Fueling Global Warming

Federal Subsidies To Oil In The United States

A REPORT FOR GREENPEACE BY
Douglas Koplow
AND
Aaron Martin
INDUSTRIAL ECONOMICS, INCORPORATED

Solar: The Global Warming Solution

GREENPEACE

1436 U Street, NW
Washington, DC 20009
1-800-326-0959
www.greenpeaceusa.org

FUELING GLOBAL WARMING: FEDERAL SUBSIDIES TO OIL IN THE UNITED STATES

By:

Douglas Koplow and Aaron Martin
Industrial Economics, Incorporated
2067 Massachusetts Avenue
Cambridge, MA 02140

Prepared for:

Greenpeace
1436 U Street, NW
Washington, DC 20009

June 1998

ACKNOWLEDGMENTS

This report was written for Greenpeace by Douglas Koplow and Aaron Martin, both of Industrial Economics, Incorporated. Kalee Kreider oversaw the work for Greenpeace.

We owe a large debt of gratitude to scores of people in government agencies, environmental organizations, and universities across the country who went out of their way to give both time and information. Although too numerous to list individually, the report would not have been possible without their help.

We would like to list our peer review panel individually. They shared their knowledge and ideas in their individual area(s) of expertise and helped us to greatly improve our analysis. These individuals are: Thomas Barthold (Joint Committee on Taxation); Nils Axel Braathen (Organisation for Economic Cooperation and Development); Mark Delucchi (University of California at Davis); James Erb (Pennsylvania Department of Environmental Protection); David Garlick (formerly with the Oil and Gas Division of the Texas Railroad Commission); Christine Hansen (Interstate Oil and Gas Compact Commission); Rick Heede (Rocky Mountain Institute); Mike Hix (RAND Corporation); William Hochheiser (U.S. Department of Energy); J. Andrew Hoerner (Center for a Sustainable Economy); Joe Loper (Alliance to Save Energy); David Madland (Taxpayers for Common Sense); Norman Myers (Honorary Visiting Fellow, Oxford University); Richard Neu (RAND Corporation); Jan Pieters (Organisation for Economic Cooperation and Development); Jon Rasmussen (U.S. Energy Information Administration); Earl Ravenal (former official in the Office of the Secretary of Defense, Cato Institute, and Georgetown University School of Foreign Service); David Roodman (Worldwatch Institute); Marshall Rose (U.S. Minerals Management Service); Ronald Steenblik (Organisation for Economic Cooperation and Development); Tracy Terry (U.S. Environmental Protection Agency); and Carrol Williams (U.S. Minerals Management Service). Of course, any remaining errors and omissions are the responsibility of the authors.

About the Authors:

Douglas Koplow, a Senior Associate with Industrial Economics, Incorporated in Cambridge, MA, has worked on natural resource subsidy issues for the past ten years. He is the author of *Federal Energy Subsidies: Energy, Environmental, and Fiscal Impacts* (Washington, DC: The Alliance to Save Energy, 1993) and a co-author of *Federal Disincentives: A Study of Federal Tax Subsidies and Other Programs Affecting Virgin Industries and Recycling* (Washington, DC: U.S. Environmental Protection Agency, August 1994). Mr. Koplow holds a M.B.A. from the Harvard Graduate School of Business Administration and a B.A. in Economics from Wesleyan University.

Aaron Martin, a Research Analyst with Industrial Economics, has worked on a variety of environmental issues including hazardous waste, natural resource damage assessment, and the cumulative impact of exposure to multiple toxicants. He has also worked on community development and environmental conservation in a number of Latin American countries. Mr. Martin holds a B.S. in Geological Sciences and Environmental Studies from Tufts University.

FOREWORD BY GREENPEACE

In 1997, the issue of human-induced climate change attracted unprecedented attention. Not only are physical signs of global warming, such as temperature change and sea level rise, increasingly apparent, but governments have agreed to a legally binding instrument, the Kyoto Protocol, to begin to address the problem. How quickly the industrialized world will cut emissions of the six major greenhouse gases, how many of the loopholes negotiated in Kyoto will remain, and what role developing countries will play in emissions reductions are all central issues at high level climate talks in June and November 1998 under the Framework Convention on Climate Change.

Governments' actions, policies, and spending are benchmarks for evaluating their commitment to greenhouse gas reductions and the proliferation of clean energy solutions. Nowhere is this illustrated more clearly than through continued government subsidization of coal, oil, nuclear, and other forms of so-called "dirty" energy. These subsidies are increasingly controversial. The World Bank, Organization for Economic Cooperation and Development (OECD), the United Nations Development Programme (UNDP), the *Economist,* and other influential financial publications have all called for their removal or reduction.

In the late 1980s, federal subsidies to oil were more than four times higher than those to all renewable energy and energy efficiency sources combined; subsidies to all fossil fuels were ten times higher. With the goal of evaluating existing patterns of government support, Greenpeace commissioned Industrial Economics, Inc. in Cambridge, Massachusetts to assess current federal subsidies to U.S. oil.

The results of this comprehensive, peer-reviewed analysis demonstrate that the federal government continues to subsidize the oil industry with billions of dollars of taxpayer funds each year, and that the historic bias in government support against renewables and efficiency is likely to remain. Not only do these subsidies divert needed public support for emerging clean energy technologies, but they often make it more difficult for cleaner fuels to compete in the marketplace.

Notwithstanding the tremendous historical subsidies to fossil fuels, this current support directly undermines current and future government policies aimed at reducing greenhouse gas emissions. The bias in public support also impedes real competition within deregulated or "liberalized" energy markets by distorting relative fuel prices. The oil industry continues to argue that the high costs of solar and renewable power mean that clean power solutions are not economically viable in the near to mid-term. The viability of these energy alternatives must be evaluated taking into consideration the $5 to $35 billion in annual subsidies to oil documented in this study, as well as the billions in additional support flowing to other fossil fuels both in the U.S. and abroad.

Eliminating subsidies and incorporating environmental externalities into energy prices are achievable, market-based solutions that can play an important near-term role in combating climate change. It is our hope that this independent, peer-reviewed study will make an important contribution towards this end.

Kalee Kreider
US Climate Campaign Director
Greenpeace

TABLE OF CONTENTS

TABLE OF CONTENTS
(continued)

TABLE OF CONTENTS
(continued)

TABLE OF CONTENTS
(continued)

LIST OF EXHIBITS

APPENDIX

LIST OF EXHIBITS
(continued)

EXECUTIVE SUMMARY

Despite increasing concerns over climate change and other environmental consequences of our heavy reliance on oil, the U.S. government continues to subsidize the fuel. Subsidies to oil are provided to producers, transporters, and consumers in varied and often subtle ways. These subsidies not only cost taxpayers billions of dollars per year, but they often exacerbate environmental damage. They can also reduce oil prices, suppressing market signals to governments, oil consumers, and oil producers to begin shifting to alternatives.

This study examines federal subsidies to oil in detail, including policies directly targeted to the oil sector and a pro-rated share of more generally-targeted provisions. By highlighting and quantifying this support, we demonstrate that subsidies continue to play a substantial role in the U.S. economy and identify logical areas for reforms that can save taxpayer money, reduce environmental damages, and help the country to meet carbon reduction targets. Our analysis includes a broad array of subsidy areas, including tax breaks, research and development support, subsidized credit programs, defense of oil supplies, below-market sale of public oil resources, subsidized oil transport, and private sector liabilities that are shifted onto the public. We have also analyzed federal levies on oil and deducted these from our subsidy values as appropriate to obtain our net subsidy estimate. Where available data did not permit specific subsidies to be quantified, we have described them qualitatively.

SUBSIDIES TO OIL ARE BILLIONS OF DOLLARS PER YEAR

The U.S. government provided net subsidies of between $5.2 and $11.9 billion to the oil sector during 1995, excluding the cost of defending Persian Gulf oil supplies. We estimate defense of oil supplies to be worth an additional $10.5 to $23.3 billion, demonstrating the magnitude of this specific subsidy element. Thus, our estimate for net federal subsidies to oil, including defense, is $15.7 to $35.2 billion for 1995. Because of the sensitivity of our totals to the defense subsidy, we present our results both with and without this item.

The large range between our high and low estimates is indicative of the uncertainty surrounding some of the data inputs needed to estimate specific subsidies. Factors contributing to this range include differences between the cost of subsidies to taxpayers versus their value to the oil industry, differences between data sources, and the use of multiple methodological approaches to assess certain subsidies.

LARGEST INDIVIDUAL SUBSIDIES TO OIL

Exhibit ES-1 lists the fifteen largest sources of subsidy to the oil fuel cycle at the federal level. As shown in the exhibit, the largest non-defense subsidies are worth between $4.5 and $11 billion, over 85 percent of our total non-defense estimates. Including defense, the fifteen largest subsidies are worth $15 to $34 billion, more than 95 percent of our totals. The most significant of these subsidies, grouped by topic, are described below. A complete listing of subsidy elements can be found in Appendix Exhibit A-1.

- **Defense of Persian Gulf Oil Supplies.** Defense of Persian Gulf oil shipments and infrastructure comprises two-thirds of the total high estimate, conferring a subsidy of $10.5 to $23.3 billion per year. The range represents the variation in analytical approaches used by defense analysts (described in detail in Chapter 4).

- **Provision of the Strategic Petroleum Reserve.** Stockpiling oil to protect against supply disruptions provided between $1.6 and $5.4 billion in subsidies to oil markets in 1995 (see Chapter 4). The high estimate includes the 1995 increment of compounded interest incurred on the many years of unrepaid debt.

- **Tax Breaks for Domestic Oil Exploration and Production.** Despite reforms intended to narrow the applicability of tax breaks for oil and gas, the industry continues to benefit substantially from tax subsidies, as described in Chapter 2. Three tax breaks benefiting oil exploration and production (the expensing of exploration and development costs, excess of percentage over cost depletion, and accelerated depreciation of oil-related capital) reduced oil industry tax payments by between $1.1 and $2.3 billion during 1995.

- **Support for Oil-related Exports and Foreign Production.** Tax credits for foreign royalties paid, deferrals of U.S. income taxes due for multinational oil companies, and credit subsidies through the Export-Import Bank and the Overseas Private Investment Corporation, provide between $0.8 and $1.6 billion per year in subsidies for exports and foreign production. These provisions are presented in detail in Chapters 2 and 3.

Exhibit ES-1

15 LARGEST SUBSIDIES TO OIL
(sorted in descending order)

	Subsidy	Subsidy Amount (Oil Share, $Millions)	Percent Share: Excluding Defense Low	Excluding Defense High	Including Defense Low	Including Defense High	Description
1.	Oil Defense	$10,459 - $23,333	NA	NA	66.8%	66.3%	Defense operations to protect and secure Persian Gulf oil shipments and infrastructure.
2.	Strategic Petroleum Reserve	$1,560 - $5,427	30.0%	45.8%	10.0%	15.4%	Storage of crude oil to be sold during price shocks and supply disruptions to stabilize domestic supply.
3.	Foreign Tax Credit	$486 - $1,057	9.3%	8.9%	3.1%	3.0%	Allows a portion of foreign tax payments to be credited against, rather than deducted from, U.S. taxes due.
4.	Accelerated depreciation of machinery and equipment	$720 - $976	13.9%	8.2%	4.6%	2.8%	Allows machinery and equipment within the oil industry to be depreciated more quickly than their actual service lives.
5.	Excess of percentage over cost depletion	$335 - $746	6.5%	6.3%	2.1%	2.1%	Allows firms to deduct more than their investment in oil properties from their taxes.
6.	Public liability for plugging, abandoning, and remediating onshore wells	$119 - $451	2.3%	3.8%	0.8%	1.3%	Annualized shortfall in bonding levels needed to cover existing liabilities on on-going operations.
7.	Accelerated depreciation of buildings other than rental housing	$234 - $355	4.5%	3.0%	1.5%	1.0%	Allows buildings owned by the oil industry to be depreciated more quickly than their actual service lives.
8.	U.S. Coast Guard	$308 - $308	5.9%	2.6%	2.0%	0.9%	Water infrastructure (maintenance of coastal shipping; provision of navigational support; ice clearing).
9.	Deferral of income from controlled foreign corporations	$62 - $303	1.2%	2.6%	0.4%	0.9%	Allows oil companies to delay payment of U.S. taxes due on earnings from certain foreign corporations.
10.	Low Income Home Energy Assistance	$274 - $274	5.3%	2.3%	1.8%	0.8%	Assistance for low income energy consumers to buy oil.
11.	U.S. Army Corps of Engineers	$239 - $259	4.6%	2.2%	1.5%	0.7%	Maintenance of waterways heavily used by oil tankers and barges.
12.	Expensing of exploration and development costs	($146) - $243	-2.8%	2.0%	-0.9%	0.7%	Allows expenses related to multi-year oil well assets to be deducted from taxes in the current year rather than capitalized.
13.	U.S. Export-Import Bank	$197 - $241	3.8%	2.0%	1.3%	0.7%	Subsidized loans and insurance to support the sale of oil-related equipment and consulting services abroad by U.S. corporations.
14.	Royalty Undercollection due to Artificially Low Posted Prices	$31 - $130	0.6%	1.1%	0.2%	0.4%	Undercollection due to use of below-market prices in computation of production value by integrated companies.
15.	Tax break from federal/state interaction	$56 - $119	1.1%	1.0%	0.4%	0.3%	State revenue losses from federal tax breaks due to basing state taxable income calculations on federal tax returns.
-	All other subsidies	$724 - $970	13.9%	8.2%	4.6%	2.8%	
	TOTAL VALUE OF TOP 15 SUBSIDIES						
	Excluding Defense*	**$4,477 - $10,889**	**86.1%**	**91.8%**			
	Including Defense*	**$14,936 - $34,223**			**95.4%**	**97.2%**	
	TOTAL SUBSIDIES						
	Excluding Defense	**$5,200 - $11,859**	**100%**	**100%**			
	Including Defense	**$15,660 - $35,192**			**100%**	**100%**	

* Numbers do not add due to rounding.

- **Provision and Maintenance of Coastal and Inland Shipping Routes.** With a large share of the total tonnage shipped through the nation's waterways and ports, oil benefits disproportionately from subsidies to water infrastructure (see Chapter 3). Reforms over the past ten years have increased the share of infrastructure costs borne by shippers; however, substantial subsidies remain. Tax exemptions for bonds used for harbor construction and spending by the U.S. Coast Guard and the Army Corps of Engineers continue to provide subsidies worth $600 to $650 million per year to oil.

- **Unfunded and Underfunded Liabilities.** Inadequate bonding and user fees for the current stock of onshore and offshore oil operators shift $170 to $550 million in liability insurance premiums from oil companies to the public each year. These subsidies are described in Chapter 5.

- **Royalty Losses.** Due to creative accounting by oil producers and lapses in auditing practices by some government agencies, the federal government loses at least $80 and $200 million per year in royalties (see Chapter 6). Adequate data were not available to quantify the full value of royalty-related subsidies.

FEDERAL TAX DATA SUGGEST EFFECTIVE TAX RATES ON OIL REMAIN LOW

Data on actual tax payments by the largest oil companies indicate that the industry continues to benefit from substantial federal tax breaks. As shown in Exhibit ES-2, the average effective federal tax rate (i.e., taxes paid as a percentage of taxable income) on integrated operations fell from 21.5 percent during the 1977 to 1981 period to only 11.9 percent in 1995. Although the statutory tax rate also fell during this period, the major oil companies continued to pay taxes at a rate over 20 percentage points below the statutory level.

Tax breaks to industry remain a moving target. The Taxpayer Relief Act of 1997 included two new tax subsidies to oil, as well as one tax break that was not targeted at the oil sector, but that benefits oil nonetheless.

AGGREGATE FEDERAL SUBSIDIES FOR OIL, BY ACTIVITY SUPPORTED

Individual subsidies can be classified by the type of activity they encourage, ranging from support for oil exploration and development to providing regulatory oversight to the oil industry. As shown in Exhibit ES-3, maintaining secure oil supplies is by far the largest activity supported by the federal government. Security concerns, which include the two largest individual subsidies (the Strategic Petroleum Reserve and defense of Persian Gulf oil supplies), comprise over 75

Exhibit ES-2

FEDERAL TAXES PAID BY FRS COMPANIES (Note 1)
(Millions of Dollars)

	1977-1981	1982-1986	1987-1991	1992-1995	1995
		(Multi-year Totals)			(Single Year Total)
Income Subject to U.S. Taxation (Note 2)	204,903	177,382	135,138	97,545	30,195
Actual Taxes Paid (Refunded)	44,059	30,074	20,858	8,490	3,585
Average Effective U.S. Federal Tax Rate for FRS Companies	21.5%	17.0%	15.4%	8.7%	11.9%
Average Federal Statutory Marginal Rate During Period	46.8%	46.0%	35.3%	34.7%	35.0%
Average Rate Differential	-25.3%	-29.0%	-19.8%	-26.0%	-23.1%
Resulting Reduction in Tax Liability at Marginal Rate	(51,272)	(51,520)	(26,309)	(25,443)	(6,982)
Sources of Reduced (Increased) Tax Liability					
Provisions related to foreign taxes paid	80.6%	96.4%	107.2%	81.5%	83.0%
Provisions related to state & local taxes paid	4.6%	3.5%	5.4%	2.9%	2.2%
Investment tax credits	14.9%	14.7%	1.4%	1.3%	1.4%
Percentage depletion	2.6%	2.1%	2.1%	0.9%	1.0%
Alternative Minimum Tax offset	0.0%	0.0%	-0.2%	0.4%	0.0%
Other (e.g., Section 29 credits)	-2.7%	-16.7%	-15.9%	13.0%	12.4%
Total (Note 3)	100.0%	100.0%	100.0%	100.0%	100.0%

Notes:

(1) FRS companies are comprised of major energy producing corporations that report annually to the Energy Information Administration's Financial Reporting System. Nearly 80 percent of these firms' revenues are derived from petroleum operations.

(2) Includes income from all activities, not just oil. The figures are net of accelerated depreciation and expensing. These tax provisions are factored into taxable income rather than being reported as deductions from that income. Therefore, the reduction in tax liability, which is calculated based on taxable income, does not account for tax breaks related to accelerated depreciation and expensing.

(3) Numbers do not add due to rounding.

Source: U.S. Energy Information Administration, Department of Energy, *Performance Profiles of Major Energy Producers 1995*, datafile for Table B19 provided by EIA.

Exhibit ES-3

AGGREGATE FEDERAL SUBSIDIES FOR OIL, BY ACTIVITY SUPPORTED
(Millions of 1995 Dollars, Net of User Fees)*‡

	Low Estimate			High Estimate		
	Subsidy	**% Share, excluding Defense**	**% Share, including Defense**	**Subsidy**	**% Share, excluding Defense**	**% Share, including Defense**
Research and Development / Provision of Basic Market Information	$215	4%	1%	$243	2%	1%
Cost of Access to Oil Resources	$81	2%	1%	$205	2%	1%
Exploration and Production	$2,005	39%	13%	$4,093	35%	11%
Support for Oil-related Transportation	$690	13%	4%	$776	6%	2%
Security of Oil Supply						
Excluding Defense Costs	$1,560	30%		$5,427	46%	
Including Defense Costs	$12,019		77%	$28,760		82%
Regulatory Oversight and Response to Oil Contamination	$147	3%	1%	$166	1%	0%
Transfer of Oil-related Liability to Public Sector	$171	3%	1%	$557	5%	2%
Assistance for Energy Consumers	$274	5%	2%	$274	2%	1%
Crosscutting Tax Provisions	$56	1%	0%	$119	1%	0%
Subsidy Offsets*	$0	0%	0%	$0	0%	0%
TOTAL, excluding Defense	**$5,200**	**100%**		**$11,859**	**100%**	
TOTAL, including Defense	**$15,660**		**100%**	**$35,192**		**100%**

*Many federal programs benefiting oil are partially funded by user fees levied on program beneficiaries. The subsidy figures shown in this exhibit have already deducted user fees. Detailed data on user fees and gross subsidy values are provided in the Appendix exhibits. The final category in this exhibit, "Subsidy Offsets," allows for adjustments to account for any additional fees on oil that are not program specific, yet appropriately deducted from gross subsidies. No such adjustments were appropriate in 1995. Exhibit 2-1 further explains our treatment of federal levies.

‡Numbers do not add due to rounding.

percent of our estimates if defense of Persian Gulf oil is included, and at least 30 percent of all non-defense subsidies. Incentives for oil exploration and production, at over 35 percent of the total, are the largest category of support for non-defense subsidies in our low estimate, and second largest in our high.

The third largest subsidy activity is support for oil-related transportation, a category often overlooked. This support primarily involves maintenance of oil shipping routes and infrastructure, and is worth over $700 million per year. It is important to remember that this category includes only the transport of oil; subsidies to transportation systems that rely on oil (and which therefore increase the demand for oil) are not included in our analysis.

The remaining subsidy categories each comprise between one and six percent of our total estimates. Though small on a percentage basis, the dollar value of these categories is still substantial. For example, transfers to the public sector of liability for properly closing oil drilling operations were worth as much as $500 million in 1995.

SUBSIDIES IN CONTEXT

Aggregate subsidy values provide one perspective on the size of oil subsidies. It is equally important to evaluate their magnitude in the context of oil prices. While not all subsidies affect prices, these comparisons offer a better idea of the impact subsidies have on consumption behavior than the aggregate subsidy values alone. We have also found it useful to examine subsidy values in the context of two major policy initiatives within the past decade to modify oil demand patterns: the carbon tax and the Btu-tax. These metrics are shown in Exhibit ES-4.

The subsidy metrics are evaluated using three scenarios, reflecting the complexity associated with U.S. government subsidies that partly benefit foreign rather than domestic petroleum:[*]

- **Scenario 1** evaluates domestic subsidies only, excluding credit subsidies to international banks, defense of Persian Gulf oil supplies, and tax breaks for foreign operations.

- **Scenario 2** allocates a portion of the foreign subsidies to the domestic market, reflecting the fact that some of the foreign oil supported by these programs is imported into the United States.

[*] Both the subsidies (the metric numerator) and the petroleum consumption figures (the metric denominators) have been adjusted to best reflect the specific scenario. The consumption figures used for Scenario 1 are for domestic petroleum only, and consumer expenditures exclude the value of imported oil prior to domestic refining. Scenarios 2 and 3 include total U.S. consumption and expenditure data.

Exhibit ES-4

OIL SUBSIDIES IN CONTEXT
(All figures reflect 1995 values)

	Scenario 1 Domestic Subsidies Only (Note 1)	**Scenario 2** Domestic and Pro-rated Share of Foreign Subsidies (Note 2)	**Scenario 3** Total U.S. Subsidies for Domestic and Foreign Oil (Note 3)
Subsidy Value ($million) (Note 4)	$4,445 - $10,226	$5,430 - $12,417	$15,660 - $35,192
Per Barrel of Domestic Consumption ($/bbl)	$1.2 - $2.8	$0.8 - $1.9	$2.4 - $5.4
As % of U.S. consumer expenditures, net of user fees	2.9% - 6.6%	2.7% - 6.1%	7.7% - 17.3%
Per Btu ($/mmBtu)	$0.25 - $0.57	$0.16 - $0.36	$0.45 - $1.02
Per Metric Ton of Carbon ($/ton carbon)	$7.41 - $17.06	$9.06 - $20.71	$26.12 - $58.70

Notes:

1) Does not include subsidies for foreign oil (i.e., foreign lending, foreign tax breaks, and Persian Gulf defense). Consumption data (both barrels and Btus) were adjusted to exclude net imports since they do not benefit from domestic subsidies. Consumer expenditure data were adjusted to exclude the value of net imports upon arrival to U.S. refineries, again because that value is not impacted by domestic subsidies.
2) Subsidy value includes the pro-rated share of foreign subsidies that benefit net imports. Foreign tax breaks and lending subsidies are pro-rated by U.S. net imports' share of total foreign petroleum products supplied. Persian Gulf defense spending is pro-rated by the percentage of total Persian Gulf production imported by the U.S. Total U.S. consumption and expenditure figures are used.
3) Includes all subsidies for domestic and foreign oil. Total U.S. consumption and expenditure figures are used
4) See Appendix Exhibit A-7a for additional detail on the derivation of adjusted subsidy values and the subsidy metrics.

