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Alaskan North Slope Oil In National Perspective

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At present, West Coast refineries are unable to utilize all of the crude oil produced on the Alaskan North Slope, largely because of the effects of restrictive governmental regulations. Restrictions on sulfur-dioxide emissions, for example, have forced refiners to install more desulfurization capacity in order to process the high-sulfur Alaskan crude. At the same time, price controls on refined petroleum products have reduced the incentive for refiners to invest in such capacity—or to invest in the capacity required to tailor the Alaskan end-product mix closer to the regional end-product demand.

Other regulations have forced the oil industry to use inefficient methods for delivering surplus Alaskan oil to other regions of the United States. At present, U.S. tankers carry that oil to Gulf Coast refineries through the Panama Canal, which is a relatively high-cost method for dealing with the surplus. However, this is the only currently available option, because of laws which effectively ban Alaskan oil exports and prohibit the use of foreign vessels in U.S. intercoastal trade, and because of lengthy permit processes which have long delayed the construction of domestic pipelines. These difficulties also reduce the incentive to develop Alaskan resources, since North Slope producers' higher transportation costs reduce the wellhead price which they now receive.

The proposals for eliminating the surplus generally focus on increasing the ability of West Coast refineries to utilize heavy high-sulfur crude or on developing alternative transportation and marketing options. Some observers propose expanding West Coast refinery desulfurization capacity, or even constructing a desulfurization facility at the terminus of the Trans-Alaska pipeline system itself. Others propose transportation alternatives, including pipelines to convey the surplus to other domestic markets or international exchange ("swap") arrangements which would achieve the same aim indirectly.

Other alternatives have hardly been considered, although they might be even more efficient methods for dealing with the Alaskan-oil problem. These include the possible relaxation of California environmental-quality standards and the use of foreign-flag tankers in U.S. intercoastal trade. Policymakers apparently believe that such measures would undermine other high-priority national objectives, such as protection of the environment and national security, and hence they will not be discussed further here. This paper instead analyzes certain transportation and marketing alternatives, to determine whether the various options would help achieve the key objective of the nation's energy policy: namely, to reduce U.S. dependence on foreign-oil imports and to reduce its vulnerability to supply interruption.

The first section provides background information on the development of the Alaskan North Slope oil reserves and the reasons for the current surplus relative to West Coast refinery capacity. It attributes the surplus largely to the particular density and sulfur characteristics of North Slope crude, and to the limited refinery capacity existing on the West Coast for processing that crude into the products demanded by end-users in the region. The second and third sections consider the alternatives to the current inefficient method of dealing with the surplus, that is, shipment by U.S. flag tanker to Gulf Coast refineries through the Panama Canal.

The analysis shows that export exchanges represent the most efficient method of marketing Alaskan North Slope crude, and thus would result in the greatest producer cost savings on

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the crude that otherwise would be shipped through the Panama Canal. As a result, exchanges would provide the greatest producer return at the wellhead, and thus the greatest incentive for increased Alaskan oil production. On the other hand, exchanges would increase gross imports relative to other alternatives, and thus would embody a higher risk of supply interruption. Largely on these grounds of energy security, Congress to date has maintained restrictions on the export of Alaskan oil.

I. Development of the Alaskan Oil "Surplus"

The huge Prudhoe Bay oil deposit on the Alaskan North Slope—estimated to contain some 9.4 billion barrels of crude—was discovered in early 1968, but none of that oil came to market until nine years later, because of environmental controversies and delays in developing a delivery route. But with the help of the energy-crisis atmosphere created by the 1973 Arab oil embargo, Congress authorized the accelerated construction of the Trans-Alaska Pipeline System. The 789-mile pipeline, linking the vast Prudhoe Bay field with the southern Alaskan port of Valdez, was completed in July 1977 with an initial capacity of 1.2 million barrels per day, and with an ultimate design capacity of 2.0 million b/d. North Slope production began in mid-1977, and output gradually expanded to the 1.2 million b/d level by September 1978, with a further increase to 1.5 million b/d attained by late 1979.

Reasons for the surplus

The Federal Energy Administration and the oil industry originally believed that West Coast consumption of refined petroleum products would continue to grow at the 5-percent annual rate experienced during the decade preceding the 1973 oil embargo. They thus predicted that West Coast (District 5) refineries would be able to utilize the entire production of Alaskan North Slope crude anticipated during the first few years of pipeline operation.[1] But the Arab oil embargo, the attendant sharp run-up in world oil prices, and the 1974-75 recession all led to an alteration of historical consumption patterns. West Coast consumption of refined products increased at only a 2½-percent annual rate during the recession and recovery of the 1974-78 period, so that refinery crude-oil requirements fell considerably below the original forecasts.

The process was complicated by the fact that West Coast refineries lacked the specialized equipment required to process the relatively heavy, high-sulfur Alaskan crude, to make the end-product mix produced from that oil conform more closely with the composition of the region's end-product demand.[2] Gasoline, jet fuel, diesel and other "light" products distilled in the initial stages of refining account for the bulk of West Coast product demand. But North Slope crude yields a relatively large percentage of high-sulfur residual products, such as heavy fuel oil, asphalt and petroleum coke. Moreover, even after those products are removed in the refining process, a heavy residuum remains, which can be converted into the desirable light products only through the use of additional expensive cracking equipment.

The high-sulfur content of North Slope crude also poses major emission-control problems under current air-quality regulations. California utilities, under pressure to reduce their sulfur-dioxide (SO_2) emissions, require residual oil with a sulfur content of no more than 0.5 percent. But Western refiners cannot provide utilities with a fuel oil of that type from North Slope crude without the use of expensive desulfurization equipment.

