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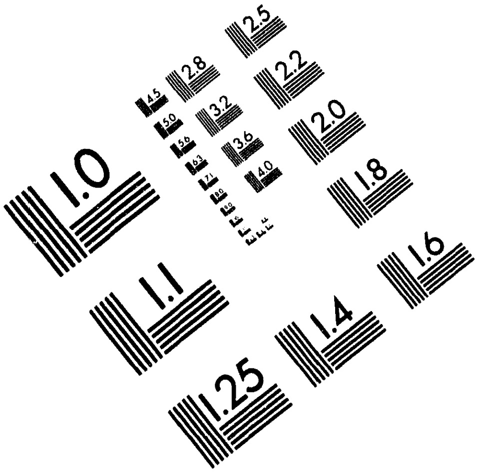

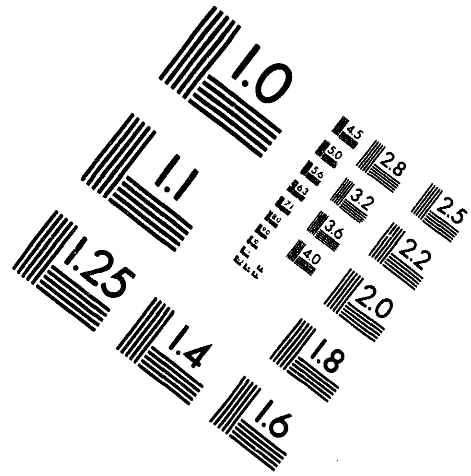

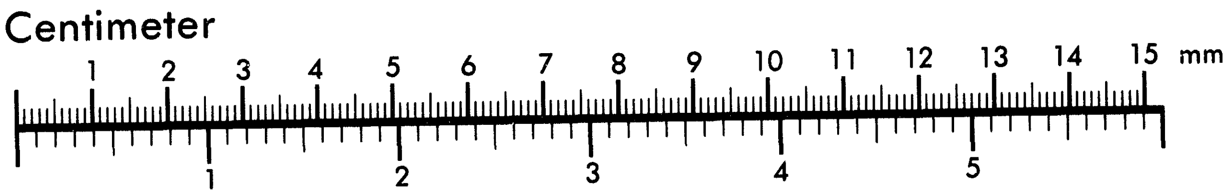

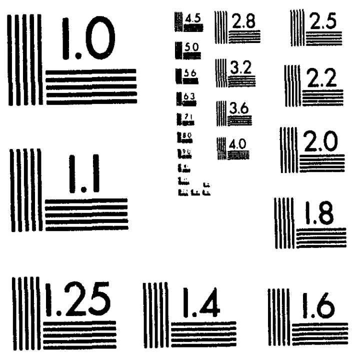

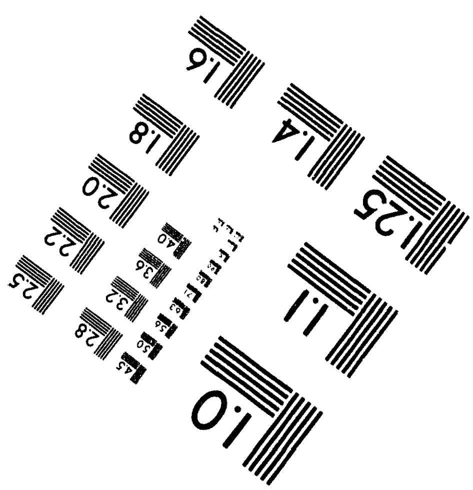

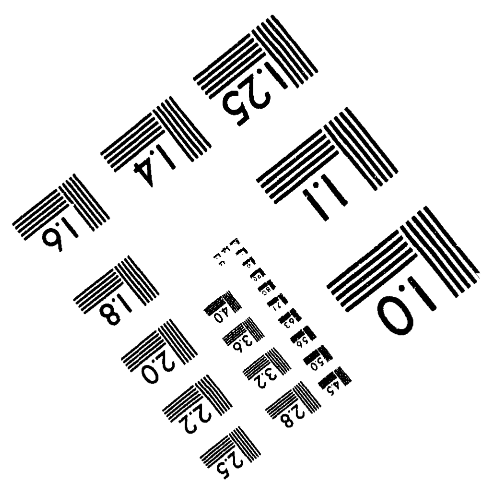

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1 of 2

EXPORTING ALASKAN NORTH SLOPE CRUDE OIL

Benefits and Costs

U.S. Department of Energy
Washington, D.C.

June 1994

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MASTER

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PREFACE

The Department of Energy study examines the effects of lifting the current prohibitions against the export of Alaskan North Slope (ANS) crude. The study concludes that permitting exports would benefit the U.S. economy. First, lifting the ban would expand the markets in which ANS oil can be sold, thereby increasing its value. ANS oil producers, the States of California and Alaska, and some of their local governments all would benefit from increased revenues. Permitting exports also would generate new economic activity and employment in California and Alaska. The study concludes that these economic benefits would be achieved without increasing gasoline prices (either in California or in the nation as a whole).

Lifting the export ban could have important implications for U.S. maritime interests. The Merchant Marine Act of 1970 (known as the Jones Act) requires all inter-coastal shipments to be carried on vessels that are U.S.-owned, U.S.-crewed, and U.S.-built. By limiting the shipment of ANS crude to U.S. ports only, the export ban creates jobs for the seafarers and the builders of Jones Act vessels. Because the Jones Act does not apply to exports, however, lifting the ban without also changing U.S. maritime law would jeopardize the jobs associated with the current fleet of Jones Act tankers. Therefore the report analyzes selected economic impacts of several maritime policy alternatives, including:

- Maintaining current law, which allows foreign tankers to carry oil where export is allowed;
- Requiring exports of ANS crude to be carried on Jones Act vessels; and
- Requiring exports of ANS crude to be carried on vessels that are U.S.-owned and U.S.-crewed, but not necessarily U.S.-built.

Under each of these options, lifting the export ban would generate economic benefits.

This report does not fully address the implications of changing U.S. maritime law. For example, the report does not examine whether limiting exports of ANS crude to Jones Act vessels would be consistent with existing U.S. international trade policies and commitments. Because this report does not address these trade-related issues, it makes no attempt to weigh the benefits of lifting the ban against any costs that might result from changes in U.S. maritime law.

Based on a limited review of environmental issues this report finds no plausible evidence of any direct negative environmental impacts from lifting the ban. Further, the Administration is committed to maintaining its current policy against the development of Arctic National Wildlife Refuge (ANWR) and environmentally-sensitive areas of the Outer Continental Shelf (OCS).

EXECUTIVE SUMMARY

OVERVIEW OF FINDINGS

Our examination of the Alaskan North Slope (ANS) crude oil export issue found that there would be a significant number of benefits to the United States from allowing the export of ANS crude. The principal conclusions of this study are:

- Exporting ANS crude oil would partially relieve the downward pressure on West Coast prices of both ANS and California crude oils. Little, if any, increase in consumer petroleum prices would be likely.

- Higher crude oil prices would lead to better oil producer profitability, which in turn, would raise investment in domestic oil production.

  - Incremental production in Alaska and California could be as high as 100 to 110 thousand barrels per day (mb/d) by the end of the decade.

  - Reserve additions in Alaska alone could be as large as 200 to 400 million barrels--a size that roughly equates to the known reserves in major North Slope fields such as Point McIntyre or Endicott.

- Improving conditions for West Coast oil producers would raise royalty revenue for the Federal Government and tax and royalty revenues for the States of Alaska and California. During the years 1994 to 2000:

  - Federal receipts related to royalties and sales of Elk Hills oil production would total between $99 and $180 million (1992 $).

  - Alaska would gain $700 million to $1.6 billion in State severance taxes, income taxes, and royalties.

  - California returns from the State share of Federal royalties and State and local taxes would be $180 to $230 million.

  - Under the low oil price scenario three-fourths of these benefits accrue between 1994 and 1996.

- Exporting ANS crude oil would result in a substantial net increase in U.S. employment. In all cases examined, gains related to increases in oil industry investment and State and Federal revenues would be much larger than job losses in the U.S. maritime sector.

  - By 1995, the net increase in U.S. employment would be from 11,000 to 16,000 jobs. By the end of the decade, exporting ANS crude could generate from 10,000 to 25,000 jobs. The range of estimates grows over time due to uncertainty in future oil prices.

- The estimate of the level of net job generation is relatively insensitive to whether ANS oil is exported on foreign-flag, U.S.-flag, or Jones Act tankers (U.S.-constructed and -crewed). Exporting oil in foreign-flag vessels would be the least expensive option, thereby generating higher returns for producers and the State of Alaska. This would lead to the highest level of overall job creation, but also would produce the highest level of job losses in the maritime sector. Exporting ANS crude on Jones Act vessels would lower corporate returns, oil production, and revenues for Alaska, but job losses in the maritime sector would be small. These differences offset each other, thereby eliminating the sensitivity to the method of exportation.[1]

- Direct, indirect, and induced employment losses related to the maritime sector could be as high as 3,300 jobs if foreign-flag tankers are employed for exports of ANS crude oil.

o No significantly negative environmental implications were found.

- Lifting the ANS export ban would decrease the incentive for opening the Arctic National Wildlife Refuge (ANWR), and would not affect California production from Outer Continental Shelf (OCS) areas.

- No modifications to the Trans-Alaskan Pipeline System (TAPS) would be required, although incremental production arising from ANS crude exports would extend the economically viable lifetime of the system a few years.

- Exporting ANS crude probably would decrease crude oil tanker movement in U.S. waters.

- Greenhouse gas emissions from generating steam to produce additional heavy oil would increase slightly, but this increase would be insignificant.

This report does not fully address the implications of changing U.S. maritime law. For example, the report does not examine whether limiting exports of ANS crude to Jones Act vessels would be consistent with existing U.S. international trade policies and commitments. Because this report does not address these trade-related issues, it makes no attempt to weigh the benefits of lifting the ban against any costs that might result from changes in U.S. maritime law.

The aspects of the study that lead to these findings and the study methodology are summarized in the sections that follow. The body of the report and its appendices provide details.

THE CURRENT SITUATION

The inability to export excess ANS crude oil depresses the open market price of ANS crude on the West Coast. This accounts for part, but not all, of the large differential between the refined value of West Coast crude oil and the low prices refiners offer producers for indigenous crude

[1] If an export restriction only required U.S.-flag ships to be used (i.e., thereby allowing foreign-built vessels into the ANS trade), then the negative employment effects could be greater. This would be the case if the financial attractiveness of ANS exports drew U.S.-flag ships from other international trade that foreign-flag ships then assumed.

oils. The result is that the West Coast generates the largest gross refiner margins in the world. Our preliminary analysis of West Coast petroleum markets concluded that:

- California refiners today purchase the State's indigenous crude for prices that are between $0.90 and $2.50 per barrel lower than its refined value relative to ANS crude oil. This market bias probably would remain even if exporting ANS crude raised the price of all West Coast crudes.

- The low cost of acquiring West Coast crude oil is not shared with consumers of refined products. West Coast petroleum product prices are, and always have been, at parity with those in other parts of the United States, despite West Coast refiners' low crude oil costs. The result is a gross refiners' margin on the West Coast that averaged $2.40 per barrel, or 31 percent higher than the U.S. average.[2]

- The margin on the West Coast is large enough to accommodate an increase in crude oil prices of $1.00 to $2.00 per barrel without hampering the refinery investment needed to meet future environmental standards.

Currently, ANS and California crude oil production still exceeds West Coast requirements, although ANS production has fallen to the point that relatively little is being sold into the Gulf Coast spot market. If ANS production continues to decline sharply, the surplus may evaporate in the next few years. On the other hand, ANS production has shown a resilience that defies pessimistic predictions of some market analysts. The following section describes the study methodology formulated to address this uncertainty.

STUDY METHODOLOGY

Oil Prices

The study considers two scenarios. In the first, world oil prices would stay constant in real terms through the remainder of the decade. In the second, there would be a $7.50 per barrel real price growth during 1994 to 2000. These price paths, displayed in Figure ES.1, are the high and low price paths from the Energy Information Administration (EIA) 1994 Annual Energy Outlook-1994 (AE094).

Initially, we thought the low price case would be most favorable to ANS crude oil exports. Accordingly, for consistency, assumptions in the low price case were given export-favorable values. In the high price case, assumptions were given values that tended to reduce the benefits, or raised the costs, of ANS crude oil exports. This approach was favored over a point estimate base case analysis due to the wide range of uncertainty in many areas.

ANS and California crude oil price statistics were examined to determine their historic relationships to world oil prices. This relationship was assumed to continue until the West Coast crude oil supply excess disappears through either a natural decline in domestic production or exports of ANS crude oil.

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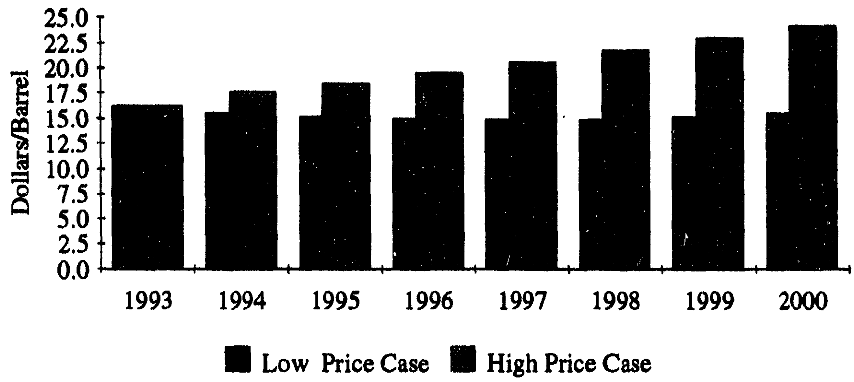
[2] This understates the regional differences because California is such a large part of the national average refining capacity.

Figure ES.1 World Oil Price Scenarios (1992 $)

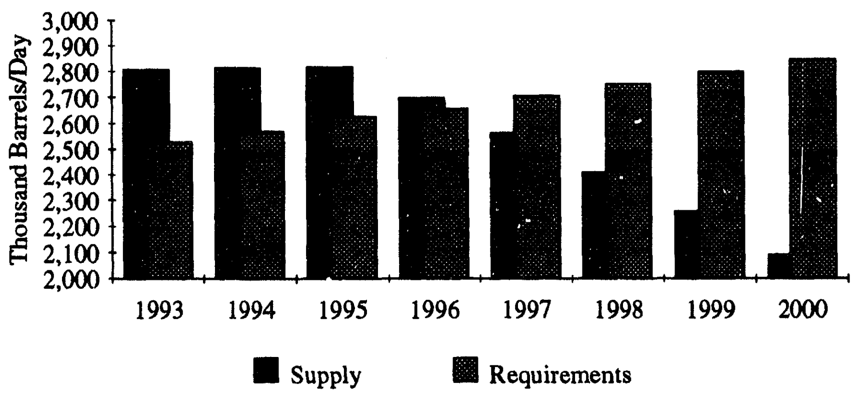


We assumed that when the West Coast crude oil surplus disappears, ANS crude prices would rise to "world market" levels. This is defined as the cost of Arab Light crude oil delivered to California. In the low price case, we added a refining premium determined in our refinery analyses--typically $0.20 to $0.35 per barrel. In the high price case, to remain conservative, no refinery premium was added. The value of ANS crude in Japan was similarly determined. California crude oil is assumed to rise also, but only by 80 percent of the increase in ANS prices. Our data analysis showed that this figure is consistent with historic patterns.

Crude Oil Requirements and Supply

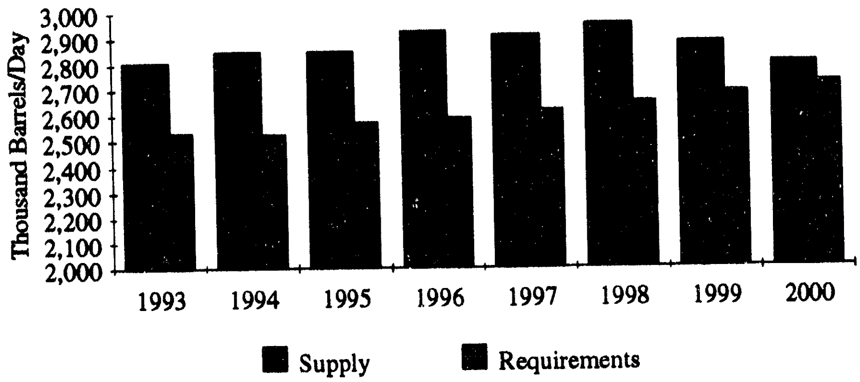
Starting with EIA's AEO94, high and low price case petroleum consumption projections for the U.S. West Coast (PADD V)[3], we estimated refinery crude requirements. Two domestic crude oil production scenarios were developed that were indicative of high and low price conditions. The results are the supply-demand patterns shown in Figures ES.2 and ES.3.

Figure ES.2 Crude Oil Requirements & Supply -- Low Price Case



[3] PADD V consists of Alaska, Arizona, California, Hawaii, Nevada, Oregon and Washington.

Figure ES.3 Crude Oil Requirements & Supply -- High Price Case



The important features of these two cases are:

- o Under low price conditions, rising petroleum product consumption increases crude oil requirements. At the same time, lower prices depress domestic production so that, by 1997, the PADD V surplus has disappeared.

- o In the high price case, lower consumption and higher oil production perpetuate the surplus throughout the decade.

Export Scenarios and Tanker Requirements

The Jones Act (The Merchant Marine Act of 1920) requires oil transported between U.S. ports to be moved in U.S.-constructed, -built, -owned, and -crewed tankers. In 1993, about 35 Jones Act tankers were used to transport ANS crude oil.[4]

- o In the low price scenario, tanker requirements would fall steadily throughout the decade; by 2000, only 21 tankers would be needed.

- o In the high price case, shipping requirements would actually increase to 38 tankers by 1995 to 1996, then fall to 29 vessels by 2000.

These cases provide the baseline against which three export scenarios were evaluated. The options for export of ANS crude oil were:

- o In the first case, exports would be permitted on world trade, foreign-flag vessels. There would be ample supply of foreign-flag vessels, so costs would be at world levels (that is, the shipping cost would be about $0.40 per barrel to Japan).

[4] Several more foreign-flag tankers transport crude oil to the Virgin Islands refinery.

- o In the second case, exports would be restricted to U.S.-flag vessels, but not necessarily to U.S.-constructed vessels. The effect of this constraint would be to increase transportation costs slightly due to the requirement that the vessels meet U.S. crew requirements. Shipping costs to Japan were estimated at about $0.46 per barrel. Given a permissive reflagging policy, there would again be an ample supply of ships available.

- o In the final case, exporting vessels would be taken from the present Jones Act fleet. This has two main cost implications:

  - There would be a limited number of Jones Act ships, and the principal exporting company would not have direct access to the largest class of tanker (capable of transporting nearly two million barrels of oil per trip). Costs per barrel for exports on tankers that carry 1.3 to 1.4 million barrels per trip would be about 13 percent higher than the U.S.-flag option above.

  - Removing some Jones Act tankers from the domestic ANS trade would raise the average cost of transporting ANS crude domestically by one to three cents per barrel.

The shipping costs used in this study were the result of a detailed, ship-by-ship analyses for each of the years in the 1994 to 2000 period. Transportation cost development took into consideration the fact that the majority of the tonnage in the ANS crude trade is owned or long-term leased by oil producing companies. For these vessels, the appropriate costs to consider are the marginal operating costs. Where third party leasing of Jones Act tankers from non-affiliated ship operators was required in the analysis, incurred costs included recovery of capital investment because market conditions usually support the higher costs for short-term charters.

For the two non-Jones Act shipping cases, three export levels were compared to the baseline, no-export case:

- o Exporting only the PADD V surplus crude oil (i.e., the oil that is now shipped to the Virgin Islands, the Gulf Coast spot market, and to the mid-continent by pipeline).

- o Exporting the surplus and 150 mb/d from PADD V supply as long as the PADD V supply surplus exists.

- o Exporting the PADD V surplus and 300 mb/d from the West Coast supply.

In the Jones Act shipping case, only one scenario was considered. It was assumed that the exporter, due to tanker availability and size limitations, would choose only to export the crude that otherwise would be sold in the Gulf Coast market and 150 mb/d from the West Coast supply. In the near-term, this is more realistic than the above assumptions because shipments to the Virgin Islands and through pipelines to the mid-continent are encumbered by contracts that would be difficult and expensive to abrogate. However, these high-cost shipments incur a significant penalty.

The effects on tanker requirements for the foreign-flag export case are shown in Figures ES.4 and ES.5. It is important to note that:

o In the low price case, exports only hasten the loss of 7 to 10 tankers that will result from the natural decline in ANS production by 1998.

o In the high price case, exports reduce the U.S.-flag tanker fleet by 14 to 15 vessels. The remaining fleet size, 20 to 23 vessels, is about the same number as in the low price case. Higher losses for this scenario are caused by the increased shipping requirements associated with a larger, and continuous PADD V surplus.

These Figures underscore the fact that if foreign-flag ships are used for exports, maritime losses are immediate.

Figure ES.4 U.S.-Flag Shipping in ANS Trade -- Low Price Case with Exports

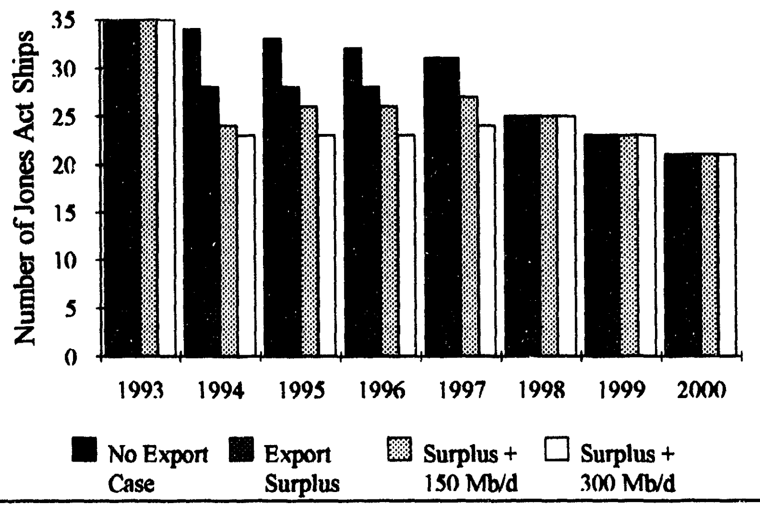
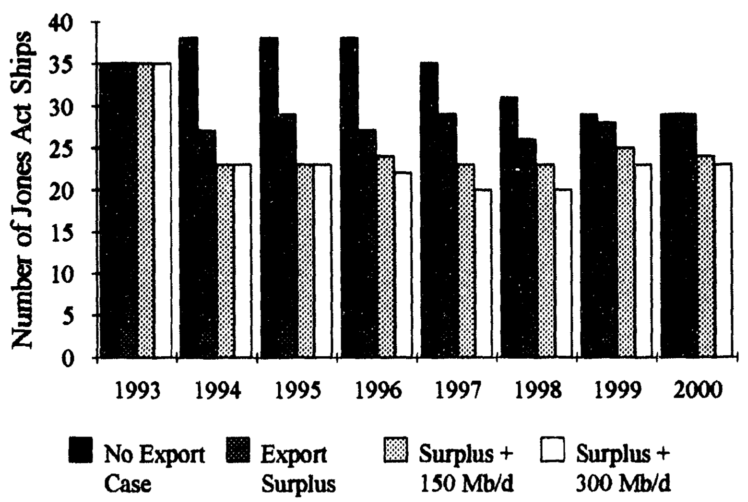


Figure ES.5 U.S.-Flag Shipping in ANS Trade -- High Price Case With Exports



OIL PRODUCTION, REVENUE, AND EMPLOYMENT IMPLICATIONS FOR EXPORTING ANS CRUDE OIL

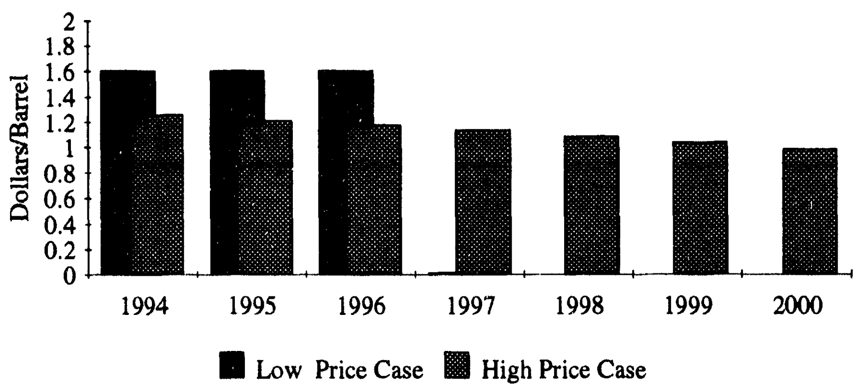
This section tabulates the quantitative effects of ANS crude exports on oil production, revenues, tanker requirements, and employment. Significant assumptions and observations are included in each subsection.

Results below are for cases where 150 mb/d are exported from PADD V crude oil supplies. The analysis indicated little benefit for exporting only the PADD V excess supply because limiting exports to this surplus amount would have little effect on depressed crude oil prices on the West Coast. Exporting 300 mb/d from the West Coast supply offered little extra benefit over the 150 mb/d case. This is, in part, because the value of exported ANS crude oil would fall in Japan and, at the same time, its marginal value would rise on the West Coast as more crude is exported. These cases are discussed in the main body of the report.

Oil Price Increases

ANS crude price increases on the West Coast are estimated to be in the $1.60 range for the low price case,[5] and $1.20 per barrel in the high price case.[6] Figure ES.6 shows that the price change effect in the low price case is only attributed to the years in which a PADD V surplus of crude oil exists. In the high price case, the increase, although lower in magnitude, persists through the year 2000.

Figure ES.6 Incremental Effect of Exports on West Coast ANS Oil Price (1992 $)



[5] Exporting the PADD V surplus and 300 mb/d from the West Coast supply raised ANS prices $1.83 in the low price case. This was offset, however, by a drop in the value of exported ANS crude as increased exports saturate the market.

[6] The refining premium is ignored in the high price case to be consistent with the conservative assumptions made in that scenario.

Oil Investment Revenues

Incremental oil revenues are generated by higher sales prices for domestic oil, higher prices gained by sales in the Far East markets, and lower transportation costs. These incremental revenues could be reinvested by oil producers after subtracting taxes and royalties from gross revenues. However, an increased world-level price for ANS crude would not generate incremental investment revenue for all producers. More than half of ANS production and 75 percent of California production is refined by the integrated producer/refiners that own the oil, or trade it for oil that is more conveniently located. The "market price" of this crude is only a transfer price between two divisions of the same company, so it is not assumed to produce potential investment revenue in this study.

Producers' incremental revenue flows, as shown in Table ES.1, are important determinants of the study results. The table shows that:

- In the low price case, incremental revenues would disappear after 1996 because it is assumed that market prices for ANS and California crude oil would rise to "world levels" even if the ban is not lifted. However, additional investment made between 1994 and 1996 would raise oil production in the later years over current projections. To remain conservative in our estimates of benefits, we ignored the additional investment revenue this production might create (some incremental production may be near marginal costs), but included the Federal and State revenues that the incremental production would generate.

- In the high price case, lower returns for the 1994 to 1996 period result from the omission of the refining premium for ANS crude oil valuation on the West Coast and in Japan. However, because the surplus continues through the year 2000, incremental revenue generation continues throughout the decade. The incremental revenue, after taxes and royalties are subtracted, is assumed to be used for investment in oil production activities.

- The U.S.-flag export case creates slightly higher revenues than the foreign-flag export case despite higher shipping costs, due to tax shelter considerations associated with investment cost recovery for company-owned tankers.[7] Favorable tax treatment is assumed to encourage greater investment and production.

- In the Jones Act shipping case, high cost domestic shipments to the Virgin Islands and mid-continent are not exported (see earlier description of Jones Act shipping scenario), thereby lowering producer returns.

[7] If U.S.-flag shipping is employed for the exports, then taxes and royalties would be computed employing full capital recovery (or depreciation) in the cost of shipping. This creates a tax "shelter" that is not present if foreign-flag shipping is chartered from an unaffiliated third party. The tax shelter effect slightly increases production for the U.S.-flag case, and lowers Alaska revenues.

Table ES.1 Cumulative Oil Company Investment Potential (Millions of 1992 $)

Type of Export Tankers	Low Price Case 1994-1996	1997-2000	Total	High Price Case 1994-1996	1997-2000	Total
Foreign-Flag:						
Alaska	$455	$1	$456	$334	$426	$760
California[a]	158	0	158	122	169	291
Total	613	1	**614**	456	595	**1051**
U.S.-Flag:						
Alaska	480	1	481	376	477	853
California[a]	158	0	158	122	169	291
Total	638	1	**639**	498	646	**1144**
Jones Act:						
Alaska	425	0	425	317	414	731
California[a]	158	0	158	122	169	291
Total	583	0	**583**	439	583	**1022**

[a] Only ANS revenues are affected by the type of shipping employed. Therefore, California investment revenues are identical in all three cases.

Oil Production

Production calculations are based on full reinvestment of after-tax revenues in domestic oil production. This is a very reasonable assumption for California independent producers, but one that some might consider questionable for ANS producers. Examination of financial statistics for ANS producers showed little difference between the average of all large integrated companies in the extent to which revenues have been reinvested in the United States. Currently, foreign investment offers a higher rate of return for larger companies than domestic development activities.[8] If exporting ANS crude oil increased rates of return for ANS production, the tendency would certainly be to increase Alaskan investment over what would otherwise be the case.

In the case of Alaska, producers' after-tax revenues were assumed to be invested in activities that yielded reserve additions at the current rate of $2.05 per barrel. Data in Table ES.1 imply that reserve additions in the range of 200 to 400 million barrels could be produced by the investment resulting from exports of exports of ANS crude. By comparison, the known reserves remaining (in today's economic conditions) in Prudhoe Bay total about 3.5 billion barrels. Current reserves at Endicott and Point McIntyre, major secondary fields on the North Slope, are 262 and 356 million barrels respectively.[9]

[8] Performance Profiles of Major Energy Producers-1992, EIA, January 1992.

[9] Historical and Projected Oil and Gas Consumption, Alaska Department of Natural Resources, February 1994.

Table ES.2 shows the production response potential in the three export cases. Of note is that the total production response is relatively insensitive to the method of shipping chosen. The ANS production response in the high price case is greater than the low price case, but this is offset by lower incremental California production. The California production price elasticity is much higher at low world oil prices than it is for the high price case.

Table ES.2 Oil Production Potential (Thousand Barrels Per Day)

	Low Price Case		High Price Case	
Type of Export Tankers	By 1996	By 2000	By 1996	By 2000
Foreign-Flag:				
Alaska	11	54	8	63
California	18	53	7	33
Total	29	107	15	96
U.S.-Flag:				
Alaska	11	57	9	71
California	18	53	7	33
Total	29	110	16	104
Jones Act:				
Alaska	11	54	8	60
California	18	53	7	33
Total	29	107	15	93

Federal and State Revenue

Table ES.3 presents estimates for State and Federal revenue totals during two time periods: 1994 to 1996 and 1997 to 2000. The primary sources of these revenues are:

- o Alaska--Alaska's 12.5 percent royalty and 15 percent severance tax produce most of the State's returns.

- o California--Revenues come from a share of Federal royalties, State and local income and property taxes, and the State share of a producing field near Long Beach, California.

- o Federal--Receipts are the sum of royalties on California production and sales price increases for the U.S. Department of Energy's (DOE) 50 mb/d production at Elk Hills, California. These revenues are products of the price increase projected for California-produced crude oil; therefore they are not affected by the type of tankers employed to export the oil.