- **Scenario 3** sets an upper bound by assuming all subsidies benefit domestic markets. Although in reality not all the oil supported by internationally oriented programs reaches U.S. markets, foreign tax breaks and lending programs primarily benefit U.S. corporations, and supply shocks in the Persian Gulf affect the price of *all* U.S. oil, regardless of its origin.

Subsidies as a Percent of Oil Prices

Subsidies to domestic oil are worth between $1.20 and $2.80 per barrel of domestic crude consumed. This range is equivalent to roughly 3 to 6.5 percent of consumer expenditures on petroleum products in 1995.[†] The range is slightly lower in our second scenario, although the uncertainty associated with the values suggests that the differences would probably not be statistically significant.

In our third scenario, total federal subsidies for oil are equivalent to as much as 17 percent of U.S. consumer expenditures on petroleum. In addition, the subsidy intensity of imported oil is much higher than domestic production. These results indicate two important points. First, if a significant portion of the benefits of subsidies to foreign production flows back to the U.S. oil sector, subsidy reform would have a noticeable impact on consumption decisions. Second, domestic oil would become more competitive with imports, resulting in some marginal oil wells becoming economic again.

Subsidy Intensity in the Context of Proposed Oil Taxes

Tremendous attention has focused on efficient mechanisms to reduce the impact of climate change. Taxes on carbon are an oft-suggested tool to “get the prices right” (i.e., to internalize environmental externalities) in energy markets. A number of economists have estimated economically efficient carbon tax levels that would begin the transition to lower-carbon fuels. Their results suggest median values of between $9 and $14 per ton.[‡]

[†] Because our subsidy estimates are net of user fees, we have adjusted expenditure data to eliminate the portion of prices attributable to the various fees on oil.

[‡] Values are estimates for the 1990-2000 period; studies generally show the efficient tax rate rising over time. The calculated tax values are set at a rate such that the marginal cost of carbon-emitting activities reflects the estimated damage these activities cause the environment. We use a median carbon tax estimate rather than an average because the source of our data contained an outlier, $142.50 per metric ton of carbon (1995 dollars), that exceeded all of the other estimates by more than a factor of six. Carbon tax rate data are from five studies (Nordhaus, Cline, Peck and Tiesberg, Fankauser, and Maddison) summarized in the Intergovernmental Panel on Climate Change, *Climate Change 1995: Economic and Social Dimensions of Climate Change*, Contribution of Working Group III to the Second Assessment Report of the IPCC, Cambridge University Press, 1996, Table 6.1, p. 215.

Our three subsidy scenarios suggest that federal oil subsidies are worth $7.50 to nearly $60 per ton of carbon emitted from U.S. petroleum consumption. While subsidy removal should not be substituted for a carbon tax, since the latter is aimed specifically at mitigating externalities associated with fossil fuels, the comparison is instructive. The relative size of the values suggests that even without the political will to implement a carbon tax, phasing out oil subsidies could help to improve the price signals that now exist within oil markets. In addition, the fact that the subsidy intensity actually exceeds these carbon tax values underscores the market distortions that would remain if carbon taxes were implemented without concurrent subsidy reform.

A comparison to proposed taxes on Btus (British thermal units) illustrates a similar point. Btus measure the heat content of a fuel. During 1992 and 1993, the U.S. Congress proposed a Btu-based tax on energy. In addition to raising revenues, proponents argued that the tax would ensure that energy prices reflected the environmental impacts associated with the production and consumption of particular fuels. The proposed tax rate set for oil was $0.31 per million Btu (scaled to 1995 dollars). In comparison, oil subsidies for 1995 ranged from 50 to 325 percent of the proposed tax value, depending on the scenario. Had the tax been implemented, much of the hoped for benefit in terms of price signals would merely have offset distortions already in place from federal subsidies to oil. Environmental externalities still would not have been reflected in oil prices.

<u>Summary</u>

The evaluation of subsidies in the context of the oil market demonstrates that subsidies to oil are important and probably impact oil consumption decisions. Eliminating subsidies throughout the fuel cycle will help clarify price signals at every stage of the production chain, improving economic efficiency. In conjunction with externality-based taxes, the price of oil would begin to provide suppliers, consumers, and governments much more accurate information with which to adjust their economic decision making.

RECOMMENDATIONS

The impacts of oil subsidies merit greater attention as the world tries to shape a global climate change strategy and address the many competing needs for scarce government funds. While it has long ago been recognized that oil prices do not reflect the environmental costs of petroleum consumption, our analysis shows that prices do not even reflect the direct costs of petroleum production. At a time of tight fiscal constraints and cuts to social programs, the government should not spend billions of dollars every year to subsidize oil and the environmental problems that result from its consumption.

The costs of supplying oil should fall on the user, not on the general taxpayer. Continued subsidization of oil makes little sense. Subsidies to the oil fuel cycle distort oil exploration, production and consumption decisions; reduce the incentive to develop substitutes; intensify environmental degradation; and cost taxpayers billions of dollars per year. Our analysis suggests that subsidy reform can be a positive force in achieving environmental improvements and substantial fiscal savings, while also eliminating the price distortions that hinder economic efficiency. Furthermore, our analysis suggests that the magnitude of subsidies is large enough that they can impede the efficacy of other policy reform efforts (such as carbon taxes) if ignored.

The historically low oil prices now in effect provide a tremendous opportunity for governments to phase out their oil subsidies with minimal inflationary risks. To help this process, efforts to characterize, report, and remove oil subsidies need to be intensified. Based on our analysis, we make the following recommendations for structural change. To reduce economic dislocations, many of these reforms should be phased in over time.

1) **Decouple oil subsidies from rural economic development.** Many subsidies to oil exploration and production are justified on the grounds that they provide jobs and livelihoods for isolated rural populations. Data suggest that development policies focused on natural resource extraction have rarely been successful. In addition, rapid advances in telecommunications and computer technology provide an increasing range of development options for geographically isolated communities. By decoupling oil development and jobs, governments can stop subsidizing environmental degradation and work to create cleaner, higher value job opportunities for rural populations.

2) **Internalize oil-related defense costs into market prices.** Where governments choose to intervene in oil markets to ensure the security of supplies, the costs of this intervention should be recovered through a user fee on oil consumers. Given the magnitude of these costs, excluding them from the price of oil creates significant and undesirable distortions in consumption behavior.

3) **Treat the Strategic Petroleum Reserve like a formal government enterprise.** SPR costs taxpayers billions of dollars per year in direct costs and foregone interest. The Reserve should be treated as a government enterprise, financed through taxes on oil consumption and formally held responsible for repayment of invested capital plus interest.

4) **Include subsidy reform as an integral element in strategies to mitigate the impacts of climate change.** Taxing emissions makes little sense if governments simultaneously continue to subsidize fossil fuels. Subsidy identification, reporting, and removal should be an integral part of climate change mitigation programs.

5) **Improve the transparency of oil leases on public lands so terms can be easily compared.** Subsidized lease terms can provide large benefits to oil producers at the taxpayers' expense, and the resulting acceleration in oil development creates or aggravates environmental problems. Leasing of public oil reserves should be done in a transparent manner at both the federal and state levels. Environmental groups should work with the relevant government agencies to develop a standard disclosure form to be completed for each sale. Modification of lease terms should also be reported in a standardized, publicly available format. This disclosure form will ensure that lease-related subsidies are visible and that lease terms are comparable across sales. Given the international nature of oil markets, the goal of this disclosure system should be to allow international comparisons of lease terms.

INTRODUCTION CHAPTER 1

Despite increasing concerns over the environmental consequences of our heavy reliance on oil, the U.S. government continues to subsidize the fuel. Subsidies to oil are provided to producers, transporters, and consumers in varied and often subtle ways. These subsidies not only cost taxpayers billions of dollars per year, but they often exacerbate environmental damage. They can also reduce oil prices, suppressing market signals to oil consumers to decrease consumption and begin shifting to alternatives.

This study examines federal subsidies to oil in detail. By highlighting and quantifying this support, we demonstrate that subsidies continue to play a substantial role in the U.S. economy and highlight logical areas for reforms that save taxpayer money, reduce environmental damages, and potentially help the country to meet carbon reduction targets.

1.1 SUBSIDY BASICS

Subsidies represent government policies that benefit particular sectors of the economy. Government subsidies are common in most countries and benefit many industries. When these subsidies reduce the prices of natural resources or natural resource intensive products, they encourage additional pollution and habitat destruction. An overview of subsidy basics will make the rest of this report easier to understand.

- **Subsidies are not just cash.** A great deal of market activity involves controlling and sharing the risks and rewards of economic activities. Subsidies are government-provided goods or services, including risk-bearing, that would otherwise have to be purchased in the market. Subsidies can also be in the form of special exemptions from standard required payments (e.g., tax breaks).

- **Defining the baseline.** Subsidies must often be measured against some baseline. What would taxes owed have been in the absence of this special tax break? How much would industry have had to pay in interest to build that new facility if the government had not guaranteed the loan? Our baseline assumes standard corporate tax rates and no special agency programs to finance or absorb market risks for oil-related endeavors.

- **Subsidy targeting.** One issue related to defining a baseline is that of narrowly targeted subsidies versus more broadly targeted programs that benefit oil as well as some other industries. Industry representatives inevitably conclude that only subsidies directly targeted at the oil industry should count as benefits to oil producers or consumers. In fact, many other subsidies tilt the energy playing field towards oil even if other industries also benefit. It is useful to consider a handful of common subsidy targeting approaches.

  - *Single sector.* The clearest and easiest subsidies to identify and allocate are those directly targeted to the oil industry, such as government financing of oil-related research and development programs through the Department of Energy.

  - *Multiple sectors.* Other subsidies are beneficial to a number of economic sectors, including oil. For example, the oil, gas, and hard rock minerals industries are all eligible for the percentage depletion allowance (discussed in Chapter 2). Since many other energy sources do not benefit from this provision (and the rates vary even for those that do benefit), the policy contributes to inter-fuel market distortions.

  - *Geographic region.* Most state and local subsidies are targeted to particular geographic regions (i.e., the state or locality). To the extent that natural resource intensive industries are located in the region receiving the subsidy (for example, corporate tax rate reductions in a large, oil producing region), policies can encourage incremental pollution and the development of "subsidy clusters" that rely on continued subsidization to survive.

  - *Factor of production.* Some subsidies are targeted at a particular factor of production (e.g., labor, capital) instead of specific industries. Although broadly available to all industrial sectors, subsidies affecting factors of production can cause market distortions nonetheless. Accelerated depreciation provisions, for example, allow any industry using capital equipment to deduct the capital from taxes more quickly than the anticipated service life of the capital asset. These provisions give capital intensive energy types a competitive advantage over types that require less capital investment, such as some demand-side management options. In addition, sector-specific depreciation rules in the tax code can create additional distortions between different capital-intensive energy sectors.

- **Externalities are extra.** While environmental externalities such as pollution certainly constitute subsidies to industry, many subsidy studies (including this one) do not analyze them. The uncertainty regarding their value is larger, and authors often wish to focus on the many ways that government subsidies directly help polluting industries. Properly functioning markets would both eliminate internal subsidies to oil and include a tax equal to the remaining externalities.

- **Treating offsets.** In addition to providing subsidies, the government also levies fees on oil. While subsidies act to distort energy markets in favor of oil, certain fees may have the opposite effect, and are properly treated as offsets to subsidies. Our basic approach for calculating net subsidies is shown in Exhibit 1-1. Where fees represent standard treatment of all industries, they are not considered subsidy offsets. Where a fee is levied only on oil (or on oil plus a few other sectors), it must be evaluated further. Many of these fees are earmarked to pay for government activities such as oil spill cleanup or the remediation of contamination from underground gasoline storage tanks. If the levies pay for oil-related government activities, then they are treated as *user fees* rather than subsidy offsets and they are credited against the oil-related government program spending that they support. To the extent that a particular fee is levied only on a few industries (including oil) and receipts do not support an oil-related purpose, it is referred to as a *special tax*. Special taxes are extra charges on oil that do not pay for activities related to the industry. Thus, they offset subsidies by decreasing oil's competitive advantage. We subtract special taxes from our gross subsidy numbers. Exhibit 2-1 provides a flow chart illustrating how to differentiate these various types of fees.

- **Linkage between subsidy levels and oil prices.** In the aggregate, subsidies throughout the world to the oil fuel cycle depress oil prices, encouraging overconsumption. However, not every individual subsidy has an impact on oil prices. Many subsidies to domestic oil producers, for example, simply keep these producers competitive with less expensive imports (which are themselves subsidized through a variety of mechanisms). Subsidies that have little or no effect on commodity prices will not likely change *consumption* patterns for oil. However, removing even these subsidies will affect the market behavior of oil *producers*. Their removal will also save taxpayers money.

- **Cost to taxpayers versus value to recipients.** The cost of a subsidy to taxpayers does not necessarily equal the value of the subsidy to recipients. Many government loan programs, for example, allow corporations to borrow funds at the lower interest rates obtained by the U.S. Treasury. Such loans do not directly cost the taxpayer but they have an incremental benefit to the industry that we try to measure here. In contrast, government programs may be inefficient and unproductive. Thus, while the programs cost the taxpayer a great deal of money, industry may value them at much less than their direct cost. We were unable to incorporate this latter category in our analysis.

Exhibit 1-1

CALCULATING NET SUBSIDIES TO OIL

Calculating the net subsidies to oil involves three main steps, shown below. Instead of deducting aggregate user fees, as shown in Step 2, we have deducted each user fee from the specific federal program it supports. This approach does not affect the resulting aggregate figures, but provides more detail on individual program subsidies.

1) Measure total federal subsidies to the oil fuel cycle:

+ Subsidies directly targeted to oil
<u>+ Pro-rated portion of more broadly targeted programs to reflect oil's share</u>
= Gross subsidies to oil

2) Deduct fees collected from the oil industry and oil consumers:

- User fees collected from the oil sector to pay for oil-related government activities
<u>- Fees levied only on the oil industry, but that support non-oil activities ("special taxes")</u>
= Gross offsets

3) Calculate net subsidies to oil

+ Gross subsidies to oil
<u>+ Gross offsets</u>
= Net subsidies to oil

1.2 SCOPE, METHODOLOGY AND LIMITATIONS

This report focuses on subsidies to oil throughout its entire fuel cycle, including oil exploration, development, transport, refining, and consumption. The report also includes research and development, decommissioning, and remediation related to these stages of the fuel cycle wherever possible. Subsidies evaluated include federal agency activities, tax breaks, resource sales, liability shifting, and below-market insurance programs. Programs benefiting more than the oil sector, as outlined in the "Subsidy Basics" section above, have been included in our estimates, and in every case have been **pro-rated to reflect only the portion accruing to oil.** We have also included incremental reductions in state taxes attributable to the federal tax breaks, and post-closure liabilities associated with oil well abandonment that are regulated at the state level, but not sufficiently funded by state-level user fees at this time.

We have chosen fiscal year 1995 as the base for our estimate, partly to allow for lags in data availability and partly so that our figures will be comparable to Greenpeace's estimates of European energy subsidies.[1]

To address the complexity of government programs that support oil, we have adopted the following conventions in how we classify and report our data:

- **Gross and Net Subsidy Numbers.** Many government programs of benefit to oil are at least partially funded through user fees on industry. This fact represents significant progress over the past 20 years in charging industries a higher percentage of the cost of government-provided goods and services that are required by activities of those industries. While fiscally prudent, the user fee approach can sometimes create a system in which specific government offices rely on industry user fees for their continued existence, increasing the risk of cooption. For this reason, we track gross subsidy values for each program evaluated, and identify programs with high user fee collections and potentially higher cooption risks.[2] However, gross numbers alone overstate the effective transfer of wealth from government to the oil industry. Thus, our primary focus is on net subsidy numbers, deducting special taxes and user fees from gross subsidy values when it is appropriate to do so.[3]

---

[1] Elisabeth Ruijgrok and Frans Oosterhuis, *Energy Subsidies in Western Europe,* Amsterdam: Greenpeace International, May 1997.

[2] A reliance on user fees does not mean cooption occurs *per se*. In addition to the magnitude of fees collected as a percentage of the program budget, the risk of cooption rises where funds collected are fed directly back into local operations rather than to the U.S. Treasury.

[3] While special taxes on oil may offset the *aggregate* subsidies to the industry, they may affect different activities than subsidies. Therefore, subsidies and special taxes may not counteract each other. For example, subsidies may encourage increased oil exploration and development even though special taxes further down the supply chain affect oil transport or refining.

- **Range Estimates to Bound Uncertainty.** We have used high and low estimates for many of the programs included in the analysis. This variation reflects differences in analytic approaches or data sources. The origin of very large variances between the high and low values on specific items is explained in more detail in the report.

- **Separation of Domestic Subsidies to Foreign Oil from Subsidies to Domestic Oil in our Discussion of Results.** While both foreign and domestic subsidies cost the taxpayer money, their impact on the market differs. We present domestic subsidies to foreign oil separately from support for domestic oil to make our results more useful to readers.

- **Separate Reporting of the Cost of Defending Oil Shipments.** Our aggregate subsidy values are quite sensitive to the estimated cost of defending Persian Gulf oil shipments, as these costs are as large as all other programs combined. As a result, we provide aggregate data both with and without these defense costs so that policy analysts can more clearly see the impact of non-defense subsidies.

Our analysis is subject to a number of caveats. First, by focusing only on oil we are unable to present a holistic picture of the distortions that energy subsidies have caused in the marketplace. Second, we do not attempt to quantify the impact of subsidies on prices and the effect subsidy removal might have on long-term energy production or consumption patterns. Third, we were unable to analyze every federal agency involved with oil due to the limitations of the available budget information. Exhibit 1-2 lists the programs that were not analyzed. Fourth, we did not evaluate oil-related environmental externalities or exemptions from environmental laws. Fifth, while we analyze subsidies to fuel transport, we do not analyze subsidies to transportation systems overall, even though these likely increase the demand for oil. Had we done so, our subsidy estimates would be higher. Finally, any change in economic structure will cause short-term economic dislocations, including job losses in some parts of the economy and job gains in others. Evaluating the magnitude and distribution of these dislocations was also beyond the scope of our analysis.

Exhibit 1-2

FEDERAL PROGRAM SUBSIDIES TO OIL NOT QUANTIFIED IN THIS REPORT

Program	Oil-Related Activities
Department of Agriculture	
U.S. Forest Service	Oversight of natural resource development, including oil production, on National Forest System land.
Department of Commerce	
U.S. National Oceanic and Atmospheric Administration	Navigational aids and provision of marine predictions useful for oil shipping; marine research useful for addressing oil contamination; natural resource damage assessments and restoration related to oil contamination.
Department of Defense	
Security of Alaskan Oil Supply	Military exercises and contingency planning for oil infrastructure.
Department of the Interior	
U.S. Fish and Wildlife Service	Oil contamination prevention, response, and restoration.
Bureau of Indian Affairs	Technical assistance, geological and economic studies, and marketing and training programs for Native American landowners who want to develop their oil resources.
Environmental Protection Agency	Regulation of oil industry impacts on environmental quality.
Multi-lateral Development Banks	Investments in foreign oil operations by the World Bank, its affiliates, and other multi-laterals that receive large contributions from the United States.
Naval Petroleum Reserve	Development and sale of federal oil reserves, not always at market price.

1.3 REPORT STRUCTURE

The remainder of this report is organized topically to enable sometimes complex subsidy mechanisms to be explained in greater detail. Chapter 2 provides an overview of federal tax subsidies to, and special taxes on, the oil fuel cycle. Chapter 3 examines government programs directly supporting oil or required to oversee the oil industry. These include research and development, construction and maintenance of transportation infrastructure, oversight of the industry, and credit subsidies for oil-related exports and foreign investment.

Chapter 4 examines government spending to defend oil supplies, including defense of oil shipping and the cost of the Strategic Petroleum Reserve oil stockpile. Chapter 5 evaluates unfunded liabilities associated with oil spills and the proper closure of oil-related infrastructure. Chapter 6 examines the issue of oil leases in detail, and explains how governments provide subsidies to producers through lease sale practices and lease terms. This chapter also examines the various government programs in place to manage oil production on federal lands. Chapter 7 presents our summary findings and our recommendations for policy changes. Detailed tables used to derive our estimates are contained in the Appendix.

FEDERAL TAX SUBSIDIES AND SPECIAL TAXES ON OIL — CHAPTER 2

Tax subsidies result from selective tax legislation that benefits particular groups of people or industries in the economy. In effect, they share the costs of certain actions between the private sector and the government, impacting investment decisions by increasing the expected returns associated with a particular pattern of economic activity. Tax subsidies take a variety of forms. Credits allow certain expenditures to be deducted from taxes owed. Reductions in the tax rate lower the percentage tax levels on particular activities relative to standard levels. Reductions in the taxable *basis* maintain the standard percentage tax rate, but allow higher than normal deductions from taxable income. Finally, alterations in the taxable entity may allow shifting of income and expenses in ways not normally allowed to reduce the tax burden.[4]

Tax subsidies directly targeted at oil production are the easiest provisions to identify. However, many provisions available to a broader range of economic activity also benefit the oil sector. This latter class of provisions are still properly included in our analysis of oil because other types of economic activity that could substitute for oil are placed at a relative economic disadvantage. Whenever we have included more broadly targeted tax breaks in our assessment, we have pro-rated the subsidy so that numbers included in the report reflect only oil's share. The degree of distortion in economic activity from tax subsidies varies from provision to provision. In general, greater distortions in economic decision making are likely to result from provisions that narrowly target beneficiaries and create large divergences from the standard tax rates paid by other entities in the economy.

Politicians often argue that tax breaks are costless. They are not. Although tax breaks do not require outlays from the U.S. Treasury, they reduce baseline tax revenues, funds that must be raised in other ways, often from other economic sectors. In addition, tax breaks can create economic distortions that encourage inefficient or unwarranted investment. For example, in the early 1980s, provisions allowing for highly accelerated depreciation of nuclear plants permitted much of the 40-year investment to be written off in a period of less than ten years.[5] The larger

[4] For additional background on tax expenditures, see Douglas Koplow, *Federal Energy Subsidies: Energy, Environmental, and Fiscal Impacts -- Appendix B*, Washington, DC: Alliance to Save Energy, 1993, "Chapter B2: Tax Subsidies to Energy."

[5] Richard Morgan, *Federal Energy Tax Policy and the Environment*, Washington, DC: Environmental Action Foundation, April 1, 1985.

the amount that actual service life exceeds the tax depreciation period, the greater the portion of the capital risk associated with these investments borne by the federal government. As occurred with nuclear power plants, this reduces the normal market signals that encourage investors to seek alternatives with shorter, less risky paybacks. Although tax subsidies to oil are not as severe as this example, their impact on market signals is the same.

