Policy Analysis

Cato Institute Policy Analysis No. 227: Time to End the Alaskan Oil Export Ban

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Executive Summary

The Trans-Alaska Pipeline Authorization Act of 1973, while opening vast oil reserves around Prudhoe Bay for production, effectively requires that Alaskan oil be consumed domestically, not exported. As a result, petroleum development on the Alaskan North Slope and in California has been greatly restrained.

The natural market for North Slope oil is Japan, Korea, and northern East Asia, to which oil can be shipped for about 50 cents per barrel, but North Slope producers are required to use domestic tankers and market exclusively in the United States and its territories, a mandate that has often resulted in shipping costs of $5 per barrel. That price distortion has led to artificially low domestic prices for heavy crude on the West Coast, discouraging otherwise profitable exploration and production investments in Alaska and California.

Oil production in the United States has declined 23 percent since prices collapsed in 1986, and net oil imports have doubled. Part of the drop in U.S. production is due to exhaustion of the resource--oil basins in the lower 48 states are mature, and most are in permanent decline--but that is not true of many of California's and Alaska's oil fields.

The artificial inhibition of U.S. oil production has severe consequences for jobs and economic growth. Over the coming decades the cost could be as high as $125 billion and the loss of tens of thousands of well-paid jobs in petroleum development, oil-field services, manufacturing, and transportation. Given the massive costs and paltry benefits of the oil export ban, Congress should immediately act to free the Alaskan oil trade and repeal the prohibition on oil exports.

Introduction

Congress authorized construction of the Trans-Alaska Pipeline system during the crisis caused by the 1973 Arab oil embargo. In part because of expert lobbying by the maritime industry, the act that authorized the construction of the pipeline also prohibits the export of Alaskan oil in order to ensure "energy independence." In 1973 neither Congress nor the petroleum industry fully understood the implications of the export ban, which has had the effect of depressing West Coast crude oil prices. For a decade that did not matter, because world oil prices exploded just about the time that oil production began on the North Slope. It was not until oil prices collapsed in 1986 that the prohibition on the export of crude oil began to have a critical impact on the development of new supplies.

Given royalties, taxes, and the high cost of transporting and refining Alaskan crude, that price discount has proven significant and, in many cases, sufficient to discourage or postpone development. That is because, compared with oil fields in the U.S. Gulf and midcontinental regions or in the Middle East, Alaskan deposits are expensive to develop, operate, and maintain, given the crude oil's quality, weight, and sulfur content.[1]

Moreover, the bulk of Alaska's oil is in remote and hostile environments, which drives up exploration and development costs. Thus, while profits are to be made in oil production in Alaska, the margin is often thin, particularly given the relative abundance of other sources of petroleum.

In the last several years there has been a series of oil discoveries in Alaska at Cook Inlet near Anchorage as well as in the high Arctic. Billions of barrels of potential reserves are contained in those discoveries, as well as in huge deposits discovered decades ago that, for one reason or another, have not been developed. Much of that oil will be costly to develop and may never be produced, given the economic distortions engendered by the Alaska oil export ban.

This study examines the political history of the oil export ban, the potential oil reserves on the Alaska North Slope, the economics of oil production on the West Coast, and the economic ramifications of the price distortion engendered by the prohibition on exports. The analysis reveals that the export ban has been an extremely costly proposition, a policy that costs tens of thousands of jobs and billions of dollars in lost economic growth.

The Ban on Crude Oil Exports

By any measure, the 1970s were extraordinary for the oil industry and for the state of Alaska. After the mammoth discovery of oil in the Arctic, the industry laid plans for the development of North Slope crude and its transport to market. Experiments with an icebreaker-tanker, the Manhattan, were disappointing, and it became evident that the oil would have to travel overland by pipeline. There were two basic choices: one, a pipeline could be routed east to McKenzie Delta and then south through Canada, finally arriving in the Upper Midwest; two, the pipeline could go due south through Alaska to an ice-free port in Prince William Sound.

For several years after the discovery at Prudhoe Bay in 1967, the producers did not seriously consider exporting the crude oil. At the time, the Mandatory Oil Import Program restricted crude oil imports in order to maintain a domestic price level just about twice the level of foreign crude oil prices. That effectively removed all incentive to export.

The situation began to change in 1971. Domestic oil producers could no longer keep pace with demand. Moreover, worldwide petroleum demand was growing at over 7 percent per year, and prices in the world market were approaching those in the United States. Early in 1973 world prices exceeded U.S. prices, and by mid-1974 world oil prices were twice the level of "controlled" domestic oil prices.

The oil companies' preference for disposing of Alaskan North Slope crude oil was simple: They sought the quickest solution, resulting in the highest present value for netback (or wellhead) prices. That solution was to transport the oil overland by pipeline to Valdez, Alaska, and then by tanker to the closest domestic markets--the U.S. West Coast.[2] The state of Alaska also supported the pipeline to Valdez--as a royalty owner it sought to maximize its own future income. Moreover, maximizing pipeline mileage in Alaska was bound to stimulate the local economy, creating jobs and a short-lived boom.

