per day of crude oil.

Enhanced recovery projects continue to be developed on the North Slope. Production began from the West Sak unit late in 1984, where hot water is now being injected into the reservoir. West Sak overlies a large portion of the Kuparuk River Field and was discovered in 1969 at the same time the Kuparuk River Field was found. Kuparuk River began production in 1981. A fivefold expansion of the first Arctic tertiary project, an enriched gas miscible flood system in the Prudhoe Bay Field, was approved by operators and the expansion phase construction has begun. Over 100 million barrels of additional recovery are anticipated with full-scale operation scheduled for late 1986 or early 1987.

3. North Slope Crude Oil Production

Table B-2 provides data on North Slope oil production by major field from 1975 to 1985. The Sadlerochit Reservoir has been the predominant source of North Slope oil production, accounting in 1985 for nearly 90 percent of total Alaskan production. Technical Appendix A provides the range of projected Alaskan North Slope oil production estimates (through the year 2000) used in this study.

Table B-3 shows Alaskan North Slope crude oil production by company for 1984. Nearly half the production was by Sohio, which produced nearly 800 thousand barrels per day.

TABLE II B-1

ESTIMATES OF NORTH SLOPE CRUDE OIL RESERVES
(Billion Barrels)

<u>Name of Field</u>	<u>Year Discovered</u>	<u>Estimated Recoverable Reserves*</u>
Prudhoe Bay	1968	5.0-7.2
Kuparuk River	1969	0.8-1.3
Milne Point	1980	.04-0.1
West Sak	1969	3.0-5.0
Endicott	1969	0.3-0.5
Lisburne	1968	0.3-0.6
Ugnu	1969	0.0-3.0
Point Thompson	1981	0.3-0.6
Colville River Delta	1985	**
Gwydyr Bay	1984	.00-.06
Seal Island	1984	**
Undiscovered Fields*** (Onshore)	---	2.5-14.6
Total North Slope		12.2-34.0

* Estimated Recoverable Reserves includes potential as well as proved reserves; total North Slope proved reserves were nearly 7.1 billion barrels as of 1986.

** Not yet determined to be commercial.

*** Department of Interior, Geological Survey Circular 860, Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States, 1981. This estimate does not include 3.3 billion barrels of Alaskan offshore crude oil determined by the Department of the Interior, Minerals Management Service in 1984.

TABLE II B-2

CRUDE OIL PRODUCTION
(B/D)

	<u>North Slope</u>				South Alaska	State Total
	Kuparuk River	Prudhoe Bay	Milne Point	Total ANS		
1975	-0-	7,863	-0-	7,863	189,342	197,205
1976	-0-	12,614	-0-	12,614	170,973	183,587
1977	-0-	315,775	-0-	315,775	153,685	469,460
1978	-0-	1,089,532	-0-	1,089,532	137,345	1,226,877
1979	-0-	1,283,321	-0-	1,283,321	117,597	1,400,918
1980	-0-	1,521,627	-0-	1,521,627	99,307	1,620,934
1981	2,992	1,521,019	-0-	1,524,011	85,137	1,609,148
1982	88,784	1,531,773	-0-	1,620,556	75,099	1,695,655
1983	109,258	1,536,778	-0-	1,646,036	67,844	1,713,880
1984	126,490	1,540,400	-0-	1,666,890	60,233	1,727,123
1985	215,345	1,554,444	2,411	1,772,200	47,203	1,819,403

Kuparuk River includes a small amount of production from Kuparuk River (West Sak) for 1983 and 1984.

Prudhoe Bay production into Trans Alaska Pipeline began fourth quarter of 1977. Includes condensate. Prudhoe Bay (Lisburne) included 1981-1985.

Milne Point production began November 4, 1985.

South Alaska production calculated by subtracting ANS production from State total after rounding.

1985 figures are estimated, based on actual production through 1985 except for Milne Point, which is based on November production.

NOTE: The above data are from final corrected figures of the State of Alaska Oil and Gas Conservation Commission through 1984.

TABLE II B-3

ALASKAN NORTH SLOPE CRUDE OIL PRODUCTION
BY PRODUCING COMPANY - 1984
 (Thousand B/D)

<u>Name of Company</u>	<u>North Slope Oil Production</u>	<u>Percent of Total</u>
Sohio	788	47.3
Atlantic Richfield	406	24.3
Exxon	333	20.0
British Petroleum	36	2.2
Mobil Corporation	32	1.9
Phillips Petroleum	32	1.9
Others (Amerada Hess, Louisiana Land & Exploration, Marathon, Shell, Texaco, and Unocal	39	2.4
<u>Total</u>	1,667	100.0

NOTE: North Slope production includes production from Prudhoe Bay and from Kuparuk. In 1984, Prudhoe Bay and Kuparuk had daily production of 1,540,000 and 127,000 barrels respectively.

C. CURRENT LEGISLATIVE AND REGULATORY STATUS

1. Introduction

Congress has placed a number of statutory restrictions on the export of U.S. crude oil. These restrictions are:

- o Section 7 of the Export Administration Act of 1979, as amended (50 U.S.C. App. 2406);
- o Section 103 of the Energy Policy and Conservation Act (42 U.S.C. 6212);
- o Section 28(u) of the Mineral Leasing Act of 1920 (30 U.S.C. 185), as amended by the Trans-Alaska Pipeline Authorization Act of 1973 (43 U.S.C. 1652);
- o Section 201 of the Naval Petroleum Reserve Production Act of 1976 (10 U.S.C. 7430);
- o Section 28 of the Outer Continental Shelf Lands Act of 1953 (43 U.S.C. 1343).

The main reason for this legislation was Congressional concern about the adequacy of oil supplies for the U.S. domestic market and the maintenance of low oil prices under the then prevalent price controls. It was widely held that any exports of price-controlled crude would have to be replaced by higher priced imports, which would raise consumer prices and add to inflationary pressures. Congress was also concerned about growing U.S. dependence on foreign oil supplies and wanted to ensure that U.S. crude oil reserves were utilized to reduce import dependence.

2. The Export Administration Act of 1979 (EAA)

The Export Administration Act of 1979, as amended, is the principal statute that restricts the export of Alaskan North Slope of (ANS) crude oil. It applies the most stringent conditions of any legislation that restricts crude oil exports. Specifically, Section 7(d) of the EAA effectively prohibits the export of ANS crude oil unless it is pursuant to a bilateral international oil supply agreement entered into by the United States before June 25, 1979, or to any country pursuant to the International Emergency Oil Sharing Plan of the International Energy Agency. Section 7(d) does allow for ANS crude exports if the President makes certain findings and recommends to the Congress that exports be allowed, and thereafter obtains express Congressional approval within 60 days of the recommendation. The President must find that exports of crude oil:

- o will not diminish the total quantity or quality of petroleum refined within, stored within, or legally committed to be transported to and sold within the United States;
- o will, within three months of the initiation of the exports, result in lower acquisition costs for the domestic refiners if they must purchase imported crude oil to replace such exports, and of that savings not less than 75 percent will be passed on to the consumers through wholesale and retail mechanisms;
- o will be made only pursuant to contracts which may be terminated if the crude oil supplies of the United States are interrupted, threatened, or diminished;
- o are clearly necessary to protect the national interest; and
- o are in accordance with the provisions of the EAA.

The consumer's savings test significantly impedes the President's discretionary authority to allow crude oil exports. Congress must adopt a joint resolution agreeing with the President within 60 days.

Section 7(d)(2) does allow for crude exports based upon exchanges with adjacent foreign countries to achieve increased efficiency of transportation. Crude exchanges, however, remain subject to the five conditions set forth above.

In spite of substantial improvement during the 1980s in the world energy outlook in general and in the U.S. forecast in particular, the Congress recently passed the Export Administration Amendments Act of 1985 (EAAA). The EAAA continued and strengthened the restrictions on the export of ANS crude oil. In fact, while the EAAA runs for three years, the ban on ANS crude oil exports (Section 7(d)) was extended for five years.

3. Energy Policy and Conservation Act (EPCA)

Section 103 of the Energy Policy and Conservation Act generally requires the President to prohibit the export of domestically produced crude oil, subject to certain possible exceptions. Should the President determine that the export of crude oil is in the national interest and consistent with the purposes of EPCA, a national interest finding may be made by the President and such oil can be exported. Authority to make such findings has been delegated to the Secretary of Commerce.

Under this legislation, a national interest finding on crude oil must take into account the need to leave uninterrupted or unimpaired exchange agreements with persons or governments of a foreign state; temporary exports for convenience or increased efficiency of transportation across parts of an adjacent foreign state; and "the historical trading relations of the United States with Canada and Mexico."

4. Mineral Lands Leasing Act (MLLA)

Domestic crude oil that is transported by pipeline over rights-of-way granted under Section 28(u) of the Mineral Leasing Act (MLA) of 1920 is subject to all the limitations and licensing requirements of the EAA. Should the President desire to export such crude oil, he must make and publish an express finding that the export will not diminish the quantity or quality of petroleum available to the United States, is in the national interest, and is in accordance with the EAA. Exempt from these restrictions is crude oil that is exchanged with adjacent foreign states or temporarily exported across adjacent foreign states for convenience or increased efficiency.

If the President makes the findings necessary to authorize an export, he must submit a report to Congress. After receipt of the report, Section 28(u) provides that Congress has 60 days to pass a concurrent resolution of disapproval. Of course, such a provision now is recognized as unconstitutional under the Supreme Court's decision in Immigration and Naturalization Service v Chadha, 462 U.S. 919 (1983).

5. Naval Petroleum Reserves Production Act of 1976 (NPRPA)

The Naval Petroleum Reserves Production Act of 1976 requires any petroleum produced from the Naval Petroleum Reserves to be subject to all of the limitations and licensing requirements of the Export Administration Act. Before any petroleum from the Naval Petroleum Reserve may be exported, the President must make and publish an express finding that such exports will not diminish the total quality or quantity of petroleum available to the United States, are in the national interest, and are in accord with the EAA. Two limited exceptions are available: exchange agreements with adjacent foreign states, and temporary export for convenience or increased efficiency of transportation across parts of an adjacent foreign state.

6. Outer Continental Shelf Lands Act (OCSLA)

Section 28 of the Outer Continental Shelf Lands Act states that the export of any oil or gas produced from the outer Continental Shelf shall be subject to the requirements and provisions of the EAA.

Should the President want to export crude oil subject to the OCSLA, he must make and publish a finding that such exports will not increase reliance on imported oil or gas, are in the national interest, and are in accord with the provisions of the EAA.

If the President makes the findings necessary to authorize exports, he must submit a report to Congress, which has 60 days to pass a concurrent resolution of disapproval. Again, this provision would be unconstitutional under the decision in Chadha cited earlier.

Exempt from these restrictions are:

- o oil that is exchanged in similar quantity for convenience or increased efficiency of transportation with persons or the government of a foreign state;
- o oil that is temporarily exported for convenience or increased efficiency of transportation across parts of an adjacent foreign state and reenters the United States;
- o oil that is exchanged or exported pursuant to an existing international agreement.

7. Short Supply Regulations

The Short Supply Regulations contained in the Export Administration Regulations (15 CFR 377) implement the statutory restrictions set forth above. These regulations prohibit the export of crude oil except for the following special situations:

- o temporary exports of crude oil being exported for convenience or increased efficiency of transportation across parts of an adjacent foreign state, and reentering the United States in the same form;
- o equivalent importation of crude oil that will result directly in the importation into the United States of an equal or greater quantity of that same commodity;

D. GOVERNMENT REVENUES AND EXPENDITURES

1. Federal Taxation

Firms and individuals who produce, transport, refine or market Alaskan North Slope oil are subject to income taxation. In addition, the Windfall Profits Tax applies to production from some fields, and other tax levies such as state royalty, severance and corporate income taxes also affect production decisions. However, on the Federal level, only the crude oil Windfall Profit Tax and the corporate income tax on Alaskan oil production and transportation need be examined in detail; the policy alternatives examined in this study have little effect on the revenues derived from other measures.

2. Taxation of Oil and Gas Exploration and Production

The Federal tax system provides significant incentives related to capital recovery for oil exploration, production, and transportation. These incentives apply generally to all domestic oil and shipping activity. The most significant are intangible drilling costs and percentage depletion, which currently allow certain taxpayers to claim a deduction equal to 15 percent of gross sales on up to 1,000 barrels per day. At this time, the percentage depletion incentive does not apply to North Slope production because the Tax Reduction Act of 1975 denied its benefits to integrated companies, which is the only type of oil companies currently operating on the Alaskan North Slope.

Intangible drilling costs (IDCs) include all expenditures other than for the purchase of tangible property incident to and necessary for the drilling and preparation of wells for production. They may generally be written off when incurred or "expensed." Integrated companies may only expense 80 percent of such costs attributable to successful wells; the remaining 20 percent of the IDCs must be capitalized and recovered through depreciation. Since IDCs make up a large proportion (about 65-85 percent) of the costs associated with successful wells, and nearly all of the costs of unsuccessful wells, the ability to expense them currently rather than to recover them over the life of the well provides an incentive for oil exploration and development.

There is also an investment incentive whenever capitalized expenditures can be recovered in less than the full life of the investment. Capitalized intangible drilling costs may be amortized over 36 months, thereby providing accelerated cost depletion. Tangible drilling costs (e.g., the cost of casing and valving), and lease equipment costs, which must be capitalized, are eligible for 5 year recovery under the Accelerated Cost Recovery System (ACRS), and also qualify for a 10 percent investment tax credit (ITC).

Investments in oil and gas pipeline facilities would generally be recoverable over 10 years and also qualify for the ITC. Lease bonus payments and pre-acquisition geological and geophysical expenses must be capitalized and recovered through cost depletion (depreciation).

Qualified tertiary injection expenses may also be expensed. These expenses are the amounts paid for any tertiary injectant (other than a recoverable hydrocarbon) that is used as part of an enhanced recovery process.

3. Windfall Profit Tax

Except as specifically exempted by statute, crude oil produced in the United States is subject to Windfall Profit Taxation at varying rates dependent upon the age of the producing field, method and volume of production and quality of crude. Oil produced from the Sadlerochit and West Sak Reservoirs at Prudhoe Bay, with the exception of State royalty oil, is subject to the Windfall Profits Tax. Oil produced from other reservoirs north of the Arctic Circle were exempted by statute. The tax rate depends upon whether the production is primary or secondary production (70 percent), or incremental tertiary production (30 percent). The Windfall Profit Tax is deductible from both Federal and State taxable income in calculating the corporate income tax.

The Crude Oil Windfall Profit Tax Act of 1980 (PL 96-223, as amended) defines the taxable windfall profit as the excess, if any, of the wellhead price of the oil over a calculated "adjusted base price," reduced by the State severance tax on that profit. The adjusted base price for Sadlerochit oil is based upon its May 1979 price as determined under Department of Energy regulations at that time. The adjusted base price is the original base price, less \$0.21, adjusted for inflation. In 1984, the average adjusted base price for Sadlerochit oil was \$17.14 per barrel. (Note: For further discussion of the Windfall Profits Tax, see Section III(A) of this study.)

4. Taxation of Shipping

North Slope crude must be transported by ship to U.S. West and Gulf Coast consumers. Current tax law provides several incentives for investment in ships and shipping facilities.

Profits of qualified vessels -- if they are covered by certain agreements with the Secretary of Transportation -- may be sheltered from taxation by depositing them in a capital construction fund. To qualify, vessels must be documented in the United States and must have been built or rebuilt in the United States. In addition, depreciation on these vessels (generally five-year ACRS recovery allowances) may also be deposited in the fund. Earnings on all amounts in the fund are exempt from current Federal taxation.

Amounts withdrawn from the fund to acquire, build or rebuild eligible vessels -- or to repay principal on the debt incurred in such investments -- are not taxed immediately. However, the taxpayer's basis (amount which can be depreciated) in the acquired vessels is reduced to the extent that fund withdrawals represent profits paid in or income earned by the fund. This reduces the depreciation allowances on the new or rebuilt vessel, making more of the vessel's operating revenue subject to taxation. The taxpayer is also entitled to an ITC on at least one-half of its withdrawals for these purposes if the vessel is used in domestic trade.

In short, the deductions for amounts contributed to the Merchant Marine capital construction fund allow the taxpayer to defer if not avoid paying Federal income taxes on its qualified shipping income -- while possibly claiming ITCs -- as long as the contributions are used for further shipping activities.