By the end of the decade, incremental production could be financially significant. However, the diversity of sources of revenue, some of which are the product of increased oil prices, implies that returns would begin soon after the ban is lifted.

Table ES.3 Cumulative State and Federal Revenue (Millions of 1992 $)

Type of Export Tankers	Low Price Case 1994-1996	Low Price Case 1997-2000	Low Price Case Total	High Price Case 1994-1996	High Price Case 1997-2000	High Price Case Total
Foreign-Flag:						
Alaska	$667	$179	**$846**	$610	$1019	**$1629**
California	102	79	**181**	74	156	**230**
Federal	96	3	**99**	72	108	**180**
U.S.-Flag:						
Alaska	612	189	**801**	521	942	**1463**
California	102	79	**181**	74	156	**230**
Federal	96	3	**99**	72	108	**180**
Jones Act:						
Alaska	562	164	**726**	450	820	**1270**
California	102	79	**181**	74	156	**230**
Federal	96	3	**99**	72	108	**180**

The Effect of ANS Exports on the U.S. Maritime Fleet

Table ES.4 shows the number of tankers and seafarer jobs that would be eliminated if exports were made in foreign-flag tankers. As noted earlier, these losses would be immediate if exports were permitted. However, they are already projected to occur within the next few years as ANS oil production declines, even if the export ban was not lifted.

Table ES.4 Tanker and Seafarer Job Losses Due to Foreign-Flag Exports of ANS Crude Oil[a]

	Low Price Case Tankers	Low Price Case Seafarer Jobs	High Price Case Tankers	High Price Case Seafarer Jobs
1994	10	632	15	934
1995	7	441	15	934
1996	6	375	14	885
1997	4	238	12	758
1998	0	0	8	472
1999	0	0	4	238
2000	0	0	5	316

[a] "Losses" are the year-by-year differences between the no-export case and the case where the PADD V surplus supply of crude oil is exported along with 150 mb/d from PADD V supplies.

Transportation costs for exporting ANS crude in U.S.-flag tankers are only slightly higher than foreign-flag tanker costs. As was shown earlier, there is little difference in financial measures or oil production if exports were required to be carried on U.S.-flag or Jones Act tankers. This is because most of the U.S.-flag tanker capacity is owned (or leased long-term) by ANS producers, and the out-of-pocket cost to a producer-exporter is just the operating cost of the vessel (fuel, maintenance, and crew costs). This out-of-pocket cost approximates market charter rates for foreign-flag tankers.

If exports were required to be shipped on Jones Act tankers, tanker and job losses of the magnitude shown in Table ES.4 would not occur. Large Jones Act tankers would be employed to export oil, but the distance to Pacific Rim ports is over half again as far as the distance from Valdez to California. In addition, removing larger tankers for export duty would decrease the average size of tankers remaining in the domestic ANS trade, thereby increasing the domestic shipping requirements. These factors offset to a great extent, so that the likely loss in tankers is, at most, one or two small vessels with a total of no more than 118 seafarer jobs.

The employment and ship requirements for the U.S.-flag (not necessarily U.S-constructed tankers) case is similar to the Jones Act case, but with a caveat. If the financial attractiveness of ANS exports drew U.S.-flag ships from other international trade, and foreign flag ships then took over that foreign trade, larger losses of U.S. crews might result.

Production of Alaskan crude oil could increase by 50 to 70 mb/d by the year 2000 if ANS crude oil was exported. A 120,000 deadweight ton (dwt) tanker can transport 45 mb/d of crude oil from Valdez to Los Angeles, so incremental production could restore the need for one or two medium class domestic tankers--thereby offsetting the losses in the U.S.-flag or Jones Act cases.

While seafarer jobs losses would be partially mitigated if exports are restricted to U.S.-flag shipping, this limitation would not address the concerns of the U.S. ship building industry. Starting in the late 1990s, double hull requirements of the Oil Pollution Act of 1990 (OPA90) will force replacement of, or extensive modification to, most of the tankers in the U.S. fleet (foreign tankers that serve U.S. ports also will have to meet the terms of OPA90). If foreign-built tankers could be reflagged and operated in the ANS oil trade, thereby minimally satisfying the U.S.-flag requirement, then new OPA90-compatible tankers would be built overseas at lower cost. If exports were carried on Jones Act-compatible tankers, this issue would become moot because the Jones Act requires U.S. construction to satisfy OPA90 requirements.

Employment Effects of the Lifting the ANS Export Ban

Lifting the ANS export ban would have a positive net impact on potential U.S. output and employment, even after considering the impacts on the maritime sector. Table ES.5 displays the aggregate results of the employment analysis. For oil related activities:

- Lifting the ANS ban has the potential to increase direct and indirect employment in oil-related investment, oil production, and through the employment effects of additional State tax revenues for citizens by between 6,500 and 9,700 jobs in 1995 and between 5,400 and 13,900 jobs in 2000 (depending on which mode of export shipping is used). Potential employment increases could be even larger if incremental government revenues were used in whole or in part to increase State and local government employment.

- o Induced employment (i.e., employment due to expenditures by direct and indirect employees) was estimated separately. Induced employment due to increases in oil-related investment, oil production, and State revenues would range from 5,100 to 7,700 in 1995 and 4,700 to 11,500 in 2000.

Table ES.5 Direct, Indirect, and Induced Employment

	Low Price Case		High Price Case	
Type of Export Tankers	1995	2000	1995	2000
Foreign-Flag:				
Oil-Related	17,320	10,574	13,936	24,343
Maritime	(1,559)	0	(3,301)	(1,117)
Net	15,761	10,574	10,635	23,226
U.S.-Flag:				
Oil-Related	16,790	10,889	13,219	25,362
Maritime	(417)	0	(417)	(417)
Net	16,373	10,889	12,802	24,945
Jones Act:				
Oil-Related	15,320	10,122	11,677	23,295
Maritime	(417)	0	(417)	(417)
Net	14,903	10,122	11,260	22,878

The potential increases in direct and indirect employment outside the maritime sector would be significantly larger than the maximum potential adverse impact on maritime employment. The maximum direct and indirect job losses in the maritime sector are estimated to be between 300 and 2,400 jobs in 1995 and between zero to 800 jobs in 2000. In addition, we note the following:

- o If ANS exports are carried on foreign-flag ships, the adverse effect on maritime employment would end when the PADD V surplus disappears--by 1997 in the low price case.

- o If ANS exports are carried on U.S-flag or Jones Act ships, relaxation of the export ban could actually offset most of the direct and indirect maritime employment losses as more oil is produced and shipped.

The employment impacts were estimated using the Department of Labor's Bureau of Labor Statistics (BLS) employment coefficients. A description of the methodology and sensitivity analysis on various assumptions used in the employment calculations are reported in the main body of the report.

As a quick check on the order of magnitude of these results, we note that increased net oil production in the year 2000 would contribute $520 to $560 million (1992 $) to real GDP in the low price case. Application of a rule of thumb of one job per $50,000 increase in GDP would result in an estimated 10,400 to 11,200 additional jobs associated with oil-related revenues. These estimates compare favorably with the figures shown in Table ES.5 above.

Finally, ANS exports and the attendant increase in crude oil prices are not likely to cause significant employment losses in the refining sector of the economy. Refinery capacity in the United States fluctuates with petroleum product consumption, not marginal refining economics. Refineries do indeed go out of business, but if product consumption dictates, the same refineries often reopen under new management.[10] Despite dire predications of impending increases in product imports due to deteriorating refinery margins, petroleum product imports to the United States have remained less than 10 percent of petroleum supply for 20 years. In the last five years, imports have fallen to five percent of U.S. petroleum supply.

EFFECT OF ANS CRUDE OIL EXPORTS ON PETROLEUM PRICES

There are four primary reasons why we believe that refined product price increases would be minimal or non-existent if crude oil market prices on the West Coast increase in response to ANS crude oil exports:

- o First, West Coast gasoline and diesel fuel prices always have been at or above world market levels. This opens the West Coast to outside competition if prices rise much farther.

    - Our examination of the Pacific Rim refined product market shows that a price increase of a few cents per gallon for gasoline, diesel, or jet fuel in California would make Pacific Rim supplies financially viable.

    - A statistical analysis of the last six years of monthly crude oil and refined product prices indicates that California gasoline price movements correlate much more strongly with Gulf Coast (Texas) gasoline prices than they do with California refiners' crude oil supply costs. This implies that market arbitrage keeps West Coast product prices in line with outside sources even though little product actually moves between the West Coast and other regions.

- o Second, integrated refiner/producers with West Coast refineries own about 60 percent of the crude production in PADD V.[11] Although market prices for West Coast crude supplies would rise, this is irrelevant for a refiner that processes crude from its own production assets; that refiner's cost of supply remains the cost of crude oil production and transportation. While it might seem that the refiner is forgoing an opportunity to sell ANS crude oil at a higher price, that is not the case. Doing so would require purchase of replacement crude oil at market prices to support the refiner's refined product distribution requirements. In summary, if crude oil market prices rise, there is a much smaller incurred cost than seems to be the case at first glance.

- o Third, the history of West Coast product marketing is one of aggressive competition in product markets, despite their non-competitive behavior on the upstream side of the industry. This suggests that major refiners in PADD V that their own crude oil production may restrain their product price increases to acquire market share from their competitors.

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[10] One large West Coast independent refiner, for example, as part of its ANS crude oil supply agreement, must offer its refinery for sale to its crude oil supplier if its financial condition dictates a sale or closing.

[11] Over 50 percent of ANS crude production and 75 percent of California crude production.

- o Finally, our refinery analysis showed that the manufacturing cost increase of light petroleum products is smaller than would be expected from a simple allocation of crude oil price increases. This is because the imported crudes that would replace ANS oil tends to be more compatible with West Coast product demand.[12]

In summary, the West Coast consumer is unlikely to notice any change in product prices caused by export of ANS crude oil.

ENVIRONMENTAL IMPLICATIONS

Protection of the environment is a primary consideration in all energy policy decisions of the Clinton Administration. Our review found no plausible evidence of any direct negative environmental impact from lifting the ANS export ban. This conclusion reflects, in part, the historical decline in California production levels and the structure of California's environmental regulations. When indirect effects are considered, it appears that the market response to removing the ANS export ban could result in a production and transportation structure that is environmentally preferable to the status quo in certain respects. Specific findings follow:

- o ANS and ANWR--The Administration, with strong support in Congress, firmly opposes exploration, development, or production activities in ANWR. Lifting the export ban may, in fact, weaken the case for opening ANWR, because it would be difficult politically to argue for opening ANWR while exporting ANS crude oil.

  To a degree, lifting the ban on ANS crude oil exports would offset future pressure to open ANWR. Company reinvestment of incremental revenues derived from lifting the ban could expand recoverable reserves within currently developed areas on the North Slope by 200 to 350 million barrels between 1995 and 2000. This amount equates in magnitude to a 10 percent extension of remaining reserves at Prudhoe Bay, and would reduce the need to develop ANWR.

- o The ANS Export Ban and TAPS--Lifting the export ban will not require expansion of TAPS and related infrastructure due to the natural decline in North Slope field productivity. The modest increase from a declining baseline production level that could result from lifting the export ban would not restore production to current levels, much less increase them. Environmental emissions associated with the operation of TAPS would also decline over time as throughput decreases from design capacity. Finally, incremental production associated with lifting the ANS export ban would extend the economically viable lifetime of TAPS by no more than two or three years.

- o Tanker Operations--Lifting the export ban will reduce overall tanker movements in U.S. waters. This is because increased onshore California production will decrease the need for waterborne movements of crude to the State. ANS crude oil exports may also reduce oil transportation risks by eliminating movement of ANS crude oil to the Gulf Coast that involve multiple loading and unloading operations. Eliminating the ANS export ban does

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[12] To some extent, this is happening now. Imports of Oman crude in California are rising because it produces products that are more compatible with California's new diesel specifications.

not change requirements of OPA90 on either foreign or domestic tankers loading or discharging oil in U.S. ports.

- o California Air Quality Considerations--Our specific findings in this area are:

  - Lifting the export ban should not affect the level of emissions at California refineries because emissions in California non-attainment areas are generally subject to absolute caps, often including a reduction schedule as dictated by California regulations. In addition, the absolute amount of crude input required to meet California product needs would decline slightly in the near term, as imported oil that provides a higher proportion of gasoline substitutes for ANS crude oil.

  - California heavy oil producers are subject to strict permitting constraints and offset requirements that would prevent any increase in overall emissions as production activity rises.

  - Imported oil that would substitute for ANS crude exports would have a lower sulfur content than ANS crude, thereby lowering the average sulfur content of the crude processed in California refineries. This would reduce sulfur-related emissions from refineries and, all other things being equal, from combustion of fuels produced in California refineries.

- o California Offshore Areas--California offshore activities are limited by drilling moratoria in effect in most areas, and by limitations relating to the siting of onshore facilities imposed by state, county, and local governments. Offshore development is so encumbered by high capital costs that the small oil price increases proposed by this study would not change project economics measurably, and therefore, would not lead to increased offshore development.

- o Greenhouse Gas Emissions--Lifting the export ban would have no appreciable impact on greenhouse gas emissions. We estimate that annual emissions from thermal enhanced oil recovery (TEOR) activities would increase by less than one-quarter of a million metric tons (i.e., less than two one-hundredths of one percent of 1990 U.S. carbon emissions). The net effect would be even lower if the benefits stemming from cogeneration of electricity at natural gas-fueled TEOR sites is taken into account.

- o Product Price Increases--As discussed above, we doubt that petroleum product prices would rise following removal of the export ban. If they do, higher prices will spur conservation, reducing both greenhouse and smog-causing emissions.

TRADE EFFECTS

Exporting ANS crude to Japan and other Pacific Rim countries could improve the U.S. trade balance with those countries, but the net national trade benefit would likely be small. Considering the low price case as an example, if PADD V's surplus ANS crude supply was exported along with an additional 150 mb/d from PADD V supply, about $2.0 billion in annual exports would be generated. Since, in the near term, crude oil must be imported to replace exports, the effect would be to shift a portion of the U.S. trade deficit away from Japan and toward another country such as Saudi Arabia, Mexico, or Indonesia.

Our analysis shows that incremental domestic oil production would appear to offset these imports partially. However, the response would be slow to develop. For example, it would take several years to generate even half the amount of ANS crude removed from PADD V. Therefore, in the short term, the net trade effects probably would be neutral.

DEPARTMENT OF DEFENSE CONSIDERATIONS

The investment planning conducted by DoD is based on fleet projections for the year 2000. The fleet projections that have been provided to DoD by the U.S. Maritime Administration (MARAD) have already taken into account reductions in the tanker fleet that are similar in magnitude to those projected under either of the price assumptions covered in this paper. Therefore, regardless of the price assumptions, the proposed changes to policies on ANS crude export would have no impact on DoD operations.

DoD and the Department of Transportation (DOT) are currently working on estimates of manpower requirements for the Ready Reserve Force (RRF). This study will determine whether there will be an adequate number of civil mariners to staff the RRF in wartime. The DoD determination of that adequacy depends on the implementation of DOT's new Maritime Security Program and the future size of the RRF. However, determination of whether there will or will not be a shortage is several months away. Because of the higher cost associated with Jones Act shipping, DoD would not, however, argue for a requirement that exports be carried on Jones Act ships.

CHAPTER 1
BACKGROUND

THE CLINTON ADMINISTRATION'S DOMESTIC NATURAL GAS AND OIL INITIATIVE

Throughout the summer and fall of 1993, the U.S. Department of Energy (DOE) conducted an intensive effort to identify actions that the Federal Government could take to improve conditions in the natural gas and oil industries of the United States. On December 9, 1993, President Clinton released the Domestic Natural Gas and Oil Initiative--a compendium of actions aimed at boosting markets for domestic natural gas and oil, while developing a long-term strategy to address America's dependence on insecure sources of foreign oil. One of the action items was a review of the prohibition on exporting Alaskan North Slope (ANS) crude oil.

A BRIEF REVIEW OF THE ANS EXPORT BAN HISTORY

The Trans-Alaska Pipeline Authorization Act of 1973 permitted building a pipeline from the North Slope producing fields to Valdez, but, through an amendment to Section 28 of the Mineral Leasing Act, placed strict prohibitions on exporting the oil.

Much of the public opposition to the pipeline centered around environmental concerns about robust Alaskan oil development. However, as with most major public issues, there were many agendas. For example:

- In the debate on the Trans-Alaskan Pipeline authorization bill, organized labor switched sides and lobbied for the pipeline. The quid pro quo was that the oil would be statutorily prevented from being exported.[13] In that case, ANS crude would have to be carried on Jones Act (U.S.-constructed and -crewed) tankers--a substantial mission for the U.S. maritime fleet.

- Others in Congress, who were concerned about U.S. oil shortages following the 1973 Arab oil embargo, thought that the ANS pipeline would make it easy to export U.S. reserves, thereby increasing U.S. vulnerability to a supply disruption.

The final result of these concerns was that the Act narrowly passed (then Vice President Spiro Agnew cast the tie-breaking vote), with strict export prohibitions included. Subsequent legislation, the 1977 amendments to the Export Administration Act of 1969 (EAA) and the Energy Policy and Conservation Act of 1975, strengthened the export restrictions. The Export Administration Act of 1979, which replaced the 1969 EAA, essentially prohibits the export of ANS crude oil during non-emergency periods, except for limited exports to Canada.

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[13] From testimony of Maritime Union officials in public meetings conducted by DOE in March 1994.

The ANS export ban has been studied frequently. These studies have consistently shown net benefits from lifting the export ban. For example:

- o In 1985, a study was required by section 126(a) of the EAA. It was an interagency effort led by the Department of Commerce. Further "review" of the issue was recommended.

- o In 1990, the General Accounting Office, with the help of DOE's Energy Information Administration (EIA), studied the issue at the request of Congressman Philip Sharp.

- o ANS exports were considered, but were not part of either the 1987 DOE Energy Security Study or the Bush Administration's National Energy Strategy.

Both the Reagan and Bush Administrations were committed to opening the Arctic National Wildlife Refuge (ANWR) to oil exploration. Lifting the export ban would have made that politically more difficult.

In 1992, the State of Alaska sued the Federal Government, challenging the constitutionality of the ban and claiming that it cost the State billions of dollars in lost tax and royalty revenues. A Federal court upheld the ban on March 1, 1994, and Alaska plans to appeal.

Ironically, President Bush came close to signing an Executive Order lifting the ban late in 1992 at the urging of Alaska's governor. However, he was prevented from doing so by the Department of Justice's defense against the Alaska lawsuits. The Justice Department had taken the position that other statutes embraced the language of the EAA on the subject, so the ban was legally still in place even though the EAA had expired.

The history of debate on the ban is robust, and sometimes quite colorful, but it cannot be fully covered here. Nevertheless, this brief overview serves to demonstrate that this has been a highly charged emotional issue for years. The congressional and public correspondence that DOE has received since announcing the study shows that it remains so today.

WINNERS AND LOSERS

Perhaps the most vocal group advocating lifting the ANS export ban today are the California independent crude oil producers. These companies, many of which produce only a few hundred barrels of oil per day (some less), argue that their prices are abnormally depressed by several artificial factors, the most significant of which is the West Coast's "over-supply" of ANS crude oil. These companies are the classic economic price-takers. That is, because major refiners own and control the oil pipelines from the oil fields to refineries, the producers can only accept what the refiners offer. Even though most pipelines do not operate as common carriers, independent producers argue that if the ban was lifted, refiners would be forced to bid for their crude oil, and its price would rise. Refiners disagree.

Allowing export of ANS crude oil has positive and negative aspects. On the positive side, the oil may have a higher market value in Pacific Rim countries that are less gasoline-oriented than the U.S. West Coast. If this is the case, opening West Coast markets to world oil trade should raise U.S. market prices for Alaskan oil. A similar effect might be seen in California. The result would be increased State and Federal royalty and tax revenues, and an improved financial climate for beleaguered independent West Coast oil producers.

On the negative side, higher California crude oil prices would raise costs for West Coast independent refiners. Because it is unlikely that the increased costs could be reflected in higher petroleum product prices, refining profits could decline. In addition, exporting ANS crude oil in foreign-flag tankers would accelerate the decline in the requirement for U.S. maritime tankers on the West Coast.

Eight years have passed since the Executive Branch of the Federal Government last comprehensively evaluated this important trade and energy issue. At the time the 1985 Commerce Department study was performed, more than 850 thousand barrels per day (mb/d) of ANS oil moved past California to eastern U.S. destinations. The high cost of this transportation in U.S.-flag vessels suggested that there were large efficiency-related returns for permitting ANS crude exports to Pacific Rim countries.

Today, the situation is somewhat different. ANS crude production has fallen, and petroleum demand is higher on the West Coast. Combined with lower oil production in California, the result is that less than 300 mb/d of ANS crude is shipped east and little of it enters the Gulf Coast market. As ANS crude production declines in the future, this quantity will fall. This has three implications:

- First, the demand for U.S.-flag tankers in the Alaskan trade will drop even if the export ban is not lifted.

- Second, as high-cost ANS oil shipments to the U.S. Gulf of Mexico and Virgin Islands fall to zero, the economic and financial rewards for lifting the ban would seem to lessen. This is because exporting ANS oil will no longer "save" the several dollars per barrel that it costs to move the oil east.

- Finally, in the last part of this decade, the U.S. West Coast will again be dependent on foreign oil for its incremental supplies. In theory, this will tie the West Coast price structure more closely to Pacific Rim oil markets and could raise prices for incremental supplies.

A market for ANS crude exports might exist even when the West Coast becomes a substantial oil importer. With restraints on exporting removed, some producers might find it financially advantageous to avoid the higher costs of U.S.-flag shipments to the lower 48 States. If ANS crude is valued higher in the fuel oil-oriented economies of Pacific Rim countries than in the gasoline-oriented United States, the attractiveness of exporting ANS crude might increase further. This reasoning suggested that the ANS crude export study should have two major components:

- One is to estimate, under reasonable scenario assumptions, the amount of ANS oil that might be exported and its price. Reaching that objective requires estimation of a number of parameters including ANS crude production, California oil production, petroleum demand, shipping costs, and so on.

- o The second set of tasks involved assessing the impact of exports on:
  - State and Federal revenues;
  - employment (California and national);
  - the West Coast refining industry;
  - the U.S. shipping industry; and
  - incremental oil production resulting from higher oil prices and additional investment by oil producers.

The following sections describe how this analysis was structured, and the results that were obtained.

CHAPTER 2
PRELIMINARY ANALYSES

CALIFORNIA CRUDE OIL BRINGS RELATIVELY LOW PRICES

Many analysts and economists have examined California crude oil prices and attempted to explain why they are so low. It is true that California crude oils are predominantly heavy and viscous (hard to refine, some say), but California is dominated by large, complex refineries that can break the crude oil down into very good yields of light products. When simple quality adjustment factors that apply in the U.S. Gulf Coast markets, or, for that matter, throughout the world, are applied to California crude oils, they generate prices estimates that are much higher than what the California refiners offer.

This problem is relevant to the ANS export issue because it helps characterize the market conditions that plague West Coast producers. It also suggests that removing the ban may help correct some, but not all, of the problems faced by independent producers in California. Table 2.1 shows that, even considering the price depressing effects of the ANS export ban, California wellhead prices are low compared to prices in other areas.

Table 2.1 Undervaluation of California Heavy Crude Oil (1992 $)

Crude Oil Type[14]	Refined Value	Net to Wellhead	Typical Posted Price	Under-Valuation
		Single Complex Refinery Analysis		
Alaskan North Slope	$16.16	-	-	-
Kern River (13 Degree API)	15.33	$14.33	$11.80	$2.53
Wilmington (17 Degree API)	15.67	15.07	12.44	2.63
		World Oil Model (Multi-Refinery)		
Alaskan North Slope	13.20	-	-	-
Kern River (13 Degree API)	11.53	10.53	9.63	0.90
Wilmington (17 Degree API)	12.52	11.92	10.16	1.76

Table 2.1 displays the refined values of two typical California heavy crude oils relative to the refined value of ANS crude (the absolute price of ANS is unimportant; it is the relative value that is significant). Starting with the refined values we adjusted to wellhead values and compared this to prices typical of those that refiners offer.

- o Refined values of the two heavy crudes were adjusted to the wellhead by subtracting $1.00 for Kern River and $0.60 for Wilmington crudes. These transportation costs are consistent with the only common carrier pipeline in the State (ARCO's Line 63).

[14] Kern River Crude Oil is one of many San Joaquin Valley heavy crude oils. Wilmington is produced near Los Angeles.

o "Typical Posted Price" was calculated using the historic analysis of posted price relationships between California and ANS crudes, included as Appendix B. There it is shown that San Joaquin Valley (SJV) 13 degree API heavy crudes, on average, have been posted at about 73 percent of the price of ANS spot prices. The factor for Wilmington crude is 77 percent.

It is interesting to note that the difference in refined value between the two heavy crude oils and ANS crude oil ranges between 5 and 11 cents per degree API. This price difference is even lower than the 10 to 15 cents employed to adjust lighter crudes in U.S. Gulf Coast markets. The California contradiction, however, is that when "typical" wellhead posted prices are compared to the refinery values netted to the wellhead (by subtracting transportation costs as in Table 2.1), the posted prices are found to be significantly lower than the crude oil's true value to refiners. The single refinery model analysis indicates the undervaluation may be in the range of $2.50 to $2.60 per barrel.

The World Oil Refining Logistic Demand (WORLD) Model offers a picture similar to the single complex refinery model, but that the amount of undervaluation may be only $0.90 to $1.76 per barrel.[15]

We examined the effect of exporting ANS crude oil on the relative values of ANS and California heavy crudes, and found that exports generally helped close the gap, particularly in the WORLD Model cases. However, the degree of structural bias imposed in California between the refinery and the wellhead is not likely to be fully addressed by exporting ANS crude oil.

PADD V CONSUMER PRICES AND CRUDE OIL COSTS[16]

This section explores the price relationships between PADD V crude oil and petroleum prices. In doing so, it addresses constraints that would mitigate a product price increase on the West Coast if prices for domestic crude oil rise.

PADD V Petroleum Product Price are at World Levels

Some have argued that, if the ANS export ban is lifted, crude oil prices would rise on the West Coast and consumers would pay the cost of removing the ban. But Table 2.2 shows that West Coast product prices are, and always have been, at parity with other parts of the U.S., despite West Coast refiners' low crude oil costs. Therefore, West Coast refiners do not have much room to raise prices further without opening their markets to domestic supplies from the U.S. Gulf Coast or foreign imports.

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[15] On closer reflection, we concluded that modeling calibration problems that were not solvable within the time available, minimized the apparent undervaluation of California crudes. We were not able to model the situation wherein a producer of ANS crude oil without West Coast refineries would send ANS crude oil to the U.S. Gulf, mid-continent, or Virgin Islands at an apparent loss. In reality, one producer does this (although the "loss" is simply lower production profits) to prevent West Coast ANS crude prices from collapsing. Our quick solution was to constrain the WORLD Model's inter-region shipments. However, this produced abnormally low marginal values for California crudes, thereby magnifying the differences between estimates of their refined values and that of ANS crude oil.

[16] PADD V consists of Alaska, Arizona, California, Hawaii, Nevada, Oregon, and Washington.

Table 2.2 shows volume-weighted petroleum product prices, crude oil costs, and their differences--termed gross margins--for PADD V and the United States as a whole.[17] On average over the 1988 to 1993 period, the gross margin in California is $2.40 higher than the national average.[18] While gross margins should not be confused with profit margins, the difference in gross margins suggests that there is ample room for an increase in crude oil prices without significantly affecting West Coast consumer prices.

Table 2.2 Petroleum Product Prices and Refiner Gross Margins (1992 $)

Weighted Averages	1988	1989	1990	1991	1992	1993
U.S. Products	$21.88	$25.09	$30.64	$26.95	$26.05	$24.58
PADD V Products	22.69	25.59	30.97	25.72	27.49	26.81
U.S. Crude Costs	14.67	17.97	22.22	19.06	18.43	16.41
PADD V Crude Cost	12.86	16.30	20.46	16.23	16.32	14.41
Gross Margins						
U.S. Average	7.21	7.12	8.42	7.89	7.62	8.17
PADD V Average	9.82	9.29	10.51	9.49	11.17	12.39

Refining Expense and Gross Margins

A significant increase in the cost of crude oil might not be affordable for refiners if current or future expenses of operation are abnormally high on the West Coast. For example:

- Gross margins in PADD V might be high because it is so expensive to refine California's heavy crude compared to the light sweet crudes available in PADD III.[19]

- If crude oil costs rise, PADD V refiners might not be able to afford the modifications necessary to meet the environmental standards posed by the Clean Air Act Amendments of 1990 and other statutes.

Even in the extreme, the first argument does not go far to explain the difference in margins. The primary expense associated with California heavy crudes is breaking down the residuum in cokers. While a similar expense exists at U.S. Gulf Coast refineries, about 60 percent of each barrel of typical California SJV heavy crudes must be coked versus about half that for crudes

[17] The primary source of prices is refiners' wholesale prices and sales volumes reported in EIA's Petroleum Marketing Annual for various years. Crude oil prices were obtained there also, with the exception of the imported crude prices and those for ANS oil. The latter is an average of ANS spot prices in Los Angeles, and the former is simply the ANS crude price plus $1.00 per barrel, a price typical of landed Indonesian crude oil.

[18] Realize that this comparison understates the difference between PADD V and the U.S. Gulf or East Coast refining areas because PADD V is part of the national average.

[19] PADD III consists of Alabama, Arkansas, Louisiana, Mississippi, New Mexico, and Texas.

characteristic of U.S. Gulf refinery inputs. At coker costs of $1.75 per residuum barrel processed,[20] the cost difference amounts to $0.51 per crude oil barrel.

This comparison overstates the cost difference for PADD V because the "average" barrel refined there is lighter than 13 degree API SJV heavy crude. In fact, the 1992 average API gravity of crude inputs in PADD V was about 25 degrees, versus 32.4 degrees for PADD III refineries and 31.3 degrees for the nation. Furthermore, the average sulfur content for crude oil inputs in PADD V was 1.19 percent versus 1.23 percent for PADD III and 1.16 percent for the nation. In summary, higher heavy oil processing cost in PADD V probably only account for about $0.25 to $0.50 per barrel of the higher gross margin.

Regarding meeting future environmental standards, the National Petroleum Council's recent report on refining suggests that the national average cost over the next few years will be in the range of $1.00 per barrel of refinery crude oil capacity. Built into these figures was an "industry judgement" factor that it is 40 percent more expensive to perform the same construction and operation in California than in the Gulf Coast area--the cheapest area (the PADD II factor was 20 percent).[21] Since this logic suggests that the national average cost of adding refinery capacity would be somewhat greater than that on the Gulf Coast, the additional environmental compliance expense for PADD V could be in the range of $0.20 to $0.40 per barrel.

Even if these two arguments are both true, then, taken together they amount to less than $1.00 per barrel, and may be as low as half that amount. The appropriate conclusion is that the gross margin differential between PADD V and the nation as a whole could amply support an increase in crude oil prices of $1.50 to $2.00 per barrel without necessarily causing an increase in consumer prices.

Inter-Market Arbitrage and Consumer Prices

The U.S. West Coast is geographically remote from the active Gulf Coast markets and those of the Pacific Rim. Yet, since California product prices are already at, or above, the other markets, there would seem to be limits to which prices could rise. To address this issue, we compared spot prices in California and Washington State to Singapore spot product plus transportation to the West Coast. We also examined California retail gasoline prices to assess the effect of changes in California crude oil costs. These analyses are detailed in Appendix G and summarized below.

[20] This is the sum of fixed and variable costs as set forth in Appendix III of the August 1993 National Petroleum Council report on refining.

