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BY THE U.S. GENERAL ACCOUNTING OFFICE

Report To The Honorable Bill Nelson House Of Representatives

Response To Questions About The Windfall Profit Tax On Alaskan North Slope Crude Oil

This report describes how oil producers are determining the removal price of Sadlerochit oil, which is the starting point for calculating the windfall profit tax. Under the Crude Oil Windfall Profit Tax Act of 1980, oil producers pay a tax on the difference between the free market price of a barrel of oil and its controlled selling price under Department of Energy regulations with certain adjustments. Sadlerochit oil is from the Prudhoe Bay field, which is located on Alaska's North Slope and is the field with the greatest volume of oil production in the United States.

Most Prudhoe Bay producers are using net-back methods to establish the oil's removal price. Net-back generally involves valuing Alaskan oil on the basis of the market value of other oil in delivery areas, such as the U.S. Gulf Coast or the West Coast, and then deducting the costs of transporting the Alaskan oil to the various refineries or markets.

Despite two IRS revenue rulings issued to ensure consistency among producers, differences still exist among the Prudhoe Bay producers' net-back practices. IRS plans to develop and issue in early 1985 further guidance to producers on removal price determinations.

UNITED STATES GENERAL ACCOUNTING OFFICE

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UNITED STATES GENERAL ACCOUNTING OFFICE
WASHINGTON, D.C. 20548

GENERAL GOVERNMENT DIVISION

B-209475

The Honorable Bill Nelson
House of Representatives

Dear Mr. Nelson:

In response to your request, this report answers questions relating to the amount of windfall profit tax collections on Alaskan North Slope crude oil and the methods used to determine oil producers' tax liabilities. (See app. VIII.) The windfall profit tax was designed so that the tax would be due only on sales of oil at price levels above those that existed in 1979.

Most of the questions and our responses relate to a central issue: how the removal price is established for oil from the Sadlerochit reservoir in the Prudhoe Bay oil field. Other Alaskan oil is tax exempt. The removal price is the basis for calculating the windfall profit tax, which, in calendar year 1982 totaled $1.04 billion for Sadlerochit oil. Usually, the removal price for other domestic oil is equivalent to the sales price. However, for Sadlerochit oil the producers construct the removal price because most of this oil is not sold in Alaska. Rather, it is removed from the wellhead premises and is then transported long distances by integrated oil companies for processing in their refineries.

For windfall profit tax purposes, most Prudhoe Bay producers are using net-back methods to establish a constructive removal price. Net-back generally involves valuing the Alaskan oil on the basis of the market value of other oil in the general delivery areas, such as the U.S. Gulf Coast and the West Coast, and then deducting all the overland and waterborne costs of transporting the oil from the North Slope to those markets.

The Internal Revenue Service (IRS) issued revenue rulings to ensure consistency among the producers' net-back practices. However, the rulings did not address all the differences that exist. Producers' practices differ as to which comparable domestic or foreign crude oils should be used as benchmarks to establish a market value for the Sadlerochit oil, as well as other related aspects of the valuation process. These aspects include (1) whether the Sadlerochit oil's market value should be determined at the time the oil is removed from the wellhead premises or upon delivery to the market and (2) whether an adjustment should be made for credit terms available for the benchmark oil.

Producers also deduct different overland and waterborne costs from the market value of the Sadlerochit oil to determine its removal price. These costs involve field handling costs, pipeline losses, tariffs, and waterborne shipping costs. Field costs are the costs of moving the oil from the wellhead to the Trans-Alaska Pipeline System and may include gathering, separating, cleaning, and dehydration costs. Some, but not all, producers deduct these costs in netting-back to determine removal prices for windfall profit tax purposes.

Another difference in deductions involves pipeline losses. The largest portion of the pipeline losses are not physical losses, such as leaks or vaporization. Rather, some of the crude oil is routinely removed from the pipeline and refined locally to make diesel fuel for operating the pumping stations along the pipeline. Most producers make net-back deductions for these pipeline losses; but, the deductions vary among the producers, ranging from about 5 cents to 10 cents a barrel. IRS officials believe that a standard formula for calculating pipeline losses must be developed and used consistently by the producers.

Besides pipeline losses, producers also deduct tariffs. The eight owners of the pipeline have each established a tariff, which is subject to the Federal Energy Regulatory Commission's approval. Despite hearings spanning 6 years, the Commission has not decided which tariffs are appropriate. Even thereafter, any of the parties can appeal to the courts. The continuing uncertainty presents IRS with windfall profit tax liability problems, particularly in terms of closing tax examinations. For example, IRS may need to obtain agreements from the oil companies permitting recomputation of liabilities if the Commission or the courts set different tariffs than the ones currently used. In the absence of such agreements, the Internal Revenue Code would generally prohibit IRS from redetermining a taxpayer's liability once an examination has been completed and the taxpayer's liability has been assessed.

The net-back deductions for shipping Sadlerochit oil from Valdez, Alaska also reflect some differences among the producers. Some producers who use company-owned/controlled vessels deduct what they deem to be their intracompany costs. On the other hand, another producer uses an average transportation rate developed by an outside firm.

Appendix I presents some general background information about the windfall profit tax and the production and distribution of North Slope oil. In appendixes II through VI we provide our responses to the questions asked. Because the questions are interrelated, we grouped them and provided our responses and other relevant information among the following general subject areas:

--North Slope crude oil pricing (app. II),

--Trans-Alaska Pipeline System tariffs (app. III),

--waterborne transportation costs from Valdez, Alaska (app. IV),

--volumes of Alaskan North Slope crude oil (app. V), and

--amount of windfall profit tax on North Slope oil (app. VI).

As arranged with your office, we did not make 3-year projections of total and exempt Alaskan North Slope oil production. Appendix VII contains a statement on our objective, scope, and methodology.

Most of our contacts with IRS, other federal and state governmental agencies, and industry representatives were made from February through July 1983 and served as the basis for our July and August 1983 briefings to your office on preliminary answers to the questions. Also, in May 1984, we obtained additional information from IRS officials on new developments, particularly the Service's efforts to draft a "methodology paper" to provide producers more explicit guidance on the pricing of North Slope oil. IRS plans to have this guidance available during early 1985.

We requested and received comments on a draft of this report from the Commissioner of Internal Revenue and the Chairman, Federal Energy Regulatory Commission. (See apps. IX and X.) Their comments resulted in minor changes in this report. We requested, but did not receive, comments from the Department of the Treasury.

As arranged with your office, we are sending copies of this report to the Secretary of the Treasury, Commissioner of Internal Revenue, and the Chairman, Federal Energy Regulatory Commission. Unless you publicly announce its contents earlier, no further distribution of this report will be made until 10 days from the date of the report.

Sincerely yours,

W. J. Anderson

William J. Anderson
Director

C O N T E N T S

TABLES

THE WINDFALL PROFIT TAX AND ALASKAN NORTH SLOPE OIL

Anticipating that the lifting of oil price controls would significantly increase oil industry profits, the Congress enacted the Crude Oil Windfall Profit Tax Act of 1980 (P.L. 96-223). The oil tax has been described as perhaps the largest and most complex tax ever levied on a U.S. industry. Generally, the tax applies to all domestic oil, including Alaskan oil, produced after February 1980. The following sections discuss how the windfall profit tax is structured and imposed on the oil industry in general and how the tax affects Alaskan North Slope producers in particular.[1]

THE TAX IS COMPLEX IN DESIGN AND OPERATION

The windfall profit tax is unique in the way it is structured and imposed on the oil industry. The tax is very complex in design and operation and requires interaction among producers, operators, and withholding agents. Producers are the one million or so individuals and business entities who own an interest in oil-producing properties and are liable for the tax. Operators are the approximately 18,000 individuals or entities who actually manage the oil production process and provide to first purchasers and other withholding agents much of the basic data necessary to compute the applicable windfall profit tax. Withholding agents--particularly the 500 to 600 first purchasers of crude oil--compute and remit to the U.S. Treasury the windfall profit tax attributable to the oil's production and sale.

The applicable windfall profit tax rate is determined through a matrix of oil tiers and producers. There are three different oil tiers, generally graduated on the basis of (1) the "windfall" element and (2) an incentive aspect to encourage new production. Generally, tier 1 oil may be referred to as old oil. In tier 2, the main category is stripper oil, which is defined as crude oil from a property whose average daily production per well does not exceed 10 barrels per day. In tier 3, newly discovered oil is oil from a property that had no production in one specific year, 1978.

The other part of the tax rate matrix is the type of producer. There are four kinds of producers--integrated oil companies, independent producers, royalty owners, and tax-exempt

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[1]Earlier GAO reports include IRS' Administration of the Crude Oil Windfall Profit Tax Act of 1980 (GAO/GGD-84-15, June 18, 1984) and Uncertainties About the Definition and Scope of the Property Concept May Reduce Windfall Profit Tax Revenues (GAO/GGD-82-48, May 13, 1982).

parties. For tier 1 and tier 2 oil, integrated oil companies and royalty owners are subject to higher windfall profit tax rates than are independent producers. For tier 3 oil, the tax rate is the same for all producers subject to the tax.

The following tables provide further details on the structure of the tax. Table 1 shows the applicable windfall profit tax rates by oil tiers and producer status and also identifies the various types of exemptions. Table 2 shows how the windfall profit tax is calculated for one barrel of tier 1 (old) oil owned by an integrated oil company or a royalty owner. This is only one example; many variations of the calculation are possible depending on the removal price of the oil, the state in which the oil is produced, the tier of the oil, and the kind of producer involved.

Table 1

Windfall Profit Tax Rates by Oil Tiers and Producer Status

Windfall Profit Tax Oil Tiers and Exempt Oil	Producer Status			
	Integrated oil company[a]	Independent producer (first 1,000 barrels)[b]	Royalty owner[c]	Exempt producers[d]
	Windfall Profit Tax Rates			
Tier 1: Old oil[e]	70%	50%	70%	0%
Tier 2: Stripper oil National petroleum reserve oil	60%	30%	60%	0%
Tier 3: Newly discovered oil[f] Heavy oil Incremental tertiary oil	30%	30%	30%	0%
Exempt oil[g]	0%	0%	0%	0%

[a]An integrated oil company engages in multiple phases of the oil industry--exploration, production, transportation, refining, and retailing.

[b]The 1980 Windfall Act allows independent producers to pay lower tax rates than integrated oil companies on tier 1 and tier 2 oil. The reduced tax rates for an independent producer apply only to the first 1,000 barrels of oil per day of combined production of tiers 1 and 2 oil.

[c]Royalty owners include any owners of economic interests that are defined as royalties for income tax purposes. This includes landowner royalties, overriding royalties, and net profits interests.

[d]Three categories of producers are exempt: (1) qualified governmental interests; (2) qualified charitable interests; and (3) certain Indian tribes, organizations, and individuals. Section 4994 of the Internal Revenue Code provides definitions and special rules with respect to these exemptions.

[e]The Windfall Profit Tax Act defines tier 1 oil by exclusion, i.e., tier 1 oil means "any taxable crude oil other than tier 2 oil and tier 3 oil." Generally, tier 1 oil will be produced either from an onshore property that had production in 1978 or produced from Outer Continental Shelf leases entered into before January 1, 1979, provided the oil does not qualify as tier 2 or 3 oil.