Evaluating net subsidies to oil requires examining both tax breaks and special taxes on oil. Our approach to categorizing the various federal levies on the oil industry is summarized in Exhibit 2-1. Where taxes that are specific to the oil industry are used for general revenue purposes, they are treated as a special tax and netted from total subsidy values. However, not every levy on oil is a "special tax." Many levies are earmarked for a specific purpose that benefits the production or sale of oil, or ameliorates a problem related to the oil fuel cycle. In essence, they reimburse the government for services to the industry. Examples include fees for leaking underground storage tanks, oil spills, and road building.[6] So long as these funds are used for their stipulated purpose and pay interest on any unused balances, they are not counted as special taxes, but are rather viewed as user fees. User fees are treated as offsets to the costs of programs they support. Other oil-related payments, such as royalties (discussed in detail in Chapter 6), are also not considered special taxes because they reflect a return to the resource-owner for selling the oil in question.

The remainder of this chapter examines federal tax breaks and special taxes for oil in more detail.

2.1 FEDERAL TAX BREAKS TO OIL

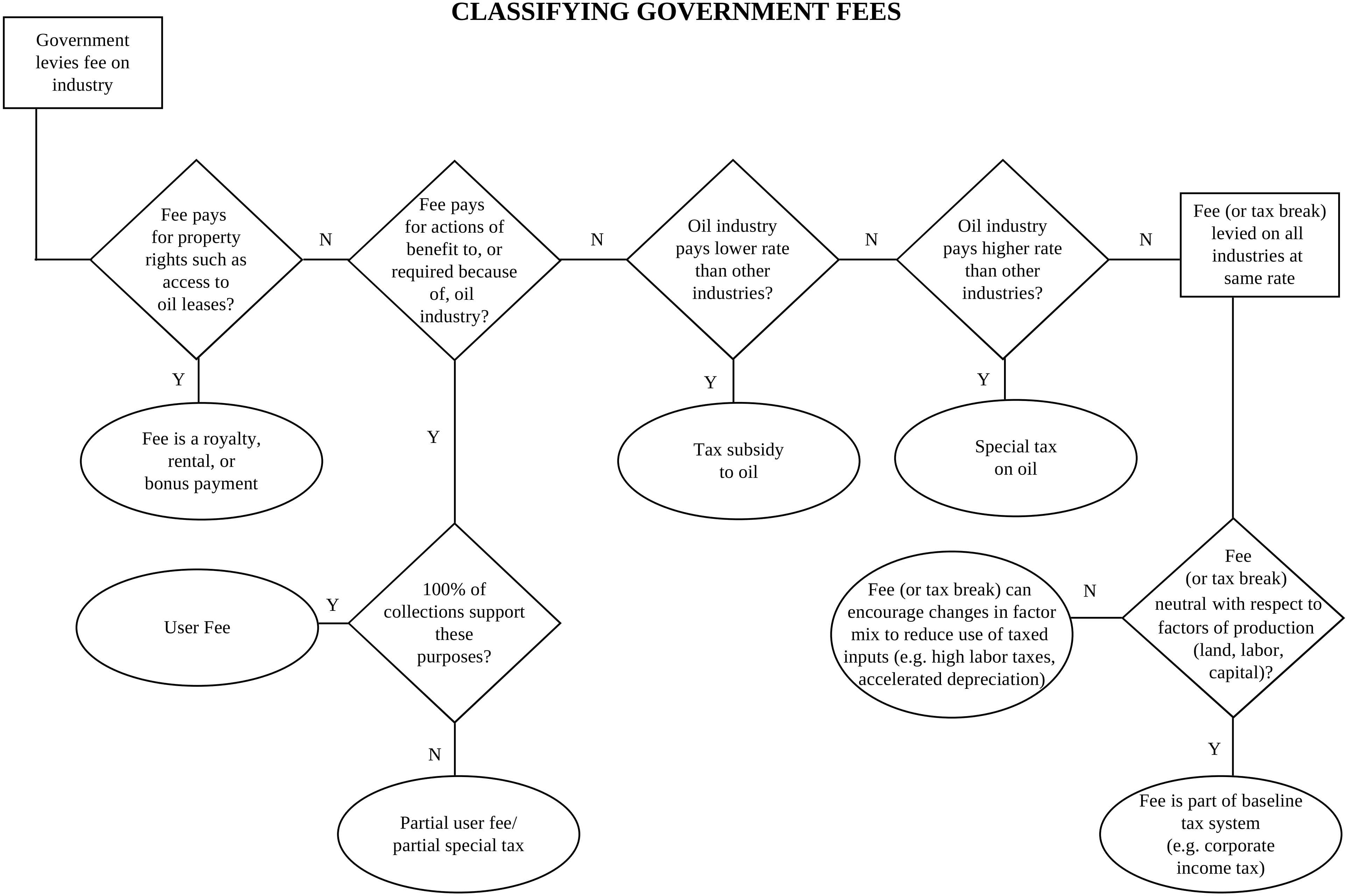
We present tax breaks to oil in two ways.[7] The first section examines specific provisions that benefit oil, using data from the Joint Committee on Taxation (JCT) and the U.S. Treasury to estimate the value of the subsidies they provide. The second section provides a rough measure of the aggregate value of all tax breaks using data on the overall taxes paid by the major oil companies. These sections represent *alternative approaches* to estimate the value of subsidies to the industry; they are not additive.

[6] Oil is generally viewed as a primary beneficiary of new road construction. This reflects the fact that oil is virtually the only fuel used in road transport and because use of oil for this purpose is by far the fuel's major market, nearly three times the next largest market, that of home heating oil.

[7] Tax breaks are also called tax expenditures to reflect their cost to the government.

Exhibit 2-1

CLASSIFYING GOVERNMENT FEES



2.1.1 Major Tax Provisions Benefiting Oil

Tax expenditure estimates are made on an annual basis by both JCT and the Treasury. The two organizations prepare their estimates independently and often do not agree on estimated tax losses. Both sources develop estimates using a revenue loss approach, which estimates how much additional revenue the Treasury would collect in the absence of particular tax provisions, and best reflects the cost to taxpayers for these provisions.[8] The Treasury also develops a second set of estimates using an outlay equivalent approach. Outlay equivalents reflect the fact that tax breaks convey tax-free benefits. The approach measures the amount that would have to be paid to the taxpayer to derive the same *after-tax* income as obtained under the revenue loss approach. For this reason, the outlay equivalent approach best reflects the value of the breaks to industry.

We have pro-rated the tax expenditure estimates to reflect their value to the oil industry. The exhibits that follow include both a high and a low estimate for many of the provisions, and this range can be fairly large. Differences between our high and low estimates sometimes reflect variance in our calculation methods or allocation assumptions. More often, however, the range reflects differences between the revenue loss and outlay equivalent approaches, as well as differences in the assumptions made by JCT and the Treasury. Since neither of these groups publish detailed derivations of their estimates, we were unable to evaluate particular assumptions in order to narrow the estimate range.

Exhibit 2-2 provides an overview of federal tax breaks benefiting oil and Appendix Exhibit A-2 provides more detailed information on each estimate.[9] The following are the largest sources of subsidy:

- **Accelerated depreciation.** Accelerated depreciation provisions enable capital investments to be written off more quickly than their actual service lives. While this provision applies to all capital investments (including renewable energy), the largest beneficiaries are established, capital-intensive industrial sectors, of which oil is one. We have pro-rated these provisions based on the portion of total capital expenditures that is related to oil. Although the tax losses from accelerated depreciation have been reduced substantially since the Tax Reform Act of 1986, the Congressional Research Service notes that the economic decline rate for both equipment and buildings is still "much slower than that reflected in

---

[8] This calculation is made for each tax break individually. In reality, companies often find alternative mechanisms to shelter income when a particular tax break is removed. Thus, the values from both sources should be viewed as rough estimates.

[9] All estimates are net of the alternative minimum tax (AMT). The AMT was instituted to counteract the large deductions that profitable corporations used in the 1980s to eliminate their tax liability completely. In theory, the AMT ensured that such firms, regardless of eligibility for particular tax breaks, paid some taxes to the Treasury. In practice, it has had very little impact on the actual taxes paid by the oil industry.

Exhibit 2-2

FEDERAL TAX EXPENDITURES BENEFITING OIL IN FY1995
(Millions of 1995 Dollars)

Provision	Prorated Share Benefiting Oil Low	Prorated Share Benefiting Oil High	Primary Source of Variance*
Tax Provisions Targeted Directly at Oil			
Expensing of oil and gas exploration and development costs	(146)	243	JCT/Treasury
Excess of percentage over cost depletion	335	746	JCT/Treasury & Est. Meth.
Alternative (non-conventional) fuel production credit	10	27	Est. Meth.
Exception from passive loss limitation for working interests in oil and gas properties	31	31	NA
Enhanced oil recovery credit	25	25	NA
Expensing of tertiary injectants	25	25	NA
Subtotal for Direct Provisions‡	**280**	**1,097**	
Broader Tax Provisions Also Benefiting Oil			
Deferral of income from controlled foreign corporations	62	303	JCT/Treasury & Allocation
Foreign Tax Credit	486	1,057	Allocation
Expensing of research and experimentation expenditures	15	25	JCT/Treasury
Credit for increasing research activities	18	28	Est. Meth.
Accelerated depreciation of buildings other than rental housing	234	355	JCT/Treasury
Accelerated depreciation of machinery and equipment	720	976	Allocation
Treatment of Alaska Native Corporations	5	8	Allocation
Deferral of tax on shipping companies	10	48	JCT/Treasury
Exclusion of interest on industrial development bonds for airports, docks, and sports and convention facilities	50	77	Est. Meth.
Subtotal for Indirect Provisions‡	**1,599**	**2,876**	
Subtotal for All Provisions **‡**	**1,879**	**3,973**	
Incremental Reduction in State Tax Liability Due to Federal Tax Breaks to Oil	**56**	**119**	
TOTAL‡	**1,936**	**4,092**	

* There are three primary sources for variance between the high and low estimates for tax breaks to oil: differences between the expenditure estimates reported by the Joint Committee on Taxation and the Treasury ("JCT/Treasury"), between the Treasury's methods for estimating tax expenditures ("Est. Meth."), and between the allocation methods used for prorating expenditures to oil ("Allocation").

‡ Numbers do not add due to rounding.

tax depreciation methods."[10] We estimate that accelerated depreciation provisions conferred tax benefits worth $954 million to $1.33 billion in 1995.

- **Percentage depletion.** Normally, capital assets are deducted from taxable income over a period of years, until the entire investment is written off. Percentage depletion allowances for oil allow the industry to write off a percentage of the gross *income* from oil production each year, as opposed to a percentage of the gross *investment*. As a result, deductions can actually exceed the original investment. Beginning in 1975, the provision was successively narrowed so that it primarily benefited smaller, independent oil companies. However, this trend has been reversed somewhat since 1990, because percentage depletion has been allowed on transferred properties (even if the new owner would not otherwise be eligible for percentage depletion benefits) and exempted from the Alternative Minimum Tax.[11] In 1995, the value of this provision was approximately $335 million to $746 million.

- **Expensing of Oil Exploration and Development Costs.** This provision allows oil companies to immediately deduct many types of expenses from their taxable income that other industries must deduct over multiple years.[12] The ability to expense these costs encourages increased exploration and extraction of domestic oil. According to the Congressional Research Service, this provision is mostly claimed by integrated oil producers.[13] We estimate the value of this provision to be as much as $243 million in 1995.

- **Foreign Tax Credits (FTCs).** Foreign tax credit provisions allow firms that operate in both the U.S. and abroad to avoid double taxation. In reality, oil companies are often able to receive credit for payments to foreign governments that are actually royalties rather than taxes paid.[14] This is especially apparent when oil companies report paying taxes in countries that have no corporate income taxes. In other cases, tax rates are

---

[10] Congressional Research Service, *Tax Expenditures: Compendium of Background Material on Individual Provisions,* Senate Committee on the Budget, December 1996, pp. 228, 233.

[11] *Ibid*.

[12] This provision applies to investments in producing wells only. Investments into dry wells, as with any defunct asset, can be written off immediately under standard tax law.

[13] Congressional Research Service, December 1996, p. 53.

[14] See Edwin Rothschild, *Oil Imports, Taxpayer Subsidies and the Petroleum Industry,* Washington, DC: Citizen Action, May 1995, pp. 13-15, for a detailed history of the foreign tax credit and oil companies.

higher for oil companies than for other sectors, suggesting similar shifting.[15] By disguising royalties as taxes, oil companies can claim *credits* against U.S. taxes owed rather than *deductions*, as royalties are normally treated.

Using an approach developed by Wahl, our low estimate assumes that all foreign taxes paid in nations that have no standard corporate income taxes are actually royalties.[16] We then calculate the additional taxes that would be paid if they were treated as royalties instead of taxes (i.e., deducted instead of credited). Our high estimate assumes that 50 percent of all foreign tax credits claimed by oil companies are really disguised royalties, including a portion of the tax paid in foreign nations that *do* have some corporate income taxes.[17] These approaches yield estimates of $486 million and $1.06 billion for this subsidy in 1995.

- **Deferral of Foreign Income.** When a U.S. firm earns income through a foreign subsidiary, that income is taxed only when it is repatriated as dividends or other income (at which point taxes paid on the income in the foreign country are also credited against U.S. taxes owed). Because the parent firms are able to time when this happens, they can defer their U.S. tax liabilities for many years. As international oil companies are both large and operate in many other countries, it is clear that they benefit from this tax deferral. We estimate that this provision confers between $62 and $303 million in reduced taxes per year.[18]

[15] Proposals to reform FTCs claimed by oil companies have been introduced for about the past six years, but have been unsuccessful. Although quantitative analyses of the benefits to oil companies prepared by JCT are not publicly available, JCT did confirm that oil companies continue to pay differential rates in many large oil producing nations. Pat Dreissen, Joint Committee on Taxation, personal communication, February 24, 1998.

[16] See Jenny Wahl, *Oil Slickers: How Petroleum Benefits at the Taxpayer's Expense*, Washington, DC: Institute for Local Self Reliance, August 1996, p. 7.

[17] Wahl's high estimate assumed that all foreign taxes paid were disguised royalties, an assumption that we did not feel was realistic (Wahl, p.7). Corporate income taxes do exist in other countries. Furthermore, Braathen has argued that, in addition to taxes paid on profits, some governments require *de facto* taxes in the form of required exploration and development spending (Nils Axel Braathen, OECD, personal communication, December 11, 1997). Nonetheless, we agree that the practice of disguising royalties as taxes is likely to occur in countries that have some corporate income tax, and not just those that have none. In such cases, taxes paid would include both the corporate income tax and royalties. Such an arrangement would benefit both foreign governments and the oil companies.

[18] Our low estimate follows Wahl's methodology, allocating the total value of the tax expenditure by the 10 to 15.9 percent of the 7,500 largest controlled foreign corporations that were associated with oil and gas interests in 1996 (Wahl, p. 6). We then allocate a portion of this to oil based on oil's share of total foreign pre-tax income earned by the largest U.S. energy companies. Our high estimate pro-rates the deferred foreign income of major oil producers (based on EIA data) by oil's share of total foreign pre-tax income.

- **State and Federal Interactions.** Most state tax systems use the adjusted gross income value from federal returns as a starting point for calculating state taxes. Thus, tax breaks that reduce the federal taxable income also reduce the taxes paid at the state level, magnifying the distortionary effect of the federal breaks. Our estimate assumes an average state corporate tax rate of 5 percent, yielding a 3 percent increase in tax benefits ($56 to $119 million) once interactions between state and federal taxes are taken into account.[19]

2.1.2 Effective Tax Rates on the Oil Sector

Another way to estimate the value of tax breaks is to examine data provided by the Energy Information Administration (EIA) on actual taxes paid by the industry. The *statutory*, or *marginal*, tax rate is the percentage of taxable income that would be paid as taxes in the absence of special provisions. The average *effective* tax rate measures what the industry actually paid. The difference between the two values is a proxy for the aggregate value of all tax breaks to a particular industry.[20]

As with tax expenditures, the effective tax rate data provided by EIA are subject to a number of caveats. First, they are based on survey data of only the largest oil producers. Thus, they do not reflect tax breaks (such as percentage depletion) that are primarily used by smaller firms.[21] Second, they are calculated after standard business deductions, such as depreciation, and therefore do not reflect the benefits enjoyed by the industry from accelerated depreciation provisions or the expensing of exploration and development costs.

According to the EIA's data, the average effective tax rate on integrated operations fell from 21.5 percent during the 1977-1981 period to only 8.7 percent for 1992 to 1995. During that same period, the corporate statutory rate has also fallen by about 12 percentage points, from 47 to

---

[19] Average percentage rates are from Wahl, p. 8.

[20] Corporations pay a graduated income tax, rising from a low of 15 percent on the first $50,000 in taxable income in 1995 to 35 percent for all taxable income over $18.3 million. Given the large multinational oil companies in our data set, as well as IRS recapture provisions which charge higher marginal rates of 38 and 39 percent for taxable income between $100,000 and $335,000 and between $15 and $18.3 million, it is reasonable to assume an overall statutory rate of approximately 35 percent for oil.

[21] George Miller, Chairman of the U.S. House of Representatives Committee on Natural Resources, states that the effective tax rate on independent oil and gas producers is estimated to be zero. (George Miller, "Unjustified Giveaway to the Oil Industry," *Albion Monitor*, September 2, 1995, obtained from http://www.monitor.net/monitor, September 1997.) In contrast, the Independent Petroleum Association of America, representing the independent oil and gas producers, claims that a 1995 survey of independent producers "found that the effective tax rate for the industry [was] 20 percent greater than other industries." (Independent Petroleum Association of America, "Domestic Oil and Natural Gas Producers Call on Congress for Fairer, More Competitive Tax System," July 31, 1996, obtained from http://www.ipaa.org, October 29, 1997.) Given that the majors have a lower effective tax rate than other industries, and that independents are eligible for additional tax breaks, IPAA's finding seems counterintuitive.

35 percent. However, as Exhibit 2-3 shows, integrated producers have paid roughly 25 percentage points less in taxes than their statutory rates suggest they owe. This differential is evidence of the substantial tax breaks they have received over the past 20 years.

Special provisions reduced integrated producers' tax liabilities by roughly $7.0 billion in 1995. This approach yields subsidy estimates nearly $3 billion higher than what we calculated on a provision-by-provision approach. About $1 billion of this differential can be accounted for by the fraction of foreign tax credits claimed and state/local tax deductions that are properly excluded from U.S. taxable income to avoid double taxation. This leaves a $2 billion discrepancy between the two estimation methods that we are unable to reconcile given available data. Due to this limitation, we use the lower estimates for tax subsidies, calculated on a provision-by-provision basis, in our totals. Although this approach is more conservative, it may understate the value of tax breaks to oil.

Exhibit 2-3 also illustrates that the Alternative Minimum Tax provisions, implemented to ensure that all profitable companies pay a fair tax regardless of tax preference items, have made little difference in the taxes owed by the integrated energy firms included in the EIA survey.

Other tax data made available by EIA (see Exhibit 2-4) indicate that the production part of the oil fuel cycle benefits from substantially lower taxes overall than downstream operations, and that global tax rates on all oil operations have fallen since 1980. In 1995, integrated oil companies had an aggregate effective tax rate for federal, state, local, and foreign taxes of 37 percent for their U.S. refining, marketing, and transportation operations, compared to only 20.3 percent for domestic production.[22]

2.2 THE EVER-CHANGING TAX ENVIRONMENT: NEW TAX BREAKS FOR OIL

While tax expenditure provisions expire, others are enacted with each new tax bill passed by Congress. In this ever-changing arena, continued vigilance is necessary to provide an up-to-date picture of subsidies. The recently passed *Taxpayer Relief Act of 1997* (TRA) is an example of a very large (though fairly infrequent) revision of the tax code that often contains many new tax subsidies. This specific act contained approximately $130 billion in new tax breaks.

We analyzed TRA to identify components that provide new subsidies to oil, and found a few new provisions that benefit the industry.[23] None of these items are included in our quantified subsidies since they were not in effect during 1995, our base year.

---

[22] U.S. Energy Information Administration, *Performance Profiles of Major Energy Producers 1995*, supporting data file provided by Jon Rasmussen, EIA, August 1997.

[23] The proposed H.R. 1648, "The National Security Act of 1997," contained five provisions increasing subsidies to oil production, but only one was eventually integrated in TRA 1997. The defeated provisions included an attempt to count water reinjection to maintain well pressure (a process used by most wells) as "advanced" recovery eligible for the enhanced oil recovery tax credit. They also included a provision to expand capital expenses that could be deducted from taxes immediately. See "H.R. 1648 The National Energy Security Act of 1997," provided by the Office of Wes Watkins (R-Oklahoma), November 6, 1997.

Exhibit 2-3

FEDERAL TAXES PAID BY FRS COMPANIES (Note 1)
(Millions of Dollars)

	1977-1981	1982-1986	1987-1991	1992-1995	1995
		(Multi-year Totals)			(Single Year Total)
Income Subject to U.S. Taxation (Note 2)	204,903	177,382	135,138	97,545	30,195
Actual Taxes Paid (Refunded)	44,059	30,074	20,858	8,490	3,585
Average Effective U.S. Federal Tax Rate for FRS Companies	21.5%	17.0%	15.4%	8.7%	11.9%
Average Federal Statutory Marginal Rate During Period	46.8%	46.0%	35.3%	34.7%	35.0%
Average Rate Differential	-25.3%	-29.0%	-19.8%	-26.0%	-23.1%
Resulting Reduction in Tax Liability at Marginal Rate	(51,272)	(51,520)	(26,309)	(25,443)	(6,982)
Sources of Reduced (Increased) Tax Liability					
Provisions related to foreign taxes paid	80.6%	96.4%	107.2%	81.5%	83.0%
Provisions related to state & local taxes paid	4.6%	3.5%	5.4%	2.9%	2.2%
Investment tax credits	14.9%	14.7%	1.4%	1.3%	1.4%
Percentage depletion	2.6%	2.1%	2.1%	0.9%	1.0%
Alternative Minimum Tax offset	0.0%	0.0%	-0.2%	0.4%	0.0%
Other (e.g., Section 29 credits)	-2.7%	-16.7%	-15.9%	13.0%	12.4%
Total (Note 3)	100.0%	100.0%	100.0%	100.0%	100.0%

Notes:

(1) FRS companies are comprised of major energy producing corporations that report annually to the Energy Information Administration's Financial Reporting System. Nearly 80 percent of these firms' revenues are derived from petroleum operations.

(2) Includes income from all activities, not just oil. The figures are net of accelerated depreciation and expensing. These tax provisions are factored into taxable income rather than being reported as deductions from that income. Therefore, the reduction in tax liability, which is calculated based on taxable income, does not account for tax breaks related to accelerated depreciation and expensing.

(3) Numbers do not add due to rounding.

Source: U.S. Energy Information Administration, Department of Energy, *Performance Profiles of Major Energy Producers 1995*, datafile for Table B19 provided by EIA.

Exhibit 2-4

GLOBAL TAX BURDEN FOR MAJOR OIL COMPANIES, BY ACTIVITY*
(Includes Federal, State, Local, and Foreign Tax Payments)

	U.S. Petroleum			Foreign Petroleum		
Year	**Oil and Gas Production**	**Refining/Mktg/ Transp**	**Total**	**Oil and Gas Production**	**Refining/Mktg/ Transp**	**Total**
1980	45.9%	42.5%	45.2%	73.9%	39.5%	66.5%
1985	44.6%	44.0%	44.4%	68.4%	83.5%	68.9%
1990	32.6%	37.2%	34.2%	54.0%	37.8%	50.2%
1995	20.3%	36.9%	28.2%	52.8%	30.6%	48.1%
Average, 1977-1995	38.5%	37.8%	39.0%	61.6%	42.4%	57.4%

* Rates shown equal total tax payments to all governments as a percent of taxable income.