[21] PADD II consists of Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, Oklahoma, South Dakota, Tennessee, and Wisconsin.

Regarding the Far East products market:

- o Although PADD V is a net product exporter, the balance in light products is delicate. In 1992, PADD V exported 46 mb/d of light products and imported 31 mb/d. In 1993, the figures were about the same. Canada is the largest source of imported gasoline, jet fuel and naphtha, but several cargos from Venezuela, the Virgin Islands, Korea, Singapore, Saudi Arabia, China, Thailand, and Mexico also appear each year. This means that some industry companies found it economically feasible to purchase and ship products to the West Coast despite the high costs of travelling long distances in small tankers.

- o When Singapore product prices are increased by the cost of transporting product to the West Coast, they are seen to be close to West Coast levels. A mix of Singapore gasoline could be sold in PADD V for prices that are only two to four cents above existing Los Angeles and San Francisco pipeline spot prices, and at parity with spot prices in Seattle. Similarly, jet fuel is within two to four cents per gallon of West Coast spot prices.

Thus, the examination suggests that, in some cases, it might be financially viable to send cargos past Singapore to PADD V if PADD V prices rise a few cents per gallon. It is important not to over-stylize import economics. Market prices should be viewed as random variables with distributions that probably center near the prices quoted in trade papers such as those employed in this study. The closer two prices are together, on average, in separate markets, the more often nimble traders will find it profitable to buy in one market and to sell into another. The fact that we see an occasional light product cargo being shipped to the West Coast from Pacific, South American, and Caribbean countries verifies this characterization.

To examine the effect of other markets on West Coast markets, we began by attempting to characterize gasoline prices in California as a function of crude oil costs that refiners pay. To test the assumption that refiners' gasoline pricing is a direct response to oil cost changes, we performed a large number of simple data regressions. The first set of regressions linked the average refiner retail gasoline price in California to crude oil prices in the State. The statistical relationship was very poor, no matter whether we used monthly or quarterly data.

That analysis led to considering gasoline prices in the Gulf Coast market. A statistical analysis of the last six years of monthly prices indicated that California gasoline price movements correlate much more strongly with Gulf Coast (Texas) gasoline prices than they do with California refiners' crude oil supply costs. This implies that there is market arbitrage that keeps West Coast product prices in line with outside sources, even though little product moves between the West Coast and other regions.

The statistical analysis we conducted was purposefully simplistic, but revealing. Clearly, there is some relationship between crude oil costs and gasoline prices because the raw materials cost is about one-half the price of the finished product in California (more than half in Texas). Nevertheless, it seems that small to moderate price changes in California's gasoline market are better explained by events that shape gasoline markets elsewhere than they are by differences in California crude oil prices.

These observations suggest, but do not prove, the existence of a link between U.S. Gulf and California gasoline prices that may dominate small changes in California crude oil prices. Whatever that link is, however, it is not evident in EIA's supply data because little gasoline is observed moving between the Gulf and West Coasts. Most of what does move is shipped via pipeline from El Paso, Texas, to Phoenix, Arizona, and does not directly affect the huge California market.

Nevertheless, one might conjecture that arbitrage between markets would keep prices linked, or, at least, limited to a maximum difference. As long as no event destabilizes the basis of arbitrage (e.g., a sharp increase in tanker rates), it remains effective in linking prices without a significant amount of physical deliveries taking place. This phenomena might be compared to that in the spot and futures markets for petroleum and other commodities. Spot and futures prices vary within narrow limits and ultimately converge despite the fact that very little physical delivery is taken as a result of futures contracts.

THE JAPANESE MARKET FOR ANS CRUDE OIL

Before World War II, Japan was a major purchaser of U.S. West Coast crude oil. The crude was not from Alaska, of course; it was Wilmington crude from North Los Angeles. An examination of Japanese petroleum consumption and refinery configurations suggests that a market exists there today for ANS crude oil.

Oil provides more than half of Japan's primary energy supply, and virtually all of it is imported. Table 2.3 shows that Middle East countries provided three-quarters of Japan's supply in 1992, up from 68 percent in 1988. The shift was associated with reduced imports from Indonesia and Mexico. Within the Middle East, the United Arab Emirates and Saudi Arabia picked up Iraq's market share.

Over 60 percent of Japan's crude oil is provided by the producing countries' national oil companies. Only 27 percent is supplied by the international oil majors.

Japan's over four million barrels per day of crude oil supply includes at least 500 mb/d of Middle East crudes in the 32 to 34 degree API range (Saudi Light, Iranian Light, etc.). In addition, there is another 100 to 150 mb/d in that gravity range available from other sources (e.g., Mexican Isthmus crude oil). Compared to the United States, Japanese refinery inputs are light (i.e., high API degree levels) due to the addition of large amounts of Abu Dhabi and Qatar crudes. Most of these Middle East crudes, although of higher API gravity, also have more sulfur.

Table 2.3 Suppliers of Japan's Crude Oil (% of Total)

	1988	1992
Middle East Total	**68.4%**	**75.2%**
Saudi Arabia	14.4	21.5
UAE	20.0	24.3
Asia Total	**17.4**	**14.8**
Indonesia	13.3	10.0
Africa	**0.7**	**0.4**
Americas	**5.4**	**2.3**
China	**7.8**	**5.9**

Source: PAJ Annual Review 1992, Petroleum Association of Japan.

Japan's petroleum consumption is distributed much more uniformly across the product barrel than in the United States. Gasoline constitutes only 15 percent of product demand, for example, compared to 50 percent in California. The result is that distillates and residual fuels are more important elements of the refining process than are lighter products. Within those categories of fuels, excessive sulfur detracts significantly from the value of the product and the crude oil from which it is refined.

The combination of using lighter crude oils and low gasoline production allows Japanese refineries, on average, to be less complex than their U.S. counterparts. ANS crude oil fits this situation well due to its relatively low sulfur content and its good yield of distillate and kerosene-range products. Appendix C addresses refinery considerations in detail, describing the many considerations that, together, infer that ANS is a good candidate for sales to Japan.

In summary, ANS crude is not only geographically convenient to the Japanese market, it is also compatible with Japanese refineries. No attempt was made here to extend the detailed analysis to other Pacific Rim countries, but we felt that potential markets exist there also. Singapore, Korea, and Taiwan add another 2.0 to 2.5 million barrels per day of refining capacity. Korea and Taiwan are similar in their product needs and almost as close to Valdez as Japan. A closer examination may be warranted to determine limits to the size of the total export market that exists. At this point in our review, however, we thought it sufficient to conclude that Japan provide a ready source of sales for several hundred thousand barrels per day, probably as a replacement for a like amount of Arab Light crude oil, or a mix of ultra-light and heavy middle cost crudes.

OIL PRICE PROJECTIONS AND THE WEST COAST SUPPLY/DEMAND BALANCE

Rather than attempt to reach a consensus of opinion among knowledgeable petroleum economists about the future of oil prices, we elected to use two distinct scenarios to bound the uncertainties. The paragraphs below describe those cases.

Oil Prices

The study considers low and high price scenarios. In the first, world oil prices stay constant in real terms through the remainder of the decade. In the second, there is $7.50 per barrel in real price growth during 1994 to 2000. These price paths, displayed in Table 2.4, are the high and low price paths from EIA's Annual Energy Outlook-1994 (AE094).

Initially, we thought the low price case would be most favorable to ANS crude oil exports. Therefore, we elected to make assumptions in the low price case that were export-favorable, and do the opposite in the high price case. This approach was favored over a point estimate base case analysis due to the fairly wide range of uncertainty involved in some areas.

ANS and California crude oil price statistics were examined to determine their historic relationships to world oil prices. The historic relationships we found were assumed to continue until the West Coast crude oil supply excess disappears through either a natural decline in domestic production or exports of ANS crude oil.

Table 2.4 World Crude Oil Prices (1992 $/Barrel)

	Low Price Case	High Price Case
1993	$16.14	$16.14
1994	15.43	17.50
1995	15.09	18.36
1996	14.89	19.43
1997	14.77	20.49
1998	14.85	21.70
1999	15.09	22.95
2000	15.44	24.16

Source: AEO94, and the Petroleum Marketing Monthly, EIA.

The West Coast Supply and Demand Balance

Product consumption and crude oil production in PADD V are two of the most important elements in this analysis. The method by which we established the balance and its future projections in the high and low price cases is described in detail in Appendix D. A few comments are appropriate here because the PADD V surplus is an integral component of the shipping discussion that follows.

Tables 2.5 and 2.6 describe the PADD V overflow in 1993 and subsequent years. In the low price case, the surplus disappears by 1997. In fact, there is a significant deficiency by 1997. At that point in this case, we assume that PADD V crude oil prices will rise to the level of imported foreign crude oils. Likewise, California heavy crude oil prices are also assumed to rise. Neither may be the case, but if a supply deficiency of 144 mb/d does not reduce the disparity in prices, then a few hundred thousand barrels per day of exports will not either.

In the high price case, the situation is substantially different. ANS production is higher (due to higher prices) and consumption is lower--thus, a larger surplus exists. Taken at face value, this scenario would seem to be one that would maximize the effect of exports on the U.S.-flag tanker fleet. That is, a higher surplus would require more tankers to transport it to the U.S. Gulf of Mexico, so exporting the surplus would eliminate more ships.

Table 2.5 ANS Crude Oil Surplus--Low Price Case

	ANS Crude Oil PADD V Surplus Distribution (mb/d)							
	1993	1994	1995	1996	1997	1998	1999	2000
PADD V Surplus	279	248	190	42	-144	-341	-539	-758
To Virgin Islands	97	84	84	0	0	0	0	0
To Mid-Continent	60	85	56	0	0	0	0	0
California Crude to Mid-Continent	53	53	50	42	0	0	0	0
ANS to Gulf Coast	69	26	0	0	0	0	0	0

Table 2.6 ANS Crude Oil Surplus--High Price Case

	ANS Crude Oil PADD V Surplus Distribution (mb/d)							
	1993	1994	1995	1996	1997	1998	1999	2000
PADD V Surplus	279	327	325	343	293	303	197	77
To Virgin Islands	97	100	100	100	100	100	57	0
To Mid-Continent	60	85	85	85	85	85	85	22
California Crude to Mid-Continent	53	55	55	55	55	55	55	55
ANS to Gulf Coast	69	87	85	103	53	63	0	0

At the same time, high prices keep crude oil production relatively robust, thereby eliminating much of the need for price-related actions. Because prices are high, the incremental production returns are lower in California (for reasons described in detail in Appendix E).

Our rationale (described in detail, Appendix D) in developing the distribution projections was as follows:

- o ANS oil shipments to the U.S. Gulf of Mexico via Panama would be the first non-PADD V shipments to be eliminated as the surplus falls.

- o ANS oil shipments through pipelines to the mid-continental United States would grow to 85 mb/d in 1994 due to increased pipeline capacity, and would stay at this level until the surplus disappears.

- o Shipments of ANS crude oil to the Virgin Islands would remain near their recent levels--about equal to pipeline shipments--until the PADD V surplus disappears (it is not clear that shipping ANS crude oil to the Virgin Islands is more or less profitable than shipping it to mid-continent refineries; we do not know the terms of crude oil pricing arrangements in these contracts).

- o The remainder of the surplus is assumed to be California crude oil shipped out on pipelines. Since this crude oil is now predominantly owned by All American Pipeline affiliated companies, the economics appear to be viable.

The PADD V surplus would continue throughout the decade if prices recover and remain high. Of note in the high price case are our assumptions that:

- o ANS oil shipments to the mid-continent are restricted only by pipeline capacity during most of the decade.

- o With ANS oil flowing through the All American Pipeline, it is likely that the pipeline's trading affiliates will still see it as economical to purchase and ship mid-California crudes eastward at their present rate.

- o Faced with a choice to ship to the Virgin Islands or sell in the U.S. Gulf of Mexico spot market, we believe that ANS crude sellers will take the former approach, Therefore, we kept Virgin Islands shipments near their highest historic levels until the surplus begins to disappear.

SHIPPING CONSIDERATIONS

A detailed, ship-by-ship examination of the current tanker fleet that carries ANS crude oil was made so that the effects of lifting the ban could be described properly. This was important because shipping costs are a significant component of profits and losses associated with exporting ANS crude oil. Many complex factors were involved, including:

- o Ports on the West Coast have restrictions that limit the size of a tanker that can be used to deliver oil there (e.g., Puget Sound is limited to tankers in the 120,000 deadweight tons (dwt) range or smaller). Other ports limit the amount of the larger ships' capacity that can be used (San Francisco's port has draft limitations, for example).

- o Tankers owned by ARCO and Exxon would tend to serve ports where those companies' refineries are located.

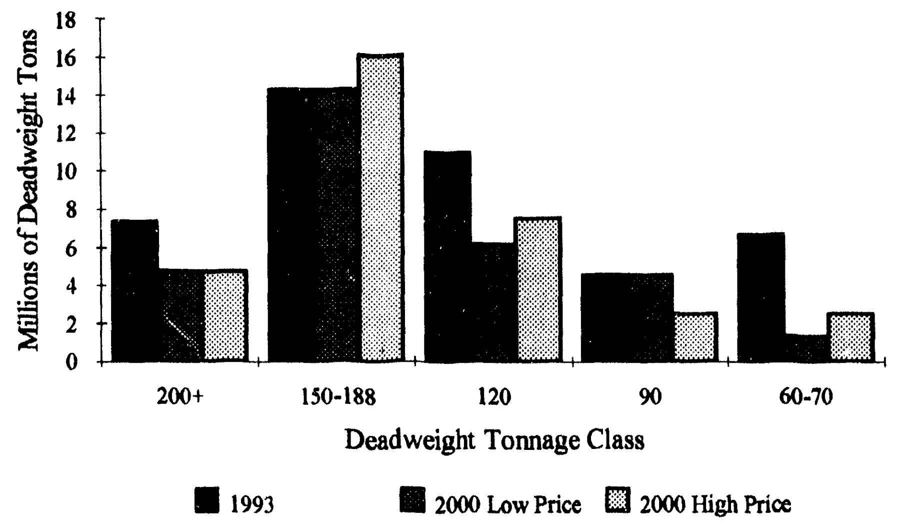
- o Before the year 2000, some ships will reach the dates that they must be rebuilt or retired due to the Oil Pollution Act of 1990 (OPA90).

This effort contained two main categories of analysis: sizing the fleet, and estimating shipping costs. These are summarized below and examined in greater detail in Appendix F.

Tanker Fleet Size

The 1993 ANS tanker fleet was comprised of 35 ships with a total of 4.4 million dwt of capacity, and supported 876 job slots. Figure 2.1 shows the distribution of tankers employed currently (1993), and our projections of the year 2000 fleet in both the high and low price cases.

Figure 2.1 Distribution of ANS Tankers -- 1993 and 2000



The 150 to 188 dwt class tanker is the "work-horse" of the fleet providing most of the capacity available. However, smaller tankers are still needed to serve some ports due to size and tankage limitations. In both projection scenarios, the most significant decline is in the smallest class of tanker. This is appropriate; in fact, charters of this class of vessel are currently down sharply from only a few years ago. The primary observations to make about the two scenarios we considered are:

- In the low price case, by the year 2000, the number of ships employed in the ANS trade will fall to 21, with 3.0 million dwt of capacity involved. The associated job slots will fall by 336 to 540.

- In the high price case, 29 ships with 3.8 million dwt of capacity will remain employed in the year 2000. Job slots will decline by 131, but will remain relatively high at 745.

These figures are used as the basis for examining the effects of ANS crude oil exports on the U.S. tanker fleet in the next chapter.

Shipping Costs

A number of variables affect shipping costs including:

- o Size of the ship (larger ships cost less per barrel of oil delivered);
- o Distance to be travelled (longer distances increase crew and fuel costs); and
- o Length of charter (long-term charters produce low rates at near operating costs, while short-term charters usually are higher as the ship owner attempts to recover costs of downtime between charters and to recover a portion of capital costs).

Table 2.7 displays tanker costs per barrel of oil shipped from Valdez, Alaska, to the ports that normally receive ANS crude oil. Also included are U.S.- and foreign-flag rates to Japan. Two calculations are shown: full cost, which includes capital recovery, and operating cost only. These are important distinctions because a company usually only incurs the true full cost for any single voyage when it charters another company's ship for a short period (otherwise the relevant cost is the marginal, or operating, cost).

In calculating tanker costs and their effects on revenue flows from the export of ANS crude oil, we used tankers' operating costs when the ships were owned or under long-term lease by the company transporting the crude oil. Thus, most of the crude moving to California, since it is transported largely on proprietary vessels, incurs only operating costs. Third-party, full cost charges are, for the most part, incurred when small ships are used. These tankers are predominantly owned by independent shipping firms.

It might be somewhat surprising to note that the cost to ship crude oil on an owned or long-term leased tanker to Japan is not much more than a foreign-flag vessel. Use of this lower cost is appropriate as long as the vessel is already under ownership or long-term lease by the exporter. In the first case, the capital cost is already expended; in the second, long-term chartering usually involves paying for the ship even if it is not used. Thus, both are the equivalent of sunk costs.

Employing already-owned or already-leased U.S.-flag vessels may actually cost less than using foreign-flag ships. Since taxes are paid on net revenues that consider the full cost basis of shipping if the vessels are owned or leased, employing U.S.-flag vessels leaves the exporter with slightly higher after-tax revenues. In computing severance and income taxes, full cost accounting for owned or leased tankers generally has a sheltering effect on the exporter's gross revenues.

Table 2.7 Crude Oil Shipping Costs (1992 $/Barrel)

Destination	Cost for Given Deadweight Tonnage (1,000 dwt) 200+	150-188	120	90	60-70
Operating Cost Only:					
Alaska	-	-	-	$0.46	-
Puget Sound	-	-	$0.37	0.47	$0.61
San Francisco	$0.98	$0.59	0.49	0.59	0.93
Los Angeles	0.32	0.37	0.52	0.73	0.82
Hawaii	-	-	0.58	0.75	0.81
U.S. Gulf of Mexico[a]	2.84	2.89	3.25	-	-
Virgin Islands	1.17	-	-	-	-
Japan U.S.-Flag	0.46	0.52	-	-	-
Japan Foreign-Flag	0.40	-	-	-	-
Full Cost Including Capital Recovery:					
Alaska	-	-	-	0.86	-
Puget Sound	-	-	0.85	0.92	1.06
San Francisco	1.47	1.08	1.14	1.17	1.53
Los Angeles	0.74	0.87	1.18	1.43	1.43
Hawaii	-	-	1.35	1.48	1.39
U.S. Gulf of Mexico[a]	3.61	3.88	4.54	-	-
Virgin Islands	2.66	-	-	-	-
Japan U.S.-Flag	1.18	-	-	-	-
Japan Foreign-Flag	0.40	-	-	-	-

[a] Includes the cost of the Trans-Panama pipeline and short-term, third party shipping in the Gulf of Mexico to the United States.

CHAPTER 3
FINDINGS AND CONCLUSIONS

SUMMARY

This chapter addresses the detailed findings of the study. Specific sections and their general conclusions are:

- o If ANS crude oil is exported from the West Coast to Japan, its value will be slightly higher than Arab Light crudes in Japan. In addition, exporting ANS from PADD V will raise its value there, along with the values of California indigenous crude oil.

- o Exporting ANS crude oil would stimulate imports of crude oil that is better suited to California's light product requirements, thereby improving refining efficiency. This will mitigate product price increases as crude oil market prices rise on the West Coast.

- o Higher crude oil prices would lead to better oil producer profitability, which in turn would raise investment in domestic oil production.

  - Incremental production in Alaska and California could be as high as 100 to 110 mb/d by the end of the decade.

  - Reserve additions in Alaska alone could be as large as 200 to 400 million barrels--a size that roughly equates to the known reserves in major North Slope fields such as Point McIntyre or Endicott.

- o Improving conditions for West Coast oil producers would raise revenues for the Federal Government and the States of Alaska and California. During the years 1994 to 2000:

  - Federal receipts related to royalties and sales of Elk Hills oil production would total between $99 and $180 million (1992 $).

  - Alaska would gain $700 million to $1.6 billion in State severance taxes, income taxes, and royalties.

  - California returns from the State share of Federal royalties and State and local taxes would be $180 to $230 million.

- o Exporting ANS crude oil would result in a substantial net increase in employment. In all cases examined, projected gains related to increases in oil industry investment and State and Federal revenues would be much larger than projected job losses in the U.S. maritime sector.

  - By 1995, the net increase in U.S. employment would be between 11,000 and 16,000 jobs. By the end of the decade exporting ANS crude oil could generate between 10,000 and 25,000 jobs. The range of estimates for the end of the decade is larger due to uncertainty about the future of oil prices in general.

- The estimate of the level of net job generation is relatively insensitive to whether ANS oil is exported on foreign-flag, U.S.-flag, or Jones Act tankers (U.S.-constructed and -crewed). Exporting oil in foreign-flag vessels would be the least expensive option, thereby generating higher returns for producers and the State and Federal governments. This would lead to the highest level of overall job creation, but would also produce the highest level of job losses in the maritime sector. Exporting ANS crude on U.S.-flag or Jones Act vessels would lower producer returns, oil production, and State and Federal revenues; but job losses in the maritime sector would be small. These differences offset, thereby eliminating the much of the sensitivity to the method of exportation.

o Tanker Fleet Analysis--The ANS crude trade part of the U.S. tanker fleet is projected to decline from the current 35 ships to 21 ships if low price conditions prevail, and to 29 ships under high price conditions.

  - Exports in foreign-flag vessels would retire 5 to 12 U.S. vessels in the low price case in 1995, and 11 to 19 tankers in the high price case. If the ban remains in place, these ships would be employed a few more years.

  - Requiring the crude oil to be exported in U.S.-flag or Jones Act vessels would reduce tanker losses to one or two small vessels. Incremental oil production in Alaska would restore the need for even tankers in a relatively short period of time.

o Environmental Considerations--We reviewed a number of potential environmental negatives associated with exporting ANS oil and found no significant related impacts. The arguments against allowing exports include: providing reasons for opening ANWR, increasing air emissions from refineries and production facilities, promoting offshore production activities, and the environmental risks inherent with waterborne oil shipments.

o The investment planning conducted by U.S. Department of Defense (DoD) is based on fleet projections for the turn of the century. The fleet projections that have been provided to DoD by the U.S. Maritime Administration (MARAD) have already taken into account reductions in the tanker fleet that are similar in magnitude to those projected under either of the price assumptions covered in this paper. Therefore, regardless of the price assumptions, the proposed changes to policies on ANS crude export will have no perceptible impact on DoD operations.

FRAMEWORK OF THE ANALYSIS

Our intent was to structure two general cases that would bound the assessment of the costs and benefits of exporting ANS oil. This was the approach that led to proposing two price paths and the two supply/demand scenarios discussed in Chapter 2 and Appendix D. We structured the high price case to favor retaining the ANS export ban, and the low price case to favor lifting the ban. This was because high oil prices perpetuate the PADD V crude oil supply excess, a situation that creates maximum U.S. tanker displacement if exports employ foreign-flag vessels.

As the study began, the focus was on exporting ANS crude oil in foreign-flag tankers. Two developments shifted the focus:

- o First, as shipping costs and the tanker fleet composition became available, it was obvious that exports could be carried to the Pacific Rim countries in U.S.-flag vessels already owned or leased by producers at costs that rival foreign-flag shipping.

- o Second, it seemed possible that some maritime employee unions would support lifting the ban if exports were required to use U.S.-flag or Jones Act vessels.

Therefore, three primary cases were considered: foreign-flag exports; U.S.- flag (not necessarily U.S.-constructed vessels) exports; and Jones Act vessels taken from the current Jones Act fleet. The primary differences between these three assumptions are:

- o If exports are permitted on world trade, foreign-flag vessels, there is ample supply, so transportation costs would be at world levels (about $0.40 per barrel to Japan).

- o If exports were restricted to U.S.-flag tankers, but not necessarily to U.S.-constructed vessels, transportation costs would increase slightly due to the requirement that the vessels are operated by U.S. crews. Shipping costs to Japan were estimated at about $0.46 per barrel. Given a permissive reflagging policy, there would be an ample supply of ships available.

- o In the final case, exporting vessels were assumed to be taken from the present Jones Act fleet. This has two cost implications:

    - Since there are a limited number of Jones Act ships, and the principal exporting company does not have direct access to the largest class of tanker (capable of transporting nearly two million barrels of oil per trip), the cost per barrel for exports would rise above $0.50 per barrel.

    - Removing some of the larger tankers from the domestic ANS trade may raise the average cost of transporting ANS oil domestically by one to three cents per barrel.

As we progressed through the analysis, it became increasingly obvious that the greatest gains would come when enough ANS oil was exported to raise PADD V prices to world levels. Because that point cannot be defined precisely, that led to evaluating several export levels for both the high and low price cases, and for each class of shipping.

For the two non-Jones Act shipping cases, the three export levels that were compared to the baseline, no-export case are:

- o Exporting only the PADD V surplus crude oil.

- o Exporting the surplus and 150 mb/d from PADD V supply as long as the PADD V supply surplus exists.

- o Same as the above except 300 mb/d is exported from the West Coast.

In the Jones Act shipping case, only one scenario was considered. It was assumed that exporters, due to tanker availability and size limitations, would choose only to export the crude oil that otherwise would be sold in the U.S. Gulf Coast market and 150 mb/d from the West Coast supply. In the near-term, this scenario is more realistic than the above assumptions because shipments to the Virgin Islands and through pipelines to the mid-continent are encumbered by contracts that would be difficult and expensive to abrogate.

Although all 14 of the cases were run through the study's models, the results were not sufficiently informative to display all of them here. The reason for this is that:

- o In the surplus-only export case, revenue generation and incremental crude oil production was low because we assumed that exports would not affect West Coast crude oil prices. The returns, therefore, were so small as to make it questionable whether a convincing case could be made to change ANS export policy. It is clear that shipping assets would be available and the incentive would exist to export more oil.

- o Exporting 300 mb/d plus the PADD V surplus did not return much over exporting 150 mb/d. This is because the value of ANS crude to the Pacific Rim refineries declines as the market becomes saturated. Furthermore, the value of ANS crude would rise substantially in the PADD V market. (Refinery valuations are discussed in the next section.)

To limit our discussion of results here, we chose to discuss these two cases qualitatively and to tabulate them in Appendix H.

REFINERY/TRADE FLOW ANALYSIS

The main objective of this part of our analysis was to estimate the potential impacts on crude oil prices that would result from lifting the export ban on Alaskan crude oil. Our quantitative analysis focussed on the Japanese market because Japan is the principal potential destination for Alaskan crude oil. However, the results would be generally applicable to other nearby Pacific Rim countries such as Taiwan and South Korea.

If the value of ANS crude in Japan minus the shipping cost from Valdez is higher than its value in California (or other parts of the United States) minus shipping costs, the "netback" to Valdez would be higher. If that was the case, ANS crude would be exported to Japan and financial benefits would accrue to the exporters--Alaska, California, and the Federal Government.

Refinery Simulation Models

Potential markets for ANS crude oil outside the United States can be evaluated vis-a-vis the U.S. market using simulation analysis with regional refinery models. Refinery simulations, as configured in this study, strive to meet a distribution of petroleum product consumption in the most efficient (least cost) manner. The primary way they do this is by picking crude oils that minimize total costs of transportation and processing.

As each case is solved, the model produces a marginal value for the "next" barrel of crude oil of each type. This value is taken as the market price for crude oil if the conditions of that case are met. Comparison of this imputed value of ANS crude oil in different regional markets sheds light on the potential movements of ANS crude oil once the export ban on ANS crude oil is lifted.

Two different models were used in our analysis. The first model, the Advanced Refinery Modeling System (ARMS), is a generic, single refinery model. The second model, the World Oil Refining Logistic Demand (WORLD) Model, is an 11-region world oil refining logistics demand model. In the latter, the western region includes the refineries of PADD V and western Canada. The model's Pacific region is dominated by Japan, but also includes other Pacific Rim countries such as Korea and Singapore. For simplicity, in the following paragraphs we will refer to both models as examining exports to Japan, but it should be remembered that the WORLD Model results address a much broader geographical range.

We chose two models to examine the valuation problem from narrow and broad perspectives. The WORLD Model is quite aggregated, and in linear programming models such as these, aggregation often produces over-optimization. That is a problem with ARMS also, but on a much smaller scale. Over-optimization tends to lead to higher oil valuations than are appropriate.

Differences in Japanese and PADD V Petroleum Markets

In Chapter 2, we made note of the fact that Japan has a much less gasoline-intense economy than the U.S. market (refer to Appendix C for the details of this examination). This dictates major differences between the refinery configurations and the crude slates of PADD V and Japan.

Simply stated, Japan's refineries use crude oil that is much lighter than PADD V, but of higher sulfur content on average. Japan imports virtually all of its oil--4.38 million barrels of crude oil per day in 1992--about 75 percent of which comes from the Middle East. The average sulfur content of imported crude oil for refining use was about 1.35 percent by weight and the average API gravity was higher than 35 degree API.

PADD V refinery receipts, by contrast, averaged about 25 degree API in 1992, with 1.2 percent sulfur. The difference in PADD V is due to the use of heavier California crude oils and ANS crude. One should bear in mind that although U.S. PADD V crude oils are relatively heavy, their sulfur content is low compared to other heavy crude oil, particularly that from the Middle East.

Without the severe demands of high gasoline production, Japanese refiners can meet product requirements with refineries that are of lower complexity than PADD V. Comparing the two regions reveals that:

- o In California, coker, hydrocracker, and fluid catalytic cracker are 24, 31, and 22 percent of the capacity of crude oil distillation capacity. In Japan, the percentages are 2, 15, and 3 percent.

- o In Japan, distillate and residual fuel desulfurization are 33 percent and 9 percent of the capacity of crude distillation. In California, the percentages are 14 percent and 5 percent.

The differences in the capacities of desulfurization units reflect Japan's much greater demand for distillate and residual fuel oil, and environmental restrictions on the sulfur content of these fuels. The sulfur problem is less severe in California because much of the residual oil that cannot be refined into gasoline or light products is sold as ship fuel in the international bunker fuel market. There, sulfur is not a problem at all.

Even with its low-complexity refineries, in Japan the existing crude oil mix has too much gasoline producing capability. This makes ANS crude a good product to meet Japan's demand for kerosene and middle distillates.

Effect of ANS Crude Exports on Crude Oil Valuation

Simulation results from both the ARMS and the WORLD Models show that Japan or the Asia-Pacific region would import ANS crude oil if the ban on ANS oil exports is lifted. But what would be the value of ANS oil in those markets? The answer lies in the valuation of ANS crude relative to other oils traded in the world oil market. If a foreign refinery values ANS oil more than U.S. refiners in the West Coast, there will be exports.

We obtained results from the two models that were identical in direction, but dissimilar in magnitude. That is:

- o Japan's refineries valued ANS crude oil higher than Arab Light, but the magnitude of the premium declined as more that was used there. We attribute most of the increase in value to ANS crude oil's ability to produce lower sulfur fuel oils and to its kerosene and middle distillate yield.

- o The value of ANS crude oil to California/PADD V refineries increases as its availability falls. This is because removing ANS crude oil makes room for importing lighter crude oil that is more compatible with gasoline production. Refining lighter crude oil makes more of the heavy oil processing equipment discussed above available so that the marginal barrel of ANS oil, and California crude oil also, have higher values.

Table 3.1 shows the results for Japanese refineries from the two models. For a given level of ANS oil imports, the more aggregate WORLD Model estimates the value differential between ANS oil and its potential competitor, Arab Light, as two to three times as high as the less aggregate model. Table 3.2 shows that the WORLD Model produces consistently more ANS-favorable results for PADD V also.