[f]The Economic Recovery Tax Act of 1981 (P.L. 97-34) provided for a gradual reduction of the windfall profit tax rate applicable to newly discovered oil, from the 30 percent rate applicable in 1980 and 1981 to a rate of 15 percent in 1986 and later years. The rates were subsequently revised by the Deficit Reduction Act of 1984 (P.L. 98-369). The revised rates are 22.5 percent for 1984 through 1987, 20 percent in 1988, and 15 percent in 1989 and thereafter.

[g]Four categories of oil are exempt: (1) Alaskan oil produced from a well located North of the Arctic Circle or oil produced from the northerly side of the divides of the Alaska and Aleutian ranges and which is more than 75 miles from the Trans-Alaska Pipeline, except Sadlerochit oil; (2) stripper oil, that is, oil from a property that averages 10 barrels or less of average daily production per well, which is owned by independent producers; (3) royalty oil in specified amounts, e.g., three a day for production in calendar year 1984; and (4) certain oil that was released from price controls in order to provide "front-end" financing for tertiary recovery projects. Section 4994 of the Internal Revenue Code provides definitions and special rules with respect to these exemptions.

Table 2

Computation of the Windfall Profit Tax

Sale of one barrel of oil (removal price)[a]	$30.00
Less: Adjusted base price[b]	(19.17)
Less: State severance tax adjustment[c]	(1.08)
Windfall profit[d]	$ 9.75
Times: Windfall profit tax rate[e]	x 70%
Windfall profit tax[f]	$ 6.83

[a]Removal price usually is equivalent to the selling price.

[b]The windfall profit tax was designed so that the tax would be due only on sales of oil at price levels above those that existed in 1979. The 1980 Windfall Act accomplishes this by using a base price concept. The base price depends upon the classification of the oil into one of three different tax tiers. The initial base prices are tied to prices permitted in 1979 by Department of Energy regulations. The base prices, under the 1980 Windfall Act, are adjusted quarterly for inflation.

[c]Most states that have crude oil resources impose a severance tax on either the value or the quantity of resources extracted. The severance tax rates vary among the states. If certain requirements are met, a portion of the severance tax paid to the state may be deducted in computing windfall profit tax liability. This deduction is called the state severance tax adjustment. The adjustment is the difference between the actual severance tax imposed on a barrel of oil and the severance tax that would have been imposed had the oil sold at its adjusted base price. For example, using a 10 percent severance tax rate, the adjustment is computed as follows:

$30.00 - $19.17 = $10.83
$10.83 X 10% = $ 1.08

[d]By law, the taxable windfall profit may not exceed 90 percent of the net income attributable to each barrel of oil. By including such a provision in the act, the Congress wanted to preclude producers from incurring losses on crude oil production solely as a result of the windfall profit tax.

[e]As shown in table 1, the windfall profit tax rate varies depending on the oil tier and the producer's status. The 70 percent rate is for tier 1 oil owned by integrated producers and royalty owners.

[f]The windfall profit tax is deductible for income tax return purposes.

ALASKAN NORTH SLOPE OIL IS UNIQUE

Alaskan North Slope oil is presently produced from two fields--the Prudhoe Bay oil field and the Kuparuk River oil field--with total production of about 1.6 million barrels a day. Prudhoe Bay is by far the larger of the two fields, producing about 1.5 million barrels daily. Generally, Prudhoe Bay production comes from the Sadlerochit reservoir.[2]

About 1.3 million barrels of the daily production from the Sadlerochit reservoir are subject to the windfall profit tax. This taxable oil is the so-called operating or working interest, which is leased from Alaska. This oil amounts to seven-eighths of total production. The other one-eighth of the Sadlerochit production is the state's royalty share and is not subject to taxation because the 1980 Windfall Act provides an exemption for economic interests in oil production held by state and local governments.

Sadlerochit oil is classified as tier 1 oil because the reservoir had production in 1978. Three integrated oil companies--Standard Oil Company of Ohio, Atlantic Richfield Company, and Exxon--control about 94 percent of the working interests in Sadlerochit oil. These and other integrated oil companies are subject to a windfall profit tax rate of 70 percent on tier 1 oil. Ownership of the remaining 6 percent of the working interests in Sadlerochit oil is spread among nine companies.

Production from the other North Slope oil field--Kuparuk River--amounts to about 89,000 barrels a day. Kuparuk production is exempt from the windfall profit tax. As defined in section 4994(e) of the Internal Revenue Code, the term "exempt Alaskan oil" includes "any crude oil (other than Sadlerochit oil) which is produced . . . from a well located north of the Arctic Circle." The Kuparuk River oil field is located north of the Arctic Circle.

Alaskan North Slope oil is unique in that no sizable markets are located near the oil's production. Since only a small amount of the oil is refined in Alaska, most of the oil must be transported long distances. Oil from the various producing wellheads in the Prudhoe Bay and Kuparuk fields is gathered and transported to Pump Station Number One, the point where the oil enters the Trans-Alaska Pipeline System. The oil then flows about 800 miles through the pipeline to storage terminals at the port of Valdez on the southern coast of Alaska.

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[2]A small amount of oil, about 600 barrels a day, is produced from the Lisburne reservoir in the Prudhoe Bay oil field. The Lisburne oil is exempt from windfall profit tax.

From Valdez, ocean-going tankers transport most of the oil to refineries in other states and U.S. possessions. In 1982, about 47 percent of the North Slope oil was delivered to the West Coast of the United States, about 32 percent to the Gulf Coast, about 8 percent to the East Coast, and the remainder to Hawaii, Puerto Rico, and the Virgin Islands.

The following tables and figure present further details on the production and distribution of North Slope oil:

--Table 3 gives the percentage interests held by producers in North Slope oil and the Trans-Alaska Pipeline System;

--Figure 1 illustrates transportation routes for shipments of Alaskan North Slope crude oil; and

--Table 4 quantifies, by destination, the crude oil shipments from Valdez, Alaska during calendar year 1982.

Table 5 shows a hypothetical example comparing the computation of the windfall profit tax on Sadlerochit oil with other domestic oil. The starting point for the calculation is the removal price of the oil.

Table 3

Percentage Interests in Prudhoe Bay Oil Field, Kuparuk River Oil Field, and Trans-Alaska Pipeline System

Name of producer	Percentage interests		
	Prudhoe Bay[a]	Kuparuk	Pipeline system
Amerada Hess	0.5	0.0	1.5
Arco	21.7	57.1	21.4
British Petroleum	b	28.7	16.7
Chevron	0.8	0.1	0.0
Exxon	21.7	b	20.3
Getty	0.5	0.0	0.0
Louisiana Land	b	0.0	0.0
Marathon	b	0.0	0.0
Mobil	2.1	0.4	4.1
Petro Lewis	0.1	0.0	0.0
Phillips	2.0	0.3	1.4
Sohio	50.4	9.5	33.3
Union	0.0	4.1	1.4
Total[c]	99.8	100.2	100.1

[a]These percentages, and those for Kuparuk, represent working interests. The percentages for Prudhoe Bay are those agreed upon in 1982 by the major interest owners.

[b]Less than 0.1 percent.

[c]Amounts do not total to 100 percent due to rounding.

Sources: Prudhoe Bay oil field and Kuparuk River oil field data were obtained from the Alaska Department of Natural Resources; Trans-Alaska Pipeline System data were obtained from the Federal Energy Regulatory Commission.

ILLUSTRATIONS OF TRANSPORTATION ROUTES FOR SHIPMENTS OF ALASKA NORTH SLOPE CRUDE OIL

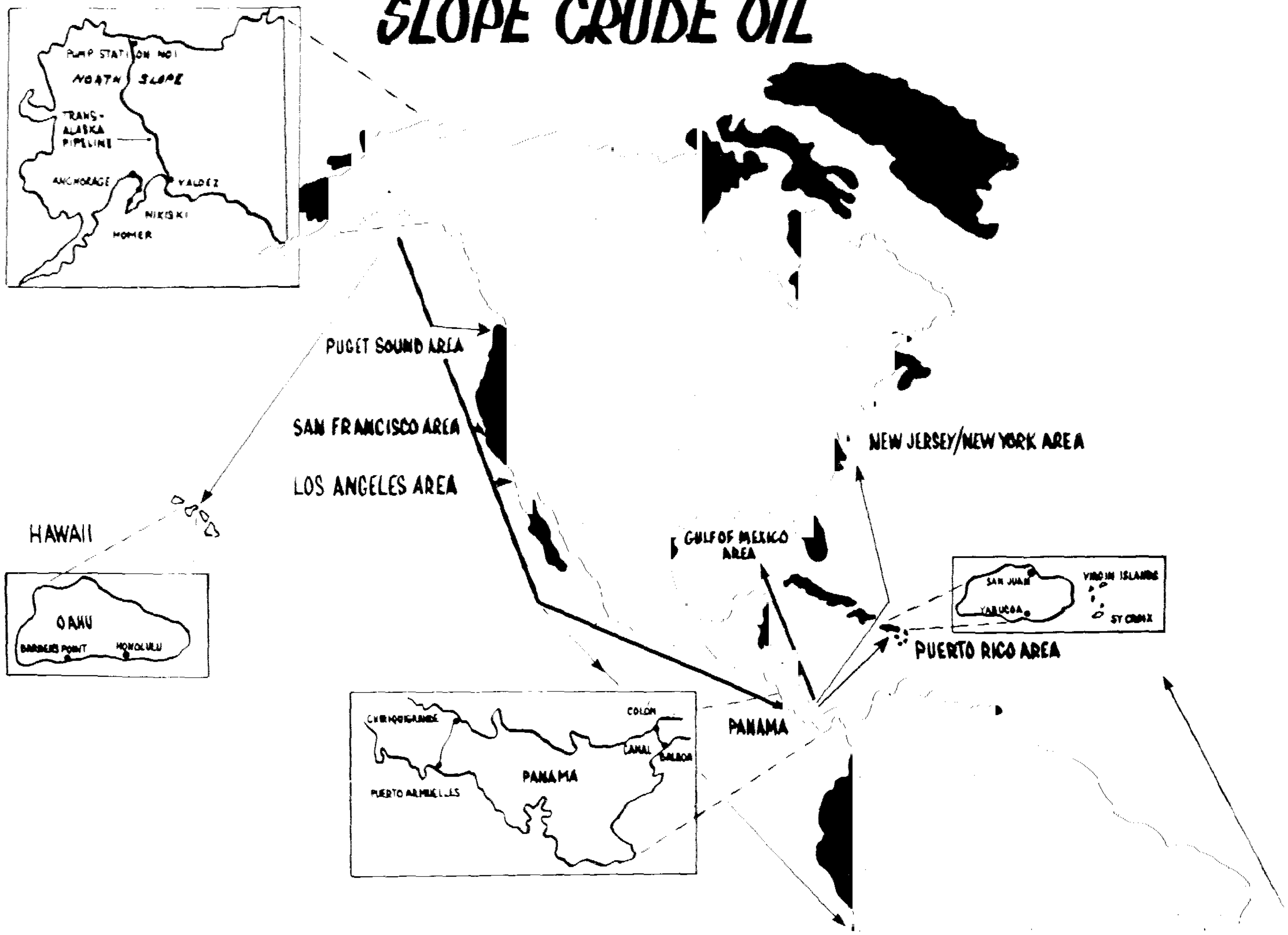

Table 4

Alaskan North Slope
Crude Oil Shipments from Valdez, Alaska
During Calendar Year 1982