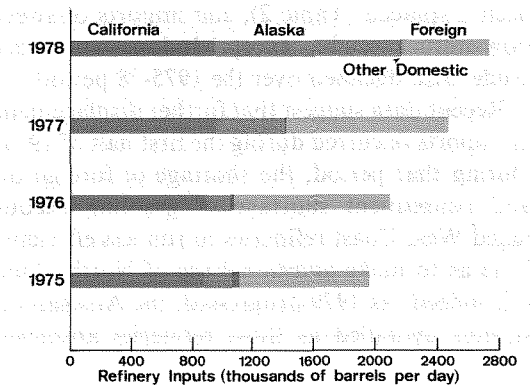
Yet the economic environment under domestic oil-price controls has not provided refiners with the incentive to make those necessary investments. Under the Federal price-control system instituted in 1973, refiners were permitted to raise their prices above the May 15, 1973 level to reflect increased costs. But for certain products—gasoline, diesel fuel and home heating fuel—refiners could allocate increased costs only proportionally to the *volume* of such products produced.[3]

For items such as gasoline, production costs are disproportionately high relative to their

share of total production, so that refiners have been unable to pass on all of the increased costs of such items. Indeed, price controls on gasoline were liberalized to permit a better recovery of costs only in March 1979. Moreover, strict environmental requirements often have posed a roadblock to the expansion or modification of refinery capacity. Environmental regulations and price controls on refined products thus have been largely responsible for the surplus of Alaskan oil on the West Coast.

Chart 1

Sources of West Coast (District V) Crude Oil Supplies[1]



[1] District V includes Alaska, Arizona, California, Hawaii, Nevada, Oregon and Washington.

"Backing out" imports

Nevertheless, within the limits of their technical capacity to process relatively heavy, high-sulfur crude, West Coast refineries have been able to use North Slope crude to "back out" or displace foreign oil of comparable quality. This is shown in the changing composition of West Coast refinery crude-oil supplies (Table 1 and Chart 1). As Alaskan oil production rose from about 191,000 b/d to 1.2 million b/d over the 1975-78 period—reflecting the start-up of Prudhoe Bay production—that state's share of total West Coast supplies rose from 10 to 44 percent.[4] California's share meanwhile dropped from 45 to 35 percent, although that state experienced rising output over the period. More importantly, foreign oil imports declined sharply both in absolute volume and as a share of total supplies (from 43 to 21 percent). By 1978, imports of

Table 1
Origins of West Coast Crude Oil Supplies[1]
(thousands of barrels per day)

					Percent of Total Supplies	
	1975	1976	1977	1978	1975	1978
Total West Coast Production	1076.1	1068.7	1424.4	2171.6	54.7	79.3
Alaska	191.3	173.1	463.6	1216.0	9.7	44.4
California	882.7	893.2	957.8	951.2	44.9	34.7
All Other West Coast[2]	2.1	1.8	3.0	4.4	.1	.2
Imports From Other States	38.7	17.6	3.9	2.2	2.0	.1
Foreign Imports	851.5	1008.8	1040.8	564.9	43.3	20.6
Total Crude Oil Supplies	1966.3	2095.1	2469.1	2738.7	100.0	100.0

[1] Including lease condensate (i.e., natural gas liquid).

[2] Arizona and Nevada.

Source: U.S. Department of Energy, Energy Information Administration, *Energy Data Reports: Crude Petroleum, Petroleum Products, And Natural Gas Liquids;* and *Energy Data Reports: Crude Petroleum, Petroleum Products, And Natural Gas Liquids in P.A.D. District V.*

sour (high-sulfur) crude from Saudi Arabia, Iran and other Persian Gulf nations had largely been displaced (Table 2), and imports of sweet (low-sulfur) crude, except Indonesian sweet crude, also declined over the 1975-78 period.

Recent data suggest that further displacement of imports occurred during the first half of 1979. During that period, the shortage of foreign oil and consequent shortage of gasoline encouraged West Coast refineries to run less efficiently so as to make additional use of North Slope oil. Indeed, as 1979 progressed, the Alaskan oil surplus dwindled as those refineries absorbed 1.0 million b/d of the 1.2 million b/d flowing from Prudhoe Bay. But in November, a project to raise the capacity and flowthrough of the Trans-Alaska pipeline to 1.5 million b/d was completed, raising the surplus by year-end to about 500,000 b/d. The 1.0 million b/d now being absorbed by refineries may represent just about a maximum, given the limitations on their capacity for processing high-sulfur crude. As a result, a 500,000 b/d surplus of Alaskan oil now exists in terms of Western refinery consumption.

Table 2
Origins of West Coast Crude Oil Imports
(thousands of barrels per day)

					Percent of Total Supplies	
Sweet Crude, by Source	**1975**	**1976**	**1977**	**1978**	**1975**	**1978**
Indonesia	295.4	450.0	424.1	386.4	34.7	68.4
Other S.E. Asia[1]	5.3	15.2	60.6	41.6	.6	7.4
Canada	163.5	87.3	20.1	11.9	19.2	2.1
South America[2]	5.3	4.3	4.3	1.8	.6	.3
Africa[3]	22.2	30.0	10.5	0	2.6	0
Total Sweet	491.7	586.8	519.6	441.7	57.7	78.2
Sour Crude, by Source						
Saudi Arabia	95.6	179.7	197.8	15.8	11.2	2.8
United Arab Emirates	49.9	84.5	125.9	80.1	5.9	14.2
Iran	105.2	90.0	99.8	0	12.4	0
Other Persian Gulf[4]	96.8	45.3	54.0	25.3	11.4	4.5
South America[5]	12.3	22.5	43.7	2.0	1.4	.3
Total Sour	359.8	422.0	521.2	123.0	42.3	21.8
TOTAL WEST COAST	851.5	1008.8	1040.8	564.9	100.0	100.0