5. Federal Expenditures

Apart from the special tax benefits available to shipping and oil production, Federal revenues are at risk under a number of non-tax Federal programs if ANS exports are allowed. About 70 tankers engaged in the Alaska oil trade were constructed under Title XI financial guarantees and represent contingent U.S. Government liabilities of \$1.9 billion. Any idling of these tankers would trigger government outlays on the guarantees, for unemployment compensation and for the cost of preserving the displaced, militarily-useful tankers that might be needed for the National Defense Reserve Fleet.

6. State Fiscal Considerations

The production and distribution of oil are also affected by taxation and other policies at the State level. Alaskan North Slope production is most directly affected by State of Alaska measures but is also influenced by some State of California measures. Each State collects royalties and severance taxes from crude oil production on State-owned land and each State levies business activity (income) and property taxes. The fiscal operations of both States are affected by the production and distribution of North Slope oil.

Energy-based revenues provide a substantial proportion of Alaskan State income. Severance tax collections, currently levied on non-royalty production at the rate of 15 percent of wellhead value, have grown at an average annual rate of 55 percent since 1975. Severance tax revenue represented nearly 75 percent of tax collections in 1984. Lease rents and royalties from oil and gas production contribute almost as much to State revenues as severance taxes. In addition, the property tax is now imposed only on oil and gas producers, and at least 75 percent of Alaskan corporate income tax receipts are derived from oil and gas production or transportation.

The existing prohibition on export of ANS crude influences California's fiscal position and economic development by depressing crude oil and petroleum product prices on the West Coast. ANS production that is not consumed in Alaska or on the West Coast is usually transported to the U.S. Gulf or East Coasts on U.S. flag vessels, at more than three times the transportation costs to the West Coast. Accordingly, North Slope producers have significant incentives to discount their excess crude on the West Coast and avoid the added transportation costs to the Gulf or East Coast. The surplus of crude on the West Coast tends to depress wellhead crude values and production in California, which reduces California royalty and tax collections.

The downward pressure on California production introduced by the Federal export prohibition is mitigated to some extent by low severance tax rates. The California severance tax is applied as a user charge with rates set each year to cover administrative costs associated with oversight of the State's oil and gas industry.

E. TRANSPORTATION AND TRADE PATTERNS

1. Introduction

When ANS oil was discovered in the 1960s, it was expected that West Coast markets would consume virtually all of its production. However, by the time the oil began to flow through the TAPS in 1977, West Coast markets could not absorb all the ANS crude production, which was much higher than originally anticipated. In addition, West Coast demand had not grown as rapidly as expected, and California oil production was greater than had been projected. These factors, combined with the export ban, made it necessary to transport some ANS crude through the Panama Canal to the Gulf Coast, East Coast, Puerto Rico, and the Virgin Islands.

With the exception of ANS shipments, U.S. maritime involvement with oil transportation has been in decline. Crude oil and petroleum product pipelines have increased their market share and changes in trade flows have eliminated some tanker markets. The Alaska shipping trade is now the primary source of employment for domestic tankers.

2. Legislation

ANS shipping patterns have been shaped by the export ban and by several other laws and Federal regulations. The following are brief summaries of relevant regulations and trade laws.

- o Jones Act - The Jones Act (Sec. 27 of the Merchant Marine Act, 1920) requires that all cargo transported in the domestic maritime trades be carried in vessels built in the United States, documented under U.S. law, owned by U.S. citizens, and crewed by U.S. seamen. This requirement holds whether the cargo moves directly between two U.S. ports or is transshipped via a foreign port or ports (e.g., pipeline shipments across Panama). An important exception to the Jones Act is that ocean shipments to and from the Virgin Islands may be on foreign-flag vessels.
- o The primary function of the Jones Act is to maintain a market for U.S. tankers. This is necessary because vessels that are U.S.-built and U.S.-operated have much higher capital and operating costs than foreign tankers. Even with capital and operating subsidies, U.S. tankers have had only limited success competing with foreign vessels. Without subsidies, U.S. tankers are simply unable to compete with foreign flag tankers.
- o Construction Differential Subsidy Program - Under the Merchant Marine Act of 1936, certain ships are eligible for a subsidy applied to up to 50 percent of the cost of their construction in U.S. shipyards. Tankers built with Construction

- o Differential Subsidy (CDS) assistance are also U.S.-built, U.S.-manned, and U.S.-owned. However, unlike the Jones Act, this subsidy applies only under the condition that affected ships are not eligible to operate in the domestic trades on a full-time basis. Soon after the TAPS opened, the demand was greater than the available supply of large Jones Act tankers to carry ANS crude oil from Valdez to Panama. As a result, large U.S. flag crude tankers built with CDS assistance were given permission to enter the ANS trade on a temporary basis, as the law permitted. Very Large Crude Carriers (VLCCs - tankers over 100,000 DWT) were permitted to operate in the domestic ANS trade for periods of up to six months per year under the condition that all Jones Act tankers over 100,000 DWT were fully employed. Since 1977, CDS-built tankers have been allowed to operate in the domestic trades on 42 different occasions.
- o While the use of CDS-built VLCCs has helped somewhat to alleviate the shortage of suitable tonnage, the six-month time restriction and the "100,000 DWT rule" have limited competition, necessitated the use of smaller vessels, and resulted in higher shipping costs than would have been the case otherwise.
- o Title XI of the Merchant Marine Act of 1936 - Title XI established the Ship Financing Guarantee Program, which provides loan guarantees on up to 75 percent of a vessel's financing, subject to Federal operating and financial conditions.
- o As of June 25, 1985, 70 tankers had about \$1.9 billion in Title XI guarantees or about 27 percent of the total \$6.9 billion Title XI exposure. Any changes that affect the fortunes of ships in the ANS trade can therefore also affect the Federal Government's loan commitments.
- o Port and Tanker Safety Act - The Port and Tanker Safety Act imposed more stringent environmental standards for crude oil and petroleum product tankers operating in U.S. waters. As a result, many tanker owners have decided that, given market conditions, it would not be worthwhile to incur the costs necessary to meet the new requirements for older, small tankers and so, from 1981 to 1984, 66 ships totaling 1.8 million DWT were scrapped.

3. Demand for Shipping Capacity

The factors that determine the demand for shipping capacity include: number of shipments, length of voyage, barrels per ton of cargo, and number of days in operation. For example, to ship crude from Valdez to Panama takes 32 days (round trip); there are 7.2 barrels per long ton; and the average vessel operates 345 days per year at 93 percent of capacity. Based on these factors, for every

100,000 B/D of ANS crude shipped to Panama, about 510,000 DWT of tanker capacity is required, roughly twice the capacity necessary for the Valdez to California route.

4. ANS Shipping Trades

Valdez to Gulf Coast/East Coast/Puerto Rico: This trade accounts for the largest part of ANS shipping, requiring about 700,000 DWT of capacity for each 100,000 B/D of traffic. Typically, the oil is transported from Valdez to a terminus of the Panama Pipeline in Jones Act vessels of 100,000 to over 200,000 DWT, or in one of the five CDS-built vessels of over 200,000 DWT. The pipeline transports the oil from the Pacific side to the Caribbean side where it is transferred to tankers of 90,000 DWT or less that carry it to its final destinations on the Gulf and East Coasts.

Valdez to West Coast (includes Hawaii and Alaska): Oil is generally carried to the West Coast in tankers of over 100,000 DWT except when volumes are small or the port has shallow draft restrictions. Intra-Alaska shipments are typically carried in tankers of under 50,000 DWT.

Valdez to Virgin Islands: The average volume of ANS shipments to the Virgin Islands is 100,000 B/D and, with few exceptions, it is transported around Cape Horn by foreign-flag tankers.

5. ANS Trade in Recent Years

Chart E-1 shows volumes and destinations of ANS shipments for the years 1981 to 1985. As ANS shipments increased from 1981 to 1982, tanker capacity in the trade also increased, reaching a high of 7.4 million tons in 1982. However, the opening of the Trans Panama Pipeline in October of that year reduced the tonnage needed by an estimated 560,000 DWT. Lower shipments to Panama in 1984 reduced needed capacity by another 600,000 DWT, and in 1985, the needed capacity fell to its present level of 6.1 million DWT, or 59 tankers.

U.S.-flag carriage now comprises the full-time equivalent of 18 tankers (2.9 million DWT) on the Valdez to Panama route (almost all over 100,000 DWT); the full time equivalent of 21 tankers (1.9 million DWT) for the trip from Valdez to the West Coast (mostly 55,000-90,000 DWT); and the full-time equivalent of 20 tankers (1.3 million DWT) that operate from Panama to Gulf and East Coast ports (mostly over 55,000 DWT).

6. California Oil Pipelines

A large projected increase in offshore California production plus continuing shipments of Alaskan North Slope crude oil will result in a daily surplus of several hundred thousand barrels of crude oil on the West Coast. In order to move this oil surplus from California

and Alaska to Gulf Coast refineries, two interstate pipelines have been proposed -- one of which is under construction.

The All American Pipeline is scheduled to start moving heavy crude through its 30-inch system during the first quarter of 1987. The other proposed pipeline is the Pacific Texas Pipeline Company which plans to begin construction in early 1987 with completion scheduled for mid-1987.

Some industry sources project that sufficient surplus California offshore oil will not be available until the early 1990s to fill the 300,000 B/D capacity of the All American Pipeline. There is also some doubt that the much larger 900,000 B/D Texas-Pacific pipeline to carry both Alaskan and offshore California crude oil will ever be built.

There have been recent activities in California and Texas that have some long range impacts on California interstate oil pipelines. One -- a November referendum to restrict hydrocarbon development offshore Santa Barbara -- was defeated by the voters resulting in a victory for energy producers. The other activity concerns the extension of the All American Pipeline to Houston from McCamey, Texas, and has not been resolved as yet.

7. The All American Pipeline

The All American Pipeline Company (AAPL) is a unit of Celeron Corporation which is a subsidiary of the Goodyear Tire and Rubber Company. Projected costs of the nearly 1,800-mile and 30-inch heated pipeline is about \$1.5 billion. Construction costs are estimated at \$885 million and capitalized interest and overhead compose the remaining \$615 million. Financing for the pipeline was completed in late October when 14 international and domestic banks agreed to provide more than \$700 million of term loans.

The AAPL will move crude oil from a point near Santa Barbara, California to Webster, Texas on the Gulf of Mexico. The pipeline is more than twice the length of the Trans-Alaska Pipeline. It is scheduled for completion in the first quarter of 1987. There will be 21 pump/heat stations along the route to ensure the flow of the heavy crude that will take about 18 days to reach the Texas refineries. The tariff is expected to be about \$1 a barrel less than shipping the crude oil from California to the Gulf Coast via the Panama Canal or the Trans-Panamanian Pipeline.

Construction efforts are currently underway on four sections of the All American Pipeline. Over 646 miles of pipeline had been installed as of mid-January 1986. Pipe is being laid at the rate of 5 miles per day from waiting stockpiles. Installation of pumping stations was scheduled to begin in February 1986.

There has been a delay in the pipeline's acquisition of an operating permit from McCamey to Webster in Texas. At issue is a 6.6 mile stretch of pipeline south of Austin that would cross the Edwards Aquifer, the area's major source of fresh water. A lawsuit has been filed by a group of landowners against the Texas Railroad Commission to halt Commission hearings on granting an operating permit through the Aquifer. The opponents feel that there is a threat of leaks which could pollute the natural underground water system.

If the court upholds the lawsuit, then the Railroad Commission must promulgate new safety regulations for the pipeline that could take months. If the court rules against the landowners, the Railroad Commission could approve the operating permit later this year. The Aquifer is already crossed by 28 crude oil, gas and product pipelines and the company anticipates that an operating permit will be granted in the Spring. The company has obtained over 1,400 miles (82 percent) of the 1,750 miles of private-right-of-way, Federal, State, and County easements that will be needed for the project.

Although the All American Pipeline has no throughput commitments as yet, it is likely that it will use the pipeline to ship its own supplies of crude oil. In 1982, Celeron acquired interest in 24 leases in the Santa Barbara Channel and the Santa Maria Basin off southern California. In one of these leases, Celeron owns a 27 percent stake in a 70-well offshore drilling platform called Julius that is designed to produce 40,000 B/D and is scheduled to start production in early 1987. In late January 1986, a 3,700 B/D discovery was found in the Point Sal area of the Santa Maria Basin in which Celeron has a 10 percent interest.

Along with these offshore finds, Celeron has also recently purchased heavy crude oil properties in Kern County, California. The two properties are the Formax holding of 198 acres in Kern County with 106 production wells on the land and the Chevron Hill Property which covers 502 acres of the South Belridge Field and has 130 production wells. The company plans to drill new wells on the properties and, with steam injection methods, they expect to increase production substantially in both areas. In addition, Celeron has been meeting with a large number of producers of offshore California crude and Gulf Coast refiners to report on the progress of the pipeline and to obtain information on the transportation needs of these groups.

One remaining crucial factor is whether the interstate pipelines would be profitable in light of the recent sharp drop of oil prices below \$20 a barrel. The company spokesmen from the All American Pipeline recently indicated that the pipeline needs to move about 100,000 B/D to break even. If oil prices settle at about the \$20 level, there would be no problem; however, if heavy crude prices remain at or below the \$15 level, there would be some concern about the profitability of the pipeline.

8. The Pacific Texas Pipeline Company

The second California interstate pipeline will carry crude oil from a Long Beach tanker terminal to Midland, Texas. The route for the 1,026 mile pipeline is similar to that of the All American Pipeline Company, but they are not in direct competition. This pipeline will not be heated and will carry lighter crude oil from Alaska as well as heavy crude oil from offshore Santa Barbara. The project is planned for a capacity of 900,000 B/D and is expected to be in operation by late-1987. It is estimated that companies will save about \$2 a barrel by using the pipeline rather than shipping oil through the Panama Canal or the Panama pipeline.

The plans for this pipeline are still in the engineering, design, and environmental permit stage. During June 1985, the project was given a vote of confidence when the Los Angeles Harbor Improvement Corporation (LAHIC) approved a resolution for a \$430 million issue of tax-exempt bonds. These bonds will help finance the port facilities for the California-to-Texas pipeline. This means that after the pipeline project has obtained the required permits and agreements, it will be able to fund a major part of the \$1.6 billion cost for the pipeline with low-cost financing. The \$430 million will be used at Los Angeles for the pipeline's receiving terminal and related facilities. Construction on the pipeline is expected to begin in 1986 and will take 16 to 18 months.

There are a number of reasons to question whether the Pacific Texas Pipeline will be built. Financing has not been completed as yet and although pipe purchases have been made, much of the pipeline is still in the planning stage. Although construction of the pipeline is expected to begin in 1986, it is obvious that the projected oil surpluses cannot support two pipelines before 1990. The longer that this group delays moving forward on the project, the more likely that it will be built later, if at all.

9. Recent Changes in the Trade

As recently as 1981, it cost \$5.00 to \$5.50 to transport a barrel of oil from Valdez to the Gulf Coast and about \$1.40 per barrel to ship AHS crude oil to West Coast ports. Since then there have been major changes in the trade.

With the opening of the Panama Pipeline, the transfer of oil from the Pacific to the Caribbean has become more efficient, accounting for an estimated decline of 500,000-600,000 DWT in the amount of capacity needed. There has also been considerable scrapping of old tankers since 1981: over 3 million DWT in tanker capacity was scrapped in 1983 and 1984. Moreover, there has been the introduction of new tonnage into the trade. Four tankers in the

70,000-140,000 DWT range were rebuilt and reflagged under the provisions of the Wrecked Vessels Act since 1981, and Exxon decided to build two 209,000 DWT tankers that will enter the fleet in 1986 and 1987.

Finally, on May 3, 1985, the Department of Transportation decided to allow a one-year opportunity for owners of tankers built with CDS subsidies to repay the unamortized balance on the subsidies (plus interest) in return for the right to operate full-time in the domestic trades. Owners of two ships have taken advantage of the offer, which has added 530,000 DWT to the ANS trade.

As a result of these changes, there has been almost continual decline in ANS shipping rates. We estimate that by 1985, the average cost to ship ANS crude to the Gulf Coast was about \$4.00 per barrel, \$1.00 to \$1.50 less than it was in 1981, and that it cost about \$1.15 to ship oil from Alaska to the West Coast, down from \$1.50 in 1981.