Table 3.1 ANS Crude Oil Valuation in Japan Versus Arab Light Crude Oil (1992 $)

Japan's ANS Crude Import Level (mb/d)	Additional Worth of ANS Crude Oil Versus Arab Light Crude Oil: ARMS Model	WORLD Model
0	$0.55	$1.47
300	0.39	0.85
600	0.13	0.49

Table 3.2 Effect of Exports on the Value of ANS Crude Oil on the West Coast (1992 $)

Reduction in PADD V ANS Crude Supply (% of Total)	Increase in the Value of ANS Crude Oil: ARMS Model[a]	WORLD Model[b]
10%	$0.16	$0.29
20	0.37	0.63
30	0.63	1.03

[a] Includes complex refineries in California only.
[b] Includes all refineries in the Western Region, which encompasses Washington State and western Canada.

Modeling Representation

To remain on the conservative side, we chose to use the ARMS Model results to adjust the ANS crude value in both markets in the low price case. We thought that the WORLD Model offered valuable insights into trade flows but more time was needed to calibrate the model to historic relationships. To implement the results, we fit curves to ARMS Model results that modified ANS crude value in Japan and in PADD V as a function of export levels.

The important relationship that came from this analysis was that ANS crude value rises in PADD V as it is exported, and it falls in Japan. This has intuitive appeal. More important, it suggests that, at some point, it is no longer advantageous to send ANS oil to Japan due to the changing valuation relationships. We found this point to be somewhat less than exporting the PADD V surplus supply plus 300 mb/d from the West Coast and contributed to our de-emphasis of this case.

In general, we attempted to make assumptions for the high price case that were negatively oriented toward ANS oil exports. Examples are those assumptions that resulted in a larger PADD V surplus for a longer period of time. To be consistent with that philosophy, we assumed that ANS crude would only sell at parity with Arab Light crude oil in both the California and Japanese markets.

This assumption has particular significance for California. It means that there is no advantage in exporting more than the amount that causes the ANS market price to rise to world levels. For this reason, in the case of California there is no difference in the high price case results for the 150 mb/d and 300 mb/d export cases.

Finally, we examined the value of California heavy crude oils as ANS crude is exported. Kern River crude oil is used as an example in Table 3.3, which shows increases in the refinery valuation of the heavy crude oil as ANS oil is exported. The ARMS Model showed that Kern River crude oil valuation would rise penny for penny with ANS oil valuation (at complex refineries), while the WORLD Model gave it an edge at higher export levels.

Table 3.3 Effect of ANS Crude Oil Exports on the Value of Kern River Heavy (13 Degree API) Crude Oil

Reduction in PADD V ANS Crude Supply (% of Total)	Increase in the Value of Kern River Crude Oil (1992 $): ARMS Model[a]	WORLD Model[b]
10%	$0.15	$0.21
20	0.37	0.65
30	0.64	1.34

[a] Includes complex refineries in California only.
[b] Includes all refineries in the western region which encompasses Washington State and western Canada.

In Chapter 2 we noted that, at the California wellhead, heavy crude oil is under-valued. The distinction between wellhead and refinery value is important. We show that exports will increase the value of California crudes to refiners. Because refiners set the price for it at the wellhead (refiners are the posters for crude oil and control the means to transport it to the refineries), to realize these refinery value increases, they will have to be willing to increase postings along with the open market prices for ANS. Our analysis (in Appendix B) indicates that refiner/posters historically have maintained the relationship between ANS and heavy crudes by allowing only about 73 percent of the market price increase at the wellhead.

Effects on U.S. West Coast Product Prices

An increase in the price of ANS crude oil on the West Coast would raise the value of other crude oils produced in that region. In addition, higher-priced, but better quality imported crude oils would be used to replace exported ANS oil. As a result, the average acquisition cost of crude oils would increase.

The magnitude of changes in prices for refined products depends on factors such as savings in processing costs that could be achieved due to purchase of lighter crude oil, refiners' ability to change refinery configurations in response to changing market conditions, and relative increase in refinery crude oil acquisition costs. Price changes, however, would not be the same for all products.

Price increases for lighter products such as gasoline would be expected to be very small due to two major factors.

- o First, the exportation of ANS crude and the importation of gasoline-producing crude oils would reduce refiners' processing costs, which could offset all or part of the increase in refiners' crude oil acquisition costs.

- o Second, all other things being equal, refining lighter foreign crude oil would reduce production of residual fuel, which is effectively a waste product on the West Coast. It typically sells for less than crude oil prices in the ship bunker fuel market. Our refinery analysis showed a positive return for reducing residual fuel production at complex refineries.

If refining lighter crudes resulted in being able to produce the same amount of light product that was the case using an ANS crude-heavy refiner input mix, the increase in refinery "efficiency" would mitigate the increase in product price increases.

Crude Oil "Netback" Analysis

The preceding analysis was conducted for the primary reason of estimating the potential increase in prices that would appear if exports were permitted. The fundamental component of this analysis is the netback value of ANS crude oil at Valdez. Table 3.4, presents a simplified view of this computation.

Table 3.4 ANS Export Netbacks to Valdez[a]

		ANS Exports from PADD V (1992 $)	
	Current Situation (No Exports)	150 mb/d	300 mb/d
West Coast ANS Price	$14.09	$15.70	$15.92
Shipping from Valdez	0.52	0.52	0.52
Valdez Netback	13.57	15.18	15.40
ANS Price in Japan	15.44	15.25	15.13
Shipment from Valdez	0.40	0.40	0.40
Valdez Netback	15.04	14.85	14.73
Netback Differences	1.47	(0.33)	(0.67)

[a] The price of Arab Light (including cost, insurance, and freight (c.i.f.)) in Los Angeles is $15.42.

In the static situation, ANS crude oil marketed in Japan would bring about $1.47 per barrel more revenue to an exporter than selling it on the West Coast after considering transportation costs. The value of ANS crude oil in Japan is based on a Japan-landed price for Arab Light crude of $14.95 plus a $0.46 refining premium for ANS crude.

As ANS crude is shipped to Japan, its refinery premium falls so that, at the 150 mb/d level shown, it would bring $15.25. At the same time, the value of ANS crude in California would rise to the value of Arab Light ($15.42 landed in Los Angeles) plus a small refining premium. The 300 mb/d case simply carries this analysis one step farther.

From the table, it might seem that exporting 150 mb/d to Japan would be losing $0.33 per barrel compared to shipping the oil to California. While this is true on the margin, the no-export alternative is a Valdez netback of $13.57. The 150 mb/d export case may seem somewhat sub-optimal, but the level of exports that would cause ANS crude West Coast price to rise to "world levels" cannot be predicted precisely--either in this analysis, or by a prospective exporter. Even though it seems that money is being lost, that is not the case if the alternative to exports is to accept the current market price in PADD V.

This netback calculation provided the basis for calculating oil company investment revenue, Federal and State income, and employment.

PRODUCER/EXPORTER REVENUES

Incremental oil producer revenues would be generated by higher sales prices for domestic oil sales, higher prices gained by sales in the Far East markets, and by lower transportation costs. After calculating how much companies would net from increased crude oil sales revenues, Federal, State, and local taxes and royalties were subtracted to yield after-tax revenues.

More than one-half of ANS crude production and 75 percent of California production is refined by the integrated producer/refiners that own the crude, or traded it for crude that is more conveniently located. The "market price" of this crude is only a transfer price between two divisions of the same company, so it was not considered to produce investment revenue.

Producers' incremental revenue flows, as shown in Table 3.5, are important determinants of the study results. The table shows that:

- o In the low price case, incremental revenues would disappear after 1996 because it is assumed that market prices for ANS and California crude oil would rise to "world levels" even if the ban is not lifted. However, investment during 1994 to 1996 would raise oil production in the later years. We ignored the additional investment revenue that this would generate, but included the taxes and revenues that it would generate.

- o In the high price case, lower returns for the 1994 to 1996 period would result from omission of the refining premium for ANS crude oil on the West Coast and in Japan. However, because the surplus continues through the year 2000, incremental revenue generation would persist throughout the decade.

- o The U.S.-flag export case would create slightly higher revenues than the foreign-flag export case despite higher shipping costs, due to tax shelter considerations associated with investment cost recovery for company-owned tankers.[22]

- o In the Jones Act shipping case, high cost domestic shipments to the Virgin Islands and mid-continent are not exported, thereby lowering producer returns.

Table 3.5 Cumulative Oil Company Investment Potential (Millions of 1992 $)

	Low Price Case			High Price Case		
Type of Export Tankers	1994-1996	1997-2000	Total	1994-1996	1997-2000	Total
Foreign-Flag:						
Alaska	$455	$1	$456	$334	$426	$760
California[a]	158	0	158	122	169	291
Total	613	1	**614**	456	595	**1051**
U.S.-Flag:						
Alaska	480	1	481	376	477	853
California[a]	158	0	158	122	169	291
Total	638	1	**639**	498	646	**1144**
Jones Act:						
Alaska	425	0	425	317	414	731
California[a]	158	0	158	122	169	291
Total	583	0	**583**	439	583	**1022**

[a] Only ANS revenues are affected by the type of shipping employed. Therefore, California investment revenues are identical in all three cases.

OIL PRODUCTION

The methodologies employed to calculate incremental crude oil production are discussed in detail in Appendix E. In summary:

- o For Alaska, after-tax revenues from the exporters (not all ANS producers) were used to invest in expanding the reserve base. New reserves were put into production and reached peak production after four years, then began a slow decline. The effect of this modeling process is that production in response to a price increase builds throughout the decade, even in the low price case.

[22] If U.S.-flag shipping is employed for the exports, then taxes, and royalties would be computed employing full capital recovery (or depreciation) in the cost of shipping. This creates a tax "shelter" that is not present if foreign-flag shipping is chartered from an unaffiliated third party. The tax shelter effect slightly increases production for the U.S.-flag case, and lowers Alaska revenues.

- A more complex investment model was constructed to represent the California situation. The model responds to price changes, but implicit in the formulation was that incremental revenues were reinvested by producers.

Incremental production in the early years is projected to be small, but would build throughout the decade to levels that are slightly over 100 mb/d. Put in context, 100 mb/d is slightly more than the amount of daily production some expect to see from Point McIntyre or from one of the California offshore fields like Point Arguello or Santa Ynez.

In the case of Alaska, producers' after-tax revenues were assumed to be invested in activities that yielded reserve additions at the current rate of $2.05 per barrel. Data in Table 3.5 imply that reserve additions in the range of 200 to 400 million barrels could be produced by exporting ANS crude. By comparison, the known reserves remaining (in today's economic conditions) in Prudhoe Bay total about 3.5 billion barrels. Current reserves at Endicott and Point McIntyre, major secondary fields on the North Slope, are 262 and 356 million barrels respectively.[23]

Production potential is based on full reinvestment of producers' after-tax revenues in domestic oil production. This is a very reasonable assumption for California independent refiners, but one that some might consider questionable for ANS producers. Examination of financial statistics for ANS producers showed little difference from the average of all large integrated companies in the extent to which revenues have been reinvested in the United States. Currently, foreign investment offers a higher return for larger companies than domestic development activities.[24] If exporting ANS crude oil increased rates of return for ANS production, the tendency would certainly be to increase investment over what would otherwise be the case.

Table 3.6 shows the production response potential in the three export cases. Of note is that the total production response is relatively insensitive to the method of shippers chosen. The ANS production response in the high price case is greater than the low price case, but this is offset by lower incremental California production. California productions price elasticity is much higher at low world oil prices than it is at the levels assumed in the high price case.

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[23] "Historical and Projected Oil and Gas Consumption," Alaska Department of Natural Resources, February 1994.

[24] Performance Profiles of Major Energy Producers--1992, EIA, January 1992.

Table 3.6 Oil Production Potential (mb/d)

Type of Export Tankers	Low Price Case By 1996	Low Price Case By 2000	High Price Case By 1996	High Price Case By 2000
Foreign-Flag:				
Alaska	11	54	8	63
California	18	53	7	33
Total	29	107	15	96
U.S.-Flag:				
Alaska	11	57	9	71
California	18	53	7	33
Total	29	110	16	104
Jones Act:				
Alaska	11	54	8	60
California	18	53	7	33
Total	29	107	15	93

FEDERAL AND STATE REVENUE

The primary sources of revenues for the Federal Government and the States of California and Alaska are:

- Alaska--Alaska's 12.5 percent royalty and 15 percent severance tax produce most of the State's returns.

- California--Revenues come from a share of Federal royalties, State and local income and property taxes, and the State share of a producing field near Long Beach, California.

- Federal--Receipts are the sum of royalties on California production and sales price increases for DOE's 50 mb/d production at Elk Hills, California.

Federal oil income is significant only for California. The sources are:

- Elk Hills Sales--The increase in wellhead prices in California also apply directly to Federal Government sales of oil from Elk Hills. Elk Hills production currently is approximately 50 mb/d.

- Onshore Royalties--The royalty rate is 12.27 percent of oil value for a declining production level initially equal to about 50 mb/d. Incremental onshore royalty revenue is produced by both a price increase and incremental production. California receives half these royalties.

- Offshore Royalties--The offshore royalty rate is 16.86 percent of production value, of which the State receives 3.3 percent. We assumed that no incremental offshore production would occur.

These revenue sources are entirely dependent on the extent to which California crude oil prices rise. That is, the method of shipping exports does not influence revenues associated with California. Table 3.7 shows the details of Federal receipts that are derived from improvement in the California oil market.

Table 3.7 Federal Revenue Detail-California
(Millions of 1992 $)

	Low Price Case			High Price Case		
	1994-1996	1997-2000	Total	1994-1996	1997-2000	Total
California Royalties						
Onshore	2.2	2.9	5.1	1.6	4.3	5.9
Offshore	35.5	0.1	35.6	26.5	42.3	68.8
Total Royalties	37.7	3.0	**40.7**	28.1	46.6	**74.7**
Elk Hills Sales	58.0	0	**58.0**	44.0	61.0	**105.0**
Total	**95.7**	**3.0**	**98.7**	**72.1**	**107.6**	**179.7**

Table 3.8 presents estimates for State revenue. The diversity of sources of revenue, some of which are the product of increased oil prices, implies that financial returns would begin soon after the ban is lifted.

Table 3.8 Cumulative State Revenue
(Millions of 1992 $)

	Low Price Case			High Price Case		
Type of Export Tankers	1994-1996	1997-2000	Total	1994-1996	1997-2000	Total
Foreign-Flag:						
Alaska	$667	$179	**$846**	$610	$1019	**$1629**
California	102	79	**181**	74	156	**230**
U.S.-Flag:						
Alaska	612	189	**801**	521	942	**1463**
California	102	79	**181**	74	156	**230**
Jones Act:						
Alaska	562	164	**726**	450	820	**1270**
California	102	79	**181**	74	156	**230**

THE EFFECT OF ANS EXPORTS ON THE U.S. MARITIME FLEET

Table 3.9 shows the number of tankers and seafarer billets (job slots) that would be eliminated if exports were made in foreign-flag tankers. Current staffing levels in the U.S. maritime fleet imply that each billet supports 2.36 jobs (i.e., seafarers, on average, actually work at their maritime jobs something less than six months per year). As noted earlier, these losses would be immediate if exports were permitted. However, they would occur within the next few years as ANS oil production declines, even if the export ban was not lifted.

Table 3.9 Tanker and Seafarer Billet Losses Due to Foreign-Flag Exports of ANS Crude Oil[a]

	Low Price Case		High Price Case	
	Tankers	Billets	Tankers	Billets
1994	10	268	15	396
1995	7	187	15	396
1996	6	159	14	375
1997	4	101	12	321
1998	0	0	8	200
1999	0	0	4	101
2000	0	0	5	134

[a] "Losses" are the year-by-year differences between the no-export case and the case where the PADD V surplus supply of crude oil is exported along with 150 mb/d from PADD V supplies.

Transportation costs for exporting ANS crude in U.S.-flag tankers are only slightly higher than foreign-flag tanker costs. As shown earlier, there is little difference in financial measures or oil production if exports were required to be carried on U.S.-flag or Jones Act tankers. This is because most of the U.S.-flag tanker capacity is owned (or leased long-term) by ANS producers and the out-of-pocket cost to a producer-exporter is only the operating cost of the vessel (fuel, maintenance, and crew costs). This approximates market charter rates for foreign-flag tankers.

If exports were required to be shipped on U.S.-flag or Jones Act tankers, tanker and job losses of the magnitude shown in Table 3.10 would not occur. Large tankers would be employed to export oil, but the distance to Pacific Rim ports is over half again as far as the distance from Valdez to California. These offset to a great extent so that the likely loss in tanker requirements is one or two small vessels with a total of no more than 50 billets.

Production of Alaskan crude oil could increase by 50 to 70 mb/d by the year 2000 if ANS crude oil was exported. A 120,000 dwt tanker can transport 45 mb/d of crude oil from Valdez to Los Angeles, so incremental production could restore the need for one or two medium class domestic tankers--thereby offsetting the losses in the U.S.-flag or Jones Act cases.

While seafarer jobs losses would be mitigated if exports are restricted to U.S.-flag shipping, this limitation would not address the concerns of the U.S. ship building industry. Starting in the late 1990s, OPA90 double hull requirements will force replacement of, or extensive modification to, most of the tankers in the U.S. fleet (foreign tankers that serve U.S. ports also will have to meet the terms of OPA90. If foreign-built tankers could be reflagged and operated in the ANS oil trade, thereby minimally satisfying the U.S.-flag requirement, then new OPA90-compatible tankers would be built overseas at lower cost. If exports were carried on Jones Act-compatible tankers, this issue would become moot because the Jones Act would require U.S. construction to satisfy OPA90 requirements.

EMPLOYMENT ANALYSIS

Methodology

Employment impacts are estimated using BLS employment coefficients. Reported direct and indirect employment are "first round" effects, i.e. employment from increased production includes field workers, oil service workers, and workers providing materials used in production activity.

Induced employment (employment due to expenditures by direct and indirect employees) was calculated separately, but is combined in the results shown below. Induced employment is calculated at a rate of 20 jobs per million dollars in direct and indirect employment income as recommended by BLS.

Investment

Estimates of increased investment in oil activities are based on the pricing and investment analysis outlined in the above sections.

Lifting the export ban will raise the price of ANS crude oil from an artificially depressed level. Furthermore, the bulk of the increase in ANS crude prices will be mirrored in California crude prices. In both Alaska and California, higher crude market prices encourage increased investment and subsequent production.

ANS exports and the attendant increase in crude oil prices are not likely to cause significant employment or investment losses in the refining sector of the economy. Refinery capacity in the United States fluctuates with petroleum product consumption, not marginal refining economics. Refineries do indeed go out of business, but if product consumption dictates, they often open under new management.[25] Despite dire predictions of impending increases in product imports due to deteriorating refinery margins, petroleum product imports to the United States have remained less than 10 percent of petroleum supply for 20 years. In the last five years, imports have fallen to five percent of domestic petroleum supply. Therefore, our base estimates assume no displacement of domestic investment resulting from higher crude prices.

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[25] One large West Coast independent refiner, for example, as part of its ANS crude oil supply agreement, must offer its refinery for sale to the crude oil supplier if its financial condition dictates a sale or closing.

Government Revenue

Higher oil prices and production increase government revenues at the State level and county levels. We assume that incremental revenues are distributed to residents in the form of tax deferrals or reductions.

As an alternative, we considered a situation where State and local governments use all incremental revenue to increase services by hiring additional personnel. This case results in the creation of about 9,800 to 11,200 additional jobs in 1995, and between 2,900 and 10,900 additional jobs in the year 2000.

Maritime

Direct maritime employment is calculated from information supplied by MARAD on billets per tanker and jobs per billet. Indirect effects are calculated using the ratio of BLS indirect to direct employment in waterborne transportation. This produces a significantly larger employment effect than simply using the BLS multipliers (jobs per million dollars per year) with revenues lost from the U.S. shipping industry due to foreign-flag exports. For this reason, the indirect maritime job losses estimated in this report probably are overstated.

As incremental Alaskan production increases, more maritime jobs would be created to transport the oil to lower 48-State refineries. This additional employment can be estimated by noting that, on average, one tanker would be required per 45 mb/d of oil production increase. With about 25 billets per tanker, 59 direct jobs are created per 45 mb/d of incremental Alaskan production.

State and Regional Impacts

Although the employment analysis is national in scope, some inferences can be drawn regarding impacts in individual areas. California and Alaska, which directly benefit from increased investment, oil production, and government revenues, realize the bulk of direct and indirect job gains. The employment coefficients of the Department of Commerce Bureau of Economic Analysis Regional Input-Output Multiplier System II (BEA RIMSII) model suggest that California retains a much larger proportion of total direct, indirect, and induced jobs from investment and oil production within its borders than does Alaska, as shown in Table 3.10. This outcome reflects the greater ability of the diverse California economy to supply specialized inputs and satisfy induced demand from internal production.

Table 3.10 In-State Multipliers for Total of Direct, Indirect, and Induced Employment Per Million Dollars of Output (1989 $)

Activity	California	Alaska
Crude Petroleum and Natural Gas Production	7.5	4.0
Investment		
New Construction	26.5	10.0
Maintenance and Repair	31.1	16.9
Non-Electric Machinery	23.7	13.9

Findings

Lifting the ANS export ban would have a positive net impact on potential U.S. output and employment, even after considering the impacts on the maritime sector. For oil related activities:

- o Lifting the ANS ban would have the potential to increase direct and indirect employment in oil-related investment, oil production, and through the employment effects of State tax deferrals for citizens by between 6,500 and 9,700 jobs in 1995 and between 5,400 and 13,900 jobs in 2000 (depending on which mode of export shipping is used). Potential employment increases would be even larger if incremental government revenues were used in whole or in part to increase State and local government employment.

- o Induced employment (i.e., employment due to expenditures by direct and indirect employees) was estimated separately. Induced employment due to increases in oil-related investment, oil production, and State tax deferrals would range from 5,100 to 7,700 in 1995 to 4,700 to 11,500 in 2000.

The potential increases in direct and indirect employment outside the maritime sector would be significantly larger than the maximum potential adverse impact on maritime employment. The maximum direct and indirect job losses in the maritime sector are estimated to be between 300 and 2,400 jobs in 1995 and between zero to 800 jobs in 2000. In addition, we note the following:

- o If ANS exports are carried on foreign-flag ships, the adverse effect on maritime employment would end when the PADD V surplus disappears--by 1997 in the low price case.

- o If ANS exports are carried on U.S-flag or Jones Act ships, relaxation of the export ban could actually offset most of the direct and indirect maritime employment losses as more oil is produced and shipped.

As a quick check on these results, we note that increased net oil production in the year 2000 would contribute approximately $520 to $560 million (1992 $) to real GDP in the low price case. Application of a rule of thumb of one job per $50,000 increase in GDP would result in an estimated 10,400 to 11,200 additional jobs associated with oil-related revenues.

Table 3.11 displays the aggregate results of the employment analysis. There it is clear that exporting ANS crude oil would result in a substantial net increase in employment. In all cases examined, gains related to increases in oil industry investment and State and Federal revenues would be much larger than job losses in the U.S. maritime sector.

- o By 1995, the net increase in U.S. employment would be between 11,000 and 16,000 jobs. By the end of the decade exporting ANS crude oil could generate between 10,000 and 25,000 jobs. The range of estimates is larger due to uncertainty about the future of oil prices in general.

- The estimate of the level of net job generation is relatively insensitive to whether ANS oil is exported on foreign-flag, U.S.-flag, or Jones Act tankers (U.S.-constructed and -crewed). Exporting oil in foreign-flag vessels would be the least expensive option, thereby generating higher returns for producers, and for the State and Federal governments. This would lead to the highest level of overall job creation, but would also produce the highest level of job losses in the maritime sector. Exporting ANS crude on U.S.-flag or Jones Act vessels would lower corporate returns, oil production, and State and Federal revenues, but job losses in the maritime sector would be small. These differences offset, thereby eliminating the sensitivity to the method of exportation.

Table 3.11 Direct, Indirect, and Induced Employment

	Low Price Case		High Price Case	
Type of Export Tankers	1995	2000	1995	2000
Foreign-Flag:				
Oil Related	17,320	10,574	13,936	24,343
Maritime	(1559)	0	(3,301)	(1,117)
Net	15,761	10,574	10,635	23,226
U.S.-Flag:				
Oil Related	16,790	10,889	13,219	25,362
Maritime	(417)	0	(417)	(417)
Net	16,373	10,889	12,802	24,945
Jones Act:				
Oil Related	15,320	10,122	11,677	23,295
Maritime	(417)	0	(417)	(417)
Net	14,903	10,122	11,260	22,878

ENVIRONMENTAL IMPLICATIONS

Protection of the environment is a primary consideration in all energy policy decisions of the Clinton Administration. We therefore reviewed, with assistance from the U.S. Environmental Protection Agency, the implications of lifting the export ban from the perspective of environmental quality in both Alaska and California, and the potential for environmental risks from oil transportation.

Our review found no plausible evidence of any direct environmental impact from lifting the ANS crude export ban. This conclusion follows from the historical decline in California production levels and the structure of California's environmental regulation. When indirect effects are considered, it appears that the market response to removing the ANS crude export ban could result in a production and transportation structure that is environmentally preferable to the status quo in certain respects.

ANS and ANWR

Lifting the ANS crude export ban will have no adverse impact on ANWR. The Administration, with strong support in Congress, firmly opposes exploration, development, or production activities in ANWR. The Administration views ANWR and lifting of the ANS export ban as distinct issues. The ANWR policy was not reviewed as part of the export ban review, and there are no plans for any such review.

The only apparent potential for the current ANS crude review to intersect concerns related to ANWR arises in the event that some future Administration might propose to reverse our ANWR policy. In this regard, lifting the export ban appears to weaken the case for opening ANWR because it would be difficult politically to argue for opening ANWR while exporting ANS crude oil.

To a degree, lifting the ban on ANS oil exports would offset a future impetus to open ANWR. Company reinvestment of incremental revenues derived from lifting the ban could expand recoverable reserves within currently developed areas on the North Slope by 200 to 350 million barrels between 1995 and 2000. This amount equates in magnitude to a 10 percent extension of remaining reserves at Prudhoe Bay. In comparison, the remaining reserves at the Endicott and Point McIntyre Fields, considered major contemporary North Slope developments, are 262 million and 356 million barrels, respectively.

The ANS Crude Export Ban and the Trans-Alaskan Pipeline System

Lifting the export ban will not require expansion of the Trans-Alaskan Pipeline System (TAPS) and related infrastructure. The natural decline in North Slope field productivity will keep total Alaskan production far below the design capacity of the current TAPS pipeline and related infrastructure, regardless of the modest increase from a declining baseline production level that could result from lifting of the export ban. Environmental emissions associated with the operation of TAPS will also decline over time as throughput decreases from design capacity.

By the middle of the next decade, ANS production is projected to fall sharply. Examination of the North Slope oil production decline curve shows that incremental production associated with lifting the ANS export ban would extend the economically viable lifetime of TAPS by no more than two or three years.

Tanker Operations and the Potential for Environmental Damages

Lifting the export ban will reduce overall tanker movement in U.S. waters. While shipments out of Valdez will rise with incremental increases in Alaska production (although still declining with respect to historical levels over time), tanker movement in California waters will decline as increased onshore production resulting from higher prices meets a larger share of California's oil requirements.

Lifting the export ban may also reduce oil transportation risks by eliminating movements of ANS oil to the Gulf Coast that involve multiple loading and unloading operations. Two considerations suggest that the imported oil that replaces exported ANS oil may reduce environmental risk.

- o First, imported oil will tend to be shipped directly to high-volume ports such as Los Angeles and San Francisco, rather than to be carried down the Canadian and U.S. coastline, as now is the case with Alaskan oil.

- o Second, since imported oil generally would be lighter than ANS oil, a future spill would tend to leave less residual damage.

Eliminating the ANS crude export ban does not change requirements of OPA90 on either foreign and domestic tankers loading or discharging oil in U.S. ports.

California Air Quality Considerations

Our review of air quality implications included refinery emission, refinery volumes, oil field emission, and sulfur content. Conclusions are:

- o Refinery Emissions--Lifting the export ban should not affect the level of emissions at California refineries. Refineries are subject to a variety of emission restrictions involving absolute emission caps, technology requirements, and emission rate limitations. In general, refinery emissions in California non-attainment areas are subject to absolute caps, often including a reduction schedule dictated by California regulations.

- o Refinery Volumes--The absolute amount of crude oil input required to meet California product needs will decline slightly in the near term, as imported oil that provides a higher proportion of gasoline is substituted for ANS oil.

- o Oil Field Emissions--California heavy oil producers are subject to strict permitting constraints and offset requirements that will prevent any increase in emissions as production activity rises.

- o Average Crude Oil Sulfur Content--Imported oil that would substitute for exported ANS oil will have a lower sulfur content than ANS oil. Even after full phase-in of increased California production, the weighted average sulfur content of California and imported crude would be lower than that of the ANS crude it will replace. Processing lower sulfur crude oil would tend to lower the sulfur content of refinery emissions and, all other things being equal, would reduce the sulfur in petroleum products produced in California refineries.

California Offshore Areas

California offshore activities are limited by drilling moratoria in effect in most areas, and by limitations relating to the siting of onshore facilities imposed by State, county, and local governments.

Given an environment where regulation rather than price is the controlling factor, we anticipate that the small price changes associated with removal of the export ban will have no effect on the level of offshore oil activity, and therefore we have not included any incremental Outer Continental Shelf (OCS) production in calculations of economic benefits. In this regard, there is a clear difference between offshore and onshore drilling. First, the two operate in different regulatory settings. Second, offshore development is so encumbered by high capital costs that the small oil price increase proposed by this study would not change project economics measurably.

Greenhouse Gas Emissions

Lifting the export ban will have no appreciable impact on greenhouse gas emissions. About two-thirds of the projected California production increase would be from heavy oil requiring thermal enhanced oil recovery (TEOR) methods. However, under current air quality regulations, thermal EOR will be fueled by natural gas rather than oil. Energy used for TEOR often involves efficient cogeneration of electricity and steam, minimizing increases in net energy use.

Assuming that two-thirds of incremental California production is heavy oil requiring TEOR fueled by natural gas, the maximum California production increase considered in this analysis implies an increase in carbon emissions from TEOR activities of less than one-quarter of a million metric tons--less than two-one hundredths of one percent of 1990 U.S. carbon emissions. The net effect would be even lower if the benefits stemming from cogeneration of electricity at natural gas-fueled TEOR sites were taken into account.

APPENDIX A
PUBLIC MEETINGS ON ALASKAN NORTH SLOPE CRUDE OIL EXPORTS
MARCH 8-10, 1994

BACKGROUND

On March 8 and 10, DOE and MARAD representatives held public meetings in San Francisco, California, and Anchorage, Alaska, respectively, to obtain public opinion about the impact of lifting the ban on exporting ANS crude oil. On March 9, two meetings were held in Juneau, Alaska; the first was with the Governor's Deputy Chief of Staff, Commissioners of the Departments of Revenue and Natural Resources, and Alaska's Attorney General; the second was with 10 to 15 Alaskan State senators and representatives. On March 10, after the public meeting, the DOE/MARAD team met with staff of the Alaskan Departments of Revenue and Natural Resources, and later with British Petroleum (BP).

The notes below briefly synopsize the opinions expressed by most of the persons and organizations that participated in the discussions. On some issues, participants expressed diametrically opposed views. We make no attempt here to explain the disparity. Rather, the difference should be viewed as indicative of the fundamental depth of disagreement among stakeholders in the controversial question of exporting ANS crude oil.

SAN FRANCISCO - MARCH 8, 1994

Testimony was limited to 10 to 15 minutes due to the number of participants (over 18 organizations). After all speakers had finished in the afternoon, we opened the floor to comments and rebuttals, during which an interesting debate between the two sides of the issue developed. It focused largely on whether or not an increase in the ANS crude price would affect the price of California heavy crude (the independent refiners said it would not; independent producers said it would). While there was no resolution, it was interesting to note that the participants seemed to agree both that ANS spot prices in California would rise, and that the increase would be approximately $1.00 per barrel.

