REPORT ON ALASKA BENEFITS AND COSTS OF EXPORTING ALASKA NORTH SLOPE CRUDE OIL

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REPORT ON ALASKA BENEFITS AND COSTS OF EXPORTING ALASKA NORTH SLOPE CRUDE OIL

Institute of Social and Economic Research
University of Alaska - Anchorage

For the Alaska State Senate
Finance Committee

FINDINGS AND CONCLUSIONS
Appendix A: background information and analysis
Appendix B: assumptions, methodology, and calculations

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May 1987

Foreword and Minor Revisions
July 1987

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included:

THE EXPORT OF ALASKA CRUDE OIL
ITS SIGNIFICANCE FOR
PACIFIC BASIN PETROLEUM TRADE

by
Samuel A. Van Vactor and Arlon R. Tussing

prepared for the
International Association of Energy Economists
Annual Meeting
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table of contents at end

FOREWORD

This Report was prepared for the Alaska Senate Finance Committee in order to help answer two questions ---

* Whether the prospective fiscal and other economic benefits TO ALASKA from an end to the federal ban on exports of North Slope oil are enough to justify a serious effort by the State to get the law changed.

* Whether the prospective energy-supply, international payments, fiscal, and other economic benefits TO THE UNITED STATES are enough to give such an effort a reasonable hope of success.

Alaska Benefits

The answer to the first question hinges primarily on the impact exports would have on the wellhead prices of crude oil produced in Alaska. Increasing prices by $2 to $4 per barrel (depending on whether the production was established or "incremental") would have two important effects:

1 The royalties and severance taxes collected by the State on each barrel produced would increase.

2 Oil companies operating in Alaska would increase their investments in field development and exploration, causing an increase in production (and hence a larger base against which the State royalties and taxes would be levied.)

The Report findings leave no doubt that overcoming the export ban would be worth a great deal to the State of Alaska. The prospective fiscal and other economic benefits to the State number in the billions of dollars. Thus, a serious State effort to change the law is indeed warranted, provided that it has a reasonable hope of success.

National Benefits and Costs

The answer to the second question involves the $4-per-barrel impact that the ability to export Alaska crude oil would have on wellhead prices in California as well as in Alaska. Specific national benefits, in addition to those previously mentioned would include:

1 Higher wellhead prices would generate greater federal corporate income tax receipts, Windfall Profits Tax receipts in both Alaska and California, plus greater State and local tax receipts and royalties paid to State and local government and private landowners in California.

2 Oil companies operating in Alaska would increase their investments in field development and exploration, causing an increase in production (and hence a larger base against which royalties and taxes of various sorts would be levied.)

3 The increase in Alaska and California crude-oil production would more than offset the additional imports of foreign oil that would be required to replace the domestic production that was exported. The results would include ---

a A greater degree of national energy self-sufficiency.

b Reduction in the U.S. balance-of-payments deficit (and reductions in the bilateral trade deficits with Japan, Korea, and Taiwan).

Against these benefits, however, it was necessary to consider the unfavorable impact on the U.S. merchant marine (for which the intercoastal shipment of Alaska crude oil constitutes the largest single segment), and possible increases in consumer fuel prices on the West Coast.

The Report indicates that the prospective national benefits from removing the Alaska crude-oil export ban are very large. The resulting increase in domestic crude-oil production will be many billions of dollars; the prospect is for similar reductions in net U.S. oil imports and in the net balance-of-payments cost of imported oil. Increases in federal tax and other revenues would amount to hundreds of millions of dollars per year. These benefits appear to overshadow by many times the adverse effects that crude-oil exports might have on the merchant marine or on consumer fuel prices (and the latter appear to be negligible).

Educating the Public

Very few Americans now seem to be aware of the potential benefits of exporting Alaska oil. Many members of Congress, however, seem well-indoctrinated in the losses that would be imposed on domestic maritime interests. Paradoxically in light of the high-profile campaign being waged by U.S. business and government to get Japan to import more American goods, U.S. oil exports often tend to be pictured as an economic "favor" to Japan --- not a politically popular thing at the present time. The authors thus believe that the key to Congressional action on the oil-export issue is information of the kind contained in this Report.

Conservative Assumptions and Results

The revenue and production estimates in this Report are conservative; they are based upon an assumption that world oil prices will average around $15 per barrel (1986 dollars) into the mid-1990s.

At the time of this writing (July 1987), official OPEC prices centered around $18, while spot and futures values were well over $20. If world prices were to settle at or above these levels, West Coast crude-oil production can be expected to exceed the values projected in this Report. The export ban would continue to have a powerful effect on production volumes and revenues, however. **With higher oil prices generally, the net impact of the export ban (or of removing it) upon crude-oil production and revenues in Alaska and California is indeed likely to be considerably greater than indicated in this Report. There are two main reasons:**

* An average world price of (say) $4 above our base case --- i.e., $19 dollars per barrel --- would make economic those oil-development ventures in Alaska and California which this Report deemed to be uneconomic at a $15 world price without exports. But it would also reveal an even greater volume of additional production in Alaska and California that would become economic to develop if wellhead prices were to increase by another $4 per barrel.

* With world prices around $19 per barrel, Alaska and California production without exports is likely to be about the volume projected in this Report for $15 with exports. The result would be to prolong the "West Coast oil surplus" for about 5 years (to about 1997), and thus to prolong the period during which the export ban continues to depress wellhead prices and production in Alaska and California.

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FINDINGS AND CONCLUSIONS

CONTENTS

Wellhead-Price Impact of the Export Ban

The ban on exports of Alaska North Slope ("ANS") crude oil reduces the average price producers receive at the wellhead by $2 to $3 per barrel, and the marginal price (the price they would receive on additional production) of ANS crude by about $4 per barrel. (The foregoing figures are 1987 constant dollars.)

Because Alaska crude oil competes directly with crude oil produced in California for sales to West Coast refiners, the ban on exporting ANS crude oil also reduces both the average and marginal prices of California crude oil by about $4 per barrel. (1987 constant dollars)

See Appendix A: 3.2 & 3.3

These relationships result from the fact that Alaska and California between them produce more crude oil than U.S. West Coast refineries demand, and will continue to exist for as long as a "West Coast oil surplus" exists.

See Appendix A: 3.2

Past Impact of the Export Ban

Because of the complicated structure and impact of the crude-oil price-control and entitlements system that prevailed from before ANS production began in mid-1977 through January 1981, we have not attempted to estimate losses in wellhead values or government revenues during that period, but they were surely substantial.

Since federal crude-oil price controls were terminated at the beginning of 1981, through the end of 1986, the crude-oil export ban has therefore reduced sales revenues on the 3.8 billion barrels produced in Alaska by about $11.9 billion, and sales revenues on the 2.4 billion barrels of crude

oil produced in California by about $9.7 billion. Total revenue losses in the two states during the five-year period were therefore about $21.6 billion. (The foregoing figures are in nominal dollars.)

See Appendix B: B.2 and E.1.

The largest shares of these revenue losses were absorbed by (a) State and local government in Alaska and California though loss of royalty and tax revenues, (b) the federal government through loss of Windfall Profits Tax revenues, (c) the oil producers through reduced profits, and (d) private landowners in California through reduced royalties.

From 1981 through 1986 the export ban directly cost the State of Alaska alone approximately $3.7 billion in royalties, production taxes, and corporate income taxes; the federal government lost about $4.4 billion in net windfall profits tax ("WPT") revenues on production from just the Prudhoe Bay field. (nominal dollars)

See Appendix A: 1.2;
See Appendix B: E.2 through E.6.

We have not calculated state and local government revenue losses in California, lower federal or state oil-and-gas lease-bonus receipts, reductions in federal corporate profits tax receipts, or the secondary and multiplier impacts of lower government revenues --- but all of these were also surely substantial.

During the period of exceptionally high world crude-oil prices (1979 through 1985), the reductions in ANS and California wellhead values undoubtedly had <u>some</u> depressing effect on exploration and development incentives in those regions, but the effect on production through 1986 may not have been profound, and is at any rate impossible to calculate with any confidence.

Future Effect of the Export Ban On Alaska and California Production

Beginning with the collapse of world oil prices in early 1986, the roughly $4-per-barrel reduction in the marginal price of Alaska and California crude oil will have a substantial impact on the economics of production in those states.

This price penalty will determine the feasibility of projects to maintain or enhance output from producing fields in Alaska and California through infill drilling, waterflood, and through "miscible-gas" and thermally-enhanced recovery ("TEOR") techniques on several of the biggest oil-producing properties in the United States. The price penalty will also govern the feasibility or timing of development in a number giant oilfields in Alaska and California, which have already been found, but which are not yet in production.

See Appendix A: 2.1 and 2.2.

Under the world-market price assumptions adopted for this report, removal of the export ban would likely increase West Coast crude-oil production by about 500 thousand barrels per day (mb/d) by 1989-1990, of which 300 mb/d would be in Alaska and 200 mb/d in California.

See Appendix B: 2.2.

This additional production would postpone from 1991 until 1994 the date at which the West Coast would have to import foreign crude oil (other than low-sulfur supplies being imported even now because of refinery-design and air-quality bottlenecks). If exports were permitted, however, perpetuation of the "West Coast surplus" would no longer have a depressing effect on West Coast oil production.

About 460 million barrels of additional Alaska production and 280 million barrels of additional California production can be expected over the whole period 1987-2000, if exports are permitted. Most of the increase would occur in the years 1988-1991; some of the additional oil that would be produced during this period is oil that would otherwise be produced later, after the West Coast surplus ended. By the year 2000, annual production levels would about the same, regardless of whether or not exports were permitted in the late 1980s and early 1990s.

Authorizing exports of ANS crude oil is likely to attract Japanese and other foreign capital to Alaska oil exploration and development even after the West Coast oil surplus disappears, and thus result in a sustained increase in Alaska crude-oil production. The present report does not attempt to quantify this impact.

Future Revenue Impact of the Export Ban

So long as the West Coast oil surplus exists and the export ban continues in place, the average price of Alaska crude oil will continue to be depressed by at least $2 per barrel, and the return to new production in either California or Alaska will continue to be depressed by about $4 per barrel. (1987 constant dollars)

The export ban will therefore affect the future value of Alaska and California crude-oil production in two ways: (a) It will increase the value of that crude-oil that would be produced, even under the lower prices caused by the West Coast oil surplus, and (b) it will depress the amount of oil produced.

Given the world-oil price trend assumed for the present report and perpetuation of the export ban, the surplus will end (i.e., the U.S. West Coast will shift from being an exporter to being an importer of crude oil) by 1992. In the years 1987 through 1991, however, we estimate that the direct cost of the export ban in the form of reduced wellhead prices, disregarding the greater volumes that would be produced, will total about $6.9 billion in Alaska and $7.4 billion in California.

See Appendix B: C.3 to C.5.

Taking into account the expected impact on production in Alaska and California, the export ban will reduce the value of crude oil produced in the two states by about $6 billion per year in the years 1988-1990; the cumulative loss will be about $27 billion for the whole 1987-91 period, and $50 billion for the period 1987 through 2000. (1987 constant dollars)

See Appendix A:3.5 & 4.2 (Alaska)
See Appendix B: D.

The cost to the State of Alaska of reduced wellhead prices and lower volumes attributable to the export ban, in the form of lower royalties tax revenues attributable to crude-oil production, is projected be in the range of $500 to $600 million through year 1990. Revenue losses will likely total about $2 billion over the five-year period 1987-1991, and more than $3 billion over the period 1987 through 2000. (1987 constant dollars)

See Appendix A:4.3.2.
See Appendix B: E.

We have made only <u>pro forma</u> projections of the impact on federal revenues, and have not made any projection at all for State and local revenues in California. Under present law and the world-market price assumptions of this report, there would be no federal Windfall Profits Tax receipts regardless of import policy.

Other Alaska Economic Impacts

Elimination of the export ban would have several corollary effects on the Alaska economy. The direct effects would include:

* Additional petroleum-development investments that would create (or preserve) several hundred high-paying jobs in petroleum-extraction, construction, and related industries.
* Higher petroleum revenues would prevent the State government from having to reduce expenditures and local-government aid by as great a margin as now contemplated.
* Higher petroleum revenues would postpone the date at which the State would terminate the Permanent Fund dividend program or reintroduce the personal income tax.

Disposable personal income would thus be substantially higher without the export ban.

These direct effects, plus the multiplier effects linked to them are likely to have the following implications:

* Total petroleum employment, including exploration and headquarters employment, would be about 1,000 higher.
* Total State appropriations and expenditures would increase by the amount roughley equivalent to the increase in revenues, with 85 percent of the increase going to operating expenditures and 15 percent to capital appropriations.

* Higher revenues allow the Permanent Fund dividend to be retained for one additional year (1989), and reimposition of a State personal income tax deferred for one additional year (until 1990).
* Total employment in Alaska would be higher than in the no-export case by about 12 thousand in 1990 and 1991.
* Real per-capita disposable income would be about $400 million per year higher through 1991, owing to higher wage and salary receipts and lower personal tax rates. After 1991 these stimulating effects will diminish slowly.

See Appendix A:4.4.

U.S. Balance-of-Payments Impacts

Exports per se are not likely to have a systematic impact one way or another on the overall U.S. balance of payments. The volumes of ANS crude oil exported to the Far East would be offset almost exactly by imports of comparable crude oils to U.S. refineries. It is also reasonable to expect the average shipboard price (FOB Valdez) of U.S. crude oil exported to Japan, Korea, or Taiwan to be just about the same as the average landed price (CIF LOOP or Marcus Hook, for example) of the added Mexican, North Sea, or other crude oils imported in its place. Increased U.S. oil production and/or reduced U.S. oil consumption attendant on higher wellhead prices for Alaska and California crude oil will, however, affect the U.S. balance of payments by reducing **net** U.S. dependence on imported oil.

See Appendix B: A.4.

The export ban can be expected to increase the net U.S. requirement for imported oil by a peak value of about 500 thousand barrels per day in 1990 and 1991. This will be about 3 percent of total U.S. oil demand. Total import requirements for the period 1987-2000 would be about 800 million barrels less, if exports were authorized.

Under the world-market price assumptions of this report, permitting exports of ANS crude oil would reduce the U.S. overall payments deficit by about $3 billion per year in 1990 and 1991. The total deficit reduction over the period 1987-2000 would be on the order of $15.6 billion. (1987 constant dollars)

See Appendix B: C.7.

Authorization of exports would affect the bilateral balance of trade between the United States and Japan even more substantially. **If Japan were the destination of all ANS exports, the U.S. bilateral trade deficit with Japan would be reduced by a peak value of $3.4 billion in 1988 and $14.8 billion over the period 1987-1994.** (1987 constant dollars) (The authors do not believe that bilateral trade balances with individual countries have any economic significance, but are reporting this projection only because it is a politically sensitive question.)

Other Considerations

The utilization of domestic tankers for shipment of ANS crude oil is doomed to fall steeply, beginning in 1988 or 1989, regardless of U.S. policy toward export of ANS crude oil. Even without exports, the need to ship ANS crude oil further than California is likely to end by 1992. Accordingly, there will be no need to construct any new "Jones Act" tankers to carry Alaska crude oil beyond the West Coast in any event.

Higher wellhead prices for crude oil produced in Alaska and California are not likely to result in substantially higher petroleum-product prices in the West Coast states.

The reason is that petroleum **products** (in contrast to crude oil) may be imported to and exported from the United States under present law. West Coast refineries frequently export high-sulfur fuel oil to East Asia, for example, and import unfinished gasoline. As a result, West Coast product prices already reflect world-market price levels. Much, if not all, of the increase in prices for crude-oil refined on the West Coast that would result from authorizing exports of ANS crude oil, would therefore take the form of lower refining margins and lower profits for companies that produce less crude oil in Alaska and California than they refine in the region.

A "compromise" that limited licenses to export ANS crude oil to any volume less than the whole "West Coast surplus" would not enhance incentives to develop new production in Alaska or California. The reason is that, if any ANS crude oil were still required to be shipped by tanker <u>via</u> Panama, the discounted price received for that supply would continue to dominate the West Coast crude-oil price structure. Even though the wellhead returns on the oil actually exported, and the royalties and severance taxes attributable to that oil, might increase, the <u>marginal</u> price of Alaska and California crude oil would still remain about $4 per barrel below world-market levels.

A compromise that would guarantee the same level of utilization for domestic tankers in shipment of Alaska crude oil beyond the West Coast as is now provided by the export ban, would be to require all exports to be carried out in U.S.-built, operated, and manned tankers through the year 1991.

Support in Congress and the national administration for permitting exports of ANS crude oil would be enhanced by some formula that guaranteed the federal government a substantial share of the potential increase in sales revenues. In order to preserve the favorable impact of exports on production incentives, any new tax installed for this purpose should not diminish marginal prices at the wellhead.

An export tax of $2 per barrel, applicable only to crude oil from the Prudhoe Bay or Kuparuk units, would probably generate federal revenues of about $600 million per year in 1987 and 1988, and a total of about $2.4 billion over the period 1987-1991. (1987 constant dollars)

The foregoing projection assumes that the North Slope operators would carry out such exchanges as minimized the total export-tax liability associated with any given volume of exports. Such arrangements would assure marginal production, including incremental production at Prudhoe Bay or Kuparuk, of world-market prices.

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APPENDIX A: BACKGROUND INFORMATION AND ANALYSIS

1. OVERVIEW AND SUMMARY

Paradoxically, ending bars to export of U.S. oil could help U.S. energy security.

--- United States Department of Energy
March 1987.

1.1 OVERVIEW.

1.1.1 INTRODUCTION. The world's three largest known accumulations of petroleum occur under and in the lands surrounding ---

* The Persian Gulf,
* The Eastern Carribbean, in an arc stretching from Louisiana through Texas and Eastern Mexico into the heavy-oil belt of Venezuela, and
* **The Arctic Ocean, including highly prospective provinces in and offshore of the U.S.S.R. and Canada, as well as Alaska.**

The United States has a strong territorial position in both the Caribbean and Arctic regions. The Southwestern oil-and-gas-producing States constitute the most intensively explored territory on earth, and although large volumes of hydrocarbons remain to be found and produced in the region, its biggest and most prolific oilfields have been discovered and are already largely depleted.

The Arctic, whose U.S. sector includes State, Federal and Native lands in Alaska and the adjacent outer continental shelf ("OCS"), is the least-known or developed of the great petroleum-bearing regions. Virtually all of the "giant" and "supergiant" oil and gas finds in North America over the last generation have nevertheless been in the Arctic. Northern Alaska has been producing oil in commercial quantities for only a decade, but it already contains the number-one and number-two oil-producing fields on the continent --- Prudhoe Bay and Kuparuk River. Several more huge deposits have been identified: Some of them are in the early stages of evaluation or development; others, such as the Lisburne and Endicott fields, are currently being developed for production and will almost certainly come on stream.

Arctic petroleum exploration and development face exceptional natural handicaps, in remoteness, extreme climate, and a host of unusual environmental features. They are also suffer from an unnatural economic handicap in the form of statutory prohibitions on the export of crude oil produced in the United States and transported through pipelines crossing federal lands. **This restriction, which appears in slightly different forms in both the Mineral Leasing Act and the Export Administration Act, reduces the wellhead value of existing Alaska crude-oil production by about $2 per barrel.**

More importantly, any additional crude oil produced in Alaska or California must now bear the cost of transportation to other U.S. regions, either through the Panama Canal in small tankers or loaded from and reloaded to tankers in order to cross the Isthmus by pipeline. This cumbersome requirement reduces the prices of newly developed crude oil in the West Coast states by about $4 per barrel below the values that would prevail if surplus Alaska crude oil could be shipped directly to its next-nearest and most lucrative markets, which would be in the Far East.

The result is a significant reduction in the known resources of crude oil in Alaska and California that are now economically feasible to develop. **The present report projects the reduction in crude-oil output resulting from the export ban to reach about half a million barrels per day in the early 1990s.**

Since the proceeds from exporting any Alaska North Slope ("ANS") crude oil to Far Eastern refineries at world-market prices would finance the import of an offsetting amount of Caribbean or North Sea oil to U.S. Gulf or East Coast ports, the outcome of the ban on exporting ANS crude oil turns out to be an increase in the net import dependency of the United States, and in the U.S. international payments deficit. The present report describes the additional domestic resources whose development may be sensitive to U.S. export policy, and provides preliminary estimates of the economic values that are at stake.

1.1.2 THE ENERGY DEPARTMENT'S VIEW. This analysis has the endorsement of U.S. Secretary of Energy John S. Herrington. In his March 1987 report to the President on energy security, the Secretary summarizes the issues as follows:

> **At present there is effectively a ban on exporting crude oil from North Alaska. Because of this, about half of the 1.8 million barrels per day of North Alaskan crude oil is shipped to California, while roughly the other half goes all the way down and across Panama to refiners along the Caribbean and Gulf Coasts. Removal of the export restrictions would permit some Alaskan oil to be shipped a shorter sea distance to markets in the Pacific Rim, especially to Japan. With lower transportation costs, the "netback" to Alaskan producers would be higher. They would be encouraged to produce more oil and to look for more.**
>
> **Section 27 of the Merchant Marine Act of 1920 (Jones Act) requires carriage of Alaskan crude by U.S. flag tankers between**

U.S. ports. Approximately 40 percent of the U.S. domestic tanker fleet is currently employed in the Alaskan crude trade.