Source: U.S. Energy Information Administration, Department of Energy, *Performance Profiles of Major Energy Producers 1995,* supporting datafile provided by Jon Rasmussen, EIA, August 1997.

- **Increased ability to utilize existing oil and gas percentage depletion allowance.** Existing rules cap the ability of firms to offset their taxes with the percentage depletion allowance. These rules have reduced the value of this tax subsidy to larger producers over the past twenty years. TRA relaxes these rules, increasing the ability of existing producers to use the existing provision by about $70 million between 1998 and 2000. As currently written, this provision will exist for only two fiscal years. Thus, once the subsidy is annualized and pro-rated between oil and gas, the market impacts are not likely to be substantial. However, short-term provisions are often extended year-after-year for decades. Extensions would increase the importance of the subsidy substantially.

- **Increased Ability to Utilize Existing Accelerated Depreciation Provisions.** The Alternate Minimum Tax (AMT) was developed to ensure that all profit-making entities paid a minimum level of tax, despite the range of tax breaks available to them. One aspect of the AMT was slower depreciation than available to non-AMT taxpayers. TRA eliminates this distinction. As a result, the provision effectively reduces the minimum tax level under AMT and increases the losses to the Treasury under the standard accelerated depreciation provisions. The Joint Committee on Taxation estimates that incremental losses to the Treasury will be $18.3 billion for FY1997 through FY2007 from all industries.[24] Allocating this subsidy based on oil's share of total AMT payments yields a new subsidy to oil worth $770 million, or about $70 million per year.[25] Allocating based on the oil sector's share of total capital spending yields a similar result.

- **Elimination of the use of motor fuels tax receipts for deficit reduction.** Road transportation is almost entirely dependent on oil, and cars and trucks provide the fuel's primary market. A tax on gasoline and diesel fuel finances many of the country's roads. For the past several years, a portion of the gasoline tax went to deficit reduction rather than to road construction. These funds offset a portion of the general taxes now used to build roads.[26] TRA eliminated the use of any of the motor fuels tax receipts for deficit reduction. If receipts previously allocated to deficit

[24] Joint Committee on Taxation, "Estimated Budget Effects of the Conference Agreement on the Revenue Provisions of H.R. 2014, the 'Taxpayer Relief Act of 1997': Fiscal Years 1997-2007," July 30, 1997, JCX-39-97, p. 2.

[25] According to JCT, the share of current AMT payments is a reasonable method by which to allocate benefits to specific industries. Tom Barthold, JCT, personal communication, February 20, 1998.

[26] Some analysts counted this portion of the tax as an offset to oil subsidies, ignoring the fact that billions of dollars of general tax revenues supplement the gasoline excise tax to finance road construction and repair. See, for example, U. S. Energy Information Administration, *Federal Energy Subsidies: Direct and Indirect Interventions in Energy Markets*, November 1992.

reduction are now used to increase road spending, then what was once an offset to subsidies will disappear. The result could be a $2 billion increase annually in net subsidies to highway construction.

- **Climate Change Action Plan**. The Clinton administration's greenhouse gas emission reduction plan may also include new subsidies to the oil industry. Although the support will not start until FY1999, early discussions suggest the plan will provide $5 billion in incentives, a portion of which may provide tax breaks and research support to the oil industry for emission reduction activities.[27]

2.3 SPECIAL TAXES ON OIL

As we discussed at the beginning of this chapter, the government levies many fees on the oil industry. Some fees reflect the baseline treatment of all industries in the economy, while others specifically target the oil. Of this latter category, "user fees" reimburse the government for its oil-related activities, while "special taxes" increase oil's general tax burden above the normal baseline for all industries. In this report, we deduct user fees from the specific oil-related programs they help fund. We treat special taxes as a general offset to overall subsidies.

Exhibit 2-5 summarizes federal taxes specific to oil. Nearly all of these levies are user fees because they serve to address issues associated with oil production and consumption, such as leaking storage tanks and spills. The largest federal levy, that on motor fuels, pays for the construction of roads. While not related to oil production *per se*, it is clear that the public construction of highways greatly benefits oil producers since the primary demand for oil is from the cars and trucks using these roads. Thus, the motor fuels tax, like many other federal taxes on oil, is appropriately treated as a user fee.

At the Federal level, the only levy on oil that qualifies as a "special tax" on industry is the crude oil windfall profits tax, which was created to prevent the oil industry from selling existing reserves at the higher market price that prevailed during the oil price shocks. In many markets with short-term scarcities that lead to windfall profits for a period of time, the government rarely intervenes to levy a special tax as it did for oil. However, the windfall profits tax was no longer in effect in 1995, so it does not affect our analysis.

[27] "Administration Begins Crafting Plan to Cut Greenhouse Emissions," *Inside EPA*, October 31, 1997, p. 10.

Exhibit 2-5

FEDERAL TAXES ON OIL

Provision	Tax Base	Non-User Fee Share to Oil	Net Oil Subsidy Offset ($millions)	Allocation Base and Rationale
Motor Fuels Excise Tax				
Leaking Underground Storage Tank Trust Fund	Consumption	0%	$0	Funds oil-related problem.
Aquatic Resources Trust Fund	Transport/ Consumption	0%	$0	Funds oil-related problem.
Highway Trust Fund	Consumption	0%	$0	Funds road construction, benefiting oil consumption and refined product transport.
Mass Transit Account	Consumption	Note 1	Note 1	Cross-subsidy between roads and mass transit. May provide net benefit to some non-oil electric.
Deficit Reduction	Consumption	Note 1	Note 1	Would need to be netted against transit funding from general fund to determine any net tax on oil consumption. Discontinued in 1997.
Airport & Airway Trust Fund	Consumption	0%	$0	Funds transit infrastructure dependent on petroleum.
Crude Oil Windfall Profits Tax	Production	100%	$0	Expired; no current impact on oil companies.
Superfund Feedstock Fee	Consumption	0%	$0	User fee; funds environmental damage predominantly associated with petroleum and petrochemical industries.
Oil Spill Liability Trust Fund	Transport	0%	$0	User fee; funds environmental damages associated with petroleum transport.

Notes:

(1) Both provisions include some tax collections from oil that are used for non-oil purposes (e.g., deficit reduction and electric trains and trolleys). Thus, a portion of these provisions are special taxes on oil that offset some of the billions of dollars from the general fund used to build road infrastructure. Full accounting of these programs would both deduct these special taxes from the oil subsidy totals and add spending for road building to those totals. Because we have not evaluated subsidies to highways in this report, we do not deduct these special taxes either.

2.4 SUMMARY

Tax subsidies to oil remain an important source of government support for the oil fuel cycle, providing $1.9 to $4.1 billion in benefits during 1995. Efforts to curb special tax breaks, which culminated with the Tax Reform Act of 1986, have been steadily eroded over the past ten years. Tax rates on integrated operations of large oil producers were only 12 percent in 1995, versus a statutory rate of 35 percent. In the 1990s, rates have been at their lowest levels since the Energy Information Administration began tracking the data in 1977. Congressional efforts continue to try to broaden the definition of existing tax breaks for oil and gas, including three provisions of benefit to the industry contained in the recently enacted Taxpayer Relief Act of 1997. Greater efforts are needed to reduce tax subsidies to oil, encouraging improved price signals to investors, producers, and consumers.

FEDERAL AGENCY PROGRAMS SUPPORTING OIL CHAPTER 3

Many types of government programs subsidize oil, with different programs benefiting each stage of the oil fuel cycle. Government labs invest in research and development of direct benefit to the industry. Government employees gather and publish basic industry or geological data that helps oil producers decide where and when to invest. Government entities also build and maintain vital transportation infrastructure heavily used to move both crude and refined products, ensure safe and environmentally sound operations at oil extraction sites, and guarantee or subsidize loans used by the industry to invest in new operations or to sell equipment to higher risk customers. Unless the industry is charged for these services, government involvement reduces the risk of, or increases the returns to, oil-related activities. The effect is to encourage greater investment in, and production of, oil.

This chapter summarizes most federal program subsidies. Where programs receive funding from user fees, the net subsidy costs of the program are reduced accordingly. Exhibit 3-1 summarizes net program subsidies to oil. Exhibit 3-2 illustrates the programs with substantial cost recovery now in place. Government programs to ensure the stability of oil supplies are discussed in Chapter 4, and programs to oversee oil leasing activities are discussed in Chapter 6. A more detailed presentation of estimates for each individual agency program, as well as information on data sources, can be found in the Appendix to this report.

3.1 RESEARCH AND DEVELOPMENT

General support for research and development (R&D) can help industries identify promising approaches for oil exploration, production, and processing, and reduce the cost of researching new technologies. The federal government, through the U.S. Department of Energy (DOE) and its predecessor agencies, has a history of heavily funding energy research. Since 1980, only NASA, the Department of Defense, and the Department of Health and Human Services have spent more on R&D.[28]

[28] National Science Foundation, *Science and Engineering Indicators - 1996*, p. 25.

Exhibit 3-1

FEDERAL PROGRAM SUBSIDIES TO OIL
(Millions of 1995 Dollars, Net of User Fees)

Department/Agency	Low Estimate	High Estimate	Primary Oil-Related Activities
Department of Commerce			
National Oceanic and Atmospheric Administration	NQ	NQ	Oil spill response; natural resource damage assessment related to oil spills.
Department of Defense			
Army Corps of Engineers	239	259	Maintenance of waterways heavily used by oil tankers and barges.
Navy Supervisor of Salvage	0	18	Maintenance of inventory of equipment for responding to oil spills, including commercial spills.
Defense of Oil Shipments -- All Branches			Defense of oil shipments.
Alaska	NQ	NQ	
Persian Gulf	(Note 1)	(Note 1)	
Department of Energy			
Energy Information Administration	54	54	Development and maintenance of basic information on petroleum markets
Fossil Energy-Related Programs	118	118	Research and development related to oil.
Federal Energy Regulatory Commission	(0)	(0)	Oversight of oil pipeline transport; supported through user fees.
Strategic Petroleum Reserve	(Note 1)	(Note 1)	Storage of crude oil to be sold during price shocks and supply disruptions to stablize domestic supply.
Department of Health and Human Services			
Low Income Home Energy Assistance Program	274	274	Block grants to assist low-income households in meeting their home energy needs.
Department of the Interior			
Bureau of Land Management	(Note 1)	(Note 1)	Management of onshore oil leases on public lands.
Fish and Wildlife Service	NQ	NQ	Environmental assessments of oil spill areas or areas under consideration for oil leasing.
Minerals Management Service	(Note 1)	(Note 1)	Management of offshore oil leasing; management of all oil royalties from oil extraction on public lands.
United States Geological Survey	20	43	Development of basic geological and hydrogeological information on oil reserves and other parameters of value for oil extraction. Research on oil contamination.
Department of Transportation			
Coast Guard	455	455	Maintenance of coastal shipping; provision of navigational support; ice clearing; oil spill response.
Maritime Administration	84	84	Provision of subsidies to U.S. built ships, including oil tankers.
Pipeline Safety	0	0	Oversight of oil pipeline safety; supported through user fees.
Environmental Protection Agency	NQ	NQ	Oversight of oil industries; oil spill response.
Export-Import Bank	197	241	
Overseas Private Investment Corporation	10	31	
TOTAL, excl. Defense of Oil Shipments	**1,452**	**1,578**	Note 3
TOTAL, incl. Defense of Oil Shipments	**1,452**	**1,578**	Note 3

Note:

(1) Defense of oil shipments and the Strategic Petroleum Reserve are discussed in Chapter 4 on supply security. We estimate the value of these subsidies between $12 billion and $23 billion in 1995. Department of the Interior oil resource programs management programs are examined in Chapter 6 on the cost of access to oil resources. These programs cost approximately $125 million in 1995.

(2) NQ = not quantified

(3) Totals do not add due to rounding

Exhibit 3-2

FEDERAL PROGRAMS BENEFITING OIL WITH LARGEST CONTRIBUTIONS FROM USER FEES, 1995 (Millions of Dollars)

	Gross Spending	Offsetting Collection	Share of Oil-Related Spending Paid for by User Fees	Primary Source of Collections
Department of Defense				
Army Corps of Engineers				Inland Waterway Trust Funds (fee on fuels in commercial vessels), Harbor Maintenance Trust Funds (fee on commercial users of specific ports), and other collections from federal agencies and non-federal interests.
Low Estimate	564	325	58%	
High Estimate	584	325	56%	
Department of Energy				
Federal Energy Regulatory Commission	25	25	101%	Regulated industries pay full cost of FERC's licensing, inspection, and other operations.
Department of the Interior				
Mineral Management Service	91	11	12%	Oil Spill Liability Trust Fund (fee on domestically-produced and imported oil) and unspecified federal and non-federal sources. See Chapter 5 for information about the fund, and Chapter 6 for information about MMS.
United States Geological Survey				
Low Estimate	28	8	27%	Primarily from other federal sources for services provided, plus some receipts from unspecified non-federal sources.
High Estimate	66	23	35%	
Department of Transportation				
Coast Guard	527	72	14%	Oil Spill Liability Trust Fund (fee on domestically-produced and imported oil).
Pipeline Safety	6	6	99%	Pipeline Safety Fund (fee on pipeline operators) and Oil Spill Liability Trust Fund (fee on domestically-produced and imported oil).

The *pattern* of federal support for R&D can influence which energy technologies are commercialized and when. Historically, the pattern of federal R&D spending for energy has favored fossil and nuclear energy over renewables and efficiency. Between 1950 and 1993, the government allocated 22 percent of its energy R&D expenditures to fossil fuels, 63 percent to nuclear fission and fusion, and only 16 percent to renewables and efficiency combined.[29] This pattern had begun to shift by 1995, with funding moving away from nuclear energy to renewables and efficiency. However, fossil fuels, primarily coal and oil, still received almost one-quarter (23 percent) of total R&D spending, albeit of a much smaller federal R&D pie.[30] Nonetheless, decades of favoritism for petroleum has contributed to innovations and improvements that reduced the cost of oil extraction and development. During 1995, DOE continued to provide $808 million in subsidies to fossil fuels, of which $118 million supported oil.[31,32] This amount could easily have been borne by the oil companies themselves.

In terms of private R&D, the petroleum extraction and refining sector had one of the lowest R&D investment levels among all industries, averaging only 0.9 percent of sales between 1983 and 1993. The average for all manufacturing sectors during that same period was over 3 percent of sales.[33] One possible explanation for this low investment is that public support for R&D allowed the industry to reduce its spending. Another reason may be that oil service firms, rather than the major oil producers, have been the source of higher R&D spending levels, and that this spending is not reflected in aggregate statistics.

3.2 PROVISION OF BASIC INDUSTRY INFORMATION

Every business requires data on its competitive environment. In the oil industry, this information includes basic data on oil deposits and geology, production and distribution, and prices. The federal government has long provided these data at little or no charge. For example, the Energy Information Administration within the Department of Energy provides a host of basic data on oil prices, production, and investment that is of substantial benefit to both oil producers and consumers. Similarly, the U.S. Geological Survey has provided core data on mineral resources for most of this century. These two programs cost taxpayers between $74 and $97 million for oil-related activities in 1995. While industry often supplements the data they provide,

[29] Doug Koplow, "Energy Subsidies and the Environment," in Organization for Economic Cooperation and Development, *Subsidies and Environment: Exploring the Linkages*, 1996, p. 205.

[30] U.S. Department of Energy, "FY1996 Internal Statistical Table by Appropriation," November 8, 1995.

[31] The total for all fossil fuel subsidies includes DOE's Clean Coal Technology and Fossil Energy Research and Development Programs. U.S. Executive Office of the President, Office of Management and Budget, *Budget of the United States Government, Fiscal Year 1997*, pp. A-443 and A-451.

[32] DOE staff noted that federal spending on oil R&D has continued to decline since FY1995. William Hochheiser, U.S. Department of Energy, personal communication, January 13, 1998.

[33] National Science Foundation, p. 20.

the availability of baseline information helps firms to focus their efforts. In many other industries, these data are gathered by the private sector and sold to interested firms rather than financed by the taxpayer.

3.3 TRANSPORTATION INFRASTRUCTURE

Oil is often extracted thousands of miles from the point of consumption. Thus, transporting the oil is an extremely important factor in oil economics. Nearly all of the crude oil moved in the United States travels by pipeline or by water. Water shipments in the coastal areas of the country move by tanker, whereas shipments on the inland waterways move by both tanker and barge. Refined products are shipped via a wider range of modes, including barge, rail, road, and pipeline.

3.3.1 Coastal and Inland Waterways

Water transportation infrastructure is a good example of a general subsidy that substantially benefits oil and distorts energy markets. Although oil is not the only commodity shipped through U.S. ports and inland waterways, it is one of the main commodities. Crude oil and refined products comprised 38 percent of all waterborne tonnage transported in 1995. While crude oil comprises a much larger share of coastal shipping than refined products, the situation is reversed for inland transport.[34]

Historical subsidies to water infrastructure have helped to reduce the overall cost structure of water shipments for oil. Most of the costs of capital infrastructure development were financed through Congressional appropriations, and there has been no attempt to recover these historic costs through increased charges on current users. Between 1950 and 1977, an estimated $13.6 billion (1995 dollars) of federal spending on water infrastructure accrued to the petroleum sector.[35]

The government continues to provide substantial support for water transport. The Army Corps of Engineers is heavily involved with building and maintaining ports, harbors, and the nation's inland water transportation system. Dredging of harbors and waterways, as well as the construction and operation of locks, benefit oil shippers. The U.S. Coast Guard also plays an important role in regulating coastal shipping. Activities benefiting oil transport include shipping lane and navigational maintenance and improvements (including ice clearing); shipping channel patrol; oil spill prevention and response; and inspection of waterfront facilities, including transfer pipelines used to unload oil tankers. Although the share of these programs' costs borne by users has risen over time, subsidies remain.

---

[34] U.S. Army Corps of Engineers, *Waterborne Commerce of the United States, 1995*, "Part 5 - Waterways and Harbors, National Summaries," Table 2-1.

[35] Cone et al., *An Analysis of Federal Incentives to Stimulate Energy Production*, Richland, WA: Battelle Memorial Institute, December 1978, p. 219.

Our subsidy estimates for both the Army Corps of Engineers and the Coast Guard pro-rate total subsidies for water transport based on oil's share of total tonnage shipped, and they deduct all user fees collected to support the programs.[36] In 1995, the Army Corps conferred over $235 million in subsidies to oil. Subsidies through the Coast Guard were over $450 million.

3.3.2 Shipping

In addition to subsidies for water infrastructure and services, the federal government provides shipping subsidies to U.S.-flag vessels, including oil tankers, through the Maritime Administration, or MARAD. MARAD's objective is to increase the competitiveness and productivity of the U.S. Merchant Marine. Toward that end, it provides operating subsidies to U.S.-flag ship operators engaged in foreign commerce in order to offset the differences in U.S. and foreign operating costs. In the past, MARAD also subsidized certain construction costs for merchant ships when U.S. costs exceeded those in other countries. We estimate that MARAD provided approximately $80 million in subsidies to oil-related shipping in 1995.

3.3.3 Pipelines

Government involvement with pipelines is centered on rate and safety regulation (described in the next section) and provision of rights-of-way (discussed in Chapter 6). We did not identify any examples at the federal level of public money being used to build or maintain pipeline infrastructure.

3.4 GOVERNMENT OVERSIGHT OF INDUSTRY BEHAVIOR

The federal government regulates occupational health and environmental issues of the oil industry, as well as oversees rate setting in pipeline natural monopolies. If oil requires a significantly higher level of public oversight than substitute energy sources, financing this oversight from general tax revenues rather than user fees will hide important price signals about the relative economics of energy alternatives.

A variety of federal agencies provide environmental oversight of oil. The Environmental Protection Agency regulates emissions to air, land, and water. The Fish and Wildlife Service and the National Oceanic and Atmospheric Administration both evaluate impacts of oil on ecosystems. The Coast Guard and the Office of Pipeline Safety oversee oil pipelines and transfer stations to prevent leaks and spills. Finally, the Coast Guard, EPA, and the Navy Supervisor of Salvage respond to oil spills and assist in clean-ups. Some, but not all, of these costs of environmental oversight are recovered from the industry through user fees. For example, the Oil Pollution Act (described in Chapter 5) allows agencies to recover costs related to oil spills from

[36] Note that allocating total subsidies by tonnage moved may understate the true subsidies to oil, especially in the case of ports and harbors. To the extent that oil tankers are the deepest ships using these facilities, proper cost accounting would assign oil the full cost of dredging or other harbor modifications required to handle this type of vessel.

responsible parties and the Oil Spill Liability Trust Fund, which was created through a tax on oil. However, no mechanism exists for recovering the costs of other types environmental oversight, such as EPA's responsibilities for ensuring the safety of the oil industry's emissions.

The Federal Energy Regulatory Commission regulates pipeline rates. However, the full cost of this oversight is recovered through user fees; thus, FERC does not provide a net subsidy to oil.

3.5 CREDIT PROGRAMS SUPPORTING EXPORT OF OIL-RELATED GOODS AND SERVICES

Most subsidies to oil encourage additional domestic production or consumption. However, a handful of lending programs provide subsidies to U.S. firms in the oil sector who wish to export their equipment or expertise to other countries. The U.S. Export-Import Bank (Eximbank) and the Overseas Private Investment Corporation (OPIC) both serve to promote U.S. industry abroad. The World Bank and the International Finance Corporation (IFC), to which the U.S. is a major contributor, focus on developing specific industrial sectors in specific countries. Although their primary focus is not on U.S. business, U.S. firms are substantial beneficiaries of their lending activity.