Arguments For Exporting ANS Oil

In this meeting, the principal supporters of exports were independent California oil producers. The analytical framework for their position was a study conducted by Professor Martin Carnoy of Stanford University and Lenny Goldberg of Lenny Goldberg & Associates.

<u>Oil Prices</u>

Carnoy/Goldberg estimated that both ANS and California heavy crude oil wellhead prices would rise $2.00 to $2.50 per barrel if ANS crude oil could be exported to Japan. The basis of value for ANS oil in Japan was taken to be average Japanese crude oil import prices.

Phillips Petroleum, an integrated oil company that is a producer of California OCS crude oil (Point Arguello) and a minor producer in Alaska, testified for removing the ban. Their representative estimated that ANS crude prices would rise by about $1.10 per barrel.

Considerable debate arose on how much heavy oil prices would increase along with ANS oil prices if ANS oil could be exported. Berry Petroleum observed that Line 63 Blend would provide the link that would raise San Joaquin Valley (SJV) heavy crude oil. This crude oil is a mix of SJV light and heavy crudes that are blended to allow shipment down ARCO's unheated Line 63 to Los Angeles.

Oil Production

Carnoy/Goldberg estimated that a price increase of $2.00 to $2.50 per barrel would increase California heavy oil production by 100 to 200 mb/d, or potentially as much as the decline in production since 1986. They estimated that Alaskan production would rise by about 300 mb/d. Comments included:

- Several participants voiced the view that light crude oil production in California is in a decline that cannot be arrested, so most of the supply elasticity would be associated with heavy crude oil (below 20 degree API).

- California has a high reserves-to-production ratio; recovery rates are as much as 80 percent of in-place oil with thermally enhanced recovery technology (Santa Fe). This indicates that, potentially, there is a substantial amount of oil in the State yet to be recovered.

- The short-term supply response may be 7 to 10 percent as shut-in wells become economic to produce again (MacFarland). Tannehill confirmed that their short-term response to the price increase in 1990 to 1991 was about 10 percent.

On the subject of production economics:

- Both Tannehill and MacFarland said that their production decreases have been very steep since prices peaked during 1990 to 1991. Tannehill has fallen from about 3 mb/d in mid-1991 to about 1.8 mb/d now. Many wells taken out of production recently by very low prices could return if prices rise.

- Santa Fe said that lifting costs in California average around $7.00 to $8.00 per barrel including taxes. Developing a well costs about $3.00 per barrel in their case, therefore, development ceases to be economic at $10.00 per barrel for heavy oil. It follows that, if the basic price for heavy oil remains in the $8.00 range, even a $2.00 to $2.50 increase attributable to exporting ANS oil would not bring back much investment and production.

- As further evidence of the effects of price on developments, Santa Fe described a drilling program for about 100 wells that was justified and approved when prices were around $12.00 to $13.00 for heavy oil. The program is no longer financially sound.

- Santa Fe and Berry pointed out that shut-in TEOR wells, where the reservoirs are allowed to cool, required as much as $5.00 per barrel to reheat and bring back onto production.

- o Tannehill said that their properties, some of which were developed as long as 50 years ago, simply require a constant drilling program to keep well depth below the oil in the reservoirs. Each well produces reliably at 20 to 25 barrels per day (7,000 to 9,000 barrels per year) and costs about $100,000. Oil prices must be high enough to exceed operating costs and recover capital investment in a reasonable time.

Refining

Carnoy/Goldberg proposed that crude oil price increases would be borne by refiners, not consumers, since West Coast product prices primarily track Gulf and East Coast product markets. Refiner gross margins, by Gulf Coast standards, they argue, are very high[28] and could absorb a significant increase in crude oil prices.

Berry Petroleum, on behalf of the California independent producers, said that additional supplies of heavy oil would be accommodated because refiners would build more coking capacity as they have done in the past. Texaco's recent addition of a large coker in its Bakersfield refinery was cited as an example.

Revenues/Employment/Trade Balance

The Carnoy/Goldberg study estimated that:

- o Yearly Federal tax revenues would rise $1 billion, Federal royalties would increase by $50 million, and that California and Alaska would net $150 million and $600 million, respectively.

- o Increased heavy oil production in California would create between 5,500 and 15,000 jobs. This would exceed the jobs lost in the maritime sector due to lifting the ban.

- o The "direct trade balance" improvement would be $2.2 to $3.6 billion per year, largely due to the increase in domestic production resulting from the price effects of lifting the ban on exports.

Phillips agreed with the Carnoy/Goldberg employment estimates given the 100 to 200 mb/d production increase. Alaskan revenue was put at $200 million per year, and the Federal Government was projected to get $300 million. However, Phillips was less sure about the marketability of ANS crude oil in Japan.

A representative of the Kern County Board of Supervisors discussed the effects of the oil price decline on Kern County. All of Kern County's discretionary spending depends on its one percent ad valorem property tax applied to oil properties. The County estimated that a $2.50 per barrel wellhead oil price increase on only existing production would add $32 million per year to County tax collections.

[28] Carnoy and Goldberg report, p.24.

General and Qualitative

A number of participants argued for the Federal Government to lift the export ban to create a "free market" or "level playing field" on the West Coast. They (e.g., MacFarland) said that the ban favors refiners who can purchase SJV heavy crudes cheaply.

If there is a reason to subsidize the U.S. maritime fleet for DoD needs, then the Federal Government should do it directly, not force the subsidy on independent producers (MacFarland). (A former governor of Alaska proposed requiring DoD to use displaced crude oil tankers to transport military products.)

Another theme that was voiced in San Francisco and Anchorage was that keeping the ban was inconsistent with the Clinton Administration's push to open Japanese markets to U.S. exports (e.g., Phillips).

Arguments Against Exporting ANS Oil

Opponents to exports include those with interests in the U.S. maritime fleet (employee unions, shipbuilders and repairers, and shipowner/operators), refiners, the All American Pipeline (which transports to Texas 80 mb/d of ANS oil that is bound for the Midwest), and their consultants (e.g., Pace Consultants).

Oil Prices

Most of the participants who agreed that exports would raise ANS oil prices estimated that the change would be in the order of $1.00 per barrel (Tosco, Pace, Coalition to Save Alaskan Oil). These estimates seemed to be derived from prices for comparable foreign oil and its cost of transportation to Japan.

The most forceful price-related argument against lifting the ban was that SJV heavy crude oil prices would not rise at all, even if ANS crude prices did.

- o One argument was that heavy oil prices must already be at "world" value because export licenses have been granted, yet very little is being exported (e.g., Tosco and the Coalition).

- o An audience participant (from the Los Angeles law firm of Hoecker, McMahon, Jeys, & Buck) agreed that SJV prices would not rise. He reasoned, however, that refiners who control the large crude oil pipelines also post all the SJV crude oil prices and will not let independent producers realize the market value of their crudes no matter what happens to ANS oil. (Coalition representatives also expressed this view.) He said that producers could not export SJV oil because pipeline operators had demanded too high a price to transport the oil to port. Berry Petroleum confirmed this, saying that effectively Texaco had exported SJV oil using the independent producers' export license.

- o One persistent argument was that California refiners lack the capacity to process more heavy oil and would not pay more for it (this is discussed in more depth below).

- o Tosco and Pace argued that the California market was where SJV heavy oil was most valuable, so it is already receiving its fair price. This is because the State's high coker capacity allows for the most valuable products to be made from heavy oil. Otherwise, the value would be established by the Singapore residual fuel market netted back to the West Coast. Tosco showed that California prices are nearly always higher than Singapore high sulfur fuel oil, which is similar to California heavy crude oil.

- o Another argument was that the difference between ANS crude prices on the West and Gulf Coast, $0.80 to $1.00 per barrel, reflect the extent to which West Coast ANS crude prices are depressed (Coalition and U.S. Oil and Refining).

Refining/Marketing/Consumer Prices

The principal argument against the production effect for lifting the ban was that California heavy oil prices would not rise and that California refineries were already using all the heavy oil they could process. Relating to the capacity issue:

- o Tosco and others stated that cokers in California operate at maximum capacity so there is no room for more SJV oil. A few years ago, production was as much as 200 mb/d higher, but Tosco argued that much of the higher volume was not available to the at-capacity cokers, so it was essentially "topped." Thus heavy oil's low price. Today, there are fewer refineries in California (whether or not there is less coker capacity warrants further investigation).

- o Apparently high refining margins for SJV heavy oil reflects recovery of investment in coking capacity (Pace).

- o Small and medium refiners that are deprived of ANS oil will not turn to heavy SJV crudes because they cannot get financing to upgrade their refineries. Even asphalt producers cannot switch because SJV oil makes a different type of asphalt than does ANS crude. (Western Independent Refiners Association).

- o In debating refiners on heavy oil processing investment, the Tosco representative said that the company would not add capacity, nor would it pay more for heavy oil when it could purchase high sulfur fuel oil in Singapore.

- o The All American Pipeline system representative said that the fact that SJV is transported east by their pipeline indicates that there is not enough capacity for it on the West Coast.

U.S. Oil and Refining (U.S. Oil) (in Washington State) indicated that they would effectively lose capacity if they shifted from ANS to Middle East sour crude. Currently, ANS crude is 90 percent of their feedstock; switching to Mideast crudes would reduce their crude runs to 45 percent of the present level.

U.S. Oil, Pace, and Tosco brought up the effect that ANS exports would have on the ability to meet the Federal Clean Air Act (CAA) and California Air Resources Board (CARB) gasoline specifications in the last half of the decade. U.S. Oil noted that the baseline specifications, against which their future gasoline would be measured, are derived using ANS oil. Replacing that with higher sulfur Middle East oils would not allow the refinery to meet the CAA and

CARB specifications. Pace observed that shifting to less desirable crudes would open the window to foreign refiners who could "cherry-pick" their best gasoline for exportation to the U.S. and "dump" dirtier gasoline into their normal overseas markets.

WITCO, a Bakersfield refiner, indicated that, to the extent that SJV prices rose, it would undercut their export margins for petrochemical naphtha. This is because land-locked small refiners would not be able to get cheap foreign crudes and would have to absorb the full impact of any crude oil price increase. Their competitors use foreign heavy crudes, such as Venezuelan Bachequero 13, which would not rise in price. Powerine, representing the Western Independent Refiners Association (WIRA), said that some refineries are configured to run ANS oil and might have to cut back output to unprofitable levels if it were not available. The result might be product shortages.

Somewhat contradicting WITCO's statement, Tosco said that it would pass on every cent of its increased crude oil costs (which it said would be attributable to ANS crude price increases) to consumers.

Supply Security, Logistics, and Safety

Several refiners raised the issue of the fungibility of ANS oil and its effect on logistics. They said that, since a number of refineries process ANS crude, in the event of an emergency, they can trade among themselves to distribute a shortfall. If, instead of ANS oil, refiners process a number of types of foreign crudes, then storage requirements would be greater.

In addition, crude imports, which would be transported on VLCC-class vessels (Very Large Crude Carrier), would have to be lighter because there are only three deep-water facilities in California. This complicates logistics, raises transportation costs, and increases the possibility of an oil spill.

U.S. Oil and others held that the vulnerability to supply disruptions increases with the shipping time for crude oil. That is, a break in supply takes longer to fill if its replacement comes from a foreign source. Foreign crude oil would take 20 to 25 days to reach the West Coast, while ANS crude takes only about five days to reach the Puget Sound. Foreign suppliers were considered less reliable in the sense that delays are more common.

U.S. maritime industry representatives voiced concern about the reliability of foreign crews, in one case (Atlantic Marine Officers Association) citing the non-U.S. crew aboard the U.S. company-owned tanker (the Braer) involved in the Shetland oil spill.

Maritime Interests/National Security

Of the remaining U.S.-flag tankers eligible to operate in the domestic trade, 60 to 70 percent of the capacity is employed principally in the ANS crude oil trade. Although the total number will fall as ANS production declines, permitting exports will hasten the decrease. Four principal constituencies might be affected, based on the manner in which the ban is lifted:

- U.S. Seamen--They would see their jobs go overseas since foreign salaries are substantially lower.

- U.S. Independent Ship Owners--They have invested in more expensive U.S.-built, U.S.-crewed ships that cannot compete in the international trade.

- U.S. Shipbuilders--They have relied primarily on DoD construction for more than a decade; cannot compete with foreign shipbuilders that are subsidized directly by their countries. U.S. shipbuilders are looking forward to replacement business stemming from the double-hull requirements of OPA90.

- Ship Service Companies--They provide dry-docks and maintenance support for the U.S. fleet.

All were represented at the hearing in San Francisco. Among the points made were:

- The U.S. seafaring work force has provided a stock of willing, already trained volunteers for war-related duties such as the Persian Gulf War of 1990 to 1991 (Marine Engineers Beneficial Association (MEBA)).

- U.S.-flag ships that are military useful could be used in other contingency operations (Coalition); 216 foreign-flag ships were chartered during the Persian Gulf War--these might not be available in a conflict that was less well-supported by our allies (MEBA).

- Building and servicing Jones Act tankers will help the U.S. shipping industry transition from support by Defense contracts to commercial activities (Shipbuilders Council of America/San Francisco Drydock).

- U.S. orders for double-hulled tankers are being delayed due to this review of ANS oil exports.

The president of OSG Bulk Ships, Inc., representing the Coalition to Keep Alaska Oil, observed that 44 ships totalling five million dwt are engaged in the ANS crude trade. Roughly 2,000 to 2,500 merchant mariners depend on the ANS crude trade for employment. The effect of permitting ANS oil exports on this sector of the economy were described as "devastating."

General and Qualitative

One theme voiced by the maritime sector representatives was in answer to the "free market/level playing field" argument of the California independent producers. The maritime industry said that their investments were made on the assumption that Congress and the Administration had agreed that the ANS market was not to be "free." The compromise between environmentalists and energy security advocates in the 1970s that brought about the ban on ANS oil exports was a deal that should remain in place, at least because substantial investment had been made assuming that laws would not be changed.

On another subject, the representative from WITCO said that America should use its natural resources at home to create products that could be exported. In doing so, it would retain the value-added within the U.S. economy.

Finally, the Coalition representative observed that California independent producers do indeed have a problem with today's low prices, but it is an OPEC problem, not one related to ANS oil exports. He observed that the price depression that is putting them increasingly below operating costs is mirrored in the drop of world oil prices in general.

ANCHORAGE - MARCH 10, 1994

Speakers at this meeting included local politicians, business persons, representatives of Native American organizations, oil companies, and union officials. In general, statements were much more qualitative and policy oriented than in San Francisco. While it was not surprising that most speakers supported lifting the ban, an undercurrent of compromise was unexpectedly present. Contributions are sorted below by group categorizations.

Local and State Politicians

Three mayors, or their representatives, spoke--all supported lifting the ban. Revenue enhancement was the underlying reason for their positions, since the cities they represent derive revenues from oil-related properties (the representative from the Valdez City Council estimated that 85 percent of the city's revenue is oil tax related). Some of the specific points made were:

- o The cost of the export ban is $970 million per year (Mayor of Kenai, Alaska, citing Arnold Tussing study).
- o National security is no longer an issue. The United States cannot reclaim energy independence so we should move to establish reliable trading partners (Mayor of Kenai).
- o Lift the ban but offer something to the maritime industry (Valdez City Council, Democratic State Chairman, Bill Sheffield-former Governor of Alaska). (Governor Sheffield proposed using displaced U.S.-flag tankers to transport the DoD petroleum products.)
- o Open the ANWR (Sheffield).
- o Ensure that foreign ships entering Prince William Sound conform to U.S. safety standards (Valdez City Council).
- o As an aside, the representative of the Mayor of Anchorage supported lifting the ban but dedicated most of her testimony to the allegedly excessive cost of Federal environmental regulation on State and local agencies.

Unions

- o U.S. shipping adds to national security (Marine Engineers).
- o Revenues paid to foreign-flag shipping companies end up in other countries (Marine Engineers).
- o Open ANWR (AFL/CIO).
- o Lift the ban, but do not use foreign shipping or crews (Teamsters).
- o Opening trade in oil is consistent with Clinton Administration's trade policy (Teamsters).
- o The TAPS statute resulted from a tie vote that the then Vice President (Agnew) broke. The AFL/CIO supported TAPS only after the ban was added. Thus, if there is a compromise, the maritime trade unions must be involved (AFL/CIO).

Oil Companies

Notable was that BP openly supported lifting the ban in its public testimony. The other two major producers, ARCO and Exxon, have remained publicly silent on the issue. Privately, their representatives indicate that most of their ANS crude oil is used within their own systems, or is traded for supply elsewhere. As such, they might see little gain from selling crude in export transactions.

- o BP commented that:
  - Margins in Alaska are not competitive globally; in non-U.S. areas they are $1.00 to $2.00 per barrel higher than Alaska, and even higher in developing areas.
  - Much of the production projected for the year 2000 depends on investments yet to be made, and BP will not "...bet (the) company on higher prices."
  - They would plow back some of the increased revenues from exports.
  - Original ANS reserve expectations doubled; much more oil is there than is on company books.
  - Parties should structure an "appropriate" arrangement with the maritime sector.
- o Petrostar is an independent refiner and one of the largest distributors of product in Alaska. The company supported lifting the ban and made the following points:
  - The impact of a price rise on Alaskan consumers is minimal--about $25.00 to $30.00 per year per family for home heating oil.

- Nothing is inherently bad about foreign-flag vessels; Hess uses them to pick up oil at Valdez (about 50 mb/d on average).

- Estimated that 200 to 300 mb/d will be exported.

Native American Businesses and Organizations

Included in this group are the Northwest Alaskan Native Association (NANA) and Arctic Slope Regional Corporations, and the Doyon Corporation, as well as several others who made appeals on behalf of Native Americans. Doyon and NANA are partners in the ANS Endicott Field. These groups all supported lifting the ban on exports. Two principal reasons were that:

- o Exporting ANS crude oil would raise State and local tax revenues that could be used to perpetuate subsidies to Native Americans. This would include medical care, schools, and, in some cases, adding water and sewer service to villages.

- o An increase in ANS oil prices would stimulate oil-related development on Native American lands.

Other Organizations

California Independent Producers Association (CIPA)--(See San Francisco testimony) proposed a compromise wherein, in return for removing the export ban, the Federal Government would guarantee maritime unions' pension funds.

Alaska Department of Revenue--indicated that West Sak may be the next major development project on the North Slope if wellhead prices get high enough. They also put State and Federal cost of the ban at $1 billion/year.

Resource Development Council--appealed for opening ANWR. They agreed with lifting the ban while protecting the U.S. maritime industry.

STAFF MEETING WITH ALASKA DEPARTMENTS OF REVENUE (DOR) AND NATURAL RESOURCES (DNR) - MARCH 10, 1994

This hour-long meeting dealt mostly with revenue flows associated with lifting the ban. Points of interest include:

- o The State of Alaska severance tax is 15 percent after a 12.5 percent royalty is subtracted (total about 25 percent).

- o State income tax on incremental income is about 1.5 percent.

- o Property taxes are not tightly related to oil prices, although assessments may rise if there is a sharp increase in prices. New investment would increase property taxes.

- o ARCO and Exxon place most of their ANS crude within their own systems or trade it for like crude. They probably would not see an increase in revenues unless product prices rise with the ANS oil spot price. This is because, within their systems, crude oil prices are simply internal transfers of revenues. Tax payments might change, however. This means that if product prices do not rise, these two companies, with 40 to 50 percent of ANS crude production, might not have new revenues to invest as crude prices increase.

- o Dr. Logsdon, economist with the DOR, provided output from the computer model his Department employs to project Alaskan production. At our request, using his 1993 revenue base case, he produced iterations that showed how price increments affect production and recoverable reserves. We plan to use this as a primary input to the study to model the incremental production that would be gained from an increase in wellhead oil prices.

MEETING WITH BRITISH PETROLEUM - MARCH 10, 1994

Following the above meeting, members of the study team met with the BP Alaska staff and management. Several points in the meeting were:

- o In recent years, BP's margin has dropped by about two-thirds. Capital expenditures have dropped in response.

- o If the ban were lifted, the wellhead price of ANS crude oil would rise about $1.00 to $1.50 per barrel; other estimates of $2.00 to $2.50 per barrel (e.g., Carnoy/Goldberg study) are too high.

- o BP estimates that the export potential may be as high as 250 mb/d: 100 to 150 mb/d that are currently being shipped eastward and 100 mb/d from oil that is now being sold on the West Coast. This is higher than they thought earlier.

- o The increase is largely due to the influx of foreign crude that is, to some extent, backing out ANS crude in California and the Puget Sound.

  - Canadian oil production tax incentives have led to a 70 mb/d increase in Canadian crude oil imports into PADD V by pipeline. In addition, 30 mb/d of Canadian crude oil that is being shipped to the U.S. Gulf of Mexico could also shift to the West Coast.

  - Other foreign crude oil has made a significant penetration into West Coast markets. Kuwait and Ecuador, for example, have substantial sales to West Coast refiners.

- o Canada is now exporting crude oil to the Far East. This demonstrates the feasibility of exporting crude from the West Coast to the Far East.

- o The U.S. Gulf Coast already imports crude oil from Ecuador and Venezuela. These crudes could replace ANS crude on the Gulf of Mexico Coast if the ban were lifted. Furthermore, these sources are closer than the Middle East.

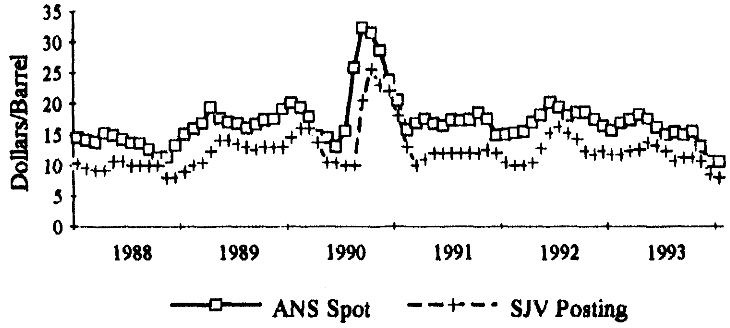
- o BP supports a complete lifting of the ban on ANS crude oil exports, and believes that a partial lifting of the ban still would not allow the market to determine oil prices.

APPENDIX B
HISTORIC RELATIONSHIP OF ANS AND CALIFORNIA CRUDE OIL PRICES

BACKGROUND

Figure B.1 shows a five-year series of ANS crude spot prices in Los Angeles[29] and posted prices for SJV heavy crude.[30] The ANS crude price is delivered to Los Angeles, while the SJV price could be considered a near-wellhead price for the 13 degree API heavy crude oil. In general, the two series move together, but there are periods when the absolute magnitude of a price change varies.[31]

Figure B.1 ANS and SJV Prices -- SJV Postings and ANS Spot (Los Angeles)



Exporting ANS oil from the U.S. West Coast is likely to increase ANS crude prices somewhat. Here we analyze the historic data to determine the extent to which a price increase in the lower West Coast market will translate to higher prices at the wellhead for California crude oils.

ABSOLUTE PRICE RELATIONSHIPS

Over the entire period shown in Figure B.1, ANS prices exceeded the SJV posted prices by $4.54 per barrel. It is difficult to put the two prices on the same geographical basis due to the scarcity of data on pipeline transportation charges for moving the SJV oil to refining centers in Los Angeles.[32] If the SJV crude oil is blended up to Line 63 specifications, the total cost to move it into the Los Angeles market is about $1.00 per barrel. It should cost about $0.20 to move ANS crude oil from the Los Angeles harbor to a refinery in Los Angeles.[33] This leaves a difference of about $3.74 per barrel, or $0.27 per API gravity degree.

This implicit quality differential is substantially higher than the $0.10 to $0.15 per gravity degree that is common in the oil markets of PADD III, a fact that lends credibility to the allegation that California heavy crude oil is underpriced at the wellhead. In actuality, $0.27 per gravity degree

[29] Source: Telerate data series.

[30] Source: Oil and Gas Journal data base.

[31] Some of the apparent shift in the SJV series is due to the fact that our ANS oil prices are recorded at the middle of each month, while the SJV prices were recorded at the beginning of each month.

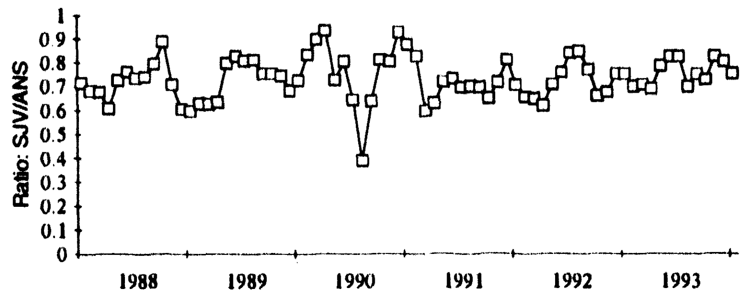
[32] Only ARCO's Line 63 operates as a common carrier and posts a tariff.

[33] Local pipeline and terminalling charges plus port fees.

understates the price differential for some refiners. If a refiner (typically an independent refiner) does not have a favorable contractual access to terminals in the port area and to pipelines leading to its refinery, it must pay the "inland" price for ANS crude oil which may be as much as $1.00 per barrel higher than the Los Angeles Harbor spot price.

From a modelling point of view, the ratio of SJV to ANS crude prices provides a better relationship than the absolute difference. Figure B.2 shows that this ratio also is quite variable. A closer examination of the data supporting Figures B.1 and B.2 indicate that the largest variations in the ratio of the two prices arise when ANS prices lead SJV prices as changes occur. On average, over the five years shown, SJV posted prices are about 73 percent of ANS spot prices at Los Angeles Harbor.

Figure B.2 ANS and SJV Price Ratio -- SJV Postings to ANS Spot in Los Angeles



RELATIVE CHANGES IN PRICE

To determine the responsiveness of SJV wellhead postings to changes in the spot market prices for ANS crude oil, we divided the five-year period shown in Figure B.1 into 13 periods of rising and falling prices. These data are shown in Table B.1 below.

Using a simple regression of one series on the other, we found that SJV crude oil prices rose and fell slightly more than ANS prices during periods of change. The regression indicated that for every 10 percent change in ANS price, SJV prices would change 10.7 percent. This simple model fit the data with an R^2 of 0.98--a very good fit indeed.

There are a number of crude oil types in California, ranging from very heavy (10 degree API) through relatively light (e.g., 34 degree API Elk Hills). Most of the volume, however, by Gulf Coast standards is heavy crude oil. Another large percentage of the State's volume, for example, is the Ventura-Los Angeles Basin 17 degree API range oils, of which Wilmington 17 degree API is an example. On average, California crude oil is about 20 degree API and has an insignificantly higher amount of sulfur than ANS crude.

Table B.1 Price Changes: SJV Heavy Crude Versus ANS Crude

Corresponding Periods		Price Change Percentage		Ratio of
SJV HVY	ANS	SJV HVY	ANS	Changes
5/88-11/88	4/88-11/88	-25.6%	-25.6%	1.00
12/88-5/89	11/88-4/89	75.0	70.6	1.06
6/89-9/89	4/89-8/89	-10.7	-17.2	0.62
9/89-2/90	8/89-1/90	28.0	25.0	1.12
3/90-8/90	1/90-6/90	-37.5	-34.7	1.08
8/90-10/90	6/90-9/90	155.0	146.3	1.06
10/90-3/91	9/90-2/91	-48.1	-51.2	0.94
3/91-11/91	2/91-10/91	25.0	17.5	1.43
11/91-3/92	10/91-12/91	-20.0	-19.9	1.01
3/92-7/92	12/91-6/92	62.5	36.2	1.73
7/92-2/93	6/92-1/93	-27.7	-22.5	1.23
2/93-5/93	1/93-4/93	17.0	15.7	1.09
3/93-1/94	4/93-1/94	-41.8	-41.4	1.01

Our analyses indicate that the results shown above for SJV 13 API crude oil apply in principle to all California crudes, but the price ratios are different. We examined the California wellhead price data series EIA publishes to determine the relationship between ANS oil spot prices in Los Angeles and the average wellhead price in California. Although the time series of the ratios exhibited volatility not unlike the second figure above, the average ratio was, at 0.80, slightly higher. We, therefore, conclude that for every $1.00 increase in ANS oil spot prices, about 80 percent of the changes would be seen at the California wellhead.

CONCLUSIONS

On average, over the last five years, SJV wellhead prices have been about 73 percent of the levels of ANS oil spot prices in the Los Angeles Harbor. If we assume that this relationship is likely to persist after ANS crude oil is allowed to be exported, then, for every $1.00 rise in the West Coast price of ANS oil, we would see a $0.73 increase in SJV heavy crude oil prices.

On the other hand, one might conclude that the relationships shown in Table B.1 above should prevail. That is, for a 10 percent change in the ANS oil price in Los Angeles, SJV wellhead prices would rise 10.7 percent. In this case, a $1.00 rise in ANS oil prices would translate to an increase in SJV heavy crude wellhead prices of $0.78.

The volume-weighted average price of all California crudes should rise about $0.80 per $1.00 increase in ANS oil spot prices at Los Angeles.

APPENDIX C
REFINING AND TRADE FLOW ANALYSIS

INTRODUCTION

Present legislation effectively bans the export of crude oil produced in the United States. The ban has been in effect for years, and is particularly stringent with respect to crude oil produced in Alaska, particularly on the North Slope. The Alaska crude oil export ban is specifically provided for in the Trans-Alaska Pipeline Authorization Act of 1973 and in other legislation. The ban on exports of domestically produced crude oil is not total. Exceptions are permitted, but the conditions that must be met are stringent. Currently, only small quantities are exported.

The main objective of this Appendix is to estimate the potential impacts on crude oil prices that would result from lifting the export ban on Alaskan crude oil. The report focuses on the Japanese market and the U.S. West Coast market. Japan is the principal potential export market for Alaskan crude oil. Export to that market would also affect the price of Alaskan crude oil as well as crude oil and product prices on the West Coast and the volume of petroleum imported in that area.

The next section of this report describes the factors that would determine the trade flow of Alaskan crude oil if the export ban were abolished. These factors include demand for end-use petroleum products, refinery configurations, and crude oil mix available to the region.

The following section describes the methodology used in the analysis to generate values for and export volume of Alaskan crude oil. Two different models are used to provide analytical results at different regional levels. The EIA WORLD Model is more aggregate in regional refinery representation, but is capable of simulating crude oil trade flows. ARMS of Math Pro Inc. is a single refinery model which can be configured to model refinery operations at a very disaggregated level. Solutions of model runs from two different models provide useful validity checks in terms of crude oil valuation and the potential of ANS exports.

The last section presents the model-generated results. In general, refinery crude oil acquisition costs would rise if the ban on Alaskan crude oil is lifted. Prices for refined products on the U.S. West Coast might also increase. The increase for gasoline would likely be quite small with most of the price increases concentrated in the heavier refined products.

VALUATION OF POTENTIAL FOREIGN MARKET FOR ANS CRUDE OIL

The value of ANS crude oil in a regional market depends on factors such as demand for refined petroleum products, refinery configurations, competing crude oils used in the regional refinery, and the characteristics of ANS crude oil.

Potential markets for ANS crude oil outside the United States can be identified by simulation analysis of regional refinery models. Refinery models can simulate the effects of demand for end-use petroleum products on costs of production. The model solution also provides information on the value of specific crude oil to the refinery operations in the market. A comparison of the imputed value of ANS crude oil in different regional markets sheds light on the potential movements of ANS crude oil once the export ban on ANS is lifted.