[1] Malaysia and Brunei

[2] Bolivia and Chile

[3] Algeria, Angola, Gabon, Libya, Nigeria, and Tunisia

[4] Egypt, Iraq, Kuwait, Oman, Qatar

[5] Ecuador and Venezuela

Source: U.S. Department of Energy, Energy Information Administration, *Energy Data Reports: Crude Petroleum, Petroleum Products, and Natural Gas Liquids.*

II. Alternatives for Dealing with the Surplus

The present 500,000 b/d "surplus" of Alaskan North Slope crude is now shipped by U.S. flag tankers from the Alaska pipeline terminus at Valdez to Gulf Coast refineries through the Panama Canal (Figure 1). But this is one of the most costly ways of marketing Alaskan oil, mostly because the Jones Act, of 1917 vintage, requires that all domestic cargoes be carried by U.S. flag vessels. The present transportation system also yields Alaskan producers a relatively lower price at the wellhead.[5] This is because petroleum's selling price in any given market is based on the average landed price for comparable quality OPEC crude, which means that North Slope producers must absorb transportation costs in order to compete against foreign crude in those markets.

In the interest of raising the wellhead price, those producers have proposed several alternatives for dealing with the surplus Alaskan oil. These alternatives have included: 1) construction of additional desulfurization and cracking capacity on the West Coast; 2) construction of overland pipelines to U.S. refineries farther East; and 3) exchanges with foreign nations on a barrel-for-barrel basis. In the latter two cases, domestic markets farther East would eventually receive the Alaskan oil, or equivalent amounts of foreign oil acquired through exchanges.

Refinery modification option

The West Coast (District 5) market—serviced primarily by California and Washington refineries—is the most attractive *domestic* market for Alaskan crude. West Coast sales yield North Slope producers the greatest price at the wellhead, because of that market's proximity to the production source and therefore low transportation costs. The surplus thus could be reduced if oil firms installed the cracking capacity and desulfurization equipment necessary to handle greater amounts of North Slope crude, either at existing West Coast refineries or at new facilities near the Trans-Alaska pipeline terminus at Valdez. Retrofitting existing refineries would enable those plants to utilize greater quantities of high-sulfur Alaskan crude. Construction of a desulfurization plant at Valdez, on the other hand, could supply West Coast refineries with larger quantities of low-sulfur crude, well-suited to present refinery configurations and end-product demand.

Pipeline option

Some government and industry leaders have proposed building pipelines as a means of transporting the West Coast surplus to U.S. markets farther East (Figure 1). Domestic alternatives include the Sohio (PACTEX) line or the Northern Tier line, both of which would traverse only U.S. territory. But there are several Canadian alternatives—the Trans-Mountain, Kitimat and Foothills pipelines—although only the former appears to be a viable competitor to the U.S. pipelines.

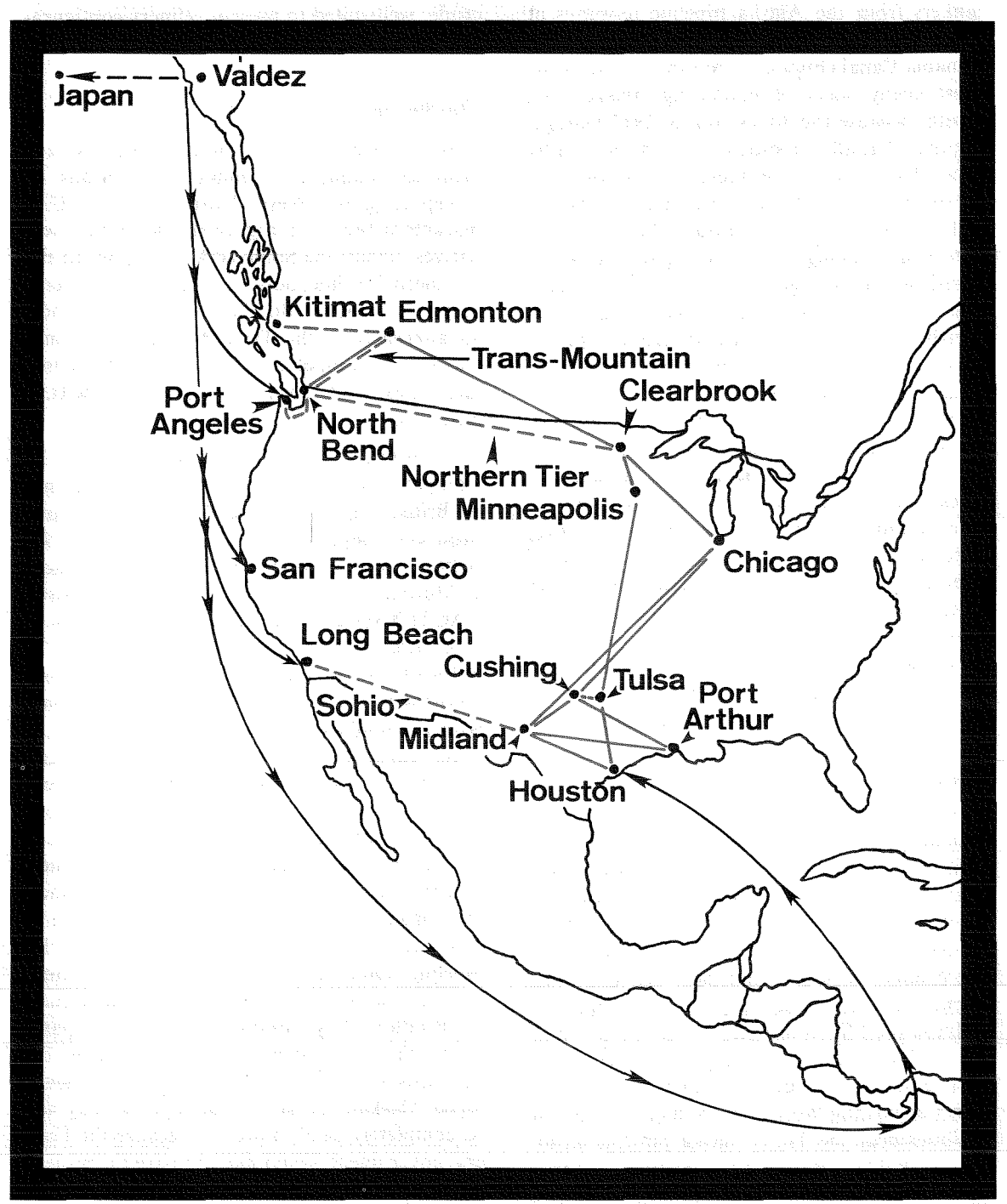
a) *Sohio pipeline.* In 1974, Standard Oil Company of Ohio (Sohio)—which is a partner of British Petroleum, the major North Slope producer—began to develop plans for a $1-billion project to move crude from Long Beach, California, to Midland, Texas. The proposed PACTEX system would include construction of a terminal at Long Beach, conversion of 778 miles of an existing natural-gas pipeline, and construction of about 215 miles of new pipeline, with an initial capacity of about 500,000 b/d.