Restrictions on the export of Alaskan crude distort the market and interfere with efficient allocation of domestic resources. The inflow of Alaskan oil to California has created a crude oil excess there that has depressed wellhead prices and will reduce long-term California production over what might otherwise occur. Thus, lifting the restrictions would increase the wellhead value of both Alaskan and Californian crude oil. Increased cash flow and profitability would stimulate additional exploration and production in both States. Dropping the effective ban would also head off a possible misallocation of resources in the future, such as construction of additional pipelines to transport crude oil from California.

Producing more crude in Alaska and California would enhance U.S. energy security, because it would reduce net U.S. oil imports --- and thus reduce world dependence on insecure oil supplies. Greater security and diversification of oil supplies for U.S. trade partners in the Pacific would also reduce the likelihood of their bidding up world oil prices in a supply disruption. And Federal and State tax revenues would both be increased --- because the value of this U.S. crude oil at the wellhead had risen.

There are several reasons why the ban on exporting Alaska crude oil remains in place. Some believe that exporting any American crude to foreign countries would make this country less secure. In fact, however --- given the integrated nature of the world oil market --- it is net U.S. oil imports, not the amount of crude oil exports, that are important to our energy security. If net oil imports actually decline somewhat by allowing crude oil exports (through higher production in Alaska and California), then U.S. energy security has been improved.

A more contentious argument against allowing exports from northern Alaska is that it would likely result in the idling of a large number of U.S. tankers and a loss of jobs in the U.S. maritime industry. The loss of tankers would reduce the availability of militarily useful tankers for defense purposes in case of an emergency that required them.

California consumers of petroleum products (both industrial and residential) are concerned about removal of the export ban for another reason. They fear a potential price increase in petroleum products that might occur in California as the excess crude in that region was shipped elsewhere. Also, large investments in pipelines to move excess California crude to other U.S. markets would be jeopardized if the export restrictions vanished. (pp 89-90)

We have little quarrel with the Secretary's statement of the issues. Exports of Alaska crude oil would undoubtedly raise "netback" prices at the wellhead in Alaska and California, and thus encourage greater production from developed fields and new fields in both states. Federal and State tax revenues would indeed be enhanced.

The Secretary fairly summarizes the case against exports as well, but some if not all of the objections he recites (without endorsing or criticizing them, it should be noted) are superficial or of doubtful merit. Exports would indeed reduce the utilization of domestic tankers, and would likely cause layoffs among maritime workers. The argument from a security standpoint is questionable, however: What difference would it make in a military emergency whether or not the tankers that supplied U.S. forces were U.S.-built or otherwise? The abandonment of California oil-pipeline construction projects, which the Secretary first offers as an efficiency gain from exports, curiously appears again as a contra argument. Finally, for reasons set out in the body of the report, we do not believe that California consumers need to be concerned that exports will cause a rise in the local price of petroleum products.

The present report is an attempt to give approximate numbers to the probable effect of exports on wellhead prices in Alaska and California, the likely impact on production from established and new oilfields in the two states, and the State and Federal revenue effects, and other significant consequences. It is not the result of any new research on production costs, or any new engineering or econometric models, but has been built up from data in publicly available materials, interviews in March 1987 with knowledgeable oil-industry personnel, and other qualitiative information available to the investigators.

1.2 IMMEDIATE IMPACTS OF REMOVING THE EXPORT BAN.

If East Asia were a permitted destination for the crude-oil volumes that are surplus to the needs of refineries on the U.S. West Coast, **there would be an increase of about $4 per barrel ---**

* in the market value of that ANS crude which is now shipped to Gulf and East Coast ports;
* in the prices of most California crude oil refined in California;

and most importantly from a national-interest standpoint,

* **in the market value of all new Alaska and California production.**

There would also be a smaller, but still substantial increase --- on the order of $2 per barrel ---

* in the average wellhead price of the ANS crude oil now refined on the West Coast.

These price increases would be based on the fact that

* World-market prices for grades of crude oil similar to ANS are just about as high (if not a little higher) at refineries in Japan, Korea, and Taiwan, as at refineries on the U.S. Gulf and East Coasts; while
* Transportation of "surplus" West Coast crude oil to the Orient would sharply reduce those tanker-transport costs which have to be subtracted from "refinery-gate" prices (either in the eastern U.S. or in the Far East), in order to arrive at the wellhead value of the "marginal" barrel produced in California or Alaska.

Table 1.1 contains our projections of wellhead prices in Alaska and California for the period 1985-2000, both under the status quo, in which exports are prohibited, and assuming that unlimited exports were authorized beginning in 1987.

1.2.1 PAST COSTS. Between the beginning of 1981, when federal crude-oil price controls ended, through 1986, the export ban reduced the wellhead value of the crude oil that was produced in Alaska by about $11.9 billion, and the wellhead value of California crude oil by about $9.7 billion. The cost to the State of Alaska alone in royalties, production taxes, and corporate income taxes was about $3.7 billion; the federal government lost about $4.4 billion in net windfall profits tax ("WPT") revenues from the Prudhoe Bay field alone.

1.2.2 DIRECT GAINERS FROM EXPORTS: ALASKA, THE U.S. TREASURY, WEST COAST OIL PRODUCERS, CALIFORNIA. Even if these price increases did not affect the amount of oil produced in Alaska or California, the increase in producer sales revenues in the two States could be expected to total about $3 billion per year in the years 1987-1990, and total about $18 billion over the period 1987-1995. The direct beneficiaries would be the State of Alaska, the Federal Treasury, those oil companies that produce more crude oil in Alaska and California than they refine in the Pacific States (chiefly Standard, Arco, Exxon, Texaco and Shell), and State and local governments in California, in that order.

1.2.3 LITTLE OR NO IMPACT ON U.S. CONSUMERS. Higher wellhead prices in Alaska and California would have little or no adverse impact on U.S. consumers. They would not increase oil prices elsewhere in the United States because ANS prices at Gulf and East Coast refineries are already determined by the prices of Latin American, North Sea, or Middle Eastern crudes that could replace them. **The higher market value of Alaska and California crudes would not even have much effect on petroleum-product prices faced by West Coast consumers, because both the import and export of petroleum products are now permitted under federal law.** As a result, West Coast product prices are not determined by West Coast crude-oil prices, but rather by the prices at which residual oil can be exported from, and gasoline imported to, the region.

1.2.4 DIRECT LOSERS FROM EXPORTS: CERTAIN OIL COMPANIES; DOMESTIC SHIPPING INTERESTS. The combination of increased crude-oil costs and sticky petroleum-product prices implies that some crude-short West Coast refiners (those which refine more oil than they produce in the Pacific States) could be unfavorably impacted, along with the domestic maritime industry, for which tanker shipments between Valdez and other U.S. ports is now a major captive business. While it is the maritime interests that provide the greatest political support for the crude-oil export ban, any benefit they now receive is doomed to disappear quickly regardless of U.S. export policy. **Our analysis indicates that, if exports are not authorized, West Coast crude-oil production, and the need to ship "surplus" Alaska crude oil beyond California, will begin declining steeply in 1988 or 1989, and will be at an end by 1992.**

Table 1.1

WELLHEAD PRICES IN ALASKA AND CALIFORNIA WITH AND WITHOUT THE EXPORT BAN

PRICE CATEGORY	CASE	1987	1988	1989	1990	1991	1992	1993	1994	1995	2000
		PROJECTED									
WTD-AVG REFINER COST 1985 1986 actual 28.82 15.28	NPC lower				14.74					17.93	21.82
REPRES. GULF-COAST CRUDE	all cases	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	$20.00
ANS VALDEZ NETBACKS											
Netback from Far East	all cases	$14.00	$14.00	$14.00	$14.00	$14.00	$14.00	$14.00	$14.00	$14.00	$19.00
Netback from U.S. Gulf	export	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$12.00	$12.00	$19.00
	no-export	$10.00	$10.00	$10.00	$10.00	$12.00	$12.00	$12.00	$12.00	$12.00	$19.00
	difference	$.00	$.00	$.00	$.00	$-2.00	$-2.00	$-2.00	$.00	$.00	$.00
Volume refined on West Coast	export	1087	1083	1054	988	994	999	1004	1009	1013	937
	no-export	1122	1158	1177	1172	1156	1120	1079	1042	1038	939
	difference	-35	-75	-123	-184	-162	-120	-75	-34	-26	-2
average "discount" 1985 1986 actual $2.63 $1.60	export	$.00	$.00	$.00	$.00	$.00	$.00	$.00	$.00	$.00	$.00
	no-export	$2.08	$2.11	$2.11	$2.08	$2.03	$1.94	$1.84	$.87	$.85	$.00
	difference	$-2.08	$-2.11	$-2.11	$-2.08	$-2.03	$-1.94	$-1.84	$-.87	$-.85	$.00
Average netback from West Coast	export	$14.00	$14.00	$14.00	$14.00	$14.00	$14.00	$14.00	$14.00	$14.00	$19.00
	no-export	$11.92	$11.89	$11.89	$11.92	$12.98	$13.03	$13.08	$13.13	$13.15	$19.00
	difference	$2.08	$2.11	$2.11	$2.08	$1.02	$.97	$.92	$.87	$.85	$.00
AVERAGE ANS VALDEZ NETBACK	export	$14.00	$14.00	$14.00	$14.00	$14.00	$14.00	$14.00	$14.00	$14.00	$19.00
	no-export	$11.18	$11.28	$11.40	$11.56	$12.82	$12.86	$12.89	$13.07	$13.13	$19.00
	difference	$2.82	$2.72	$2.60	$2.44	$1.18	$1.14	$1.11	$.93	$.87	$.00
TAPS tariff	export	$5.33	$4.74	$4.21	$3.74	$3.84	$3.95	$4.06	$4.17	$4.29	$4.13
	no-export	$5.38	$4.79	$4.27	$3.80	$3.91	$4.02	$4.14	$4.26	$4.38	$4.27
	difference	$-.05	$-.05	$-.06	$-.06	$-.07	$-.07	$-.08	$-.09	$-.09	$-.14
AVERAGE ANS PUMP-STATION #1 NETBACK		$8.67	$9.26	$9.79	$10.26	$10.16	$10.05	$9.94	$9.83	$9.71	$14.87
		$5.80	$6.49	$7.13	$7.75	$8.91	$8.83	$8.75	$8.81	$8.75	$14.73
		$2.87	$2.77	$2.66	$2.51	$1.24	$1.22	$1.19	$1.01	$.96	$.14
AVERAGE CALIFORNIA WELLHEAD PRICE		$14.00	$14.00	$14.00	$14.00	$14.00	$14.00	$14.00	$14.00	$14.00	$19.00
		$10.00	$10.00	$10.00	$10.00	$12.00	$12.00	$12.00	$12.00	$12.00	$19.00
		$4.00	$4.00	$4.00	$4.00	$2.00	$2.00	$2.00	$2.00	$2.00	$.00

1.3 INCREASES IN ALASKA AND CALIFORNIA CRUDE-OIL PRODUCTION.

From a national standpoint, the most important effect of removing the ban on exporting ANS crude oil would be the greater incentives oil companies would have to invest in additional production at already-producing fields in Alaska and California, and to complete projects that are already underway or planned for several huge new fields. Alaska and California contain a number of projects, involving many billions of barrels of oil in known reservoirs, whose financial feasibility has become very sensitive to expected wellhead revenues since world oil prices collapsed in 1986. A $4-per-barrel increase in the market value of new crude-oil production is equivalent to about 60 percent of the average mid-1986 wellhead price of ANS crude oil, and about 40 percent of the posted price of a typical California heavy crude oil (Kern River). The leverage that such a price differential would exert on production incentives in Alaska and California is clearly much greater than that which would be created for production elsewhere in the United States, by an import fee of, say, $5 per barrel.

1.3.1 PRODUCTION POTENTIALS IN ARCTIC ALASKA. The authors have examined the status, projected costs, and likely influence of wellhead-price expectations on the following ANS production ventures, all of which were underway or being planned or actively considered by industry before oil prices plunged early in 1986. The list may not contain every development prospect in known ANS reservoirs: there are several "tight holes" (completed exploration wells whose results are still a closely-held secret) on ANS federal offshore acreage.

Prudhoe Bay unit infill drilling
Prudhoe Bay unit extension drilling (Sag River and Eileen plays)
Prudhoe Bay unit tertiary recovery
Kuparuk River unit infill drilling
Kuparuk River unit extension drilling
Kuparuk River unit tertiary recovery
Milne Point unit (resumption of suspended production)
Gwyrdr Bay unit
Lisburne formation
Endicott unit
Seal Island unit
West Sak pilot project
Point Thomson unit.
and others.

Table 1.3 shows the authors' projections of most likely production levels for ANS crude oil, with and without exports, for the years 1987 through 2000. If the export ban is continued, ANS production is likely to fall from a peak of 1.8 million barrels per day (mmb/d) in 1987 to 1.4 mmb/d in 1990, 1.1 in 1995, and .9 mmb/d in the year 2000. Exports can be expected to improve the outlook by about 300 mmb/d in 1990.

Beginning in the early-to-mid 1990s, however, declining production (in part the result of the export ban) will make the U.S. West Coast a net importer of crude oil. As a result, wellhead prices in Alaska and California will converge upward toward world-market levels and, by about the year 2000, production will be about the same without respect to earlier U.S. export policy.

1.3.2 PRODUCTION POTENTIALS IN CALIFORNIA. See Chapter 5. Table 1.3.2 shows the authors' projections of most likely production levels for California crude oil, with and without exports, for the years 1987 through 2000.

TABLE 1.3.1

ACTUAL AND PROJECTED ALASKA CRUDE-OIL PRODUCTION WITH AND WITHOUT THE EXPORT BAN

AREA AND/OR CATEGORY	SOURCE OR CASE	ACTUAL 1985	ACTUAL 1986	PROJECTED 1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	TOTAL
ALASKA PRODUCTION		mb/d	mb/d	mb/d	mb/d	mb/d	mb/d	mb/d	mb/d	mb/d	mb/c	mb/d	mb/d	mil bbl
North Slope														
Prudhoe Bay	AK DPR						1148					842	536	
	export			1500	1500	1455	1261	1094	948	822	713	618	360	4391
	no export	1550	1550	1470	1313	1172	1047	1001	966	925	713	618	360	4141
	difference			30	187	283	214	93	-18	-103	0	0	0	251
Kuparuk River	AK DPR						222					129	61	
	export			280	262	246	230	216	202	190	178	166	120	970
	no export	180	240	260	255	231	210	196	187	180	176	166	120	939
	difference			0	7	15	20	20	15	10	2	0	0	33
Milne Point	AK DPR						27					21	6	
	export			0	20	20	30	24	19	15	12	10		62
	no export	3	19	0	20	19	15	12	14	14	12	10	4	53
	difference			0	0	1	15	12	5	1	0	0	-4	9
Lisburne	AK DPR						57					117	50	
	export			40	50	60	80	80	80	80	80	80	30	334
	no export			40	50	60	51	48	52	62	78	80	30	294
	difference			0	0	0	29	32	28	18	2	0	0	40
Endicott	AK DPR						82					58	21	
	export			40	50	100	100	100	100	88	77	67	34	343
	no export			0	40	80	100	102	104	92	77	67	32	321
	difference			40	10	20	0	-2	-4	-4	0	0	2	8
West Sak	AK DPR											33	57	
	export											50	150	263
	no export											15	150	211
	difference											35	0	52
Seal Island	export											40	64	152
	no export											12	64	119
	difference											26	0	32
Other	AK DPR			[including Seal Isalnd]								26	37	
	export									45	55	66	168	279
	no export									9	24	66	168	254
	difference									36	31	0	0	25
NORTH SLOPE SUBTOTAL	AK DPR						1536					1226	768	
	export	1733	1809	1820	1882	1881	1701	1514	1349	1240	1114	1097	926	6780
	no export	1733	1809	1790	1678	1562	1423	1359	1323	1281	1080	1034	928	6331
	difference			30	204	319	278	154	27	-41	35	63	-2	449
COOK INLET	AK DPR						22					10	8	
	export	66	47	42	38	34	31	28	25	22	20	18	11	119
	no export	66	47	39	32	27	22	21	22	22	20	18	11	106
	difference			3	6	8	9	6	3	0	0	0	0	13
TOTAL ALASKA PRODUCTION	AK DPR						1558					1236	776	
	export	1799	1856	1862	1920	1915	1732	1541	1374	1263	1135	1115	937	6900
	no export	1799	1856	1829	1710	1589	1445	1381	1345	1304	1100	1052	939	6438
	difference			33	210	327	287	161	30	-41	35	63	-2	462

TABLE 1.3.2

ACTUAL AND PROJECTED CALIFORNIA CRUDE-OIL PRODUCTION WITH AND WITHOUT THE EXPORT BAN

AREA AND/OR CATEGORY	SOURCE OR CASE	ACTUAL 1985	ACTUAL 1986	PROJECTED 1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	TOTAL
CALIFORNIA PRODUCTION North Slope		mb/d	mb/d	mb/d	mb/d	mb/d	mb/d	mb/d	mb/d	mb/d	mb/d	mb/d	mb/d	mil bbl
Thermally Enhanced Oil Recovery	CEC						490					525	530	
	export			444	437	431	425	437	450	463	470	490	530	2419
	no export	468	450	430	411	392	375	367	406	429	459	481	530	2316
	difference			14	26	39	50	70	44	34	11	9		103
All Other Onshore	CEC						377					357	112	
	export			463	433	405	379	374	368	363	358	353	338	1905
	no export	504	495	452	413	378	345	348	355	360	358	353	338	1856
	difference			11	20	27	34	26	13	3				49
State Offshore	CEC						197					182	163	
	export			113	133	157	186	185	185	184	184	183	154	853
	no export	105	95	112	131	154	180	178	177	177	178	179	154	837
	difference			1	2	3	6	7	8	7	6	4		16
Federal OCS	ADL for CEC						405					250	155	
	export	81	77	111	160	230	330	343	356	370	385	400	400	1711
	no export			103	136	181	240	271	311	350	385	400	400	1598
	difference			8	24	49	90	72	45	20				113
TOTAL CALIFORNIA PRODUCTION	CEC	[not equal to sum of above]					1064					1064	1031	
	export			1131	1163	1223	1320	1339	1359	1380	1397	1426	1422	6888
	no export	1161	1117	1097	1091	1105	1140	1164	1249	1316	1380	1413	1422	6607
	difference			34	72	118	180	175	110	64	17	13	01	281
ALASKA PRODUCTION (from previous table)	AK DPR						1558					1236	776	
	export			1862	1920	1915	1732	1541	1374	1263	1135	1115	937	6900
	no export	1799	1856	1829	1710	1589	1445	1381	1345	1304	1100	1052	939	6438
	difference			33	210	326	287	160	29	-41	35	63	-2	462
COMBINED ALASKA AND CALIFORNIA	AK & CA						2622					2300	1807	
	export			2993	3083	3138	3052	2880	2733	2643	2532	2541	2359	13788
	no export	2960	2973	2926	2801	2694	2585	2545	2594	2620	2480	2465	2361	13045
	difference			67	282	444	467	335	139	23	52	76	-2	743
REMAINDER OF UNITED STATES	NPC-lower						4515					3354	2735	
	both cases	6011	5694	5276	4889	4530	4197	3931	3682	3449	3231	3026	1895	17436
U.S. crude oil & lease condensate	sum above						7137					5654	4542	
	export			8269	7972	7668	7249	6811	6415	6092	5763	5567	4254	31224
	no export	8971	8667	8202	7690	7224	6782	6476	6276	6069	5711	5491	4256	30481
	difference			67	282	444	467	335	139	23	52	76	-2	743
Natural-gas liquids [includes AK & CA]	NPC-lower						1284					1083	942	
	export			1491	1437	1382	1307	1228	1157	1098	1040	1004	767	5629
	no export	1609	1571	1479	1386	1302	1223	1171	1131	1094	1030	990	767	5495
	difference			12	51	80	84	57	26	4	10	14		134
TOTAL U.S. PETROLEUM LIQUIDS	sum above						8421					6742	5484	
	export			9760	9409	9050	8556	8039	7572	7190	6803	6571	5021	36853
	no export	10580	10238	9681	9076	8526	8005	7647	7407	7163	6741	6481	5023	35976
	difference			79	333	524	551	392	165	27	62	90	-2	877

2. ALASKA AND CALIFORNIA IN U.S. NATIONAL OIL SUPPLY

2.1 PRODUCTION, RESERVES AND RESOURCES

Alaska and California and adjacent offshore lands accounted for 35 percent of U.S. crude-oil production in 1986[1] and, according to a 1985 report of the U.S. Geological Survey ("USGS"), 48 percent of the nation's "measurable" crude-oil reserves, and 29 percent of the expected "undiscoverable recoverable" crude-oil resources.[2]

2.1.1 UNDEVELOPED RESOURCES IN KNOWN POOLS. The Energy Department and USGS figures cited do not give proper emphasis to the strategic position of the two states in national oil supply, because **the most important crude-oil assets from the perspective of national oil supply for the rest of the the 20th Century are the known but undeveloped resources in Alaska and California.** Most reports and debates on national energy policy seem to neglect these petroleum deposits, which are also missing from the federal government's most frequently cited oil-resource statistics because, while they are not technically "proved", neither are they "undiscovered".[3]

The outlook for U.S. domestic oil production depends, at least through the 1990s, on the decisions major oil companies will make whether or not to invest in developing the crude oil that is known to exist in already-found pools and to be producible with existing technology. **Alaska and California totally dominate the nation's inventory of such undeveloped "oil-in-place".**[4]

2.1.2 ENHANCED RECOVERY IN PRODUCING FIELDS. Most of the known but undeveloped petroleum in Alaska and California is made up of the oil in a number of already-producing "supergiant" fields[5], which conventional "primary" and "secondary" recovery[6] would leave behind in the reservoir. Between now and the end of the Century, the production potential from thermally enhanced oil recovery ("TEOR") projects in six of the nation's seven largest-producing fields, Prudhoe Bay and Kuparuk River in Alaska, and the Kern River, Belridge, Midway-Sunset, and Wilmington) almost certainly surpasses the potential of all new-field and TEOR projects in the other 48 states.