10. Proprietary Tonnage

Approximately 40 percent of domestic tanker tonnage in the Alaska trade is owned by oil companies; the remainder is chartered (see Appendix B for explanation of types of charters). Among the oil companies, there is a wide variance in the amount of proprietary tonnage versus chartered tonnage. Sohio, for example, must charter its entire tanker requirements because it is controlled by a foreign company (British Petroleum), which cannot own U.S.-flag tonnage.

Exxon owns about 30 percent of its fleet, for all its operations, and charters the rest. In 1985 for the ANS trade, it had five tankers operating in the Pacific and seven tankers operating east of Panama.

For all its operations, Arco owns 70 percent of its fleet and charters the remainder. For the Alaska trade in 1985, it had eight tankers operating in the ANS trades, all in the Pacific. On July 26, 1985, Arco repaid its unamortized CDS (plus interest) on two 265,000 DWT VLCCs, which will be deployed in the Valdez to Panama trade.

Chevron used seven different tankers in the ANS trades during 1985, most making only a few trips during the first eight months of the year. Finally, three other oil companies recently operated tankers in the ANS trade for at least some period of time: Mobil (3), Sun Oil (3), and Texaco (2).

11. Militarily Useful Tankers

Although all tankers available to the country might be used in a military emergency, certain vessels are particularly useful -- the tankers under 100,000 DWT that can carry refined products (not just

crude oil, which has no direct value in military operations) and can serve most port areas without special offshore loading or unloading arrangements.

The Alaska trade is particularly important for maintaining the active use of these tankers. During 1985, out of 81 tankers that participated in the ANS trade for any period of time, 57 tankers totaling 3.4 million DWT were militarily useful; all but seven of these were capable of transiting the Panama Canal.

TABLE E-1
HISTORICAL TRADE FLOWS
FOR AHS CRUDE
(Thousand B/D)

<u>Year</u>	<u>West Coast</u>	<u>Gulf/East Coast</u>	<u>Virgin Islands</u>	<u>Total</u>
1978	681	347	27	1,055
1979	878	310	81	1,269
1980	956	472	106	1,534
1981	868	542	126	1,536
1982	817	701	100	1,618
1983	836	712	106	1,654
1984	969	569	118	1,656
1985*	1,000	630	128	1,758

West Coast statistics include shipments to Alaska and Hawaii
 Gulf/East Coast statistics include shipments to Puerto Rico.

* Statistics from January - August

F. FOREIGN POLICY

The oil shocks of 1973-74 and 1979-80 clearly demonstrated how global the oil market has become. When oil supplies were disrupted and output reduced, prices rose dramatically, even in countries that do not import oil, as buyers scrambled to outbid each other for the available oil. Thus, in the future, the United States will be affected by price rises in the global oil market, even if supplies to the U.S. are not disrupted. The Pacific Rim oil importing countries were (and still are) particularly vulnerable to oil supply disruptions and in past disruptions greatly contributed to bidding up global oil prices. The security of U.S. oil supply therefore depends not only on the physical possession of crude oil, but also on our ability to obtain it at a reasonable price. Energy security requires that we take measures to mitigate the price increase due to a supply disruption and thus lessen the damage to the U.S. economy.

Foremost among the measures to protect the U.S. from oil price rises in an oil supply disruption is the Strategic Petroleum Reserve. It now contains about 490 million barrels of oil, or over 100 days of net imports of crude oil. In addition, the U.S. has sought to persuade its IEA partners to increase the level of their oil reserves for use in an emergency. The existence of substantial oil stockpiles around the world creates a buffer that would dampen the tendency for a global oil supply disruption to result in sharp price rises.

The Administration has also moved toward a more open trading system that would allow market forces to determine oil prices and distribution. In the International Energy Agency, the U.S. has led the formation of a consensus that reliance on market forces is an effective means to promote stability and energy security. The U.S. has encouraged the United Kingdom and Norway to rely on the free market in determining oil prices and quantities, and to resist efforts by OPEC to control the market.

To aid the development of a free global energy market which would enhance U.S. energy security, recent steps have been taken by the Administration to relax U.S. crude oil export restrictions on non-Alaskan North Slope oil. Pursuant to the agreement reached at the Quebec Summit in March 1985, the President made national interest findings under the Energy Policy and Conservation Act, the Mineral Lands Leasing Act and the Outer Continental Shelf Lands Act to permit the export of crude oil to Canada. Likewise, Canada liberalized its crude oil trade with the United States. The President, on the recommendation of his Economic Policy Council, announced his decision to lift controls on Alaskan Cook Inlet oil in October 1985. The Secretary of Commerce found that allowing exports of crude oil from Alaska's Cook Inlet is in the national interest and consistent with the purposes of the Energy Policy and Conservation Act. The production on Cook Inlet is small, about

47,000 B/D in 1985. Only about 4-5 MB/D is anticipated to be available for export to the Pacific Rim countries. This action allows for, but does not require, the export of crude to the Pacific Rim. The message is positive and encourages reciprocal market opening moves across the board.

G. ENERGY SECURITY

In discussing energy security, it is useful to distinguish between oil supply vulnerability and oil import dependence. Our exposure to higher oil costs is not limited to the level of our imports, so long as trade is unrestricted. Our energy security depends more on how high oil prices may rise during a disruption rather than on the level of our oil import dependence. The difference is important because while we all may agree that improving energy security is a worthy objective, we may differ considerably in terms of how to achieve that objective.

Even if the United States imported no oil, price increases caused by supply disruptions would impose large costs on our economy. Certain sectors (e.g., agriculture, chemicals, petrochemicals, and the automobile industry) would suffer unemployment and idle resources due to large oil price increases. In addition, the effect of a disruption on our import dependent trading partners would be transmitted back to our economy in the form of reduced demand for some U.S. exports and higher prices for goods imported by the United States.

The most effective energy security policy is to maintain an adequate strategic oil stockpile (as the United States does) and to urge other oil consuming countries to increase their stockpiles to reasonable levels and to encourage them to develop flexible response measures for use in the event of an oil supply disruption. Such flexible policies would include a market response to changing oil prices.

In the event of an oil supply disruption, restrictions on the export of domestic oil will not reduce the impact on the United States. Domestic oil consumption would fall and the economy would suffer losses even if Alaskan oil were retained for domestic use. Restrictions on Alaskan oil exports would result in less imports coming into this country than would otherwise be the case, but such restrictions cannot insulate the United States from price increases in the world oil market. As noted previously, past oil supply disruptions have already demonstrated the highly integrated nature of the world oil market.

The disruption experiences of 1973, 1979, and 1980 showed that the critical factors in mitigating supply shortages--and thus enhancing energy security--are the adequacy of stockpiles and excess production capacity.

At the time of the 1973 and 1978 disruptions, world oil demand had almost reached total oil production capacity. The price increases that resulted from those disruptions were partially responsible for the worldwide recession from which we are now recovering. In

addition, the price increases encouraged significant conservation and energy efficiency improvements. Both results led to reduced world oil demand and current spare production capacity estimated at about 10 million barrels of oil per day. As international economic recovery continues and energy demands by developing countries increase, this spare production capacity will diminish, but world demand is not expected to press again against total production capacity until the 1990s. Thus, in terms of the critical factors affecting energy security, the United States and its allies are significantly better off than in the recent past.

Note: One example of the benefits of stockpiling: it is estimated that a stock release of 25-30 million tons "would have been sufficient to replace the entire physical shortfall during the first three months of the 1979 and 1980 supply disruptions". [IEA statement, 1984]

H. EMPLOYMENT

Lifting the ban on exports of Alaskan North Slope (ANS) crude oil would have employment effects. This section surveys historical trends in employment for the economic sectors that would be principally affected.

The following average annual employment data were provided by the Alaska Department of Labor for Alaskan industries that are directly involved in the production of oil and refined products:

TABLE H-1

TOTAL EMPLOYMENT IN ALASKA
(number of workers)

<u>Year</u>	<u>Oil and Gas Extraction (SIC 13)</u>			<u>Oil Refining</u>
	<u>State</u>	<u>Anchorage Area</u>	<u>Northern Labor Market Area</u>	<u>(SIC 291)</u> <u>State</u>
1974	2,608	1,279	383	50
1975	3,440	1,249	1,166	61
1976	3,644	1,344	1,264	70
1977	4,347	1,492	1,961	93
1978	5,138	1,825	2,384	146
1979	5,382	1,868	2,612	146
1980	6,159	2,522	2,779	177
1981	8,177	3,130	3,872	190
1982	8,085	3,525	3,574	167
1983	7,444	3,733	3,330	187
1984	8,045	3,422	3,612	202
1985E	8,789	4,149	3,875	220

Note: 1985 data are based on the first six months of the year.

Source: ES-202 employment counts provided by the Alaska Department of Labor.

Oil and gas extraction (Standard Industrial Classification (SIC) 13) measures employment in crude oil production. Although most of this employment is in the Alaskan North Slope (ANS) area, the Alaskan Department of Labor estimates that nearly all SIC 13 employment in the Anchorage area is related in some way to ANS crude oil production. State employment figures show that over 98 percent of the employment growth in Alaskan oil and gas extraction over the 1974-1984 period has occurred in the Anchorage and Northern labor market areas. In 1984, Alaskan private sector employment was 158,077, five percent of which were employed in crude oil production.

Employment in oil refining (SIC 291) and pipelines (SIC 46, which excludes natural gas) is directly affected by ANS crude oil production. Four refineries are currently operating in Alaska, but only one of these, the Mapco Refinery at North Pole, uses ANS crude oil. Capacity at Mapco is 46,500 B/D, a third of Alaskan refinery capacity but only 2.6 percent of estimated 1985 crude oil production. Alaskan refinery employment is estimated to be 2.5 percent of oil and gas production employment (SIC 13) for 1985.

Workers stationed along the Trans-Alaska Pipeline (TAPS) are included in the State employment estimates for pipelines (SIC 46). Alaskan employment in pipelines is less than 15 percent of overall oil and gas production employment, based on 1985 estimates. Since the TAPS is in place, workers currently employed on pipelines are primarily involved with maintenance.

Although it is likely that there are significant indirect employment effects within the Alaskan economy caused by oil production, they cannot be measured with accuracy. There is, for example, a wide variety of service industries in the North Slope area which depend mainly on spending by the oil industry and its employees. The same is true for the Anchorage area, which serves as a base for oil company staff support facilities and where many oil workers either reside or visit frequently in between their one or two week work shifts on the North Slope.

In addition, significant increases in State and government employment may have resulted from increased revenues derived from State and local taxes on oil production. According to the Alaska Department of Labor, petroleum revenue to the State increased from \$477.6 million in fiscal year 1977 (or 55 percent of the State's general fund) to \$2,861.6 million in fiscal year 1984 (or 84 percent of the State's general fund). Over this same period, State government employment increased from 14,376 in 1977 to 19,860 in 1984. Also, local government employment increased from 19,083 in 1977 to 28,400 in 1984.

Employment in construction also increased as added State and local government revenues were used to finance construction projects and to provide mortgages to first-time homeowners at lower-than-market interest rates.

Under current export restrictions, all ANS crude oil not processed by Alaskan refineries must be shipped to other markets in the United States. Due to the Jones Act and other statutory requirements, all U.S. tankers carrying ANS oil to U.S. ports must be U.S.-owned and operated, and must have American crews. However, direct shipments of ANS oil to the Virgin Islands are exempt from the Jones Act.

Maritime employment on the so-called Jones Act tankers is shown in Table H-2. These data show the number of tankers, the average number of seafarers per tanker, and the number of seafarers on U.S. flag tankers actually engaged in shipping ANS oil in January of each year. Seafaring employment and the number of tankers increased in the 1980-1982 period and declined thereafter. Also, there is some indication that the average number of seafarers per tanker has declined over the 1981-1985 period, although this is not true for all routes.

The size of the Jones Act tanker fleet employed in the ANS trade measured in deadweight tons (DWT), number of tankers, and average tanker size on each trade route are shown in Table H-3. Shipments from Panama to Gulf and East Coasts and Puerto Rico are made on relatively small tankers, while shipments from Valdez to Panama are made on large tankers. There is no apparent trend in average tanker size over time.

TABLE H-2

NUMBER OF SEAFARERS
AND NUMBER OF JONES ACT TANKERS
(January of Each Year)

	<u>Valdez to</u> <u>West Coast</u>	<u>Valdez to</u> <u>Panama</u>	<u>From</u> <u>Panama (a)</u>	<u>Total</u>
1980				
Seafarers	1,394	681	1,806	4,025 (c)
Tankers	22	11	23	58 (c)
Ratio (b)	63	62	79	69 (c)
1981				
Seafarers	1,431	708	2,062	4,306 (c)
Tankers	22	11	27	61 (c)
Ratio (b)	65	64	76	71 (c)
1982				
Seafarers	1,293	1,237	3,117	5,647
Tankers	19	20	41	80
Ratio (b)	68	62	76	71
1983				
Seafarers	1,267	1,272	2,362	4,901
Tankers	20	19	33	72
Ratio (b)	63	67	72	68
1984				
Seafarers	1,635	1,090	1,513	4,239
Tankers	27	17	22	66
Ratio (b)	61	64	69	64
1985				
Seafarers	1,523	959	1,385	3,866
Tankers	26	15	21	62
Ratio (b)	59	64	66	62

Notes:

- (a) Shipments from Panama include shipments bound for the Gulf and East Coasts and Puerto Rico.
- (b) Ratio refers to the average number of seafarers per tanker.
- (c) Totals include shipments from Panama to the Virgin Islands on U.S. flag tankers.

Source: U.S. Maritime Administration.

TABLE H-3

SIZE OF JONES ACT TANKER FLEET (IN DWT)
AND NUMBER OF JONES ACT TANKERS
(January of Each Year)

	<u>Valdez to</u> <u>West Coast</u>	<u>Valdez to</u> <u>Panama</u>	<u>From</u> <u>Panama (a)</u>	<u>Total</u>
1980				
Size	2,343,100	2,122,500	1,192,300	5,791,900 (c)
Number	22	11	23	58 (c)
Ratio (b)	106,505	192,955	51,839	99,860 (c)
1981				
Size	2,436,600	2,148,400	1,393,500	6,027,800 (c)
Number	22	11	27	61 (c)
Ratio (b)	110,755	195,309	51,611	98,816 (c)
1982				
Size	1,841,900	2,954,300	1,817,000	6,613,200
Number	19	20	41	80
Ratio (b)	96,942	147,715	44,317	82,665
1983				
Size	1,785,700	3,273,500	1,762,200	6,821,400
Number	20	19	33	72
Ratio (b)	89,285	172,289	53,400	94,742
1984				
Size	2,144,000	2,603,900	1,316,000	6,063,900
Number	27	17	22	66
Ratio (b)	79,407	153,171	59,818	91,877
1985				
Size	2,220,100	2,433,200	1,315,300	5,968,600
Number	26	15	21	62
Ratio (b)	85,388	162,213	62,633	96,268

Notes:

- (a) Shipments from Panama include shipments bound for the Gulf and East Coasts and Puerto Rico.
- (b) Ratio refers to average tanker size as measured by the ratio of deadweight tonnage (DWT) to the number of tankers.
- (c) Totals include shipments from Panama to the Virgin Islands on U.S. flag tankers.

Seafaring employment is measured in terms of billets, which are positions or work stations. The U.S. Maritime Administration estimates that 2.3 seafarers are needed for each billet to cover different shifts and to allow for vacation and sick leave. There is no clear relationship between the number of seafarers per ship or per deadweight ton (DWT). Furthermore, the data in Table H-4 show that seafaring employment is about the same for different tanker sizes.