There was also a clear and direct economic incentive for the producers to export North Slope oil. Exporting the oil would have reduced transportation costs (and raised wellhead prices); it also would have skirted domestic price control regulations, giving rise to opposition from advocates of price controls.

Unfortunately for the oil companies and for Alaska, the proposed pipeline crossed hundreds of miles of federal land. Only the Department of the Interior could grant a wide enough right-of-way, and Congress would therefore have to amend the Mineral Leasing Act to allow the Trans-Alaska Pipeline project to go forward.

Opposition to the project, however, was disparate and intense. Environmentalists and Californians feared oil spills along the West Coast and therefore supported a trans-Canadian pipeline that would bring oil from the North Slope, across Canada, and into the Midwest without need for tankers. Midwestern legislators likewise opposed the Trans-Alaska Pipeline because of the economic gain that an overland trans-Canadian pipeline would bring to their region.

To prevail against such intense opposition, proponents of the Valdez route agreed to provisions in the bill that effectively banned exports. A specific presidential finding that it was in the "national interest" had to be made before any oil carried in the pipeline could be exported. Only if both houses of Congress passed a concurrent resolution objecting to such a presidential finding could the export ban remain in place.[3]

The export ban was adopted largely to neutralize an unexpectedly powerful voice in the pipeline debate: the U.S. maritime industry and its labor unions, who saw an uncommon opportunity to enlarge the coastal tanker fleet if the Valdez route were approved by Congress and an even larger potential gain if Alaskan oil had to be consumed domestically. Banning oil exports would advantage them because section 27 of the Merchant Marine Act of 1920 (the Jones Act) requires that cargoes shipped between U.S. ports be moved by U.S.-flag vessels only. The maritime industry, hardly interested in forwarding a low-cost, high-profit case for exports, argued that a ban on exporting oil would enhance national security, create jobs, and reduce reliance on foreign oil.

According to Arlon Tussing, then the chief economist for the Senate Interior Committee, the export ban was adopted by Congress largely out of spite. Members who favored an overland pipeline, or simply resented the exploitation of an energy "emergency" (the Organization of Oil Producing Countries' oil embargo) to railroad what would otherwise have been unpopular legislation through Congress, deliberately imposed a condition on the Trans-Alaska Pipeline that they believed (correctly) might someday make North Slope crude less profitable to the producing companies and Alaska.[4]

Supporters of the oil export ban continued to strengthen the prohibition on exports after the Trans-Alaska Pipeline was finally approved in November 1973. The Energy Policy and Conservation Act of 1975, the Naval Petroleum Reserves Production Act of 1976, the 1978 amendments to the Outer Continental Shelf Lands Act, and the 1977 and 1979 amendments to the Export Administration Act all contained language in some way restricting the export of Alaskan oil.

The 1979 amendment to the Export Administration Act was perhaps most significant, the culmination of an energetic lobbying effort by the maritime industry.[5] Whereas the original act had allowed the president to remove the ban if he felt that it was in the national interest to do so, the new test required that the president find that, "within three months of the initiation of the exports, [ending the ban would] result in lower acquisition cost of the domestic refiners if they must purchase imported crude oil to replace such exports, and that savings not less than 75 percent will be passed on to the consumers through wholesale and retail mechanisms."[6]

That standard is all but impossible to meet because economic productivity and domestic employment would gain from the export of oil; consumers would gain only indirectly. In 1989 Congress extended the Export Administration Act for four years, virtually without opposition.

"Bringing Coal to Newcastle"

In mid-1977, when the Trans-Alaska Pipeline opened and shipment of North Slope crude began, government regulators and oilmen were slow to understand the economic implications of the oil export ban. Suddenly, the West Coast was flooded with oil--which should not have surprised the industry, since there was no other profitable destination for Alaskan oil. Total petroleum demand in the western states (known as PAD District V) at the time was about 2.6 million barrels per day.[7] Production on the North Slope, however, totaled 1.5 million barrels per day by year's end, in addition to production from Cook Inlet and California. ARCO and Exxon had West Coast refineries, but Sohio, with half the North Slope crude production, had no immediate market.