Destination	Daily average in thousands of barrels	Percent of total
U.S. West Coast:		
--Puget Sound area (Anacortes, Cherry Point, Ferndale, and Port Angeles, WA)		
--San Francisco area (Benicia, Richmond, and San Francisco, CA)		
--Los Angeles area (El Segundo, Long Beach, Los Angeles, and Huntington Beach, CA)		
Total West Coast	763	47.0
U.S. Gulf Coast:		
--Texas (Baytown, Beaumont, Corpus Christi, Freeport, Houston, Nederland, Port Arthur, Port Neches, and Texas City)		
--Louisiana (Alliance, Baton Rouge, Chalmette, Garyville, Lake Charles, and St. James)		
--Mississippi (Pascagoula)		
Total Gulf Coast	513	31.6
U.S. East Coast:		
--New Jersey (Bayway, Paulsboro, and Perth Amboy)		
--Pennsylvania (Philadelphia)		
--New York (New York City)		
Total East Coast	122	7.5
Virgin Islands (St. Croix)	100	6.2
Puerto Rico (San Juan and Yabucoa)	67	4.1
Hawaii (Barber's Point and Honolulu)	38	2.3
Alaska (Homer and Nikiski)	19	1.2
Total	1,622	99.9

Source: Based on estimates provided by the Maritime Administration and the Panama Canal Commission.

Table 5

Comparative Computation of the Windfall Profit Tax on Sadlerochit Oil and Other Domestic Oil

	Sadlerochit oil	Other domestic oil
Sale of one barrel of oil (removal price)[a]	$22.00	$30.00
Less: Adjusted base price	(19.17)	(19.17)
Less: State severance tax adjustment[b]	(0.42)	(1.08)
Less: Trans-Alaska Pipeline System tariff adjustment[c]	(0.06)	N/A
Windfall profit	$ 2.35	$ 9.75
Times: Windfall profit tax rate	x 70%	x 70%
Windfall profit tax	$ 1.65	$ 6.83

[a]The removal price for Alaska's Sadlerochit oil is less than the removal prices for other domestic oils. Most Alaskan oil must be transported very long distances before it can be refined. Thus, producers deduct pipeline tariffs and water-borne transportation and other costs in netting-back to establish a removal price for Sadlerochit oil.

[b]The severance tax adjustment for the Sadlerochit oil is based on Alaska's 15 percent severance tax rate. For other domestic oil, a severance tax rate of 10 percent is assumed.

[c]The Windfall Profit Tax Act of 1980 had a special adjustment provision for Sadlerochit oil. That is, the 1980 Act stated that the adjusted base price for Sadlerochit oil for each taxable period is increased by the excess of $6.26 over the Trans-Alaska Pipeline System tariff. For example, if the tariff is $6.20 a barrel for transporting crude oil through the pipeline, the resulting adjustment is 6 cents a barrel. This adjustment provision was eliminated, effective January 1, 1983, by section 284 of the Tax Equity and Fiscal Responsibility Act of 1982 (P.L. 97-248).

NORTH SLOPE CRUDE OIL PRICING

TASK FORCE QUESTIONS

--How is the wellhead price of Alaskan North Slope crude oil actually determined for purposes of windfall profit tax?

--If the wellhead price of Alaskan North Slope crude oil for purposes of windfall profit tax is related to the market price for West Texas Sour crude oil deliverable to the Gulf of Mexico, how is the market price established?

--Is it appropriate to use the cost of West Texas Sour crude oil deliverable to the Gulf of Mexico as a benchmark for determining the removal price of Alaskan North Slope crude oil for purposes of windfall profit tax? Is there a more appropriate benchmark that could be used?

GAO RESPONSE

A wellhead price, per se, does not exist for North Slope oil. Accordingly, most Prudhoe Bay producers are using net-back methods to determine the removal price of Sadlerochit oil for windfall profit tax purposes. Net-back is the general method of establishing the removal price by valuing the oil at the refinery or market area and then deducting all the overland and waterborne transportation costs involved in moving the oil from the North Slope to the various refineries or markets. Differences exist, however, in the net-back methods used by the producers.

In netting-back, at least three producers have used the posted prices of West Texas Sour crude oil as a benchmark for placing a value on deliveries of Sadlerochit crude oil to the Gulf Coast. At least one producer has used West Texas Sour as a benchmark to value deliveries of Sadlerochit oil to the West Coast. As is the conventional method in the oil industry, the market prices of West Texas Sour and other domestic oils are established by the field prices posted by purchasing refineries. In valuing Sadlerochit oil, the posted price of West Texas Sour oil is adjusted for certain quality differences and transportation costs to the refinery.

According to most of the industry and government officials we contacted, West Texas Sour is an appropriate benchmark for pricing Gulf Coast deliveries of Sadlerochit oil because the two oils have similar physical properties, such as sulfur content, gravity, and product yield upon distillation. However, these sources questioned the appropriateness of using West Texas Sour as a benchmark for valuing West Coast deliveries of Sadlerochit oil primarily because no West Texas Sour crude oil is actually delivered to the West Coast.

IRS has been studying the issues involved in Sadlerochit crude oil pricing since June 1982, particularly the issue of how the removal price of Sadlerochit oil should be determined. Two IRS revenue rulings have been issued concerning Alaskan North Slope crude oil pricing. Ruling 83-124 dealt with the issue of constructing a sales price on the basis of the gross income from the property under the principles of Internal Revenue Code Section 613. Ruling 83-161 dealt with the issue of determining removal price by netting-back from the sales prices in the market area to which the oil is delivered.

These rulings have been helpful in achieving more uniformity among the producers' net-back practices. However, the rulings do not address all the differences that exist among the producers. This could significantly affect windfall profit tax revenues, given that a very small per barrel price adjustment has a multimillion dollar effect on windfall profit tax liabilities. In May 1984, IRS officials informed us that the Service was drafting a "methodology paper" to cover more explicitly the various aspects of removal price determinations and hopes to have this guidance available during early 1985.

The Prudhoe Bay producers are determining the removal prices for Sadlerochit oil by using different net-back methods

The market prices of domestic crudes, such as West Texas Sour, are determined largely by the purchasing refineries, which post field prices. Posted field prices are the traditional means in the oil industry by which offers are made to buy crude oil under specified terms and conditions for a stated price. The selling price is generally equivalent to the removal price, for the purpose of calculating the windfall profit tax.

Because the Prudhoe Bay oil field is located in an isolated area, the posting of prices there is very limited. The field is a very long distance from the major U.S. refining centers on the West and Gulf Coasts. Also, the Prudhoe Bay integrated producers take a large percentage of the oil for use in their own refineries or exchange it for other oil. Because the extent of posted prices for Sadlerochit oil is very limited, some companies use the posted prices for domestic oils similar in quality, such as West Texas Sour, as a starting point for valuing Sadlerochit oil.

The methodology for determining removal prices for Sadlerochit crude oil was the subject of congressional hearings in December 1982 and in February 1983.[1] At the February 1983 hearings, representatives of the three largest producers of North Slope crude oil testified--Sohio Oil Company, a group within the Standard Oil Company of Ohio; Exxon Company, U.S.A., a division of Exxon Corporation; and Arco Petroleum Products Company, a division of Atlantic Richfield Company. These three producers, with about 94 percent of the working interests in the Prudhoe Bay oil field, provided testimony about their net-back methods.

As was brought out during the hearings, Prudhoe Bay producers use different net-back methods to calculate removal prices for Sadlerochit oil. The following paraphrased excerpts from the February 23, 1983, congressional hearings provide a comparative synopsis of the three companies' pricing philosophies:

--Sohio has no refineries on the West Coast nor on the Gulf Coast. Thus, the company either sells or exchanges virtually all of its North Slope oil, about 597,000 barrels of daily production in 1982. About 40 percent of Sohio's 1982 production of North Slope oil was delivered to the West Coast and about 60 percent to the Gulf Coast and Caribbean area. Sohio transports its North Slope oil to the various market areas utilizing chartered U.S.-flag tankers operated by contract with outside parties. For each of these market areas, Sohio negotiates a selling price for its North Slope oil based on prices customers would pay for competing imported crude oils, with what the company considers appropriate adjustments for differences in oil quality. From the value received from those arm's-length, third-party transactions in each geographic area, Sohio deducts the Trans-Alaska Pipeline System tariffs and waterborne and other transportation costs to establish the removal prices in Alaska.

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[1]U.S., Congress, House of Representatives, Committee on Small Business, Subcommittee on Energy, Environment, and Safety Issues Affecting Small Business, Gasoline Marketing Since Decontrol, December 1 and 2, 1982. See also, U.S., Congress, House of Representatives, Committee on Energy and Commerce, Subcommittee on Oversight and Investigations, Windfall Profit Tax and Product Marketing Consequences of the Wellhead Pricing Practices of Alaska North Slope Crude Oil Producers, February 23, 1983.

--Exxon's 1982 production of Alaskan North Slope oil averaged about 325,000 barrels a day. In 1982, Exxon used about 94 percent of its North Slope crude in its own refineries. About one-third of its production went to its West Coast refinery, and two-thirds went to its Gulf Coast and East Coast refineries. Exxon's general approach to pricing its North Slope crude recognizes the West Coast as one market area and the Gulf/East Coast as another market area. The value for North Slope crude processed in its own refineries is determined by Exxon's assessment of the market value in each of the market areas. Exxon's assessment of market value is based on factors such as its own commercial transactions and posted prices of domestic crudes in the area as adjusted for quality. After the market value for North Slope crude for each market area is determined, Exxon deducts pipeline tariffs and what the company determines to be its waterborne transportation costs to arrive at the net-back value for each market area. These net-back values are then averaged by volume shipped to each of the market areas to arrive at a removal price. About 70 percent of the marine transportation is by U.S.-flag tankers chartered from outside companies.

--Arco uses most of its North Slope crude oil in its own refineries. In 1982, about 70 percent of Arco's 340,000 barrels a day of North Slope production went to the company's West Coast refinery at Los Angeles, California. An additional 25,000 barrels a day was sold by Arco on the West Coast. The remainder of Arco's North Slope oil, about 50,000 to 75,000 barrels a day, went to the Gulf Coast. Arco establishes a single wellhead price for its North Slope oil, regardless of destination. In establishing this price, Arco starts with the market price for North Slope oil in the Gulf Coast area. This market price is determined by reference to a domestic crude oil actively traded in the Gulf Coast area. From this market price, Arco deducts the Trans-Alaska Pipeline System tariffs and waterborne transportation costs from Valdez to the Gulf Coast. The resulting figure is the removal price for North Slope oil, for both Gulf Coast and West Coast deliveries. About 70 percent of Arco's North Slope production is transported in company-owned ships. For the company-owned ships, market shipping rates, called U.S. Freight Rate Averages, are used. Actual charges are used for shipments on chartered vessels.