In March 1979, however, Sohio announced that it was abandoning the PACTEX project because of delays in pipeline authorization, which it said made the project no longer economically feasible. The company had counted on the pipeline being in operation in 1978, when the surplus first developed. But now, even if construction were to start immediately, the pipeline would not be completed until sometime in 1982—not too long before a projected decline in Prudhoe Bay production. The company claims that it could not justify the pipeline on the basis of as yet undiscovered and undeveloped Alaskan resources. The pipeline may not be completely dead, however, because the Federal government would like to revive the project on national-security grounds.

b) *Northern Tier pipeline.* The Administration has announced its support for a $1.4-billion

Figure 1

Alaskan Crude Oil Transportation Alternatives



Current tanker route via Panama Canal

Existing pipelines

Proposed pipelines

Proposed tanker route to Japan (equivalent amount to be returned to United States)

Note: The Trans-Mountain proposal calls for the reversal and possible expansion of that existing east-to-west pipeline.

project developed by a number of railroads, consulting firms and small oil companies, which would move crude between Port Angeles, Washington, and Clearbrook, Minnesota, and thence by existing pipelines to refineries in the Midwestern states. The project would entail construction of a marine terminal at Port Angeles, and a 1,568-mile pipeline from there to Clearbrook, with initial capacity of 600,000 b/d.

The pipeline would be especially helpful for refineries in the Northern Tier states bordering on Canada (such as Montana, North Dakota and Minnesota). Those refineries are almost wholly dependent upon Canadian crude, which will become unavailable after 1982 because of Canada's own domestic needs.

Export-exchange option

Under export-exchange (swap) arrangements, Alaskan oil would be shipped to Japan, in exchange for which an equivalent amount of Japan-bound foreign-produced crude would be diverted to the U.S. Gulf or East Coasts. Mexico has been frequently mentioned as a possible third party in such a swap arrangement. However, this option remains precluded by the Trans-Alaska Pipeline Authorization Act of 1973 and also by the 1977 and 1979 amendments to the Export Administration Act.

The 1973 legislation prohibits exports of domestic crude oil transported by pipeline over Federal rights-of-way—unless such exports are exchanged with adjacent nations to promote transportation efficiency, or unless the President finds that an export transaction is in the national interest and does not "diminish the total quantity or quality of petroleum available to the United States." The restrictions have been tightened even further by the 1977 and 1979 amendments to the Export Administration Act. The latest legislation requires the President to certify that any export proposal would actually help reduce the cost to refineries, distributors and consumers, and also requires explicit Congressional approval of any export transaction.

III. The Alternatives and National Energy Policy

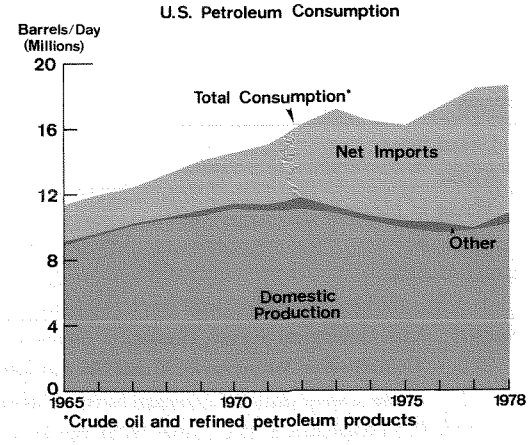
In deciding upon the appropriate method for dealing with surplus Alaskan oil, policymakers should consider not only the relative efficiency of the various options, but also the contribution they can make to the nation's energy-policy goal of reduced U.S. dependence on foreign oil. Alaskan North Slope production, since coming on stream in July 1977, has contributed significantly to that goal. Production has risen gradually to a current level of 1.5 million b/d, displacing a roughly equivalent amount of foreign crude oil at U.S. refineries on the West and Gulf Coasts.