Potential major markets for ANS crude oil are in the Pacific Basin. Japan is the principal market in that area because of its distance to Alaska and the compatibility of its refinery configurations with ANS crude oil. For this reason, this analysis focuses on the U.S. West Coast and Japan.

Comparison of Regional Markets

Crude oils differ in quality and consequently command different prices. In general, the sulfur content and API gravity of a specific type of crude oil affect its value. In addition, the first cut (crude oil assay) from a crude oil distillation unit also affects its value; crude oils which produce intermediate products that require less further processing to match end-use demand generally command higher prices.

Because regional demand for petroleum products differ, its demand for crude oil may also be different. In the following, a brief discussion of the California and Japan petroleum market would shed light on the potential movements of ANS if the export ban on ANS oil is lifted.

Demand for Refined Products

The composition of demand for end-use products in Japan differed sharply from that on the U.S. West Coast in 1991 (Table C.1). The gasoline share of the petroleum market was about 15 percent in Japan, but was about 50 percent in California. The market share of residual fuel oil was about 16 percent in Japan, but was only about eight percent in California. The market share of liquefied petroleum gases (LPG) in Japan was 12 percent compared with only four percent in California. The significant differences in end-use product demand indicate that the demand for ANS crude oil may also be very different in these two regions.

Table C.1 Demand for Petroleum Products in Japan and California in 1991 (Demand in mb/d; Shares in Percentage)

	Japan[a]		California[b]	
Product	Demand	Market Share	Demand	Market Share
Motor Gasoline	787	15%	818	50%
Jet Fuel and Kerosene	531	10	254	16
Distillate Fuel	1,162	22	207	13
Residual Fuel	862	16	125	8
Other	851	16	149	9
Liquified Petroleum Gases	616	12	59	4
Natural Gas Liquids	107	2	14	1
Crude Oil	367	7	13	1
Total	**5,283**	**100%**	**1,639**	**100%**

Sources: [a] EIA, International Energy database - derived from International Energy Agency Database
[b] EIA, State Energy Data Report 1991, May 1993

Refinery Configurations

Table C.2 compares capacities for key refinery processing units in Japan and California for 1993. The capacities reflect the need and requirement to meet end-use demand in these two regions. Two major categories of processing units stand out in the comparison. The first converts heavy-end crude components to more valuable lighter products such as gasoline and distillate. The second removes sulfur from the products.

The comparison of processing units can be expressed in terms of the ratio processing units to the crude oil distillation units in the region. In California, coker, hydrocracker, and fluid catalytic cracker were 24, 31, and 22 percent of the capacity of crude oil distillation. In Japan, the percentages were 2, 15, and 3 percent.

Note that a coker converts asphalt or residual fuel oil to intermediate products to be processed in either a fluid catalytic cracker or a hydrocracker. A hydrocracker converts higher boiling range petroleum materials such as aromatic cycle oils and coker distillates into gasoline and jet fuel. A fluid catalytic cracker converts heavy oil into gasoline and lighter products. The relative importance of these capacities for these conversion units were substantially greater in California than Japan in 1992. The differences in importance of conversion units in these two regions reflect the effects of a much greater market demand for gasoline in California with respect to the requirement to convert the heavy-end crude components into lighter products.

In contrast, desulfurization units in Japan have a much greater capacity than those in California. In Japan, distillate desulfurization and resid desulfurization were respectively 33 percent and nine percent of the capacity of crude distillation. In California, the percentages were 14 percent and five percent. The differences in the capacities of desulfurization units reflect the much greater demand for distillate and residual fuel oil, and environmental restrictions on the sulfur content of these fuels.

Table C.2 Capacity for Key Refinery Processing Units in Japan and California (Thousand Barrels)

	Japan[a]		California[b]	
Processing Units	Capacity	Ratio to Distillation Capacity	Capacity	Ratio to Distillation Capacity
Crude Distillation	4,875	1.00	2,011	1.00
Vacuum Distillation	1,760	0.36	1,236	0.61
Coker	83	0.02	487	0.24
Visbreaker	20	0	36	0.02
Naphtha Desulfurization	781	0.16	408	0.20
Distillate Desulfurization	1,610	0.33	289	0.14
Resid Desulfurization	428	0.09	110	0.05
Cat Reformer	762	0.16	445	0.22
Fluid Catalytic Cracker	749	0.15	625	0.31
Hydrocracker	122	0.03	434	0.22
Alkylation Plans	68	0.01	115	0.06

Sources: [a] Oil and Gas Journal, December 1993.
[b] EIA, Petroleum Supply Annual 1992.

Crude Oil Mix Used in the Refinery

Given the demand for end-use petroleum products and the refinery configurations, the output of refined products and the efficiency of refinery operations depend largely on the quality and volume of crude streams available to a refinery. The optimal crude oil mix would include crude oils with sulfur content, API gravity, and crude oil assay that are best suited for processing in a given refinery and that minimize the cost of meeting a particular slate of petroleum product demand.

In 1992, Japan imported 4.38 million barrels of crude oil per day. Average sulfur content of imported crude oil for refining use was about 1.35 percent by weight and the average API gravity of these crude oils was higher than 35 degree.

In 1992, California imported about 140 mb/d. The remaining crude oil used was indigenous California production and about 1.4 million barrels per day of ANS crude oil. The average API gravity of the crude oil used in California refineries was lower (heavier) than crude oil used in Japan.

The demand for petroleum products in California normally would require a lighter crude oil mix than that in Japan. Lighter crude oils could reduce processing costs to meet high gasoline demand in California. In Japan, the existing crude oil mix has too much gasoline producing capability; it could use crude oil such as ANS to meet its demand for kerosene and middle distillates. If the ban on ANS crude oil exports is lifted, a competitive oil market would ensure that a profit maximizing refiner would seek a crude oil mix which minimizes operating costs and maximizes profits.

Characteristics of ANS Crude Oil

ANS crude oil has an API gravity of 26.4 degree and a sulfur content of 1.06 percent by weight. The assay of ANS crude oil indicates that it produces a very small fraction of gasoline range products (about 8 percent). In a market like California, which has very high gasoline demand, a great deal more processing is required to convert light gas oil, heavy gas oil, and residual fuel oil to lighter products such as gasoline and jet fuel. The fluid catalytic cracker and hydrocracker would be used to convert gas oils to gasoline and jet fuel, and the coker process would be used to convert residual fuel to lighter products.

In Japan, the demand for distillate and residual fuel is much greater than the demand for gasoline. Therefore, the processing required to convert the heavy end of a barrel to lighter products is much less. In addition, the relatively low sulfur content of ANS crude also implies a lower utilization of desulfurization units which further reduces processing costs in Japan.

Would refineries in Japan outbid refineries in California for at least some portion of Alaskan crude? The answer depends on the savings in processing costs and crude oil acquisition costs that could be achieved by substituting ANS crude for other imported crude oils, as well as on the relative prices of ANS and internationally traded crude oils.

STUDY METHODOLOGY

Is there a foreign market for the ANS crude oil? Virtually all the professionals in the market believe that there is, so there must be. Analytically, the answer lies in the valuation of ANS crude relative to other oils traded in the world oil market. If a foreign refinery values ANS oil more than U.S. refiners in the West Coast, there will be exports. The economic feasibility of exporting ANS crude can be quantitatively evaluated by simulating market and refinery conditions that refiners face in both California and Japan. These conditions include demand for petroleum products, refinery configurations, and crude oil mix that refiners use.

Two different models were used in the analysis of the valuation of ANS crude oil. The first model, ARMS, is a generic single refinery model. The second model, WORLD, is an eleven-region world oil refining logistics demand model.

The ARMS Model is capable of simulating refinery operations to meet the demand for petroleum products. Given the demand for end-use products and a particular refinery configuration, the ARMS Model can be solved either by maximizing refinery profits or by minimizing refining costs. Solutions from the ARMS Model also provided an imputed price for each type of crude oil used in the model, based on processing costs, which are inputs to the model simulations. These imputed prices reflect the combined effects of demand for refined products and refinery processing costs.

The ARMS Model is configured to simulate refinery operations in both California and Japan. Model outputs provide imputed values of ANS crude oil in California and in Japan independently. It also provides valuable insight on the potential of ANS crude oil in the Japanese petroleum market. In addition to the imputed values of crude oils used in the model refinery, model results also show the ability of refineries in using a different crude oil mix to meet a pre-determined demand slate.

The WORLD Model is a world regional linear programming model. The objective function of the model is to minimize costs given demand for petroleum products, product specifications, refining technologies, transportation links, and crude oil assays. The WORLD Model has 11 world regions; has a representation of over 120 world crude oils which include a detailed representation of 50 refinery processes; has a detailed breakout of 28 major, minor, and military petroleum products and demand; and has comprehensive inter-regional transportation of crude oils, products, and intermediate products.

Key outputs from a WORLD Model run can be categorized into two groups. The first group includes physical information such as crude, non-crude products, and intermediates movements, generation and purchase of utilities and variable non-crude feedstocks, process unit operations, regional refining throughput and utilizations, and blending activities and compositions. The second group includes refining and market economic information such as marginal costs on every crude where there is an active movement into the region, finished product marginal costs in every region, economic rents on process units at their capacity limit, and economic rents on capacitated transportation modes at their capacity limit.

The WORLD Model regional refinery representation is more aggregated than the ARMS Model. California is included in Region W, which consists of all the states in PADD V and Western Canada. Japan is included in Region P, which consists of all countries in the Southeast Asian countries.

The ARMS Model provides valuation of ANS crude in two of the regions of special interest. The WORLD Model, however, provides capability in both the valuation of ANS crude in an equilibrium market framework and the potential flow of ANS crude oil to the Asian Pacific region. Using two different models also provides an opportunity to cross-check the validity of model results due to differences in modeling assumptions.

Differences in modeling approach also resulted in differences in model operations and assumptions. For the ARMS Model, refinery output is fixed and the effects of reducing or increasing the use of ANS on crude oil valuation may be affected by assumptions on replacement crude oils. For the WORLD Model, regional demand slates are fixed. However, refinery outputs in each region can change if there are opportunities to change crude oil mix and reduce costs of production. Refinery operations represented in the WORLD Model are, therefore, more efficient than that represented in the ARMS Model.

ARMS Model Scenarios:

- o The ARMS Model is configured to simulate refinery operations in California and Japan in 1992.

- o The California refineries are aggregated into three groups on the basis of accessibility of ANS crude oil. These are:

  - Complex refinery,
  - Simple refinery, and
  - Inland refinery.

  The purpose of this grouping is to identify refineries that will be directly affected by the export of ANS crude and to simulate the effects of losing ANS crude on refiners' ability to find replacement crude oil from foreign sources. For the complex refinery, simulation results will provide an imputed value of ANS crude relative to the world swing crude Arab Light.

- o The Japanese refineries are aggregated into a single refinery. The 1992 Japanese demand for petroleum products, refinery capacity, and crude oil imports are used to calibrate the Japanese refinery operations.

  Model solution from this simulation provides an imputed value of ANS crude relative to the world swing crude Arab Light.

  Comparing the imputed value of ANS crude and Arab Light in California and Japan provides information on the preference of crude oils in these two regions.

- o Conduct a parametric analysis of the effects of lower availability of ANS to California complex refinery on the valuation of ANS crude in California. Conduct a parametric analysis of the effects of increased availability of ANS crude to Japanese refineries on the valuation of ANS in Japan. These parametric analyses change the availability of ANS crude by 300, 450, and 600 thousand barrels.

- o Simulate the effects of the 1996 California reformulated gasoline specifications to the complex refinery on the value of ANS crude.

WORLD Model Scenarios:

The WORLD Model is configured to simulate four different market conditions. These are:

- o 1994 market demand and refinery operations.

  The current projections of the 1994 world oil market in the EIA Short Term Energy Outlook is used as a point of reference for conducting refinery simulations. Refinery configurations for each world region are based on data published in the December 1992 issue of the Oil and Gas Journal. Market demand for petroleum products uses historical data reported in both the International Energy Agency and EIA publications. We established a 1994 Base Case with the export ban on ANS crude oil in place. Then we simulated changes in 1994 crude oil trade flows by allowing exports of ANS crude oil to the Asia Pacific Region.

- o The effects of reformulated gasoline on refinery operations in 1994.

  The 1996 reformulated gasoline specifications are imposed on the 1994 scenarios to simulate the effects of reformulated gasoline specifications on the values and export potential of ANS crude oil.

- o The year 2000 oil market under low world oil price assumptions.

  The EIA AEO94 low world oil price case is used to simulate the ANS crude oil export potential. Two model runs are performed: a base case without ANS exports and a scenario case that allows exports of ANS crude oil to Region P. The volume of exports is determined endogenously. ANS crude oil production is projected to be about 1,025 mb/d.

- o The year 2000 oil market under high world oil price assumptions.

  The EIA AEO94 high world oil price case is used to simulate the ANS crude oil export potential. Two model runs are performed: a base case without ANS exports and a scenario case that allows exports of ANS crude oil to Region P. The volume of exports is determined endogenously. ANS crude oil production is projected to be about 1,600 mb/d.

In addition to the above four sets of model runs, the WORLD Model is also used to generate a number of parametric model runs with the upper bound on export volume set at 100, 300, 500, and 700 mb/d. These parametric export analyses are aimed at simulating potential export of ANS crude over time. They portray a pattern of price changes associated with each of the four export volumes.

ANALYSIS OF RESULTS

Simulation results from both the ARMS and the WORLD Models show that Japan or the Asia-Pacific region would import ANS crude oil if the ban on ANS oil export is lifted. Price of ANS crude oil would rise. Refinery acquisition costs of crude oil will increase, but product prices might not change noticeably.

Effects on U.S. West Coast Crude Oil Prices

Lifting the export ban on ANS crude would change the U.S. West Coast from a segmented crude oil market to a more competitive oil market. West Coast refiners would face competition from foreign refiners for ANS oil, and the price of ANS crude oil would be determined in the world market. Exporting ANS crude oil would raise not only the price of ANS crude oil but also indigenous U.S. West Coast crude oil prices.

Table C.3 reports the effects of five different levels of ANS oil export on imputed value of ANS and California indigenous crude oil. These imputed values increase with the volume of ANS oil exports. The value of ANS oil to West Coast refiners would increase from as little as $0.03 per barrel for an export level of 100 mb/d to $2.13 per barrel for an export level of 880 mb/d. The corresponding increase in value of California oil ranges from $0.01 to $1.66 per barrel.

An increase in the value of California oil resulting from the export of ANS oil reflects changes in crude oil imports and changes in utilization of refinery downstream conversion units. Exporting ANS crude and importing lighter crudes that are better gasoline producers would free-up downstream conversion units. Capacity released from processing ANS crude could be used to process other indigenous U.S. West Coast heavy crudes. This increased heavy crude oil processing capability would enable refiners on the U.S. West Coast to produce additional volumes of lighter, more valuable products and would raise the demand for, and prices of, indigenous West Coast heavy crude oils.

Note that simulation results show, without restrictions, 880 mb/d of ANS crude would be exported and the market value of ANS crude would increase by $2.13 per barrel. These changes assume instantaneous adjustment of all markets to the new equilibrium levels. In practice, some time would be required before markets adjust completely. The smaller, market-constrained increases are equivalent to those that would result from gradual change of market conditions resulting from lifting the export ban on ANS oil export.

Table C.3 Effects of ANS Crude Exports on the Valuation of Crude Oil

	Increases in Valuation of Crude Oil (1992 $/Barrel)	
Export Volume (mb/d)	ANS Crude	Average California Crude
100	$0.03	$0.01
300	0.22	0.13
500	0.93	0.64
700	1.37	0.97
880 (unrestricted)	2.13	1.66

Implication for Prices of Refined Petroleum Products

An increase in the price of ANS crude oil on the U.S. West Coast would raise the value of other crude oils produced in that region. In addition, higher-priced imported crude oils would be used to replace exported ANS oil. As a result, the average acquisition cost of crude oils would increase. The prices for refined products might increase also.

The magnitude of changes in prices for refined products depends on factors such as savings in processing costs that could be achieved due to purchase of lighter crude oil, refiners' ability to change refinery configurations in response to changing market conditions, and relative increases in refinery crude oil acquisition costs. Price changes, however, would not be the same for all products.

Price increases for lighter products such as gasoline would be expected to be very small due to two major factors. First, the exportation of ANS crude and the importation of better gasoline-producing crude oils would reduce refiners' processing costs, which could offset all or part of the increase in refiners' crude oil acquisition costs. Second, in a competitive international market, free trade in petroleum products assures that differences in product prices across international refining regions would not exceed transportation costs. In addition, model simulation results show that if refiners can adjust refinery configurations to changing market conditions, marginal costs of producing lighter products may decline slightly.

The price increase for residual fuel oil would probably be greater than for lighter products. Historically, there is a general parity between the prices for crude oil and residual fuel; an increase in the price of crude oil inputs to West Coast refineries would certainly raise the price of residual fuel. Market forces would also ensure higher prices for residual fuel; production of residual fuel would decline because imported crude oils produce a smaller volume of residual fuel. In addition, the exportation of ANS crude oil would enable refiners to convert more heavy crude oils to lighter products.

Overall, lifting the export ban on ANS crude oil would likely have little impact on consumers. The estimated change in gasoline price is less than one-half of a penny per gallon. The economic impact on industrial users would also be small because the share of residual fuel oil in total energy consumption in both industrial use and power generation is very small.

APPENDIX D
PADD V PETROLEUM SUPPLY/DEMAND BALANCE

ANS CRUDE OIL PRODUCTION

During the last few years, ANS crude oil production has continually defied claims of an imminent decline. In its 1991 annual report, for example, Alaska's DNR projected year 1995 ANS crude production to be 1,469 mb/d and year 2000 production was estimated to fall to 997 mb/d. By the 1994 forecast, the year 1995 production estimate had risen to 1,605 mb/d. Year 2000 production was still estimated to fall to near the same level (1,025 mb/d).

In large part, uncertainty about the future decline in ANS oil production is the result of the inability to predict future investment strategies of the small number of large ANS producers and to assess accurately the production response to investment. Usually then, production projections are made on the basis of known projects, and frequently much of the information comes from trade press articles. For these reasons, many times, projections are intrinsically conservative when viewed from the clear perspective of hindsight.

This is a difficult problem to address in a study such as this one, but it argues for employing very recent production forecasts. Several sources of estimates are discussed below.

EIA Data

Preference would be to use EIA ANS crude oil projections that are consistent with the high and low price forecasts. However, EIA AEO94 projections were being revised as we began the quantitative analysis on the ANS oil export study. Therefore, we looked for projections whose price projections approximated EIA's as near as possible.

EG&G Idaho, Inc. Studies

EG&G, the operator of DOE's Idaho National Engineering Laboratory, performed two studies of ANS operations for the DOE Fossil Energy Office. The first[34] was performed to assess the resource potential on the North Slope and to evaluate the effect of production economics on the Alaskan North Slope Oil Delivery System (primarily the pipeline). The second[35] updated the first study and explored several undeveloped fields. Both studies are very useful in assessing the question of whether or not incremental oil price increases could bring about reserve additions, but their baseline projections were somewhat dated. In addition, the models employed by EG&G did not lend themselves to studies of incremental production and the temporal dynamics of production development.

[34] "Alaska Oil and Gas: Energy Wealth or Vanishing Opportunity?", EG&G Idaho, January 1991.

[35] "Alaska North Slope National Energy Strategy Initiative: Analysis of Five Undeveloped Fields", May 1993.

Alaska Department of Natural Resources

The Alaska DNR estimates production each year based on known projects and has tended historically to underestimate production. Similar views were expressed in EG&G studies performed for DOE.[36] Our impression is that projections do not involve detailed field economics or a specific price projection. Rather, they are accumulations of estimates made by others, publicly available project descriptions and their success rates, and whatever information the DNR can obtain from producers. The DNR was a primary source for the EG&G studies discussed above.

We have chosen to use the latest DNR projections as the more pessimistic projection of ANS production. This is because it seems to be largely dependent on production projects that are either underway or very likely to be so soon. This assessment is consistent with the more informed view documented in the EG&G studies. As noted above, year 2000 ANS production is 1,025 mb/d.

Three points are worth noting:

- We altered the forecast slightly to reflect ARCO's more modest prospects for its Sunfish strike by subtracting half the projected production proposed by DNR.

- 1993 ANS production was abnormally low due to maintenance and infrastructure modifications conducted in the summer (e.g., installation of the GHX-2 gas handling facility at Prudhoe Bay). Production was at a low point in July and August, then recovered during the remainder of the year. For this reason, the 1993 average seems low compared to the out-year projections.

- Comments above notwithstanding, the DNR 1994 projection of 1,643 mb/d for ANS production seemed high. Even though the GHX-2 gas-handling facility was estimated to add 50 mb/d by some, an underlying decline would be present. Therefore, we reduced production to 1,600 mb/d for 1994 and 1995. This may understate somewhat the near-term production potential--as is appropriate for the more pessimistic case in this study.

Alaska Department of Revenue

The Alaska DOR employs a "rate of return" model and explicit forecasts of domestic oil prices in its projections. Projects, including new field development, are assumed to be undertaken when they offer producers a given financial payback, then production follows development. The body of projects available, therefore, is not only limited to current activities, but also includes identified possibilities that may be profitable given the right trend in oil prices.

The latest DOR projection we have available was done in the fall of 1993. Three price scenarios were run:

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[36] See also Petroleum Intelligence Weekly, "ARCO's Discoveries Brighten Alaskan Production Prospects," April 26, 1993, p.5. This article observed that with unaccounted for prospects including ARCO's Sunfish project (250 mb/d), enhanced oil recovery (270 mb/d), and new North Slope production (100 mb/d), year 2000 production may be boosted as high as 1,634 mb/d.

- The DOR low-price case seems close to EIA's AEO94 low price scenario. West Texas Intermediate (WTI) crude oil prices stay in the $16.00 to $17.00 range (in 1992 $) for the foreseeable future. Inasmuch as the WTI price is $1.00 to $2.00 higher than the "world oil price," this is very similar to EIA's case. Year 2000 ANS production is 1,176 mb/d, or 151 mb/d higher than the DOR projection for that year.

- In the DOR mid-price scenario, WTI climbs from $18.00 in 1995 to $20.33 by the year 2000. For the difference in price, ANS production rises to 1,268 mb/d.

- In the high-price case, WTI crude rises to the $19.00 range in 1995, and appreciates slowly to slightly over $21.00 by the year 2000. Year 2000 ANS production is almost 1,500 mb/d. EIA's high-price case is somewhat more optimistic in that the comparable WTI price would be about $25.00 per barrel.

We thought that the DOR High Price Case projections provided a reasonable upper bound on ANS production, even though its price range seemed lower than EIA's out-year, high world oil price scenario. For this reason, we employed it to represent the upper bound conditions on ANS production. On a qualitative basis, we discovered that it is quite similar to some producers' optimistic cases for ANS production.

Some have made the case that the DOR projections are too optimistic, particularly for the next few years. That assessment has become more reasonable because oil prices have not significantly recovered from the depressed levels seen at the end of 1993. One argument is that the DOR projections show several hundred thousand barrels per day of production added in the mid-1990s --largely at Prudhoe Bay. Producers have commented that no projects are currently underway that would produce such increases by that time. One might suggest that a more appropriate upper bound case would be to delay the DOR production increases several years. At this point, however, such a modification would be arbitrary, so we decided to remain with the original projection and recognize that it may be overly optimistic.

The DOR production projection rises and falls in the out-years as new projects become productive. It is unlikely, however, that completion of any project could be predicted accurately in time. Therefore, we thought it appropriate to smooth DOR's projection with a three-year moving average.

Table D.1 below presents a synopsize of year-by-year production assumptions for the high and low price case assumptions.

Table D.1 Alaskan North Slope Crude Oil Production Estimates (mb/d)

Year	Pessimistic Case[a]	Optimistic Case[b]	Year	Pessimistic Case[a]	Optimistic Case[b]
1994	1,600	1,628	2000	1,025	1,496
1995	1,600	1,652	2001	907	1,368
1996	1,518	1,679	2002	794	1,261
1997	1,404	1,655	2003	718	1,172
1998	1,282	1,667	2004	624	1,088
1999	1,163	1,582	2005	535	1,003

[a] Based on the Alaska DNR projection.

[b] Based on the high-price projection from the Alaska DOR projection in Revenue Sources Book, Forecast and Historical Data, Fall 1993.

NON-ANS PADD V CRUDE OIL PRODUCTION

As was the case with ANS crude oil production, we originally intended to use EIA AEO94 projections for California oil production, but were dissuaded by the extent to which they diverged from recent history. It was necessary, therefore, to employ a few simple assumptions, based on historic trends, to estimate production during the remainder of the decade. Those assumptions and results follow.

Low Price Case

California Onshore Production--EIA AEO94 projections are clearly too high in that they start from an unrealistic level in 1993 (920 mb/d vs. 801 mb/d actual for January to October). We set a decline rate of 4.5 percent starting at the 1993 average production. The decline rate is the average annual decline between 1985 and 1993. During this period, the decline reached 10 percent one year--associated with the 1986 price drop--and one year there was no decline--associated with the 1990 to 1991 Middle East War.

California Offshore Production--Here the EIA AEO94 estimates are too high in 1993, but probably understate the out-year potential. The principal reason is that production at Santa Ynez will probably rise from its current level of 25 mb/d to 100 mb/d in the next year or two. We assumed addition of 75 mb/d due to Santa Ynez over 1994 to 1995. We did not explicitly consider Point Arguello, which is now producing near its maximum potential of 80 to 100 mb/d. Qualitatively, these observations led to assuming that, in the out-years, offshore production remained constant at 212 mb/d.

Southern Alaska--The early years of the projection are relatively constant. The primary issue here is whether or not developments such as ARCO's Sunfish leases materialize in the future. Because of this uncertainty, and for compatibility with the ANS production projections, we used the Alaska DOR estimates for South Alaska, but with only half the Sunfish production realized. This is consistent with ARCO's recent pessimism regarding that find.

Other States--Nevada produces a small amount of crude oil (4 to 5 mb/d), and may have some additional potential. California State waters may also have some additional potential. For that reason, we added 10 mb/d attributed to "other states."

High Price Case

California Onshore Production--California wellhead oil prices in this scenario increase 40 percent during the 1993 to 2000 period. Analysis of historic price production/relationships for the State indicates that a supply elasticity of 0.15 fit the data well with a two-year lag. Employing this relationship curtails the drop in California onshore production and causes it to increase slightly during the remainder of the decade. This is consistent also with statements made by California independent producers that reserves depletion is not a major factor. Rather, current period economics dictate whether or not production will rise or fall.

California Offshore--Most of California areas are under leasing moratoria that will prevent new developments. In addition, pipeline constraints and the inability to permit onshore processing facilities for crude oil will prevent any significant new production during the remainder of the decade. For that reason, we have not varied offshore production levels from the low-price case.

Southern Alaska--The projection here is exactly that of the DOR, including all of the ARCO Sunfish discovery.

Other States--Same as for the Low Price Case.

PADD V CRUDE OIL REQUIREMENTS

Crude oil requirements are dictated by indigenous petroleum product consumption. We elected to employ EIA's AEO94 projection for West Coast product demand in both the high and low price cases, but it was necessary to make a few adjustments. EIA's AEO94 forecast is for Census Region 9, which is identical to PADD V except that it does not include Arizona. For that reason we raised Region 9 consumption by 6.5 percent to represent total PADD V. In the base year of 1993, we used actual 1993 PADD V consumption ("Product Supplied" from EIA's Petroleum Supply Monthly) for reference purposes.

Due to refinery gain, NGL consumption, and a few other factors, crude oil requirements at refineries are always less than product output. For the past five years, product consumption in PADD V has exceeded crude oil put into refineries by 4.3 to 5.3 percent. To capture the dynamics of the balance in the region, we assumed that product consumption exceeded crude oil requirements by 4.5 percent in the out-years. This carries with it the implicit assumption that refinery capacity will grow slightly in the future as regional demand rises.

Even during periods of very high ANS crude output, and large volumes being shipped to the rest of the United States, PADD V still imported several hundred thousand barrels per day of foreign crude oil. The reason may be that the crude was favorably priced, or, more likely, lighter crudes were needed to meet light product requirements. To represent this phenomena, we assumed that 231 mb/d of crude oil, the average over 1989 to 1993, will continue to be imported as part of the basic supply to PADD V. As indigenous PADD V crude oil production falls, a deficit is created even with this foreign crude, and that would be filled with additional imports.

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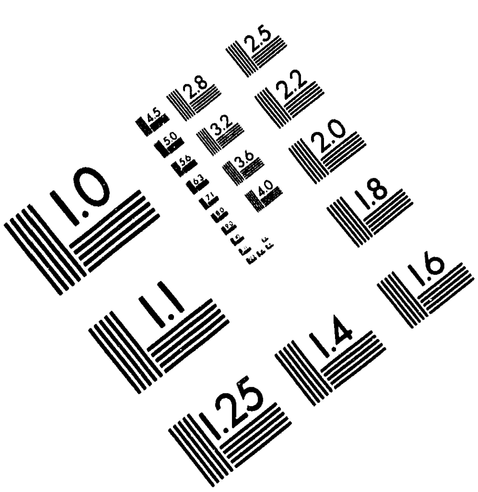

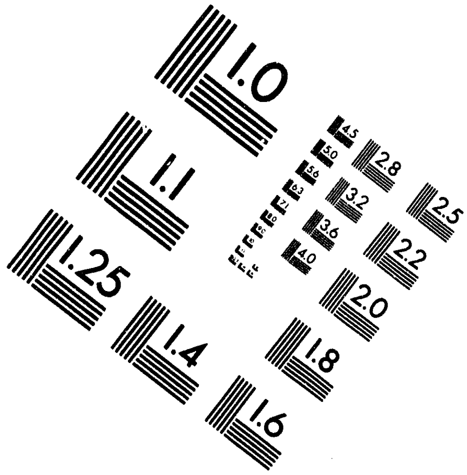

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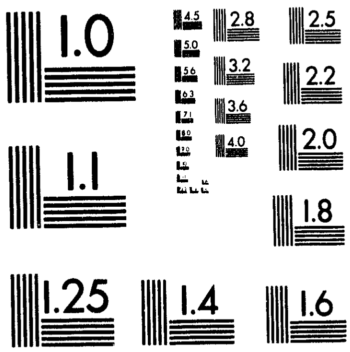

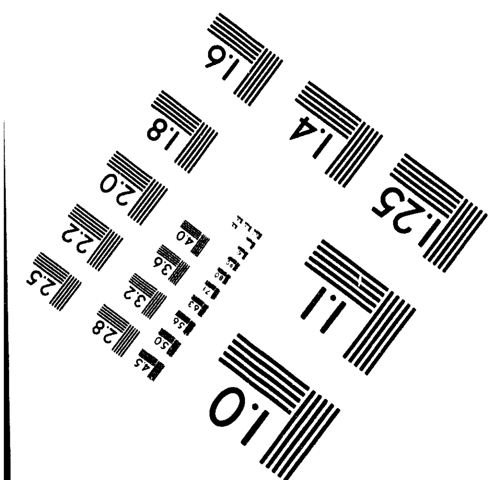

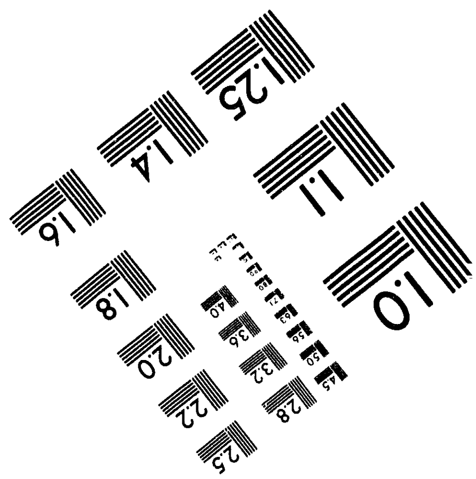

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ALLOCATION OF PADD V CRUDE OIL SURPLUS

Allocation of the surplus production in PADD V is necessary to compute maritime shipping requirements. Based on the 1993 data, which are actual historic observations, we derived the out-year balances for the no-export case using the following logic:

- o Gulf Coast--It is most expensive to ship ANS crude oil to the U.S. Gulf of Mexico market. BP uses long-lease tankers to move the oil to Panama where it transits the trans-Panama pipeline to the U.S. Gulf, then it is delivered by small ships that are short-term chartered. While the cost of this trip is at least $1.50 more than shipments to California, BP sells ANS crude in the Gulf of Mexico at a premium of less than $1.00 over California prices. This is done for small quantities to prevent dumping the oil into California markets and depressing prices for the majority of BP's sales there.