TABLE H-4
RELATIONSHIP BETWEEN CREW SIZE
AND TANKER SIZE FOR JONES ACT TANKERS
EMPLOYED IN THE AFS TRADE

<u>Trade Route</u>	<u>Tanker Size</u>	<u>Crew Size (number of billets)</u>	
		<u>Range</u>	<u>Average</u>
Valdez to:			
West Coast and Panama	less than 55,000 DWT	17-32	24
	55,000-90,000 DWT	21-32	28
	110,000-140,000 DWT	23-32	28
	170,000-190,000 DWT	22-31	28
Panama	over 200,000 DWT	28-29	29
Panama to:			
Gulf and East Coasts	less than 55,000 DWT	17-33	25
	55,000-90,000 DWT	21-36	28

Source: U.S. Maritime Administration

III. EFFECTS OF CHANGES IN INCENTIVES FOR ANS PRODUCTION

INTRODUCTION

Section 126 requires that this study address "the issues and related data concerning possible changes in the existing incentives to produce crude oil from the North Slope of Alaska, including changes in Federal and State taxation, pipeline tariffs, and Federal leasing policies...." A wide variety of options exist that would increase the incentives to produce ANS oil, ranging from decreasing taxes on oil producers to providing direct subsidies for production. Any change that directly or indirectly raises the profitability of oil production on the Alaskan North Slope would potentially stimulate increased oil production during the time period being studied (1987-2000). Specific policy options were selected for analysis to serve as examples for each of the three categories referred to in Section 126. The policy options demonstrate the types of impacts which could occur in response to changes in the incentives to produce oil from the Alaskan North Slope. Inclusion of a policy option for analysis does not in any way imply an endorsement for that option, nor does exclusion of an option imply disapproval.

ASSUMPTIONS

The discussion of taxation, tariffs and leasing would be premature without first mentioning the assumptions underlying the analysis.

The following discussion briefly addresses the oil price, industry investment and price elasticity elements of Section III analysis; a more thorough treatment of each issue can be found in the technical appendices. The basic assumptions are:

Oil Prices - The analysis draws upon the midpoint of the U.S. average refiner acquisition cost and the related Valdez FOB price. In this case, the 1985 U.S. Imported Refiner Acquisition Cost (IRAC) and Valdez prices are \$27 and \$23 per barrel, respectively.

- The midpoints 1987 prices are projected to drop to \$24, and \$20 respectively by 1990.

Industry Investment - The analysis assumes that companies will increase investment in anticipation of higher profits yielded by the increased incentives. The industry investment occurs on a short-and long-term basis:

- Short-term - Increased incentives will increase the investment in production from proved reserves. This can entail using enhanced recovery techniques or waiting longer before shutting in a well. Once a well is shut in, it cannot be reopened. Therefore, the increase in production from these short-term investments represents a permanent addition to total oil production.
- Long-term - The anticipation of higher future profits from production will stimulate increased exploration activity and earlier development of new fields. Due to the long lag time between discovery and production, the increase in production caused by this type of investment does not occur until 15 years or more after investment. This increase in production does not constitute a permanent increase in total production; rather development and production are shifted forward in time.
- The proceeds from incentives that result in higher wellhead prices will be invested in a manner consistent with the preceding discussion and based upon private companies' perceptions of oil price movements and attractive acreage to explore. However, increased current cash-flow is not a requirement for increased current investment.

Supply Elasticity - This represents a common method of quantifying an oil production response resulting from an increase in a wellhead price. In as much as price effects are cumulative and there is at least a 10-15 year lag between exploration and marketed Alaskan production, the price elasticity of supply will not reach its full value until after 15 years from the initial (1987) price change.

A. POLICY OPTIONS AND ESTIMATES OF RESULTING CHANGES IN NETBACK PRICE

POLICY OPTIONS ANALYZED

Taxation

The policy option examined regarding possible changes in Federal taxation relates to an exemption of ANS crude from the Federal Windfall Profit Tax (WPT). Oil produced from the Sadlerochit and West Sak Reservoirs at Prudhoe Bay, with the exception of Alaska state royalty oil, is subject to the Windfall Profit Tax. It would be possible to make changes in WPT that only affect the Alaskan North Slope. The policy option considered is an exemption of all ANS oil from the WPT.

Turning to State taxation, the most significant and most obvious tax is the State Severance Tax. Policy options considered are a 25 percent and a 50 percent reduction in the severance tax rate.

Tariffs

The tariffs charged for transporting oil through the Trans-Alaskan Pipeline System (TAPS) have been the subject of extended litigation. A settlement was reached in late October, 1985 between the U.S. Department of Justice, the State of Alaska, and six of the eight pipeline owners. Under the settlement, pipeline tariffs will be calculated according to an agreed-upon formula and will depend on the amount of oil flowing through TAPS. Adoption of the settlement tariffs is not a policy option per se, since it is, for the most part, a fait accompli. However, the impacts of the settlement are of interest. Therefore, this study evaluates the change in tariffs from what they would have been in the absence of the settlement to what they will be under the settlement as if it were a policy option.

Leasing

Two important issues were identified in the category of Federal leasing policies: lease availability and royalty rates. Changes in the availability of acreage for lease do not impact on the incentives to produce oil, but they can restrict the ability to do so. No specific policy options were identified regarding lease availability because current policies have not and are not expected to restrict activity.

With regard to royalty rates, there is a Federal statutory minimum royalty rate of 12.5 percent for Federal leases. Reducing this rate would increase the incentives to produce oil. Policy options considered were a 25 percent and a 50 percent reduction in the royalty rate for all current and future Federal leases.

Change in Wellhead Price

It is most common and familiar to discuss the incentives to produce oil in terms of the wellhead price. A higher wellhead price provides oil producing companies with an economic incentive to produce more oil. However, of the policy options analyzed, only changing the TAPS tariffs would directly impact wellhead price. The other policy options analyzed affect the return to the producer without affecting the wellhead price. (For the purposes of this study, "return to the producer" was defined as the wellhead price minus royalty payments, severance taxes, and windfall profits tax payments.) In the appendix, the "equivalent wellhead price" is calculated for each policy option analyzed. The equivalent wellhead price is defined as the wellhead price that results in the same return to the producer as does the policy option. Table III-1 shows the original wellhead price and the equivalent wellhead price for each policy option identified.

1. Federal and State Taxation

Windfall Profit Tax - The Windfall Profit Tax only applies to ANS production from Prudhoe Bay (the Sadlerochit and West Sak Fields), and is scheduled to be phased out by 1994. Assuming mid-point oil prices, the wellhead price falls below the \$17.85 per barrel threshold price from which the WPT is calculated between 1987 and 1990. Only if oil prices turn out to be near the high end of the projected range would any ANS production be subject to the WPT.

The recent declines in oil prices make it unlikely that the wellhead price will rise above the WPT threshold base price. (Note: The ANS wellhead price in March 1986 is estimated at \$8.43-9.17 per barrel - see Table VI-1.) However, if prices rise, then exempting Sadlerochit and West Sak oil from the WPT would increase the incentives to produce oil from these two fields. Assuming high future oil prices, exemption from the WPT would increase return to the producer by an amount equivalent to a 9.1-21.8 percent increase in wellhead price. In short, this means an increase in the 1987 and 1990 wellhead prices from \$18.58 and \$19.68 to \$20.28 and \$23.98, respectively (see Appendix C, Table 7).

State Severance Tax Rate - Most ANS oil is taxed by the State of Alaska at a rate of 15 percent. Table 6a in Appendix C shows that reducing the rate by 25 percent to 11.25 percent would increase the return to the producer by an amount equivalent to a 4.4 percent increase in wellhead price. Reducing the severance tax rate by half to 7.5 percent (see Table 6b) would be equivalent to an 8.8-13.1 percent increase in wellhead price -- i.e., from \$16.09 and \$16.66 per barrel in 1987 and 1990 to \$17.50 and \$18.85 per barrel, respectively.

2. Pipeline Tariffs

TAPS Settlement -- Tariffs under the settlement will be lower than the current tariffs, increasing the return to the producer. Reducing the tariffs according to the settlement directly increases wellhead price by 11.4-29.9 percent. Much of the oil produced from the North Slope is produced by companies that are part owners of the pipeline. For these companies, reduction of the tariff means an increase in profits from producing and a decrease in pipeline profits. Therefore, for these companies, the increase in profits per barrel of oil produced caused by reducing the tariffs will be less than calculated here.

3. Federal Leasing Policies

Lease Availability - OCS lease sales are scheduled to be held every three years for the Beaufort Sea and Chukchi Sea Planning Areas. The first step in determining which areas are to be offered for sale is nomination of the most promising areas by interested firms. Until 1982, a value estimate and an Environmental Impact Statement (EIS) were completed for each tract offered prior to the sale. The

need for a value estimate and an impact analysis for each tract constrained the number of tracts which could be offered in a sale and less than half of the tracts nominated were offered.

Under area-wide leasing, which began in 1982, value estimates are done after the sale is held and the EIS is done on an area-wide basis, instead of tract-by-tract, allowing the acreage offered to be increased substantially. In 1984 and again in 1985, the area-wide leasing process was modified to allow earlier consultation and to resolve conflicts by deleting from the sale low-potential areas which are identified as environmentally sensitive or for which other conflicts arise. The result is a process which focuses on promising acreage but still provides flexibility to respond to changing conditions. If, due to new information or increases in wellhead price, an oil producer decides that an area has economic potential, and that area is not environmentally sensitive or unleaseable for other reasons, it will be offered for lease within three years. It is unlikely that holding lease sales more frequently than every three years would result in acreage being leased sooner or in more wells being drilled. Further, it would not be possible to include more acreage in each sale than is currently offered because acreage deletions are done in response to legitimate environmental concerns.

Onshore Federal lands on the North Slope include the Naval Petroleum Reserve - Alaska (NPRA) and the Arctic National Wildlife Refuge (ANWR). Lease sales have been held for NPRA, but early results have been disappointing and industry interest in this area has decreased. A lease sale in 1984 in NPRA received no bids, and a decision was made not to hold a sale in 1985. Future sales will be held if and when more interest is shown in bidding on NPRA leases. In contrast, there is considerable industry interest in exploring ANWR. However, Congressional action would be required to allow exploration and development of ANWR. The Department of the Interior is currently conducting a study of the resource potential of ANWR, to be submitted to Congress as required by section 1002 of the Alaska National Interest Lands Act of 1980. However, if Congress does allow exploration and drilling in ANWR, the long lead time for development in this area would mean that any production from ANWR would not begin until after 2000.

The recent decline in world oil prices may serve to discourage firms from undertaking new wildcat drilling. Companies will drill where geological structures are promising and sizeable financial returns are expected. Reduction of Alaskan wellhead prices resulting from lower world oil prices may lessen companies' interest in remote, marginal fields. Therefore, the issue will not be solely confined to the volume of acreage available but will encompass the selection of acreage, the taxation regime and future level of oil prices.

Royalty Rates - Significant production from Federal leases is not expected to occur before 2000. However, Table 5a (See Appendix C) shows that reducing the royalty rate on existing and new leases by 25 percent would increase the return to the producer on any oil from Federal leases by an amount equivalent to a 3.6 percent increase in wellhead price. Reducing the rate by 50 percent (see Table 5b) would be equivalent to a 7.1-7.5 percent increase in wellhead price.

B. IMPACTS

The policy options identified in Section III-A involve major changes in the incentives to produce oil. However, as the analysis in this section shows, the long-run impacts of these changes would generally be small.

1. Production Impacts

Increasing the incentives to produce oil from the North Slope will result in more oil being produced during the time period being studied (1987-2000). The projected increase in crude oil production includes both (1) permanent oil supply increases due to price effects; and (2) shifts in the timing of production increasing near-term oil production at the expense of later production. The permanent oil supply increase comes primarily from old oil fields where increasing the wellhead price increases the economic life of existing wells.

Generally speaking, higher prices mean that old wells can be operated longer, thus increasing the ultimate oil recovery from a given well. Once a well is no longer economical to operate and is closed down, it essentially cannot be reopened for production if prices later increase.

Between 1987 and 2000, the increase in production which would occur comes mostly from this increase in recovery from existing wells. Increasing the incentives to produce also has the effect of making some fields economic to develop at an earlier time. Because of the long lag times involved, these wells would not begin producing until around 2000. By shifting forward in time the development of fields which would have been developed later, production in the early years of the next century is increased. As the production from these new wells begins to decline, production falls below what it would have been without the increased incentives.

The size of the near-term supply responses from implementation of the policy options described in Section III-A is difficult to predict (See Appendix C for the methodology used). Table III-2 presents three estimates of the production responses based on

different assumptions. The "medium" estimates can be interpreted as the most likely supply response and only medium estimates are used in the discussion of other impacts.

Exemption of North Slope production from the Windfall Profit Tax would have no impact on total production at mid-range prices because the wellhead price is projected to stay below the base-price until 1995, by which time the WPT will have been phased out. Even if high prices are expected, the production response will be small (0 - 10,400 B/D), due in part to the fact that the WPT only applies to a portion of the total North Slope production.

Reduction of the royalty rate will not cause a significant increase in production during the time period studied. There is no production from Federal leases on the North Slope currently, and there is not expected to be any significant production before the year 2000. Because little production is expected from existing Federal fields, any production response from changing the Federal royalty rate could only come from increased exploration and development. However, the long lag time in developing North Slope fields means that such an increase in exploration would not impact production during the next 15 years.

Adoption of the TAPS Settlement would have the biggest impact of the policy options analyzed causing a possible increase in production of 37,000 - 114,000 B/D in 2000. However, as discussed in Section III-A, the fact that some of the producers are also part owners of the pipeline means that the estimates presented in Table III-2 for the TAPS settlement may be high.

Reduction of the State severance tax rate would have less of an impact on production than the TAPS settlement. Even reducing the rate by half would only increase production by 6,100 - 18,400 B/D in the year 2000.

2. Federal and State Revenue Impacts

None of the policy options analyzed would affect government outlays. Estimates of the impact on Federal income tax and Windfall Profit Tax and State of Alaska income tax, severance tax, and royalty revenues were calculated (see Table III-3) for each of the policy options identified in Section III-A. Impacts on bonus bid revenues would be small relative to other revenue impacts and were not included. Analysis of the windfall profits tax, the severance tax rate, and the Federal royalty rate assumed that the new TAPS tariffs had been adopted. The specific revenue impact is dependent upon the crude oil price assumed and transportation costs.

Significant production from Federal leases is not expected to occur before the year 2000. Therefore, reducing the Federal royalty rate would not impact Federal or State revenues during the study period.

The windfall profits tax would generate substantial revenues only in conjunction with high world oil prices. At the highest price levels considered in the study (\$27-\$33 in 1985 dollars), elimination of the tax on North Slope crude production would reduce Federal revenues by about \$1.5 billion in 1985 dollars before the scheduled phase-out of the tax in 1993. With oil prices at the mid-point (\$20.50-\$22.10) of the range considered, the tax would only apply in 1992 and 1993 when the projected wellhead value (in 1985 dollars) of North Slope crude rises above the \$17.85 per barrel base price, and elimination of the tax in 1987 would reduce Federal revenues by only \$100 million or less. State of Alaska revenues would not be significantly affected, since elimination of the tax would result in little, if any, increase in total production.

Reductions in State of Alaska severance tax rates would result in significant net revenue losses to the State and gains to the Federal Government. A 25 percent reduction in severance tax rates would cost the State of Alaska about \$4.5 billion by the year 2000 despite stimulating additional production in 2000 of more than 10,000 B/D. On the other hand, the Federal Government would realize roughly \$2.8 billion of additional revenues over that time period. A 50 percent severance tax reduction would reduce State of Alaska revenues through 2000 by roughly \$9.0 billion, while increasing Federal revenues by \$5.6 billion.

Reduction in total transportation costs due to the new TAPS tariffs will increase State of Alaska revenues and decrease Federal revenues during the study period. With mid-range oil price assumptions, these tariffs are estimated to reduce Federal revenues through the year 2000 by roughly \$4 billion, despite increased production of more than 70,000 B/D in the year 2000 relative to production with the old tariffs. In contrast, the State of Alaska is projected to gain about \$8.6 billion. The marked disparity between governments arises from the substantial increase in State royalty and severance tax payments, which are deductible from income for Federal taxes.

3. Petroleum Industry Impacts

Increasing the incentives to produce Alaska North Slope oil would have significant impacts on that segment of the petroleum industry with exploration and development activities in North Alaska, but would have negligible impact on the lower-48 petroleum industry. In 1986, proven reserves in North Alaska equalled about 7.1 billion barrels. Each one dollar increase in the ANS wellhead price, consequently, creates a 7.1 billion dollar increase in the assets of North Slope producers. Also, with production of about 1.8 million B/D on the North Slope, each one dollar per barrel increase in the

wellhead price increases producer gross revenues by about \$657 million per year. Much of this increase in gross revenues does not stay with the petroleum companies. State and Federal taxes reduce these revenues by about 55 to 65 percent so that net producer revenues for a one dollar increase in the wellhead crude price equals about \$260 million per year.

The increase in production stemming from implementing any of the policy options described is not enough to have a significant impact on the lower-48 refinery and market conditions, and no other significant petroleum industry impacts are anticipated as a consequence of the various policy options.