Most of the other Prudhoe Bay producers provided us information for 1982 showing that they also used net-back methods to determine the removal price of Sadlerochit oil. There are net-back differences among these producers, just as there are among the largest producers.

One net-back difference among Prudhoe Bay producers is in the benchmark oils used to value the Sadlerochit oil in each market area. Some Prudhoe Bay producers use domestic oils, whereas other producers use foreign oils as a benchmark to establish the value of Sadlerochit oil.

Also, the Prudhoe Bay producers do not uniformly value the Sadlerochit oil in terms of timing. Some producers determine the oil's market value at the time it is removed from the wellhead premises and transported to the Trans-Alaska Pipeline System. Other producers value the oil upon delivery to the refinery, which may be 2 or 3 months after the oil's production.

Another difference among the Prudhoe Bay producers in using a benchmark oil to value Sadlerochit oil may involve credit terms. Industry practice is to pay for West Texas Sour oil on the 20th day of the month following the month of delivery to the refinery. But for Sadlerochit oil the practice is to pay for it within 10 days after delivery to the refinery. Because of this difference in payment practices, one company official stated that Sadlerochit oil is less valuable than West Texas Sour crude oil. Accordingly, in using West Texas Sour oil to value Sadlerochit oil, this company considers the difference in credit terms and makes an adjustment. Although we did not make an actual determination, other companies could be making different credit term adjustments.

After a value is established for the Sadlerochit oil at the refinery or market area, the producers deduct the costs of moving the oil from the North Slope to the refineries or market areas. However, just as producers use different factors to estimate the value of the Sadlerochit oil, different costs are also deducted.

One difference involves field costs. These are the costs of moving the oil from the wellhead to Pump Station Number One where the oil enters the Trans-Alaska Pipeline System. Sometimes these costs are referred to as upstream costs and may include gathering, separating, cleaning, dehydration, and other field handling costs--that is, costs upstream of the meter at which the oil volume is measured for transfer into the Trans-Alaska Pipeline System. Some producers deduct these costs in netting-back to establish a removal price for windfall profit tax purposes. Other producers do not.

A second difference in transportation cost deductions among the producers involves pipeline losses. Such losses result, in part, from any pipeline leak that might occur and from vaporization. Vaporization is attributable to temperature and pressure changes within the pipeline. However, the largest portion of the pipeline losses are not physical losses, such as leaks and vaporization. Rather, some of the crude oil is routinely removed from the pipeline and refined locally to make diesel fuel for operating the pumping stations along the pipeline.

According to some producers, the filed tariffs do not cover pipeline losses. The Federal Energy Regulatory Commission, in commenting on a draft of this report, said it is expected, however, that the tariffs finally determined to be just and reasonable will include the expenses associated with crude oil removed for operating the pumping stations.

In netting-back for windfall profit tax purposes, most producers deduct for pipeline losses. The deductions vary among the producers, ranging from about 5 cents to 10 cents a barrel. IRS officials informed us, in May 1984, that the Service probably will permit producers to deduct pipeline losses in netting-back to determine removal prices for Sadlerochit oil. The officials noted, however, that a standard formula for calculating such losses must be developed and used consistently by the producers. Further, once determined, the applicable removal price must be applied to the respective producer's gross volume of oil entering the pipeline at Pump Station Number One. IRS officials believe that the calculation of tax with respect to gross volume is necessary because windfall profit tax liability arises at the point where the oil is produced and removed from the wellhead premises--not at some later point.

In addition to pipeline losses, the producers also deduct the pipeline tariffs. Pipeline tariffs and the related net-back issues are discussed in detail in appendix III.

A fourth difference in net-back deductions among the producers involves waterborne transportation costs. These costs are discussed in appendix IV.

West Texas Sour oil is considered a reasonable benchmark for pricing Gulf Coast deliveries of Sadlerochit oil

West Texas Sour is very comparable to Sadlerochit oil in physical properties, such as sulfur content, gravity, and product yield upon distillation. At least three Prudhoe Bay producers use West Texas Sour crude oil as a benchmark for pricing Sadlerochit oil delivered to the Gulf Coast.

Most of the industry and government officials we contacted during our review believe that West Texas Sour is an appropriate benchmark for pricing Gulf Coast deliveries of Sadlerochit crude oil. According to the Alaska Department of Revenue, West Texas Sour is the principal domestic crude oil traded on the Gulf Coast. The oil is traded actively by many parties, and no small group of producers dominates the production or refining of the oil.

This is not to say that West Texas Sour is the only appropriate benchmark for valuing Gulf Coast deliveries of Sadlerochit oil. Some foreign crude oils have also been used or considered for use. Some of these are the Arabian and Mexican crude oils. At least three Prudhoe Bay producers use foreign crude oils as benchmarks for pricing Sadlerochit oil delivered to the Gulf Coast.

In contrast, most of the industry and government officials we contacted believe that it is inappropriate to use West Texas Sour as a benchmark for pricing Sadlerochit oil delivered to the West Coast. The primary reason for this opinion is that no West Texas Sour is actually delivered to the West Coast. At least one producer has used West Texas Sour as a benchmark to value deliveries of Sadlerochit oil to the West Coast.

At the state level, Alaska's tax regulations provide that any benchmark oil used to value Sadlerochit oil must actually be sold in significant quantities in or near the same market where the Sadlerochit oil is delivered. Thus, Alaska's regulations would not allow the use of West Texas Sour as a benchmark to price Sadlerochit oil delivered to the West Coast.

Information provided us by six producers who shipped Sadlerochit oil to the Gulf Coast during 1982 shows that different market prices were used for determining the removal price. For example, the December 1982 prices for Sadlerochit oil on the Gulf Coast, as reported by the producers, ranged from $29.00 to $31.05 a barrel. Most of this difference can be attributed to the use of different benchmark oils.

IRS guidance on the pricing of Sadlerochit oil

IRS' Southwest regional office formed a study group in June 1982 to identify and coordinate resolution of Sadlerochit oil pricing issues for windfall tax purposes. The primary issue was how the removal price of Sadlerochit oil should be determined. Generally, the removal price for most domestic oil for windfall profit tax purposes is equivalent to the sales price in the field. However, the removal price of Sadlerochit oil arose as an issue because most of the oil is not sold in the field but is removed to distant refineries by integrated oil companies or exchanged for oil located elsewhere.

In August 1982, the Southwest Regional Commissioner requested technical assistance from IRS' Office of Chief Counsel concerning the determination of removal prices for Sadlerochit oil. The Chief Counsel responded to this request on April 20, 1983. On August 8, 1983, Revenue Ruling 83-124 was issued.

The August 1983 ruling states that the Windfall Profit Tax Act requires that a representative market or field price be established in Alaska for Sadlerochit oil. IRS' legal position, as explained in the revenue ruling, is that section 4988(c) of the Internal Revenue Code provides the general rule that "removal price" means the amount for which a barrel of crude oil is sold. This code section further provides that when crude oil is removed from the premises before it is sold, a sales price must be constructed on the basis of gross income from the property under section 613. According to the regulations for section 613, if the oil is not sold on the premises, the gross income from the property shall be assumed to be equivalent to the representative market or field price of the oil before transportation.

Although not specifically stated, the revenue ruling appears to require the use of a single removal price--that is, one representative market or field price--by all Prudhoe Bay producers in determining windfall profit tax liability. Case law interpreting the term "representative market or field price" indicates that once such a price is determined it applies to all producers in the applicable field (for oil not sold in the immediate vicinity of the well). Generally, the representative price is calculated by using the weighted average of all oil sales in the field.

The volume of oil sales in the immediate vicinity of the Prudhoe Bay field, however, was insufficient to establish a representative price. Therefore, IRS issued supplemental guidance, Revenue Ruling 83-161, on October 21, 1983. This ruling permits producers to net-back from the various market areas to determine removal prices for Sadlerochit oil.[2]

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[2]Federal law prohibits the exporting of Sadlerochit oil. If this prohibition is ever lifted, there may be sufficient sales in the immediate vicinity of the Prudhoe Bay field to establish a representative price, and a net-back approach for determining removal prices would be inapplicable. However, if the point of sale were at Valdez, Alaska (the southern terminus of the Trans-Alaska Pipeline) and not at the immediate vicinity of the well, then a net-back from Valdez to the North Slope would still be necessary to establish a removal price.

In recognizing a net-back approach for determining removal prices for Sadlerochit oil, the October ruling clarifies that any benchmark oil used to value Sadlerochit oil must be sold in "appreciable amounts in the same market" as the Alaskan oil. Under this criterion, West Texas Sour crude oil could not be used to value Sadlerochit oil delivered to the U.S. West Coast. However, the ruling does not specifically address many other aspects of the net-back pricing methods used by the producers.

As discussed earlier in this appendix, a number of differences exist in the Prudhoe Bay producers' net-back practices. The October ruling does not fully address which comparable domestic or foreign crude oils should be used as benchmarks to establish a market value for the Sadlerochit oil. Also, IRS' guidance does not address related aspects of the valuation process. These aspects include (1) whether the Sadlerochit oil's market value should be determined at the time the oil is removed from the wellhead premises or upon delivery to the refinery and (2) whether an adjustment should be made for the payment or credit terms available for the benchmark oil.

Moreover, the October 1983 ruling does not address certain costs deducted from the market value of the Sadlerochit oil. Differences among the producers in these net-back deductions involve field handling costs, pipeline losses, and waterborne shipping costs.

In May 1984, we learned from IRS officials that the Service was drafting a "methodology paper" to cover more explicitly the various aspects of removal price determinations. The officials said that IRS had conducted a series of meetings with various producers and their representatives to ensure that the methodology was both practicable and equitable. IRS hopes to release the methodology paper during early 1985.

IRS officials anticipate that examinations of the windfall profit tax on Sadlerochit oil will result in liability adjustments

Service officials believe that substantial adjustments to and, for the most part, increases in producers' tax liabilities will be proposed and applied retroactively. This will occur if the soon-to-be issued methodology paper for determining removal prices disallows some of the present net-back deductions being taken and if lower Trans-Alaska Pipeline System tariff rates than those now being applied are approved.

A very small per barrel adjustment generates millions of dollars in additional windfall profit tax liability. For example, if the taxable windfall profit is adjusted upward by only 1-cent per barrel, the increased tax liability of Prudhoe Bay producers is over $7,700 per day or about $2.8 million a year.[3]

Equally large or even greater adjustments to windfall profit tax liabilities could result for taxable periods after 1982 if lower tariffs are set for the Trans-Alaska Pipeline and applied retroactively. As discussed further in appendix III, the tariff rates have been in dispute since 1977 when they were initially filed by the pipeline owners. Administrative hearings on the reasonableness of the rates are still ongoing. Even after the Federal Energy Regulatory Commission reaches a decision, any of the parties can appeal through the judicial system.