- o Virgin Islands--BP has a supply contract with Hess in the Virgin Islands to supply crude oil at prices that are convenient to both parties. We do not know the details of that arrangement but know that it must be renewed periodically and that it involves rather complex pricing terms. A reasonable conclusion is that BP receives a better return than selling ANS crude in the Gulf of Mexico market, but it is not as profitable as West Coast sales. Therefore, we assumed that if ANS oil could not be exported, the Virgin Islands would receive an ANS crude supply until the surplus expired. These shipments are not a major factor in maritime considerations because they can, and do, employ foreign-flag shipping.

- o Mid-Continent--BP has a contract with ARCO to transport ANS crude from Los Angeles on its Line 90 pipeline to Cadiz, California, where it enters the All American Pipeline system and moves to West Texas. From there it is transported through other pipelines to mid-continent refineries. BP receives favorable pricing on the pipelines so that, in our estimate, the net back to Valdez is comparable to the Virgin Islands shipments. Therefore, we have assumed that, like the Virgin Islands, BP will continue to ship to the mid-continent as long as a PADD V surplus exists.

- o California Crude Shipments East--Celeron, an All American Pipeline affiliate, purchases, blends, ships, and sells California crude in California as well as at the eastern end of the All American Pipeline system. Some may follow ANS crude into mid-continent refineries. We expect that this will remain a viable strategy as long as prices are depressed on the West Coast. When exports begin, or the surplus expires, we assume that these shipments will no longer take place.

The PADD V surplus would continue throughout the decade if prices recover and remain high. Of note in the high price case are our assumptions that:

- o ANS oil shipments to the mid-continent are restricted only by pipeline capacity during most of the decade.

- o With ANS oil flowing through the All American Pipeline, it is likely that the pipeline's trading affiliate will still see it as economical to purchase and ship mid-California crudes east at their present rate.

- o Faced with a choice to ship to the Virgin Islands or sell in the Gulf of Mexico spot market, we believe that ANS crude sellers will take the former approach, Therefore, we kept Virgin Islands shipments near their highest historic levels until the surplus begins to disappear.

Tables D.2 and D.3 show the results of the above assumptions.

Further consideration of PADD V supply was necessary to examine shipping requirements. This is treated in detail in the discussion of the tanker analysis.

Table D.2 PADD V Crude Oil Supply/Demand Balance--Low Price Case

	1993	1994	1995	1996	1997	1998	1999	2000
Domestic Crude Supply (Volumes in mb/d)								
California Onshore	801	765	731	698	666	636	608	580
California Offshore	137	175	212	212	212	212	212	212
Alaska N.[a]	1,541	1,600	1,600	1,518	1,404	1,282	1,163	1,025
Alaska S.[b]	42	34	32	29	39	36	33	30
Other States	10	10	10	10	10	10	10	10
Total Supply	2,531	2,583	2,585	2,467	2,331	2,176	2,026	1,857
Product Consumption (Volumes in mb/d)								
Region 9	NA	2,512	2,571	2,600	2,650	2,691	2,738	2,787
Arizona	NA	163	167	169	172	175	178	181
Total Consumption	2,635	2,676	2,738	2,769	2,822	2,866	2,916	2,968
Crude Oil Requirement (Volumes in mb/d)								
Total Requirement[c]	2,527	2,566	2,625	2,656	2,706	2,749	2,796	2,846
Domestic[d]	2,252	2,335	2,394	2,425	2,475	2,518	2,565	2,615
PADD V Surplus[e]	279	248	190	42	(144)	(341)	(539)	(758)
Distribution of Shipments								
ANS Crude to Virgin Islands	97	84	84	0	0	0	0	0
ANS Crude to Mid-Continent	60	85	56	0	0	0	0	0
California Crude to Mid-Continent	53	53	50	42	0	0	0	0
ANS Crude to Gulf of Mexico	69	26	0	0	0	0	0	0

Note: Numbers may not add due to rounding.

[a] Alaska North low in 1993 due to maintenance, GHX2 project.

[b] DNR Forecast; 12 Sunfish used.

[c] Product consumption (exclusive of refinery fuel use) times the ratio of product consumption to crude inputs in the Petroleum Supply Annual for 1989 to 1993 (about 95.5 percent).

[d] Assumes minimum of 231 mb/d of imports based 1989 to 1993 data.

[e] PADD V production minus domestic crude oil requirement.

Table D.3 PADD V Crude Oil Supply/Demand Balance--High Price Case

	1993	1994	1995	1996	1997	1998	1999	2000
Domestic Crude Supply	(Volumes in mb/d)							
California Onshore	801	765	750	754	759	765	771	778
California Offshore	137	175	212	212	212	212	212	212
Alaska N.[a]	1,541	1,628	1,652	1,679	1,655	1,667	1,582	1,496
Alaska S.[b]	42	40	39	41	43	65	73	72
Other States	10	10	10	10	10	10	10	10
Total Supply	2,531	2,617	2,663	2,696	2,679	2,720	2,649	2,568
Product Consumption	(Volumes in mb/d)							
Region 9	NA	2,496	2,542	2,558	2,591	2,621	2,656	2,695
Arizona	NA	162	165	166	168	170	173	175
Total Consumption	2,635	2,659	2,708	2,725	2,759	2,792	2,829	2,870
Crude Oil Requirement	(Volumes in mb/d)							
Total Requirement[c]	2,527	2,522	2,568	2,584	2,617	2,648	2,683	2,722
Domestic[d]	2,252	2,291	2,337	2,353	2,386	2,417	2,452	2,491
PADD V Surplus[e]	279	327	325	343	293	303	197	77
Distribution of Shipments								
ANS Crude to Virgin Islands	97	100	100	100	100	100	57	0
ANS Crude to Mid-Continent	60	85	85	85	85	85	85	22
California Crude to Mid-Continent	53	55	55	55	55	55	55	55
ANS Crude to Gulf of Mexico	69	87	85	103	53	63	0	0

Note: Numbers may not add due to rounding.

[a] Three-year moving average of DOR High Price Scenario.

[b] Includes total DOR forecast.

[c] See low price case note.

[d] Same as low price case.

[e] PADD V production minus domestic crude oil requirement.

APPENDIX E
INCREMENTAL CRUDE OIL PRODUCTION

BACKGROUND

If exports of ANS crude oil raise crude oil prices or save on costs of shipping and handling, the resulting revenues may be invested in oil production-related projects in the geographical areas where the new profits are made. This is particularly true for small companies, but less so for the major integrated companies.[37] Whatever the investment strategy, to assess the impact of an ANS export decision, we must relate revenue generation to incremental production.

ESTIMATING INCREMENTAL PRODUCTION

Two separate efforts were involved.

- o ANS Crude Oil Production--Here, we employed historic relationships between non-pipeline investment and reserve additions for the North Slope, and calculated incremental production from the reserves added.

- o California Crude Oil Production--To assess the effects of a price increase in the State, our consultant[38] constructed a rate-of-return model that accounted for the unique aspects of California production economics (such as extensive use of TEOR).

The results are described below.

Alaskan North Slope Production

Alaskan projects are expensive and take a relatively long time to affect production. Wells and associated equipment tend to produce at the same rates (subject to normal decline), independent of short-term aberrations in prices. As was clear in 1986 and 1987, however, prices affect investment directly. The result is a delayed production response.

<u>Methodology</u>

Figure E.1 shows the reserves-investment relationship clearly. As investment fell in the late 1970s, reserve additions also dropped. Both responded sharply to the rise in prices in the early 1980s and the decline in the middle of the decade.

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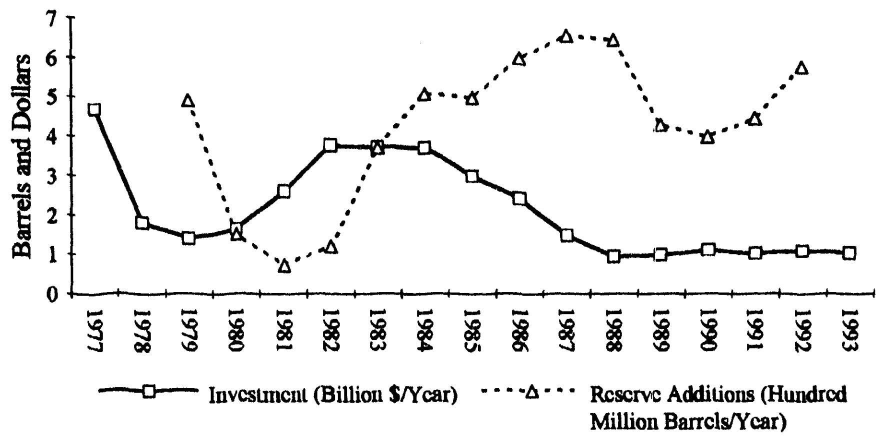
[37] The large ANS producers made it clear in our interviews that they allocate company investment where potential returns are high. If North Slope production projects are not as rewarding as other opportunities open to a company, they would not necessarily reinvest in Alaska the incremental revenues made as a result of exporting ANS crude oil.

[38] Advanced Resources International, Arlington, Virginia.

Figure E.1 Alaska Oil Reserve Additions versus Investment--3-Year Moving Averages



Employing the data that support the figure and historic production statistics, the cost (in 1992 $) per barrel of reserve additions can be estimated as follows:

Table E.1 Cost of Reserve Additions (Production and Reserves in Million Barrels; Investment in Millions of 1992 $)

North Slope Production to Date	9,188
Plus Current Reserves (Total Alaska-Cook Inlet)	6,151
Sum of North Slope Oil	15,339
Total Non-Pipeline Investment (1992 $)	$44,605
$/Barrel for Proved Reserves	$2.91
1988-1993 Reserve Additions	3,013
Non-Pipeline Investment	$6,179
$/Barrel for Proved Reserves	$2.05

<u>Observations</u>

If monies from higher ANS oil prices and shipping cost savings are invested in production-related activities, then the reserve additions would add incrementally to ANS production. The following table exhibits the dynamics of incremental production making the following assumptions:

- o Investment--$100 million per year.
- o Production buildup from reserve additions--zero the first year, 25 percent of the maximum rate the second year, 50 percent of the maximum rate the third year, and the maximum rate in the fourth year.

- o Three years at the maximum rate.

- o Production decline rate--12 percent per year.

Table E.2 shows the effect of a constant $100 million investment each year. Although the production rate is slow to build, by the end of the decade it will have reached 30 to 40 mb/d. This figure would be higher or lower depending on the amount available for investment yearly.

Table E.2 Average ANS Production Rate from $100 Million in Reserve Additions (mb/d)

	Cost of Reserve Additions	
Year	$2.34/Barrel	$2.91/Barrel
1995	0	0
1996	3.01	2.12
1997	9.04	6.37
1998	21.10	14.87
1999	33.16	23.36
2000	45.22	31.86
2005	86.98	61.28
2010	109.02	76.80

In this study, we estimated the amount of after-tax investment revenue that would be available each year, then used the above methodology to calculate yearly production. We made the following reasonable assumptions:

- o Gross incremental revenues were reduced by royalties, severance, and income taxes before investment.

- o Some producers, whose combined share of ANS production totals about 45 percent, do not now and probably would not ever sell significant amounts of their crude oil in the export market because they refine it themselves on the West Coast. Unless product prices rise along with crude oil, these companies do not benefit financially. If no product price increase occurs, there are no incremental revenues generated to invest in additional production.

- o We assumed that all the incremental revenues for the remaining producers' share is invested in ANS crude production activities that add to reserves.

- o The cost of acquiring reserves was assumed to be the lower figure in the above table ($2.05 per barrel). This assumption reflects the fact that investment during the early years of ANS oil production included infrastructure construction that is not appropriate to apply here.

California Crude Oil Production

The situation in California is vastly different from Alaska due to the different qualities of crude oil and production methods. Whereas Alaskan crude is of intermediate quality (about 27 degree API with 1 percent sulfur), and currently requires only modest use of enhanced recovery methods, much of California crude is very heavy (e.g., 13 degree API) and requires extensive use of TEOR technology. Although production efforts in Alaska are very capital intensive, per barrel variable costs are low compared to the $7.00-$8.00 per barrel average for California crude oil.

High variable costs in California make production very price sensitive when absolute prices are depressed. This is the situation in our low price case. World oil prices in the $15.00 per barrel range imply California heavy oil prices of $10.00 and under. At this level, routine activities such as maintenance and drilling are often curtailed. This leads, after a delay, to wells being shut-in. At that point, production falls sharply.

Methodology

An investment model[39] for California light and heavy oil fields was constructed to estimate incremental production that might result from a wellhead price increase for indigenous crude oil. The additional level of methodological complexity was necessary because a simple econometric method of employing price elasticities of supply does not adequately portray the complex situation described above. Developing the model involved a field-level analysis of California oil production and its financial characteristics. Four main sources of incremental production were addressed explicitly:

- o Existing Stock of Wells--1992 field level statistics were used to describe and categorize the more than 41,000 producing wells in the State. The model dynamically examines each category over time, as its production declines, to estimate the fraction of production that falls below the financial shut-in threshold. Higher prices create more revenue, thereby keeping a larger portion of the existing well stock above the shut-in threshold.

- o Replacement Wells--Routinely, a small fraction of existing wells are taken out of operation for various technical reasons usually related to maintenance or unexpected developments. Putting these wells back in service requires a capital outlay that may not be justified if prices are low. The model simulates this activity by evaluating whether existing prices warrant the investment. No infrastructure costs are assumed (e.g., steam generation) to be incurred in this process.

- o In-Fill Drilling--Better economic conditions (i.e., higher oil prices) justify increased drilling in areas that have not been efficiently swept with the existing stock of wells. This may involve introducing existing steam generation to new wells or drilling in nearby areas that are not well drained due to non-heterogeneity of the geological structure. In this case, development incurs the cost of drilling and surface structures, but not such large expenditure items as steam generation and pipelines. Because these activities are within developed areas,

[39] Described in detail in "Assessment of the Impact on California Oil Production from Lifting the Ban on ANS Exports", Advanced Resources International, Arlington, VA, June 1994.

the reserves recovered per well are reduced from the level normally seen in each particular field.

- Expansion to New Areas--While California is a mature producing area, even within well-developed fields there are areas that could be converted to TEOR, drilled deeper, or redrilled using more modern techniques. This category of investment requires the highest capital outlay (all surface facilities expenses are assumed to be incurred); therefore, it is the last type of production to contribute as prices rise. If steam-electric power cogeneration is present, it is assumed that sale of the electrical power pays the capital costs of the steam generation equipment and the producer incurs the variable cost of steam generation. Without cogeneration, all steam generating capital costs must be paid by the project.

These four categories should be viewed as activities that take place, as prices rise, in the order described. For example, if underlying prices are low, a modest price increase will essentially only preserve the existing stock of wells longer. If underlying prices are high, that is already being accomplished by the market and investment of incremental revenues would tend to go to categories 3 and 4.

Activities that qualify on economic grounds come on-line after an appropriate delay period: their contributions to production also include build up and decline phases. For this reason, some of the output may include rather abrupt increases in production due to prices having passed through an earlier threshold. In reality, this does not happen due to the diffuse nature of investment decision making in the real world. Although this may constitute an over-stylization, it is not indicative of inaccuracy in the aggregate sense over time.

Observations

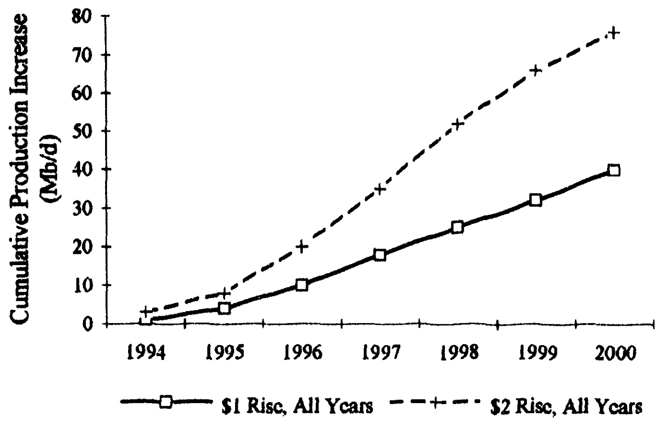
Figures E.2 and E.3 show how the model estimates that incremental production would change in the low and high price scenarios if California wellhead prices rose $1.00 and $2.00 per barrel. Price increases were held constant over the 1994 to 2000 period.

The incremental effects of a $1.00 to $2.00 increase are substantial in the low price scenario. This is not to say that $1.00 or $2.00 per barrel in the low price case corrects the decline in California oil production--it does not. The effect of continued prices in the $10.00 range or lower throughout the decade have a devastating effect that increases over time. In the low price case, the 1997 California production decline rate, with no price increase, is about 11 percent. Adding $2.00 per barrel to wellhead price reduces the decline rate from 11 percent to about four percent.

This price change might be put in context by recalling that the low price scenario produces average California wellhead prices of $10.00 or less. While average variable production costs in California currently are in the $7.00 to $8.00 per barrel range, a significant number of producers have variable costs above $10.00, and they would eventually shut in wells. In addition, fixed costs can only be ignored for a time; they then must be included in consideration of companies' financial viability. In the model, as in reality, when wells' revenue flows fall to the point that fixed and variable costs exceed revenues substantially, production that would be profitable at higher prices is shut in. For this reason, small price increases provide large incremental production effects when base prices are low.

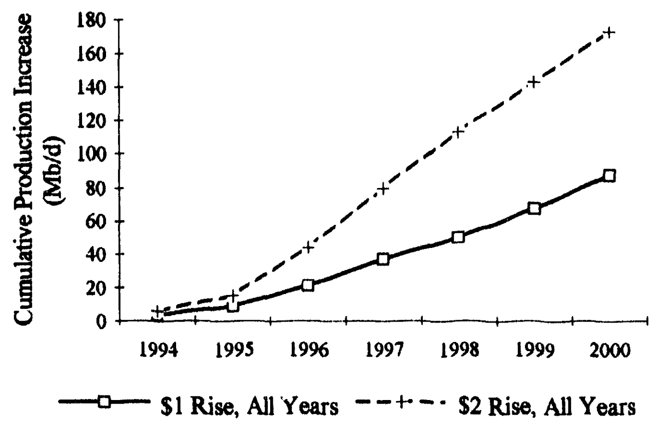
Figure E.3 shows the effects of similar price increases in the high price case. While significant, the absolute effects shown are less than half that of the low price case. This is because the base price level is substantially above operating costs for much of the decade. Some of the existing stock of wells would be lost as production declines so that revenues no longer cover fixed and variable costs, but the effect is much smaller than in the low price case.

Figure E.2 Effect of California Oil Price Increase -- High Price Case



Price increases in the high price case provide for higher levels of investment that better perpetuate State production levels. What would have been a three percent production decline rate by 1997 falls to less than one percent with a price boost of $2.00 per barrel.

Figure E.3 Effect of California Oil Price Increase -- Low Price Case



The situations described above do not fully describe the dynamics of cases explored in this study, particularly in the low price case. A fundamental assumption is that when PADD V crude oil production falls to the point that there is no longer a substantial over-supply, depressed oil prices will rise toward[40] their market values. By 1997, in the low price case, a PADD V deficit has developed so that about 150 mb/d of additional foreign crude oil would have to be imported.

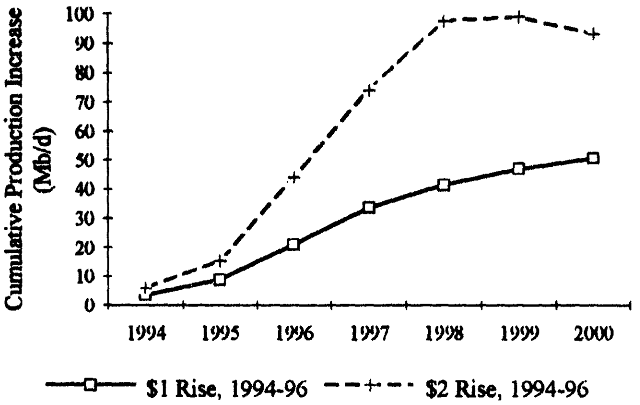
If falling ANS and California production creates a supply deficiency on the West Coast which raises prices, then this would account for some of the production effect shown in Figure E.2 above. It would not be appropriate to treat this "market-related" incremental production as a direct product of removing the ban on ANS crude exports.

Figure E.4 shows the effect of this refinement for the low price case assuming that exports raise California oil prices during 1994 to 1996, then market forces take over. Prior to 1997, incremental production rises as in Figure E.2. By 1998, however, an increasing fraction of the

[40] Toward, not necessarily "to" their market value. Specifically, without other actions to open the market for California crude oil, price will not rise to the true market value at refineries.

additional production is attributed to market forces. Production brought on by the initial price boost begins to decline and actually decreases in the $2.00 per barrel case. The net effect is that, by the year 2000, about half the incremental production shown in Figure E.2 would be attributed to exporting ANS crude oil.

Figure E.4 Effect of California Oil Price Increase -- Low Price Case



APPENDIX F
IMPACT OF REMOVING ALASKAN OIL EXPORT BAN ON U.S.-FLAG TANKERS

The U.S. maritime industry will be impacted by any lifting of the ban on ANS crude exports. As a result of the Jones Act (The Merchant Marine Act of 1920), U.S.-flag tankers transport most ANS crude.[41] If the ban is lifted and some of this oil is exported, foreign-flag tankers are likely to transport that oil, if no statutory reservation is made requiring use of U.S.-flag vessels. This will accelerate the loss of U.S. ships, which will be laid up, scrapped, or sold as ANS crude production decreases.

THE LOW OIL PRICE SCENARIO

Under this study's low price scenario, ANS production will peak in 1995 and decline to about one million barrels per day in 2000. Between 1993 and 2000, MARAD estimates that 14 ships will be lost due to declining ANS production, even if the ban stays in place. However, if the ban is lifted and there are exports of only enough ANS crude to eliminate the so called "West Coast surplus," the same tanker losses will occur as in the no-export case, but earlier. For instance, in 1995 in the no export case, 33 full-time tankers will be required. Allowing only for exports of the West Coast surplus, five additional ships will be lost in 1995.

THE HIGH OIL PRICE SCENARIO

Under the high price scenario, ANS production will peak in 1996 and decline to 1.5 million barrels per day in 2000. Under this scenario with the ban on exports in place, fleet requirements would rise to 38 tankers in 1994 to 1996. Of this fleet size, 29 vessels will be required to transport ANS crude oil to the West Coast, compared with 21 under the low price case. Exports of only the West Coast surplus would eliminate the requirement for nine vessels in 1995. With additional exports of 300 mb/d, only 23 vessels will have employment in 2000, versus 29 if exports were not allowed.

THE U.S. TANKER FLEET

The U.S.-flag tanker fleet relies heavily on the ANS crude oil trade. In 1993, the U.S.-flag tanker fleet, as reported in the MARAD annual report (including specialized carriers such as LNG, chemicals, etc.) had 185 vessels totaling 12.45 million dwt. Eliminating special purpose vessels, the tanker fleet contained 151 ships with 10.9 million dwt. MARAD fleet forecasts show that the tanker fleet faces significant losses by 2000 due to continued declines in trade other than ANS crude deliveries. These losses will occur with or without the ANS crude oil export ban in place. Lifting the ban, however, will accelerate tanker losses since there are virtually no alternative uses for these vessels.

Demand for U.S.-flag tankers rose with the need to transport ANS crude to U.S. ports and recently, as ANS production has declined, so has demand for U.S.-flag tankers. From 1988 to

[41] In 1993, U.S.-flag tankers transported 94 percent of all ANS crude oil. The remainder was shipped on foreign-flag tankers to the U.S. Virgin Islands, which are currently exempt from Jones Act requirements.

1993, U.S.-flag tanker employment on all ANS crude routes has declined from the full-time equivalent of approximately 55 ships and 5.4 million dwt to 35 tankers (19 percent of the fleet) totaling 4.3 million dwt (34 percent of the deadweight tonnage of the fleet).[42] Over these same years, Alaskan crude oil production decreased from 1,970 mb/d in 1988 to about 1,550 mb/d in 1993.

ANS crude oil production and the employment of U.S.-flag tankers are linked because the Export Administration Act of 1979 effectively prohibited the exports of ANS crude and the Jones Act requires that U.S.-built, U.S.-flag vessels transport all cargoes between U.S. ports.

BASIS FOR THE ANALYSIS

A review of tanker employment in the ANS trades since 1987 shows the gradual decline in numbers of U.S.-flag domestic trade vessels.

Table F.1 Vessel Employment

	Days Employed	Number of Vessels	Full-Time Equivalents[a]
1987	19,737	75	56
1988	18,577	70	53
1989	14,350	65	41
1990	13,132	56	38
1991	13,893	56	40
1992(P)	13,013	55	37
1993(P)	11,031	45	32

[a] Days employed divided by 350 days full employment/year.
(P) Preliminary Data

For the vessel projections and transportation cost estimates used in this study, full-time employment was assumed based on an average of 350 days per year per vessel, less positioning time when vessels switch normal destinations. However, Table F.1 shows that the ANS trades have offered a substantial amount of part-time employment to vessels primarily engaged in other trades over the years.

Actual capital and operational costs of the vessels expected to be employed in the ANS vary significantly by operator and the specific characteristics of individual vessels. Accordingly, estimates were employed for capital, operation, and fuel costs by vessel size class, and are shown in Table F.2.

[42] Percentages include special purpose vessels used for chemicals, LNG, etc.

Table F.2 U.S.-Flag Domestic Trade Vessels

Vessel Size (dwt)	Operating Cost ($/Day)	Fuel Rate ($/Sea Day)	Capital Cost ($/Day)
35-55,000	$15,400	$ 5,625	$11,150
60-75,000	16,450	5,625	20,570
90,000	15,425	9,000	25,920
120,000	15,685	10,500	37,020
150-190,000	15,450	11,250	40,390
200,000 +	15,340	12,000	42,260

Fuel costs depend on the type of main engines (steam or diesel) as well as assumed speed of the vessels. Most tankers in world trades are now diesels and travel at reduced speeds (10-14 knots) to conserve fuel. For the domestic trade analysis, we assumed that the primarily steam-driven vessels would continue to operate at or near their average design speeds (15.5 knots), with a fuel cost of $75 per metric ton.

Table F.3 provides the round trip distances used to develop the days per voyage and maximum number of voyages per year. Days per voyage also reflect special port conditions such as lightening requirements.

Table F.3 Voyage Parameters

From	To	Distance In Nautical Miles	Days/ Voyage	Voyages/ Year
Valdez	Nikiski	666	5.8	60.4
	Puget Sound	2,450	10.6	33.1
	San	3,430	14.0	25.0
	Francisco	4,111	14.8	23.7
	Los Angeles	4,924	17.2	20.3
	Hawaii	9,324	30.2	11.6
Panama	U.S. Gulf	3,080	11.8	29.7
Valdez	Yokohama	6,802	22.0	15.9
Kuwait	Yokohama	13,428	44.0	8.0
Kuwait	Los Angeles	22,982	72.4	4.8

ESTIMATES OF FUTURE U.S.-FLAG TANKER REQUIREMENTS

Tables F.4 through F.7 present estimates of future U.S.-flag tanker requirements based on four scenarios of ANS crude oil distribution developed by the working group. Table F.4 assumes that the export ban stays in place and Alaskan crude production declines according to EIA base case estimates. This decline results in a loss of two tankers in 1995 and a loss of 12 more by the year 2000.

Table F.4 Export Ban in Place--Low Price Case
(Yearly Oil Averages in mb/d)

	1993	1995	1998	2000
Total ANS Crude Loadings	1,545	1,600	1,282	1,025
West Coast Destinations	1,375	1,516	1,282	1,025
U.S. Gulf Coast (Tanker)	70	0	0	0
U.S.-Flag Tankers Required	35	33	25	21

Source: MARAD estimates.

Table F.5 is based on DOE estimates that assume a higher world oil price in the future than in the base case,[43] and has a higher ANS crude oil production level and higher loading levels in 1994 to 2000 compared to Table F.4. Table F.5 reflects a possible "best case" scenario for the maritime industry because the higher associated production levels would sustain higher levels of tanker employment than with the export ban in place. This table shows an actual gain of three tankers by 1995 and a net loss of only six vessels by 2000.

Table F.5 Export Ban in Place--High Price Case
(Yearly Oil Averages in mb/d)

	1993	1995	1998	2000
Total ANS Crude Loadings	1,545	1,652	1,668	1.496
West Coast Destinations	1,375	1,467	1,504	1,496
U.S. Gulf Coast (Tanker)	70	85	63	0
U.S.-Flag Tankers Required	35	38	31	29

Source: MARAD estimates.

Table F.6 assumes that the export ban is lifted in 1994 and sufficient ANS crude exports occur to eliminate the West Coast surplus. As in Table F.4, ANS crude production declines according to DOE base case estimates. As is shown in Table F.6, with the export ban lifted, all oil that would have been shipped to the Gulf and by the All American Pipeline to the Midwestern United States, is exported. The West Coast continues to receive ANS crude oil at the same level as the Table F.4 scenario after adjusting for California oil that would be backed out of mid-continent destinations. These assumptions result in tanker requirements in 1998 and 2000 that are the same as those in the Table F.4 scenario. This is because exports are assumed to cease in 1997 when the shortage of crude on the West Coast revises West Coast crude prices to world levels. By 1997 to 1998, ANS crude production will have declined to the extent that no oil will be shipped to the Midwestern United States, either with or without the ban.

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43 DOE assumes world crude oil prices of $16.38 in 1993 and $15.44 in the year 2000 for its base case estimates and $16.38 in 1993 and $24.16 in the year 2000 for its high price estimates.

Table F.6 Export Ban Lifted--Low Price Case, Export Surplus Only[a]
(Yearly Oil Averages in mb/d)

	1993	1995	1998	2000
Total ANS Crude Loadings	1,545	1,600	1,282	1,025
West Coast Destinations	1,375	1,411	1,282	1,025
U.S. Gulf Coast (Tanker)	70	0	0	0
U.S.-Flag Tankers Required	35	28	25	29

Source: MARAD estimates.

[a] Exports begin in 1994 at a level of 248 mb/d and decline to zero by 1997.

Table F.7 reflects the assumption that the export ban is lifted in 1994 and that an additional 150 mb/d are exported. This will require additional foreign oil imports at an approximately equivalent amount to the 150 mb/d exported. We assumed that certain institutional factors, such as contractual agreements and producers supplying their own West Coast refineries, could be abrogated instantly. If that was not the case, then maritime shipping costs and export benefits would both be lessened. These assumptions result in a loss of nine tankers in 1995 and five more by 2000.

Table F.7 Export Ban Lifted--Low Price Case, Export Surplus Plus 150 mb/d[a]
(Yearly Oil Averages in mb/d)

	1993	1995	1998	2000
Total ANS Crude Loadings	1,545	1,600	1,282	1,024
West Coast Destinations	1,375	1,260	1,282	1,024
U.S. Gulf Coast (Tanker)	70	0	0	0
U.S.-Flag Tankers Required	35	26	25	21

Source: MARAD estimates.