3.5.1 How Credit Subsidies Work

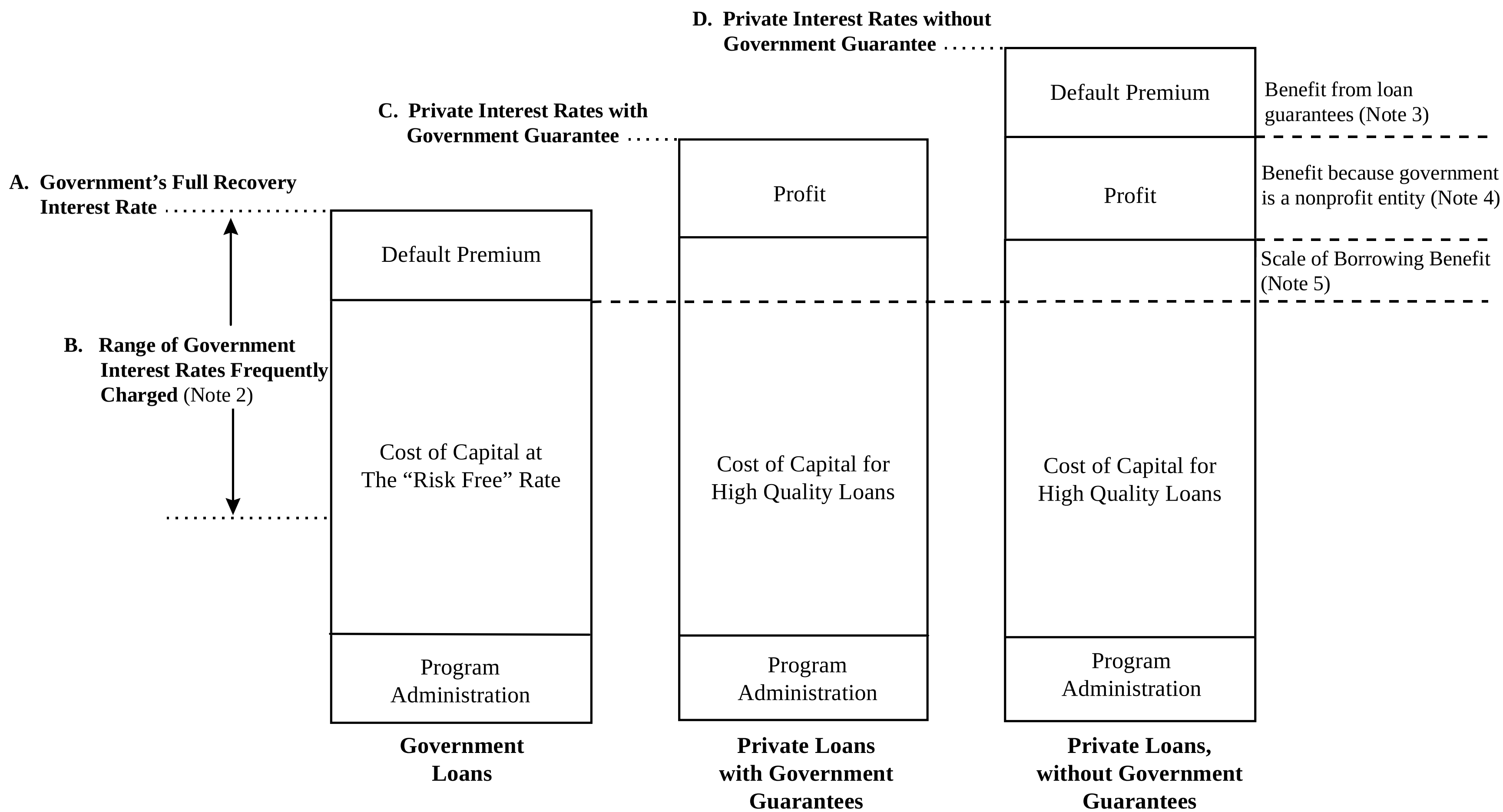
The lending institutions provide credit subsidies in three main ways: below-market loans, loan guarantees, and below-market credit insurance. Below-market loans provide borrowers with artificially low interest rates. In some cases interest rates are so low (as in the case of concessional loans) that the loan is essentially a grant. Loan guarantees also indirectly provide borrowers with lower interest rates. Guarantees by financially strong institutions such as Eximbank reduce the risks to commercial lending banks, allowing them to charge the borrower lower rates than would otherwise be available for a given level of risk. Finally, below-market credit insurance provides companies with artificially low costs of insuring against business and political risks.

All of these instruments have two levels of subsidy. The first, the cost to the taxpayer, measures the lending programs' losses. One source of losses is the difference between the interest rate (or insurance premium) that a borrower pays, and the cost of those funds (or insurance) to the federal government. If OPIC, for example, borrows money from the Treasury at an interest rate of eight percent and lends it to Joe's Oil Company at six percent to develop an oil field in Algeria, the immediate subsidy would be two percent. The total cost to the taxpayer would also include the cost of making and overseeing loans, which banks normally recover through the interest and fees they charge, as well as any uncovered losses from loan defaults or insurance claims. The percentage of the government's full cost of running a credit program that is recovered from beneficiaries varies widely by program. We depict this range of cost recovery in Exhibit 3-3.

Exhibit 3-3

SUBSIDIES THROUGH GOVERNMENT LENDING PROGRAMS

(Note 1)



<u>Notes</u>

(1) Chart is illustrative. Absolute and relative size of components will vary by type of loan and type of lender. The subsidy cost to taxpayers equals the government's full recovery interest rate minus what it actually charges (A-B). The value of the lending subsidy to recipients equals the private interest rate minus what the government charged (D minus B or C minus B, depending on the program). This difference is also referred to as the value of government intermediation.

(2) Depending on program goals, interest rates charged to borrowers can fall anywhere within this range.

(3) Appropriate default premium varies by loan. Premiums that are too small yield uncovered losses, which are common in many government lending programs. Federal loan guarantees shift default risks (they are not eliminated) from the private sector to the government, allowing private lenders to charge lower interest rates to borrowers. Default premium subsidies are very difficult to estimate ahead of time; however, historical data on actual defaults can provide a good proxy value.

(4) Private lenders need to earn a minimum return in order to continue lending. Government programs do not.

(5) Federal government's large size often enables it to obtain a lower interest rate than private companies, even before default premium is taken into account.

The second level of subsidy, also shown in Exhibit 3-3, is a bit more complicated. Even if the government-supported banks were to recover their costs of operations from borrowers, they might still confer a large subsidy to the recipient sectors. The banks are large institutions that can borrow at or very near the federal government's cost of funds. Investors view the risk of the federal government not paying back loans as so remote that the rate charged the Treasury is often called the "risk free rate." A similar situation holds true for insurance programs: the federal government's cost of capital to finance an insurance program is lower than what would be available to private firms. Because it has access to less expensive capital, the government can charge lower interest rates and insurance premiums than private companies. Costs are reduced still further by the fact that the government is a non-profit entity, and thus does not mark up its rates to earn a return. Finally, the government often provides higher risk loans and insurance policies than private institutions may be willing to make.

By going through a government-supported bank, Joe's Oil can borrow money or purchase insurance at lower rates than would be available to it from private institutions. It may also be able to obtain loans and insurance for business in high risk countries that its private bank is simply unwilling to offer. The difference between what the company pays the government-supported bank and what it would have to pay a private institution is captured in our high estimate (which we call the value of government intermediation) and provides the best measure of the value of the credit programs to the recipient.

Credit programs have been some of Congress' favorite ways to confer subsidies. Although the programs provide tangible benefits to recipients, the cost of the subsidies has historically been fairly invisible to outsiders. In some cases, the programs can confer benefits to industry without losses to the government. In other cases, programs (such as loan guarantees) do not require immediate outlays of cash, and program losses often do not become visible until many years later.

The attractiveness of these programs is apparent in the fact that outstanding direct loan and guaranteed loan balances for federal credit programs are approaching $1 trillion.[37] To better control these programs, a number of laws have been passed over the past ten years governing the measuring, reporting, and auditing of credit subsidies.[38] These laws eliminated the previous practice of recording lending on a cash basis -- an approach that makes loan guarantees all but invisible until they begin to default. Overall, the laws have greatly improved the federal government's ability to track the likely long-term financial impact of lending programs on the Treasury. However, credit reform provides few insights as to the value of government loans and guarantees to the private sector, the second level of subsidy described above.

---

[37] U.S. General Accounting Office, *Credit Reform: Review of OMB's Credit Subsidy Model*, GAO/AIMD-97-145, August 1997, p. 1.

[38] These included the Federal Credit Reform Act of 1990, the Chief Financial Officers Act of 1990, and the Government Management Reform Act of 1994.

3.5.2 Subsidies to Oil Through Credit Programs

Since not every energy firm has access to cheap loans or insurance from the governmental lending institutions, the banks' patterns of involvement can distort the relative economics of different forms of energy. The importance of distortions from these lending programs should not be underestimated: they have heavily favored established fossil fuels over emerging renewables and end-use efficiency. Between 1980 and 1989, for example, more than 70 percent of Eximbank's energy sector loans and guarantees went to fossil fuels; support for non-hydro renewables and efficiency during that same period was negligible. Support for the energy sector through the multilateral development banks followed a similar pattern for the 1980 to 1988 period, with 48 percent going to fossil fuel (three quarters of this to coal and oil) versus one percent for non-hydro renewables and efficiency.[39]

As shown in Exhibit 3-4, this pattern of support has continued into the 1990s. Especially within both OPIC and Eximbank, energy continues to be an extremely important component of their lending activity, yet very little financial support benefits end-use efficiency and non-hydro renewables. Support for oil exceeds 40 percent of the energy commitments of the International Finance Corporation and Eximbank's guarantees and insurance program. Oil comprised 24 and 40 percent of OPIC's and Eximbank's energy commitments, respectively.

The value of this support is quite large. Exhibit 3-5 compares the government and private costs of capital for 1995. Government debt is the least expensive source of funds by far, at 6.9 percent. The highest grade (i.e., lowest default risk) corporations had to pay nearly three-quarters of a percentage point more to borrow funds. In reality, corporate expansions are financed not only through debt but also through stock (equity), which is a more expensive source of funds. The weighted average cost of capital (WACC) estimates the cost of funds to a particular firm (or industry) given the existing mix of debt and equity. The WACC for the largest oil refining companies was 10.7 percent. The average cost of capital in the higher risk oil and gas extraction industry was over 14 percent, more than *double* the direct cost of government debt. Thus, the government can provide loans at interest rates considerably lower than the oil industry may otherwise be charged.

Measuring the subsidies to oil through international lending programs is a surprisingly difficult task. The basic information required is standard data used by the banks to track loan and insurance disbursements and performance. Since all the banks publish audited financial reports, all must use transaction-by-transaction data on non-performance to estimate annual losses and write-offs on their activities. Yet, very little of this data is contained in any of the banks' standard reports. In addition, formal requests for information that we submitted to both Eximbank and OPIC suggest that these basic data are dispersed across an array of bank databases and not tracked in any routine manner. Neither bank was able to fulfill our data requests in a timely or efficient manner. As a result, we were unable to aggregate total subsidies to oil using loan-specific data.

[39] Koplow, 1996, p. 207.

Exhibit 3-4

INTERNATIONAL LENDING FOR OIL AND GAS
(Millions of U.S. Dollars)

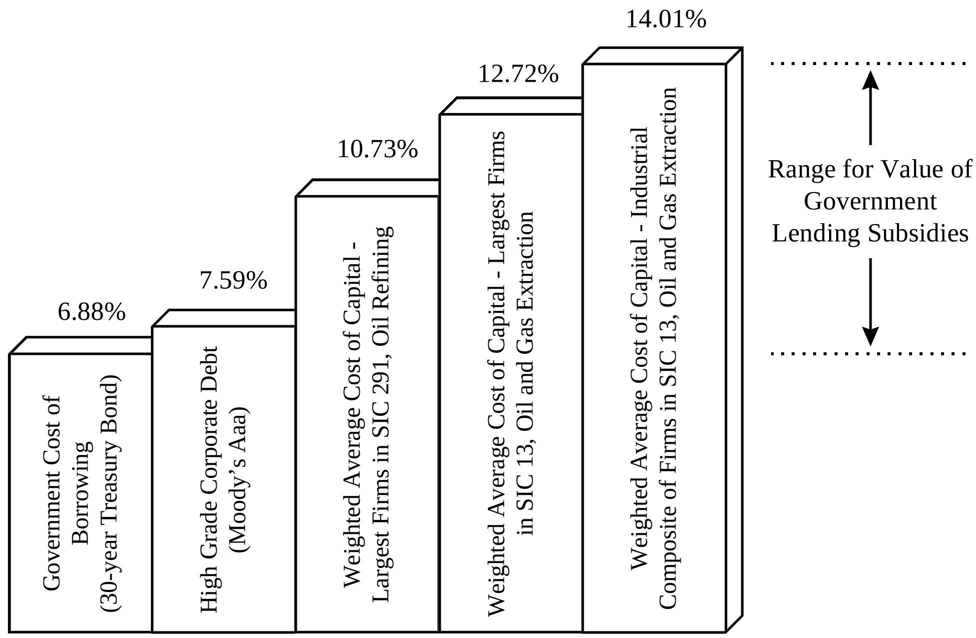
	OPIC		Eximbank		World Bank IBRD & IDA	World Bank IFC
Energy Type	**Finance (Note 1)**	**Insurance (Note 1)**	**Loans Outstanding (Note 2)**	**Guarantees and Insurance Commitments (Note 2)**	**Lending (Note 3)**	**Investment Portfolio (Note 2)**
All Oil and Gas Commitments	738	3,487	544	5,242	5,935	715
Oil Only	314	1,780	341	4,065	NA	642
Total Energy Commitments	1,921	6,710	1,337	9,577	25,621	1,436
Total Commitments, All Sectors	6,149	16,038	5,445	42,194	171,906	9,461
Oil/Total Energy	16.3%	26.5%	25.5%	42.4%	NA	44.7%
Oil & Gas/Total Energy	38.4%	52.0%	40.7%	54.7%	23.2%	49.8%
Energy/Total Commitments	31.2%	41.8%	24.5%	22.7%	14.9%	15.2%
Oil/Total Commitments	5.1%	11.1%	6.3%	9.6%	NA	6.8%
Oil & Gas/Total Commitments	12.0%	21.7%	10.0%	12.4%	3.5%	7.6%

Notes:
(1) Overseas Private Investment Corporation (OPIC) data are for financing implemented during fiscal years 1992 through 1996.
(2) Eximbank and International Finance Corporation (IFC) data represent total outstanding obligations as of the end of their 1995 fiscal years. Eximbank activity has been allocated to oil based on the loan/guarantee mix of commitments for FY1980 through 1989 using data in Koplow, 1993.
(3) International Bank of Reconstruction and Development (IBRD) and International Development Association (IDA) data are for financing implemented during fiscal years 1988 through 1995.

Sources:
Annual Reports: Overseas Private Investment Corporation (1992-1996), Export-Import Bank (1995), The World Bank (1997), and International Finance Corporation (1995).
Dennis Koromzay, Power Department, International Finance Corporation, personal communication, November 4, 1997.
Ramin Shojai, Oil and Gas Division, The World Bank Group, personal communication, November 3, 1997.
Claus Westmeier, Oil, Gas, and Mining Division, International Finance Corporation, personal communication, November 10, 1997
Douglas Koplow, "Export-Import Bank: Summary Table on Energy Loan Portfolio, 1980-89," *Federal Energy Subsidies: Energy, Environmental and Fiscal Impacts, Appendix B,* April 1993, p. B4-143b.

Exhibit 3-5

THE PRICE OF RISK IN THE OIL INDUSTRY, 1995



Notes: The weighted average cost of capital (WACC) incorporates both debt and equity financing, a more accurate measure of the cost for large projects. There are a number of financial models used to calculate the WACC, with small variations in the resulting cost of equity. The WACC values shown here are an average of these approaches.

Sources: Ibbotson Associates, *Cost of Capital Quarterly*, 1996 Yearbook, p. 2-49.
Board of Governors of the Federal Reserve System, *Federal Reserve Bulletin*, June 1997, p. A23.

Data reported by both Eximbank and OPIC under the Credit Reform Act in their annual reports did enable us to make a rough estimate of those banks' overall direct credit subsidies for oil.[40] Due to the unavailability of transaction-specific data on lending and insurance performance, we have pro-rated the bank's overall losses according to oil's share of each bank's total commitments. The implicit assumption is that the banks' losses for individual sectors are proportionate to each sector's share of total commitments. We were not able to estimate subsidies from the World Bank and its affiliates because they did not report data on loan performance in a similar way.

Exhibit 3-6 shows our estimate of Eximbank's and OPIC's subsidies to oil. Our low estimate represents the cost to the Treasury in FY1995 of OPIC and Eximbank commitments related to oil. This cost has three components: anticipated losses on new commitments made during FY1995, the 1995 installment on losses from obligations in each bank's portfolio made prior to Credit Reform, and administrative costs not recovered through fees charged to clients. We estimate the sum of these costs for oil-related commitments at $10 million for OPIC and nearly $200 million for Eximbank. The vastly different sizes mirror the banks' different missions. OPIC expects to break even on operations. Eximbank serves to help U.S. exporters compete by setting terms "commensurate with those available from foreign export credit agencies," and it does not expect to break even.[41]

While our low estimate reflects the cost to the Treasury of the banks' oil-related commitments, our high estimate also incorporates the value of the commitments to the recipient companies. This estimate recognizes that because both OPIC and Eximbank can borrow money from the U.S. Treasury at extremely low interest rates, they are able to pass these savings through to their borrowers in the form of below-market interest rates and insurance premiums. It also recognizes that private banks are willing to provide loans at lower rates when guaranteed by government-supported banks. These benefits are independent of the subsidies provided by the government's failure to recover the costs of its programs. Following the approach used by the Organization for Economic Cooperation and Development, we estimate the value of these benefits at one percent of all outstanding commitments related to oil.[42] The total value of our high estimate is the sum of our low estimate (i.e., the cost to the Treasury) plus this incremental benefit to the recipient companies. As shown in Exhibit 3-6, our high estimate for the subsidies provided by OPIC and Eximbank are approximately $31 million and $241 million, respectively.

---

[40] Historical data on actual losses incurred on loans serves as a proxy for estimating the default premium that would have been included in a private sector interest rate.

[41] U.S. General Accounting Office, *Export-Import Bank: Options for Achieving the Possible Budget Reductions*, GAO/NSIAD-97-7, December 1996, p. 12.

[42] Ronald Steenblik, Organization for Economic Cooperation and Development, personal communication, February 25, 1998. A more accurate way to value the direct loans would be to compare the interest rate charged by the bank to a market cost of capital similar to those shown in Exhibit 3-5. Unfortunately, detailed data on interest rates charged by the banks were not available.

Exhibit 3-6

SUBSIDIES TO OIL THROUGH INTERNATIONAL LENDING PROGRAMS
(Millions of U.S. Dollars)

	Eximbank	OPIC
Direct Subsidies (Note 1)	2,134	110
Intermediation Benefits (Note 2)		
Commitments Outstanding, 1995		
Loans	5,445	
Loans and Guarantees		6,149
Guarantees and Insurance	42,194	
Insurance		16,038
Total	47,639	22,187
Minimum Intermediation Subsidy		
1% Interest Rate and Premium Benefit (Note 3)	476	222
Total Subsidies		
Low Estimate (Note 4)	2,134	110
High Estimate (Note 5)	2,610	332
Estimated Subsidy to Oil (Note 6)		
Low	197	10
High	241	31

Notes:

(1) Direct subsidies (i.e., bank losses) include administrative costs that are not recovered through the rates charged by the bank to its clients, plus uncovered losses on loans, guarantees, and insurance.

(2) The intermediation benefit includes interest rate savings to private borrowers resulting from government guarantees, the government's lower cost of capital, and its non-profit status.

(3) The one percent value follows the practice utilized by the OECD in in its subsidy analysis. Actual savings to borrowers in the oil industry are likely to be larger, as shown in Exhibit 3-5.

(4) Includes only the direct subsidy (i.e., bank losses)

(5) Includes the direct subsidy plus intermediation benefits.

(6) Pro-rated by oil's weighted average share of loans, guarantees, and insurance commitments.

Sources:

Annual Reports: Overseas Private Investment Corporation (1992-1996) and Export-Import Bank (1995).

Douglas Koplow, "Table: Value of Government Intermediation in Borrowing," *Federal Energy Subsidies: Energy, Environmental and Fiscal Impacts, Appendix B,* April 1993, p. B7-4.

Ronald Steenblik, Organisation for Economic Cooperation and Development, personal communication, February 25, 1998.

3.6 CONSUMPTION SUBSIDIES

The primary program used to subsidize oil consumption is the Low Income Home Energy Assistance Program (LIHEAP), run by the Department of Health and Human Services. As its name implies, LIHEAP helps low-income households to heat and cool their homes. Part of the funding also supports weatherization assistance. Although not directly targeted at oil, about $275 million in LIHEAP funds were used to purchase the fuel in 1995. An increased emphasis on weatherization in the short term could help reduce the need for subsidized oil purchases over the long term.

3.7 SUMMARY

Numerous federal agencies provide services of value to the oil industry. Some of the most valuable subsidies, such as loan guarantees, are also among the most difficult to track and quantify. Federal programs providing research and development support, basic industry information, industry oversight, transportation infrastructure, export financing, and consumption subsidies provide between $1.5 billion and $1.6 billion per year in subsidies to oil. These subsidized services reduce the cost of oil-related investment and consumption while increasing the federal budget deficit.

DEFENDING OIL SUPPLIES — CHAPTER 4

The United States needs oil. Despite some progress on alternatives, oil continues to fuel our transportation fleet and our military. However, much of the nation's oil is transported through fairly precarious means. Approximately, 25 percent of our domestic crude flows through the Trans-Alaska Pipeline System, and about 45 percent of our total petroleum consumption is transported through a limited number of oil tanker channels.[43,44] These delivery systems are vulnerable to disruption.

Markets react in three primary ways to vulnerable supplies. First, they demand a higher price to reflect the higher risks. Second, they invest in approaches to make the supply less risky. This includes diversification of suppliers, the development of new supplies, the establishment of stockpiles to cover demand if supply is interrupted, and the attempt to reduce the likelihood of supply disruptions. Third, markets develop substitute materials and ways to use the limited supplies more efficiently.

In the oil industry, corporations have invested in diversifying their supply base across countries. However, it has been the United States government, rather than private firms, that has developed the largest stockpiles (such as the Strategic Petroleum Reserve, described later in this chapter) and spent billions of dollars in defense costs to reduce the likelihood of supply interruptions and price shocks. Because the government has borne these costs of securing supply, they are not reflected in the current price of oil. Thus, producers and consumers lack important price signals that would encourage investment in substitutes. The government's costs act as a subsidy to oil. We estimate the costs of defending oil shipments and stockpiling reserves for our base year, 1995. This estimate has two elements: defending oil shipments from the Persian Gulf and the costs of building and maintaining the Strategic Petroleum Reserve. We also qualitatively discuss oil-related military activities within Alaska. In order for markets to make well-informed decisions between energy types, these costs should be reflected in the price we pay for oil.

[43] U.S. General Accounting Office, *Trans-Alaska Pipeline: Ensuring the Pipeline's Security*, GAO/RCED-92-58BR, November 1991, p. 5.

[44] Net petroleum imports account for approximately 45 percent of U.S. petroleum products supplied. See U.S. Energy Information Administration, *Annual Energy Review, 1996*, Table 5.7.

4.1 MIDDLE EAST OIL SECURITY

Although the Middle East supplies approximately 27 percent of the world's crude oil, the bulk of its production goes to Europe and Japan, not to the United States.[45,46] Nevertheless, the United States is not insulated from the market impacts of disruptions in Persian Gulf oil production. The current market share of the region's producers, as well as their share of known, low-cost reserves, influence markets. Changes in Middle East crude prices strongly affect world oil prices, and with them the United States.

Given the importance of oil in the world economy, events in the Middle East can severely impact economic stability worldwide. The economic importance of the region and its traditional instability have motivated a large U.S. military focus on the Middle East, and this focus has been clearly linked to oil even by Department of Defense personnel.[47] The protection from price spikes that DoD provides greatly benefits oil consumers worldwide. A separate question is whether the military's presence in the Middle East also benefits producers. To some degree, the answer is yes. The military presence protects industry investments in oil extraction and shipping infrastructure from hostile action. This protection directly reduces the cost of regional operations. However, price stability can hurt some producers in the short-term who would benefit from the price surges that sometimes accompany supply disruptions. In addition, the military's activities related to the Middle East clearly hurt domestic oil producers in the short-term, since they must compete with imports that do not reflect the military defense component in their delivered cost to U.S. markets. [48]

---

[45] This figure is based on a ten year weighted average for the period 1986 to 1995. The Middle East's share of oil production rose more than eight percent over that period, to approximately 30 percent in 1995. See U.S. Energy Information Administration, *International Energy Annual 1995*, December 1996, Table 2.2.

[46] In 1995, the United States had net petroleum imports from the Persian Gulf of 1.563 million barrels per day versus 3.365 and 3.979 million barrels per day for Europe and Japan, respectively. See U.S. Energy Information Administration, *International Petroleum Statistics Report*, September 1997.