In commenting on a draft of this report, IRS stated it may well face a critical problem after the 1982 tax year in that if the tariff issue is not resolved, IRS may be compelled to take a position based on actual Trans-Alaska Pipeline System costs because the net-back removal price determination will have to be computed within the statutory period for making tax deficiency determination/assessments.

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[3]The figure of $2.8 million a year is calculated by first reducing 1-cent per barrel by 15 percent, which is Alaska's severance tax rate. (This aspect of the windfall profit tax is illustrated and discussed earlier in app. I; see table 2.) The resulting figure, $0.0085 per barrel, is then multiplied by 1.3 million barrels per day of taxable Sadlerochit oil and by 365 days to give the yearly amount of taxable windfall profit. Finally, the 70 percent tax rate is applied, which results in additional windfall profit tax of $2.8 million a year.

TRANS-ALASKA PIPELINE SYSTEM TARIFFS

TASK FORCE QUESTIONS

--How are the tariffs charged for the Trans-Alaska Pipeline System established?

--What was the projected pay-out for the Trans-Alaska Pipeline System when that pipeline was established?

--What is the projected pay-out period for the Trans-Alaska Pipeline System today, based on current tariffs?

--What is the current rate of return on depreciated capital investment in the Trans-Alaska Pipeline System at this time?

GAO RESPONSE

The eight owners of the Trans-Alaska Pipeline System each establish a common carrier tariff, which is subject to the Federal Energy Regulatory Commission's approval. The tariffs have been in dispute since they were initially filed in 1977 by the eight owners, each of which is a wholly owned subsidiary of a major oil company. Generally, these initial tariffs, the majority of which are still in effect, are deducted by the producer companies in netting-back to establish a removal price for Sadlerochit oil for windfall profit tax purposes.

In evaluating common carrier tariffs, such as those for the Trans-Alaska Pipeline System, the regulatory agency does not use pay-out periods as a basis for its evaluation. Rather, the agency determines appropriate rate base and rate of return methodologies, which are then used to arrive at an appropriate rate of return on the Trans-Alaska Pipeline System investment. The appropriate rate base and rate of return for the Alaskan pipeline have been centrally at issue in longstanding administrative proceedings before the Federal Energy Regulatory Commission and are still unresolved. Even after the Commission reaches a final decision, any of the parties can appeal through the judicial system.

The continuing uncertainty as to what are reasonable and just tariffs presents IRS with windfall profit tax liability problems. For instance, once IRS has nearly completed its examinations of Prudhoe Bay producers, the Service may need to obtain agreements from the producers permitting recomputation of windfall profit tax liabilities should the Federal Energy Regulatory Commission or the courts set different tariffs. In the absence of such agreements, the Internal Revenue Code would generally prohibit IRS from redetermining a taxpayer's liability once an examination has been completed and the taxpayer's liability has been assessed.

Each owner establishes a pipeline common carrier tariff that is subject to federal approval

The Trans-Alaska Pipeline System is a common carrier system engaged in interstate commerce. The Interstate Commerce Act requires that every common carrier pipeline provide transportation upon reasonable request and charge just and reasonable rates. The question of what are "just and reasonable" rates for the Trans-Alaska Pipeline System has been in dispute since Sadlerochit oil first began flowing through the pipeline in June 1977 and is still unresolved.

Shortly before the Trans-Alaska Pipeline System began operating, each of the owners filed initial tariff rates in May and June 1977 with the Interstate Commerce Commission. As mentioned earlier, the owners are eight oil pipeline companies, each of which is a wholly owned subsidiary of a major oil company. Each of the eight pipeline companies is a common carrier and is entitled to propose a tariff for oil moved through its undivided percentage interest in the Trans-Alaska Pipeline System. In this respect, the system conceptually can be viewed as being eight separate common carrier pipelines, even though physically there is but one pipeline.

In August 1970, before the Trans-Alaska Pipeline System was built, the companies entered into a formal agreement on the pipeline system design and formed the Alyeska Pipeline Service Company as their common agent to contract for and to supervise the system's construction. However, each of the eight participating pipeline companies was required to separately arrange for financing its respective share of the Trans-Alaska Pipeline System. These individual financing arrangements and other factors resulted in the eight common carriers having different rate bases and different tariffs.

The eight carriers' initial tariffs for the Trans-Alaska Pipeline System filed in May and June 1977 ranged from $6.04 to $6.44 a barrel for piping oil approximately 800 miles from Prudhoe Bay to the port storage terminals at Valdez. The weighted average of the eight tariffs was $6.20 a barrel. Although in dispute as to their appropriateness, most of the original tariffs have remained unchanged, except for a 7-month period immediately following their initial submission.

It can be said that the 7-year old conflict over the tariff rates is a case study of a protracted dispute between public and private sectors. However, virtually no precedents exist for regulators to use in evaluating undivided-interest pipeline systems. Because little was known about regulating undivided-interest pipeline systems, the public record regarding the justness and reasonableness of the Trans-Alaska Pipeline System tariffs is long and complicated. Some of the key milestones and highlights in the continuing controversy are discussed below.

In May and June 1977, the eight pipeline companies filed initial tariffs that averaged about $6.20 a barrel. Almost immediately, the Interstate Commerce Commission, which was authorized to rule on the appropriateness of filed tariffs, found that it had reason to believe the proposed rates were not just and reasonable. Consequently, the Commission suspended the filed tariff rates for the full 7 months permitted by statute; imposed substantially lower interim tariffs, averaging about $4.84 a barrel, for the suspension period;[1] and referred the proceedings to one of its administrative law judges for further fact-finding as to appropriate rates.

About 1 month later, in August 1977, the administrative law judge directed that the Trans-Alaska Pipeline System case be developed or heard in two phases. Phase I administrative hearings were to address generic or methodology type questions, such as what rate-making methodology should be used to establish a rate base and a rate of return for the pipeline system. Phase II administrative hearings were to address case-specific issues, such as questions concerning the allowability of certain pipeline expenditures.

About 2 months later, in October 1977, under the provisions of the Department of Energy Organization Act (P.L. 95-91), the Interstate Commerce Commission's functions and regulatory responsibilities relating to the interstate transportation of oil by pipeline were transferred to the Federal Energy Regulatory Commission. In October 1977, an administrative law judge was designated by the Federal Energy Regulatory Commission, and hearings on the Phase I issues began in February 1978.

About 24 months later, based upon over 24,000 pages of evidentiary transcript, the administrative law judge issued a Phase I initial decision in February 1980 as to what constitutes just and reasonable rates. Pending a decision on Phase II issues, the administrative law judge ordered interim rates that were lower than the original tariffs filed by the pipeline companies. However, as a matter of agency practice, the administrative law judge's interim rates are proposals only. As such, they must be

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[1]The pipeline carriers thereafter filed petitions in the U.S. Court of Appeals seeking review of the Commission's order and injunctive relief against suspending the proposed initial tariff rates. After the Court of Appeals upheld the Commission's suspension authority, the carriers appealed to the Supreme Court. In a decision dated June 6, 1978, the Supreme Court unanimously affirmed the lower court's decision. Trans Alaska Pipeline Rate Cases, 436 U.S. 631 (1978).

approved by the Federal Energy Regulatory Commissioners, who have not done so because they have been deliberating similar issues regarding other pipelines.

About 34 months later, in November 1982, the Federal Energy Regulatory Commissioners remanded the Phase I issues to an administrative law judge for further fact-finding proceedings. Basically, the Commissioners wanted the Phase I decision reevaluated in light of a new and landmark regulatory policy announced by the Commission for oil pipelines. The new policy decision, known as the Williams case, established industry-wide standards for testing the propriety of oil pipeline rates.[2]

About 15 months later, on March 9, 1984, the Williams case was remanded to the Federal Energy Regulatory Commission by a U.S. appellate court.[3] Among other matters, the court held that the Commission had failed to give "due consideration to responsible alternative ratemaking methodologies during its administrative proceedings." The court noted, however, that the Commission already had "benefit of an extensive record and should be able to issue a new order within the next twelve months."

The remand of the Williams case has added another element of uncertainty to the resolution of the Phase I issues in the Trans-Alaska Pipeline System case. For example, on April 6, 1984, the administrative law judge responsible for the Phase I fact-finding proceedings formally asked the Federal Energy Regulatory Commissioners for guidance as to whether he should

--continue to evaluate Phase I issues based on the principles in Williams, even though that case itself was remanded for further study; or

--send the Phase I issues back to the Commissioners for a decision.

The Commissioners had not responded as of June 6, 1984. In any event, any decision rendered by the administrative law judge as to just and reasonable tariffs will be subject to approval by the Commissioners. Even thereafter, the regulatory agency's final determination can be appealed through the judicial system by any of the parties.

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[2]Federal Energy Regulatory Commission, Williams Pipe Line Company, Docket No. OR79-1-000, November 30, 1982.

[3]Farmers Union Central Exchange, Inc. v. Federal Energy Regulatory Commission, No. 82-2412 (D.C. Cir. 1984).

<u>Common carrier tariffs are evaluated in terms of an appropriate rate of return on pipeline investment rather than pay-out periods</u>

Generally, the establishment of just and reasonable pipeline tariffs is not approached in terms of pay-out periods. Rather, in evaluating common carrier tariffs, the regulatory agency determines appropriate rate base and rate of return methodologies, which are then used to arrive at an appropriate rate of return on investment. Similarly, the pipeline companies told us that their filed tariffs for the Trans-Alaska Pipeline System were calculated on the basis of a rate of return analysis, not on the basis of pay-out period considerations, that is, the period for recovering the cost of the pipeline. The appropriate rate base and rate of return for the Trans-Alaska Pipeline System have been centrally at issue in the Phase I administrative proceedings and are still unresolved.

Nonetheless, a brief synopsis of these issues may be useful, comparing the position of the pipeline companies with the initial Phase I decision rendered by the Federal Energy Regulatory Commission's administrative law judge in February 1980. The position of the pipeline companies is that the original tariffs filed in 1977 were set in conformance with, and are justified by, longstanding traditional ratemaking principles. Specifically, the companies contend that the tariffs are properly derived from the so-called "consent decree" methodology.

The consent decree was a 1941 settlement of a suit brought by the United States against major oil companies and their pipeline subsidiary companies alleging that dividends paid by the subsidiary pipeline carriers to their parent oil company owners constituted illegal rebates. The 1941 consent decree did not ban all rebates from pipeline subsidiaries to their parent companies but merely limited the amount of dividends a common carrier could pay to such owners in any 1 year up to 7 percent of the pipeline valuation. Again, according to the pipeline companies, the Trans-Alaska Pipeline System tariffs were set in conformance with the consent decree methodology and provide a 7 percent return on pipeline valuation, which is one form of rate base.

In the initial Phase I decision, however, the administrative law judge concluded that pipeline valuation rate base under the consent decree methodology was a mixture of numerous disparate elements and was based neither on original cost nor fair value. The administrative law judge further concluded that a regulatory agency had never used the consent decree methodology as the test of reasonableness of tariffs. Rather, the sole purpose of the consent decree was to provide a limit on the amount of dividends that pipelines may pay to shipper owners. The judge also pointed out that the consent decree had the effect of encouraging debt financing. According to the administrative law judge's initial Phase I decision, the actual Pipeline System capitalization is about 90 percent debt and, thus, the consent decree method produced a 15.1 percent return on a total capital rate base for the period examined at that time (1978 to 1979).