4. Consumer Impacts

None of the policy options considered would have a direct impact on the Valdez FOB price. However, the small increase in ANS crude oil production stimulated by a change in the incentives would reduce the demand for OPEC oil and create a slight downward pressure on the world oil price. While that price change is small, it would affect a large quantity of oil, and the amount spent on oil by U.S. consumers would decrease. Analysis based on the Energy Information Administration model used for world oil price projections indicates that implementing the TAPS settlement tariff will result in a 5 cents to 12 cents/bbl decrease in world oil price by the year 2000. This drop in oil price will result in a savings to consumers of \$300 - \$750 million per year (see Table III-4). Reduction in the severance tax rate would reduce oil prices by up to 5 cents/bbl in the year 2000 resulting in savings of up to \$300 million per year.

5. Transportation Impacts

The additional amount of shipping capacity that would be required to accommodate the increase in ANS production arising from implementation of the policy options considered is minimal. Changing the TAPS tariffs has the greatest impact on production of any of the policy options analyzed resulting in an additional 8,800 B/D in 1990. If all of this additional production is shipped to the Gulf/East Coasts (which is the destination that requires the most shipping), there will be the need for an additional 60,000 DWT in shipping capacity. This would require the full-time use of one 60,000 DWT tanker. If the additional crude is shipped to the West Coast, an additional 17,000 DWT will be required -- the equivalent of using a 90,000 DWT tanker for about two months a year. The net effect is an increase in shipping of between four-tenths of one percent to just about one percent.

The largest oil production response for the year 2000 is 75,200 B/D. Such an increase in production would require an increase of 149,000-511,000 DWT in shipping capacity. Although implementation of one of the policy options would mean that more shipping capacity

is being used, there would still be sufficient available tanker tonnage. The minimal increase in shipping requirements predicted could be met with existing tonnage, since ANS production is expected to decline in the future. There would be no need for the construction of any new tonnage to handle the small increase in production predicted.

6. Employment Impacts

Alaska North Slope oil production increases, caused by changes in Federal and State taxes, pipeline tariffs, and Federal leasing policies, are expected to have a relatively small impact on U.S. employment. Employment increases may occur in the Alaskan oil industry, in the shipping industry, and other Alaskan sectors. The most important employment effects would occur in Alaska's oil and gas extraction industry, classified in the Standard Industrial Classification as SIC 13. In particular, ANS oil-related employment effects of each of the six policy options analyzed affect not more than about five percent of total industry employment (see Table III-5). Employment effects in shipping are similar in magnitude to those in oil and gas extraction (see Table III-6). Increases range up to 134 seafarers or 3.16 percent of 1984 seafaring employment. Effects on seafaring employment are 50-60 percent as large as those projected for SIC 13 oil and gas extraction industries.

Other sectors may be affected by increased incentives as well. The petroleum refining sector, SIC 291, only employed 202 workers in Alaska during 1984. Therefore, increased refinery employment should not affect the area's economy nearly as much as employment increases in oil and gas extraction. Also, workers are needed to maintain the Trans-Alaska Pipeline System (TAPS). However, now that the TAPS is in place, few if any additional workers should be needed if ANS production is increased. Other sectors such as services in the North Slope area and construction are likely to experience small employment increases if ANS crude oil production increases. It is, however, very difficult to estimate these effects. Finally, changes in State and local revenues caused by implementing a policy option would impact the level of government employment. The size of these impacts depends on how the State and local governments react to changes in revenues and is difficult to predict.

An explanation of the methodology used to estimate employment impacts for the oil and gas extraction industry and the shipping industry is included in Technical Appendix C.

7. Trade and National Security Impacts

Financial incentives that result in increased ANS oil production during the 1987-2000 period yield positive trade and energy security benefits. Any increase in oil production from the North Slope directly reduces the amount of crude oil imported, lowering the

balance of trade deficit and decreasing U.S. reliance on foreign supplies.

Since the supply responses associated with the policy options considered are small, the trade benefits are small. For 1990, the largest supply response projected is 8,800 B/D. This increase would reduce the annual trade deficit by about \$77 million. A 75,200 B/D increase in the year 2000 would reduce the trade deficit by about \$892 million. In comparison, the trade deficit for 1985 was well over \$100 billion.

The impact that an increase in production would have on the world oil price is very small (see Section III-B-4). Still, to the extent that the amount of oil imported is reduced, U.S. vulnerability to supply disruptions could be reduced. It is important, however, to remember that increasing the incentives to produce oil will change the future timing of oil production, causing an increase in near-term production (the next 20-30 years) and a decrease in far-term production (see Section III-B-1). Along with the benefits of increased energy security in the near-term are the costs of possible increased foreign dependence in the future.

8. Foreign Policy

The policy options analyzed in Section III of this study, which involve changes in the Federal and State tax systems, pipeline tariffs, and Federal leasing policies are primarily domestic in their effects and should be evaluated accordingly. There is, however, an international aspect to these changes. In the Agreement on an International Energy Program, the United States agreed with other industrial democracies to enhance energy security by encouraging indigenous energy production. The Administration has already taken great strides toward encouraging energy production in the United States by restoring market incentives to the oil and natural gas industries and by partially deregulating the rail and trucking industries, including the transport of coal and other energy products. To the extent changes in tax policies, pipeline tariffs, and Federal leasing policies increase energy production in the United States, the United States enhances its energy security, consistent with an important international agreement with friends and allies.

9. Environmental Impacts

Environmental impacts stemming from increased incentives to produce oil from ANS, including impacts from increased exploration and drilling activity and from increased volumes of oil shipped in tankers, would be negligible.

Of environmental impacts from tanker transportation, by far the greatest proportion of adverse effects (e.g., spills and air pollution) occur in loading, unloading, and in maneuvering in or

near port. Increased production from the North Slope would cause an increase in tanker traffic in the Valdez area. However, because the United States is an oil importer, increased production from ANS would decrease oil imported from abroad and the total amount of oil landed at destination ports would not increase.

Increased incentives to produce oil would result in an increase in adverse impacts associated with exploration and drilling activity. However, these impacts can be mitigated by limiting access to environmentally sensitive areas. Further, all exploration and development plans must be approved and environmental permits must be obtained before a field can be developed.

In any case, the increase in production associated with implementing any of the policy options analyzed and the resulting increase in volume of oil shipped from Valdez are almost negligible. Therefore, unless the incentives to produce are increased by far more than they would be under the policy options analyzed, there will be no significant environmental impacts.

TABLE III-1

IMPACT OF POLICY OPTIONS ON RETURN TO PRODUCER
SHOWN AS EQUIVALENT CHANGE IN WELLHEAD PRICE
(\$1985/Barrel)

<u>Policy Option</u>	<u>1987</u>	<u>1990</u>	<u>1995</u>	<u>2000</u>
1. Federal and State Taxation				
Exempt all ANS oil from WPT -				
Base Case (3)	18.58	19.68		
Equivalent Wellhead Price	20.28	23.98		
Ratio - Equivalent/Base Case	1.091	1.218		
Reduce severance tax by 25% -				
Base Case (2)	16.09	16.69	21.38	26.89
Equivalent Wellhead Price	16.80	17.43	22.32	28.09
Ratio - Equivalent/Base Case	1.044	1.044	1.044	1.044
Reduce severance tax by 50% -				
Base Case (2)	16.09	16.69	21.38	26.89
Equivalent Wellhead Price	17.50	18.88	23.26	29.27
Ratio - Equivalent/Base Case	1.088	1.131	1.088	1.088
2. Pipeline Tariffs				
Change to new (settlement) TAPS tariffs -				
Base Case (1)	14.44	13.58	16.46	20.70
New Wellhead Price	16.09	16.69	21.38	26.89
Ratio - New/Base Case	1.114	1.229	1.299	1.299
3. Federal Leasing Policies				
Reduce royalty rate by 25% -				
Base Case (2)	16.09	16.69	21.38	26.89
Equivalent Wellhead Price	16.66	17.29	22.15	27.86
Ratio - Equivalent/Base Case	1.036	1.036	1.036	1.036
Reduce royalty rate by 50% -				
Base Case (2)	16.09	16.69	21.38	26.89
Equivalent Wellhead Price	17.24	17.95	22.91	28.81
Ratio - Equivalent/Base Case	1.072	1.075	1.072	1.071

(1) Base case is with old (pre-settlement) tariffs and mid-point prices.

(2) Base case is with new (settlement) tariffs and mid-point prices.

(3) Base case is with new (settlement) tariffs and high prices.

TABLE III-2

SUPPLY RESPONSE FROM IMPLEMENTATION OF POLICY OPTIONS
(Thousand B/D)

<u>Policy Option</u>	<u>1987</u>	<u>1990</u>	<u>1995</u>	<u>2000</u>
1. Federal and State Taxation				
Exempt all ANS oil from WPT - (assuming high prices)				
Amnt of oil affected	1,520	1,050		
Supply Low	0.0	0.0		
Response Medium	0.0	5.2		
High	0.0	10.4		
Reduce severance tax by 25% -				
Amnt of oil affected	1,800	1,700	1,550	1,400
Supply Low	0.0	0.0	3.3	6.1
Response Medium	0.0	1.8	6.7	12.2
High	0.0	3.7	10.0	18.4
Reduce severance tax by 50% -				
Amnt of oil affected	1,800	1,700	1,550	1,400
Supply Low	0.0	0.0	6.5	11.9
Response Medium	0.0	5.2	13.1	23.9
High	0.0	10.5	19.7	36.0
2. Pipeline Tariffs				
Change to new (settlement) TAPS tariffs -				
Amnt of oil affected	1,800	1,700	1,550	1,400
Supply Low	0.0	0.0	20.4	37.1
Response Medium	0.0	8.8	41.1	75.2
High	0.0	17.6	62.0	114.3
3. Federal Leasing Policies				
Reduce royalty rate by 25% -				
Amnt of oil affected	negl	negl	negl	negl
Supply				
Response	--	--	--	--
Reduce royalty rate by 50% -				
Amnt of oil affected	negl	negl	negl	negl
Supply				
Response	--	--	--	--

TABLE III-3

CUMULATIVE CHANGES IN GOVERNMENT RECEIPTS
(Billions of 1985 dollars)

	<u>Total</u>	<u>Corporate Income</u>	<u>Severance Tax</u>	<u>Royalties</u>
<u>Alaska Severance Tax</u>				
<u>25% Reduction:</u>				
Federal Government.	<u>2.8</u>	<u>2.8#</u>	<u>n/a</u>	<u>n/a</u>
1987 - 1990	.7	.7	n/a	n/a
1991 - 1995	1.0	1.0#	n/a	n/a
1996 - 2000	1.1	1.1	n/a	n/a
State of Alaska	<u>(4.5)</u>	<u>.5</u>	<u>(5.1)</u>	<u>.1</u>
1987-1990	(1.2)	.1	(1.3)	*
1991-1995	(1.6)	.2	(1.8)	*
1996-2000	(1.8)	.2	(2.0)	.1
<u>50% Reduction:</u>				
Federal Government	<u>5.6</u>	<u>5.6#</u>	<u>n/a</u>	<u>n/a</u>
1987 - 1990	1.3	1.3	n/a	n/a
1991 - 1995	2.0	2.0	n/a	n/a
1996 - 2000	2.3	2.3#	n/a	n/a
State of Alaska	<u>(9.0)</u>	<u>1.1</u>	<u>(10.2)</u>	<u>.2</u>
1987 - 1990	(2.4)	.3	(2.7)	*
1991 - 1995	(3.2)	.4	(3.6)	*
1996 - 2000	(3.5)	.4	(4.0)	.1

n/a - not applicable

- includes windfall profit tax liabilities in 1992 - 1993.

* - less than \$50 million.

NOTE: Table may not add due to rounding.

TABLE III-3 (continued)

CUMULATIVE CHANGES IN GOVERNMENT RECEIPTS
(Billions of 1985 dollars)

	<u>Total</u>	<u>Corporate Income</u>	<u>Windfall Profit</u>	<u>Severance Tax</u>	<u>Royalties</u>
<u>NEW 'TAPS' Tariffs: Mid-Range Prices</u>					
Federal Government	(4.0)	(4.0)	.1	n/a	n/a
1987-1990	(.9)	(.9)	-	n/a	n/a
1991-1995	(1.5)	(1.5)	.1	n/a	n/a
1996-2000	(1.6)	(1.6)	n/a	n/a	n/a
State of Alaska	8.6	(.7)	n/a	4.7	4.6
1987-1990	1.4	(.1)	n/a	.8	.8
1991-1995	3.0	(.3)	n/a	1.7	1.6
1996-2000	4.1	(.3)	n/a	2.2	2.2
<u>Eliminate Federal Windfall Profit Tax</u>					
Mid-Range Prices:	(.1)	.1	(.1)	n/a	n/a
1987-1980	-	-	-	n/a	n/a
1991-1995	(.1)	.1	(.1)	n/a	n/a
High-Price Path:	(1.5)	(1.3)	(2.8)	n/a	n/a
1987-1990	(.8)	.7	(1.5)	n/a	n/a
1991-1995	(.7)	.6	(1.3)	n/a	n/a

Source: Department of the Treasury

TABLE III-4
IMPACT ON CONSUMER EXPENDITURE FOR
PETROLEUM PRODUCTS FROM THE PRODUCTION INCENTIVES

Production Incentives -----	1990		1995		2000	
	Reduction in world oil price (cents per gallon)	Reduction in consumer expenditures (ml. dollars/yr)	Reduction in world oil price (cents per gallon)	Reduction in consumer expenditures (ml. dollars/yr)	Reduction in world oil price (cents per gallon)	Reduction in consumer expenditures (ml. dollars/yr)
1. Federal and State Taxation						
Exempt all AMS oil from WPT	negl.	negl.	-	-	-	-
Reduce State Severance Tax						
by 25%	0-1	0-59	0-2	0-121	0-6	0-367
by 50%	0-2	0-117	0-3	0-302	0-11	0-673
2. Pipeline Tariffs						
Change to New TAPS Tariff	0-4	0-235	2-13	0-785	3-31	0-1899
3. Federal Leasing Policies						
Reduce Royalty Rate						
by 25%	negl.	negl.	negl.	negl.	negl.	negl.
by 50%	negl.	negl.	negl.	negl.	negl.	negl.

Source: Energy Information Administration, Oil Market Simulation (OMS) Model runs for Oil Production Sensitivity Cases 1990-2000, 3/21/86.

TABLE III-5

ESTIMATED INCREASES IN ANS OIL-RELATED
SIC 13 EMPLOYMENT
DUE TO INCREASED INCENTIVES

<u>Policy Option</u>	<u>1987</u>	<u>1990</u>	<u>1995</u>	<u>2000</u>
1. Federal and State Taxation				
Exempt all ANS oil from WPT				
Number of workers	0	22		
Percent of total	0.00%	0.31%		
25% severance tax cut				
Number of workers	0	8	28	52
Percent of total	0.00%	0.11%	0.43%	0.87%
50% severance tax cut				
Number of workers	0	22	56	101
Percent of total	0.00%	0.31%	0.85%	1.71%
2. Pipeline Tariffs				
Change to new (settlement) TAPS tariffs				
Number of workers	0	37	174	319
Percent of total	0.00%	0.52%	2.65%	5.37%
3. Federal Leasing Policies				
25% royalty rate cut				
Number of workers	negl.	negl.	negl.	negl.
Percent of total				
50% royalty rate cut				
Number of workers	negl.	negl.	negl.	negl.
Percent of total				

Source: U.S. Department of Labor (ILAB). Methodology described in Technical Appendix C.

TABLE III-6

ESTIMATED INCREASES IN ANS OIL-RELATED
SHIPPING EMPLOYMENT
DUE TO INCREASED INCENTIVES

<u>Policy Option</u>	<u>1987</u>	<u>1990</u>	<u>1995</u>	<u>2000</u>
1. Federal and State Taxation				
Complete WPT exemption				
Number of workers	0	11		
Percent of total	0.00%	0.26%		
25% severance tax cut				
Number of workers	0	3	14	28
Percent of total	0.00%	0.07%	0.33%	0.66%
50% severance tax cut				
Number of workers	0	11	29	54
Percent of total	0.00%	0.26%	0.68%	1.27%
2. Pipeline Tariffs				
Change to new (settlement) TAPS tariffs				
Number of workers	0	14	71	134
Percent of total	0.00%	0.33%	1.67%	3.16%
3. Federal Leasing Policies				
25% royalty rate cut				
Number of workers	negl.	negl.	negl.	negl.
Percent of total				
50% royalty rate cut				
Number of workers	negl.	negl.	negl.	negl.
Percent of total				

Source: U.S. Department of Labor (ILAB). Methodology described in Technical Appendix C.