Not only did a new set of producers have to find willing buyers, but refineries had to be modified to run North Slope crude oil. Alaskan crude oil is of better quality than most California crudes, but it is still heavier than most of the foreign crude oils it would displace. From 1977 through 1981 refineries in California, Hawaii, and the Puget Sound area were modified and upgraded at great expense to run heavier crude oil. By the end of the period, only occasional cargoes of specialty crude oil were imported. Figure 1 illustrates the situation. Until 1977 the gap between West Coast petroleum demand and indigenous oil supply was filled by foreign imports. That gap was closed abruptly by Alaskan oil. The region developed a surplus of about 600 thousand barrels per day that lasted through 1988 and then began a gradual decline. (The rise in oil prices in 1979 caused a significant drop in the quantity of oil demanded, which helped prolong the surplus.) When the Prudhoe Bay field began its decline, the gap narrowed quickly. In the early 1990s West Coast oil demand and supply were nearly in balance, with about 200 thousand barrels per day of North Slope and California crude oil moved to the Gulf Coast by tanker and pipeline, offset by about 100 thousand barrels per day of light, low-sulfur foreign oil imports.

Figure 1
PAD District V Demand and Supply, 1960-94
[Graph Omitted]
Source: Economic Insight, Inc.

Although PAD District V now produces just about the same volume of crude oil it refines, prices remain depressed. Petroleum product demand in PAD District V is for gasoline, diesel, jet fuel, and other light petroleum products. In contrast, the region's crude oil is heavy, and that of California is very heavy. The mismatch between the petroleum products demanded and refinery feedstocks results in a surplus of residual oil and a shortage of "light ends"--the building blocks of gasoline and distillate fuels.

Briefly, this is what goes on. Crude oil from Alaska is shipped to California refiners. Although it is of higher quality than most local crude oils, it is not light enough to offset the impact of California's heavy crude oils on refinery processing--a classic case of "bringing coal to Newcastle." Overall, about one-quarter of refinery production is residual oil. Local regulations effectively prevent the heavy fuel oil from being used in the Los Angeles Basin or the San Francisco Bay area. It is sold as heavy oil for ship fuel (known as "bunkers"), sold at a discount in the Pacific Northwest, shipped to the Gulf Coast, or exported to the Far East.

At the same time, California has a legendary demand for gasoline. Local refiners do not produce enough to satisfy the local market, particularly for high-octane fuels. So refiners top off production by using foreign imports of octane-enhancing additives, unfinished gasoline, and other light ends.

Were the market allowed to function unmolested, however, Alaskan crude oil would in all likelihood flow to northeast Asia, where there is a demand for heavy fuel oil. In turn, light imported crude oil from the Middle East and Southeast Asia would move into California, where it could be manufactured into gasoline and diesel. That would reduce the need to import gasoline additives and dramatically reduce the need to export heavy fuel oils. The crazy system of cross-transportation would be eliminated. Not only would unnecessary transportation be reduced, but refiners would be willing to pay more for local supplies of West Coast crude oil.

As mentioned before, however, neither industry nor government anticipated or understood the implications of an oil export ban combined with surplus production. In the late 1970s the onslaught of Alaska's oil was relentless. All of PAD District V's refinery modifications were not enough; the West Coast was awash in oil. A pipeline across the Isthmus of Panama was hastily built to get around the bottleneck at the Panama Canal. Tankers from all over theworld queued up at West Coast refinery centers to buy the cheapest bunker oil in North America.

Examination finds that, since 1977, the export ban has depressed Alaska and California crude oil prices by an average of $1 to $5 per barrel, depending on quality and location.[8] Consequently, the oil export ban led to massive distortions in the domestic market and lesser but still significant distortions that rippled through international oil markets. Millions of dollars, which could have been more productively invested elsewhere, were spent on refinery modifications. And although the export ban did lead to some reduction in oil imports from the Middle East, that decrease was offset, in part, by increased demand for foreign gasoline additives.

West Coast Oil Resources

Although most domestic oil fields have been thoroughly explored and are past their productive prime, the exploration of offshore California and Alaska's North Slope has proceeded by fits and starts, and relatively few wells have actually been drilled in Alaska. The resource base and ultimate recoverable reserves can only be estimated by the crudest of techniques. What is clear, however, is that the artificial depression of West Coast heavy crude prices and the high cost of bringing Alaskan crude to market--both a function of the oil export ban--distort the economics of oil production in such a way that exploration and development of those productive fields may not occur as long as the export ban is in place. The full extent of those distortions and their economic ramifications becomes clear when one examines the economics of oil production in both Alaska and California.

Alaskan Oil: Untapped Reserves?

By any reckoning, Alaska's North Slope is a world-class petroleum province. When the Trans-Alaskan Pipeline first came on-line, Prudhoe Bay was expected to produce 9.6 billion barrels of crude oil. It is now expected to produce over 12 billion barrels of oil.[9] Moreover, known fields and pools in the vicinity are expected to produce another 4 billion barrels. The true size of deposits on Alaska's North Slope, however, can be best understood by reference to the fact that it has up to 100 billion barrels of oil-in- place, of which only 16 billion barrels qualify as "proven reserves" (resources that can be profitably extracted). Usually, 30 percent to 40 percent of the oil-in-place can be produced, but there is a multitude of constraints on North Slope production.