After rejecting the consent decree methodology, the administrative law judge decided that return on total capital was a more effective methodology than other measures for evaluating the pipeline tariffs and rate of return. The Phase I decision noted that return on total capital would not be distorted by the different debt-to-equity ratios reflective of pipeline financing. Thus, following extensive testimony, the administrative law judge concluded that a just and reasonable rate of return on total capital was 11.5 percent.

To assure that the annual rate of return remained at 11.5 percent, the judge also decided that the tariffs should be automatically adjusted periodically. The judge noted, for instance, that several factors inherent in pipeline operations required that tariff rates be adjusted to meet changing conditions. One factor was that the net investment in the pipeline could be expected to decline as revenues were generated and property depreciated. Failure to periodically adjust the tariff rates in recognition of the reduced investment base would result in overcompensation and excess profits for the regulated pipeline companies.

The judge also noted that variability of oil volumes transported during the life of the pipeline further suggested a need to periodically adjust the tariffs. For example, due to possible high production in the early years and declining production in the later years, revenues could fluctuate, resulting in either an excessive or an insufficient rate of return if the tariffs were not adjusted to reflect the changed conditions.

Based upon these considerations, the administrative law judge calculated what he believed to be just and reasonable tariffs for each pipeline company for 1978 and 1979. The averages of these proposed annual tariffs were $5.88 and $5.11 a barrel, each of which is lower than the $6.20 a barrel average of the actual tariffs filed and used by the pipeline companies. However, these lower tariffs are simply proposals and have not been approved by the Commission.

<u>Uncertainty about tariffs presents windfall profit tax liability problems</u>

The continuing uncertainty as to what are just and reasonable tariffs presents windfall profit tax liability problems. If the Federal Energy Regulatory Commission or the courts set lower tariffs, additional windfall profit tax obligations could arise and IRS would need to make retroactive adjustments to producers' liabilities.

For calendar years 1980, 1981, and 1982, the Prudhoe Bay producers' liabilities will not be uniformly affected if the Commission or the courts set lower tariffs because the Crude Oil Windfall Profit Tax Act of 1980 contained a special adjustment provision for Sadlerochit oil. This provision, which was later repealed for 1983 and subsequent years, provided for a special adjustment for windfall profit tax purposes if a tariff was lower than $6.26 a barrel. Specifically, the 1980 Act stated that the adjusted base price for Sadlerochit oil for each taxable period is increased by the excess of $6.26 over the Trans-Alaska Pipeline System tariff. For example, as illustrated earlier in table 5, if the tariff is $6.20 a barrel for transporting crude oil through the pipeline, the resulting adjustment is 6 cents a barrel. Four of the initially filed tariffs are below $6.26 a barrel.

On the other hand, the other four initially filed tariffs are $6.44, $6.35, $6.31, and $6.27 a barrel--each of which is higher than $6.26 a barrel. Thus, if the Federal Energy Regulatory Commission or the courts eventually set pipeline tariffs lower than $6.26 a barrel for 1980, 1981, and 1982, IRS may need to adjust the liabilities of those producers who deducted tariff amounts higher than $6.26 a barrel. For instance, some IRS officials believe that the Service should disallow any tariff deduction made in excess of $6.26 a barrel. These officials believe that any tariff deduction before 1983 in excess of $6.26 a barrel would not reflect the oil's fair market value. IRS did not address this issue in its revenue rulings but plans to do so in its methodology paper on removal price determinations.

Another situation that perhaps can lead to windfall profit tax liability adjustments involves the Commission's or the courts' setting of tariffs higher than $6.26 a barrel for 1980, 1981, and 1982. This only could occur in those instances wherein the filed tariffs were higher than $6.26 a barrel. Based upon the tariffs recommended by the Commission staff, this situation is not likely to occur. For example, in November 1983, the Commission staff proposed tariffs of $3.10, $3.07, and $2.54 a barrel for 1980, 1981, and 1982 for one of the pipeline companies.

The amount of any potential adjustments to windfall profit tax liabilities is difficult to firmly quantify. The primary reason is that the recommended tariffs are simply proposals. Further, as mentioned, some uncertainty exists about whether tariff amounts higher than $6.26 a barrel can be deducted for taxable periods before 1983.

Effective January 1, 1983, the special adjustment provision for windfall profit tax purposes for Sadlerochit oil was eliminated under section 284 of the Tax Equity and Fiscal Responsibility Act of 1982. Thus, if the Federal Energy Regulatory Commission or the courts approve lower Trans-Alaska Pipeline System tariffs for taxable periods after 1982, there could be some very substantial upward adjustments to windfall profit tax liabilities. IRS is very much aware of the need for early determination of the pipeline tariffs because of the statute of limitations for making windfall profit tax deficiency assessments and the impact the tariffs have on determining the removal price of Alaskan North Slope crude oil.

In its windfall profit tax examinations of the Prudhoe Bay producers, IRS may need to provide for the possibility of changes in the tariffs and, in turn, the need to make retroactive liability adjustments. If IRS uses the filed tariff rates to compute and assess windfall profit tax liabilities, it may need to obtain agreements from the producers permitting recomputation and reassessment of taxes. IRS would need such agreements in the event that the Federal Energy Regulatory Commission or the courts establish different tariffs for the applicable tax periods. Such agreements are relevant particularly for taxable periods beginning January 1983, when the tariff adjustment provision for Sadlerochit oil was eliminated.

WATERBORNE TRANSPORTATION COSTS FROM VALDEZ, ALASKA

TASK FORCE QUESTIONS

--If the cost of waterborne transportation for crude oil from Valdez, Alaska, to the Gulf of Mexico is a relevant consideration in determining the removal price of Alaskan North Slope crude oil for the purposes of windfall profit tax, how is the cost of that waterborne transportation established?

--Are deemed costs of controlled transportation equipment employed?

--Are the published rates for unaffiliated parties employed?

--Are audited calculations of the actual costs of controlled transportation employed?

GAO RESPONSE

In determining the removal price for Sadlerochit oil, most Prudhoe Bay producers are deducting waterborne transportation costs from market prices. As discussed in appendix II, IRS issued Revenue Ruling 83-161 in October 1983, which permits producers to net-back from the various market areas to determine removal prices for Sadlerochit oil. The waterborne transportation costs that producers are using to net-back to removal prices vary significantly. These variances stem primarily from operating differences among the producers, such as ages and sizes of vessels and whether the vessels are owned or chartered.

Service officials believe that the costs and other deductions of producer-owned/controlled vessels, as determined by the individual producers, could be very difficult to audit. One basis for IRS' concern is that producers are using different methods to establish their waterborne transportation costs for producer-owned/controlled vessels. In its October 1983 revenue ruling, IRS did not explain what intracompany costs of producer-owned/controlled vessels are allowable deductions in determining removal prices and how various cost components, such as overhead, should be treated.

Establishment of and variation among producers' waterborne transportation costs

Factors that could contribute to waterborne transportation cost variances among producers who ship oil to the same coastal areas are numerous. One factor is the distance between ports on a coast. For example, West Coast deliveries are made from Cherry Point, Washington to Los Angeles, California, a distance of about 1,100 nautical miles. Also, the size and age of vessels may be a factor. Larger vessels have economies of scale and can generally deliver oil at a lesser price per barrel than smaller ships. Similarly, newer ships generally have lower operating and maintenance costs than older vessels. Insurance coverage may also be a factor contributing to the cost variances among producers. For example, an individual vessel's claim history and differences in deductible amounts can cause variances in insurance premiums.

At the heart of the issue, however, is whether the ships used to transport Sadlerochit oil are chartered or company owned.

Although we did not obtain specific transportation cost data to individual ports, the Prudhoe Bay producers did provide us information showing that the average costs in 1982 to ship North Slope oil ranged from $0.78 to $2.35 a barrel for West Coast Deliveries and from $4.29 to $6.63 a barrel for Gulf/East Coast deliveries. Most producers deducted waterborne transportation costs from market prices in determining removal prices for Sadlerochit oil for windfall profit tax purposes.

Producers use a variety of chartering arrangements

When chartered vessels are used to ship Sadlerochit oil, the transportation costs deducted for windfall profit tax purposes may vary depending upon the type of charter arrangement. For example, Prudhoe Bay producers may use voyage charters, contracts of affreightment, term charters, or variations of these arrangements. Under a voyage charter, the ship owner agrees to move a stipulated amount of oil in a named ship, on a named route, within a stipulated time period. The ship owner assumes all the expenses directly associated with this service, and the price of the contract is stated in dollars per ton of cargo delivered. The charterer's only responsibility is to pump the oil on board the ship at the port of origin and receive it at the destination. Similarly, under a contract of affreightment, which is basically a voyage charter except that no ship is named, the charterer's cost is the charter fee.

On the other hand, under a term charter, the rental of the ship and crew is for a specified length of time, but the destinations are not specified. The ship owner provides the ship and ordinarily the crew, maintenance, and insurance. The price of such a rental, the term charter rate, is expressed in dollars per deadweight ton per month. The deadweight tonnage of a tanker is the total carrying capacity of the ship. Thus, the term charter rate is based on potential transport capacity rather than the amount of cargo actually carried. Also, the term charterer usually pays the fuel and port charges.

According to IRS officials, a common arrangement for shipping North Slope oil involves "bare boat" charters, wherein a producer charters the ship but provides the crew and directs the movement of the vessel. In such arrangements, a portion of the producer's home office overhead costs frequently is allocated to the transportation costs deducted for windfall profit tax purposes. IRS officials said that this is an area of examination inquiry.

Regardless of the type of chartering arrangement, the charterer may pay any ancillary costs that are incurred in transporting the crude oil. Two of these ancillary costs that can have the greatest effect on transportation charges are transshipment and lightering. These two types of ancillary costs relate to loading and unloading of cargo.

Transshipment is a method of ocean transportation whereby ships dock at a deepwater terminal and unload the oil cargo to temporary storage tanks or to one or more smaller tankers, which then transport the oil to a market destination that has only shallow water port facilities. Transshipment occurs, for example, when very large tankers carrying Alaskan North Slope oil from Valdez to Panama must transfer the oil into smaller vessels that are able to carry the oil through the Canal to the U.S. Gulf and East coasts. A handling fee for each barrel of crude transshipped is usually added to the transportation charge.

Lightering is the practice of unloading part of the crude oil from a tanker onto a smaller vessel, usually a barge, to allow the partially loaded tanker to enter a port. Lightering costs are the fees paid for the use of the small vessel. The fees vary from location to location and can be assessed on a per barrel basis, an hourly basis, or some other basis. A delivery point where Prudhoe Bay producers would incur lightering costs is San Francisco Bay, which is extremely shallow. The most expensive lightering occurs on the West Coast because only ships below about 80,000 tons can enter the Bay. Data we obtained during our review show that, in January 1982, at least two North Slope tankers destined for San Francisco were above 80,000 tons--one was about 120,000 tons and the other was about 170,000 tons. Both of these vessels probably required lightering to unload oil at San Francisco Bay ports.