[47] Joshua Gotbaum, DoD's Assistant Secretary of Defense for Economic Security, was very candid about DoD's role in securing oil supplies and defending economic security in his testimony before the Senate Committee on Foreign Relations. In his prepared statement he wrote: "As this committee is only too well aware, the economic health of our Nation and its allies has on several occasions been severely affected by events in the Middle East, and their effect on oil supplies and prices. And it is the need to defend against military threats to such national interests that gives rise to the second perspective from which DoD must address the issue of U.S. dependence on stable global oil markets. The Department of Defense must be prepared to protect U.S. interests around the globe, wherever they may be threatened. This requires that we maintain the forces necessary to deter or defend against aggression. One of the key challenges that we face today is determining the appropriate strategy and force structure for the post-cold war era and to manage properly the drawdown of our forces without sacrificing the readiness to respond to threats in an increasingly complex world. And while that force structure is not predicated on meeting any single military threat, or protecting any single national interest, protecting against military threats to global oil supplies is an important factor for which we must be prepared." Joshua Gotbaum, Assistant Secretary of Defense for Economic Security, U.S. Department of Defense, *United States Dependence on Foreign Oil*, hearing before the U.S. Senate Committee on Foreign Relations, Senate Hearing 104-21, March 27, 1995, p. 24-25.

[48] The long-term impacts are less certain, as long-term volatility in prices could lead to permanent shifts away from oil, hurting the interests of all producers, both domestic and foreign.

In the following section, we quantify the subsidy from oil defense in the Persian Gulf. Deriving this estimate entails two main steps: estimating total U.S. military spending in the region and pro-rating an appropriate share of this spending to oil. Both of these steps are fairly complicated, and we discuss them in detail below. In addition, we evaluate which sectors of the oil market are most likely to benefit from the subsidy.

4.1.1 Military Spending in the Persian Gulf

Estimating the military costs for ensuring the security of the Middle East oil supply is not a clear-cut task. The Department of Defense neither reports its expenditures by geographic area nor by military objective. However, DoD and private researchers have provided estimates of defense costs for the Middle East region. They have used three main methods to do so:

- **Total Cost Approach.** The total cost approach allocates the military's entire conventional force budget geographically. The approach pro-rates the budget according to the estimated percentage of the military's active force structure that serves objectives in a region.[49] Thus, it considers the distribution of active combat units as a proxy for the geographic allocation of all defense resources, including general costs such as training and headquarters support. The approach generally uses routine, peacetime operations to avoid temporary biases caused by periodic regional flare-ups. However, some researchers add a premium for war risks, reflecting the expected value of a war occurring in any particular year.

- **Partial Cost Approach.** The partial cost approach estimates the full value of all operations that directly benefit the military's objectives in a region. It is the sum of the force, equipment, and support costs that serve the region. Unlike the total cost approach, it does not attempt to allocate the portion of DoD's budget that serves the military's activities as a whole.

- **Marginal Cost Approach.** This approach tries to assess the degree to which military spending would decline if there were no longer any objectives in a region. The estimates vary depending on whether one includes only short-term changes in operations or both short and long-term changes. In the short-term, cost savings include only the costs of operations that are dedicated exclusively to the region and are not useful for meeting objectives elsewhere. In the long-term, the military may realize added savings by restructuring to more efficiently fulfill remaining objectives. Thus, differences between the short-term and long-term marginal costs of an objective can be substantial. In addition, the marginal

[49] The total cost approach requires that combat units be assigned to individual regions. In reality, the military does not follow such rigid geographic assignments. Units may serve objectives over a broader area. In addition, they are often useful for meeting contingencies elsewhere. Under the total cost approach, they are generally assigned to the regions that are perceived as their primary areas of concern.

cost approach varies as to whether direct costs in the field alone are included, or whether support provided at the headquarters level is included as well.

Exhibit 4-1 lists the primary estimates for the cost of the military presence in the Gulf. To improve the comparability of estimates made in different years, we scaled the values to standard 1995 dollars using the GDP implicit price deflator. Once this adjustment has been made, the Persian Gulf total cost estimates range between $50 and $79 billion per year.[50] GAO's partial cost estimate adjusts to $31 billion annually, and CRS's estimate of short-term marginal costs adjusts to roughly $500 million annually.[51]

The GAO and CRS estimates are based on numbers provided by DoD that may be inaccurately low. DoD's numbers reflect costs in the 1980s, but DoD's presence in the Persian Gulf appears to have increased since then (see note 51). While the CRS short-term marginal cost estimate is about $500 million for all objectives in Southwest Asia (scaled to 1995), DoD sought supplemental funding of $630 million that year for the incremental cost of heightened operations in the Persian Gulf resulting from perceived Iraqi threats to Kuwait.[52] That figure is for supplemental costs alone, and does not include any of DoD's baseline marginal costs for the region, raising questions regarding the accuracy of the estimate. Methodological issues aside, existing analyses suggest an extremely wide range of Persian Gulf defense costs -- from $500 million to $79 billion per year.

[50] Total cost estimates from Ravenal, Kaufmann and Steinbruner, and Copulos. Detailed sourcing is shown on Exhibit 4-1.

[51] We were unable to make a second adjustment for changes in real military spending for the Persian Gulf. Between 1988 and 1996, DoD reduced its personnel by 27 percent, and real military spending decreased by an equal amount. However, over that same period, DoD increased the number of personnel ashore, naval deployments, and land-based prepositioned equipment in the Persian Gulf. The increased attention given to the Persian Gulf is seen in the rising trend of Ravenal's cost estimates during the 1990s (see Exhibit 4-1). Because trends in the Persian Gulf do not appear to mirror trends in the military as a whole, simple metrics such as changes in total real military spending would not be valid as a scaling factor. Unfortunately, detailed historic annual data on the geographic attribution of force structure were not available. See (a) U.S. Department of Defense, Office of the Under Secretary of Defense (Comptroller), *National Defense Budget Estimates for FY 1998*, March 1997, Chapter 6; (b) U.S. Department of Defense, Directorate for Information Operations and Reports, "Active Duty Military Personnel Strengths by Regional Area and by Country," obtained from http://web1.whs.osd.mil/mmid/military/309hist.htm, February 13, 1998; (c) U.S. General Accounting Office, *Overseas Presence: More Data and Analysis Needed to Determine Whether Cost-Effective Alternatives Exist*, GAO/NSIAD-97-133, June 3, 1997; and (d) William S. Cohen, Secretary of Defense, U.S. Department of Defense. *Annual Report to the President and the Congress*, April 1997.

[52] Gotbaum, pp. 24-25.

Exhibit 4-1

DEFENSE OF PERSIAN GULF OIL SHIPMENTS
(Billions of Dollars)

Source	Year of Estimate	Year of Dollars	Middle East Defense Estimate (a)	Scaling Factor to 1995 Dollars (Note 1) (b)	Adjusted Middle East Defense Estimate (1995$)	Allocation to Oil (Note 2) (c)	Oil Allocation Used by the Author	Estimate of 1995 Oil-Defense (a*b*c)	Notes	Sources	Type of Estimate (Note 3)
Ravenal, estimate of peacetime spending	FY 1992	1992	50	1.078	53.9	0.333	1.0	18.0	(4)	Ravenal, 1991	Total
Ravenal, estimate of peacetime spending plus conventional war risk premium	FY 1992	1992	55.3	1.078	59.6	0.333	1.0	19.9	(5)	Ravenal, 1991	Total
Ravenal	FY1995	1995	70	1.0	70.0	0.333	1.0	23.3	(4)	Ravenal, 1998	Total
Ravenal	FY1997	1997	82	0.959	78.6	0.333	1.0	26.2	(4)	Ravenal, 1997	Total
Kaufmann	FY 1990	1992	64.5	1.078	69.5	0.333	N/A	23.2	(6)	Kaufmann	Total
Copulus	FY 1988	1988	40	1.252	50.1	0.333	0.3	16.7	(7)	Copulus	Total
CRS, marginal costs	Note 8	1990	0.4	1.151	0.5	0.333	N/A	0.2	(8)	GAO, CRS	Marginal
GAO, partial costs	Note 9	1990	27.3	1.151	31.4	0.333	N/A	10.5	(9)	GAO, CRS	Partial

Notes:

(1) Estimates are adjusted to 1995 dollars using the GDP price deflator.

(2) We allocate 33.3 percent of DoD spending in the Middle East to oil. This percentage is based on an even split of spending among DoD's major objectives in the region: ensuring regional stability, the supply of oil, and the safety of U.S. citizens. Both Ravenal and Delucchi and Murphy believe that oil accounts for a larger percentage of spending (50-100 percent), arguing that securing supply is the largest, most important mission in the region.

(3) Total cost estimates reflect all spending related to the Middle East, regardless of whether such costs potentially serve objectives in other regions as well. These estimates include a share of DoD's general costs (e.g., overhead, support, training). Partial estimates are equivalent to total costs, but without the share of general spending. Thus, they reflect spending only for those operations directly related to meeting Middle East objectives. Marginal cost estimates reflect spending that is specific to the Middle East, or the incremental spending that would disappear immediately in the absence of U.S. objectives in the Middle East.

(4) This estimate includes peacetime defense costs for the Middle East. Ravenal allocates DoD's conventional forces budget based on the peacetime

Exhibit 4-1

DEFENSE OF PERSIAN GULF OIL SHIPMENTS
(Billions of Dollars)

geographic distribution of the military's active force structure. See Exhibit 4-1a for more information about this estimate.

(5) This estimate includes Ravenal's estimate of peacetime defense costs plus his conventional war risk premium. The premium is the product of Ravenal's estimate of the costs and probability of the U.S. engaging in a conventional war in the region. See Note 4 and Exhibit 4-1a for more information about the estimate.

(6) This estimate is based on DoD's FY1990 budget authority for conventional forces. Kaufmann estimated the geographic allocation of the budget authority based on the distribution of the military's active force structure. For more information about this estimate see Exhibit 4-1a.

(7) According to Copulus, this estimate is the amount listed in DoD's 1988 budget under the category "Gulf Contingencies."

(8) This estimate reflects the incremental costs of Southwest Asian operations. Southwest Asia includes the Middle East, Sudan, Kenya, and Somalia. The estimate is based on annualized DoD spending from 1980 through 1990. Only those costs are included that DoD acknowledges it would not incur in the absence of U.S. interests in that region. See Exhibit 4-1a for more information about this estimate.

(9) This estimate reflects all costs related to objectives in Southwest Asia. The estimate is based on annualized DoD spending from 1980 through 1990. It includes spending that DoD acknowledges is "dedicated" to, "oriented" towards, or otherwise useful for missions in that region. See Exhibit 4-1a for more information about this estimate.

Sources:

Copulus, Milton R. *Answering America's Energy and Environmental Dilemma*. The National Defense Council Foundation. 1990.

Delucchi, Mark A. and James Murphy. *U.S. Military Expenditures to Protect the Use of Persian-Gulf Oil for Motor Vehicles*. Report #15 in the Series: *The Annualized Social Cost of Motor Vehicle Use in the United States, based on 1990-1991 Data*. UCD-ITS-RR-96-3 (15). University of California, Davis, Institute of Transportation Studies. April 1996.

Kaufmann, William W. and John D. Steinbruner. *Decisions for Defense: Prospects for a New World Order*. Washington, D.C.: The Brookings Institution. 1991.

Ravenal, Earl C. *Designing Defense for a New World Order: The Military Budget in 1992 and Beyond*. Washington, D.C.: Cato Institute. 1991.

Ravenal, Earl C. Personal communications, August 1997 and March 1998.

Ravenal, Earl C. *The 1998 Defense Budget*. Chapter 7 in *The Cato Handbook for Congress*. Washington, D.C.: The Cato Institute. 1997. Obtained from http://www.cato.org/pubs/handbook/hb105-7.html, February 20, 1998.

U.S. Congressional Research Service. *The External Costs of Oil Used in Transportation*. CRS Report for Congress. 92-574 ENR. June 17, 1992.

U.S. General Accounting Office. *Southwest Asia: Costs of Protecting U.S. Interests*. GAO/NSIAD-91-250. August 1991.

4.1.2 Pro-rating Total Spending to Oil

Once total spending in the region is bounded, we evaluate the portion of that spending that is properly allocable to the defense of oil supplies versus other military objectives. Defense of oil shipments from the Persian Gulf is an example of *common costs*. Below, we provide a discussion of common costs in general and how to allocate such costs across products. We then discuss common costs in the context of Persian Gulf defense. Finally, based on our discussion of common costs, we pro-rate a portion of the military's Persian Gulf operations to oil.

4.1.2.1 Treatment of Common Costs

The term "common cost" refers to a situation in which two or more outputs are produced simultaneously from the same production process.[53] The presence of the U.S. military in the Persian Gulf region, along with all of the general overhead support that makes that presence possible, is an example of such a "production process." The "outputs" are the multiple military objectives of this presence. Recently, analysts at the RAND Corporation identified three primary purposes of the military activity related to the Persian Gulf region:[54]

- Ensuring access to oil supplies
- Preserving regional stability
- Preventing the emergence of regional hegemonic powers

Common costs create challenges for allocating production costs to individual beneficiary products. What portion of the U.S. military costs for the region is properly attributed to ensuring access to oil supplies versus another, simultaneously produced objective such as preserving regional stability? The analysis by the Congressional Research Service (CRS) cited in Exhibit 4-1 attempted to answer this question indirectly using a marginal cost approach. CRS estimated savings from defense reductions if the entire Middle East were no longer a U.S. strategic interest. Their result was a paltry $500 million in annual savings out of a total presence of $31.4 billion

[53] Shared production costs are often referred to as *joint costs* rather than common costs. In fact, joint costs are a sub-set of common costs, and refer to situations in which a shared production process yields fixed proportions of outputs, such as leather and beef from a cattle operation. See Ben Johnson Associates, Inc., "Costing Definitions and Concepts," obtained from http://www.microeconomics.com/ essays/cost_def/cost_def.htm, January 27, 1998.

[54] See Graham Fuller and Ian Lesser, "Persian Gulf Myths," *Foreign Affairs,* May/June 1997, pp. 42-52. Fuller and Lesser, both with RAND, argue that supplemental objectives such as maintaining Israel's security; maintaining preferential access to Gulf markets; and encouraging political and economic reform and human rights, while beneficial, are not policy drivers for the regional military presence.

(1995 dollars), or roughly 1.4 percent.[55] The marginal savings from a change in the oil objective alone, rather than the entire Middle East, would undoubtedly be smaller still. For example, if each objective has the same marginal costs, the marginal savings from eliminating oil security would be one-third of the total, or less than $200 million per year. Even if we are to assume for the moment that the CRS did a true, long-term, assessment of marginal costs, the strong common cost attributes of the defense presence (i.e., military forces are useful for more than one objective and in more than one region) make relatively small cost savings an inevitable and pre-ordained result of the marginal analysis.

Assessing the benefit of services provided at their very low marginal cost misrepresents both the real costs and the value of this military presence. In addition, the idea that the real costs should not be attributed to individual beneficiaries at all because they are common costs contradicts standard practice in both industry and in other areas of government activity.[56] Consider, for example, expensive federally-owned dams. The dam represents a massive common cost that provides electricity, irrigation, and flood control services. Once the dam is built, the marginal cost of any of these services is near zero -- yet the fixed costs must be paid by somebody, and the government allocates these costs back to the various beneficiaries of the dam.

The issue with oil is not whether common defense costs should be allocated to beneficiaries, but the fairest method of doing so. The approaches developed to allocate common costs in other industries such as dairies and oil refineries provide some useful insights to valuing oil defense.[57]

- **Split-off points.** The production of a good or service involves multiple steps. Even where some of the steps are identical for two or more outputs, a careful assessment often reveals one or more "split-off points" where inputs (and costs) can be isolated for a single output. As shown on Exhibit

[55] The Congressional Research Service analysis is based on data developed in an earlier GAO Report. Delucchi and Murphy conclude that the GAO estimates on which the CRS marginal cost analysis is based, understated defense costs by a large margin. See (a) U.S. Congressional Research Service, *The External Costs of Oil Used in Transportation*, 92-574 ENR, June 17, 1992, pp. 23-33; (b) U.S. General Accounting Office, *Southwest Asia: Costs of Protecting U.S. Interests*, GAO/NSIAD-91-250, August 1991; and (c) Mark Delucchi and James Murphy, "U.S. Military Expenditures to Protect the User of Persian-Gulf Oil for Motor Vehicles," Report #15 in the series *The Annualized Social Cost of Motor-Vehicle Use in the United States, Based on 1990-91 Data*, UCD-ITS-RR-93-3 (15), April 1996, pp. 9-12.

[56] Bohi and Toman argue that the military outlay, "to the extent it can be associated with energy protection, may be seen as a fixed cost that cannot be altered by marginal changes in energy prices and demands. As such, it is not relevant to energy policy." (See Douglas Bohi and Michael Toman, *The Economics of Energy Security*, Boston: Kluwer Academic Publishers, 1996, p. 26.) In fact, charging oil users for this protective service would very likely have an impact on energy demand patterns, by encouraging longer term shifts away from imported oil, or to more efficient mechanisms of securing the oil supply on the part of regional producers. Whether or not these market changes would then trigger longer-term military restructuring or simply reduced missions (i.e., no need to worry about oil anymore) is a separate question.

[57] Many other industries, such as organic chemicals, meat production, timber, and coal mining, have joint and/or common costs as well. Even more industries (airlines for example) have large fixed costs and *nearly* identical production processes for different products or services provided.

4-2, the split-off point for the military presence in the Persian Gulf divides the baseline presence from the objective-specific activities both in the field and at the headquarters level.

To the extent that the cost of defense analysts in DoD's Washington, DC office who are focused on oil security can be identified, these costs are properly allocated only to the oil-defense mission objective. Similarly, when the Persian Gulf force undertakes actual missions, if these missions are associated with oil rather than one of the other objectives, the costs are also properly attributed to oil. A similar line of reasoning would be used for costs specific to other objectives as well. The remaining multi-objective (common) costs would be smaller than the total, but would nonetheless need to be allocated across the objectives.

- **Bounding Common Costs.** Although common costs are impossible to allocate precisely, economists have developed some rules that help bound the reasonable costs attributable to a single output. These conditions state that the costs allocated to any activity should never be:[58]

  - Less than the costs that would be saved by discontinuing that activity (i.e., its incremental cost), nor

  - More than the costs that would be incurred if only that activity was undertaken (i.e., its stand-alone cost).

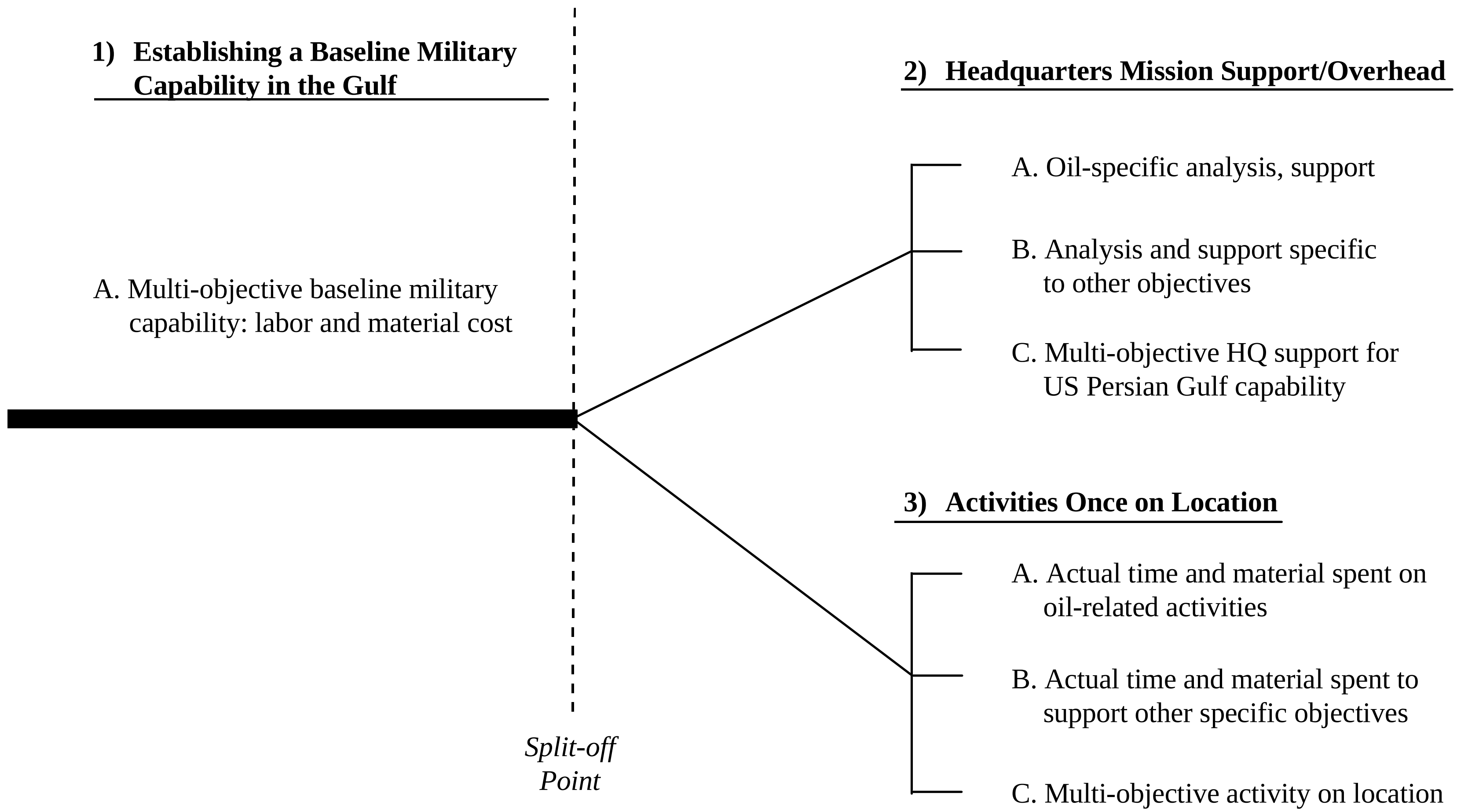
Thus, the CRS estimates for the cost of oil defense (which we estimate as one-third of the CRS estimate for total incremental costs in the region) form the absolute *lower bound* for oil-related defense costs.[59] The upper bound, the stand-alone cost, would be equivalent to all oil-

[58] These bounding statements are referred to as "Baumol-Willig" conditions, after the economists that developed the argument. See Zolton Biro, "Cost Allocation in Principle and Practice," London Economics, Ltd., October 1994, obtained from http://www.londecon.co.uk/pubs/comp/costall.htm, January 27, 1998.

[59] The use of the CRS estimate as a bounding value is complicated by a number of factors. First, the CRS measured the marginal cost of all Persian Gulf defense, not just the oil objective, although we have used their results to estimate a marginal cost for oil defense alone. Second, their numbers seem to be downwardly-biased since they appear to examine only immediate savings rather than savings from longer-term restructuring, and because they do not appear to have evaluated the marginal costs for Persian Gulf defense outside of the region (e.g., in headquarters). In addition, they originate with DoD, which is not a disinterested source. As Ravenal puts it: "When attempting to justify its entire defense budget request, or when demonstrating to our allies that we are paying a disproportionate share of the costs of an alliance, the Pentagon prefers to state its costs fully. But when defending against proposed cuts, it claims that deleting this or that unit or program from the force structure or the budget would save only the tip of its marginal costs." (Ravenal, 1991, p. 19).