Estimates of proven reserves may understate future supplies because there are a staggering number of known undeveloped fields within a few miles of Prudhoe Bay. The West Sak field, for example, has almost as much oil-in-place as Prudhoe Bay itself, but it is heavier and colder and therefore costs much more to produce. In addition, if history is any guide, continuing exploration will result in new field discoveries even without opening the Arctic National Wildlife Refuge (ANWR). Reasonable assumptions about the world oil market, combined with the removal of export restrictions, could result in total North Slope recoverable reserves of 30 billion barrels (10 billion of which have been produced and 20 billion of which are to follow), making the Alaskan North Slope one of the largest petroleum provinces in the world.

That figure may be shocking to many, since it is nearly double the present estimates of proven reserves and four times the present forecasts of future production. It suggests that present levels of production could be maintained for several decades (if such production is profitable) instead of spiraling downward as known reserves are rapidly depleted.

In 1978 Prudhoe Bay was the only known giant oil field on the North Slope. Only two other provinces (both in China and also underexplored) had a similarly small number of known giant oil fields. The average number of known giant fields in the 22 major petroleum provinces of the world is 10 each (excluding the Middle East, which has many giants, the average is 7).[10] Thus, it is reasonable to assume that the North Slope will hold many giant oil fields (recoverable reserves of 500 million barrels or more).

Figure 2 shows the more important known oil and gas fields on the North Slope. Most informed Americans know that Prudhoe Bay is the largest oil field in the United States, but few know that West Sak, 30 miles to the west, may actually contain more oil-in-place than does Prudhoe Bay.

Figure 2
Alaskan North Slope Oil Fields
[Map Omitted]

Proven reserve estimates in millions of barrels for the largest oil fields, as well as the potential for resource development, are listed in Table 1. Those figures are somewhat speculative but by no means fantasies. For example, the General Accounting Office recently commented on the West Sak field,

Although West Sak's development is uncertain, ARCO has stated that its production may be phased in as Kuparuk River production declines. In 1989 ARCO estimated that the West Sak field contained from 13 to 20 billion barrels. . . . In addition, experts told us that there could be as much as 40 billion barrels of oil in West Sak.

The DOE [U.S. Department of Energy] estimated that 5 percent of West Sak's oil in place could be recovered. However, experts and available literature suggest as much as a 25 percent recovery factor.[11]

The data in Table 1 indicate that potential production from known but undeveloped fields and deposits in the vicinity of Prudhoe Bay could be as high as 20 billion barrels-- twice the amount of oil produced in the last 15 years. Half of that potential is from the West Sak field and the other

Table 1
Crude Oil Reserves and Potential (million barrels)

Field	Proven Reserves	Potential	Status
Developed Fields			

Prudhoe Bay	12,045	2,000 to 4,000	Supergiant
Kuparuk	2,201	1,000	Giant
Endicott	456	200	Probable giant
Lisburne	201		Lower than expected
Point McIntyre	307	200	Probable giant
Milne Point	118		Marginal field
Niakuk	47		
Identified Prospects			
West Sak	148	1,000 to 10,000	Giant? supergiant?
North Star-Seal Island area	200	1,000	Smaller fields
Coleville Delta		1,000	Giant?
Kuvlum-Wild Weasel		1,000	Giant?
Badami area		1,000	Giant?
Point Thompson	200	1,000	Giant?
Total	15,923	3,000 to 20,400	A dozen giants?

Source: Historical and Projected Oil and Gas Consumption

(Anchorage: Alaska Department of Natural Resources, Division of Oil and Gas, February 1993), pp. 2, 13.

half is from a wide variety of projects involving advanced recovery from Prudhoe Bay and Kuparuk as well as the possible development of two groups of discoveries to the east and west of Prudhoe Bay.

The Economics of North Slope Crude

The geological prospects for further discoveries and development of North Slope fields are excellent. Without question, those fields are the best remaining in the United States. Why is there not a gold rush? The answer, in short, involves punishing tax rates and the high costs of production and transportation, which often make development unprofitable at current West Coast oil prices.

The North Slope of Alaska is a long way from petroleum markets, and its climate is inhospitable. North Slope crude may sell at world market levels on the Gulf Coast, but its netback price at the field in Alaska is $5 to $8 per barrel lower.

The main reason for the lower price is the remote location of North Slope oil; it costs about $3.50 per barrel to move the oil by pipeline to the port of Valdez. Furthermore, it costs at least $1, and as much as $4, per barrel to transport the oil from Valdez to refinery terminals in the lower 48 states. The result is a relatively low netback price and, more important, a highly volatile price. For example, if world oil prices drop to less than $8 per barrel, the wellhead price of oil on the North Slope could drop to zero. That nearly happened in the summer of 1986, and since then investment has plummeted 60 percent. Development expenses, which were $4 billion in 1983, fell to $1 billion in 1990.[12]

In addition to high transportation costs, North Slope producers have to pay some of the highest royalty and tax rates in the world. Royalty rates on state oil fields range from 12.5 percent to 20 percent.[13] On top of royalties, the producers pay severance taxes of 15 percent, property taxes, state income taxes, and (if there are any profits left) the federal corporate income tax. As a result, the cash flow to the producer from a barrel of North Slope oil is only about two-thirds of the netback price and less than half of the delivered price.