2.2 NEW-FIELD DEVELOPMENT

The inventory of known but undeveloped oil resources also contains a number of new giant and supergiant fields in Alaska and California from which substantial production has yet to begin, but to which the oil companies have already committed hundreds of millions of dollars in exploration, infrastructure, and development investment. Examples are the Endicott and Lisburne units on the Alaska North Slope, and the Hondo field in California's offshore Santa Ynez unit. Another instance is the West Sak deposit in Arctic Alaska, which may contain more "oil-in-place"[6] than any other field yet discovered in North America, and on which Arco recently suspended operation of a technically successful "pilot project" because field development does not seem financially warranted at current oil prices.

Figure 2.1.1

PROVED CRUDE-OIL RESERVES IN THE UNITED STATES
ALASKA AND CALIFORNIA, 1985

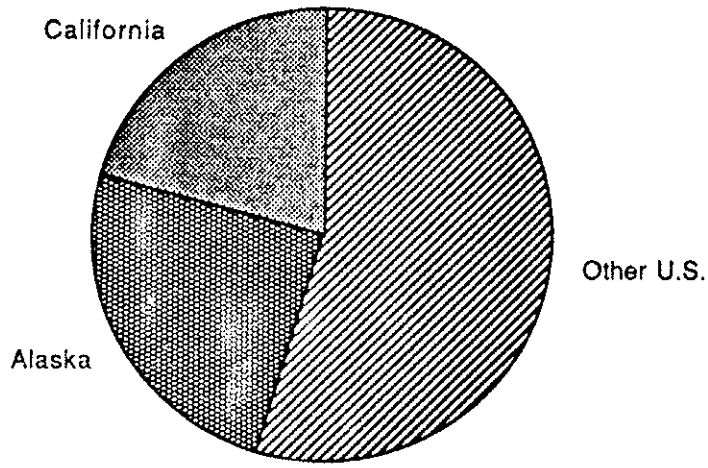
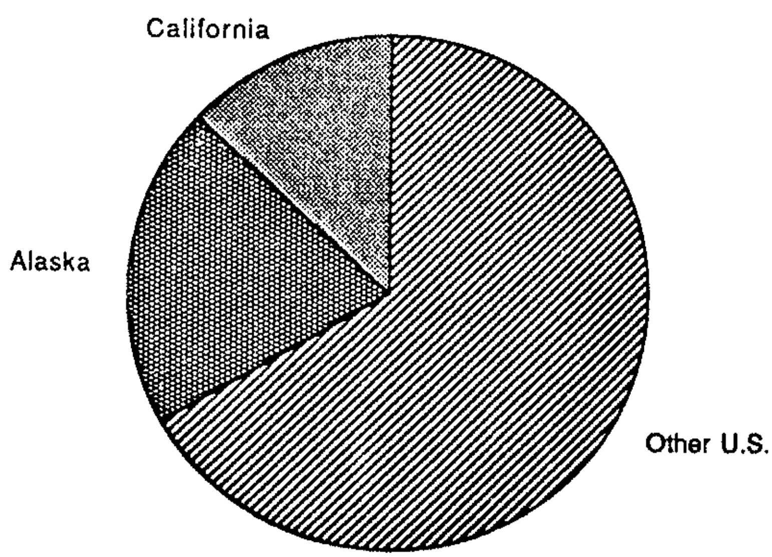


Figure 2.1.2

CRUDE-OIL PRODUCTION IN THE UNITED STATES
ALASKA AND CALIFORNIA, 1985



2.3 COST AND PRICE HANDICAPS

All of the TEOR and new-field investment projects mentioned here were under way, scheduled for development, or in process of planning when world oil prices collapsed in 1986. The financial feasibility of each of them, however, depends powerfully on the outlook for future oil prices and some of them are now in jeopardy. Despite the tremendous volumes of oil involved, there are several factors that make investment in Alaska and California production peculiarly sensitive to crude-oil prices received at the field (the "wellhead" price). These handicaps include relatively high production costs stemming from the remote location and harsh environment in the case of Alaska production, the low "quality" of typical West Coast crude oils, which cause them to sell at a significant price discount, and an exceptionally severe transport-cost burden, which is borne by the producers in the form of lower wellhead prices.

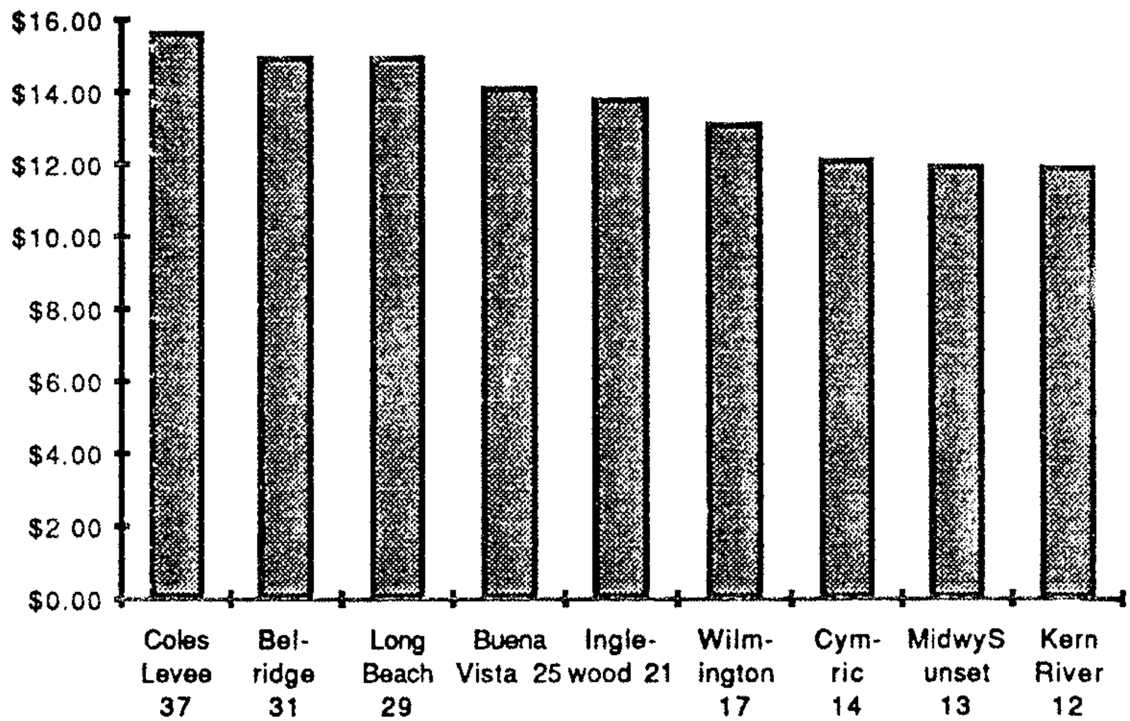
2.3.1 DEVELOPMENT COSTS. In the case of Arctic Alaska, there are the high transport costs for equipment and materials and high operating costs, which stem from the remoteness of the fields, horrible weather, soil fragility onshore and ice stress offshore.

2.3.2 HEAVY, HIGH-SULFUR SUPPLIES. Most of the additional production potential in California, and a large portion of the Alaska potential is, moreover, for "heavy" crude oil, which is more costly to to produce, as it requires TEOR techniques to maximize output. Most of California's additional heavy-oil potential is associated with steam-injection projects. Much of the West Coast supply also contains relatively large concentrations of sulfur and other contaminating elements.

Despite its additional production costs, Figure 2.2 shows that heavy, high-sulfur oils sell at deep discounts relative to "average" grades of oil, The West Coast's price penalties for "gravity" and sulfur content are often greater than in other major world refining areas, because heavy oil is such a high proportion of available supply. Transport of heavy oil tends to be more costly, often requiring heated pipelines and tankage, or dilution with lighter hydrocarbons. Even more importantly, "low gravity" and high sulfur content together make typical Alaska and California crudes more costly to refine into high-value products like gasoline, jet fuel, and "middle distillates" (heating oil and diesel fuel). This is a particular disadvantage in California, where air-quality problems prevent the use of high-sulfur fuel oils, and seriously restrict even their processing and transportation.

2.3.3 TRANSPORT TO MARKET. Even more punishing for the economics of Alaska production is the high cost of moving the oil from field to market: In 1986, the Trans Alaska pipeline ("TAPS") toll averaged more than $6 per barrel, while tanker transport costs added another dollar or two for shipments to West Coast refineries, and $4 in tanker charges plus about one dollar for transit through the Panama pipeline to refineries on the U.S. Gulf and East Coasts. **Figure 2.2** (Under a

GRAVITY AND LOCATION PRICE DIFFERENTIALS
FOR CALIFORNIA CRUDE OIL



settlement recently approved by the Federal Energy Regulatory Commission, TAPS charges will fall to about $4.50 in 1987, and $4.00 by 1990.) For oil from North Slope fields other than Prudhoe Bay, local pipeline charges on the North Slope must also be paid. All of these charges have to be subtracted ("netted back") from the world market price as seen at Lower-48 refineries in order to determine a field price in Arctic Alaska. Wellhead prices at North Slope fields, therefore, tend to average about $10 per barrel below the world market price, as measured by the prices of similar grades at the U.S. Gulf --- Arab Light for example. **In the Summer of 1986, the wellhead price of oil from Conoco's Milne Point unit, North of the Prudhoe Bay unit, actually fell below zero!** In January 1987, as a result of low (though positive) prices, Conoco suspended production from the field.

NOTES TO SECTION 2

1. U.S. Department of Energy, Energy Information Administration ("EIA"), Petroleum Supply Monthly.
2. U.S. Department of the Interior, Geological Survey ("USGS"), Circular 860.
3. The USGS report cited above does contain entries for "indicated" and "inferred" reserves, but the numbers for Alaska are clearly much too low relative to the volumes of "unproved" oil in known reservoirs enumerated below.
4. Oil in place is the volume of total liquid hydrocarbons in a reservoir, including both its recoverable "reserves" and the volumes that are not believed to be commercially recoverable.
5. A supergiant field is one believed to contain one billion barrels or more of recoverable oil, a giant contains more than one hundred million barrels.
6. Primary recovery is production that relies on natural subterranean (water or gas) pressures in the reservoir to drive oil to the surface, while secondary recovery depends on artificially-induced waterflood or gas injection. Tertiary or enhanced oil recovery ("EOR") employs heat, and/or solvents and other chemicals to assist production. The real-world demarcations among these production stages are often blurred: all three techniques are currently in use on the Prudhoe Bay reservoir, for example.

3. WEST COAST OIL PRICES AND THE CRUDE-OIL EXPORT BAN

3.1 WEST-COAST CRUDE-OIL PRICE LEVELS

Markets for crude oil on the U.S. Pacific Coast are physically and economically detached from markets elsewhere in the world. The structure of crude-oil prices in this market reflects the interplay of three factors that are peculiar to the region:

* The "surplus" of crude oil from Alaska and California, relative to the demand from refineries in the region;
* **The federal ban on foreign exports of crude oil transported by pipeline across federal lands;**
* The great share of ANS production and of West Coast crude oil shipments to other U.S. markets that is held by the three leading firms, and indeed by one firm --- Standard Alaska (Sohio).

One further characteristic of the regional market is worth noting:

* **Petroleum-product prices which, in contrast to crude-oil prices, are effectively linked with other Pacific Rim and world markets.**

3.2 THE WEST COAST CRUDE-OIL "SURPLUS"

Alaska and California crude-oil production substantially exceeds the demand for oil to be refined within the seven-state Pacific petroleum administration district ("PADD-V").[1] In 1986, production in the District (almost entirely in Alaska and California) averaged just about 3 million barrels per day ("mmb/"d), while net exports to other U.S. districts averaged 628 thousand barrels per day ("mb/d"), the bulk of which took the form of tanker shipments of ANS crude oil to the U.S. Gulf Coast. This figure was equivalent to 34 percent of Alaska production and 21 percent of the West Coast total.[2]

Producers of a commodity in an isolated region that is a net exporter of the commodity normally have to bear the cost, in the form of lower producer prices, of transporting the commodity to a market or markets capable of absorbing its surplus production. Thus, the fact that PADD-V is a <u>net exporter</u> guarantees prices at Coastal refineries in California, Washington, and Alaska that are lower than in other markets, such as the U.S. Gulf, Western Europe, or East Asia, which are <u>net importers</u> of crude oil. Figure 3.2 shows how the West Coast became a net exporter when ANS production commenced in 1977. Table 3.2 projects the West Coast crude-oil surplus through the year 2000.

3.3 THE WEST COAST CRUDE-OIL PRICE DISCOUNT.

The wellhead-price "discount" at which crude oil sells in a net exporting region such as PADD-V depends upon the cost of transporting it to an export market where refiners are willing to purchase the entire surplus. The market value of West Coast crude oil at its point of production thus tends to be the highest price it can command and yet be saleable in the export market, after addition of all shipping costs.

Figure 3.2

The West Coast Oil Surplus

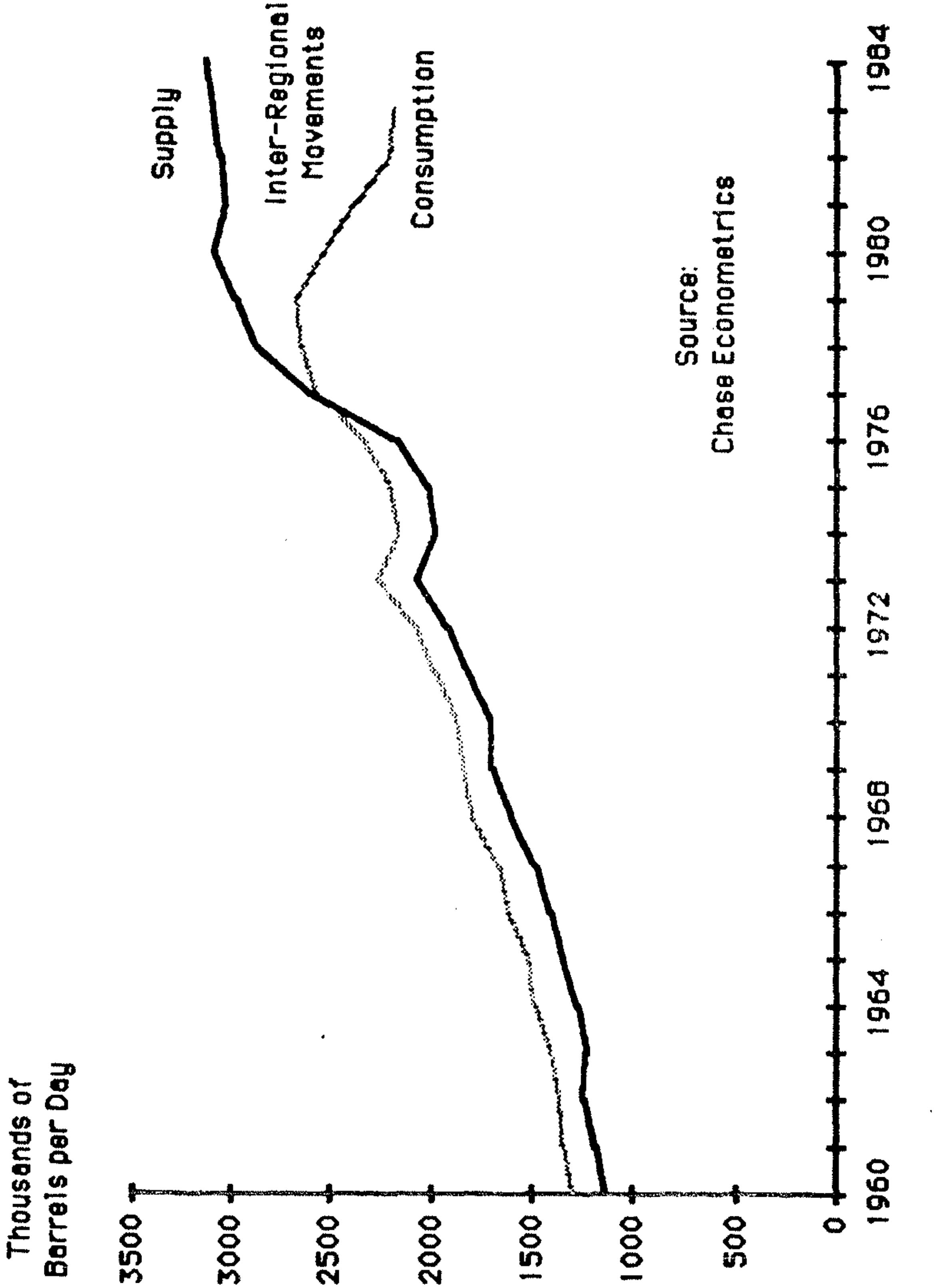


Table 3.2:

PROJECTED WEST COAST CRUDE-OIL BALANCES

AREA AND/OR CATEGORY		ACTUAL 1985	ACTUAL 1986	PROJECTIONS 1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	TOTAL
PETROLEUM DEMAND		mb/d	mb/d	mb/d	mb/d	mb/d	mb/d	mb/d	mb/d	mb/d	mb/d	mb/d	mb/d	mil bbl
Refined petroleum products	export			2346	2408	2472	2537	2591	2646	2703	2760	2819	2851	13687
	no export	2236	2273	2346	2408	2472	2537	2591	2646	2703	2760	2819	2851	13687
	difference			0	0	0	0	0	0	0	0	0	0	0
Residual fuel oil	export			290	292	293	295	295	296	296	296	296	271	1486
	no export	242	288	293	298	302	304	308	314	318	321	325	313	1597
	difference			-3	-6	-9	-9	-12	-19	-22	-25	-29	-42	-117
TOTAL WEST COAST PETROLEUM DEMAND	export			2636	2700	2765	2832	2887	2942	2999	3056	3115	3121	15167
	no export	2450	2561	2639	2706	2774	2842	2899	2961	3021	3082	3144	3163	15283
	difference			-3	-6	-9	-9	-12	-19	-22	-25	-29	-42	-116
WEST COAST REFINERY RUNS	export			2403	2435	2466	2502	2529	2556	2585	2614	2643	2646	13132
	no export	2274	2366	2405	2438	2472	2506	2535	2566	2596	2626	2657	2667	13192
	difference			-2	-3	-5	-5	-6	-9	-11	-13	-14	-21	-59
ALASKA AND CALIFORNIA PRODUCTION	export			2993	3034	3139	3056	2861	2734	2643	2537	2541	2359	13788
	no export	2620	2974	2926	2801	2693	2585	2564	2592	2620	2481	2466	2361	13044
	difference			67	282	445	467	317	141	24	57	75	-2	744
REQUIRED LOW-SULFUR IMPORTS	export			186	189	191	194	196	198	200	202	204	206	1021
	no export	177	132	186	189	191	194	196	199	200	202	204	206	1021
	difference								-1					
WEST COAST CRUDE-OIL SUPPLY	export			3179	3272	3329	3246	3076	2931	2843	2740	2745	2564	14809
	no export	3137	3156	3112	2990	2884	2779	2760	2791	2821	2684	2671	2567	14665
	difference			67	282	445	467	316	141	23	56	74	-4	744
WEST COAST "CRUDE-OIL SURPLUS"	export			776	837	862	744	548	375	259	126	102	-82	1676
	no export	863	790	707	552	412	273	225	225	225	58	14	-100	873
	difference			69	285	450	472	323	150	34	68	89	17	803
Shipments via U.S. West-to-East pipelines	export			40	71	104	225	225	225	225	225	225	225	983
	no export	45	131	40	71	104	225	225	225	225	225	225	225	983
	difference			0	0	0	0	0	0	0	0	0	0	0
OTHER TANKER SHIPMENTS FROM OR TO WEST COAST	export			736	766	757	519	323	150	34	-99	-123	-302	693
	no export	818	777	667	481	307	48	0	0	0	-167	-211	-325	-110
	difference			69	285	450	472	323	150	34	68	89	17	803
NET TANKER SHIPMENTS FROM WEST COAST	export			922	954	948	713	518	346	234	103	82	-102	-328
	no export	995	959	853	669	499	242	196	199	201	36	-6	-118	-1131
	difference			69	285	449	471	322	149	33	67	88	16	803

3.3.1 CALIFORNIA CRUDE-OIL PRICES. The magnitude of the discount for California crudes is shown in figure 3.3: In mid-1986, California crudes (and oil from Alaska's Cook inlet region) tended to have posted wellhead prices about $3 per barrel below the prices of similar grades of oil produced in Texas or imported to the Gulf and East Coasts from Mexico, the North Sea, or the Middle East. This differential is a direct reflection of the additional cost a California producer would have to absorb, in order to ship a barrel of crude oil to a Gulf Coast terminal in which it could obtain a price based on world-market values.