Exhibit 4-2

COSTING OVERVIEW OF DEFENDING PERSIAN GULF OIL



KEY

- Common costs requiring allocation = 1.A. + 2.C. + 3.C.
- Incremental cost of oil defense = 2.A + 3.A.
- Stand-alone cost of oil defense = 1.A. + 2.A. + 2.C. + 3.A. + 3. C.

specific costs, plus all multi-objective baseline costs, since these costs would be the same for one objective (oil defense) as they are for several objectives. The stand-alone cost would likely be over 95 percent of the total costs of the Persian Gulf presence.[60]

4.1.2.2 Allocating Common Costs Across Multiple Objectives

To determine a fair way to allocate costs among the various military objectives, consider a less complex example than Persian Gulf defense -- that of a dairy. The cost of buying, housing, and feeding the dairy herd must be recovered from the sale of milk if the farmer is to stay in business. Yet, a dairy takes in raw milk and converts it into a variety of products such as skim milk, cream, and cheese. The processing costs after the split-off point (the creation of new products from raw milk) may well be small relative to the common costs of caring for the herd. If none of these products are saddled with the costs of looking after the herd, the dairy will underprice its output and not earn enough revenue to survive as a business. Yet, if any particular product is loaded with too large a share of the common costs, that product will not be competitive in the market.

Determining how much of the common cost should be allocated to each product is not a perfect process. According to one practitioner, "the most to be expected is an allocation method that produces reasonable and equitable results."[61] There are, however, a few common methods used. These approaches rely on pro-rating the common costs based on the ratio of one product to the total products produced. This ratio may be based either on some variant of the value in the market of the goods produced, or on the relative physical quantities (e.g., pounds of cheese versus pounds of milk).[62] Some complex industries do not allocate the common costs at all, simply viewing their residual earnings (revenues less output-specific costs) as "contribution to joint/common costs and profit". If their residual earnings are too low, they adjust their production and pricing decisions accordingly. Each approach relies on the ability to measure the market value and/or quantity of the goods produced. Thus, they are of limited application to the allocation of a non-traded service such as defense.

[60] Assuming the incremental costs for the other military objectives are similar to those for oil defense ($100 million each), the stand-alone cost of oil defense would only be about $200 million per year less than the total cost of the Persian Gulf military presence.

[61] Ben Johnson and Associates, op. cit.

[62] Revenue-based approaches include the sales value at split-off [(quantity of product A x sales price)/(market value of all products produced)]; the estimated net realizable value (same as above, with the sales price reduced by the separable product costs after the split-off point); the constant gross-margin percentage net realizable value (same as estimated net realizable value approach except that revenues from each product are reduced by a gross margin as well as separable costs, with the gross margin equal to that earned on all products co-produced). See Charles Horngren and George Foster, *Cost Accounting: A Managerial Emphasis, 7th Edition*, Englewood Cliffs, NJ: Prentice Hall, 1991, pp. 529-536.

Another common approach for recovering fixed costs is that of *Ramsey pricing*. Stated simply, a Ramsey pricing approach allocates fixed costs based on the relative strength of demand for the products co-produced. That is, if people really need/want the product, they end up paying a much higher share of the fixed costs. A good example of this is the airline industry. The fixed costs of a business and a leisure traveler are virtually the same: reservations system, gate agents, baggage handling, plane, crew, and fuel. The business traveler gets a few extra perks -- primarily more flexibility in changing tickets -- but the cost implications of these differences are quite small. Yet business travelers, because they need the service more (they have to get transportation on short notice and cannot wait for later flights) end up paying three to four times as much for the same passage.[63] Thus, the business traveler pays a much higher proportion of fixed costs than the leisure traveler.

4.1.2.3 Allocating Persian Gulf Costs to Oil Defense

While the bounding conditions can sometimes narrow the range of uncertainty for allocating common costs substantially, they provide little help in the allocation of common costs of oil. If we take the oil share of the CRS assessment (despite the limitations discussed in note 59) to be the absolute lower bound of the cost of defending oil (the "incremental cost" parameter), we reach a value of less than $200 million per year. If we assume that the incremental cost of the other regional objectives is similar (assuming three primary objectives), we generate an upper bound "stand alone" condition for oil of nearly $70 billion annually.[64] That the truth stands somewhere in the middle is hardly helpful, as the possible range is so wide.

The Ramsey pricing model is perhaps the most applicable to oil defense. The three primary objectives that we outlined above (preserving regional stability, ensuring access to oil supplies, and preventing the emergence of regional hegemonic powers) appear to be interrelated. Demand for all three "products" fluctuates depending on the relative state of unrest in the region. For example, concern for the three objectives increased dramatically after Saddam Hussein invaded Kuwait. During periods of relative stability, demand for the three objectives decreases somewhat, but they continue to be policy drivers in the region. Because we have no means of judging each objective's relative share of total demand for "defense services," we allocate common costs equally between them. This allocation yields cost estimates for oil defense of $10.5 billion to $23.3 billion dollars in 1995.[65] In contrast, one prominent defense analyst believes that nearly all of the costs should be attributed to oil, resulting in estimates three times

[63] In economics terminology, the business traveler has a more inelastic demand for travel services than the leisure traveler.

[64] The upper bound is calculated using Ravenal's 1995 estimate of $70 million. Ravenal made an estimate of $79 million for 1997, but we do not use this value because it includes increases in spending since the base year of our analysis. Earl C. Ravenal, personal communication, March 1998; Earl C. Ravenal, "The 1998 Defense Budget," Chapter 7 in *The Cato Handbook for Congress*, Washington, D.C.: The Cato Institute, 1997, obtained from http://www.cato.org/pubs/handbook/hb105-7.html, February 20, 1998.

[65] Due to the methodological problems associated with using a short-term marginal cost approach for a service with large common costs, we exclude the CRS figure from our range.

higher than we report.[66] Yet, even our conservative estimates demonstrate the importance of oil defense in reducing the delivered cost of oil to the U.S., Europe, and Japan.

4.1.4 Identifying Beneficiaries of the Subsidy Within Oil Markets

There are two central issues regarding the beneficiaries from the defense of oil shipments. The first is whether the subsidy primarily benefits oil producers or oil consumers. This is important in evaluating how markets are likely to react were subsidies removed. The second involves dividing benefits between domestic versus foreign sectors, which addresses strong concerns expressed by domestic producers that the military spending puts them at a competitive disadvantage.

4.1.4.1 Producers versus Consumers

The benefits from Persian Gulf defense accrue to both oil consumers and producers. Delucchi and Murphy point out that as of 1992 there were at least $4 billion in U.S. petroleum investments in the Middle East, and more likely closer to $17 billion.[67] They estimate that, because of this large investment, benefits to U.S. producers are worth between 50 and 100 percent of those to U.S. oil consumers.[68] Others feel this value probably overstates benefits to producers.[69] Despite the uncertainty regarding which sector benefits most, it is apparent that both oil producers and consumers benefit in a substantial way from the military presence.

4.1.4.2 Domestic versus Foreign

Analysts have taken two main approaches to weighing the domestic versus foreign benefits of our Persian Gulf defense activity. Some have argued that the military's central interest in oil security is to protect domestic consumers from oil price shocks. Given the interest in insulating domestic markets, some have argued that the entire cost of the military defense should be allocated to domestic oil consumption.

---

[66] Earl C. Ravenal, personal communication, March 1998.

[67] This figure includes investments made by foreign subsidiaries of U.S. firms. See Delucchi and Murphy, pp. 16-17.

[68] *Ibid.*, p. 16-17.

[69] Ron Steenblik, OECD, personal communication, February 20, 1998.

Other analysts point out that the price stability provided by the U.S. presence benefits oil consumers throughout the world, not just domestic markets. In reality, price stability even for foreign producers provides some indirect benefits to the U.S., since in an international trading arena the U.S. could still suffer from price shocks affecting our key trading partners. Our summary metrics in Chapter 7 incorporate both perspectives.

4.1.5 Persian Gulf Defense Results and Summary

We estimate that defending Middle East oil costs U.S. taxpayers between $10.5 and $23.3 billion annually. While these estimates are higher than reported by the Department of Defense, which uses a faulty short-term marginal cost approach, they are lower than estimates made by independent analysts.

Beneficiaries of the oil defense subsidy include both domestic and foreign oil producers and consumers. The Persian Gulf defense costs are quite large, representing the single largest subsidy to the oil fuel cycle in our analysis. This spending helps to stabilize world oil prices, and should therefore be seen as purchasing a benefit: protection from major price swings in petroleum and security for key petroleum investments in the region. Because this benefit is being purchased by the taxpayer rather than by oil producers and consumers, important price signals to conserve oil and shift to other energy sources are being lost. U.S. policy should recover defense costs in the same way they recover other common costs such as dam construction: through user fees. Only then would the price of oil from the Persian Gulf begin to reflect more fully the resources now expended to make it available to consumers throughout the world.

4.2 ALASKA DEFENSE

Alaska is another region that has vulnerable oil supplies and may benefit from a military presence. As with the Persian Gulf, the military accomplishes multiple objectives with a core presence in Alaska, and budget data are not available to analyze in detail which costs are properly attributed to oil. The Alaska presence also differs somewhat from the Persian Gulf since the region is under domestic control and supply disruptions may be less likely.

Alaska accounts for nearly 25 percent of total crude oil production in the United States, and most of that oil travels approximately 800 miles from the North Slope, via the Trans-Alaska Pipeline System (TAPS), to a tanker terminal at the Port of Valdez on Prince William Sound. The quantity of North Slope production and the importance of oil to the United States economy make the Alaskan oil supply a key strategic asset and an obvious target for enemies of the U.S. Yet, securing the full length of the Alaskan pipeline is an enormous challenge, if not impossible.[70]

[70] U.S. General Accounting Office, *Trans-Alaska Pipeline: Ensuring the Pipeline's Security* , pp. 5 and 15.

Officially, Alyeska, the company that operates TAPS, is responsible for the pipeline's security. Alyeska maintains its own security force, which performs a combination of live visual surveillance and video and aerial surveillance. Although federal and state agencies are not directly responsible for daily security measures, the Federal Bureau of Investigation, Department of Defense, Alaska National Guard, and Alaska State Troopers serve as reactionary elements that would respond to security incidents that are beyond Alyeska's capabilities. The Federal Emergency Management Agency would be involved in the event of a natural disaster.

The military representatives that we contacted in Alaska stressed that the security of TAPS is the sole responsibility of Alyeska, and that the U.S. military does not engage in security operations.[71] One representative from Elmendorf Air Force Base's Public Affairs Office flatly denied that ensuring the security of the oil supply is among the military's objectives in Alaska, suggesting that none of the common costs of the Alaska defense presence should be allocated to oil.[72]

Historically, Alaska was considered a front line of defense during the Cold War due to its proximity to the former Soviet Union. As such, military personnel in Alaska noted that it was the focus of many Cold War defense operations. Today, the state is a useful base for operations not only in the former Soviet Union, but in Asia as well. Defense personnel there also pointed out that the military has a strong interest in the region simply because Alaska is U.S. territory and home to U.S. citizens.[73] Yet, our research indicates that Alaska's role as a large oil producer receives consideration from the government and defense community, and that the federal (and perhaps also the state) government does incur costs related to the defense of Alaskan oil shipments.

Unlike the Persian Gulf situation, federal and state agencies do not appear to be directly involved in the daily security of the Trans-Alaska Pipeline. Furthermore, the Department of Defense does not explicitly allocate its spending and activities in Alaska among differing objectives such as defense of natural resources, United States citizens, and United States borders. However, our research found the following examples of federal involvement in Alaskan oil security:

---

[71] Sergeant Mike Jones, Elmendorf Air force Base, Public Affairs Office, personal communication, September 10, 1997. Lieutenant Colonel Stanley J. Dougherty, U.S. Department of Defense, Alaska Command, personal communication, August 27, 1997. Ed Barubie, Comptroller, U.S. Department of Defense, Alaska Command, personal communication, September 10, 1997. Captain Tanner, Alaska State Troopers personal communication, August 19, 1997. Jerry Bosie, Joint Pipeline Office, personal communication, September 3, 1997.

[72] Sergeant Mike Jones, personal communication, September 10, 1997.

[73] *Ibid*.

- The Alaska Command of the Department of Defense maintains plans for assisting Alyeska security in the event of a hostile action. Likewise, the Federal Bureau of Investigation maintains plans for responding to terrorist activities involving the pipeline.[74]

- The Defense Investigative Service of the Department of Defense performs vulnerability assessments of industrial facilities that are considered essential to the nation's defense. Once its assessments are completed, the Department of Defense develops plans to defend the individual facilities. As of six years ago, the Department of Defense had nominated several TAPS facilities for "key asset" designation.[75] Defense Investigative Service personnel were unwilling to confirm whether these facilities had ultimately been designated.[76]

- The Department of Defense's Alaska Command conducted training exercises in 1985, 1987, and possibly in other years under Operation Brimfrost for the Alaska pipeline's defense.[77] Operation Brimfrost was replaced by Operation Northern Edge in 1993. Although the Alaska Command has not conducted pipeline defense exercises under Northern Edge, it initiated harbor defense exercises in 1995. Valdez, the transfer point for oil from the pipeline to tankers, is one of the ports that has been used for these harbor defense exercises.[78]

While some of these activities may have involved oil-related infrastructure simply because they provided a useful stage for training missions, others are clearly baseline support related to oil security. Unfortunately, much of the data needed to assess the spending on oil-related activities is unavailable. As a result, we were not able to prepare a quantitative estimate.

[74] U.S. General Accounting Office, *Trans-Alaska Pipeline: Ensuring the Pipeline's Security*, pp. 5 and 15.

[75] *Ibid.*

[76] Leslie R. Blake, the Manager of the Defense Investigative Service's Office of FOIA & Privacy responded to our request for information, but that response did not address our questions. She forwarded our request to the Commander of the U.S. Forces Command at Fort McPherson, Georgia. We did not receive any response from that organization. Leslie R. Blake, Manager, U.S. Department of Defense, Defense Investigative Service, Office of FOIA & Privacy, personal communication, September 12, 1997.

[77] U.S. General Accounting Office, *Trans-Alaska Pipeline: Ensuring the Pipeline's Security*, p. 11.

[78] Lieutenant Colonel Stanley J. Dougherty, personal communication, August 27, 1997. Ed Barubie, personal communication, September 10, 1997.

4.3 STRATEGIC PETROLEUM RESERVE

Many sectors of the U.S. economy are dependent on oil, and much of this oil is imported. An absence of alternative fuels makes the nation's economy vulnerable to rapid changes in the price and availability of crude. As noted by DOE's Deputy Secretary, "Disruptions in global oil markets and energy price shocks have been followed by recessions three times in the past 25 years."[79]

The Strategic Petroleum Reserve (SPR) was initiated in 1975 with the stated mission of protecting the United States from oil supply shocks that could potentially result from political, military, or natural causes. As of 1995, the existing storage capacity within the Strategic Petroleum Reserve was 680 million barrels, with a drawdown capacity (i.e., rate at which oil can be removed) of 3.9 million barrels per day.[80] By protecting consumers and refiners from oil market disruptions, SPR reduces both the need for private sector entities to establish their own inventories and the incentives for oil consumers to increase their ability to shift fuels in times of oil shortages.

4.3.1 Estimating the Annual Subsidy to SPR

The cost of SPR is commonly depicted in government publications as comprising the cost of building and maintaining the storage facilities, operating the facilities on a day-to-day basis, and purchasing oil. While all of these items are important cost elements, they present only a small part of the real cost of SPR to taxpayers.

As shown in Exhibit 4-3, we estimate the cost of providing SPR between $1.6 and $5.4 billion for 1995. These estimates are based on two different approaches. The first is an annualized cost approach that assumes SPR can write off its unpaid interest each year instead of accumulating greater debt. Depending on the interest rate used, this approach yields estimates of $1.6 billion to $2.2 billion for 1995. The largest single component of these costs is the imputed interest charges on the more than $16 billion spent to purchase oil since 1976. The second largest cost item is the financing cost on funds invested to build and maintain the capital infrastructure. Neither of these cost elements are accounted for in the government's financial reports.

[79] Elizabeth Anne Moler, Deputy Secretary, U.S. Department of Energy, testimony before the House Subcommittee on Energy and Power of the Committee on Commerce, September 16, 1997, obtained from http://www.fe.doe.gov/remarks/916moler.html, February 25, 1998.

[80] This capacity was reduced from 750 million barrels and a drawdown of 4.5 million barrels per day due to the closure and decommissioning of the Weeks Island storage facility. See U.S. Department of Energy, *Strategic Petroleum Reserve Annual Report*, February 15, 1996, p. 6.

Exhibit 4-3

STRATEGIC PETROLEUM RESERVE SUBSIDIES TO OIL, 1995
(Millions of Dollars)

	Annualized Cost to Treasury	Annualized Value to Private Sector	Cost to Treasury with Compounded Interest
Management Cost	17	17	17
Facilities Operating Cost	68	68	68
Capital Depreciation (Note 1)	81	113	81
Imputed Interest Charge on Gross Capital Investment (Note 2)	208	304	
Loss (Gain) on 1995 Oil Sales	0	0	0
Imputed Interest Charge on Working Capital for Oil Inventory (Note 2)	1,187	1,737	
Incremental Compounded Interest on New Investment During 1995 (Note 3)			5
Incremental Compounded Interest on Principal and Accrued Interest During 1995 (Note 3)			5,257
Summary of Subsidy Estimates (Note 4)	**1,560**	**2,238**	**5,427**

Notes:

(1) Depreciation is based on an asset life of 35 years in the estimate of the cost to the Treasury and 25 years in the estimate of the value to the private sector.

(2) The public cost of capital equals the is based on the 30-year Treasury bond rate. The private cost is based on the weighted average cost of capital for the largest oil refineries.

(3) See Exhibit 4-4 for more information about compounding.

(4) Numbers do not add due to rounding.

Sources:

See Exhibit A-4b for the list of sources used for this analysis.

The second approach recognizes that the Treasury must pay interest each year on SPR's debt, and that it must issue new debt to pay that interest. Thus, SPR's effective cost to taxpayers includes compounding of interest (i.e., interest accruing on unpaid interest). Using this approach, we estimate the upper bound cost of SPR in 1995, $5.4 billion. As shown in Exhibit 4-3, interest charges account for virtually all of SPR's cost under this approach.

In the remainder of this chapter, we explain in greater detail how we developed each of these estimates.

4.3.2 Annualized Cost to Build and Operate the SPR

Federal accounting for SPR is done on a cash basis. Each year, funds appropriated by Congress are reported in one of three main SPR accounts: storage facility development, management, and oil acquisition. This approach is useful in assessing the cash investment within a particular year, but provides little information on the full annualized cost of SPR to taxpayers. To estimate this annualized cost, we have adjusted many of the data elements provided in SPR's Annual Report and developed estimates for data not provided. Each element of our analysis is described below. This analysis results in SPR subsidy estimates between $1.6 and $2.3 billion in 1995.

4.3.2.1 Storage Facility Development

SPR's Storage Facility Development account is used to purchase physical capital lasting for multiple years. The account includes both capital and operating costs, though these have not been broken out in SPR's financial statements. Based on conversations with reserve staff, we estimate that at least 30 percent of the costs incurred were for operations. For the 70 percent that were capital costs, we use the standard methods of accounting to spread the costs of capital purchases over time based on the annual depreciation (or wearing out) of the capital assets[81]. Our low estimate assumes assets last 35 years, while our high estimate assumes assets last only 25 years, and thus have a higher annual depreciation charge[82].

---

[81] Marycarol Shannahan, Strategic Petroleum Reserve, personal communication, April 27, 1998. The capital share was close to 100 percent of costs in 1976, dropping to roughly 30 percent in 1991 prior to the beginning of renovations. After 2000, the capital share is expected to be less than 10 percent of the facility account.

[82] The appropriate asset life of SPR appears closer to the short end of this range. Construction on SPR began in 1976; in 1991, only 15 years later, major renovations began to repair and upgrade the Reserve. Work is expected to be completed in 2000, and these investments are anticipated to last until 2025. Shannahan, personnel communication.

4.3.2.2 Oil Acquisition

The largest cost item in any single year is the purchase of crude oil for the reserve and its transportation to SPR sites. Our assumption is that this oil will eventually be sold. Thus, we do not count the funds spent on oil as a subsidy. Rather, when sales have occurred, we compare the sale price to the purchase price of the oil to estimate the nominal gain or loss on that sale.

4.3.2.3 Imputed Interest

In the private sector, unless a company's investments can grow at least as fast as the interest rate over the long-term, a private enterprise will lose money and go out of business.[83] Thus, oil held in an inventory must grow in value at the rate of interest -- or must protect such a rate of growth in other parts of the company that would otherwise be harmed if oil were not continuously available.

Many discussions of the cost of SPR focus only on annual appropriations for oil purchases and facility construction and maintenance, implicitly treating the government investment as "free" money. However, with the United States running a budget deficit during the entire duration of SPR's existence, the government has had to issue additional debt in the form of Treasury bonds to develop and operate SPR, and it must pay interest on that debt. These are real costs to U.S. taxpayers that are directly attributable to SPR; however the government omits them from SPR's reported costs.

We estimate these interest costs in two ways. First, we use the government's long-term Treasury bond interest rate (since SPR is a long-term investment). This estimates SPR's hidden cost to the taxpayer. Second, we calculate the cost of the capital if SPR were owned and operated by the private sector instead of a service provided by the government. For this calculation, we use the weighted average cost of capital (WACC) for the largest oil refining companies because low cost government debt would not be available.[84] This second approach estimates not only the hidden interest costs of SPR, but the benefit to oil markets of having this service publicly provided.

[83] Firms can, and do, survive for short periods of time without fully recovering their fixed costs of operations.

[84] We use a 5-year rolling average rate from the 30-year Treasury bond to reflect the ability to refinance debt in a market with falling interest rates. A 5-year average is used because debt can not always be refinanced immediately, and doing so is not costless. We were unable to calculate a 5-year rolling average for the private financing cost because data were not available. Instead, we assume all debt is held at 1995 interest rates. This assumption reduces our subsidy value, since 1995 rates were lower than in the previous years. Our use of the WACC for the largest oil refiners also reduces our estimate, since interest charges for smaller firms would have been even higher.

4.3.2.4 Miscalculating the Market: Declines in Asset Value

Changes in the value of past investments can complicate the analysis of SPR's annual costs. When a private firm determines that particular assets are now worth less than what they paid for them (net of depreciation), they write these assets down to reflect a best estimate of their current value. These write-downs improve the accuracy of the firm's reported financial results, but generally do not change the original financing obligations entered into in order to purchase those assets in the first place.[85] Consider the purchase of a new automobile, for which the buyer obtains a $15,000 loan. The individual may ruin the car in an accident the next day, but still must repay the loan.

SPR has two situations where asset write-downs would be appropriate, though the program does not appear to have explicitly done so:

- **Decline in the Value of Oil Inventory.** The average acquisition cost per barrel of oil added to SPR between 1976 and 1995 was $27.30. The market price of that oil in 1995 was only $17.20 per barrel, suggesting a capital loss on oil acquisition of nearly $6 billion -- even excluding the time-value of money This is currently a paper loss, as theoretically the price of oil could rise to $27 per barrel or higher prior to when it is actually sold. We have counted only losses on actual sales in our subsidy estimates, not paper losses due to the declining market price for crude, because crude prices continue to fluctuate over a fairly wide margin. However, it may be appropriate for the SPR program to write down its inventory more formally if price projections indicate full recovery of the purchase price is unlikely. If oil inventory had been depreciated each year of the 1976 to 1995 period to reflect the decline in its market value, the reported cost of the SPR program in 1995 would have increased by about $300 million.[86]

- **Defunct Physical Assets.** SPR consists of five large underground storage facilities for oil. In 1995, one of these facilities, Weeks Island, was permanently closed due to problems with oil leakage and the potential for environmental contamination. With 9.3 percent of the SPR's total storage

---

[85] Private equity investors may bear the brunt of such write-offs through reduced share values and deferred dividend payments. To the extent that share values fall and equity investors lose money, future borrowing costs are likely to rise.