Import problem

Prior to the start-up of Prudhoe Bay production, the United States had made no real progress in slowing the import flow, despite the nearly fivefold increase in world oil prices over the 1972-77 period. On the contrary, imports of crude and refined products almost doubled between 1972 and 1977, to a record high of 8.8 million b/d (Chart 2). Over the five-year period, imported oil jumped from 29 to 46 percent of the nation's total petroleum requirements, with OPEC oil alone rising from 20 to 42 percent of total consumption. Between 1972 and 1977, oil imports in value terms jumped from $5 billion to $45 billion, and thus accounted for a major share of the nation's deteriorating foreign-trade balance. This situation reflected the effects of domestic oil-price controls in encouraging the growth of consumption and discouraging in-

Chart 2

U.S. Petroleum Consumption



*Crude oil and refined petroleum products

creased domestic production. Between 1972 and 1977, U.S. consumption of refined petroleum products rose by 12 percent, while domestic crude production dropped by 13 percent.

Late in 1977, however, North Slope oil began to displace some foreign crude of comparable sulfur content and gravity, not only in the West but in other areas of the nation. Imports of crude and refined products fell nearly 9 percent in volume and 6 percent in value terms in 1978. This displacement occurred because North Slope producers had priced their crude competitively on a delivered-cost basis with comparable-quality foreign oil, and because refiners purchasing North Slope crude had received the same entitlement benefits for Alaskan as for foreign oil.[6]

Table 3
Estimated Undiscovered Alaskan Oil Resources, 1975

	Range of Estimates (billions of barrels)		
	Low	Mean	High
Onshore			
United States	37	56	81
Alaska	6	12	19
Alaska as percent of U.S.	16%	21%	23%
Offshore			
United States	10	26	49
Alaska	3	15	31
Alaska as percent of U.S.	30%	58%	63%
Totals			
United States	50	82	127
Alaska	12	27	49
Alaska as percent of U.S.	24%	33%	39%

Source: U.S. Geological Survey, *Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States,* Geological Survey Circular 725 (Washington, D.C.: June 1975), pp. 28-31.

But imports increased again in 1979, despite a slight decline in U.S. petroleum consumption. This came about as domestic crude-oil production resumed its decline in the face of a stable North Slope production rate of 1.2 million b/d—at least until late in the year when production rose to 1.5 million b/d. In fact, Energy Department projections suggest that imports could rise to 13 million b/d by 1990, even with a modest 2-percent average annual increase in U.S. petroleum consumption.[7] At that point, imports would comprise more than 50 percent of total domestic consumption. That level of oil-import dependency could place a severe strain on the U.S. balance of payments—and on the international value of the dollar—especially in view of the expected continuation of sharp increases in world oil prices.[8]

To forestall that development, the Administration announced its proposed oil-import reduction program in July 1979. Over the long-run, the program focuses heavily on the development of synthetic fuels to reduce import requirements. However, it will take at least a decade or more for the production of oil from coal and shale to reach a significant volume. In the short-run, therefore, a solution will have to involve both the conservation and increased domestic production of conventional crude oil.

Expansion of domestic production

At the present time, Alaska provides the best hope of once again reversing the declining pattern of domestic oil production. Despite a recent lowering of estimates of undiscovered recoverable oil resources, Alaska continues to be the nation's most promising target for petroleum exploration and development. Indeed, according to the latest (1975) estimates of the U.S. Geological Survey, Alaskan fields probably contain 12 to 49 billion barrels of undiscovered oil—about one-third of the nation's total undiscovered oil resources (Table 3). But the bulk of these potential resources may be located offshore in the Outer Continental Shelf, and thus may require vast sums to develop.

Based on existing proven reserves, Alaska's crude oil production may decline around the mid-1980's as the Prudhoe Bay reservoir becomes depleted. To arrest this decline, some of

the state's undeveloped resources will have to be translated into proven reserves. The extent to which producers are encouraged to make those necessary investments will depend upon the prices realized at the wellhead. That incentive has improved dramatically over the course of the past year because of sharply rising OPEC selling prices—and because the U.S. government has permitted North Slope crude to be priced competitively in all markets with comparable-quality imported oil, provided the producer price at the wellhead does not exceed the upper-tier ceiling. For the past few months, North Slope wellhead prices have been bumping against the Federal ceilings, currently at $13.55/barrel. But producers will benefit from higher OPEC selling prices as domestic crude-oil prices are gradually deregulated by late 1981.

For any given selling price, a reduction in transportation costs also increases the producer price at the wellhead. So when policymakers determine the appropriate means for dealing with the West Coast surplus, they must consider the extent to which each alternative would lower transportation costs. It is assumed that North Slope producers, in the absence of an export ban, would be permitted to exchange only that volume of production which West Coast refineries cannot handle. Otherwise, they would be tempted to market all of their production overseas, because transportation costs associated with export exchanges would be even lower than those incurred in supplying the Western refinery market.

Nonetheless, rising world oil prices represent the dominant factor in boosting Alaskan wellhead prices, and thus in stimulating increased production. After all, North Slope producers generally stand to benefit on their entire production from every increase in the OPEC price, whereas transportation-cost savings on the surplus would increase the wellhead price for only that volume of oil that otherwise would have to be shipped through the Panama Canal. During the first half of 1979 alone, wellhead prices for North Slope oil sold on the West and Gulf Coasts rose by 75 and 112 percent, respectively, simply on the basis of the sharp run-up in the OPEC landed prices for comparable-quality oil.[9] Still further sharp increases were realized after July 1 when OPEC prices were raised in several stages again.