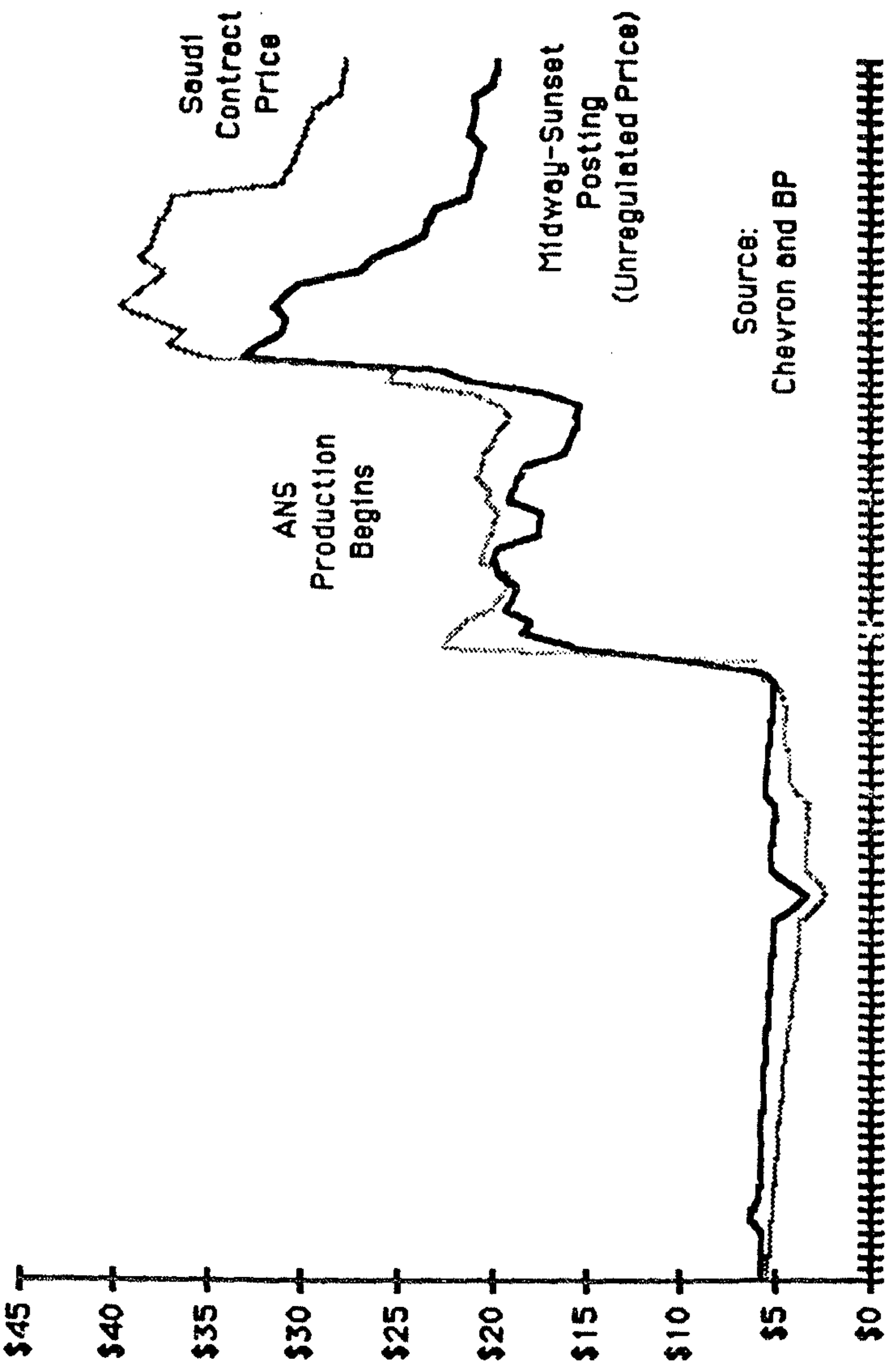
3.3.2 ANS CRUDE-OIL PRICES. Figure 3.3 also demonstrates that ANS crude oil sells for less on the West Coast than at the Gulf, as might be expected. The structure of prices for Alaska North Slope crude oil is, however, more difficult to characterize than the market for California crudes, almost all of which are refined within the State. The **average** differential between Gulf and West Coast refinery prices for ANS crude oil, as reflected in company reports to the State of Alaska for tax and royalty purposes, has cycled widely, but has centered at a value of about $2 per barrel.

3.3.3 PRICING ANOMALIES. This price differential, between average West Coast and Gulf Coast prices for ANS crude oil, is substantially less than the additional cost of transporting ANS oil beyond California to the Gulf Coast. Likewise, the sales prices reported for ANS crude oil in California have tended, until late 1986 at least, to be on the order of $1-to-$3 per barrel higher than the posted prices of comparable California crudes, even after appropriate adjustments were made for quality and intra-California transport costs. Price differentials among different grades of crude oil, and among similar crudes at different locations thus do not strictly reflect differentials in transport costs and refining characteristics, as they tend do in other markets.

Much of the variety in California petrolem pricing does indeed results from the heterogeneity of crude-oil qualities, or from bottlenecks in the intrastate oil-transport infrastructure. Crude oils of similar qualities at a single transaction point (e.g., Valdez, Los Angeles Harbor, or Bakersfield) may nevertheless vary by as much as $3 or $4 per barrel, depending on the identity of the seller, and the origin or destination of the commodity. These seeming price anomalies have generated a long stream of tax and royalty disputes between the producing companies and federal, state, or local taxing authorities, and several anti-trust suits. For reasons that will become apparent below, however, the details of and explanations for these pricing peculiarities are not crucial to the conclusions of this report. **Fundamentally, all West Coast crude oils are discounted relative to world-market values --- and the discount <u>on the margin</u>, where investment decisions are made, is about $4 per barrel. And it is the export ban that makes such discounts inevitable.**

Figure 3.3:

THE WEST COAST CRUDE-OIL PRICE DISCOUNT



3.4 EFFECT OF THE CRUDE-OIL EXPORT BAN ON WEST COAST OIL PRICES.

The current West Coast price discounts would not exist, in other words, if ANS producers were permitted to sell their crude oil in whatever markets gave them the greatest "netback" price. Without the current export prohibition, producers would market most of the crude which was surplus to the needs of the U.S. West Coast in East Asia rather than on the U.S. Gulf and East Coasts. The values of comparable grades of crude oil are almost exactly the same at East Asian ports as at the U.S. Gulf, because tanker charges for oil from the Middle East are nearly the same for the two importing regions. But on the margin, today's market values for ANS crude oil at Valdez reflect a deduction of up to $5 per barrel for transportation to a port on the U.S. Gulf. The comparable cost for shipments to Inchon or Yokohama in foreign-flag supertankers would be only about 75 cents cents per barrel. Thus, incremental supplies of crude oil produced in PADD-V would stand to gain more than $4 per barrel in wellhead value, if exports were allowed.

3.5 EFFECT OF THE CRUDE-OIL EXPORT BAN ON WELLHEAD CRUDE-OIL SALES REVENUES IN ALASKA AND CALIFORNIA.

Table 3.5 shows the total impact of the wellhead price changes on the value of crude-oil production in California and Alaska. Under the assumptions of this report, exports would increase the total value of West Coast production by something on the order of $5 to $6 billion per year through 1990, declining to less than $2 billion per year by the year 2000. The cumulative loss from the export ban will be about $27 billion for the 1987-91 period, and $50 billion for the period 1987 through 2000.

NOTES TO SECTION 3

1. The Petroleum Administration District No. V ("PADD-V") comprises the States of Alaska, Hawaii, California, Oregon, Washington, Arizona, and Nevada.
2. EIA, Petroleum Supply Annual and Petroleum Supply Monthly.

Table 3.5

ALASKA AND CALIFORNIA SALES REVENUES FOR CRUDE OIL WITH AND WITHOUT THE EXPORT BAN

		MILLIONS OF 1987 CONSTANT DOLLARS											NPV @ 10 % REAL
		1987	1988	1989	1990	1991	1992	1993	1994	1995	2000	TOTAL	
ALASKA													
North Slope	export	5759	6380	6722	6372	5611	4962	4500	3997	3888	5040	75035	40723
	no-export	3789	3985	4065	4027	4421	4275	4094	3473	3303	5005	61206	31140
	difference	1970	2395	2657	2344	1190	687	407	524	585	35	13829	9583
Cook Inlet	export	216	196	176	158	142	128	114	103	92	76	1794	1058
	no-export	159	133	111	93	100	103	106	96	86	76	1456	810
	difference	58	63	65	66	42	24	9	7	6	0	339	248
TOTAL ALASKA	export	5975	6576	6897	6530	5753	5090	4615	4100	3980	5116	76830	41781
	no-export	3947	4118	4176	4120	4522	4379	4199	3568	3389	5081	62662	31950
	difference	2028	2458	2722	2410	1231	711	415	531	591	35	14168	9831
of which, change owing to:													
Higher price, base production		1882	1698	1509	1289	557	488	426	318	284	0	8451	6237
Increased production		145	760	1213	1121	674	223	-11	214	307	35	5717	3594
													0
TOTAL CALIFORNIA	export	5777	5945	6251	6745	6844	6947	7055	7168	7287	9862	109358	53559
	no-export	4003	3983	4031	4161	5182	5465	5765	6048	6192	9862	94170	43376
	difference	1774	1962	2220	2584	1662	1482	1290	1120	1095	0	15188	10184
of which, change owing to:													
Higher price, base production		1601	1593	1612	1664	830	829	828	828	829	0	10616	7267
Increased production		173	368	607	920	831	653	462	292	266	0	4572	2917
TOTAL ALASKA & CALIFORNIA	export	11752	12521	13148	13275	12597	12037	11670	11268	11267	14978	186187	95341
	no-export	7950	8101	8207	8281	9704	9844	9964	9617	9581	14943	156831	75326
	difference	5403	5826	6108	5848	3836	3315	3018	3134	3193	1809	49621	30168
of which, change owing to:													
Higher price, base production		3483	3291	3122	2953	1387	1317	1255	1146	1113	0	19067	13504
Increased production		1919	2534	2987	2895	2448	1997	1763	1988	2081	1809	30554	16663

4. EFFECT OF THE EXPORT BAN ON ALASKA CRUDE-OIL PRODUCTION

4.1 STATUS OF NORTH SLOPE PRODUCING PROPERTIES AND PROSPECTS

4.1.1 PRUDHOE BAY. The Prudhoe Bay field, which was discovered in 1968, is the largest oil-producing property in North America. The main Sadlerochit reservoir originally had an estimated 23 billion barrels of oil in place, of which about 11 billion are considered recoverable by primary, waterflood and miscible-gas-recovery technologies. Production from this reservoir has been nearly steady at 1.5 million barrels per day ("mmb/d") since 1979, but all three major producing companies expect output to drop off rapidly beginning in late 1988 or early 1989. Average production in 1991 could be as low as 1.1 mmb/d.[1]

ARCO Alaska, Inc. is operator for the eastern area of the Prudhoe Bay unit and Standard Alaska Production Company (formerly Sohio) operates the western area. As of the end of 1986 the producers had invested $12-13 billion at Prudhoe Bay.

Prudhoe Bay was initially developed using 640-acre spacing for wells that commenced production at up to 20 mb/d each. Infill drilling at a spacing of 160 acres commenced shortly after production began in 1977; an 80-acre-spacing program commenced in 1981 and continues today. Further infill drilling over the next few years will result in well spacing at 40-acre intervals and recover an additional 80-100 million barrels. In 1986 a typical Prudhoe Bay well, with an average measured depth of 10,500 feet, cost about $2.4 million. By the end of 1986, 835 wells had been drilled and an additional 350 wells are currently planned for full field development.

To help maintain production rates, a $2-billion waterflood project began operating in 1984. The waterflood project will increase recovery by about 1 billion barrels. An $800-million natural-gas-liquids EOR ("miscible gas") project began operation in December 1986. The project will process 50 mb/d of natural-gas liquids ("NGLs") to be blended into the crude-oil stream in TAPS and, will eventually result in added recovery of 135 to 190 million barrels of oil, as well as 365 million barrels of NGLs.

Other Prudhoe Bay owners are Exxon Company, U.S.A., Amerada Hess, Chevron U.S.A., Louisiana Land & Exploration Company, Marathon Oil Company, Mobil Oil Corporation, Phillips Petroleum Company, Getty Oil Company (Texaco), Shell and British Petroleum.

4.1.2 EILEEN PROSPECT. The Eileen Field, also called West End because of its location at the west end of the Prudhoe Bay unit, involves the same Sadlerochit formation that contains the main Prudhoe Bay reservoir, and will be operated by Standard as part of the Prudhoe Bay unit. However, in the Eileen sector the reservoir is composed of carbonates, and has to be drilled separately because of its stratigraphic separation. The Eileen sector is said to have million barrels of oil in place with about 150 million barrels of recoverable reserves. When developed, production from the field is expected to peak at 60-70 mb/d.

In 1985 when Standard announced plans to develop the Eileen field, the company estimated that the total field development cost would be about $300 million --- roughly $100 million for facilities and $200 million for the 72-well drilling program. Through 1986 the companies had spent $50 million on the project. Pipe for a 15-mile line to connect Eileen to a Prudhoe Bay processing center and well-line materials are in storage on the North Slope and the drill pads themselves have been completed. However, the uncertain oil-price outlook led the owners to suspend completion the Eileen project in December 1986. The gas-injection compressor, which will arrive on the 1987 sealift, will be stored on the North Slope; current planning is for a resumption of development in connection with an anticipated 1988 startup.

4.1.3 KUPARUK RIVER. The Kuparuk River field, centered onshore about 40 miles west of Prudhoe Bay, contains the second-largest producing oil reservoir in North America. Kuparuk, operated by Arco Alaska, Inc., is estimated to have about 5 billion barrels of oil in place, of which 1.5 billion are believed recoverable with primary and existing waterflood technology. Production, which began in 1981, reached a peak of 310 mb/d in January 1987. At the end of 1986 cumulative field-development costs were about $2.8 billion and full field development was expected to total $4 billion. Kuparuk production is expected to fall below 100 mb/d by the mid-1990s.

A field-wide waterflood project and a third production facility were added in 1986. However, in 1986, because of falling oil prices, Arco reduced the number of drilling rigs in Kuparuk from four to one. Initial production rates from Kuparuk wells ranged from 200 to 2,000 barrels per day. Since Kuparuk is a solution-gas-drive reservoir, rates will decline such that the average over the life of the field will be toward the low end of this spectrum.

At the end of 1986 a total of five hundred wells, with an average depth of about 6,000 ft. had been drilled in Kuparuk. In 1986 the typical Kuparuk well cost $1.5 million. Full development of Kuparuk will require more than 700 wells.

Other Kuparuk owners are Standard Alaska Production Company, BP Alaska Exploration, Inc., Mobil Oil Corporation, Chevron U.S.A., Inc, Union Oil Company of California, and Exxon Company, U.S.A.

4.1.4 MILNE POINT. Milne Point, operated by Conoco, Inc., is the smallest field on the North Slope yet brought into production, and the first field on which production has been interrupted because of low oil prices. The field, located about about 35 miles northwest of Prudhoe Bay encompasses upland and submerged tracts and is part of the Kuparuk River Cretaceous sands reservoir formation. The Milne Point unit has about 180 million barrels in place in the Kuparuk formation and about 1.6 billion in place in the Cretaceous sands formation. An estimated 60 million barrels are recoverable from the Kuparuk in the Milne field using primary and existing waterflood recovery technology. An additional 40 million barrels could be recovered using tertiary and more advanced recovery techniques from the Cretaceous sands within the Milne field.

Production began in November 1985 and Conoco anticipated that 1986 production would reach 30 mb/d. From the start of production 45,000 b/d of water was injected into the Milne Point reservoir to maintain pressure and maximize recovery. Thus Milne became the first North Slope field to employ a secondary recovery technique during initial production. However, because of problems with the reservoir, peak production reached only 24 mb/d.

In February 1986, because of falling oil prices, Conoco suspended drilling operations at Milne Point. Milne Point production was shut down in January 1987, but is being maintained in a "warm" shutdown mode so that production could be resumed almost immediately if oil prices rose. By the end of 1986 Conoco had invested $471 million in the project. When Milne Point production was shut down the field had 34 production and injection wells, averaging 9,000 feet in depth. Drilling costs have averaged $2 million per well.

In its "warm" shutdown, Conoco is incurring $1 million per month in operating costs, nearly what the company would spend if the field were in production. Although low oil prices are the primary reason for the shutdown, other factors are that Conoco is not a TAPS owner and Milne is assessed a higher royalty than other North Slope producing fields. Conoco has indicated that lifting the export ban on ANS crude would provide a strong incentive for resuming production from the Milne Point field.

If production resumed, but no additional field development occurred, only about 15-20 million barrels would be produced from the field. However, Conoco indicated that an additional capital expenditure of about $35 million would allow production of the field's 60 million barrel reserve. No estimates are available regarding the cost of producing the Cretaceous pay in Milne, but would likely be more than double what has been spent at Milne to date.

Other Milne Point partners are Chevron U.S.A., Inc. and Cities Service Oil & Gas Corp.

While the Milne Point unit is rather small as North Slope producing properties go, its economically marginal status makes it better than the huge and prolific Prudhoe Bay and Kuparuk units, as an illustration of the development problems and production prospects for new fields in the Arctic.

4.1.5 LISBURNE. The Lisburne field, operated by Arco Alaska, Inc., includes onshore and offshore areas within the Prudhoe Bay Unit. The field underlies the the Prudhoe Bay producing formation and extends under Prudhoe Bay (the body of water). The field has an estimated 2.7 billion barrels of oil in place, exclusive of outlying portions of the field that are not expected to become economic. An estimated 250-300 million barrels are now considered recoverable under primary depletion supplemented by gas injection recovery technology. Waterflood recovery technology will probably eventually provided added production, but no confident estimate of total volumes can be made prior to the accumulation of operating experience in the field.

Lisburne production began in December 1986 at an initial rate of 35 mb/d from 25 producing wells drilled to an average depth of 11,000 feet. Field production is expected to peak in the mid-1990s at 80-100 mb/d. As of December 1986 Lisburne field development costs totalled $780 million including $210 million for production and injection wells.

Lisburne development involves the construction of one offshore and five onshore drillsites which will accommodate a total of 192 wells. The offshore drillsite, which includes a gravel causeway to shore, will be designed for 24 production wells and eight gas-injection wells. Oil will be transported nine miles from the Lisburne Production Center to TAPS Pump Station One via a 16-inch pipeline.

When Lisburne production began in December 1986, cumulative project development costs were just under $1 billion. Well costs, the biggest component of Lisburne's long-term capital cost have been reduced from about $5 million to $3.5 million apiece, but owing to the much greater depth (14,000 ft. vs. 8,500 ft. at Prudhoe Bay), these wells are still much more costly than the average Prudhoe Bay production well. Full development is expected to cost on the order of $1.5 billion.

The offshore site has been delayed until at least 1990 pending completion of an environmental impact statment ("EIS") by the Army Corps of Engineers regarding the causeway. The offshore wells are needed to allow the most efficient drainage of the reservoir. Infill drilling is anticipated on 160-acre well spacing in the 1990's. Full field development will require 180 gas-injection and production wells.

Lisburne is a difficult reservoir to produce because it lies in an older geologic formation composed of limestone/dolomite, a rock that is less porous than the sandstone of the Prudhoe Bay and Kuparuk formations. Lisburne is the first reservoirs of this type to be developed in Alaska.

Exxon Company, U.S.A and Standard Alaska Production Company are partners in the Lisburne field.

4.1.6 ENDICOTT. The Endicott field, which is expected to begin production in late 1987, will be the first commercial production from the U.S. side of the Beaufort Sea. The field, centered about 15 miles northeast of the main Prudhoe Bay operating facilities, borders the eastern side of the Prudhoe Bay Unit. Endicott, operated by Standard Alaska Production Company, will be the third largest producing field in Alaska.

The Endicott field, which encompasses about 42,200 acres, has an estimated 1 billion barrels of oil in place with 350 million barrels recoverable from primary and existing waterflood technology. Production is expected to peak at 100 mb/d in 1988-1992.

The project development includes two man-made gravel islands about 2.5 miles off the coast of the Sagavanirktok River delta in water depths ranging from 8 to 10 feet. The islands are interconnected and connected to shore by a gravel causeway. The 45-acre main production island is the largest island ever built in the Beaufort Sea. Initial production from Endicott will be from 32 to 34 wells drilled to an average depth of 10,400 ft. Initial production from Endicott wells is expected to be 3 to 5 mb/d, but this rate will fall off quickly. Full field development will require 100 wells.

The Endicott project has had the most dramatic drop in development costs of any North Slope field. Preliminary scoping of the project in the early 1980's estimated that field development would cost $3.8 billion. This approach was rejected as uneconomic. After substantial revisions, the owners allocated $2 billion for full field development of Endicott.

By the time oil prices began to plummet, Endicott module fabrication and island construction were well under way. Lower oil prices forced project planners to increase their cost cutting and efficiency efforts, but the biggest price break came from lower prices for module construction, gravel, tubular steel, and the like. Thus to date the primary impact of falling oil prices on Endicott has been that the field will be developed for a little more than half the authorized amount. The full field production costs are expected to be $1.14 billion: $550 million for facilities, $50 million for pipelines, $130 million for islands and causeways and $410 million for wells. By the end of 1987 all but $285 million of the $1.14 billion will have been expended with most of the remaining cost allocated for additional wells.