IV. POLICY OPTIONS PERTAINING TO ANS EXPORT RESTRICTIONS

Task IV involves an analysis of the economic and public policy issues related to lifting the export ban on Alaskan (ANS) crude oil. The five export scenarios to be analyzed are those specified in Section 126 of the Export Administration Act Amendments of 1985. These scenarios involve exports at 50 thousand barrels per day (MB/D), 100 MB/D, 200 MB/D, 500 MB/D and Unconstrained Exports (i.e., Free Market) levels.

The economic and policy analysis covers the 1987-2000 period. 1987 was selected as the first year because it was determined to be the earliest effective date by which Congress could make any changes in the current export prohibition on crude oil. The year 2000 was selected because it provided a sufficient time span against which to measure the long-term price elasticity of oil supply and related energy/economic impacts of lifting the ban. The section was well into preparation before the recent oil price declines occurred. Since the analysis is for the 1987-2000 timeframe, the price projections used may still be reasonable, despite the current and perhaps temporary low world oil prices. Although this chapter does not include econometric projections regarding the impact of the recent and perhaps temporary oil price declines on ANS production with and without a ban on exports, the oil price decline issue is addressed in Section VI.

Much of the analysis presented in Section IV comes from the operation of the Oil Trade Model (OTM). The model simulates the international petroleum production, refining, and transportation markets. The model uses a non-linear optimization technique to maximize the sum of producers' and consumers' surplus, subject to production constraints, consumer demand for products, transportation costs, refinery costs and technology, and taxes. The model can be used to determine the effects of government policy or international events on crude and product supply, demand, prices, and flows. Technical Appendix D provides a more complete model description.

A. EXPORT TRADE FLOWS

The trade flows associated with lifting the ban on Alaskan crude exports include: (1) the redistribution of domestic oil trade, and (2) oil exports to Pacific Rim Nations.

1. Domestic Energy Flows

The patterns of Alaskan oil trade are likely to undergo substantial changes between 1987-2000 that are independent of the export scenarios discussed later in this section. These changes center on: (1) the declines in Alaskan oil production projected during the

1990s, (2) the opening of the California-to-Texas All America Pipeline after 1987, and (3) the gradual reduction of the Valdez-Gulf and Valdez-Virgin Island/Puerto Rico trade.

The data in Tables IV (A) 1 through IV (A) 8 show the expected trade flows for the export ban case:

o West Coast

- Shipments of ANS crude to PAD V rise from the current level of one million barrels per day (MMB/D) to about 1.35 MMB/D by 1995.
- After 1995 shipments begin to decline slowly because ANS production is projected to fall from about 1.55 to 1.4 MMB/D by 2000.

o Gulf Coast/East Coast

This trade declines from the current levels of 630 MB/D to approximately 180 MB/D by 2000 because:

- There is less oil to ship due to ANS production falling from 1.8 to 1.4 MMB/D between 1990-2000.
- The All American Pipeline, commencing in 1987, will begin to move crude overland from California to Texas and by 1990 approximately 300 MB/D of California crude will move to the Gulf Coast by pipeline thus allowing an equal amount of Alaskan crude to remain in California rather than being shipped in tankers to the Gulf Coast.

IV-3

TABLE IV (A) 1
TRADE FLOW-EXPORT BAN CASE
(M B/D)

<u>Export Ban</u>	<u>1985</u>	<u>1987</u>	<u>1990</u>	<u>1995</u>	<u>2000</u>
West Coast	1,000	1,020	1,160	1,350	1,220
East Coast/ Gulf Coast	630	650	515	200	180
Virgin Islands/ Puerto Rico	128	130	25	0	0
Pacific Rim	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>0</u>
	1,758*	1,800	1,700	1,550	1,400

*Source-MARAD estimate based upon actual date January-September 1985.
Includes 300,000 B/D California-to-Texas pipeline commencing after 1987.

IV-4

TABLE IV (A) 2
PAD V (WEST COAST) OIL BALANCE
(MMB/D)

	<u>1985</u>	<u>1990</u>		<u>1995</u>		<u>2000</u>	
		<u>BAN</u>	<u>EXPORTS</u>	<u>BAN</u>	<u>EXPORTS</u>	<u>BAN</u>	<u>EXPORTS</u>
<u>DEMAND:</u>							
Product Consumption	2.37	2.30	2.29	2.43	2.42	2.61	2.60
Refinery Fuel	<u>0.17</u>	<u>0.23</u>	<u>0.23</u>	<u>0.24</u>	<u>0.23</u>	<u>0.18</u>	<u>0.17</u>
Total	2.54	2.53	2.52	2.67	2.65	2.79	2.77
<u>SUPPLY:</u>							
Alaska Crude Production	1.79	1.73	1.73	1.58	1.58	1.40	1.40
California Crude Production	1.15	1.42	1.42	1.32	1.32	1.32	1.32
Natural Gas Liquids (NGL)	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Crude Oil Imports	0.18	0.08	0.26	0.13	0.25	0.27	0.20
Net Product Imports (0.23)		(0.04)	(0.05)	(0.06)	(0.10)	0.04	0.17
Product Shipments From Other U.S. Regions	(0.09)	(0.04)	0.10	(0.03)	0.10	(0.01)	0.11
Crude Shipments to Gulf Via All American Pipeline		(0.30)	(0.30)	(0.30)	(0.30)	(0.30)	(0.30)
Refinery Gain	<u>0.30</u>	<u>0.18</u>	<u>0.19</u>	<u>0.18</u>	<u>0.18</u>	<u>0.21</u>	<u>0.19</u>
Total	3.36	3.07	3.39	2.86	3.17	2.97	3.13
<u>EXCESS CRUDE OIL SUPPLY:</u>							
Ban to Gulf/East Coast	0.82	0.54		0.19		0.18	
Unconstrained Exports to Pacific Rim	-	-	<u>0.87</u>	-	<u>0.52</u>	-	<u>0.36</u>
Total	0.82	0.54	0.87	0.19	0.52	0.18	0.36

Source: Department of Energy

IV-5

TABLE IV (A) 3TRADE FLOW-LOW EXPORT CASES (50 M B/D)
(M B/D)

<u>50 M B/D Exports</u>	<u>1985</u>	<u>1987</u>	<u>1990</u>	<u>1995</u>	<u>2000</u>
West Coast	1,000	1,020	1,175	1,360	1,350
East Coast/ Gulf Coast :	630	630	475	140	0
Virgin Islands/ Puerto Rico	128	100	0	0	0
Pacific Rim	<u>0</u>	<u>50</u>	<u>50</u>	<u>50</u>	<u>50</u>
	1,758*	1,800	1,700	1,550	1,400

*Source-MARAD estimate based upon actual date January-September 1985.
Includes 300,000 B/D California-to-Texas pipeline commencing after 1987.

IV-6

TABLE IV (A) 4TRADE FLOW-LOW EXPORT CASES (100,000 B/D)
(M B/D)

<u>100 M B/D Exports</u>	<u>1985</u>	<u>1987</u>	<u>1990</u>	<u>1995</u>	<u>2000</u>
West Coast	1,000	1,020	1,175	1,360	1,220
East Coast/ Gulf Coast	630	600	425	150	0
Virgin Islands/ Puerto Rico	128	80	0	0	0
Pacific Rim	<u>0</u>	<u>100</u>	<u>100</u>	<u>100</u>	<u>100</u>
	1,758*	1,800	1,700	1,550	1,400

*Source-MARAD estimate based upon actual data January-September 1985.
Includes 300,000 B/D California-to-Texas pipeline commencing after 1987.

TABLE IV (A) 5TRADE FLOW-LOW EXPORT CASES (200 M B/D)
(M B/D)

<u>200 M B/D Exports</u>	<u>1985</u>	<u>1987</u>	<u>1990</u>	<u>1995</u>	<u>2000</u>
West Coast	1,000	1,020	1,175	1,250	1,200
East Coast/ Gulf Coast	630	555	325	100	0
Virgin Islands/ Puerto Rico	128	25	0	0	0
Pacific Rim	<u>0</u>	<u>200</u>	<u>200</u>	<u>200</u>	<u>200</u>
	1,758*	1,800	1,700	1,550	1,400

*Source-MARAD estimate based upon actual data January-September 1985. Includes 300,000 B/D California-to-Texas pipeline commencing after 1987.

TABLE IV (A) 6TRADE FLOW-500 M B/D EXPORT CASE
(M B/D)

<u>500 M B/D Exports</u>	<u>1985</u>	<u>1987</u>	<u>1990</u>	<u>1995</u>	<u>2000</u>
West Coast	1,000	975	1,100	1,000	1,040
East Coast/ Gulf Coast	630	500	100	50	0
Virgin Islands/ Puerto Rico	128	25	0	0	0
Pacific Rim	<u>0</u>	<u>300</u>	<u>500</u>	<u>500</u>	<u>360</u>
	1,758*	1,800	1,700	1,550	1,400

*Source-MARAD estimate based upon actual data January-September 1985.
Includes 300,000 B/D California-to-Texas pipeline commencing after 1987.

IV-9

TABLE IV (A) 7TRADE FLOWS-UNCONSTRAINED EXPORTS CASE (HALF OF PRODUCTION)
(M B/D)

	<u>1985</u>	<u>1987</u>	<u>1990</u>	<u>1995</u>	<u>2000</u>
West Coast	1,000	975	830	1,020	1,040
East Coast/ Gulf Coast	630	500	0	0	0
Virgin Islands/ Puerto Rico	128	25	0	0	0
Pacific Rim	<u>0</u>	<u>300</u>	<u>870</u>	<u>530</u>	<u>360</u>
	1,758*	1,800	1,700	1,550	1,400

*Source-MARAD estimate based upon actual data January-September 1985.
Includes 300,000 B/D California-to-Texas pipeline commencing after 1987.

- California prefers to refine ANS crude in its refineries because of a lighter product yield and for environmental reasons and move its heavy crudes to the Gulf Coast.
- o Virgin Islands/Puerto Rico - This tanker trade is likely to phase out as West Coast deliveries of ANS crude increase.

There has been discussion in the industry and trade press of the possible construction of a 900 MB/D pipeline from the West Coast to Texas in the late 1980s. Construction of such a pipeline could result in the total elimination of ANS crude shipments to the Gulf/East Coasts. The construction of a second California/Texas pipeline is only at a preliminary stage of commercial discussions. Lifting the ban on Alaskan crude oil exports is likely to reduce the economic viability of a large West-to-East pipeline and virtually eliminates any chance of its being constructed.

2. Export Trade Flows

All of the export scenarios yield similar results. ANS shipments to the West Coast are expected to rise from the current level of about 1 MMB/D to a high of 1.36 MMB/D by 1995 before slowly declining to 1.22 MMB/D by the year 2000 (see Table IV (A) 1). The reason for this decline is solely due to an anticipated decline in ANS production from the current level of 1.75 MMB/D to 1.4 MMB/D. By the year 2000, the West Coast is expected to receive all but 180 MB/D of ANS production.

As this occurs, ANS shipments to the East and Gulf Coasts are expected to decline steadily from the current level of 630 MB/D to 180 MB/D in the year 2000. It should be noted that, in the event that the All-America Pipeline is able to transport volumes above 300 MB/D, shipments to the Gulf and East Coasts will be eroded further or possibly eliminated. The Pipeline's sponsors have indicated that its capacity could be expanded by an additional 150 MB/D to 450 MB/D. To the extent that the capacity of the All-America Pipeline exceeds 300 MB/D, the California-to-Texas oil flows will reduce more rapidly tanker deliveries from Valdez to the Gulf Coast. Since this pipeline will move some of California's heavy crudes to other markets, the California crude surplus will begin to disappear, oil prices will move towards market levels, and discounts will end.

Sales to the Virgin Islands and Puerto Rico, currently about 130 MB/D will likely drop to 25 MB/D by 1990 and be eliminated shortly thereafter. Likewise, these sales will be eliminated earlier if the All-America pipeline transports higher volumes than anticipated. Tables IV (A) 2-7 present data on all of the energy trade flows associated with the export scenarios. In particular, Table IV (A) 2, addresses the trade flows in the context of the overall West Coast petroleum balance.

o Unconstrained Exports/500 MB/D Cases

- Exports begin to decline in 1990 in the Unconstrained Export Case and in the next highest case after 1995.
- There is a growing demand for ANS crude on the West Coast.
- The California market can compete favorably with the Pacific Rim in terms of ANS crude prices because of growing demand and the fact that the freight rate from Valdez to West Coast is anticipated to decline while foreign rates are projected to rise.
- By 1995, the Valdez/West Coast freight rate is only an estimated \$0.14 per barrel higher than the Valdez/Far East rate - i.e., \$0.73 versus \$0.87 per barrel.

o California

- Table IV (A) 2 shows that rising California oil demand combined with lower ANS and California oil output results in less ANS oil available for export after 1990. This finding also holds for the partial export scenarios after 1995.
- Between 1990 and 1995 PAD V oil demand increases from 2.52 MMB/D to 2.67 MMB/D while Alaska oil output declines by 0.15 MMB/D.
- If large ANS exports during the 1990s were to reduce the availability of crude supplies for PAD V, this region would face the prospect of higher crude and product imports. If petroleum products rather than crude are imported, a negative impact on West Coast refiners and consumers could result (see Section IV C and D).

3. Export Markets

In terms of transportation costs, the Pacific Rim is the second most profitable market for ANS crude sales after the West Coast. The 3,300 mile voyage currently costs approximately \$0.40 and up to \$1.00 per barrel in foreign and U.S. tankers, respectively.

- Under the 50 and 100 MB/D scenarios, the entire volume could be absorbed by Japan through the year 2000.
- Under the 200 MB/D scenario, it is anticipated that Japan would purchase the bulk of the oil and that other Pacific Rim countries might purchase the remaining volumes through the year 2000.

- Under the 500 MB/D scenario, it is expected that Pacific Rim imports would peak at 500 MB/D during 1990-95 and decline to 360 MB/D by the year 2000 due to reduced ANS production and price competition from the U.S. West Coast that needs ANS crude. Other Pacific Rim countries are expected to purchase the remaining export volumes through 1995.
- Under the unconstrained exports scenario, it is expected that total exports to the Pacific Rim would peak in 1990 at about 870 MB/D, with Japan purchasing over 600 MB/D (Table IV (A) 8).
- It is important to note that these projections are based on the assumption that foreign purchasers are supplying their own shipping and obtaining ANS crude at the Valdez FOB price. These projections could vary significantly because they do not account for institutional factors regarding trade relations between ANS producers, shippers and U.S. customers. For example, these projections do not take into account a possible decision by an ANS producer to use his own domestic vessels to maintain structural relationships within its own company and commercial relationships with traditional customers.

- o crude oil exported to Canada with a validated license. In 1985, the President determined that crude oil exports to Canada are in the national interest and made the necessary findings under the EPCA, the MLLA, and the OCSLA. The exporter must certify that the oil is for use or consumption in Canada, that the oil was not and will not be transported by pipeline over a Federal right-of-way granted under the Trans-Alaska Pipeline Authorization Act, and was not derived from the Naval Petroleum Reserves; and
- o crude oil exported from Cook Inlet with a validated license. In 1985, the Secretary of Commerce, with the concurrence of the Secretaries of State, Energy, and Treasury, determined that permitting the export of crude oil derived from Alaska's Cook Inlet is in the national interest and consistent with the purposes of the EPCA. Regulations were published in the Federal Register on June 4, 1986, which permit the issuance of validated export licenses for crude oil produced in state waters of Alaska's Cook Inlet and not subject to the restrictions contained in the EAA, the NPRPA, the OCSLA, or the MLLA.