Producer after-tax revenues could be increased further by reductions in Alaskan state taxes and/or Federal income taxes (Table 4). Transportation cost savings, by raising the wellhead price on applicable volumes, would also provide an incentive to expand production—in addition to economizing on real economic resources. But none of these avenues would offer as much potential relief as increases in world oil prices.

Policy trade-offs

Two questions must be asked regarding the various alternatives for dealing with the Alaskan oil surplus. How much would each reduce transportation costs, and thus provide increased incentive for the expansion of domestic production? And how much would each stimulate the development of the domestic refining capacity and/or transportation network required to utilize domestic production efficiently within the United States? The difficulty in selecting an appropriate strategy, of course, is that the options involve trade-offs among various policy objectives.

1. Export-exchange option. This alternative would be the most efficient, or least-cost method, for dealing with the West Coast surplus. It would reduce transportation costs the most relative to the current system of shipment through the Panama Canal, and thus would provide the greatest incentive for expanding Alaskan production.[10] On the other hand, this option would involve a greater risk of supply interruption than the other alternatives, and would frustrate development of a domestic refinery/distribution infrastructure for handling Alaskan oil.

In June 1979, North Slope crude sold for an estimated $17.55/barrel on the U.S. Gulf Coast (Table 4). However, North Slope producers received a wellhead price of only about $7.98/barrel, after subtracting the trans-Alaskan pipeline tariff of $6.32/barrel and the Valdez-Panama Canal-Gulf Coast shipping cost of $3.25/barrel. But under a swap arrangement, North Slope oil could be shipped to Japanese refineries in *foreign* tankers at a cost of only about $0.40/barrel, and this cost saving would

mean a $2.85/barrel increase in the wellhead price to North Slope producers. If Mexico were the third party in the exchange, Mexican producers similarly would benefit from diverting their Japan-bound crude to U.S. Gulf Coast refineries at a shipping cost of only $0.40/barrel.

Proponents of export exchanges maintain that transportation-cost savings and wellhead-price increases of these magnitudes are essential to generate the necessary investments in expanded North Slope production. Output from the main Prudhoe Bay reservoir—the Sadlerochit—has reached its potential capacity of 1.5 million b/d, and will probably fall below that level by the mid-1980's. Some output may become available from the nearby—as yet untapped—Lisburne and Kuparuk reserves. But a major expansion of production—sufficient to meet the pipeline's full potential of 2.0 million b/d—will require heavy expenditures for developing high-cost reserves in the Beaufort Sea and other new areas.[11]

The major drawback to the swap option—insecurity of supplies—has led Congress to continue its strict restrictions on Alaskan oil ex-

Table 4
Estimated Net Return to Alaskan North Slope Oil Producers In Selling to Various Markets, June 1979 (dollars per barrel)

	United States[1]		Japan[2]	
	West Coast	Gulf Coast	Scenario A	Scenario B
Delivered Price	16.80	17.55	16.55	15.32
Less shipping cost	.95	3.25	.40[3]	.40
Value at Valdez	15.85	14.30	16.15	14.92
Less Alaskan pipeline tariff[4]	6.32	6.32	6.32	6.32
Value at Wellhead	9.53	7.98	9.83	8.60
Less severance tax (11.54%), state royalty (12.5%), and property tax	2.32	1.97	2.39	2.11
Less operating costs & depreciation	1.53	1.53	1.53	1.53
Pretax Net	5.68	4.48	5.91	4.96
Less state income tax (9.36%)	.53	.42	.55	.46
Less Federal income tax (46%)	2.37	1.87	2.47	2.07
Net Income Per Barrel	2.78	2.19	2.89	2.43

[1] Delivered prices and costs for selling North Slope crude on the West and Gulf Coasts based on estimates by the *Petroleum Intelligence Weekly*, as modified by the author through further investigation. "Delivered price" in any given market usually equals the delivered price of Saudi marker crude, plus or minus any quality differential. Saudi marker delivered price is the posted price f.o.b. in the Persian Gulf ($14.54 in June) plus the transportation cost to the particular market ($1 to the West Coast, and $1.75 to the Gulf Coast). June selling prices in U.S. markets exceeded the prices this computation would yield, however, due to the breakdown of the traditional uniform OPEC pricing structure and the resultant surcharges added to posted prices by many OPEC producers.

[2] The delivered price for North Slope crude in Japan (Scenario A) was estimated by first determining an effective rather than a posted Saudi market price. That effective price was estimated to be roughly equal to the selling price of North Slope crude on the Gulf Coast ($17.55) plus a quality differential (+$.50) minus transportation costs from the Persian Gulf (-$1.75), or to $16.30. Using that Saudi marker price ($16.30), we then added the transportation costs from the Persian Gulf to Japan (+$.75) minus a quality differential (-$.50) to derive an estimated delivered price of North Slope crude in Japan of $16.55. In Scenario B, it is assumed North Slope producers share half of the transportation cost savings ($1.43) with Japanese refineries.

[3] Based on the use of foreign flag VLCC tankers at World-scale 50. Using U.S. flag tankers, the rate would be about $1.30 per barrel.

[4] Includes charges for liability fund ($.05) and pipeline less ($.05).