Falling oil prices caused a reduction in development drilling activity in the Prudhoe Bay, Kuparuk, Lisburne and Milne Point fields. There was no decrease in Endicott drilling because the two rigs, which had been specially built for Endicott field requirements, had long term contracts with high cost cancellation penalties. A significant difference between Endicott and Prudhoe Bay is that primary and secondary recovery capabilities will be part of the production facilities at Endicott from the outset. As a result waterflood, low pressure separation, gas reinjection and gas lift can be initiated at Endicott without additional capital expenditures.

Other partners in the Endicott Field are Amoco Production Co., Arco Alaska, Inc., Exxon Corp., Union Oil Co. of California, Doyon Ltd., Cook Inlet Region, Inc., and NANA Regional Corp. Inc.

4.1.7 WEST SAK. The 250-square-mile West Sak field, which is operated by Arco Alaska, Inc., is onshore and overlies a large portion of the Kuparuk River oil field. The reservoir, which has an estimated 15-to-40 billion barrels of oil in place, may turn out to be the largest accumulation of oil in the United States. However, using the technology so far developed in Arco's pilot project, State geologists estimate only about 750 million barrels to be recoverable. It is in order to note (1) that both the amount of oil in place and the ultimate production potential of West Sak and associated accumulations of heavy oil in the

Cretaceous zone on the North Slope are highly controversial, indeed emotion-laden, issues among industry geologists and engineers, and (2) that we have yet to find any such authority who is willing to make an estimate for attribution. In the light of California experience with gigantic heavy-oil deposits, however (see Section 5), there is a good chance that estimates of ultimately recoverable volumes will expand dramatically in the future. (More than one highly authoritative individual privately speculated about oil-in-place volumes "on the order" of 100 billion barrels; another, however, was vehement that "none of that stuff will be commercial in our lifetime.")

West Sak oil is a thick, molasses-like, low-grade crude. The reservoir is composed of unconsolidated mushy sand that tries to flow into the well bore when substantial flow rates are attempted. The West Sak field is at a shallower depth which is closer to an overlying 1,800 foot-thick layer of permafrost and has a reservoir temperature of about 70 degrees F., compared to 140° for the Sadlerochit.

To date the only development in West Sak has been a two-year pilot project that involved eight production wells and five water-injection wells and one water-source well in an area about one-half mile square. The production and injection wells were drilled to a depth of 4,000 feet. Water for the injection wells was heated and reinjected under high pressure into the West Sak formation. For the pilot project the producing wells, which were located less than 500 feet apart.

If West Sak proceeds to full development, the producing wells would probably be located on areas ranging from 20 to 40 acres, with injection wells located between them. Full development of West Sak with the established technology would require up to five thousand closely spaced production and injection wells.

In 1984 Arco had estimated that the West Sak could be in full production by the late 1980's; however, the company suspended work on the West Sak pilot project in December 1986. Arco is still evaluating the pilot project results and undertaking substantial research to determine how the reservoir can eventually be economical to produce.

The other West Sak pilot participants are BP, Standard, and Exxon.

4.1.8 SEAL ISLAND. In June 1984 Shell Oil Company announced that a second well at the Seal Island prospect in the Beaufort Sea confirmed that the discovery was a commercial one (at early 1984 oil prices) that could lead to the recovery of 300 million barrels of oil. The announcement represented the first commercial discovery in OCS waters on the U.S. side of the Beaufort Sea. The wells were drilled from a man-made gravel island in 39 feet of water about five miles off the coast, 12 miles from the northern edge of the Prudhoe Bay field. Initially Shell indicated that production could begin as early as 1992, however it is unlikely that production will begin before the early or late 1990s.

Drilling at Seal Island began in June 1983. The first well flowed at a rate between .6 and 5 mb/d and the second well tested at a stabilized rate of 5 mb/d. Oil was found in the Sadlerochit formation at depths below 12,750 feet. Oil from Seal Island is rated at 40 degrees gravity, lighter than the 26-to-27-degree oil produced at Prudhoe. Lighter weight oil sells for a higher price because it is a higher quality oil which is easier and less costly to refine into gasoline and jet fuel than Prudhoe Bay crude. A third well was drilled from Seal Island on a Texas Eastern lease block to a depth of 14,490 feet and tested at up to 2.6 mb/d. The fourth well, on an Amoco lease, which was drilled to a depth of 16,200 ft., was plugged and abandoned without testing. Shell and partners paid $122 million for eight blocks in the Seal Island prospect, spent $33.2 million on gravel island construction and $86 million more to drill and test four wells.

In January 1986 Amerada Hess Corporation drilled a third well into the Seal Island prospect from a well located on Northstar Island which is 19,000 ft. northwest of the Seal Island discovery well. The Amerada Hess well flowed at rates of as much as 4.7 mb/d at a depth near 12,000 ft. This strike extended Shell's Seal Island discovery about 5 miles west. The Northstar operation may increase reserve estimates in the Seal Island area. Amerada Hess cancelled plans for further drilling when oil prices plunged. Shell's partners in the Seal Island prospect are Amerada Hess Corp, Amoco Production Co., Texas Eastern Exploration Co., and Murphy Oil U.S.A.

4.1.9 OTHER PROSPECTS IN ARCTIC ALASKA. In addition to the aforementioned fields, there are a number of other North Slope and Beaufort Sea prospects which may be developed if oil prices improve:

Ugnu Sands: The largest of these prospects is the Ugnu Sands, which underlie Kuparuk. The tarlike resource, estimated to contain about 10 billion barrels, would be much more difficult and expensive to produce than West Sak. The resource is not expected to be developed before the year 2000.

Sandpiper: Shell's Sandpiper Island, a $28-million gravel island in 49 feet of water is located about six miles from shore, and 11 miles northwest of Seal Island. The company completed one well in 1985 and Amoco took over operation of the second well in 1986. Oil flowed at stabilized rates of 500 to 2,500 b/d of 40-52 degree gravity oil. No announcements have been made regarding recoverable reserves.

Point Thomson: The Point Thomson Unit, operated by Exxon, is located on the coast of the Beaufort Sea about 50 miles east of the Prudhoe Bay field and just west of ANWR. Fifteen exploration wells in the Point Thomson Unit have indicated that the field is predominately gas --- with an estimated 6 trillion cubic feet in recoverable reserves. The field also contains an estimated 600 million barrels of crude oil and condensate in place. Various development strategies are under consideration, including a gas-cycling project that would allow recovery of liquids prior to installation of a transportation system for North Slope gas.

Colville Delta: In 1985 Texaco discovered oil in the Colville Delta area, which is located sixty miles west of Prudhoe Bay and about 8 miles west of the Kuparuk River Unit. The discovery well, which was located in water 1-1/2 to 2 feet deep and drilled led to a depth of 9,500 feet, flowed at rates of up to 1,075 b/d of 25 degree gravity oil. Following the discovery Texaco drilled two delineation wells, but results have not yet been reported. There is a chance that the field could extend as far north as Federal OCS waters. Amerada Hess also drilled one well on the Colville Delta prospect in 1986. If the Colville proves to be economic and is eventually developed, the development will probably be similar to Kuparuk in a great number of wells will likely be required.

Gwydyr Bay: In early 1987 two independent Texas oil companies, Vaughn Petroleum, Inc., and CM Oil and Gas Corp., both of Dallas, drilled a well and a "sidetrack" well in the Gwydyr Bay unit; neither was deemed capable of production. Vaughn/CM plans an additional well in January 1988 and another in January 1989. The partnership estimates that the total costs for all three wells will be about $15 million. Nine exploration wells had been drilled in the Gwydyr Bay unit prior to the present Vaughn/CM program, of which four were deemed to be capable of commercial production.

Phoenix Prospect: Tenneco is evaluating the results of drilling on the Phoenix Prospect, using the Canmar Single Steel Drilling Caisson (SSDC) on a prefabricated mat in about 60 ft. of water north of the Colville River delta. The prospect is about 12 miles from the Mukluk venture, which was abandoned in 1983, and the operator hopes to find some of the oil that that was anticpated, but not present, in the Mukluk structure. As of February 1987, the project has cost $42.9 million and total project costs are budgeted at about $70 million. If the drilling results indicate a commercial property, production could begin five years after the development decision.

Niakuk: In 1986 Standard Alaska Petroleum Co. drilled another exploratory well in the Niakuk prospect area of Prudhoe Bay which is inside the barrier islands near Heald Point. Two earlier offshore probes yielded unconfirmed oil shows. The target is a possible fault block extension of Sag River pay, which has proved productive in Prudhoe Bay field. No information on the result has been made public.

Tern Prospect: In 1982 Shell drilled an exploratory well from the Tern Prospect, a gravel island in about 22 feet of water, about 10 miles offshore in the Beaufort Sea. Shell drilled a second well in 1983 and is currently drilling a third well from the island. No drilling results have been reported.

Arctic National Wildlife Refuge: The Arctic National Wildlife Refuge ("ANWR") is the best prospect for a Prudhoe Bay type find in the North Slope area. In November 1986 the U.S. Fish and Wildlife Service recommended that the Interior Department open ANWR's coastal plain for oil and gas leasing. The agency said the coastal plain has (only) a 19-percent chance of containing commercially producible hydrocarbons, but if such resources are present, there is a 95-percent probability of more than 4.8 billion barrels of oil in place and 600 million barrels of recoverable reserves. To date the only drilling in the refuge has been by Chevron on Kaktovik Inupiat Corporation lands. The results of this drilling are still confidential. Seismic studies have identified 26 potential oil structures in the coastal plain. ANWR is 50 to 150 miles from TAPS, however, and because of controversy over the necessary Congressional approval for petroleum development in the refuge, the earliest that production from the area could occur is the mid-1990's.

4.2 ALASKA NORTH SLOPE CRUDE-OIL PRODUCTION WITH AND WITHOUT THE BAN

4.2.1 PRODUCTION IN 1990, 1995, AND 2000 WITH THE BAN. Table 1.2.1 showed the most likely scenario of Alaska North Slope Oil production by field over the period 1987-2005, assuming the export ban is continued. Total ANS production falls from a peak of 1.79 mmb/d in 1987 to 1.42 mm/b in 1990, 1.03 mmb/d in 1995, and .93 mmb/d in the year 2000. Prudhoe Bay dominates total production volumes throughout, declining from 1.47 mmb/d in 1987 to 1.05 mmb/d in 1990, 0.62 mmb/d in 1995, and 0.36 mmb/d in the year 2000. Prudhoe Bay production volumes in the table do not include 50-60 mb/d of natural-gas liquids removed and added to the TAPS throughput from the miscible-gas EOR project.

Production from Kuparuk, the next largest North Slope oilfield, falls from 280 mn/d in 1987 to 210 mb/d in 1990, 166 mb/d in 1995, and 102 mb/d in the year 2000. Lisburne production is expected to increase from 40 mb/d in 1987 to 80 mb/d in the early 1990s before declining to around 30 mb/d in 2000. Production from the Endicott field is anticipated to begin in 1988 and increase quickly to 100 mb/d by 1990 before declining also to around 30 mb/d in 2000. Production from the smaller Milne Point field declines slowly from 20 mb/d after the anticipated resumption of output in 1988.

Without the opportunity to export North Slope crude, low projected wellhead prices are likely to discourage, or at least delay, development of new offshore fields such as Seal Island and any future OCS discoveries until the late 1900s. Likewise, commercial development of the huge accumulation of heavy oil overlying the Kuparuk River field is unlikely to be feasible until the price at TAPS pump station No. 1 rises at least $7 per barrel above the current level. The most likely scenario anticipates production rates reaching 80 mb/d for Seal Island and 150 mb/d from West Sak by the latter half of the 1990s. By 2000, we also anticipate that other now-undeveloped fields will contribute more than 150 mb/d of production.

4.2.2 ADDITIONAL PRODUCTION AVAILABLE WITHOUT THE BAN. Lifting the export ban has a large effect on currently marginal or submarginal oil fields such as Seal Island and West Sak because the value of <u>new</u> production would rise by more than the average wellhead values on the North Slope, as discussed in Chapter 3. However, an improvement in the wellhead price of incremental production of up to $4 per barrel would not be sufficient to bring commercial development of the Seal Island and West Sak prospects within the next seven years, given the assumed scenario for world oil prices. Development of these and other marginal fields would proceed more quickly, however. If world oil prices turn out to be higher than assumed for this report (say, in the vicinity of today's $18 per barrel, rather than the assumed $15), the sensitivity of North Slope production to the export ban would increase markedly.

Table 1.2.1 also showed the most likely production for ANS fields assuming that the export ban is lifted. Prudhoe Bay production declines somewhat more slowly because of additional drilling investment and development of the Eileen play. Expansion of the miscible-gas EOR project to the western side of the Prudhoe Bay field is also possible at higher wellhead prices, but no additional production from this source is included in the figures in Table 1.2.1 Development of the Sag River and Niakuk plays adjacent to Prudhoe Bay may also be feasible, but were likewise ignored in the most-likely scenario for the assumed price.

Higher marginal wellhead prices available from exports would be likely to bring on additional drilling and EOR investments at Kuparuk, where oil-recovery is exceptionally sensitive to the pace of development, and the feasibility of ongoing development very sensitive, even in the short run, to realized prices. In the most likely scenario, Kuparuk production rates would be 20 mb/d higher in 1990 if the export ban is eliminated. Lesser incremental production volumes from lifting the ban are anticipated at the remaining fields. Development of the Lisburne field would proceed more rapidly, for example, bringing on higher production rates by 1990. Development plans for the Endicott field would be affected little, but field life would be extended several years by a $4-per-barrel price increase. Higher marginal wellhead prices would allow completion of the original development plans for Milne Point, which would tap 60 million barrels of total recoverable reserves.

Incremental ANS crude-oil production shown in Table 1.2.1 does not include the potential contribution of new discoveries on the federal OCS. Newly discovered fields would be brought into production more quickly under a higher anticipated wellhead price. Higher wellhead prices for incremental ANS production would also stimulate exploration activities on the North Slope, probably leading to further discoveries. Since these effects are not counted in the figures, the projected impact on Alaska crude-oil production of lifting the export ban are likely to be conservative.

4.3 IMPACT ON ALASKA STATE REVENUES.

Additional petroleum revenues that the State of Alaska may receive from lifting the export ban include petroleum lease revenues from producing fields (royalties and net-profit shares), production taxes (severance tax and conservation tax), state corporate income tax, and the state-assessed (but locally levied and received) petroleum property tax. First, we deal with additional revenues the state would receive owing to the higher wellhead prices as such, assuming there is no change in production volumes. Then, we examine the total effects on State revenue, including the effect on revenues from incremental production and the investments needed to bring it about.

4.3.1 IMPACT ON PETROLEUM REVENUES FROM BASE PRODUCTION VOLUMES. Table 4.3.1. shows the revenues the State could expect if exports continued to be prohibited; Table 4.3.2 is the State revenues to be expected from the prices that would prevail if exports were permitted if production volumes were unaffected. Table 4.3.2 shows the projection of additional state revenues under those circumstances. These figures assume that there is no change in the current state tax structure as it relates to the petroleum industry. The average wellhead prices for this scenario are calculated assuming that the Valdez price of ANS crude oil is $1 per barrel less than the world price of the representative crude oil. The TAPS tariff is assumed the same as in the no-export case.

Assuming production volumes do not change, eliminating the export ban would raise total state revenues by a cumulative $1.87 billion between 1987 and 1985. After 1995, the West Coast oil surplus is likely to disappear completely, so there would be no difference from the no-export case. The projected revenues shown in Tables 4.3.1 through 4.3.3 refer to calendar years, so that they will correspond to the use of calendar years for projection of production and revenues elsewhere in this report. Since Alaska's fiscal year ends on June 30, the corresponding fiscal years precede the calendar years by six months.

Lifting the ban would affect all types of revenues mentioned above except for property taxes, assuming there is no change in production investments for production rates. Main revenue increments in Table 4.3.2 come from royalties ($1.1 billion) and severance taxes (around $750 million). State leases for several North Slope fields include net-profit shares. However, the combination of low wellhead prices and the capital-recovery provision in the state regulations defer State revenues from this source except for Seal Island until after 2000.

4.3.2 TOTAL IMPACT ON PETROLEUM REVENUES. The total impact on Alaska State petroleum revenues of lifting the export ban includes the revenue generated by additional investments to increase production. Table 4.3.4 shows the total State petroleum revenues associated with the production scenario described in Section 4.2.2; Table 4.3.5 shows the increase relative to the no-export case. Considering now the projected change in production volumes, eliminating the export ban would be likely to raise total State revenues by $500 to $600 million annually through 1990. Because of increased oil production, revenues continue to be higher than they would be without exports by $119 million in 1995 and $35 million in 2000. By 2000, the cumulative increase in State petroleum revenues would exceed $3 billion.

Most of the additional revenues come in the form of royalties and severance taxes. Royalties are approximately $300 million greater and severance taxes about $200 million greater annually through 1990. After 1990, the incremental production revenues decline rapidly. Quicker development and depletion of reserves from Prudhoe Bay and Lisburne and the Economic Limit Factor ("ELF") in the state severance tax combine to reduce severance-tax revenues in Table 4.3.2 after 1993. In effect, lifting the export ban shifts severance tax revenues made available by the incremental production forward in time.

Table 4.3.1
SUMMARY OF TOTAL ALASKA AND FEDERAL REVENUES WITHOUT EXPORTS
(millions of 1987 dollars)

Year	Oil Produced (MMB/yr)	Royalty +Profit Share	Production Taxes	Property Taxes	State Income Tax	Total State Revenues	Total Federal Revenues
1987	653.4	461.5	396.3	228.2	129.9	1216.0	225.3
1988	612.3	479.6	395.5	227.5	124.0	1226.6	225.0
1989	570.3	488.7	370.1	225.8	117.7	1202.3	283.3
1990	519.6	483.6	327.4	222.0	109.8	1142.8	394.7
1991	496.1	534.5	353.2	210.1	106.4	1204.1	530.5
1992	482.9	515.0	335.5	198.1	102.7	1151.3	436.7
1993	467.9	493.8	319.9	193.2	99.7	1106.7	142.5
1994	394.2	415.7	229.2	211.0	91.1	947.0	-113.6
1995	377.4	386.3	193.3	235.5	92.3	907.3	96.0
1996	365.4	635.4	281.2	232.0	97.6	1246.1	732.5
1997	356.8	612.3	232.7	219.5	94.0	1158.4	691.7
1998	356.6	601.7	193.0	206.8	92.3	1093.7	682.8
1999	335.7	560.2	152.2	194.0	86.9	993.2	622.2
2000	337.2	562.4	161.7	180.9	84.7	989.8	690.4
2001	303.1	505.2	122.6	163.7	76.3	867.9	597.3
2002	272.5	556.8	90.6	146.5	68.5	862.3	480.2
2003	245.2	497.5	64.4	129.2	61.3	752.4	410.5
2004	220.6	444.4	44.6	112.0	54.5	655.5	347.9
2005	198.6	468.9	30.3	94.8	48.2	642.3	267.9
2006	173.8	408.6	22.1	77.5	40.7	548.9	221.6
2007	156.7	363.4	16.2	62.7	35.7	478.0	188.9
2008	141.4	322.9	11.1	49.3	31.3	414.6	176.0
2009	125.1	281.8	7.0	37.4	26.9	353.0	141.2
2010	113.0	249.8	3.7	31.7	24.1	309.3	109.1
2011	102.2	220.8	1.4	27.9	21.7	271.8	76.1
2012	92.4	194.5	0.2	24.1	19.5	238.2	46.3
2013	53.4	115.0	0.1	20.3	12.4	147.8	25.6
2014	48.7	99.6	0.1	16.5	11.0	127.2	15.0
2015	44.4	85.9	0.1	12.7	9.7	108.3	5.4
TOTAL	8617	12046	4355	3991	1971	22363	8749
NPV (10%)		4470	2372	1766	877	9485	3171

Table 4.3.2

SUMMARY OF TOTAL ALASKA AND FEDERAL REVENUES WITH EXPORTS: PRODUCTION UNCHANGED

(millions of 1987 dollars)