Some producers use company-owned controlled vessels

Rather than chartering vessels to ship Sadlerochit oil from Valdez to refineries, some Prudhoe Bay producers use company-owned/controlled vessels.[1] Amounts deducted for windfall profit tax purposes and their variation among producers for use of these vessels are of the most concern to IRS. These deductions, or deemed costs, vary by producer. Some of the variance is attributable to differences in voyage and port costs, which can include items such as fuel, stores and provisions, crew wages and benefits, maintenance and repair, port and dock fees, storage costs, Panama Canal transit fees and/or Panama pipeline charges, insurance premiums, cargo losses, inspection fees, and other items.

However, of more concern to IRS is that some variance stems from how the companies determine their intracompany costs. For example, for 1982, one producer calculated overhead costs at 2 cents per barrel. Another producer calculated overhead as 2-1/2 percent of transportation costs. Each producer deducted the respective overhead amount in netting-back to determine removal prices for windfall profit tax purposes. Such differences can cause transportation costs to vary among the producers. Also, according to IRS officials, other possible differences among the producers involve deductions for recovery of and return on capital investment in company-owned/controlled vessels.

Another difference that may contribute to cost variances among the producers is that at least one integrated producer uses waterborne transportation rates published by an unaffiliated firm. These rates, called U.S. Freight Rate Averages, are developed by the Shipping Cost Analysis Corporation of New York City and are based upon the weighted average cost of commercially chartered American flag tanker tonnage. The rates are expressed as percentages of the American Tanker Rate Schedule, published by the Association of Ship Brokers and Agents, Inc., for a standard voyage for each of six sized groups of vessels. Included in the calculations are long-term period charters (more than 18 months' duration), short-term period charters (18 months or less), and single voyage charters.

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[1]Controlled vessels refer to those ships that producers effectively own. A vessel is effectively owned by a producer if it (a) was built to the account of the producer, (b) was sold and then chartered or leased back by the producer in a simultaneous transaction, and (c) is under a very long-term charter or lease, generally 10 to 20 years. According to IRS officials, "effectively owned" vessels may raise some questions in the areas of depreciation and return on capital investment by any party other than the "true owner."

The rates were developed in the late 1970s, during the period of price controls on domestic oil, and were intended primarily for use by tankers engaged in shipping North Slope oil. As the name implies, U.S. Freight Rate Averages apply to U.S.-flag ships. The rate averages were developed because, by law, Alaskan oil must be transported on U.S.-flag ships. The rates were not widely used by producer shippers for energy price control purposes, nor have they been widely used for windfall profit tax purposes. The rates were not published for public use until May 1982, being available previously only to the producer that contracted with the Shipping Cost Analysis Corporation to develop the rates. According to IRS officials, these rate averages may not be representative because some shippers/producers chose not to reveal their transportation data to the Corporation.

Some IRS officials believe that transportation costs could be difficult to audit

IRS officials acknowledge that the waterborne transportation costs of producer-owned/controlled vessels are difficult to audit. For example, examining the costs and other deductions of producer-owned/controlled vessels, as determined by the individual producers, presents IRS with difficult audit questions, such as

--how much overhead is properly allocable to transportation?

--are certain costs more properly accounted for as marketing costs rather than transportation costs?

--what is the proper rate of return on a producer-owned/controlled vessel?

To date, IRS has not issued guidance detailing what types of transportation costs are allowable deductions in determining removal prices and how various cost components should be treated. Issuance of transportation cost guidance by IRS is not without precedent. For example, section 45(11)(11) of the Internal Revenue Manual sets forth guidance concerning transportation costs for foreign oil imported by integrated companies using company-owned ships. The manual states that a representative transportation charge is to be used in the net-back calculation for income tax purposes. This representative transportation charge is to be based on known independent profit-making sources, that is, arm's-length transactions.

The Internal Revenue Manual further provides, however, that if the representative transportation charge cannot be determined through representative purchase contracts for similar crude oils, the charge for transportation will be computed based on a specified rate of return on the total gross investment in the transportation facilities plus operating costs. The manual then explains what cost components are to be deducted as operating costs and how overhead should be allocated.

In May 1984, we learned from IRS officials that the Service plans to rewrite and broaden its manual procedures for calculating net-back prices for Alaskan North Slope crude oil along the lines of present section 45(11)(11) of the manual (relating to foreign oil) to cover domestic oil, such as Sadlerochit oil, and windfall profit tax considerations. To reiterate, the section currently applies only to foreign oil and income tax considerations. Service officials noted that developing broader guidance in the manual, applicable to the transportation of both foreign and domestic oil, will be difficult--especially in deciding upon an appropriate rate of return on vessels. IRS officials explained, for instance, that the economics of shipping are very cyclical, and different considerations are presented by the domestic and international markets. Nonetheless, IRS hopes to have the revised guidance drafted during early 1985.

VOLUMES OF ALASKAN NORTH SLOPE CRUDE OIL

TASK FORCE QUESTIONS

--On a monthly basis, how much Alaskan North Slope crude oil has been produced this year?

--What is the average daily volume of crude oil transported through the Trans-Alaska Pipeline System?

--On a monthly basis, how much Alaskan North Slope crude oil is produced which qualifies as "exempt Alaskan crude oil"?

GAO RESPONSE

During calendar year 1982, production of Alaskan North Slope oil was about 49.3 million barrels a month, or slightly over 1.6 million barrels a day. The average daily volume of crude oil transported through the Trans-Alaska Pipeline System was slightly under 1.6 million barrels. Of the total North Slope production in 1982, about 5.5 percent or 2.7 million barrels a month was exempt from the windfall profit tax.

Production of Alaskan North Slope oil

North Slope production is from the Prudhoe Bay and Kuparuk River oil fields. From these fields, about 591.5 million barrels of Alaskan North Slope oil were produced in 1982. This represents an average of about 49.3 million barrels of oil a month or just over 1.6 million barrels a day.

The Prudhoe Bay oil field, the largest producing oil field in the United States, was discovered in 1968. After the Trans-Alaska Pipeline System was completed and tested in April 1977, the first Prudhoe Bay oil began to flow through the pipeline on June 20, 1977. Deliveries of the oil to tankers in Valdez Harbor began on or about July 31, 1977. Prudhoe Bay production is now about 1.5 million barrels a day.

The other producing North Slope oil field, Kuparuk River, is exempt from windfall profit tax. Production from this field began in December 1981, at an initial rate of about 50,000 barrels a day. In 1982, production averaged about 89,000 barrels a day. With total estimated recoverable oil of about 1.2 billion barrels, Kuparuk is estimated to be the Nation's ninth largest known oil field in total reserves.

Table 6 presents North Slope production and pipeline volume figures for each month in 1982.

Table 6

Alaskan North Slope
Production and Volume Transported through
the Trans-Alaska Pipeline System During 1982
(Thousands of Barrels)

Month (1982)	Prudhoe Bay oil field production[a]	Kuparuk River oil field production[b]	Total North Slope production	Volume transported through pipeline
January	47,946	2,504	50,450	49,687
February	43,437	2,220	45,657	44,917
March	47,405	2,857	50,262	49,671
April	45,760	2,757	48,517	47,758
May	47,724	2,897	50,621	49,828
June	44,939	2,767	47,706	47,058
July	48,028	2,667	50,695	50,020
August	47,470	2,777	50,247	49,503
September	46,219	2,657	48,876	48,294
October	47,835	2,729	50,564	49,636
November	45,247	2,785	48,032	47,391
December	47,086	2,789	49,875	48,990
Total	559,096	32,406	591,502	582,753
Average daily production	1,531.8	88.8	1,620.6	1,596.6
Average monthly production	46,591.3	2,700.5	49,291.8	48,562.8

[a]This production is primarily from the Sadlerochit reservoir, which is subject to windfall profit tax. A small amount of this production, about 600 barrels a day, is from the Lisburne reservoir, which is exempt from windfall profit tax.

[b]Kuparuk River oil field production is exempt from windfall profit tax.

Sources: North Slope production figures were obtained from the Alaska Oil and Gas Conservation Commission's Monthly Bulletin. Pipeline volume figures were obtained from Alyeska Pipeline Service Company's operating statistics for 1982.

Average daily volume of crude oil transported through the Trans-Alaska Pipeline System

The volume of crude oil transported through the Trans-Alaska Pipeline System was 1.597 million barrels a day in 1982, or somewhat less than total North Slope production. The differences between the production and pipeline figures can be attributed to several factors. For example, some North Slope oil production is transported by the Trans-Alaska Pipeline to a refinery near Fairbanks, Alaska where it is refined, and some crude oil is extracted by the various Trans-Alaska Pipeline System pump stations to operate pipeline pumps. This is the most significant factor. Other factors contributing to the difference between the oil field production and the pipeline transportation figures are losses due to pipeline leaks and vaporization. Vaporization can result from temperature and pressure changes within the pipeline.

Exempt North Slope production

The term "exempt Alaskan oil" is defined in section 4994(e) of the Internal Revenue Code to mean

> " . . . any crude oil (other than Sadlerochit oil) which is produced (1) from a well located north of the Arctic Circle or from a reservoir from which oil has been produced in commercial quantities through such a well, or (2) from a well located on the northerly side of the divides of the Alaska and Aleutian ranges and at least 75 miles from the nearest point on the Trans-Alaska Pipeline System."

Current exempt Alaskan oil consists of production from the Kuparuk River oil field and the Lisburne reservoir. As shown in table 6, Kuparuk production averaged about 89,000 barrels a day or 2.7 million barrels a month in 1982. Oil production from the Lisburne reservoir is relatively small, averaging only about 600 barrels a day.

AMOUNT OF WINDFALL PROFIT TAX ON NORTH SLOPE OIL

TASK FORCE QUESTIONS

--How much windfall profit tax has been paid, on a monthly basis, on Alaskan North Slope crude oil this year?

--If all crude oil were subject to windfall profit tax, i.e., if the exemption for "exempt Alaskan crude oil" were eliminated, how much additional windfall profit tax revenue could the federal government anticipate receiving?

GAO RESPONSE

Windfall profit tax liabilities totaled $1.04 billion, or about $87 million a month, during calendar year 1982. Had no Alaskan crude oil been exempt from the tax, an estimated $62 million in additional windfall profit tax revenue would have been realized during 1982.

Withholding agents--generally the first purchasers of oil--compute and report windfall profit tax liabilities on a quarterly basis. Table 7 shows the reported windfall profit tax liability on Sadlerochit oil for calendar years 1980, 1981, and 1982 and compares it to the windfall profit tax liability on all domestic oil for those same periods.

At our request, IRS' Statistics of Income Division estimated the additional windfall profit tax liability if exempt Alaskan oil were taxed. The Service estimated that approximately $62 million would have been collected during calendar year 1982.

Before 1982, there was relatively little exempt Alaskan oil production. As mentioned in appendix V, production from the North Slope's Kuparuk River oil field, which is exempt from windfall profit tax, began in December 1981 at an initial rate of about 50,000 barrels a day. Total 1981 Kuparuk production was about 855,000 barrels.