Source: *Petroleum Intelligence Weekly*, June 18, 1979, page 9; estimates developed by the author through contacts with oil-industry analysts.

ports. Of course, increased domestic production—with or without swap arrangements—will tend to reduce *net* imports of petroleum for any given level of consumption, and thus will help to improve the U.S. oil-trade balance. But swaps increase *gross* imports, and so do not reduce susceptibility to a cutoff of foreign oil. Even if Alaskan oil were channeled back into the domestic market during a supply crisis, that action would simply transfer the dislocation to Japan and would thus undermine Japan-U.S. relationships.

Lifting the ban on exports also would eliminate all incentive for West Coast refiners to retrofit their plants to handle more Alaskan crude, or for North Slope producers or other investors to build pipelines to improve domestic distribution of crude. Since the export-exchange arrangement would be the least-cost (and most profitable) method for dealing with the Alaskan surplus, the overseas market would be the preferred market for selling the crude. Without assurance that Alaskan supplies would be available on the West Coast, refiners would have no incentive to retrofit their plants. Similarly, without any surplus to transport to other areas of the nation, investors would have no incentive to pursue the less efficient pipeline alternative.

2. Refinery modification option. Within the United States, transportation costs are lowest for the West Coast market (Table 4), although costs there are slightly higher than they would be under the swap option because of the costly requirement for using American-flag tankers. If West Coast refiners carried out the necessary modifications to fully utilize Alaskan production, North Slope producers would realize this transportation cost saving per each barrel of oil that otherwise would be shipped through the Panama Canal.

Elimination of price controls on refined products would provide refineries with a strong incentive to make the necessary investments. With decontrol, they could recover their increased costs and perhaps even widen their profit margins. In this regard, they have already benefitted from the so-called "tilt" rule for gasoline pricing—instituted in early March of 1979.[12] Still, they would have no incentive to modify facilities if the swap option were available.

North Slope producers would incur higher production costs in serving the West Coast market if they themselves built a desulfurization plant at Valdez to upgrade their oil. These added costs would offset some of the transportation costs saved in not having to ship oil through the Panama Canal. But producers also would realize the price premium that low-sulfur crude commands on the West Coast. On balance, then, producers might benefit as much from this option as from the refinery modification alternative.

3. Pipeline option. It is very difficult, if not impossible, to evaluate the relative costs and prices associated with this alternative. None of the proposed pipelines has received final approval, although the Administration has announced its support of the Northern Tier line. Thus, start-up and completion dates cannot be determined, and overall cost and tariff estimates are highly tenuous. Furthermore, comparisons are difficult because one proposed pipeline would be built from scratch while others would incorporate existing pipelines; in the latter case, for example, the nominal cost of transportation would tend to underestimate the true economic cost of replacement.[13] The tariff per barrel associated with any pipeline also would be highly dependent upon the operating rate—that is, the amount of throughput—yet rates of capacity utilization are unknown.

Recent estimates suggest, however, that transportation costs could be lower with the Sohio pipeline than with the Panama Canal alternative,[14] which means of course higher wellhead prices for producers. But in general, producers apparently would benefit less from the pipeline option than they would from the refinery-modification option.

Summary and conclusions

Government regulations have been largely responsible for creating a "surplus" of Alaskan North Slope oil, defined in terms of West Coast refinery capacity to process that relatively heavy, high-sulfur crude. Because of environmental regulations as well as the composition of regional refined-product demand, West Coast refineries need additional desulfurization and downstream cracking capacity to fully utilize North Slope supplies. Yet price controls on refined products

have inhibited refineries from making the necessary investments. And because of other regulations delaying domestic pipeline construction, banning exports, and forbidding the use of foreign tankers in U.S. intercoastal trade, North Slope producers are required to ship their excess output by U.S. tankers to Gulf Coast refineries through the Panama Canal. But this approach is one of the most inefficient possible ways of dealing with the surplus.

In evaluating various alternatives, policymakers must decide not only which alternative provides for the most efficient use of resources, but also which is most effective in achieving the nation's key energy objective of reduced reliance on foreign oil imports. These two objectives are of course somewhat related. The primary way to reduce reliance on oil imports is to increase domestic production through the mechanism of price incentives. Yet reducing transportation costs through a more efficient distribution system raises the producer price at the wellhead and thus increases price incentives.

The current method of disposing of the surplus—the Panama Canal approach—tends to reduce the producer price at the wellhead, and also to depress the North Slope selling price on the West Coast. This approach consequently serves to restrain potential increases in output, since a major portion of any substantial production increase also would end in the "surplus" stream and receive a lower wellhead price. Each of the alternatives discussed in this paper—export exchanges, pipelines, refinery retrofitting, crude desulfurization—are designed in one way or another to eliminate the bottleneck and provide greater production incentive.

Export-exchange arrangements would provide the least cost, or most efficient, means of dealing with the surplus. Such arrangements would provide the maximum transportation cost savings for North Slope crude that otherwise would have to be shipped through the Panama Canal. These savings would translate into the greatest increase in producer wellhead prices, and thus the greatest added incentive for increased North Slope and other Alaskan production. Each of the other options would call for various amounts of investment in new construction. As such, each would provide relatively less of a transportation cost saving and relatively less inducement for expanded production than export exchanges. There is no clear "second best" alternative to export exchanges in terms of efficiency, largely because of the highly uncertain nature of the estimated costs involved.

While economic efficiency alone would dictate the adoption of the export-exchange option—that is, the removal of Alaskan oil-export controls—certain trade-offs associated with this approach must also be considered. Export exchanges, although not affecting net oil imports, would increase *gross* imports and thus increase the nation's susceptibility to supply interruptions. Also, if Congress permitted this option, it would thereby tend to reduce, or even eliminate, the incentive for producers or refiners to undertake any of the other possible alternatives.