Year	Oil Produced (MMB/yr)	Royalty +Profit Share	Production Taxes	Property Taxes	State Income Tax	Total State Revenues	Total Federal Revenues
1987	653.4	691.8	585.0	228.2	135.0	1640.0	693.4
1988	612.3	689.3	559.6	227.5	128.6	1604.9	649.7
1989	570.3	676.1	499.7	225.8	121.9	1523.5	666.6
1990	519.6	644.9	428.5	222.0	113.4	1408.8	727.0
1991	496.1	608.7	400.2	210.1	108.0	1326.9	683.2
1992	482.9	585.4	379.1	198.1	104.3	1266.9	581.8
1993	467.9	559.7	361.6	193.2	101.2	1215.6	277.9
1994	394.2	462.2	253.9	211.0	92.3	1019.4	-16.4
1995	377.4	427.8	211.8	235.5	93.3	968.5	184.2
1996	365.4	635.4	281.2	232.0	97.6	1246.1	732.5
1997	356.8	612.3	232.7	219.5	94.0	1158.4	691.7
1998	356.6	601.7	193.0	206.8	92.3	1093.7	682.8
1999	335.7	560.2	152.2	194.0	86.9	993.2	622.2
2000	337.2	562.4	161.7	180.9	84.7	989.8	690.4
2001	303.1	505.2	122.6	163.7	76.3	867.9	597.3
2002	272.5	556.8	90.6	146.5	68.5	862.3	480.2
2003	245.2	497.5	64.4	129.2	61.3	752.4	410.5
2004	220.6	444.4	44.6	112.0	54.5	655.5	347.9
2005	198.6	468.9	30.3	94.8	48.2	642.3	267.9
2006	173.8	408.6	22.1	77.5	40.7	548.9	221.6
2007	156.7	363.4	16.2	62.7	35.7	478.0	188.9
2008	141.4	322.9	11.1	49.3	31.3	414.6	176.0
2009	125.1	281.8	7.0	37.4	26.9	353.0	141.2
2010	113.0	249.8	3.7	31.7	24.1	309.3	109.1
2011	102.2	220.8	1.4	27.9	21.7	271.8	76.1
2012	92.4	194.5	0.2	24.1	19.5	238.2	46.3
2013	53.4	115.0	0.1	20.3	12.4	147.8	25.6
2014	48.7	99.6	0.1	16.5	11.0	127.2	15.0
2015	44.4	85.9	0.1	12.7	9.7	108.3	5.4
TOTAL	8617	13133	5114	3991	1995	24233	10976
NPV (10%)		5263	2940	1766	895	10864	4791

Table 4.3.3

DIFFERENCE IN TOTAL ALASKA AND FEDERAL REVENUES WITH AND WITHOUT EXPORTS: PRODUCTION UNCHANGED

(millions of 1987 dollars)

Year	Oil Produced (MMB/yr)	Royalty +Profit Share	Production Taxes	Property Taxes	State Income Tax	Total State Revenues	Total Federal Revenues
1987	0.0	230.3	188.6	0.0	5.1	424.0	468.1
1988	0.0	209.7	164.1	0.0	4.6	378.4	424.7
1989	0.0	187.4	129.6	0.0	4.1	321.2	383.3
1990	0.0	161.3	101.1	0.0	3.6	266.0	332.3
1991	0.0	74.2	47.0	0.0	1.7	122.9	152.6
1992	0.0	70.5	43.6	0.0	1.6	115.7	145.1
1993	0.0	65.8	41.7	0.0	1.5	109.0	135.4
1994	0.0	46.5	24.7	0.0	1.1	72.3	97.1
1995	0.0	41.6	18.5	0.0	1.1	61.2	88.2
1996	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1997	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1998	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1999	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2000	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2001	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2002	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2003	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2005	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2006	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2007	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2008	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2009	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2010	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2011	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2012	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2013	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2014	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2015	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1987-2015	0	1087	759	0	24	1871	2227
NPV (10%)		793	568	0	18	1378	1620
1987-2000	0	1087	759	0	24	1871	2227
NPV (10%)		793	568	0	18	1378	1620

Table 4.3.4

SUMMARY OF TOTAL ALASKA AND FEDERAL REVENUES WITH EXPORTS: INCLUDING EFFECT OF INCREASED PRODUCTION

(millions of 1987 dollars)

Year	Oil Produced (MMB/yr)	Royalty +Profit Share	Production Taxes	Property Taxes	State Income Tax	Total State Revenues	Total Federal Revenues
1987	682.6	727.6	621.5	228.2	139.6	1716.8	740.3
1988	687.1	778.5	631.8	227.4	140.3	1778.1	572.1
1989	686.5	820.4	601.5	245.9	142.9	1810.8	710.4
1990	621.0	777.4	507.2	258.4	134.5	1677.5	642.9
1991	552.5	683.5	416.6	269.8	125.5	1495.5	740.4
1992	492.5	601.2	339.3	257.2	114.3	1312.0	506.5
1993	452.4	540.0	285.7	253.6	107.6	1186.9	130.4
1994	406.8	477.8	225.5	272.6	103.2	1079.2	19.7
1995	400.5	451.3	182.3	288.3	104.7	1026.7	239.7
1996	400.9	693.2	244.2	276.7	110.2	1324.3	767.6
1997	376.9	646.5	191.1	264.9	104.5	1207.1	694.5
1998	362.7	616.4	157.6	253.0	100.4	1127.4	647.0
1999	338.0	569.3	124.4	240.8	93.8	1028.3	577.6
2000	338.1	570.0	134.2	228.5	92.0	1024.7	638.5
2001	305.5	514.8	102.0	211.9	84.0	912.8	548.5
2002	276.2	558.6	75.4	195.4	76.5	905.9	437.0
2003	249.8	591.0	54.0	178.9	69.6	893.5	339.3
2004	226.0	527.2	38.3	162.4	63.1	790.9	282.0
2005	204.6	469.9	29.4	145.8	56.9	702.1	229.6
2006	185.4	418.5	22.4	129.3	51.2	621.3	183.0
2007	163.1	363.7	16.4	112.8	44.5	537.3	143.5
2008	148.0	323.3	11.3	96.2	39.7	470.4	109.1
2009	134.4	286.9	7.0	79.7	35.1	408.7	88.2
2010	122.1	254.0	3.7	64.4	30.7	352.8	82.1
2011	108.3	219.2	1.4	51.0	26.3	297.9	55.1
2012	98.6	192.7	0.2	37.8	22.6	253.3	33.9
2013	59.6	112.5	0.1	31.3	15.1	159.0	26.3
2014	54.8	96.9	0.1	24.9	13.3	135.2	17.1
2015	46.2	78.6	0.1	18.5	10.7	107.8	9.2
TOTAL	9181	13961	5025	5106	2253	26344	10212
NPV (10%)		5712	3019	2116	999	11845	4595

Table 4.3.5
DIFFERENCE IN TOTAL ALASKA AND FEDERAL REVENUES WITH EXPORTS: INCLUDING EFFECT OF INCREASED PRODUCTION
(millions of 1987 dollars)

Year	Oil Produced (MMB/yr)	Royalty +Profit Share	Production Taxes	Property Taxes	State Income Tax	Total State Revenues	Total Federal Revenues
1987	29.2	266.0	225.2	0.0	9.6	500.8	515.0
1988	74.8	298.9	236.4	-0.1	16.3	551.5	347.1
1989	116.2	331.7	231.4	20.1	25.2	608.4	427.1
1990	101.4	293.8	179.8	36.4	24.7	534.7	248.2
1991	56.5	149.0	63.5	59.8	19.1	291.4	209.9
1992	9.6	86.3	3.8	59.1	11.6	160.8	69.8
1993	-15.6	46.2	-34.2	60.4	7.9	80.3	-12.0
1994	12.6	62.1	-3.7	61.7	12.1	132.1	133.2
1995	23.1	65.0	-11.0	52.8	12.5	119.4	143.7
1996	35.5	57.8	-37.0	44.7	12.6	78.2	35.1
1997	20.2	34.2	-41.5	45.4	10.5	48.6	2.8
1998	6.2	14.7	-35.3	46.1	8.1	33.7	-35.9
1999	2.3	9.2	-27.8	46.8	6.9	35.2	-44.7
2000	0.9	7.5	-27.5	47.5	7.3	34.9	-51.9
2001	2.4	9.6	-20.6	48.2	7.7	44.9	-48.8
2002	3.6	1.8	-15.1	48.9	8.0	43.6	-43.2
2003	4.6	93.6	-10.4	49.6	8.3	141.1	-71.2
2004	5.4	82.8	-6.3	50.3	8.5	135.4	-65.9
2005	6.0	0.9	-0.9	51.0	8.7	59.8	-38.3
2006	11.6	9.9	0.3	51.7	10.5	72.4	-38.6
2007	6.3	0.3	0.2	50.1	8.8	59.4	-45.4
2008	6.6	0.4	0.1	46.9	8.3	55.8	-66.9
2009	9.3	5.0	0.1	42.3	8.2	55.6	-52.9
2010	9.1	4.2	0.1	32.7	6.5	43.5	-27.0
2011	6.1	-1.6	0.0	23.1	4.6	26.1	-21.0
2012	6.1	-1.8	0.0	13.7	3.1	15.1	-12.4
2013	6.2	-2.5	0.0	11.0	2.7	11.2	0.7
2014	6.1	-2.7	0.0	8.4	2.3	8.0	2.2
2015	1.8	-7.3	0.0	5.7	1.0	-0.5	3.8
1987-2015	564	1915	670	1115	282	3981	1462
NPV (10%)		1242	648	349	121	2359	1424
1987-2000	473	1723	722	581	184	3210	1987
NPV (10%)		1204	659	266	106	2236	1509

Some net-profit-share revenues are projected to be available from Seal Island starting about 2000, in addition to increased production taxes. Other North Slope fields with profit-share leases do not recover their capital investment soon enough to trigger profit-sharing, even considering the higher wellhead prices available from exports.

Although the increment to direct production revenues would be the main effect, lifting the export ban would be likely to generate nearly $600 million in petroleum property-tax revenues and $180 million in corporate income taxes between 1987 and 2000. Under Alaska law, the property-tax revenues are shared with local governments. The amounts shown in Table 4.3.5 include both the State and local shares of the incremental revenue. The increment to corporate income-tax revenues derives mainly from increases in the production and assets factors in the modified apportionment formula that the State uses for apportioning net income of firms involved in the petroleum industry.

4.4 OTHER ECONOMIC IMPACTS ON ALASKA.

Elimination of the export ban would have several directly stimulative effects on the state economy.

First, the petroleum industry would make additional development investments on the North Slope that would create (or preserve) hundreds of high-paying jobs in the petroleum-extraction, construction, and related industries.

Second, higher state revenues would prevent the State government from having to reduce expenditure as much as projected under continuation of the export ban. As approximately one-third of the State operating budget is transferred to local governments, local spending would also be much higher if exports are allowed. State and local spending would translate into higher construction and other private as well as public sector employment.

Third, higher petroleum revenues would be likely to forestall tax increases needed to pay for basic State and local services, and forestall elimination of the Permanent Fund dividends. Personal income in Alaska would thus be higher without the export ban.

These direct effects have complex multiplier effects on the state economy, which further increase jobs and income across the state. We make the following benchmark assumptions for the purposes of projecting the effects of eliminating the export ban on the Alaska economy:

1. Total petroleum employment, including exploration and headquarters employment, is about 1,000 higher.

2. Total State appropriations increase by the amount of the increase in revenues, with 85 percent of the increase going to operating expenditures and 15 percent to capital appropriations.

3. Higher revenues allow the Permanent Fund dividend to be retained for one additional year (1989), and reimposition of a State personal income tax deferred for one additional year (until 1990).

The authors used the MAP econometric model developed at ISER to project the indirect effects of higher petroleum and related industry employment and higher state revenues and spending on Alaska's population, employment, and per-capita income. Removing the export ban would increase total Alaska employment by about 12 thousand in 1990 and 15 thousand in 1991, mainly owing to reduced out-migration of younger workers resulting from more favorable employment opportunities within Alaska.

Real per-capita disposable income would increase by about $400 million (in constant 1987 dollars), owing to higher wage & salary receipts and lower tax rates. After 1991, these stimulating effects on the state economy would diminish only slowly, since the balance in the Permanent Fund --- and thus the revenues available form earnings of the Fund --- would remain higher.

NOTES TO SECTION 4

1. "Field", "reservoir", etc. The terms that distinguish various accumulations of hydrocarbons are not always employed the same way in Arctic Alaska as they are customarily used in most other producing regions, and their usage in Alaska itself is often inconsistent. This situation sometimes makes it difficult to reconcile resource or cost estimates from various sources. In the experience of the investigators, this confusion is compounded by the fact that company and state personnel are often unaware of the ambiguity of the unit for which they are supplying a resource or cost estimate.

   The term that is used most loosely in Alaska is "field". Elsewhere an oil and/or gas field is composed of all those hydrocarbons formations continuously underlying a given surface area. Thus, the accumulations that are now referred to as the Prudhoe Bay, Lisburne, Kuparuk, and Eileen "fields" would elsewhere be designated as "pools" or even "sectors" of pools in the "Prudhoe Bay Field". (Indeed, Alaska's Oil and Gas Conservation Commission's Annual Report still designates Kuparuk River and Lisburne as subdivisions of the Prudhoe Bay field.) What is now commonly called the "Milne Point Field" would probably be the "Milne Point pool of the Kuparuk River formation of the Prudhoe Bay field."

   In Arctic Alaska, the word "field" seems to be used for a smaller entity, usually (but not always) interchangeable with a "unit". Unit is, however, the most precisely and consistently employed term. But unit is a legal concept, rather than a geological one. It is defined in a "Unit Agreement" negotiated among leaseholders having working interests in a particular pool or pools, and approved by the Alaska Oil and Gas Conservation Commission. The agreement defines the unit's physical scope in three dimensions, stipulates the manner in which development and lifting costs, and produced hydrocarbons, are to be shared among the working interests, and designates an operator or operators for the property.

The upshot is that resources and reserves estimates from different authorities may differ because they are not referring to the same entity. It is almost correct to say that everybody now means the same thing when they refer to the Prudhoe Bay "field" --- the reference is to a three-dimensional entity that is congruent with the Prudhoe Bay unit. (Even here, is Eileen "in" or "out"?) Where a producing structure has not been delineated, where no unit agreement has been adopted, and particularly where the potentially producing structures are not entirely even under lease, it may be utterly impossible to get various company and government geologists to agree on the physical entity they are talking about, much less the volume of hydrocarbons contained in, or recoverable from, that entity. Thus, one authority may estimate West Sak oil-in-place at 15 billion barrels; another may prefer a number on the order of 100 billion --- and they might both be right!

The authors of this report have attempted to impose some increment in the consistency of terminology relative to the information we received from State and company sources. The reader should be warned, however, that our success has been meager. (One conclusion that stems from the present study, but which is not within is terms of reference, is that something should be done about the present confusion. We suggest that the Alaska Oil and Gas Conservation Commission and/or the Alaska Chapter of the American Association of Petroleum Geologists to agree upon a scheme of terminology for accumulations of petroleum fluids that is both internally consistent and consistent with usage outside Alaska.)

5. EFFECT OF THE EXPORT BAN ON CALIFORNIA CRUDE-OIL PRODUCTION

5.1 CALIFORNIA CRUDE-OIL PRODUCTION, RESERVES AND RESOURCES

There are three major oil-producing regions in California --- the southern portion of the San Joaquin Valley, the Los Angeles Basin, and the state offshore and federal Outer Continental Shelf ("OCS") stretching from about San Luis Obispo south to the Los Angeles area.

California has six "supergiant" oil fields, Elk Hills, Midway-Sunset, Kern River, South Belridge, Wilmington, and Huntington Beach. The the new offshore finds in the Santa Ynez unit and the Santa Maria Basin finds will ultimately be regarded as several fields (which are not yet fully demarcated, however); total reserves in known reservoirs are now estimated at over 1.2 billion barrels. Midway-Sunset, Kern River, South Belridge, and Elk Hills are in the San Joaquin Valley; Wilmington and Huntington Beach in the Los Angeles Basin. Elk Hills is owned primarily by the federal government and for decades much of its oil was shut in as a Naval Petroleum Reserve.

Table 2-1 lists the major California crude-oil fields, their original oil-in-place, cumulative oil production to date, current proved reserves and in the case of heavy oil onshore cumulative production from TEOR (estimated by the California Energy Commission --- "CEC"), and production rates for 1985.

5.2 THE ECONOMICS OF CALIFORNIA CRUDE-OIL PRODUCTION

5.2.1 HEAVY-OIL ECONOMICS. The San Joaquin Valley is the oldest producing region in California and, ironically, offers the greatest potential for increased output from already-producing reservoirs. The valley's largest field, Midway-Sunset, was discovered in 1894 and originally contained 10 billion barrels of oil-in-place.[1] Its history in illustrates some key features in both the economics of domestic oil supply and the structure of West Coast oil markets.

California crude-oil fields tend to be geologically complex. Crude oil is usually produced from multiple zones truncated by a variety of fault blocks. Thus, the the crude oil lies in a number of pools for which maximizing recovery and minimizing production costs involves a variety of recovery techniques. Moreover, crude oil produced from the Midway-Sunset field spans virtually the entire range of crude-oil "gravities" (heaviness or viscosity), from 10 to 40 degrees API. The variety of crude-oil qualities creates both production and transport problems --- some of which will be described later.

In 1974 the Federal Energy Administration ("FEA") estimated Midway-Sunset's proved reserves at 644 million barrels, and forecast production to decline from 95.9 thousand barrels per day ("mb/d") in 1974 to 87.1 mb/d in 1984.[2] Actual production in 1984 was 138.9 mb/d, more than 60 percent higher than expected. The unanticipated increase arose from the widespread introduction of Thermally Enhanced Oil Recovery ("TEOR").

5.2.2 THERMALLY ENHANCED OIL RECOVERY ("TEOR"). The introduction of TEOR in the Midway-Sunset field has increased both production and the estimate of the amount of oil that could ultimately be recovered. In 1974 the FEA determined that out of 10 billion barrels of oil-in-place only 1.9 billion barrels constituted the "proved ultimate recovery" of the field. As of 1984 over 1.6 billion barrels had already been produced. Most dramatically, the CEC now estimates that more than 2 billion additional barrels will be recovered over the next thirty years through TEOR.[3] Thus, expected ultimate recovery from the Midway-Sunset field has risen from 19 percent of the original oil in the reservoir, to 36 percent --- a result of improved technology and higher oil prices.

Shell has acheived similar dramatic results in the South Belridge oil field. In 1981 Shell acquired the Belridge Oil Company and set about to increase production by means of TEOR. In 1980 South Belridge produced 59 mb/d; by 1986 gross production had more than doubled, to 166 mb/d. South Belridge's cumulative production plus its remaining recoverable reserves, as reckoned by the California Division of Oil and Gas, now exceed the figure the Division estimated for original oil-in-place less than a decade ago.

The economics of TEOR in California's heavy oil fields resembles the mining of coal or metallic ores more than it does the discovery and production of oil from new fields. Most of the capital investment in new fields is lease acquisition, development drilling, and (especially in frontier areas like Arctic Alaska, and on the OCS) infrastructure construction. Much of this cost is already sunk before the first production well is drilled. TEOR, on the other hand, tends to occur in reservoirs are not only known to exist but which have years or even decades of production history. While lease-acquisition and "finding" costs are almost nil, TEOR requires the constant drilling of new production and injection wells. A steam generator is required every few acres, with which to pump steam and/or hot water into the oil-bearing strata. The number of wells and steam generators required depends on the topography of field, the width of the deposit and its depth, the quality of the crude oil, and the density of the oil in place, and the qualities of the surrounding rock.

Once TEOR begins, the variable costs per barrel produced are high, relative to those of conventional oil production. Wells have to "worked over" frequently; and steam generators require maintenance, repair, and replacement. Electricity may have to be purchased from a utility, and if gas rather than the heavy oil itself is used as a fuel to raise steam it can amount to considerable expense.

One of the most important constraints on TEOR development is air-quality regulation. The state's environmental regulations are complex; in practice they limit the emissions permitted from TEOR steam generators to existing absolute levels. A TEOR producer can increase production, but only if the number of pollutants from existing production can be cut back. There are two choices --- natural gas can be substituted for heavy oil as a fuel or the producer can invest in scrubbers and other facilities to clean the exhaust.

A key effect of removing the ban on Alaska oil exports is the impact on the relative prices of heavy crude oil and natural gas. Last summer, spot-market gas delivered to San Joaquin Valley TEOR operators cost more than $2 per million btu ("mmbtu"), while heavy crude-oil prices fell locally to the equivalent of gas at about $1. At such prices it is uneconomic in most fields to burn gas in order to produce oil half its thermal value. Removing the ban on Alaska exports would raise the value of heavy oil by up to $4 per barrel, or $.50 per mmbtu, with little or no impact on gas prices. Thus heavy crude oil and gas prices would move closer to parity, and the economics of heavy oil production would improve.

The cogeneration potential of heavy-oil production has an important bearing on its economics. The effect is not, however, clear-cut. In most of the planned cogeneration projects the producer substitutes gas for oil as fuel in his steam generator. The waste heat is then used to generate electricity, which displace purchases by the operator or is sold outright to the utility. Many of the TEOR producers have contracts with Pacific Gas & Electric ("PG&E") or Southern California Edison ("SCE") to sell electricity. But, some of the best potential for TEOR is not covered by existing contracts and the contract value of electricity from a new cogeneration project is considerably less than from those negotiated a few years ago.

Since every oil field and project design for TEOR is different, there is no simple means to summarize production costs nor to assess the sensitivity of future oil production to wellhead prices. The CEC has quantified the relationship between "original mobile oil saturation" (a measure of the density of the oil in place) and the price required to make its extraction economically feasible. The Commission estimated that some of the most expensive projects cost about $17 per barrel and some of the least expensive, just under $10 per barrel. This range of esimates corresponds roughly to the costs cited by companies active in heavy oil production. When oil prices collapsed in 1986, Texaco suspended or terminated production from more than two thousand wells in the Kern River field, and about 30 mb/d of production was lost.

The cost of transporting heavy crude oil is also an important consideration in the economics of EOR development. Far and away the cheapest way to move crude oil overland is by pipeline. Even then the viscosity of heavy crude oil results in extraordinary costs --- the pipelines usually have to be heated or a diluent added. There are only two heavy-crude-oil pipelines that lead from the San Joaquin Valley, and none feed directly to a refinery center in the Los Angeles Basin. In order to ship heavy crude oil by pipeline a heavy-oil producer has to buy enough light crude oil to bring the viscosity of the oil mix down to the point at which it will flow through the pipe. This is expensive, and in some circumstances is not possible. Trucking is usually not a realistic alternative other than for short distances.