By all accounts, the North Slope is one of the most difficult environments on earth. The extreme climate leaves only a few months each year in which to develop fields and move equipment and large volumes of supplies. Most facilities have to be prefabricated in the lower 48 states and moved by barge during the summer. Installation has to proceed quickly with little margin for error. Labor costs are, of course, much higher than in Texas and Oklahoma. The result is high cost for even routine and basic activities.

A large amount of data on North Slope oil field development costs is available to the public. Many of the companies, particularly ARCO, regularly describe their investment projects and their budgets. Moreover, Alaska publishes aggregate data on development and operating costs. All the data tell a remarkably consistent story, and the figures are staggering for private investment projects. From 1961 to 1993 a total of $67 billion (1993 dollars) was spent on development costs in Alaska for Cook Inlet, the Trans-Alaska Pipeline, and the North Slope fields.[14] As a result of the post-Prudhoe Bay investment, the North Slope's total proven reserves have increased from 9.6 billion to just under 16 billion barrels. Put another way, proven reserves have been added at a cost of between $3 and $5 per barrel.

Similar figures can be derived by reviewing specific projects. A large natural gas processing plant was completed in 1990, and another (the GHX-2 project) was slated to come on-line in 1994. The two plants reinject gas into the field to maintain pressure, stripping natural gas liquids for mixing with the North Slope crude oil stream to enhance recovery. The second plant is expected to cost $1.5 billion and add from 330 million to 350 million barrels of liquid petroleum reserves, at a cost of about $3.85 per barrel.[15]

Unfortunately, the calculations understate true costs because they fail to account for the time value of money. Assume that ARCO and its partners are investing $1.5 billion over four years. After completion of the project, they will receive revenue from 100 thousand barrels per day of extra North Slope crude over a 10- to 12-year period. Assuming a netback after transportation, taxes, and royalties of about $7 per barrel, that represents an annual income of about $255 million or about $2.8 billion overall. Given the 4- year lead time and the 11-year payout, the project would produce a rate of return of about 10 percent. At that rate of return, there is no allowance for operating costs and, more important, no factor to account for risk. Given Alaska's netback pricing, a 10 percent drop in world oil prices translates into almost a 20 percent drop in North Slope field prices. If world prices fell only $2 per barrel, ARCO would net around $5 per barrel instead of $7, and the rate of return would drop by more than half. At a net return of less than $3.85 per barrel, ARCO would fail to even reclaim its capital. (Those figures are meant, not to provide an accurate assessment of particular projects, but to illustrate the nature of petroleum economics with respect to Alaska's oil fields.)

Table 2 breaks down the cost of a representative barrel of Kuparuk, Endicott, or more recently developed North Slope crude oil. The figures are based on actual 1992 average delivered prices and transportation costs. Royalties and other costs are estimated.

Table 2
Netback Values of North Slope Crude

1992 average field price	$12.20
Royalties	-$1.60
Severance (production) tax	-$1.60
Property tax	-$0.50
Operating cost	-$2.00
Pipeline tariff from field to terminal	-$1.50
Estimated development cost	-$4.00
Net revenue and return on capital	$1.00

Source: Author's calculations based on figures from Alaska Department of Natural Resources, Historical and Projected Oil and Gas Consumption, various years.

Needless to say, during recent months when North Slope wellhead prices dipped below $10 per barrel (or in 1987 when they averaged $8.08), many of the North Slope's projects were in the red. Companies, of course, plan for the long term; since 1986 wellhead prices have averaged about $11.50. That level is high enough to stimulate active planning for some of the better projects; but given the fiscal terms and environmental constraints, it is not sufficient to provoke significant broad-based investment.

Future Supplies

Markets look forward, not back. Prudhoe Bay was a marvelous, lucky find. It turned a small regional company, Richfield, into a large and prosperous oil company, ARCO. It turned a regional refiner, Sohio, into the largest crude oil seller in the United States. Prudhoe Bay made modern Alaska. But now the field is in decline. The decline can be moderated by enhanced recovery techniques, but it cannot be reversed. The past profitability of Prudhoe Bay will not affect investment decisions in the future.

The focus of a company's investment decision is incremental cost and revenue. How much per barrel will it cost to develop a field? How much will it cost to move the oil to a market? What price will the oil command? What are the taxes and royalties? In short, what is the expected netback revenue? For years incremental crude oil produced on the North Slope had to be marketed east of Panama, requiring a total transportation cost of from $7 to $11 per barrel. Attempts to market the oil closer to Alaska would only depress the price of existing oil supplies from the region's other fields.