IV-13

TABLE IV (A) 8

POSSIBLE EXPORT MARKETS FOR ANS CRUDE

(Thousand B/D)

<u>Scenario/year</u>	<u>1987</u>	<u>1990</u>	<u>1995</u>	<u>2000</u>
<u>50 MB/D</u>				
Japan	50	50	50	50
South Korea/Taiwan				
<u>100 MB/D</u>				
Japan	100	100	100	100
South Korea/Taiwan	-	-	-	-
<u>200 MB/D</u>				
Japan	150	150	150	150
South Korea/Taiwan	50	50	50	50
<u>500 MB/D</u>				
Japan	200	350	350	250
South Korea/Taiwan	100	150	150	110
<u>High Export Case</u>				
Japan	200	600	360	250
South Korea/Taiwan	100	270	170	110

Source: DOE Oil Trade Model

B. PETROLEUM INDUSTRY IMPACTS

1. Transportation Savings

The primary result of allowing Alaskan oil exports would be to provide significant transportation savings. From a purely economic perspective, transportation savings represent a resource efficiency gain.

- o Moving crude from Valdez, Alaska to the U.S. Gulf Coast costs approximately \$4/bbl.
- o Shipping the identical crude from Valdez to Japan yields a savings of approximately \$3.50 per barrel because U.S. ships are more expensive to operate than foreign flag vessels.

The savings from reduced transportation charges translate into higher wellhead prices for the producers and larger tax revenues for the Federal Government, and the States of Alaska and California.

- o Alaskan oil owners currently sell their oil at a \$1 - 2 per barrel discount on the West Coast.
 - This discount is less than the extra expense that would be incurred to ship the oil from Valdez to the Gulf Coast.
 - Under a free market scenario, the West Coast discount would disappear because excess Alaskan oil is likely to be shipped to the Pacific Rim rather than be sold at a discount in California.

2. Wellhead Price Impact

The complete removal of the restrictions on ANS crude exports would raise the wellhead value of Alaskan and Californian crude oils. The figures in Table IV (B) 1 indicate the following:

- o ANS Wellhead Price
 - Complete removal of the ban would raise the price by \$1.70 per barrel in 1990 declining to about \$1 per barrel in 2000, because of the transportation savings.
 - Partial lifting of the restrictions would have less significant price impacts. For example, partial decontrol resulting in exports of 500 MB/D yields a wellhead increase of \$0.70 per barrel in 1990. Likewise, exports of 100 MB/D and 50 MB/D in 1990 raise wellhead prices by only \$0.10 and \$0.05 per barrel, respectively.

IV-15

TABLE IV (B) 1
WELLHEAD PRICE IMPACTS
(1985 dollars per barrel)

	<u>1987</u>	<u>1990</u>	<u>1995</u>	<u>2000</u>
<u>ALASKA NORTH SLOPE</u>				
Base Wellhead Price	\$16.90	\$16.69	\$21.38	\$26.89
Price Increase				
Unconstrained Exports	\$ 0.60	\$ 1.70	\$ 1.40	\$ 1.00
500 MB/D	0.60	0.70	0.74	1.00
200 MB/D	0.20	0.20	0.23	0.10
100 MB/D	0.10	0.10	0.12	0.05
50 MB/D	0.05	0.05	0.06	0.03

CALIFORNIA AVERAGE

Base Well Head Price	\$20.00	\$19.70	\$22.50	\$27.50
Price Increase				
Unconstrained Exports	\$ 0.15	\$ 1.60	\$ 1.60	\$ 1.30
500 MB/D	0.15	0.20	0.37	1.30
200 MB/D	neg	0.05	0.09	neg
100 MB/D	neg	0.02	0.05	neg
50 MB/D	neg	neg	0.02	neg

Source: Department of Energy

o California Wellhead Price

- The impacts of a complete lifting of the ANS ban are positive for California producers because the average State wellhead price increases by about \$1.60 per barrel in 1990 and \$1.30 per barrel in 2000.
- The benefits of partial relaxation of the ban are negligible in California with the exception of the 500 MB/D scenario, which would result in a \$0.37 bbl wellhead price increase in 1995.

3. Net Producer Revenues

Table IV (B) 2 shows an increase in producer revenues (net of Federal and State taxes) of \$7.7 billion for the 1987-2000 period resulting from a complete lifting of the ban. The net revenues are derived from: (1) wellhead price increases resulting from a lifting of the ban, and (2) oil production increases resulting from a lifting of the ban. (See IV (E) below.) This sum includes \$3.7 billion in net production profits in Alaska and \$4.0 billion in California.

TABLE IV (B) 2

NET OIL INDUSTRY PROFITS FROM LIFTING
THE ANS EXPORT BAN
 (Million 1985 dollars)

<u>Scenario</u>	<u>ALASKA</u>	<u>CALIFORNIA</u>	<u>TOTAL</u>
<u>Unconstrained Exports</u>	3,728.8	4,038.1	7,766.9
<u>500 MB/D</u>	2,167.8	1,410.2	3,578.0
<u>200 MB/D</u>	453.3	137.8	591.1
<u>100 MB/D</u>	226.7	68.9	295.6
<u>50 MB/D</u>	113.5	34.5	148.0

Source: Department of Treasury

Note: - Net producer profits derived by deducting Federal and State tax obligations from increased revenues flowing from a lifting of the export ban.

These calculations do not address the costs to other sectors of the economy. (See Section IV (E) for a full discussion of State and Federal tax issues.) The table also shows that the benefits to producers vary in proportion to the amount of crude exported. At small export volumes, the benefits are low, but they increase proportionately at higher levels.

4. Exploration, Development and Production

This section provides estimates of the projected increase in crude oil production that would occur in Alaska and in California as a consequence of allowing the export of ANS crude oil. As described in the previous section, the removal of export restrictions raises the wellhead price of ANS crude oil. The higher wellhead crude prices provide incentives to increase ANS production both by extending the life of existing producing wells and by increasing exploration and development activities in new fields. Section III presents a general discussion of oil production impacts as well as leasing policy issues.

Table IV (B)(3) provides a series of forecasts of increased production from Alaska and California. For both Alaska and California, the highest supply response is in the unconstrained exports scenario:

o Alaska

- Exports at unconstrained levels could result in a production increase of 5 - 15 MB/D by 2000.
- A partial relaxation of the ban allowing only 500 MB/D in exports yields a production response of 2.5 - 15 MB/D response in 1995 and a 5-15 MB/D response in 2000.
- Partial lifting of the ban, with exports of 200, 100 and 50 MB/D, yields smaller supply responses..

o California

- The supply response is slightly higher for California than for Alaska under the unconstrained exports scenario. Production expands by 8.8 - 17.8 MB/D and 12 - 24 MB/D in 1995 and 2000, respectively.

TABLE IV (B) 3
CRUDE OIL PRODUCTION RESPONSE
(Barrels per day)

	<u>1990</u>	<u>1995</u>	<u>2000</u>
<u>ALASKAN NORTH SLOPE</u>			
Base Production	1,700,000	1,550,000	1,400,000
Production Increase			
Unconstrained Exports	0-8,000	4,600-14,000	5,000-15,000
500 MB/D	0-3,400	2,500- 7,600	5,000-15,000
200 MB/D	0- 800	800- 2,400	500-15,000
100 MB/D	0- 500	400- 1,200	250- 750
50 MB/D	0- 240	200- 600	150- 450
<u>CALIFORNIA</u>			
Base Production (*1)	1,430,00	1,320,00	1,320,000
Production Increase			
Unconstrained Exports	0-11,000	8,800-17,800	12,000-24,000
500 MB/D	0- 1,300	2,000- 4,000	12,000-24,000
200 MB/D	0- 350	500- 1,000	neg
100 MB/D	neg	300- 550	neg
50 MB/D	neg	100- 220	neg

*1. Excludes natural gas liquids

Source: Department of Energy

IV-20

- The 500 MB/D export scenario also results in a supply response of 12 - 24 MB/D; other scenarios yield only negligible production increases by 2000.

The issue of future petroleum exploration and development evoked varying responses from the parties that submitted comments in response to the Federal Register Notice. Parties as diverse as the Coalition to Save Alaskan Oil, Exxon and the State of Alaska all agree that future Alaskan production will decline substantially between 1995-2000.

- The Alaskan State Department of Revenue's forecast for 1995 production is 0.9 million B/D, as compared to the current production level of 1.758 million B/D.

Exxon notes that:

"Even with the strong emphasis industry has placed on developing new Alaskan crude reserves, it is likely that levels of North Slope production will decline through the mid-1990s."

C. REFINING IMPACTS

The impact of lifting the ban on ANS exports on U.S. refiners is primarily on the West Coast. The impacts on refiners stemming from a full or partial lifting of the export ban are quite different for Gulf Coast and West Coast refineries.

Our analysis indicates that allowing the export of Alaskan oil would have a negligible impact on Gulf Coast/East Coast refiners. After examining world oil supply availability and quality and U.S. refinery configurations, we conclude that most of the oil imported to replace ANS crude would be similar in quality and quantity and would not result in appreciably changed refinery operations or costs on the U.S. East and Gulf Coasts. On the other hand, several consumer groups such as the Citizen/Labor Energy Coalition have argued that the foreign oil imported into the Gulf Coast will be several dollars per barrel more expensive than ANS crude. This would raise refiners' acquisition costs and cut their profits, and may result in higher consumer prices. Recent DOE data, however, show that foreign crude is highly competitive with and even slightly lower priced than ANS crudes on the U.S. Gulf Coast.

The response to the Federal Register Notice included many comments from independent refiners, UNOCAL, TOSCO, the American Independent Refiners Association PAD V Committee, and the Edgington Oil Company, all of whom oppose lifting the ban on the grounds that it would harm them.

- o All of these concerns argue that lifting the export ban would:
 - Compromise their access to ANS crude.
 - Raise refiners costs.
 - Raise product prices.
 - Increase consumer prices.
 - Jeopardize independents' financial strength due to reduced margins.
 - Result in petroleum product imports at the expense of the independent refiners.

In the short run, West Coast refiners will be compelled to pay higher prices (i.e., up to several dollars per barrel) for ANS crude and crude imports if export controls are lifted. They will lose the "California discount" due to the fact that ANS crude will be able to

command its market price. However, some analysts believe that the West Coast refiners may not be compelled to make many of the additional capital investments during the 1990s to accommodate surplus heavy ANS crude because they will replace it with light Indonesian supplies. This development would represent a long-term efficiency gain to the national economy.

Distillation of Alaskan crude oil yields a large fraction of high-sulfur residual fuel, which requires special refining facilities for conversion into products such as gasolines and distillates. This type of refining capacity is in particularly short supply on the West Coast because the average quality of crude oils produced in California is unusually heavy and has a high sulfur content. (See Table IV (C) 1) As increased volumes of Alaskan oil shipped to the West Coast have displaced much of the lighter feedstock previously imported, the cost of refinery processing has become higher.

Although some modifications to existing West Coast refineries have taken place in recent years, additional investments exceeding \$1 billion would be required to process more efficiently the projected mix of crudes if Alaskan oil continues to be shipped to the West Coast. Even if the prohibition on exports continues, it is uncertain whether West Coast refineries would make an additional investment of this size. Some refiners may invest in additional conversion capacity in order to produce premium products from the heavy crudes on the West Coast market. Alternatively, some refineries may change refinery configurations to displace Alaskan oil with California production. However, there is a 3-to 4-year lead time between making a decision to invest in refinery expansion or reconfiguration and the facility becoming operational. The potential for Alaskan oil exports in the future makes investors understandably hesitant to lay out capital that would be drastically devalued if the export ban were lifted.

Although refining costs may diminish with removal of export restrictions, profits to West Coast refiners may decline. The profitability of conversion capacity depends upon a large differential between heavy and light products. The value of heavy crudes and high sulfur residual oil is expected to increase by more than the value of light products between 1995 and 2000, reducing the differential and hence the profitability of conversion capacity. Refiners' margins will narrow even though the higher prices for residual fuel oil will be passed along to the consumer.

- o The OTM finds that this would yield a series of positive benefits for the refining industry.
- Allowing exports would reduce the amounts of heavy crudes routed to West Coast refineries by about 90 MB/D in 1995.

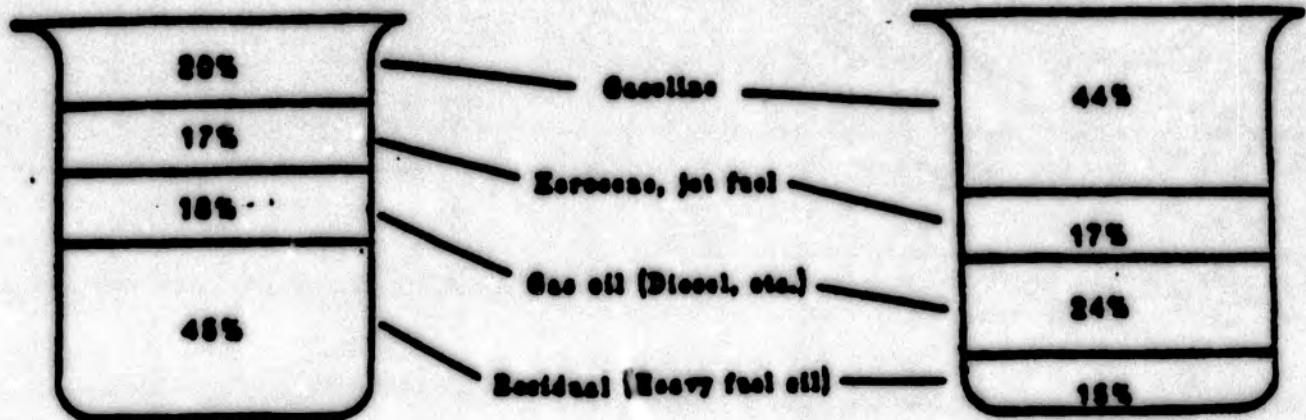
TABLE IV (C) 1

TYPICAL PRODUCT YIELDS FROM CRUDE OIL REFINING

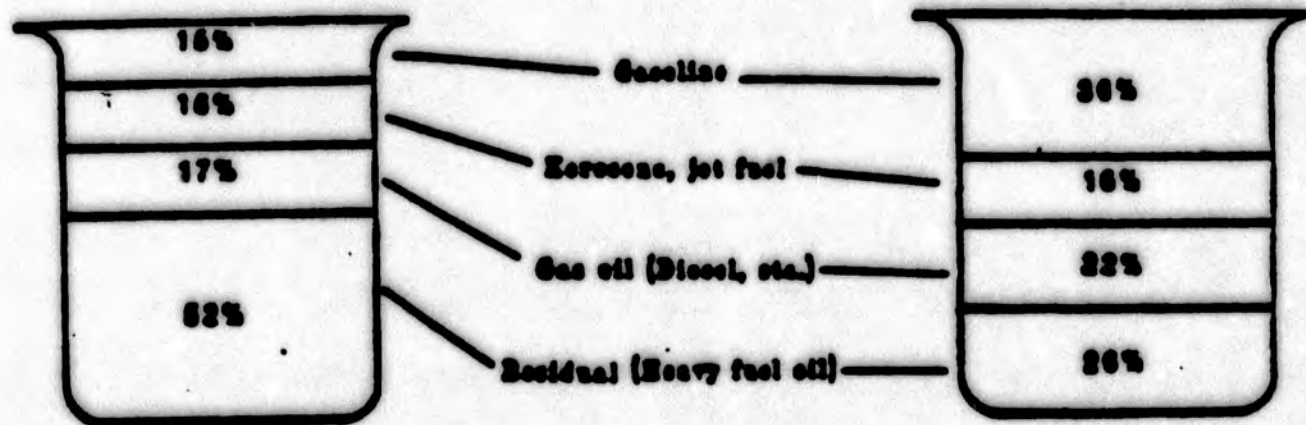
Simple Refining

Sophisticated Refining

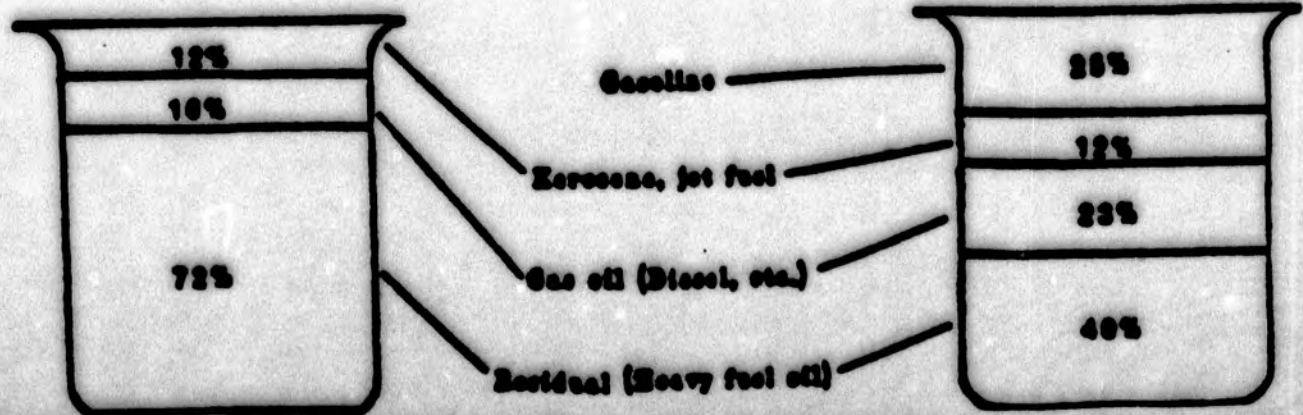
Saudi Arabian Light (33 API)



Alaska North Slope (26 API)



Kern R. California (14 API)



- Replacing heavy crude with lighter grades of oil from Pacific Basin suppliers such as Indonesia, combined with higher refinery utilization rates, would lead to a technically more favorable crude mix and refinery operation. This would result in refinery processing gains (i.e., net increases in petroleum products) and a favorable slate of light products.
- Removal of the export ban would result in a decrease in refining costs on the West Coast of 2 percent per year through 2000.
- Under some scenarios, there could be a reduction in the volume of residual fuel oil exports, which would be beneficial because resid is a low value product and the economy as a whole would benefit from exports of crude at market prices instead of sales of resid at lower prices.
- Resid exports have been high due in large part to low product prices; but higher product prices combined with lower refinery yields of resid could reduce these exports.