In future years, the exempt Alaskan oil category may increase in significance. According to a trade publication, the Kuparuk field is destined to become the second largest U.S. producer by the mid-1980s--with production of about 250,000 barrels a day.[1] This is more than double the 1982 production level of about 89,000 barrels a day.

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[1]Oil & Gas Journal, July 12, 1982, p. 80.

Moreover, industry has expectations of finding large quantities of additional Alaskan oil, particularly in offshore areas. The oil industry indisputably is committing considerable capital resources to search for additional oil in frontier areas of Alaska. Also, according to IRS officials, the oil that is discovered and brought into production will likely fall within the definition of exempt Alaskan oil.

Table 7

Windfall Profit Tax Liability: A Comparison of Sadlerochit Oil and Total Domestic Crude Oil

Quarter ending	Windfall profit tax liability[a] (millions of dollars) Sadlerochit oil	Total domestic oil	Sadlerochit liability as percentage of total
March 1980	50	788	6.35
June 1980	62	2,842	2.18
September 1980	245	3,413	7.18
December 1980	300	3,918	7.66
Total 1980	657	10,961	5.99
March 1981	685	6,953	9.85
June 1981	704	7,253	9.71
September 1981	563	6,344	8.87
December 1981	474	6,007	7.89
Total 1981	2,426	26,557	9.14
March 1982	346	5,222	6.63
June 1982	188	4,283	4.39
September 1982	274	4,404	6.22
December 1982	234	4,441	5.27
Total 1982	1,042	18,350	5.68

[a]The amounts shown represent tax liability before adjustments for the net income limitation or for errors in withholding. As mentioned in appendix I, the taxable windfall profit may not exceed 90 percent of the net income attributable to each barrel of oil.

Source: Developed by GAO staff from data provided by IRS' Statistics of Income Division.

OBJECTIVE, SCOPE, AND METHODOLOGY

The principal objective of this review was to provide answers to the questions raised in the December 6, 1982, request by Representative Bill Nelson, when he was Chairman, Task Force on Tax Policy, House Committee on the Budget (see app. VIII). Most of the questions relate to the issue of how the removal price of Sadlerochit oil is established. This is a very important issue because the removal price is the starting point for calculating the windfall profit tax. Also, Sadlerochit oil is from Alaska's Prudhoe Bay oil field--the field with the greatest volume of oil production in the United States.

In conducting the review, we interviewed officials and obtained data from various governmental and industry sources. At the federal level our primary contact was with IRS, both the national office and the Southwest regional office in Dallas, Texas. The Service's Southwest regional office is responsible for nationwide coordination of windfall profit tax examination issues, including the proper treatment of Alaskan North Slope crude oil. The region's boundaries include Texas, Oklahoma, and Louisiana--states wherein a substantial portion of the Nation's petroleum industry is located.

At the federal level, we also contacted

--the Federal Energy Regulatory Commission to obtain information about Trans-Alaska Pipeline System tariffs,

--the Maritime Administration to obtain information on ships transporting Alaskan North Slope oil,

--the Panama Canal Commission to obtain information about the movement of North Slope oil through the Panama Canal, and

--the Federal Trade Commission to obtain information about the marketing of North Slope oil.

At the state level, we contacted the Alaska Department of Natural Resources, which administers North Slope oil leases. We also contacted the Alaska Department of Revenue, which audits North Slope producers for royalty, severance tax, and state income tax purposes.

Industry contacts included private association groups, such as the Independent Gasoline Marketers Council and the National Oil Jobbers Council. These groups, in congressional hearings held in December 1982 and February 1983, expressed concerns about the pricing of North Slope oil. We also contacted most of the oil companies that produce Alaskan North Slope crude oil to determine how they priced the oil for windfall profit tax purposes.

In reporting the information obtained, we adhered to two constraints. First, by law, we cannot disclose tax return information. For this reason, our discussion focuses on the general programmatic activities IRS has underway for administering the windfall profit tax but not on specific examination information relating to individual companies.

Second, much of the information we obtained from the oil companies is proprietary and therefore we had to agree not to publish the data or otherwise use it in a company-specific manner. Accordingly, we report ranges or other statistical aggregations of the data in answering the questions posed in the request.

This review was performed from February 1983 to May 1984 in accordance with generally accepted government auditing standards.

APPENDIX VIII

Congress
of the
United States
House of Representatives

BILL NELSON
FLORIDA
NINTH DISTRICT

COMMITTEES:
BUDGET
SCIENCE AND TECHNOLOGY

December 6, 1982

The Honorable Charles A. Bowsher
Comptroller General
General Accounting Office
441 G Street, NW
Washington, D.C. 20548

Dear Mr. Comptroller General:

I am very interested in obtaining information which will enable me to determine whether current administration of the Windfall Profit Tax (WPT) is resulting in appropriate collections on Alaskan North Slope (ANS) crude oil.

It is my understanding that as a practical matter, the amount of tax collected is directly related to the amount of tariff charged by the Trans-Alaska Pipeline System, the cost of transportation for crude oil from Valdez, Alaska to the Gulf of Mexico, and the establishment of a "market price" for West Texas sour crude oil deliverable at the Gulf of Mexico. To better understand the method by which the amount of tax due under the provisions of WPT is determined, and whether that tax is being properly administered, I have prepared a number of questions to which I request that your staff respond promptly.

To expedite this process, I request that you forward to me your draft of responses to the following inquiries prior to your receipt of any relevant agency's comments.

1. How is the "wellhead price" of ANS crude oil actually determined for purposes of WPT?

2. If the wellhead price of ANS crude oil for purposes of WPT is related to the "market price" for West Texas sour crude oil deliverable to the Gulf of Mexico, how is the "market price" established?

3. How are the tariffs charged for the Trans-Alaska Pipeline System established?

   a. What was the projected "pay-out" for the Trans-Alaska Pipeline System when that pipeline system was established?

   b. What is the projected pay-out period for the Trans-Alaska Pipeline System today, based on current tariffs?

   c. What is the current rate of return on depreciated capital

IN RESPONSE, PLEASE REPLY TO:

☐ 307 CANNON HOUSE OFFICE BUILDING
WASHINGTON, D.C. 20515
(202) 225-3671

☐ 65 EAST NASA BOULEVARD, SUITE 202
MELBOURNE, FLORIDA 32901
(305) 724-1978

☐ 210 BREVARD AVENUE
COCOA, FLORIDA 32922
(305) 631-1978

☐ BREVARD COUNTY COURTHOUSE
TITUSVILLE, FLORIDA 32780
(305) 268-1776

☐ FEDERAL BUILDING, SUITE 300
ORLANDO, FLORIDA 32801
(305) 841-1776

The Honorable Charles Bowsher
Comptroller General
December 6, 1982
Page 2

investment in the Trans-Alaska Pipeline System at this time?

4. If the cost of waterborne transportation for crude oil from Valdez, Alaska, to the Gulf of Mexico is a relevant consideration in determining the removal price of ANS crude oil for the purpose of WPT, now is the cost of that waterborne transportation established?

   a. Are the published rates for unaffiliated parties employed?

   b. Are deemed costs of controlled transportation equipment employed?

   c. Are audited calculations of the actual cost of controlled transportation employed?

5. Is is appropriate to use the cost of West Texas sour crude oil deliverable to the Gulf of Mexico as a benchmark for determining the removal price of ANS crude oil for purposes of WPT? Is there a more appropriate "benchmark" which could be employed?

6. How much WPT has been paid, on a monthly basis, on ANS crude oil this year?

7. What is the average daily volume of crude oil transported through the Trans-Alaska Pipeline System?

8. On a monthly basis, how much ANS crude oil is produced which qualifies as "exempt Alaskan crude oil?" How much "exempt Alaskan crude oil" is likely to be prodiced on a monthly basis over the next three years?

9. On a monthly basis, how much ANS crude oil has been produced this year? On a monthly basis, what volume of ANS crude oil is anticipated to be produced during the next three years?

10. If all crude oil were subject to WPT, i.e., if the exemption for "exempt Alaskan crude oil" were eliminated how much additional WPT revenue could the Federal Government anticipate receiving?

If you have any questions regarding the foregoing inquiries, please do not hesitate to contact Roselee Roberts on my staff. I look forward to receiving your resonnse at the earliest possible time. Thank you for your consideration.

Sincerely,
Bill Nelson
CHAIRMAN
Task Force on Tax Policy
Committee on the Budget

rrr

COMMISSIONER OF INTERNAL REVENUE

Washington, DC 20224

SEP 7 1984

Mr. William J. Anderson
Director, General Government Division
United States General Accounting Office
Washington, DC 20548

Dear Mr. Anderson:

Thank you for the opportunity to review your draft report, "Response to Specific Questions About the Windfall Profit Tax on Alaskan North Slope Crude Oil."

The draft report describes a number of problems encountered in the administration of the Crude Oil Windfall Profit Tax with respect to crude oil produced on the Alaskan North Slope. While we are in basic agreement with its findings and conclusions, we have suggested some minor changes to the draft to enhance accuracy and clarity.

These comments are enclosed. We hope they will be helpful to your staff in preparation of the final report.

With kind regards,

Sincerely,

Roscoe Egger

Enclosure

GAO Note: Although the Commissioner referred to conclusions, the report contains no conclusions.

The enclosure is not included in the report because it contains primarily suggested wording changes. However, changes have been made to the report as appropriate.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

September 7, 1984

Mr. J. Dexter Peach, Director
U.S. General Accounting Office
Resources, Community, and Economics
Development Division
Washington, D.C. 20548

Dear Mr. Peach:

Thank you for the opportunity to review a draft of your proposed report entitled Response To Specific Questions About The Windfall Profit Tax On Alaskan North Slope Crude Oil. The draft was reviewed by senior Staff officials involved in the Trans Alaska Pipeline System (TAPS) case, now pending before this Commission.

We have endeavored to check the accuracy of the report wherever possible, particularly as it relates to this Commission and the TAPS proceeding. As a result of this review, we recommend a number of wording changes, additions and deletions. They are noted on the attached copy of your draft. We believe that each is necessary to ensure the technical accuracy and comprehensiveness of your report. Most of the changes, additions and deletions are self-explanatory. If you have any questions concerning them, please contact Mr. Dennis Melvin (357-9088) of our Office of General Counsel.

The reason for adding the language at the top of page 32, may not be entirely clear. It is well-established that the Commission lacks authority to make a retroactive rate increase. Arkansas-Louisiana Gas Co. v. Hall, 453 U.S. 571 (1981). In addition, a company cannot make retroactive a subsequently allowed higher rate. FPC v. Tennessee Gas Transmission Co., 371 U.S. 145 (1962). Thus, the Commission may not as a matter of law approve, on a retroactive basis, TAPS rates higher than those originally filed for. If we may be of any further assistance to you in this matter, please let me know.

Sincerely,

Raymond J. O'Connor
Chairman

Raymond J. O'Connor
Chairman

Enclosure

GAO Note: The enclosure is not included in the report because it consists of a copy of our draft report with handwritten, suggested wording changes. However, the suggested changes have been incorporated as appropriate in the report.

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