In the quarter century since the discovery at Prudhoe Bay, seismic charting of the North Slope has determined that, aside from ANWR, there is only one geological structure large enough to contain crude oil reserves similar to the Sadlerochit reservoir of Prudhoe Bay. That structure is the site of the $2 billion dry hole known as Mukluk.

Although prospects for finding and developing new fields on the North Slope are still very good, it is quite unlikely that a new field of the size and productivity of Prudhoe Bay will be found. Instead, development will be focused on smaller fields and extensions of existing fields. Under the best of circumstances, those projects will not have the profitability of Prudhoe Bay. Given uncertainty over world oil prices, taxes, and environmental regulations, lease holders are often reluctant to develop further capacity, even though the resource appears to have a positive rate of return. The Niakuk field north of Prudhoe Bay, for example, was put on hold for several years before it was finally developed.

In sum, oil development in Alaska operates on a razor- thin profit margin. Although a large part of the high operating costs in Alaska is due to natural factors such as the environment, the isolation of the fields, and the geology of the fields themselves, the artificially high cost of transporting oil to market--a direct result of the oil export ban mandating that the oil be sent to the lower 48 states as opposed to the Far East--has a dramatic impact on the economic viability of further oil exploration and development. The economic distortion engendered by the ban, although apparently small, turns out to be far greater than it appears on the surface.

The Economics of California Crude

California crude oils are heavy and ill suited for manufacturing gasoline, diesel, or jet fuel (the products in demand). The oil is also costly to produce, and production rates are very sensitive to movements in the world oil price or any change that affects wellhead prices.

California's oil fields are among the oldest in the country, yet they offer some of the greatest potential for increased output from already producing reservoirs. The state's largest field, Midway-Sunset, was discovered in 1894 and originally contained 10 billion barrels of oil-in-place. Its history illustrates some key features of both the economics of domestic oil supply and the structure of West Coast oil markets.

In 1974 the Federal Energy Administration estimated Midway-Sunset's proven reserves at 644 million barrels and forecast that production would decline from 95.9 million barrels per day in 1974 to 87.1 million barrels per day in 1984. Actual production in 1984 was 138.9 million barrels per day, 60 percent more than expected. Moreover, in 1992 estimates of proven reserves were 634 million barrels, almost the same as those of 1974 despite two decades of oil production. The unanticipated increase in production and reserve estimates was due to the widespread introduction of thermally enhanced oil recovery technologies.

Shell has also achieved dramatic increases in production at the South Belridge oil field. In 1981 Shell acquired the

Belridge Oil Company and set about increasing production by fracture stimulation. From 1980 to 1985 gross production more than doubled, to 166 thousand barrels per day. South Belridge's cumulative production plus its remaining recoverable reserves, as estimated by the California Division of Oil and Gas, now exceed the division's original estimate of oil-in-place.

Sadly, California's onshore heavy oil fields are now in rapid decline. Low prices have terminated a host of projects that could maintain production at past levels. Since 1985 production has dropped more than 20 percent.

Expectations of offshore oil production have also evaporated. Some of the largest discoveries of crude oil in the United States in the last decade have been off the shore of California. Two of the discoveries are located in the federal outer continental shelf at the Santa Maria Basin, north of Point Conception (referred to as Point Arguello), and the Santa Ynez unit to the south, located near the existing Hondo field. A third set of discoveries has been made in state waters off the coast midway between Point Conception and Santa Barbara, but it appears that those fields will not be produced.

In the early 1980s the unconstrained potential for the Santa Barbara area of the federal outer continental shelf was thought to be 500 thousand barrels per day. However, three factors have combined to delay start-up and reduce supply to half its potential. First, the collapse of crude oil prices in 1986 delayed or terminated many projects. Second, offshore crude oil is heavy and very sulfurous--the last sort of raw material California refiners want to buy. The high sulfur content is a particular problem in a region dedicated to improving air quality. Third, for at least a decade the industry has complained bitterly about the environmental constraints on oil development off the California coast. While some of the industry's complaints may be exaggerated, there is no doubt that safety and other environmental regulations have been a major constraint on development.

Again, the oil export ban is a serious impediment to the development of both onshore and offshore fields. The artificial glut of heavy crude coming from Alaska depresses oil prices and makes oil investments in California fields unprofitable. Although environmental factors do play a role in keeping some of that oil off the market, the export ban on Alaskan oil plays a role that is as large or larger in depressing the California oil economy.

Consequences of the Export Ban

To quantify the impact of the export ban on the economy, it is necessary to forecast West Coast demand and supply. The assessment of the effects of the export ban presented here is based on models developed for PAD District V, "In Transition: A Strategic Analysis," prepared by Economic Insight, Inc., and Energy Security Analysis, Inc.