[a] Exports begin in 1994 at a level of 397 mb/d and decline to zero by 1997.

Table F.8 presents summarized results for the case where the export ban is lifted and 300 mb/d are exported in addition to the amount required to eliminate the West Coast surplus referred to above. The additional imports required now rise to 300 mb/d in 1994, with total exports reaching 547 mb/d. This is an extreme and somewhat unlikely scenario.

Table F.8 Export Ban Lifted--Low Price Case, Export Surplus Plus 300 mb/d[a] (Yearly Oil Averages in mb/d)

	1993	1995	1998	2000
Total ANS Crude Loadings	1,545	1,600	1,282	1,024
West Coast Destinations	1,375	1,111	1,282	1,024
U.S. Gulf Coast (Tanker)	70	85	0	0
U.S.-Flag Tankers Required	35	23	25	21

[a] Exports begin in 1994 at a level of 248 mb/d and decline to zero by 1997.

Tables F.9 to F.11 show results for the high price case that are comparable to the low price Tables F.6 to F.8.

Table F.9 Export Ban Lifted--High Price Case, Export Surplus Only (Yearly Oil Averages in mb/d)

	1993	1995	1998	2000
Total ANS Crude Loadings	1,545	1,652	1,668	1,496
West Coast Destinations	1,375	1,328	1,366	1,420
U.S. Gulf Coast (Tanker)	70	0	0	0
U.S.-Flag Tankers Required	35	28	26	29

Source: MARAD estimates.

Table F.10 Export Ban Lifted--High Price Case, Export Surplus Plus 150 mb/d (Yearly Oil Averages in mb/d)

	1993	1995	1998	2000
Total ANS Crude Loadings	1,545	1,652	1,668	1,496
West Coast Destinations	1,375	1,178	1,216	1,270
U.S. Gulf Coast (Tanker)	70	0	0	0
U.S.-Flag Tankers Required	35	23	23	24

Source: MARAD estimates.

Table F.11 Export Ban Lifted--High Price Case, Export Surplus Plus 300 mb/d (Yearly Oil Averages in mb/d)

	1993	1995	1998	2000
Total ANS Crude Loadings	1,545	1,652	1,658	1,496
West Coast Destinations	1,375	1,028	1,066	1,120
U.S. Gulf Coast (Tanker)	70	0	0	0
U.S.-Flag Tankers Required	35	23	20	23

Source: MARAD estimates.

EMPLOYMENT IMPACTS ON SEAFARERS

Declining tanker demand on domestic routes will reduce seafarer employment even if the export ban is not lifted. Based on the export scenarios developed by the working group, MARAD estimates of ship losses would eliminate from 130 to 340 seafarer billets. The number of billets on a ship is multiplied by 2.36 in order to estimate the number of seafarers required to fill a billet on a yearly basis. Therefore, the loss of these billets equates to employment losses from about 310 to 790 seafarers in the high and low price cases, respectively. The peak impact of exports in the scenarios considered would occur in 1995. Under the somewhat unlikely condition that all the PADD V surplus plus as much as 300 mb/d from PADD V itself could be exported, then the job losses in 1995 might approach:

- 741 seafarer jobs in the low price case.
- 934 seafarer jobs in the high price case.

It should be noted that, in the low price case, by 1997 to 1998, these jobs would have been eliminated even if imports would not be allowed. In the high price case, of the 934 jobs "lost" due to exports, 186 would be jobs that would be added after 1993 due to increased tanker requirements in that scenario.

These estimates are direct employment effects and do not include shoreside support or administrative staffs that would be reduced as well. They also do not include indirect employment effects in support industries.

EFFECTS ON U.S. SHIPBUILDING MARKETS

The shipbuilding industry is concerned that encouraging the export of ANS crude at any level today will discourage the timely replacement of domestic trade eligible tankers reaching the end of their statutory lives under OPA90. This becomes a major issue for most vessels currently employed in ANS crude trade in the 1997 to 2004 period. Ship owners, both oil companies with proprietary fleets and independents, cannot be expected to commit the large capital investments for domestic construction of double-hull tankers if there is a reasonable expectation of exporting unlimited amounts of ANS while importing equivalent amounts, all on foreign-built tankers. They provide every incentive to delay replacement decisions.

IMPACTS ON GOVERNMENT GUARANTEED LOANS

As U.S.-flag tanker demand continues to decline, the Federal Government is exposed to possible loan defaults under the Title XI loan program.[44] Of the 151 general purpose tankers in the fleet as of October 1, 1993, 23 had outstanding Government guaranteed loans totalling $404 million. Since most major oil companies had access to relatively inexpensive long-term capital for their proprietary fleets, and thus did not make use of this program, the Title XI guarantees are concentrated in the independently owned sector. At least 15 are actively employed in ANS crude trade. These are the vessels most likely to be displaced by exports.

DoD CONSIDERATIONS

DoD and the DOT are currently working on estimates of personnel requirements for the Ready Reserve Force (RRF). This study will determine whether there will be adequate numbers of trained civilian mariners to crew the RRF in wartime. The DoD determination of that adequacy depends on the implementation of DOT's new Maritime Security Program and the future size of the RRF. However, a determination of whether there will or will not be a shortage is several months away.

CONCLUSIONS

If the ANS crude oil export ban is lifted and aggressive exports began immediately as assumed in this study, the effects on U.S. maritime tanker requirements would also be immediate. The amount of oil exports from PADD V ANS crude supply largely determines the magnitude in the impact on the U.S.-flag tanker fleet.[45]

- In the low price case, exporting only the West Coast surplus would result in the loss of the requirement for 5 of the 33 tankers employed in 1994; exporting additional PADD V supply in amounts of 150 or 300 mb/d could reduce the fleet by 7 to 10 ships. These are tankers that would otherwise have remained in the fleet until 1997 or 1998 when falling ANS production would eliminate their need.

- Higher ANS production in the high price case approaches peak fleet requirements of 38 tankers in the ANS crude trade during 1994 to 1996. Exporting the PADD V surplus crude oil and 150 to 300 mb/d from the West Coast initially reduces the tanker fleet by 12 to 16 tankers from the larger fleet requirements in this case. By the end of the decade, the ANS crude trade tanker fleet would be six tankers less than in the no-export case.

Under all scenarios, the first tankers to feel the effects of decreased demand directly will be tankers used on the longest routes: those transporting ANS crude to the Gulf Coast and Caribbean ports. After that, shipments by the All American Pipeline would be eliminated. This will occur because Alaskan producers effectively pay the price of transporting crude to their

[44] Under Title XI of the Merchant Marine Act of 1936, as amended, the MARAD is authorized to guarantee principal and interest on privately issued mortgage loans on ships built in U.S. shipyards.

[45] Assuming all exports are made in foreign-flag tankers.

customers and, when faced with a diminishing supply of oil, would cut off their most distant customers first in order to pay the smallest possible transportation costs.

The DOE scenarios confirm the widely held maritime industry expectation that the demand for tankers involved in transporting ANS crude from the eastern terminus of the Panama Canal to the U.S. East Coast, the Gulf Coast, and Caribbean ports is likely to disappear, with or without the ban, if world crude prices do not increase significantly in the study period. In the low price scenarios, even assuming no exports, these shipments cease by 1996. However, as demonstrated in the high world price scenarios without exports, such shipments could continue through the year 2000.

If exports are permitted only on Jones Act qualified vessel (tankers built in the United States, owned, and operated by U.S. citizens), seven suitably sized vessels (exceeding 180,000 dwt) would potentially be available. However, it must be noted that five are owned by ARCO and Exxon and currently are used for proprietary carriage. Thus, the charter rate prospects for the export trades would have to be quite attractive to warrant such employment by some other company. Smaller vessels would then be expected to find employment in the relatively short distance trades from Valdez to the West Coast, but the shipping costs to the owners of the crude would be higher. The net effect would be to raise the cost of tanker transportation of ANS crude to California modestly, but assure reasonable employment prospects for the remaining U.S.-flag vessels until the OPA90 phase-out deadlines are reached.

APPENDIX G
RELATING CALIFORNIA GASOLINE AND CRUDE OIL PRICES

SUMMARY

This section consists of two analyses that address external constraints that might be imposed on a rise in West Coast petroleum product prices even when local crude oil prices are rising. In Chapter 2 of the main body of this report, we showed that California product prices were already at "world levels" while crude oil prices are not. To investigate this further, we examined spot market prices in Singapore and saw that Far East product is very nearly viable financially on the West Coast. A significant increase in West Coast product prices would likely open the door to product imports, or force a correction in prices.[46]

The second part of this analysis explored the relationship between California retail gasoline prices and refiners' crude oil costs on the West Coast. While some weak correlation was found, it was determined that U.S. Gulf Coast gasoline prices exhibited a much stronger relationship. Very little gasoline moves between the U.S. Gulf and California, but the statistical similarity suggests that arbitrage may link the two markets. While significant divergences are evident from the data, they tend to be relatively short-term.

BACKGROUND

In Chapter 2 of this report, we showed that PADD V gross margins (petroleum product prices minus crude oil costs) were significantly higher than those in PADD III. We proposed that the difference was sufficient to internalize a crude oil cost increase in the order of $1.25 to $1.50 per barrel without producing a gross margin lower than PADD III. Further, if exporting ANS crude oil causes crude oil market prices to rise, the price increase in consumer petroleum prices will likely be minimal because:

- o Roughly 60 percent of West Coast oil is produced by integrated oil companies that refine it themselves, or trade their production for other West Coast supplies that are more conveniently located. The cost of this oil to companies is the cost of production, not the market cost. There is no opportunity cost associated with not selling the crude if its open market value rises, because the refining arm of the company would have to replace it with other market-valued crude.

- o The West Coast petroleum market is a study in contradiction. While the crude market is distorted by inequities between integrated and independent producers, product marketing--gasoline in particular--has been robustly competitive over the years. At least one integrated company used its ANS crude supply to make major changes in its market share at the expense of other majors and independent refiners during the 1980s. We believe that there

[46] Conversations with product traders in California confirmed that refiners quickly lower spot pipeline prices in the Los Angeles and San Francisco markets when they find that Far East product has been chartered for West Coast delivery.

is a strong potential for such competitive aggressiveness to mitigate the price increase that otherwise would be associated with rising market prices for ANS and California crude.

- Many refiners have chosen to refine ANS crude because it is a medium quality crude that may be obtained cheaply. If its price approaches its true refined value, refiners that are faced with higher costs probably would replace part of their ANS crude supply with lighter foreign crudes. This would lead to meeting light product requirements with less crude oil, thereby improving refining efficiency and offsetting some of the higher costs of crude oil supplies.[47]

Questions still remain about the extent to which increased crude oil market prices could, or would, appear in PADD V consumer prices. To address this, we examined the potential for increased product imports and the historic relation between crude and product prices on the West and Gulf Coasts.

PRODUCT IMPORTS MAY LIMIT PADD V PRODUCT PRICES

The West Coast is relatively isolated by its geography, and will become increasingly so as tighter petroleum product specifications are enacted to meet new environmental standards. With ample supplies of crude oil at bargain-basement prices, and more than adequate refinery capacity, the region never has been a significant importer of petroleum products. In fact, in 1993, PADD V exported 350 mb/d of petroleum products, of which 290 mb/d was distillate, residual fuel, and coke.

Even among the lighter products,[48] PADD V is a net exporter; however, the balance there is more delicate. In 1992, PADD V exported 46 mb/d of light products and imported 31 mb/d. In 1993, the figures were about the same. Canada is the largest source of gasoline, jet fuel, and naphtha imports, but several cargos from Venezuela, the Virgin Islands, Korea, Singapore, Saudi Arabia, China, Thailand, and Mexico also appear each year.[49] This means that some industry companies found it economically feasible to purchase and ship products to the West Coast despite the high costs of travelling long distances in small tankers.[50]

We examined the relative costs of foreign products delivered to the West Coast versus prices in PADD V markets to determine how price-competitive foreign products could be there. The results were not conclusive, but it seems that a few cents per gallon increase in PADD V product prices could make imports much more feasible.

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[47] High sulfur residual fuel and some types of gas oil are essentially throw-away products in California. Our refinery analysis showed a positive return would accrue to the refiner that lightens its crude oil input slate and produces a smaller amount of these products.

[48] Gasoline, kerosene, kerojet fuel, naphthas, and lube oils.

[49] See EIA's Petroleum Supply Annual, various copies.

[50] From EIA data, an average size cargo seems to be in the range of 250 to 275,000 barrels. That means the shipments were made in tankers of the 30 to 35,000 dwt class.

Table G.1 compares prices of gasoline and kerojet fuel in Singapore to pipeline and barge prices on the West Coast for the month of June 1993. The following assumptions were made:

- The Singapore gasoline price is a weighted average of 82 percent 92 octane unleaded gasoline and 18 percent 75 octane naphtha. The weighting produces 89 octane unleaded gasoline, but further blending might be required to meet California specifications.

- Shipping is estimated at spot rates of $1.04 per gallon,[51] and port fees were $0.10 per barrel. Customs duties are $0.52 per barrel.

Table G-1 suggests that, in some cases, it might be financially viable to send cargos past Singapore to PADD V if PADD V prices rise a few cents per gallon. It is important not to overstylize import economics. Market prices should be viewed as random variables with distributions that probably center near the prices quoted in trade papers such as those published by "Platt's." The closer two prices are together in separate markets on average, the more often nimble traders will find it profitable to buy in one market and to sell into another. The fact that we see an occasional light product cargo being shipped to the West Coast from Pacific, South American, and Caribbean countries verifies this characterization.

Table G.1 Comparison of Singapore and West Coast Product Prices ($/Barrel Unless Noted Otherwise)[a]

	Singapore c.i.f. PADD V	Los Angeles Pipeline Spot Price	San Francisco Pipeline Spot Price	Seattle Barge
Gasoline	$25.68	$25.02	$24.18	$25.61
	Singapore minus U.S. (cents/gallon)	1.6	3.6	0
Kerojet Fuel	26.56	25.11	25.28	25.46
	Singapore minus U.S. (cents/gallon)	3.5	3.1	2.6

[a] "Platt's Oilgram Price Report," product price supplement for June 1993.

The nearness in price of Singapore-sourced product to PADD V prices suggests that Pacific Rim product markets may serve to limit the extent to which West Coast product prices would rise if ANS crude was exported.[52] That is not to say that product would flood the West Coast from Singapore. Rather, the comparison above only implies that potential PADD V importers would

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[51] The crude oil tanker analysis detailed in this report shows that companies that have long-term tanker leases or own the vessels outright have significantly lower out-of-pocket shipping costs.

[52] Singapore was only used as an example here. High product prices in PADD V might also make it more profitable to divert cargos from Japan or other industrial nations in the Pacific Rim.

more frequently find it profitable to purchase cargos that otherwise would have been sold in the Far East market.

As California motor fuel specifications become more restrictive, it may become more difficult to satisfy these standards with products manufactured in less complex Pacific Rim refineries. However, some specifications are fairly easy to meet if high quality product is "skimmed" at offshore refineries. For example, gasoline produced from Indonesian crude will tend to have less sulfur than gasoline produced from West Coast crudes (all other things being equal). In addition, lowering aromatics in gasoline involves using some refinery upgrading equipment (reformers) less rather than more.

In public meetings on the ANS crude export issue, Pace Consultants (PACE), advisors to many refiners, warned about imports in the context of California's stringent specifications for gasoline. Pace indicated that as costs for cleaner gasoline rise, it creates an incentive for foreign sources to make available "cherry-picked" gasoline for the U.S. West Coast market. While this was presented as an argument against exporting Alaskan crude, it is evidence that the industry recognizes the threat of competition from offshore refiners if California's gasoline prices escalate.

CALIFORNIA GASOLINE AND CRUDE OIL PRICES

Figure G.1 shows the six-year history of California retail unleaded regular gasoline and crude oil prices.[53] The pattern seems similar between crude oil and gasoline, but, on closer inspection, there are important differences. Sometimes a change in crude price leads the change in product prices, but other times (late 1989 and early 1990 are two examples) gasoline leads crude oil, or goes, in the opposite direction.

Sales statistics show that major refiners are dominant throughout PADD V and in California in particular. Major producers make 71 percent of California's gasoline sales through company operated stations, and they supply 81 percent of the State's gasoline at the wholesale and retail sales levels combined. Major refiners provide 82 percent of the gasoline supply for PADD V states taken together.

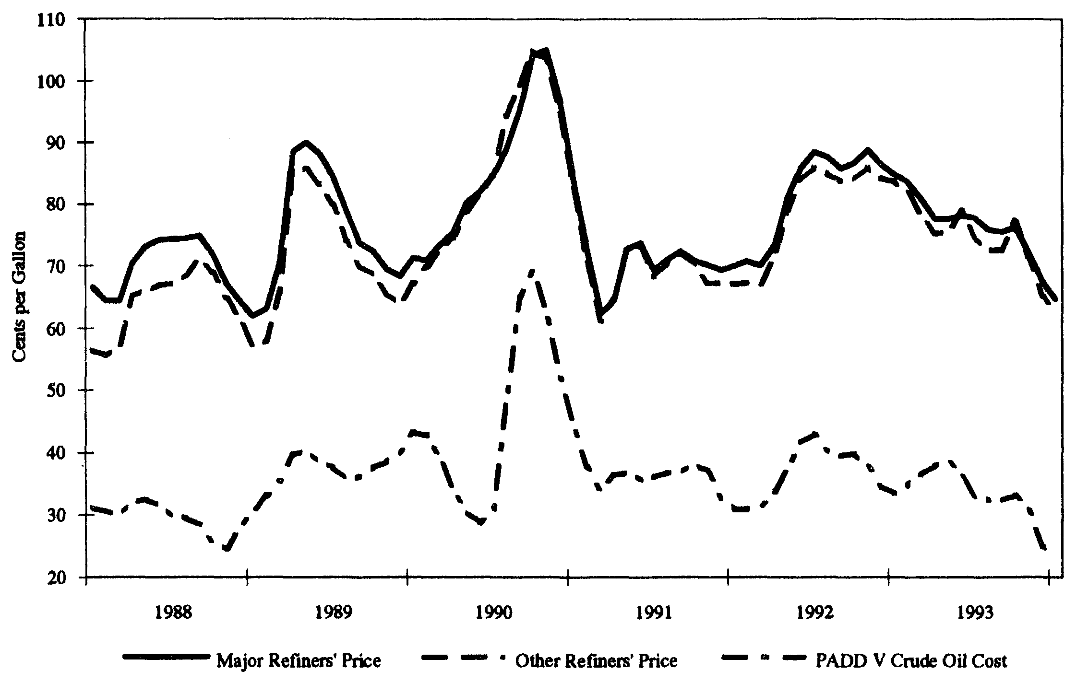
Smaller refiners tend to sell product at prices that are lower than major refiners. This is the case in other parts of the country also. While it is difficult to draw conclusive results from Figure G.1, it is at least apparent that, as prices turn downward, the price gap narrows. This suggests that the majors set the overall market prices while the smaller companies attempt to carve out niche markets with lower prices. As the majors reduce prices, smaller companies resist, but are forced to go along.

This, of course, raises the question of why large companies lower prices at all if California is an isolated market. To test the assumption that refiners' gasoline pricing is a direct response to oil cost changes, we performed a large number of simple data regressions. The first set of regressions linked the average refiner retail gasoline price in California to crude oil prices in the State. We did not intend to construct a detailed model, but rather to quickly test numerous

[53] Crude oil is a refinery receipt-weighted average of California and ANS crude prices. Product prices are ex-tax retail sales from company operated stations. Major refiners are the large integrated companies in California.

hypotheses related to the extent to which crude oil prices on the West Coast influence gasoline prices there.

Figure G.1 Crude Oil Costs and Retail Gasoline Prices in California*



*Current dollars, ex-tax

Month-by-Month Price Analysis

We began by simply regressing month-to-month price changes in gasoline back on crude oil price changes. That is, a model was proposed of the form:

$$P_g = \alpha + \beta \times P_c + \varepsilon$$

where P_g and P_c are gasoline and crude oil prices, α and β are the intercept and crude oil price coefficient determined by the regression program, and ε is a random error term.
The results were poor. The regression model's crude oil coefficient was significant at the 5 percent level, but the R^2 was only 0.3.[54] A series of trials followed including:

- o Introducing a Lag--Gasoline price changes were assumed to lag crude oil price changes by first one, then two months. R^2 stayed in the 0.3 range.

[54] R^2 is simply a measure of the fit of the linear regression model. An R^2 of 1.0 means the model describes 100 percent of the variation in the data, while an R^2 of zero means that the model describes none of the variation. R^2s of 0.7 to 0.9 are generally thought to be symbolic of good fits in analyses of scientific data. Here we only used this measure as a screen and a test of the relative explanatory powers of various variables.

- Introduction of Seasonal Dummy Variables--Assuming some of the lack of correlation was due to the run-up of gasoline in the summer driving season, we introduced dummy variables for the months of May-September each year. The R^2 remained at 0.3.

- Percentage Changes--Rather than the absolute change in price, we examined the percent change in gasoline price as a function of the percentage change in crude oil. The R^2 fell to 0.22.

It is easy to see why poor results are obtained when Figure G.2 is examined. Although there seems to be a tendency for variations in crude oil prices to relate directionally to gasoline price changes, there are many exceptions. Introducing lags and dummy variables simply cannot compensate for the scatter in the data.

Figure G.2 California Price Changes Month-to-Month, 1988-1993

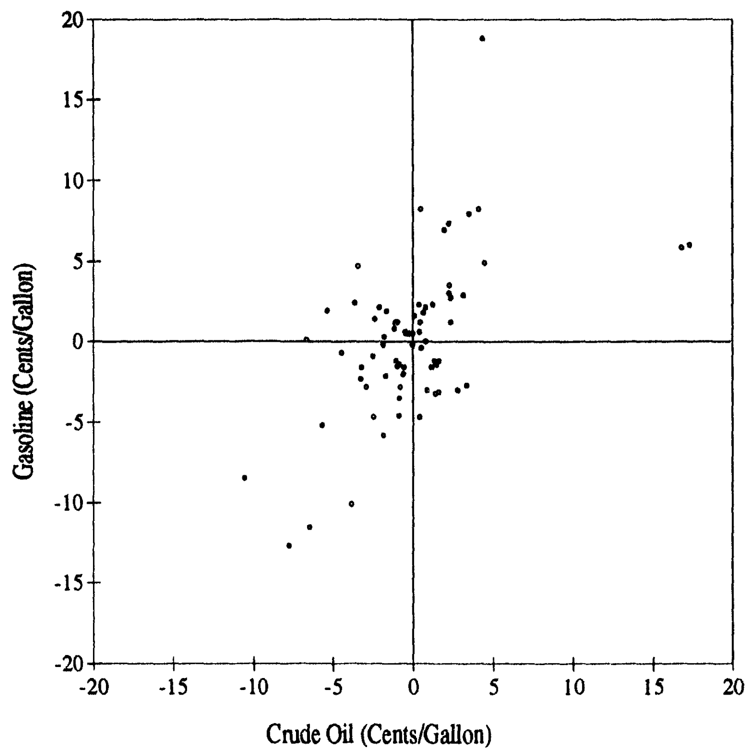
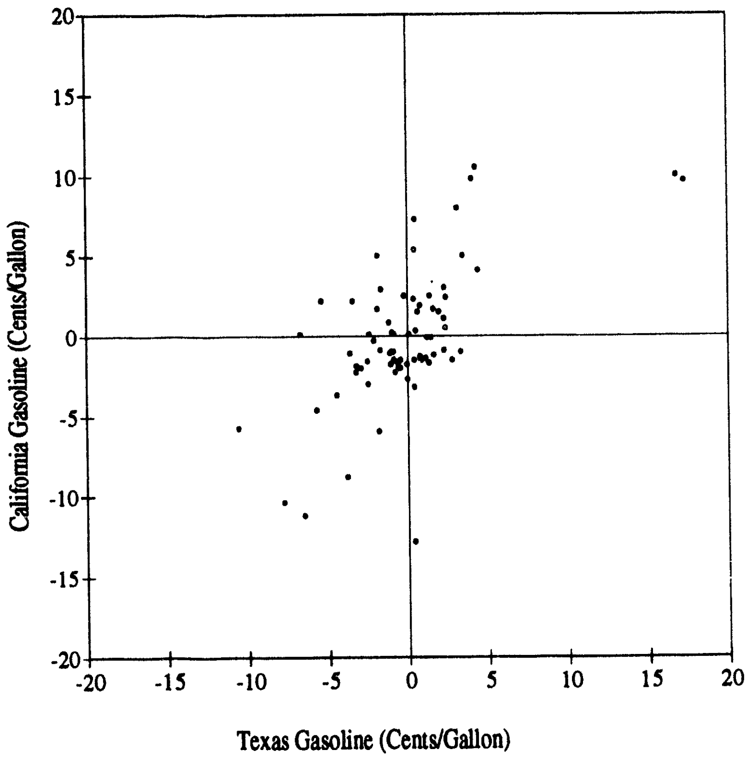


Figure G.3, on the other hand, shows that a better visual relationship exists for California gasoline price changes expressed as a function of gasoline price changes in Texas. This does not mean that Texas prices induce changes in California prices--the chart would be similar if we made California prices the independent variable. It simply says that the two price series are more closely related than California gasoline prices seem to be to California crude oil. A simple regression of California gasoline on Texas gasoline produced an R^2 of 0.597.

Figure G.3 Gasoline Price Changes Month-to-Month, 1988-1993



Quarterly Price Averages

Using quarterly average prices improved the fit of the linear regressions by eliminating much of the random, month-to-month variation in prices. This approach raised the R^2 for California gasoline versus California crude to about 0.47; with dummy variables for the second and third quarters, it was increased further to 0.57.

Applying the same quarterly analysis to California gasoline versus Texas gasoline raises its R^2 to 0.76--still measurably better than the explanatory power of California crude. Adding California crude to the Texas gasoline model (a multiple regression on two independent variables) did not improve the R^2. We obtained a slightly higher R^2 of 0.78 if crude oil price changes were allowed to lead by one quarter, but the coefficient for crude oil was negative. That is, rising crude oil prices tended to depress gasoline prices.[55]

In one final excursion, we deleted the first quarter of 1991 when prices were corrected after the Middle East War, and the first quarter of 1992 when California prices shifted abruptly to their historic normal range. The R^2 for the gasoline model fell to 0.67, but once again, including California crude oil did not improve the R^2.

[55] This probably is due to correlation between crude oil price levels and Texas gasoline prices.

Observations and Conclusions

The statistical analysis above was purposefully simplistic, but revealing. Clearly, there is some relationship between crude oil costs and gasoline prices because the raw materials cost is about half the price of the finished product in California (more than half in Texas). Nevertheless, it seems that small to moderate price changes in California's gasoline market are better explained by events that shape gasoline markets overall than they are by differences in California crude oil prices.

These observations suggest, but do not prove, the existence of a link between U.S. Gulf and California gasoline prices that may dominate small changes in California crude oil prices. Whatever that link is, however, it is not evident in EIA's supply data because little gasoline is observed moving between the Gulf and West Coasts. Most of what does is shipped via pipeline from El Paso, Texas, to Phoenix, Arizona, and does not affect the huge California market.

Nevertheless, one might conjecture that, arbitrage between markets would keep prices linked, or, at least, limited to a maximum difference. As long as no event destabilizes the basis of arbitrage (e.g., a sharp increase in tanker rates), it remains effective in linking prices without a significant amount of physical deliveries taking place. This phenomenon might be compared to that in the spot and futures markets for petroleum and other commodities. Spot and futures prices vary within narrow limits and ultimately converge despite the fact that very little physical delivery is taken as a result of futures contracts.

APPENDIX H
ADDITIONAL ANS EXPORT CALCULATIONS

Tables H.1 through H.4 display the results estimated for the two export cases not discussed in the main body of the report. That is, exporting only the PADD V surplus of crude oil, and exporting the surplus and 300 mb/d from West Coast supplies (as long as a surplus exists).

Only ANS revenues are affected by the type of shipping employed. Therefore, California investment revenues are identical for foreign-flag and U.S.-flag export cases.

Table H.1 Cumulative Oil Company Investment Potential (Millions of 1992 $)

	Low Price Case			High Price Case		
Type of Export Tankers	1994-1996	1997-2000	Total	1994-1996	1997-2000	Total
Foreign-Flag:	Export Only the PADD V Surplus					
Alaska	$66	$0	$66	$128	$83	$211
California	0	0	0	0	0	0
Total	66	0	**66**	128	83	**211**
U.S.-Flag:						
Alaska	78	0	78	156	113	269
California	0	0	0	0	0	0
Total	78	0	**78**	156	113	**269**
Foreign-Flag:	Export the PADD V Surplus and 300 mb/d					
Alaska	440	11	451	306	376	682
California	180	6	186	123	171	294
Total	620	17	**637**	429	547	**976**
U.S.-Flag:						
Alaska	478	17	495	360	447	807
California	180	6	186	123	171	294
Total	658	23	**681**	483	618	**1,101**

Table H.2 Oil Production Potential
(Thousand Barrels Per Day)

Type of Export Tankers	Low Price Case By 1996	By 2000	High Price Case By 1996	By 2000
	Export Only the PADD V Surplus			
Foreign-Flag:				
Alaska	2	8	3	21
California	0	0	0	0
Total	2	8	3	21
U.S.-Flag:				
Alaska	3	9	4	27
California	0	0	0	0
Total	3	9	4	27
	Export the PADD V Surplus and 300 mb/d			
Foreign-Flag:				
Alaska	10	53	7	57
California	21	62	7	33
Total	31	115	14	90
U.S.-Flag:				
Alaska	11	58	9	68
California	21	62	7	33
Total	32	120	16	101

Table H.3 Cumulative State and Federal Revenue (Millions of 1992 $)

Type of Export Tankers	Low Price Case 1994-1996	Low Price Case 1997-2000	Low Price Case Total	High Price Case 1994-1996	High Price Case 1997-2000	High Price Case Total
Foreign-Flag:		Export Only the PADD V Surplus				
Alaska	$102	$29	**$132**	$214	$280	**$494**
California	0	0	**0**	0	0	**0**
Federal	0	0	**0**	0	0	**0**
U.S.-Flag:						
Alaska	77	34	**111**	152	236	**388**
California	0	0	**0**	0	0	**0**
Federal	0	0	**0**	0	0	**0**
Foreign-Flag:		Export the PADD V Surplus and 300 mb/d				
Alaska	723	203	**926**	616	1,004	**1,620**
California	113	91	**204**	72	150	**222**
Federal	109	9	**118**	72	108	**180**
U.S.-Flag:						
Alaska	641	208	849	499	892	1,391
California	113	91	204	72	150	222
Federal	109	9	**118**	72	108	**180**

Table H.4 Direct, Indirect, and Induced Employment

Type of Export Tankers	Low Price Case 1995	Low Price Case 2000	High Price Case 1995	High Price Case 2000
Foreign-Flag:	Export Only the PADD V Surplus			
Oil-Related	2,603	872	4,074	4,097
Maritime	(1,075)	0	(1,926)	0
Net	1,528	872	2,148	4,097
U.S.-Flag:				
Oil-Related	2,332	1,009	3,550	4,953
Maritime	(417)	0	(417)	(417)
Net	1,915	1,009	3,133	4,536
Foreign-Flag:	Export the PADD V Surplus and 300 mb/d			
Oil-Related	18,062	11,186	13,745	22,996
Maritime	(417)	0	(417)	(417)
Net	15,845	11,186	10,444	21,662
U.S.-Flag:				
Oil-Related	17,383	11,743	12,795	24,259
Maritime	(417)	0	(417)	(417)
Net	16,966	11,743	12,378	23,842

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