Regardless of what distribution option is adopted, rising world oil prices will improve the economic climate for expanded Alaskan production. The issue of whether or not to permit Alaskan oil exports boils down to whether or not the advantages of economic efficiency (and greater producer price incentive) outweigh the disadvantages of increased risk of supply interruption such exchanges would entail. Economic factors alone argue in favor of export exchanges. A decision to retain controls on exports requires a political judgment that energy security is a more important policy consideration than economic efficiency alone.

FOOTNOTES

1. United States, Federal Energy Administration, *North Slope Crude—Where to? How? An Analysis of the Alternatives Available for the Transportation and Disposition of Alaskan North Slope Crude,* (November 29, 1976), pp. 15-17.

2. North Slope oil is described as being heavy (27 degrees American Petroleum Institute (API) gravity) and sour (1 percent sulfur content). Heavy crude oils are those with a high density or low API gravity. Generally, crude oils having a gravity of 32 degrees API or less are called heavy crude oils. Sour crude oils are those that contain relatively high amounts of sulfur (greater than 0.5 percent).

3. United States, Presidential Task Force on Reform of Federal Energy Administration Regulation, *Report on Federal Energy Administration Regulation,* ed. MacAvoy (Washington, D.C.: American Enterprise Institute for Public Policy Research, 1977), pp. 8-9, 60-64.

4. Alaska had been a significant oil producer prior to the onset of Prudhoe Bay production in mid-1977. In 1976, the state produced about 190,000 b/d of oil, with most of that output coming from the Kenai Peninsula/ Cook Inlet area in the southern part of the state.

5. At present, only one of the three major Prudhoe Bay producers—namely, Standard Oil Company of Ohio (Sohio)—has no refineries on the West Coast and thus must transport North Slope crude to Gulf Coast refineries through the Panama Canal. If Alaskan production were to expand without a commensurate increase in West Coast refining capacity to handle that crude, other producers also could be confronted with the problem of transporting their surplus through the Panama Canal.

6. The entitlements program was established in 1973 to equalize the effective acquisition costs of oil obtained by U.S. refiners under the multi-tiered system of oil prices resulting from Federal price controls on domestically-produced oil. Under this program, refiners having access to supplies of cheaper oil make cash payments to refiners who depend on more expensive oil, thus tending to equalize the effective acquisition cost of lower-tier, upper-tier and imported crude oil to the refiner. North Slope oil has been granted the entitlement status of upper-tier or "new" oil which sells at the world price. As a result, U.S. refiners using that oil are granted the same entitlements benefits for Alaskan as for foreign oil.

7. U.S. Executive Office of the President, *The White House Fact Sheet on the President's Oil Import Reduction Program* (Washington, D.C., July 15, 1979), p. 2. For a similar forecast see U.S. Congress, Congressional Budget Office, *The Decontrol of Domestic Oil Prices: An Overview* (Washington, D.C.: U.S. Government Printing Office, May 1979) p. 14.

8. A number of independent studies have concluded that world oil prices will rise sharply in real terms between now and the early 1990's. See, for example, Workshop on Alternative Energy Strategies, *Energy: Global Prospects, 1985-2000* (New York: McGraw-Hill, 1977); Organization for Economic Cooperation and Development, *World Energy Outlook* (Paris: OCED, 1977); United States Central Intelligence Agency, *The International Energy Situation: Outlook for 1985* (Washington, D.C.: Central Intelligence Agency, April 1977). The prospect of supply stringency has intensified in the light of recent Iranian and Saudi Arabian production plans.

9. Delivered price for North Slope crude in any given market usually equals the delivered price for Saudi marker crude, plus or minus any quality differential. During 1979, there was a breakdown in the traditional uniform OPEC pricing structure, however, as a result of the Iranian crisis and consequent surcharges added to posted prices among markets served by various producers. North Slope selling and wellhead prices were similarly distorted.

10. It is for these reasons that the State of Alaska has repeatedly pressed for export exchanges. That state would benefit not only in terms of the return on its royalty, i.e., ownership share, but from increased tax revenues.

11. For a discussion of this point see Howard M. Wilson, "How Operators View Prudhoe Bay Now," *The Oil and Gas Journal* (February 6, 1979), p. 71; also, Arlon R. Tussing, *The Effects of Crude Oil Pipeline Tariffs on the Economics of Petroleum Development in Arctic Alaska* (Seattle, Washington: July 5, 1978).

12. The "gasoline tilt" rule, adopted by the Department of Energy on March 1, 1979, permits up to 110 percent of crude oil cost increases to be allocated to gasoline on a pro-rata, volumetric basis; it also allows refiners to allocate to gasoline a percentage of refining costs greater than the volumetric ratio. Previously, increases in crude oil and refining costs (above the 1973-base period) were allocated to refined products strictly on a pro-rata volumetric basis. The average refinery crude oil run yields about 44 percent gasoline. Consequently only about 44 percent of crude oil and refinery cost increases could be passed on in gasoline prices, despite the fact that the costs of producing gasoline are greater than those for most other refined products.

13. This point was stressed by Arlon R. Tussing in *Economic and Policy Consideration in Choice of a West Coast Oil Port* (West Coast Oil Ports Inquiry, Vancouver, British Columbia, November 1977), pp. 5-7.

14. *Statement* of Alton W. Whitehouse, Jr., Chairman of the Board, The Standard Oil Company (Ohio), before the Senate Committee on Energy and Natural Resources (Washington, D.C., March 27, 1979), p. 8.

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