Demand for petroleum products was estimated using the Energy Information Administration's model, based on actual PAD District V population, income, car registration, and related factors. The study assumed a modest decline in inflation-adjusted oil prices. Supply forecasts were based on information from the Alaska Department of Natural Resources and the U.S. Department of the Interior and projections from the oil industry.

Figure 3
PAD District V Demand and Supply, Actual from 1960 to 1994 and Projected to 2000
[Graph Omitted]
Sources: Economic Insight, Inc., and Energy Security Analysis, Inc.

Figure 3 summarizes the expected situation. After 1995 there is a great deal of uncertainty about supply. If the bulk of the North Slope's prospects are rapidly developed, West Coast crude oil supplies have the potential to reach a new peak of nearly about 3.0 million barrels per day, against a likely regional demand of 2.8 million barrels per day. On the other hand, if that development does not occur,existing fields will undergo a slow but steady decline. The difference in the two outcomes is represented in the graph by the striped area.

Ironically, West Coast oil prices will be favorable as long as development is not. As explained earlier, PAD District V demand and supply are close to balance (although modest volumes of North Slope crude are still shipped east of Panama). West Coast crude oil prices are closer to the world level than they were during the peak of the oil surplus (particularly in summer months), but there are often discounts. More important, substantial discounting would rapidly return if any large projects were to come on-stream.

Consider the position of the major North Slope crude producers. Those companies hold most of the leases for further development, own the Trans-Alaska Pipeline system for shipment, and have the most knowledge about working in Alaska's tough environment. If a new field is so large its production cannot be absorbed on the West Coast, its oil will have to be moved to the Gulf Coast at a cost of about $3 per barrel more than local shipment. Attempts to market the crude oil in California, Puget Sound, or Hawaii could force prices down, not only for the new oil being marketed, but for all the other production.

If development does not occur, the region will begin to import significant amounts of crude oil by the turn of the century. If the oil is developed, it will mean jobs and a brighter economic future, not just for the oil industry, but for other industries as well.

Eliminating the Export Ban: Benefits and Costs

In Alaska the wellhead value of the oil produced so far is about $265 billion (in 1993 dollars). As mentioned, total development costs were $67 billion, leaving $198 billion to be divided among the producers and federal and state governments. So far, Alaska's royalties and income, production, and property taxes have totaled about $75 billion.[16] Slightly less than half of the remaining cash flow, about $55 billion, is estimated to have been paid in federal income taxes, lease payments, and the windfall profit tax. The remainder, about $57 billion (less than one-fifth of the gross revenue) has accrued to the individuals and companies that discovered and developed the resource. They, in turn, employ thousands of workers and invest heavily in projects that will not turn a profit until the next century.

The development of oil has brought extraordinary benefits to the citizens of Alaska; the income to the state has been so great that Alaskan citizens have been spared income and sales taxes. In addition, the oil industry stimulates thousands of jobs indirectly through the multiplier effect. Since the development of Prudhoe Bay and the rise of world oil prices, Alaska's population has increased by 43 percent, from 412,000 to 587,000.

Other states also receive substantial benefits from petroleum development. Each summer premanufactured processing plants and facilities are barged to the North Slope where they are installed by a workforce from all over the United States. Shipyards as far away as Newport News, Virginia, manufacture portions of the facilities and equipment used on the North Slope. Just part of one project, the GHX-2 processing plant, was constructed at New Iberia, Louisiana. That construction crested with over 2,000 jobs in Iberia and 500 in Alaska and had substantial indirect economic impacts as well.

Removing the export ban would not be costless. It could lay up 30 coastal Jones Act tankers and cause jobs to be lost in the U.S. maritime industry. The job losses would not, however, exceed the 2,000 seafarers currently dependent on the Alaskan oil trade.[17] No new tankers would be built to serve a declining trade, so the shipbuilding industry would scarcely be affected one way or the other by the end of the export ban. Moreover, many of the coastal tankers can be redeployed in other trade, and surely some of the seafarers currently dependent on the Alaskan oil shipments to the lower 48 states would be redeployed as well.

Contrast the cost to the maritime industry with the benefits derived from removing the ban. Given that the development of crude oil in Alaska and California is very price sensitive, a modest increase in wellhead prices can be expected to bring about a substantial increase in supply. That abstract idea is exemplified by the development of North Slope projects. Those fields could easily add 10 billion barrels of reserves over the next two decades.[18] At present prices, that oil would translate into $125 billion in domestic development. It is unlikely, however, that such development will occur as long as the oil export ban remains in place.

Removing the ban would not threaten America's "energy independence." First, oil is a fungible, global commodity. There is simply no way to isolate the United States from global trends in oil supply and demand and the corresponding price fluctuations that may result.[19] Second, the export prohibition has demonstrably failed to achieve its goal--however misbegotten. Oil imports have increased since 1977. Finally, the prohibition on exporting Alaskan oil has served, as noted earlier, to increase imports of gasoline additives, offsetting any theoretical gain that might have been made in the pursuit of "energy security."