To get around the transport hurdle Shell has contracted for a unit train from the San Joaquin Valley to Los Angeles. There are (or were) plans to increase the number of unit trains, but these plans may be cancelled if crude-oil prices remain depressed. The Celeron or "All

America" pipeline is scheduled to begin shipment from the Santa Barbara area to Texas in 1987. This pipeline has a capacity of 300 mb/d and was planned for the forthcoming OCS production. However, since the pipeline runs through the San Joaquin Valley, Celeron plans a spur, in order to receive excess production from the heavy-oil fields if it meets the pipeline's gravity standards for shipment. In any circumstance the pipeline toll to Texas will be high, resulting of course in lower wellhead prices.

5.2.3 CALIFORNIA OFFSHORE PRODUCTION. The largest discoveries of crude oil in the United States in the last decade have been offshore California. Two of the discoveries are located in the federal OCS --- the Santa Maria Basin, north of Point Concepcion and the Santa Ynez Unit to the south. A third set of discoveries has been made in state waters off the coast midway between Point Concepcion and Santa Barbara. Table __ lists projects underway or understudy for these areas as well as the expected peak production, the project's status, and the project start date.

The Julius platform is planned for the northern part of the Santa Maria basin; Cities Service is the operator. The platform has not yet passed all environmental review. It is scheduled to begin production in 1989 and at peak will produce 40 mb/d. The Northern area has about 300 million barrels of estimated recoverable reserves and a potential production capacity of 125 mb/d with 6 platforms.

Unocal has already constructed the Irene platform off Point Pedernales. Production is beginning as this report is written, and will peak at 20 mb/d. A second platform, the Independence operated by Exxon has been put on indefinite hold. If constructed, the Exxon unit could produce another 20 mb/d. The Point Pedernales area has 125 million barrels of estimated reserves and could produce up to 67 mb/d from four platforms.

The southern part of the Santa Maria basin is known as Point Arguello and discoveries there have been the largest in the basin to date. Texaco's platform, Harvest, will have peak production of 46 mb/d and is due on stream in the fourth quarter of 1987. A Chevron platform, Hidalgo and Hermosa are under construction and will begin production in late 1987, peaking at 20 and 27 mb/d, respectively. The Southern area has an estimated 400 million barrels of reserves and could produce 170 mb/d from five platforms.

The Hondo field of the Santa Ynez unit has been producing crude oil since 1981. Exxon plans to dramatically expand the unit with three additional platforms, Harmony, Heritage, and Heather. Together the three new facilities will have peak production of 140 mb/d. The platforms are, however on hold while Exxon tries to obtain a change in air-quality rules. The Santa Ynez unit contains about 350 million barrels of estimated reserves and if five platforms were installed it could produce up to 170 mb/d beyond the quantities coming from the existing Hondo field.

In State offshore waters Arco's Coal Point project, which is a series of platforms near Santa Barbara, has just been certified and will produce at peak 80 mb/d. Further west Shell plans platform Hercules, which would produce 30 mb/d after it is certified and completed in 1991. Unocal has a small project of 13 mb/d on hold just off Point Concepcion.

The unconstrained potential for the Santa Barbara area of the federal OCS is just over 500 mb/d. If everything identified in table ___ is completed on schedule, OCS production in the early 1990s would total just under 300 mb/d. But, as the table makes clear, the majority of the production is associated with platforms not yet constructed. Production from platforms in place or certain to be completed totals just over 100 mb/d. Thus, some 200 mb/d may depend on the level of oil prices.

REPORT ON ALASKA BENEFITS AND COSTS OF EXPORTING ALASKA NORTH SLOPE CRUDE OIL

Institute of Social and Economic Research
University of Alaska - Anchorage

For the Alaska State Senate
Finance Committee

APPENDIX B: ASSUMPTIONS, METHODOLOGY, AND CALCULATIONS

A. CRUDE-OIL PRICES.

1. Crude-oil prices are specified in whole-dollar units, in order to emphasize (a) the investigators' concern with gross comparisons of values at various locations and under different transport options, and (b) the impossibility of making projections with any greater precision over the time span covered by this report.

2. All prices are in average 1987 U.S. dollars, unless otherwise specified. 1985 and 1986 actual values are converted to 1987 dollars using the GNP deflator; the GNP deflator is assumed to increase by 5 percent from 1986 to 1987.

3. The "world market price" is denoted by the average contract price of a representative domestic crude oil (the "marker" crude) widely traded at the U.S. Gulf, which is assumed to be $15.00 per barrel from 1987 through 1995, and $20.00 per barrel from 1996 through 2000. Projected investment behavior is based on the assumption that oil companies also expect these prices. The posted price of West Texas Intermediate was used as the marker price for purposes of assessing historical relationships among prices for various grades of crude oil and in various markets.

4. Landed prices of crude oils comparable in grade and quality to the marker crude are assumed to be the same at the U.S. Gulf Coast, the U.S. West Coast, and the Far East (Japan, Korea, and Taiwan).

5. If exports of ANS crude oil are permitted:

   5.1 The Valdez netback value of ANS crude would be the world market price less $1 per barrel, (the landed price of the marker crude in the Far East, less foreign-flag tanker costs and a small "penalty" for the inferior refining quality of ANS crude).

   5.2 The average wellhead value of California crude oil will also be the world market price less $1 per barrel, (the landed price of the marker crude in California, less pipeline transport charges in California and a penalty for the inferior refining quality of California crude).

6. If exports of ANS crude oil are not permitted:

6.1 And there is no "West Coast surplus" (i.e., all Alaska and California crude oil is refined on the West Coast):

Valdez prices of ANS crude oil and average wellhead prices of California crude oil will be $1 per barrel less than the world-market price (i.e., the same as if exports were permitted).

6.2 And the "West Coast surplus" requires excess crude oil to be shipped by tanker across Panama to the U.S. Gulf or East Coast,

6.2.1 The Valdez netback value of ANS crude oil shipped to those destinations will be the world-market price less $5 per barrel,

6.2.2 The average Valdez netback value of ANS crude oil refined on the West Coast will be somewhere between $1 and $5 less than the world market price, determined by the rule described in 6.4, and

6.2.3 The average wellhead price of California crude oil will be $5 per barrel less than the world market price.

6.3 And a West Coast surplus exists, but is small enough to be disposed of by pipeline shipments from California to the Gulf Coast states:

6.3.1 The Valdez netback value of ANS crude oil shipped to those destinations will be the world-market price less $3 per barrel.

6.3.2 The average Valdez netback value of ANS crude oil refined on the West Coast will be somewhere between $1 and $3 less than the world market price, determined by the method described in 6.4.

6.3.3 The average wellhead price of California crude oil will be $3 per barrel less than the world market price.

6.4 Valdez netback prices of ANS crude oil are projected as follows:

6.4.1 The average Valdez netback price for ANS crude oil refined on the West Coast is interpreted as a weighted average of (a) the world market price on the West Coast and (b) the netback value for shipments to the U.S. Gulf. The imputed world-market-priced component of the total volume of ANS crude refined on the West Coast is calculated for 1985 and 1986. The average of volumes for those two years is adjusted upward for later years in proportion to projected West Coast refinery runs. Average Valdez netback values for crude oil refined on the West Coast in future years are projected as weighted averages of this component at world-market prices, and the remainder at Gulf Coast netback prices. The effect is that "marginal" (additional or diminished) barrels always obtain the Gulf Coast netback price; see 6.4.3 below.

6.4.2 The average Valdez netback prices for all ANS crude oil is a weighted average of the netback price for ANS crude oil refined on the West Coast and ANS crude oil shipped beyond the West Coast.

6.4.3 Marginal ANS crude-oil prices (the change in sales revenues caused by a one-barrel increase or decrease in production) at Valdez, is the netback value of ANS crude oil from the U.S. Gulf Coast or the Far East (depending on the pricing case, as described in B below).

6.5 The prices of ANS crude oil on the North Slope (at TAPS pump-station No. 1) are as projected follows:

6.5.1 The TAPS pipeline charge for each year is projected, using forecast volumes of ANS production as pipeline throughputs, by an ARTA model developed for the North Slope Borough on the basis of the tariff settlement approved by the Federal Energy Regulatory Commission ("FERC") in 1985.

6.5.2 Average ANS crude-oil prices at Pump Station No. 1 are the average Valdez netback values, less the TAPS charge.

6.5.3 Marginal ANS crude-oil prices at Pump Station No. 1, is the netback value of ANS crude oil from the U.S. Gulf Coast or the Far East (depending on the pricing case, as described in B below), less the TAPS charge. **It is this value that is assumed to determine the ANS operators' investment behavior.**

B. PRICING AND PRODUCTION CASES

1. Alaska and California production is projected under three cases:

1.1 A Gulf Coast netback-pricing case, in which all West Coast crude-oil prices are determined as described in A.6.2,

1.2 A Far East netback-pricing case, in which all West Coast crude-oil prices are determined as described in A.6.1.

1.3 A combined no-export case, in which prices are determined as in A.6.2 until West Coast production falls to a level that tanker shipments to the Gulf or East Coasts. At that point, prices are determined as in A.6.3 until the West Coast surplus diminishes sufficiently to eliminate net movements of crude oil from California by pipeline to Gulf Coast refineries. From that time, pricing will be as in A.6.1. Production under this pricing case is assumed to be determined as in 4. below.

2. Alaska and California production under cases 1.1 and 1.2 is forecast as follows:

   2.1 Production from known ANS reserves is projected by ISER on the basis of the investigators' best information regarding operator plans and economic characteristics of each field.

   2.2 Production in ANS category "other" is adapted from values for Alaska "new discoveries" in the National Petroleum Council ("NPC") study, using the imputed supply-elasticity for that category, according to the methodology described in 3, below.

   2.3 Production forecasts for Cook Inlet are based on Alaska Department of Revenue projections, adjusted using the imputed supply elasticity for non-Alaska, non-TEOR production in the NPC study, according to the methodology described in 3, below.

   2.4 Production forecasts for TEOR in California are based on the model in the California Energy Commission ("CEC") 1987 Biennial Report and the pricing assumptions described above.

   2.5 Production forecasts for onshore California production other than TEOR are based on CEC forecasts, adjusted for the pricing assumptions described above using the imputed supply elasticity for Lower-48 onshore non-TEOR production in the NPC study, according to the methodology described in 3, below.

   2.6 Production forecasts for State offshore ("tidelands") production are based on CEC forecasts, adjusted for the pricing assumptions described above using an average of the imputed supply elasticities for Lower-48 onshore and offshore non-TEOR production in the NPC study, according to the methodology described in 3, below.

   2.7 Production forecasts for the federal OCS is projected by ARTA on the basis of the investigators' best information regarding operator plans and economic characteristics of each field.

3. Price-elasticities of supply for various components of the U.S. crude-oil supply under cases 1.1 and 1.2 are imputed from the National Petroleum Council ("NPC") report, Factors Affecting U.S. Oil and Gas Outlook (February 1987), by comparing forecasts of production in the various categories under two sets of price assumptions (the "lower-" and "higher-price trend", respectively). These imputed elasticities are as follows:

CATEGORY	1990	1995	2000
Existing Fields	**.25**	**.43**	**.62**
Developed Production	.20	.35	.51
Lower 48	.00	.00	.04
Onshore	.01	.03	.04
Offshore	.0	.0	.0
Alaska	.0	.0	.06
New Investment	.85	.85	.75
Lower 48	.76	.77	.67
Onshore	.82	.83	.79
Offshore	.58	.59	.24
Alaska	1.65	1.31	1.24
EOR	.59	1.20	1.48
Lower 48	.56	1.18	1.44
Onshore	.53	1.14	1.37
Offshore	1.37	2.00	0.46
Alaska	1.35	1.64	1.95
New Discoveries	**.44**	**.93**	**1,95**
Lower 48	1.95	1.51	.97
Onshore	2.56	1.72	.85
Offshore	1.04	1.18	.85
Alaska		2.02	2.58
Total	**.25**	**.43**	**.62**

Other Subdivisions

Stripper wells	.44	.93	1.95
Natural-Gas Liquids	.19	.31	.36
Total Alaska	**.13**	**.33**	**.78**
Developed production	.0	.0	.06
New investment	1.65	1.31	1.24
New discoveries		2.02	2.58
Total Non-Alaska	**.23**	**.56**	**1.09**
Onshore conventional	.26	.32	.48
Onshore TEOR	.56	1.18	1.44
Offshore	.23	.37.	.37

Note: A single-digit ".0" indicates that the calculated elasticity is slightly negative --- an improbable result, which we reject.

4. Alaska and California production under case 1.3 is projected following the course of case 1.1 (Gulf Coast netback pricing) until the year in which West Coast surplus falls enough that tanker shipments beyond the West Coast are not required. (That year turns out to be 1991, under the assumptions adopted for case 1.1)

Beginning in that year, producers are assumed to develop just enough additional production to keep the need for such shipments at zero, as long as it is possible under the following constraints:

4.1 For any field, the cumulative production in case 1.3 may never exceed the cumulative production that would have occurred under case 1.2. (All added production relative to case 1.1 must therefore be delayed production.)

4.2 For any field in any year, production under case 1.3 may not exceed the highest production level that would have been achieved in that or any subsequent year under case 1.2. (The result is that the need of the West Coast for tanker imports of crude oil in addition to that described in ?? will not last any longer under case 1.3 than it would have under case 1.2.)

C. WEST COAST AND U.S. SUPPLY-DEMAND BALANCES

1. Both West Coast and national petroleum supply-demand balances assume that ---

    1.1 Average refinery "gain" or "loss" is zero (i.e., the number of crude-oil barrels consumed by refineries is equal to the number of barrels of product produced).

    1.2 Average additions or reductions of stocks are zero, and average volumes of crude oil in transit are constant.

2. "Crude-oil" production figures include volumes of light hydrocarbons classified in production statistics as "lease condensate", but not those volumes classified as "natural-gas liquids" ("NGL").

    2.1 NGLs are nevertheless included in regional and national petroleum balances.

    2.2 NGL production for the U.S., other than the West Coast, is projected using the pricing assumptions of A. above, the NPC forecasts of NGL production under the lower- and higher-price trends, and and the price-elasticity of supply for NGL imputed from these cases under the methodology described in B.3.

3. Petroleum-products consumption is calculated as follows:

    3.1 Petroleum-products consumption for the U.S. under pricing case B.1.1 (and under B.1.3 while that case reflects case B.1.1 assumptions) is calculated using the the world-market price assumptions of A., above, the NPC forecasts of total U.S. consumption under the lower- and higher-price trends, and a price-elasticity of demand for all petroleum products imputed from these cases under the same methodology as is described for imputation of supply-elasticities for various production categories in B.3.

    3.2 U.S. petroleum-products consumption under pricing case B.1.2 (and under B.1.3 while that case reflects case B.1.2

assumptions) is the sum of U.S. petroleum-products consumption in the case described in 3.1 above, adjusted by the difference in West Coast residual-oil consumption calculated as described in 3.4.2.

3.3 The consumption of petroleum products in the U.S., other than on the West Coast, is assumed to be the same under all West Coast crude-oil pricing cases, because the differences between these cases do not affect the prices of crude oil except on the West Coast.

3.4 The consumption of petroleum products on the West Coast is the sum of refined-product and residual-oil consumption:

3.4.1 West Coast consumption of refined petroleum products is assumed to be unaffected by the differences in crude-oil prices between the various cases, because the ability to import refined products places a ceiling on West Coast product prices.

3.4.2 West Coast residual-oil consumption is assumed to grow at an annual rate of one percentage point less than West Coast consumption of refined products for so long as pricing case B.1.1 prevails, and at two percentage points less than West Coast consumption while pricing case B.1.2 prevails. This situation reflects an assumption that the price of residual oil derived from West Coast crude oils at West Coast refineries has some upward flexibility, reflecting the cost of shipping excess resid to Far Eastern markets, where it encounters world-market prices.

4. Crude oil refined on the West Coast is projected at the average of 1985-1986 levels, adjusted for each subsequent year by half the change in West Coast petroleum-products consumption.

5. The West Coast crude-oil surplus is defined as the sum of Alaska and California production, imports of low-sulfur crude oil as described below, less West Coast refinery runs, as described in 4. above.

5.1 West Coast imports of low-sulfur crude oil required because of refinery-design and air-quality constraints are projected at the average of 1985-1986 volumes, and adjusted proportionally to the volume of crude oil refined on the West Coast.

5.2 Tanker shipments from or to the West Coast (other than imports described in 5.1 above) are the difference between the West Coast crude-oil surplus, and shipments of West Coast crude oil to the U.S. Gulf States by the Four Corners and Celeron pipelines. These shipments are forecast on the basis of the 1985-1986 average, increasing at a constant annual rate, reaching 225 thousand barrels per day in 1990, and remaining at that level. (Pipeline and refinery-design bottlenecks in California are expected to perpetuate eastward movements in these pipelines even after the West Coast becomes a net importer of crude oil.)

6. U.S. crude-oil production is calculated as follows:

   6.1 For all pricing cases, non- West Coast production is ---

      6.1.1 Total U.S. production, calculated from the NPC lower-and upper-price trend cases, through use of the world-market pricing assumptions of this study and the imputed price-elasticity of supply for non-Alaska production, determined as in B.3, less

      6.2.2 Total projected California production under pricing case B.1.1.

   6.2 For each pricing case, total U.S. production is non-West Coast production, plus the West Coast production calculated for that case.

7. U.S. petroleum balances, net imports, and their balance-of payments impact, are projected as follows:

   7.1 Net U.S. oil imports are the difference between total U.S. petroleum-products consumption from 6. above and U.S. petroleum consumption as in 3. above.

   7.2 The net annual contribution of oil imports to the U.S. balance-of-payments deficit is projected as the product of net oil imports (in barrels per day), the assumed world-market price, and the number of days in the year.

   7.3 The effect of permitting ANS oil exports on the U.S. balance of payments is the reduction effected in the balance-of-payments deficit, as determined in 7.2.

D. WELLHEAD REVENUES

1. Alaska wellhead production revenues are the sum of:

   1.1 The product of ANS production volumes and the average Pump Station No. 1 netback price, and

   1.2 The product of the Cook Inlet production volumes and the average ANS netback value at Valdez. (This assumption requires that the higher refining value of Cook Inlet production is offset by scale economies in tanker shipments from Valdez.)

2. California wellhead revenues are assumed to be the product of California production and average California prices.

3. The reduction in wellhead values attributable to the export ban during the years 1981 through 1986 is estimated at $4 per barrel for California production and Alaska production shipped beyond the West Coast, and $2 per barrel for Alaska production processed in West Coast refineries.

E. ROYALTY AND TAX REVENUES

1. The reduction in Alaska petroleum-production revenues attributable to the export ban during 1981 through 1986 are calculated from the sales-revenue losses in D.3 above on the basis of ---

   1.1 A royalty rate of 12.5 percent,

   1.2 A marginal production-tax rate (on an ex-royalty tax basis) of 15 percent, and

   1.3 The prevailing marginal corporate income-tax rate.

2. Alaska royalties, production taxes, and corporate income taxes are based on the price forecasts described in A., the production projections described in B., and the assumptions and methodology employed by the Alaska Department of Revenue, Division of Petroleum Revenue, in its quarterly Petroleum Production Revenue Forecast.

3. The reduction in federal windfall-profits tax ("WPT") receipts attributable to the export ban in 1981 through 1985 is calculated on the basis of a marginal rate of 70 percent for Prudhoe Bay production and zero for production from other ANS fields, and an average marginal rate of 52 percent for Cook Inlet.

   3.1 The basis for WPT is wellhead receipts excluding royalties.

   3.2 State production taxes are treated as a credit against WPT.

   3.3 No WPT receipts are assumed for 1986 or for the future under any of the pricing cases, because the first-sale price did not and is not projected to exceed the WPT threshold level.

4. Federal income-tax receipts for Alaska crude oil shipped beyond the West Coast are estimated for 1981 through 1986, and for 1987 forward, on the basis of prevailing marginal rates, after exclusion of royalties, severance tax, state corporate income tax, and WPT.

5. No change in net federal income-tax receipts is attributed to any change in wellhead prices for Alaska or California crude oil refined on the West Coast. It is unlikely that West Coast refiners will be able to pass through higher feedstock prices in their product prices; thus, higher income-tax receipts generated in production are likely to be just about offset by smaller receipts from transportation and refining.

6. No change in net federal income-tax receipts is attributed to production developed in during or after 1987. Under the old tax law, most minerals-extraction operations, including oil-and-gas production projects, could be and are structured so as to generate negative net income-tax revenues on a present-value life-cycle basis. (I.e., the present value of tax preferences on minerals extraction are typically greater than the present value of the stream of taxes on current income.) Pending a reexamination of this issue under the new tax law, we have assumed net life-cycle tax revenues on new oil-and-gas investment to be zero.

THE EXPORT OF ALASKA CRUDE OIL
ITS SIGNIFICANCE FOR
PACIFIC BASIN PETROLEUM TRADE

by
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Introduction

The collapse of world oil prices is a catastrophic blow to crude-oil producers, but it will be a boon to international trade. Lower prices will have two distinct effects. Firstly, substantially lower petroleum-product prices will stimulate energy demand. In turn, global energy-demand growth will be met largely with imported oil, which will be the least costly fuel at the margin for most applications in most markets. Refineries in oil-exporting countries will finally become profitable and will intensify global competition in petroleum-product markets.