There are a number of interesting institutional questions regarding refinery impacts:

- Resid Exports - Private refiners, will decide on whether or not to export residual fuel oil.
- The refiner may have covered his profit margin on co-products such as gasoline and jet fuel and will take the price he can get to unload the by-product resid.
- In this regard, many independent refiners have no separate crude supplies as compared to the ANS producers. ANS producers could sell crude or products while the independent refiners do not have similar tradeoffs. They earn profits on light co-products and simply take what they can get for the resid.

D. CONSUMER IMPACTS

The consumer effects from allowing Alaskan oil exports can be divided into short-term and long-term impacts. The short-term effect involves a possible rise in prices for consumers on the West Coast, while the long-term effect consists of projected economic benefits to all U.S. consumers.

Our analysis indicates that product prices on the West Coast could rise in response to allowing Alaskan oil exports (See Table IV (D) 1). The amount of product price increase depends upon:

- o the costs of replacement crudes for Alaskan crude;
- o future refinery configurations and operations on the West Coast;
- o prices of product imports to the West Coast; and
- o the amount of wellhead price change of California and Alaskan oil in response to allowing Alaskan oil exports.

The ranges for petroleum product price impacts in Table IV (D) 1 reflect these uncertainties. Product price increases under unconstrained export conditions could vary between little, if any, price increase to cases with up to 5 cents per gallon. Factors which could tend to lower the West Coast price impact include: lower prices for replacement crudes due, for example, to lower world oil demand; more efficient refinery configurations and operations which reduce refinery costs; availability of low-cost product imports which set a cap on West Coast product prices; and a smaller wellhead price increase subsequent to allowing Alaskan oil exports.

Table IV (D) 2 shows the estimated impact on West Coast consumer expenditures due to projected product price increases. The impacts are largest in 1990 and diminish over time.

Over the long-term, the OTM finds that allowing exports of Alaskan oil would encourage increased crude production in Alaska and California. U.S. oil consumers could benefit from lower world oil prices resulting from these increases in crude oil production.

Even small world oil price reductions can have a large effect on consumer expenditures for petroleum products. A one penny per barrel decline in U.S. oil product prices by 1995, for example, would reduce annual consumer expenditures for petroleum products by about \$60 million. This one penny per barrel price decline would reduce gasoline expenditures by an estimated \$22 million per year.

TABLE IV (D) 1WEST COAST PRODUCT PRICE INCREASES
(1985 Dollars Per Gallon)

<u>Unconstrained Exports Scenario</u>	<u>1990</u>	<u>1995</u>	<u>2000</u>
High Sulfur Resid	Increase \$0.02-\$0.04	Increase neg-\$0.05	Increase neg-\$0.05
Low Sulfur Resid	Decrease (neg-\$0.02)	Decrease (neg-\$0.02)	Increase neg-\$0.01
Distillates	Increase neg-\$0.025	Increase neg-\$0.02	neg
Gasoline	Increase neg-\$0.025	Increase neg-\$0.02	neg
Other	Increase neg-\$0.025	Increase neg-0.02	neg
Average	Increase neg-\$0.02	Increase neg-\$0.02	Increase neg-\$0.05

NOTE: Estimates for 1987 are not provided since 1987 is a transition year for implementation of lifting restrictions on Alaskan oil exports.

TABLE IV (D) 2WEST COAST CONSUMER EXPENDITURE IMPACTS
(Million 1985 dollars)

	<u>1990</u>	<u>1995</u>	<u>2000</u>
<u>Unconstrained Exports Scenario</u>			
High Sulfur Resid	60-120	neg-160	neg-170
Low Sulfur Resid	Savings (neg-30)	Savings (neg-30)	neg-15
Distillates	neg-455	neg-385	neg
Gasoline	neg-220	neg-185	neg
<u>Other</u>	<u>neg-90</u>	<u>neg-75</u>	<u>neg</u>
Total	60-855	neg-775	neg-185

NOTE: Estimates for 1987 are not provided since 1987 is a transition year for implementation of lifting restrictions on Alaskan oil exports.

Table IV (D) 3 provides estimates of the impact of lifting the ban on consumer expenditures for petroleum products. Assuming the oil supply increases discussed in Section IV (B), total removal of export restrictions would yield \$200-300 million in reduced expenditures by the year 2000. The other cases that restrict exports to 200 MB/D or less have insignificant impacts on the world oil prices and thus result in essentially no reduction in consumer expenditures.

TABLE IV (D) 3
CONSUMER SAVINGS FROM LOWER WORLD OIL PRICES
(Million 1985 dollars)

	<u>1987</u>	<u>1990</u>	<u>1995</u>	<u>2000</u>
<u>Unconstrained Exports</u>				
<u>Scenario</u>	0	\$0-120	\$120-250	\$200-300
500 MB/D	0	neg.	\$0-185	\$200-300
200 MB/D	0	neg.	neg.	neg.

Source: Energy Information, Oil Market Simulation (OMS) model runs for oil production sensitivity cases 1990-2000, 3/21/86.

E. FISCAL EFFECTS OF EXPORT OPTIONS

1. Federal Impacts

The export of North Slope crude would have a favorable impact on Federal revenues and an unfavorable impact on Federal expenditures as a result of displacement from service of U.S. flag tankers. During the 1987-1990 period, if the volume of export is less than 200,000 barrels per day (B/D), the expenditure effects are larger. In cases involving 200,000 B/D or more, the revenue effects are larger than expenditure impacts. The impacts to be discussed below are summarized in Table IV (E) 1.

Permitting exports of 200,000 B/D or more would prompt additional oil production in at least Alaska and California. Economic activity would be redirected to some extent through noticeably higher prices for petroleum products on the West Coast and slightly lower prices in the Gulf region through 1995. After 1995, lower petroleum prices generally would be expected in both regions. Assuming nominal GNP growth equivalent to the value of increased oil production, the revenue implications of three scenarios were evaluated:

- o Exports of up to 200,000 B/D would trigger Title XI guarantee outlays by the Federal Government of \$135 million before 1990 while generating \$134 million of additional revenues. From 1991 through 2000, an additional \$410 million in Federal revenues would be generated without any increase in outlays;
- o Exports of up to 500,000 B/D would trigger expenditures of \$344 million on Title XI guarantees and perhaps \$34 million on acquisitions for the Ready Reserve Force of displaced tankers while generating \$534 million of additional revenues by 1990. An additional \$1.8 billion in revenues would be collected after 1990 without an increase in outlays; and
- o Removing export controls on North Slope crude would increase Federal revenues by \$4.6 billion between 1987 and 2000 (\$1.6 billion through 1990) while boosting outlays \$.4 billion before 1990.

2. State Impacts

The revenue impacts on Alaska and California would differ markedly due to differences in royalty interests and severance tax rates as well as larger changes in Alaskan crude oil prices.

With exports of 200,000 B/D, California and Alaska revenues would increase between 1987 and 2000 by about \$57 million and \$0.5 billion, respectively. Export levels under the 500,000 B/D

case would increase wellhead prices enough on the West Coast to boost California's revenues about \$524 million over the 1987 - 2000 time frame of the study, while State of Alaska revenues would increase by \$2.2 billion. With market-determined export levels, California revenues would increase \$1.6 billion and Alaska revenues about \$4.0 billion between 1987 and 2000. The increase in California's revenues amounts to approximately 43 percent of Alaska's \$4.0 in additional revenues. This large difference stems from higher petroleum taxes in Alaska. The latter has State royalty, severance and corporate income taxes on oil production, while California has royalty and corporate taxes.

TABLE IV (E) 1

ESTIMATED GOVERNMENT REVENUE EFFECTS
SELECTED NORTH SLOPE CRUDE OIL EXPORT OPTIONS
(Millions of Dollars)

	<u>Net Change</u>	<u>Alaska</u>	<u>California</u>	<u>Federal* Gov't.</u>
Unconstrained Exports				
1987-1990	3,408	1,330	441	1,637
1991-1995	4,032	1,510	538	1,885
1996-2000	2,728	1,116	555	1,057
All Years	10,168	3,956	1,633	4,579
500MBD Case				
1987-1990	1,099	514	51	534
1991-1995	1,838	731	113	993
1996-2000	2,102	938	360	804
All Years	5,039	2,183	524	2,331
200MBD Case				
1987-1990	284	137	14	134
1991-1995	520	211	29	281
1996-2000	296	152	14	129
All Years	1,100	500	57	543

ESTIMATED GOVERNMENT OUTLAYS
SELECTED NORTH SLOPE CRUDE OIL EXPORT OPTIONS
(Millions of dollars)

	<u>Total Outlays</u>	<u>Title XI</u>	<u>Defense Reserve Fleet</u>
Unconstrained Exports			
1987-1990	416	382	34
500MBD Case			
1987-1990	340	337	3
200MBD Case			
1987-1990	135	135	0

*Includes royalties from Federal Revenues from offshore and Naval Petroleum Reserves production. These royalties are normally presented as negative outlays in federal budget presentations.

F. MARITIME IMPACTS

1. General Description of the U.S. Tanker Fleet

The U.S.-flag tanker fleet is employed in four general areas: the ANS crude oil trade, the coastwide movement of refined petroleum products, the carriage of cargoes subject to the U.S. cargo preference laws and the carriage of a small amount of oil in the U.S. foreign trade. The movement of ANS oil constitutes, by far, the largest single source of employment for the U.S.-flag tanker fleet. Of the 10.7 million deadweight tons (DWT) of tankers active under the U.S. flag as of October 31, 1985, 6.4 million DWT, about 60 percent, were employed in the distribution of ANS crude. The employment of the U.S.-flag tanker fleet is summarized in the following table:

Table IV (F) 1

Status of U.S. Tanker Fleet
As of October 31, 1985

	<u>Millions</u> <u>of DWT</u>	
Operating	10.7	78.7%
ANS Trades	6.4	
Other Domestic	2.5	
MSC Charter*	0.7	
Foreign Trade**	1.1	
Lay-up	2.9	21.3%
CDS-Built	2.1	
Other	<u>0.8</u>	
Total	13.5	

* - Military Sealift Command: the Department of Defense charters privately-owned tanker tonnage for the movement of DOD cargoes.

** - Includes carriage of cargo subject to cargo preference laws.

2. ANS Trade

Due to geographic and vessel operating factors, the waterborne distribution system that moves ANS oil to the lower 48 States has three distinct components: shipments to the West Coast, shipments to Panama, and shipments from Panama to the Gulf and East Coasts and to Puerto Rico. The structural characteristics of the various

trades generally mean that it is physically impractical to use large tankers on the routes that require small tankers and economically impractical to use small tankers on the routes more suited to large tankers. As a consequence, several distinct markets exist and serve as the basis for the analysis of the impact of exports in the tanker fleet.

Two principal factors limit the types of tankers that can be employed in any individual trade: vessel size and environmental restrictions. Due to draft restrictions, the largest tankers (up to 265,000 DWT) can only be employed in the Alaska-Panama trade. Fully loaded tankers are limited to about 190,000 DWT in Los Angeles, and less than 100,000 DWT in San Francisco Bay. Larger vessels can enter these ports but only if the ships are lightened to reduce the draft or if the cargo is off-loaded onto smaller vessels. Either option increases the per unit cost of the shipment, making the use of oversize tankers less desirable economically than appropriate sized vessels. Environmental regulatory restrictions preclude the use of tankers greater than 125,000 DWT into Puget Sound.

Draft restrictions also apply to the continuation of the Alaska trade from Panama to the U.S. Gulf and East Coasts. Panama-Gulf/East Coast operations are generally limited to tankers below 100,000 DWT; however, one 125,000 DWT tanker is being shifted from the Valdez-West Coast trade to the Panama-Gulf Coast trade using the Louisiana Offshore Oil Port (LOOP).

Although the fleet currently serving the ANS trade is in a relative state of balance, there are certain events underway that will cause adjustments to this fleet and serve to reduce further the average operating costs in this trade. In 1986 and 1987, Exxon will receive delivery of two diesel-powered Very Large Crude Carriers (VLCCs) that are currently being built in a U.S. shipyard. In addition, if domestic tanker market conditions are favorable, it is anticipated that owners of additional tankers built with construction differential subsidy (CDS) will repay the unamortized portion of CDS in exchange for total removal of domestic trading restrictions under the provisions of the one-year payback rule issued by the Secretary of Transportation. This provision expires on June 5, 1986. For the purposes of this study, it is assumed that the owners of two CDS-built VLCCs will repay their subsidy in addition to the repayment of CDS on two VLCCs in July, 1985. This provides a mid-range estimate consistent with the mid-range estimates used elsewhere in this study. Further, given the existence of an adequate market in the domestic trades, it is anticipated that replacement construction will occur as the existing fleet ages. Because it is likely that this new tonnage will be diesel-powered, operating costs will be reduced significantly. The issue of ANS export is clearly critical to these fleet expansion and replacement plans.

3. Title XI Commitments

Under Title XI of the Merchant Marine Act of 1936, as amended in 1970, the Maritime Administration is authorized to grant mortgage insurance on ships built in U.S. shipyards. Currently, there are mortgage guarantees outstanding on 73 tankers totaling 5,999,000 DWT or roughly 44 percent of the U.S.-flag tanker fleet. The distribution of this fleet between the domestic and foreign trades (as implied by construction with CDS) is detailed in the following table:

Table IV (F) 2
OUTSTANDING TITLE XI MORTGAGE GUARANTEES
(As of September 30, 1985)

	<u>Number</u>	<u>Deadweight (000)</u>	<u>Mortgage (Millions of Dollars)</u>
Tankers built with CDS	27	2,631	\$415
Tankers w/o CDS			
ANS Trade	26	2,728	732
Other Trades	<u>20</u>	<u>640</u>	<u>449</u>
	46	3,368	\$1,181
<u>Total</u>	73	5,999	\$1,596

4. ANS Export Impact

The primary impact of any export of ANS oil will be to reduce the movement of ANS crude to the lower 48 States. This will immediately reduce the primary source of employment for the U.S.-flag tanker fleet creating turbulence in the entire domestic tanker market in addition to that portion serving the ANS trade. As mentioned previously, the alternate forms of employment for the U.S. tanker fleet are limited to the dwindling domestic coastwide product movements and the small level of U.S.-flag vessel participation in the foreign trades. Of course, it is not possible to forecast the precise economic effects of turbulence in the tanker trades.

Because there is little or no alternative employment at any feasible freight rates for the tanker tonnage that would be laid-up as the result of the export of ANS crude, the net impact will be to cause lay-up and eventual scrapping of U.S.-flag tanker tonnage. The export of ANS crude would have an uneven impact on the U.S.-flag tanker fleet as a consequence of the existing market structure. The ships owned by oil companies or under long-term time charter to the oil companies represent long-term contractual commitments and, as a