In the final analysis, the oil export ban is a monument to special-interest politics and an affront to economic rationality. It takes its place with market-demand proration (1928-71), the Mandatory Oil Import Program (1959-73), and oil price and allocation controls (1971-81) in the rogues' gallery of 20th-century oil regulation in the United States. Although the oil export ban was ostensibly a measure designed to ensure energy independence, its repeal, which would dramatically increase domestic oil production, will do more to promote energy security than all the taxpayer-funded activities of the Department of Energy combined. The ban belongs in the regulatory graveyard with the other mistakes of the energy crisis era. which have almost all been repealed by a chastened Congress. It is time for Congress to do the same with the oil export ban.

Notes

[1] See, for example, Arlon Tussing, Mather Berman, Susan Fison, and Samuel Van Vactor, "Report on Alaska Benefits and Costs of Exporting Alaska North Slope Crude Oil," Institute of Social and Economic Research, University of Alaska, 1987.

[2] Arlon Tussing, "The Trans-Alaska Pipeline and West Coast Petroleum Supply, 1977-1982," U.S. Senate Committee on Interior and Insular Affairs, 1974.

[3] Mark Trexler, Export Restrictions on Domestic Oil: A California Perspective (Sacramento: California Energy Commission, 1992), p. 66.

[4] Arlon Tussing, personal communication with author.

[5] U.S. Department of Commerce, "Report to Congress on Alaskan Oil," June 1986, p. II-11.

[6] Ibid., p. II-12.

[7] The nomenclature of the Petroleum Administration for War (December 2, 1942 through May 8, 1946) and the Petroleum Administration for Defense (October 3, 1960 through April 30, 1954) is still used by the industry. District V comprises Alaska, Washington, Oregon, Nevada, California, Arizona, and Hawaii.

[8] Determining the magnitude of the "West Coast oil price discount" is a complex undertaking. North Slope oil first created a surplus during the period of price controls in 1977; price distortions in California were rampant until the controls were lifted by President Ronald Reagan in 1981. Since then the extent of the price discount has varied, depending on the season, the availability of tankers, and the capacity utilization of west-to-east pipelines. Recent ly, the price discount has been modest, relative to that in the early 1980s. However, even today the marginal barrel from Alaska must be transported to the Gulf Coast market, at an extra transportation cost of about $3 per barrel. Since most North Slope producers cannot market a newly produced barrel of oil on the West Coast, they must take account of the higher transportation cost in their investment decisions.

[9] Historical and Projected Oil and Gas Consumption (An chorage: Alaska Department of Natural Resources, Division of Oil and Gas, February 1993), pp. 2, 33.

[10] Richard Nehring, "Giant Oil Fields and World Oil Resources," Report prepared for the Central Intelligence Agency by the RAND Corporation, June 1978.

[11] General Accounting Office, Trans-Alaska Pipeline Projects of Long-Term Viability are Uncertain, GAO/RCED-93-69, April 1993, p. 33.

[12] Matthew Berman, E. Larson, and B. Tuck, "Natural Resource Depletion and Social Income Accounting: Sustainable Income in Petroleum-Dependent Economies," Presented at the First OPEC/Alaska Conference on Energy Issues in the 1990s, Anchorage, Alaska, 1992, p. 24.

[13] Historical and Projected Oil and Gas Consumption, pp. 35-48.

[14] Berman et al.

[15] International Petroleum Encyclopedia, ed. Jim West (Tulsa: PennWell, 1992), p. 198.

[16] Ibid., p. 24.

[17] Department of Commerce, pp. I-5, V-6. See also Tussing et al.

[18] Removing the ban would increase effective crude oil prices to the producer for oil presently shipped to the Gulf Coast and most new investments by 20 to 30 percent and often double the net expected income. In many cases, the extra $2 to $3 per barrel would be enough to push marginal projects over the threshold. The precise outcome is not known, but, for example, when assuming a price elasticity of 1.0, a 25 percent rise in wellhead prices results in extra production of over one-half million barrels per day.

[19] For a fuller discussion of the futility of pursuing "energy independence," see Robert L. Bradley Jr., The Mirage of Oil Protection (New York: University Press of America, 1989); Robert L. Bradley Jr., "Should the United States Prepare for Another Oil Crisis?" Southern Regulatory Policy Institute, Issue Paper no. 2, December 1989; Douglas R. Bohi and Michael A. Toman, "Energy Security Externalities and Policies," Discussion Paper ENR 92-05, Resources for the Future, 1992; and Michael A. Toman, "The Economics of Energy Security: Theory, Evidence, Policy," Discussion Paper ENR91-13, Resources for the Future, April 1991.