Secondly, lower prices and abatement of fears concerning future energy shortages will enhance the incentives for oil-consuming nations to relax trade barriers for crude oil and petroleum products. The result will be a reduction in both transport and processing costs and a gain in economic efficiency. With lower prices, the waste entailed by oil-export restrictions in the United States and Canada will be economically, and hence politically, intolerable. The shift in North American policies will have an impact on petroleum trade throughout the Pacific Basin.

If the United States allows Alaska crude oil to be exported, higher West Coast prices will provide an incentive to export Alberta crude to the state of Washington. Light low-sulfur import crudes from Indonesia and other Pacific Rim countries will find a viable market in California. Trade in petroleum products will increase. The U.S. will increase its export of high-sulfur fuel oil and increase imports of gasoline and other light fuels.

Significance of World Oil-Market Conditions

Fundamental supply-demand conditions in the world oil market are consistent with price swings as low as \$5 per barrel and as high as \$25 (in 1986 U.S. dollars) over the next decade. But it is Saudi Arabia's market share that will determine whether average prices will settle toward the high or low end of this scale. If the demand for Saudi oil is low relative to the Kingdom's revenue needs, the Saudis will be forced to compete with other oil suppliers rather than with suppliers of other fuels. The world's oil producers may find themselves in a similar situation to U.S. natural-gas producers who, in the last few years, have been faced with "gas-to-gas" competition because their product has been abundant enough to drive rival energy forms (chiefly heavy fuel oil) from ready fuel-switching markets. Under certain conditions, "oil-on-oil" competition could last for a decade. Sooner or later, however, because Middle Eastern oil has a lower marginal development and delivery cost than almost any other energy source (including oil produced elsewhere), the Saudis will regain their position as swing producer.

When there is significant demand for its crude oil, Saudi Arabia will set its price by focusing on the B-fuels market[1], where gas, oil and coal compete. Put another way, the marginal supplier of energy to the world will base its price on the marginal uses of energy and the marginal development costs of fuels competing in that market. The Saudis have almost no economic incentive to limit production or restrain development of their fields, because their oil will never be worth much more than the value of substitute B-fuels.

As late as 1972, the major oil companies forecast Saudi crude oil production of 20 million barrels per day. Such an output is still possible, and the investment required to arrive at that level of production is an order of magnitude less than the cost to consuming nations of providing a similar increment in primary-energy supply from other resources. It is a good bet that the Saudis now realize that higher levels of capacity should have been installed in the mid-1970s, in order to prevent the price runups of 1979 and 1980 (which they themselves wittingly or unwittingly engineered by holding back on production). In short, Saudi Arabia has both the incentive and the ability to meet the world's incremental energy demand through the rest of this century.

Saudi Arabia will price its energy just below the costs of its closest competitors. In the short-run the competition is other sources of oil, plus natural gas in North America and Europe, where the long-distance transmission infrastructure is more than adequate to meet current demand. In the longer-run the competition is from coal and new natural gas supplies (including the substantial cost of adding new transport capacity).

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1. We use the term B-fuels market as short for those uses that are variously tagged as "**b**ulk-fuels", "**b**oiler-fuels", or "**b**lack fuels". It refers to fuels uses in which the object of demand is calories as such, and in which residual and other heavy fuel oils actively compete with coal, natural gas, and other energy sources. In the United States, these markets are most often referred to as **b**oiler-fuel markets, although the uses in question comprise extend much further than the raising of steam for electrical generation and other industrial purpose, to include distillation of a host of substances, melting and drying of bulk materials, metallurgy and other large-scale industrial process heat. A decade ago in Europe, it was fashionable to call these uses the **b**lack fuels markets, but supplies are no longer confined to coal and heavy fuel oil, but include natural gas, uranium, municipal waste, and vegetation. For those who prefer to use whole words, **b**ulk fuels is probably the most accurate term.

In our view, oil prices are most likely to range between $10 to $20 through the early 1990s. It is important to note, however, that as long as the crude-oil market is driven by netback sales arrangements, crude-oil prices are going to fluctuate sufficiently that periodic excursions below $10 or above $20 should not be surprising. In other words, seasonal demand swings and the moods of traders and speculators will have a more profound influence on crude-oil pricing patterns than in the past. This volatility in itself will promote trade, as brokers, importers and refiners adjust inventories to take advantage of seasonally and randomly cycling prices.

The West Coast Oil Surplus

The Prudhoe Bay oilfield was discovered in 1968. Its 9.6-billion barrels of proved reserves were a dramatic addition to the U.S. total. Until that time, West Coast oil reserves were only about 15 percent of the national inventory; with the determination that Prudhoe Bay was a commercial discovery, they came to account for 40 percent.

In subsequent years, the delay in completing the Trans-Alaska Pipeline System (TAPS) kept West Coast reserves from declining at the same proportionate rate as those East of the Rockies. In addition, the development of other giant crude-oil fields in Arctic Alaska (for example, the Kuparuk, Lisburne, and Endicott), the discovery of the offshore Santa Maria field near Santa Barbara, and the progress in thermally enhanced oil recovery (TEOR) for heavy California crudes has focused national attention on West Coast oil resources. One major oil company estimates that three-quarters of all the reserves yet to be developed in the United States will be in California and Alaska.

In short, the development of West Coast oil supplies has strategic implications. This has an important bearing on the regulatory environment likely to be faced by California and Alaska oil producers, since investments in future production are now threatened by the collapse in prices.

Since January 1981, when the U.S. system of oil-price controls was terminated, most oil markets have developed a structure in which crude-oil price differentials are a rational function of quality and transportation costs. The most glaring remaning anomaly in North America stems from the U.S. federal prohibition on crude-oil exports. While this regulation affects every domestic oil producer, it is only on the West Coast that it has an important economic impact.

The discovery at Prudhoe Bay stirred a vehement debate over how and where the oil should be shipped. The industry experimented with icebreaking tankers, but finally concluded that overland pipelines were the only practical transport means. Congress had to authorize construction of the pipeline since it crossed federal lands and required a wider right-of-way than permitted under existing law. West Coast conservationists, concerned about environmental damage from marine crude-oil spills, wanted to prevent tanker movements along their shores, while Congressmen from the Midwest wanted a pipeline to go through Canada into the Chicago area. All parties acknowledged that such an overland pipeline would have lower unit transport costs in the long run, but its initial capital cost would have been considerably higher, and the industry balked. The North Slope producers preferred to ship the oil to a deepwater port on the south coast of Alaska, where it could be sent by tanker to Puget Sound, California and other markets.

Some members of Congress feared that the export of Alaska oil to Japan, Korea and other Asian countries would disadvantage U.S. refineries and the U.S. Merchant Marine. Spite from Midwesterners deprived of their own pipeline link and from conservationists resentful of legislation bypassing the newly enacted National Environmental Policy Act, joined with the protectionist interests to enact a prohibition of such exports in the Trans-Alaska Pipeline Authorization Act of 1973. Congress extended the prohibition to all domestically produced crude oil in 1979 amendments to the Export Administration Act.

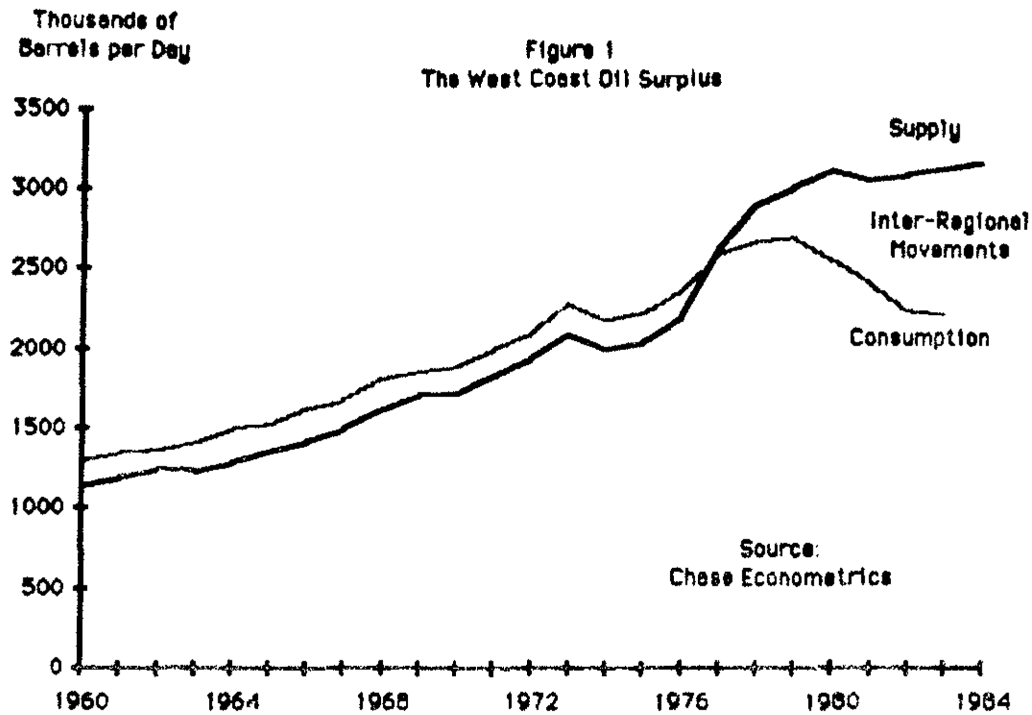
The impact of this federal legislation is clearly evident in U.S. supply and distribution statistics as well as in the pricing of Alaska and California crude oil. Since TAPS was completed in 1977, the West Coast has had surplus crude-oil production. This situation is illustrated in Figure 1. Until then, there was net flow of petroleum products from other regions. Following the attachment of Alaska North Slope crude oil (ANS), however, the flow reversed and region became a net shipper of crude oil and petroleum products to other states.

The impact of this surplus on the pricing of California and Alaska crude oil is best illustrated using posted prices from California. The pricing of Alaska crude oil is complex, since each producer has a different methodology and only average prices are publicly available. However, there is good reason to believe that ANS sold on the West Coast fetches prices of up to $5 less than the same crude oil sold in the Gulf Coast. California crude-oil prices are also about $5 less than their counterparts in Texas and Louisiana.

The West Coast "discount" is illustrated in Figure 2, where a heavy crude oil from the Midway-Sunset field in California's San Joaquin valley is compared to the official price of Arab Light. Three distinct periods are evident in the chart. From 1961 to 1972, the Mandatory Oil Import Program (MOIP) stabilized domestic prices above the world level. During the period from 1972 to 1976 price controls were in effect for domestic crude-oil production. The prices illustrated here are for the small volumes of uncontrolled production, however, and their movements closely track those of Arab Light. After 1976, however, the prices diverge: Uncontrolled California crude-oil prices are severely depressed. This shift reflects a combination of two influences --- the impact of surplus ANS and the weak market for heavy crude oil that prevailed during much of that period.

The Impact of $10 to $15 Crude Oil

The recent drop in crude-oil prices is going to have its most significant volumetric impact in the U.S. West Coast market. The Federal


Thousands of Barrels per Day
Figure 1
The West Coast Oil Surplus
3500
3000
2500
2000
1500
1000
500
0
Supply
Inter-Regional Movements
Consumption
Source: Chase Econometrics
1960
1964
1968
1972
1976
1980
1984

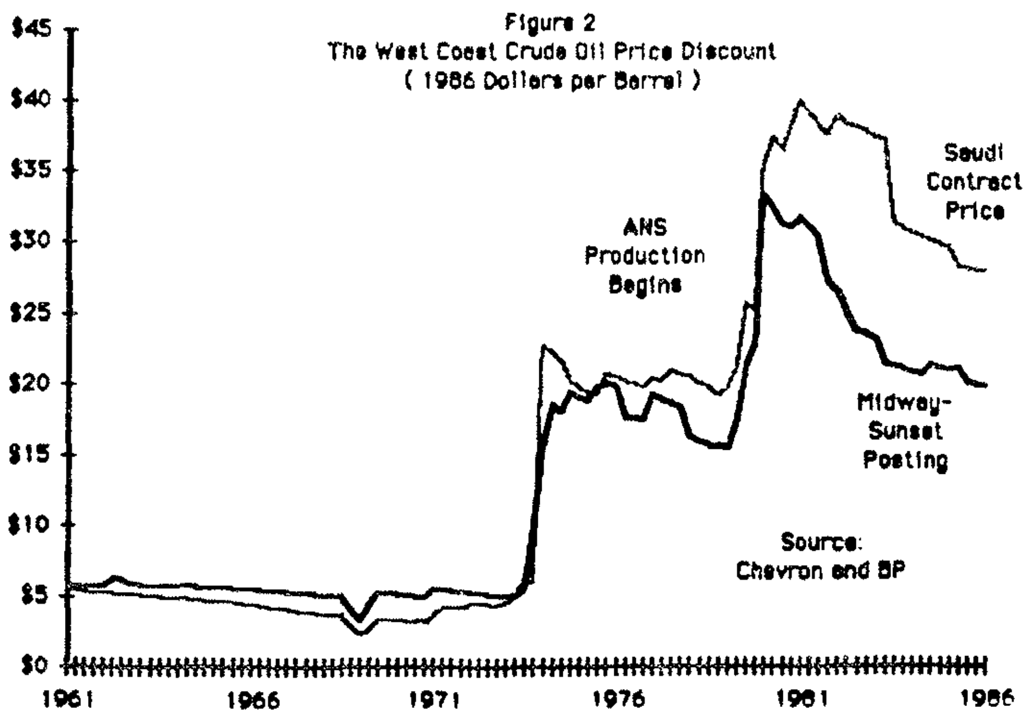


Figure 2
The West Coast Crude Oil Price Discount
(1986 Dollars per Barrel)
$45
$40
$35
$30
$25
$20
$15
$10
$5
$0
Saudi Contract Price
ANS Production Begins
Midway-Sunset Posting
Source: Chevron and BP
1961
1966
1971
1976
1981
1986

ban on exports requires Alaska and California producers to sell into the depressed West Coast market or ship their crude to the Gulf or East Coast of the U.S., using high-cost domestic tankers.

When world market levels were on the $30 per barrel, West Coast producers and governments (qua landowners and tax-collectors) were willing to tolerate depressed prices and high transport costs, relative to other producing regions. But at the new price level, much of California's heavy crude-oil production will be uneconomic, and further investment in Arctic Alaska is unlikely. Unless the regulations are changed, therefore, by 1990 crude-oil production in Alaska and California is likely to be on the order of one million barrels per day less than they otherwise would have been.

Shrinking production will have an impact on Congress in a way that no lobby, including the ones funded by the U.S. Merchant Marine, can offset. The concern flows from the rapid decline that is in prospect for established Alaska and California production absent new investment; the TEOR projects in the San Joaquin basin, offshore production at Santa Maria crudes, and further development of several giant fields on the North Slope of Alaska, depend on the maintenance of netback prices substantially exceeding three or four dollars per barrel.

Heavy crude-oil production, particularly from mature fields, is expensive. It requires fuel to generate steam and electricity to pump crude oil, as well as a constant infusion of cash for cleaning and mechanical maintenance. If light crude oil settles between $10 to $15 per barrel in Texas, prices for heavy California crudes might range between $2 and $7, as long as the West Coast crude market remains in surplus. These prices are well below the average costs incurred by most California TEOR producers. Wells will be shut in rather than maintained, and crude oil production will decline. California production is likely to decline about 10 percent per year, dropping one-half million barrel per day within five years.

The Santa Maria basin offshore California contains the largest U.S. oil find of the past decade. Industry anticipated that this and other California offshore fields could produce up to one-half million barrels per day by the end of this decade. The crude, however, is "heavy" and "sour" --- low gravity and high sulfur --- and hence of low refining value. It is also very expensive to develop. As long as there is a West Coast price discount and world oil prices are less than $15 per barrel, the planned development is unlikely to proceed.

Crude oil from Alaska's North Slope is even more disadvantaged than California production. The TAPS tariff for shipment across Alaska is now about $6 per barrel. Then, the crude must be shipped from Valdez at a charge of $1 to $2 per barrel to the West Coast or Japan and $5 or more to the U.S. Gulf Coast. Since export to East Asia is prohibited and the West Coast market is depressed, a North Slope investor (other than one already holding unutilized capacity on TAPS) faces a transport outlay of at least $11 to move his crude to a viable market. As long as world oil prices fluctuate between $10 and $15, therefore, no company will take the risk of such an investment.

Abundant resources of crude oil have been identified on the North Slope, which can be developed for less than \$10 per barrel, net of transport costs, but at current prices such development is uneconomic. The Prudhoe Bay field will begin to decline in 1987, and by the early 1990s there will be considerable space on the TAPS pipeline. Enhancement of crude-oil from Prudhoe Bay, stepout and infill development of Kuparuk and Milne Point, the opening of production in the Lisburne and Endicott formations, discoveries at Point Thomson and Seal Island, and the prodigious heavy cretaceous deposits at West Sak and Ugnu, are likely to be developed, only if their product can be moved to market at a cost substantially lower then refinery value. This result is unattainable without a relaxation of the export ban, and perhaps further reductions in TAPS transport tolls.

Without a shift in U.S. regulations, further development of Alaska's North Slope must await substantial increases in real oil prices that are not now in prospect. After 1987, production will begin to decline, dropping almost one-half million barrels per day by the mid-1990s.

Implications of Declining West Coast Supplies

Almost one-half of U.S. oil reserves are located in California and Alaska. Compared to production elsewhere, however, West Coast reserves are expensive to produce or transport and expensive to develop. When wellhead prices were more than \$20 per barrel, inefficient federal regulations hardly mattered: a \$5-per-barrel discount would be unlikely to prevent investment. Now, however, \$5 makes a great deal of difference and it is likely that the federal policy will change.

The Reagan administration's avowed policy is to reduce trade barriers and, particularly, to shrink regulation in the energy industries; there has already been considerable progress in this direction. In 1983, the Department of Commerce revised its regulations to allow the export of petroleum products. Since then there has been lively trade in heavy fuel oil from the West Coast to East-Asian markets. In late 1985, federal regulations were again revised concerning the export of Cook Inlet crude oil from Alaska, and a dribble of such exports began in January, 1986.

The President may permit ANS exports by regulation, but either house of Congress can block such a move. The expiration of the Export Administration Act might have eased Congressional restrictions, but it was renewed in 1985. Thus, the export of ANS has a substantial hurdle to overcome.

When Alaska oil was selling at delivered prices of \$34 per barrel, as it was in 1981, or even at its mid-1985 price of nearly of \$27, it was impossible to arouse much public or Congressional concern over a transfer which, after all, affected some of the "deepest pockets" in the nation. Even after deducting the inflated transportation costs of (say) \$11 per barrel, the amounts left to be divided among the beneficiaries --- principally the North Slope producers, the State of Alaska, and the federal treasury --- were stupendous. So long as oil prices remained near all-time highs, therefore, it was hardly conceivable that economic-efficiency arguments for freer trade would make much headway against the combination of xenophobia, spite, and generous campaign contributions by U.S. shipbuilders, shipowners, and maritime unions.

Congress will, however, respond to the concerns of Western states and the petroleum industry when oil production begins to decline. It will be forced to respond for the simple reason that the decline has a substantial impact on federal revenue. While a variety of measures, such as crude-oil tariffs and gasoline taxes, are under consideration, the least complicated way to enhance federal revenues from the energy industries is to liberalize trade. Every other measure has a major impact on consumers and creates a host of technical problems.

The Impact on Pacific Basin Trade

Canada now has a crude-oil surplus and a nearly empty crude-oil pipeline from Edmonton to Puget Sound. Exports were choked off in the mid-1970s because Ottawa feared long-term shortages in the Eastern provinces if Canada's Western reserves were not dedicated solely to domestic use. Alberta crude oil flowing to the state of Washington was replaced by ANS and OPEC crudes. Despite the fact that restrictions on export have been eased, Alberta crude cannot compete with Alaska oil because of the West Coast discount. On the other hand, if ANS is exported, its price to Puget Sound refineries will rise, Alberta crude will become competitive and Canadian crude-oil exports will increase.

Similar adjustments are likely in the California refinery sector. The drop in crude-oil prices has made heavy fuel oil once again competitive with gas as electric-utility and industrial fuel. California, however, prohibits the burning of high-sulfur fuel oil, and there is almost no California or Alaska crude that yields a low-sulfur residuum. The best source of such feedstocks in the Pacific Basin is thus Indonesia.

If the West Coast price discount is eliminated, Indonesian and other low-sulfur imports (including Alberta crudes) will be competitive and can be used in California refineries. This development, in turn, will provide real competition to natural gas at the burner tip, and help rationalize all energy markets in the region.

Conclusion.

The ban on the export of Alaska crude oil is the most crucial impediment to Pacific Basin petroleum trade. It creates an inefficient pricing structure on the West Coast of North America, which distorts prices in surrounding petroleum markets. This prohibition remained in place for more than a decade because high oil prices obscured the inefficiencies it created. Over the coming year, however, the distortions and waste entailed by this policy will become more apparent, and as they come to light, the policy is likely to change.

Once the inhibition on exports of Alaska crude oil is removed, there will be a cascade of reactions that will substantially increase crude-oil and petroleum-product trade throughout the Pacific Basin.