[86] Marginal analyses of the cost of SPR, such as conducted by Mark Delucchi for the Union of Concerned Scientists, do not evaluate these costs because they estimate the savings in SPR costs from today going forward if motor vehicle use were curtailed or eliminated. Thus, the starting point for such analyses is today, instead of 1976, and all past subsidies for facility construction, oil acquisition, and accrued interest are ignored. While appropriate for marginal decision making, such an approach does not accurately measure the full taxpayer cost of SPR over time. See Roland Hwang, *Money Down the Pipeline: Uncovering the Hidden Subsidies to the Oil Industry*, Union of Concerned Scientists, September 1995, pp. B-1 to B-3.

capacity, the implied capital write-off is at least $237 million.[87] Increasing past annual depreciation deductions so that Weeks Island would be worth zero in 1995 would add about $12 million per year to our subsidy estimate.

4.3.2.5 Return on Investment

The U.S. government is a non-profit entity, and therefore does not seek a return on its investment in SPR. This investment, totaling nearly $20 billion with no expected payback for decades, entails substantial financial risks. If SPR were privately owned and operated, private investors would require compensation in the form of a return on their investment for taking on those risks. The fact that SPR is provided by the government rather than the private sector increases the value of the subsidy enjoyed by oil consumers. We have not estimated these additional savings to oil consumers in our analysis.

4.3.3 Cost of SPR Including Compounding of Interest

Interest payments were the largest components in the estimate of SPR's annual cost of operations shown above. Implicit in the calculations was the write-off of each year's interest bill. In reality, this is not what happens. When individuals take out a loan from a bank to buy a $15,000 car at 10 percent interest, they must pay 10 cents per year in interest for every dollar borrowed, or roughly $1,500.[88] If they fail to pay the interest in the first year, it is capitalized (i.e., added to the original amount borrowed), increasing the total debt to $16,500. Thus, in the second year of operations they would owe the bank not only interest on the original $15,000, but interest on the $1,500 in unpaid interest from the previous year. The process of paying (or earning) interest on accrued interest is called compounding.

It is worth considering compounding when assessing the cost of SPR. Given the government's fiscal deficits throughout SPR's life, the Treasury had to issue debt to provide SPR's funding, and it had to pay interest on that debt. To pay the interest, the Treasury would have needed either to receive compensation for its investment or to issue more debt, effectively requiring it to pay interest on accrued interest. As the purpose of issuing the debt in the first place was to fund SPR, this compounding of interest would be directly attributable to SPR as well.

[87] This amount is equal to 9.3 percent of our low estimate for the remaining undepreciated capital in 1995. In fact, facility development costs are unlikely to be linearly related to the storage capacity. Rather, costs per barrel are likely to be lower for larger facilities. This suggests that the appropriate Weeks Island write-off would be higher than its share of total storage capacity.

[88] The exact amount will depend on the number of times per year interest is calculated, and the number of times per year payments are made on the debt, both of which affect the annual interest charge.

If the Treasury fully accounted for SPR's costs, it would have treated investments in SPR as formal debt obligations between the program and the Treasury, and charged SPR interest to cover the actual costs incurred by the Treasury for its debt. Thus, interest would have been calculated at the Treasury's cost of long-term borrowing (since SPR requires long-term funds), measured by the average 30-year Treasury Bond rate. To pay the interest and principal on the original investment, SPR would have collected a "price-shock insurance premium" in the form of a user fee from oil consumers. If the program did not repay the interest on its debt, the unpaid interest would have been added to its overall debt burden, and the program would have begun to pay interest on both the original debt and the accumulated unpaid interest. Thus, if the Treasury fully accounted for its investment in SPR, its costs would include compounding of unpaid interest.

SPR has paid off none of its principal and none of its accrued interest since its inception. The few oil sales it has implemented have been at prices below its average oil acquisition cost, yielding capital losses. The billions of dollars tied up in SPR for as long as 20 years, with interest compounded on unpaid interest from earlier periods, provides a proxy for the total public cost of SPR if treated as a formal enterprise during its lifetime through 1995.

We used this approach to provide an alternative estimate to the annualized cost method described above. It mirrors the financial flows that the federal government actually incurred. Funds put into SPR required the issuance of Treasury Bonds, on which taxpayers paid debt. Interest not paid throughout this period required the issuance of still more debt. Exhibit 4-4 illustrates the impact of the compounding process, and shows that the interest cost alone on the accrued debt was more than $5.2 billion in 1995, far higher than our high annualized cost estimate of $2.3 billion. As principal and accrued interest increase over time, the growth in interest charges accelerates. Thus, the incremental addition to debt in 1995 greatly exceeds that during 1979 ($360 million), when the total unpaid balance was much smaller.

As is also shown in Exhibit 4-4, SPR's total debt from direct investment and compounded interest on unpaid debt was $74.7 billion in 1995. In comparison, the value of SPR's tangible assets in that year was only $10.2 billion in oil inventory (valued at the 1995 market price) and capital assets with a book value of about $1.9 billion.[89]

[89] Although the book value of capital assets may not be an accurate representation of the market value of the assets in question, we had no data with which to assess the market value. Depending on the value of alternative uses of the storage capacity, the book value may be more or less than the actual market value of the assets.

Exhibit 4-4

FULL TAXPAYER COST OF INVESTMENT IN SPR ENTERPRISE, 1976-1995
(Millions of Dollars)

A. Annual Growth in Compounded Interest

Year	Starting Principal and Accrued Interest	New Investment (Note 1)	Government Cost of Capital (Note 2)	Effective Annual Interest Rate (Note 2)	Interest on Existing Debt	Interest on New Investment (Note 1)	End-of-Year Principal Plus Interest
1976	0	314	7.61%	7.88%	0	11	325
1977	325	448	7.68%	7.96%	26	16	815
1978	815	3,182	7.95%	8.25%	67	119	4,183
1979	4,183	3,007	8.28%	8.60%	360	117	7,667
1980	7,667	(2,000)	8.88%	9.25%	709	(83)	6,292
1981	6,292	3,333	10.05%	10.52%	662	158	10,445
1982	10,445	3,875	11.05%	11.63%	1,214	202	15,737
1983	15,737	2,316	11.59%	12.22%	1,924	127	20,104
1984	20,104	809	12.21%	12.92%	2,598	47	23,558
1985	23,558	2,509	12.12%	12.81%	3,019	144	29,229
1986	29,229	108	10.98%	11.55%	3,377	6	32,720
1987	32,720	147	10.15%	10.64%	3,480	7	36,354
1988	36,354	603	9.71%	10.15%	3,690	28	40,674
1989	40,674	415	8.91%	9.29%	3,778	17	44,885
1990	44,885	564	8.48%	8.82%	3,957	22	49,428
1991	49,428	309	8.55%	8.89%	4,396	12	54,146
1992	54,146	273	8.37%	8.69%	4,708	11	59,137
1993	59,137	51	7.89%	8.18%	4,840	2	64,029
1994	64,029	207	7.68%	7.95%	5,092	7	69,335
1995	69,335	136	7.33%	7.58%	5,257	5	74,732

Notes:

(1) New investment includes all funding to SPR in a given year, including capital, oil purchases, and management costs. Within an enterprise, all of these elements must be financed either through revenues, debt, or equity. Interest calculations assume investment funds are provided in twelve equal installments.

(2) We use a five year rolling average of 30-year Treasury bond rates to calculate the interest accrual on outstanding debt. This allows for debt refinancing in the case of falling interest rates (which we assume to be costless). The effective annual rate assumes monthly compounding. Were debt instead held to term at the initial interest rates, total program costs through 1995 would have been approximately $12 billion higher.

B. Aggregate Taxpayer Cost of SPR, 1976-1995

Liabilities in 1995	
Cumulative Invested Funds, All Purposes (i.e., Debt)	20,606
Compounded Interest	54,126
Total Liabilities	74,732
Assets in 1995	
Market Value of Oil (Note 3)	10,195
Sale Price Premium (Note 4)	5,097
Estimated Book Value of Capital Assets, Net of Depreciation (Note 5)	1,932
Total Assets	17,224
Total Apparent Taxpayer Loss on SPR Investment through 1995	57,508

Notes:

(3) The 1995 market value of SPR's oil inventory is the product of SPR's end-of-year inventory (591.7 million barrels) and the 1995 average refinery acquisition cost ($17.23/bbl).

(4) The sale price premium assumes that the oil will be sold during periods of short supply when sale prices are higher than now. We assume that the oil would be sold if prices increased by 50 percent.

(5) The market value of SPR's capital assets may be higher or lower than the book value, but adequate data were not available to estimate it.

(6) The total apparent taxpayer loss for SPR is base on debt incurred for capital investments into SPR plus the compounding of unpaid interest on that debt. As the amount of debt accumulates over time, new interest charges increase in value. Incremental debt incurred in 1995 reflects the amount of new interest charged on the accumulated debt in 1995.

Sources:

See Appendix Exhibit A-4b for a list of the sources used in this analysis.

The value of oil inventory shown above fluctuates with market prices. Because SPR sales tend to occur at times of price shocks (when prices rise), the non-crisis price of oil may not be the best indicator of the Reserve's value. Our calculation ascribes a 50 percent price premium to adjust for this factor.[90] With this premium, the value of the oil inventory rises to $15.3 billion, and the value of the assets plus inventory reaches $17.2 billion.

Based on SPR's estimated debt and assets in 1995 ($74.7 billion and $17.2 billion respectively), the government's investment yielded a loss of $57.5 billion from the program's inception through 1995. This "loss" can be viewed as a proxy for the full cost to U.S. taxpayers of SPR's protection against economically damaging price spikes. As shown in Exhibit 4-3 the Exhibit 4-4: SPR Subsidy with compounding incremental cost in 1995 was $5.4 billion. As with the annualized cost approach, this estimate does not include declines in asset values, capital write-offs, or the incremental benefits to consumers of having SPR provided by a non-profit entity.

4.3.4 Strategic Petroleum Reserve Results and Summary

Maintaining a large supply of oil is far more expensive than SPR's annual reports imply. We estimate a range value for this cost of $1.6 to $5.4 billion per year, excluding unrecognized declines in asset and inventory values. The large subsidy value is due to the billions of dollars in capital that are invested in an enterprise, but do not produce income for long periods of time.

Our analysis does not attempt to answer the question of whether this program is a good or a bad investment. Even at $5.4 billion per year, SPR may be a cost-effective way for the country to protect against the many undesirable economic impacts of oil supply disruptions. Shifting full responsibility for this function to private firms may not be a feasible alternative. Because many benefits of price stability accrue to oil consumers rather than producers, it is unlikely that individual producers would voluntarily establish adequate oil stockpiles to provide the level of protection now provided by SPR. Thus, it is possible that SPR can only exist as a government service. Nevertheless, the full cost of providing this service, including financing costs, should be borne by oil consumers, rather than the general taxpayer.[91] As with the defense costs described earlier in this chapter, charging the costs directly to oil consumers will contribute to more accurate price signals that promote increased conservation and a shift to alternatives.

---

[90] While severe supply disruptions could drive up the market price of oil by more than 50 percent, the limited drawdown capacity of the reserves (3.9 million barrels per day) means that it would take four to six months to fully put SPR oil on the market. This would reduce the Reserve's ability to capitalize on the largest prices spikes, which do not tend to last that long. In addition, since the purpose of the reserve is to reduce the price spike, sales are likely to be aimed more at reestablishing price stability than maximizing sale revenues.

[91] DOE notes that the "United States is unique among oil stockpiling countries in assigning all of the cost of the Reserve to the general taxpayer. Most other stockpiling countries partially shift the cost burden to the oil industry by requiring that their oil companies maintain inventories in excess of working needs." U.S. Department of Energy, Office of Strategic Petroleum Reserve, "Opportunity for Public Comment on Strategic Petroleum Reserve Policy," *Federal Register*, April 24, 1997, obtained from http://www.fe.doe.gov/spr/sprfedrg.html on March 5, 1998.

4.4 SUMMARY

Disruptions in the supply of oil and increases in oil's price can have enormous deleterious impacts on both the U.S. and global economies. As DOE's Deputy Secretary pointed out, price shocks and supply disruptions have been followed by recessions three times in the past 25 years.[92] To protect the U.S. economy, the Department of Defense spends billions of dollars each year to ensure a stable flow of oil from the Persian Gulf, and the Department of Energy spends billions more to maintain a stockpile of oil in the Strategic Petroleum Reserve. We estimate that these measures cost $12 billion to $29 billion in 1995. Because these costs are borne by the general taxpayer, they are not reflected in the price of oil, preventing energy markets from functioning properly. Oil supply security is by far the largest area of subsidies to oil. Unless the costs of this security are borne directly by oil producers and consumers through additional user fees on oil, large distortions in energy markets and uninformed decision-making will continue.

[92] Moler, 1997.

SHIFTING ACCIDENT, CLOSURE AND/OR POST-CLOSURE LIABILITIES TO THE PUBLIC SECTOR — CHAPTER 5

The environmental and human health risks associated with different forms of energy vary in nature and magnitude. To address the risks posed by oil, production and transportation sites require decommissioning and cleanup once they are taken out of service. A substantial effort is also necessary to safeguard against accidental releases, such as oil spills, and to remediate contamination from spills that do occur. Both the procedures to manage risks and the costs of contamination impose financial liabilities. To the extent that these liabilities are absorbed by the general public, and not oil firms, they constitute subsidies to oil. These subsidies hide important information about the costs of oil and put cleaner forms of energy at a competitive disadvantage. Only by requiring oil companies to pay the full cost of oil-related risks can informed decisions and fair competition occur between oil and cleaner energy sources.

This chapter examines subsidies from three areas of oil-related liability in detail: oil well plugging and abandonment (including both onshore and offshore wells); oil spill liability; and pipeline decommissioning. We evaluate these liabilities to determine the extent to which they are internalized by the oil companies, and we estimate the value of risks that are shifted to the public sector.

These three examples speak to a much larger issue in the natural resource subsidy arena. Many industries commonly shift accident, closure, and post-closure liabilities to the state. Business enterprises are focused on the short-term: putting a plant in operation, meeting payroll, and selling what they have produced. It is often easy for oil companies to overlook the gradual build-up of environmental liabilities because most contamination does not affect immediate operations. Output is not reduced, and insurance rates do not rise, because firms generally do not have insurance for environmental contamination.[91]

[91] The availability of environmental insurance for chronic releases remains extremely limited within the U.S. See Bruce McKenney and Doug Koplow, *Improving Access-to-Capital, Site Transition, and Brownfield Redevelopment Through More Effective Environmental Risk Management*, Cambridge, MA: Industrial Economics, Inc., prepared for the U.S. Environmental Protection Agency, February 1998.

Lenders may worry that the contaminated property can no longer serve as collateral for loans; however, many of the small operations that pose the largest risks may not receive financing through banks anyway.

Accident liabilities are generally more difficult to hide. While small oil leaks may continue undetected over time, large spills attract attention. Nevertheless, firms may be able to save money by purchasing lower levels of insurance coverage than necessary. We examine the issue of oil spill liability in greater detail below.

Closure and post-closure liabilities fall into two categories. The first involves a backlog of contamination caused before environmental regulations were instituted or properly functioning. These liabilities represent subsidies to past oil producers rather than to present ones, though the environmental problems associated with them are very real. The second category involves firms' present methods of controlling their closure and post-closure liabilities. While we examine both issues of liability below, we count only subsidies to current producers in our subsidy totals.

Governments have recognized that, without action, they could well inherit the messes oil firms leave behind. Over the past twenty years, both the federal government and many states have taken increasing precautions to ensure that environmental liabilities are not ignored by operating businesses and potentially transferred to the public. Oil shippers must purchase certificates of financial responsibility, guaranteeing a pre-set level of financial coverage in case of an oil spill. A number of state and federal taxes provide supplemental oil spill funds. Certain types of processing operations are required to set aside closure and post-closure trust funds. Oil lease holders must post bonds that require a third party to pay for remediation if the lease holder itself is insolvent. Many states also levy taxes on new oil production to finance abandoned well plugging funds that help pay reclamation and remediation costs associated with defunct oil production sites. Finally, governments can use environmental litigation to recover additional costs and damages resulting from improper closure and remediation.

Despite these important steps, substantial public liabilities remain with respect to properly closing oil wells. These arise from insufficient collections to address the backlog of abandoned well sites, and from insufficient bonding levels to adequately protect the public sector from having to use general tax revenues to address future site closure and reclamation. The adequacy of financial coverage for oil spills is uncertain, as there are a number of court cases pending that could greatly affect the portion of oil spill liability borne by the general taxpayer in the event of a large spill. The liabilities associated with pipeline decommissioning are poorly characterized and did not permit a subsidy estimate.

5.1 OIL WELL PLUGGING AND ABANDONMENT

Oil is extracted from underground reserves by drilling from the surface into the oil reserve. As oil is extracted, well pressure tends to drop. Well operators often reinject fluids or natural gas into the ground to keep the well pressure up and the oil flowing. A single oil extraction well may be supported by a number of reinjection wells. All of these wells must be properly plugged at the conclusion of drilling activity in order to prevent migration of hydrocarbons or contaminated brines into drinking water resources.[92] In addition to requiring plugging, offshore wells are generally supported by an offshore platform of some sort that must be dismantled and removed at the end of production.

From the perspective of oil well operators, dismantling offshore rigs, plugging wells, and remediating any environmental damage caused during drilling are economic burdens requiring cash outlays at a time when the sites are no longer producing oil. For large oil companies, the costs are relatively insignificant. However, many wells are sold by the large companies to smaller operators as production and returns decline. The responsibility for proper closure is transferred as well. While Federal agencies will not approve a lease transfer without believing that the new owner is financially capable of properly closing the site, our analysis of existing data suggest that comprehensive financial assurance for these new owners is often lacking.

As noted above, federal agencies and most state governments require oil well operators to purchase some form of bond prior to commencing drilling activity. The bonds (or other similar financial assurance mechanisms) guarantee that the costs of properly closing wells will be paid up to the bond limit by a third party (such as an insurance company) if the original well operators are financially insolvent. Unfortunately, the effectiveness of the financial assurance requirements is hindered both by the large number of wells drilled before the rules took effect and by required levels of assurance that are too low to cover the real cost of well closures. When financial assurances are inadequate, the public bears the excess liability, a cost that is not reflected in current petroleum prices.

5.1.1 Plugging and Remediating Onshore Oil Wells

The scale of unfunded oil well closure liabilities is substantial. The owners of many oil wells are small and financially strapped. Often, they have purchased wells (and their associated closure liability) from major oil companies as well production declined.[93] Many of these owners are unlikely to have the financial resources to properly close their sites.

[92] There are a number of known cases of contamination from oil wells. See U.S. General Accounting Office, *Drinking Water: Safeguards are not Preventing Contamination from Injected Oil and Gas Wastes*, GAO/RCED-89-97, July 1989.

[93] Within the State of Texas, for example, major oil companies sell wells to large independent producers when production falls to 10 barrels per day. The large independents, in turn, sell to "mom and pop" operators when production falls to 3 barrels per day. Thus, as revenues fall and the time for closure approaches, the financial stability of the owners actually decreases. David Garlick, former head of the Oil and Gas Division of the Texas Railroad Commission, personal communication, March 13, 1998.

The Interstate Oil and Gas Compact Commission (IOGCC) estimates that 2.7 million oil and gas wells have been drilled since state-level well regulations were instituted.[94] Of this amount, IOGCC estimates that 63,400 are abandoned with no known operator (referred to as orphan wells). IOGCC estimates that, in the "unlikely" event that all of the orphan wells had to be plugged and abandoned (P&A), the cost to the public sector would be $343 million, or an average of $5,400 per well.[95] In fact, at some point these wells will have to be plugged and abandoned, and it is unclear who other than the public sector will do so.

The IOGCC data provided a starting point for our estimate of residual on-shore well liabilities. We believe IOGCC's data understate the liabilities by a large margin due to the following weaknesses:

- **Cost Data Incomplete.** Properly closing an oil well involves not only plugging and abandoning it, but also assessing and remediating any on-site contamination. In addition, full costing of this process for orphan wells includes both the payments that governments make to contractors for services and the direct equipment and personnel costs the government itself incurs to run the program. IOGCC's estimate of $5,400 per well represents a simple average of reported costs, but many states report *only* the funds paid to P&A contractors.[96] The estimate misses remediation costs and public-sector costs associated with P&A program oversight. For the subset of states within the IOGCC survey that did incorporate remediation costs into their reported data, the average full cost of well closure was between $9,500 and $19,200.[97] These costs provide a reasonable minimum target for bonding requirements at on-going operations.[98]

[94] See Interstate Oil and Gas Compact Commission, Ad Hoc Idle Well Committee, *Produce or Plug: The Dilemma over the Nation's Idle Oil and Gas Wells*, December 1996, p. 5 (cited as "IOGCC, 1996").

[95] The cost estimate for plugging a well represents the average spending per well by state funds developed to plug abandoned wells. (IOGCC, 1996, 43). Data reported by the states are somewhat inconsistent, and many do not include costs of site assessments, site remediation, or the public sector's full personnel and equipment costs for overseeing these programs.

[96] This discrepancy is exemplified by the State of Texas. While IOGCC's data for Texas show average well closure costs of only $4,300, further evaluation found that this figure includes only the funds paid to vendors for P&A services. Rough estimates for other related costs for any well requiring remediation suggest a fully costed average of over $14,000 per well. U.S. Bureau of Land Management, Oil and Gas Program, *Bonding/Unfunded Liability Review*, March 1995, p. E-16; John Tinterra, Texas Railroad Commission, personal communication, March 6, 1998; Garlick, personal communication, March 13, 1998.

[97] The subset of states comprises Pennsylvania, Ohio, and California. These states were identified based on a conversation with James Erb, Chairman of the IOGCC Ad Hoc Well Committee that prepared the *Produce or Plug* report, October 21, 1997.

[98] In 1995, BLM's Bonding/Unfunded Liability team recommended increasing the bonding level at wells on federal property to $20,000 per well. U.S. Bureau of Land Management, March 1995, p. ES-1.

- **Well Universe Incomplete**. The focus of IOGCC's analysis is on orphan wells only. Public liabilities are also affected by a host of other types of sites. For example, there are hundreds of thousands of "pre-regulatory" wells with no bonding drilled prior to the development of state regulations. The condition of many of these is poorly characterized, and it is likely that some may require additional public funding in order to address incomplete remediation or abandonment activities. In addition, there are nearly 600,000 operating or idle oil wells that appear to have bonding levels below the expected cost of full well closure[99]. For each of these wells, the public sector is acting as a *de facto* insurer.

Our estimate for the public liability for plugging and remediating onshore wells (shown in Exhibit 5-1) involves a number of steps. First, we estimate a more realistic average value for the full cost of oil well closure; this value sets the floor for appropriate bonding levels. Second, we adjust IOGCC figures for the number of wells requiring or receiving public subsidy to include both a small fraction of the pre-regulatory wells and idle and operating wells with inadequate bonding. Third, we develop a weighted average value for current bond coverage, which allows us to calculate how much higher existing bonding coverage needs to be to reach the average full cost of closure. Finally, we calculate the cost of purchasing this additional coverage in the surety market.

Throughout our analysis, we have pro-rated all IOGCC data on oil and gas wells to reflect the oil subsector only. In addition, we have separated inadequate collections to close past abandoned sites from the annual subsidy that results from unrealistically low bonding levels today. The values shown for residual liabilities on past operations have already been credited with user fees levied in many states on oil producers for well plugging and abandonment ("plugging funds").[100] Although we report liabilities for past operations, we do not count them in our subsidy totals because they represent a past benefit to producers.

Our estimates for under-bonding for existing onshore wells are likely to be too low for a number of reasons. First, we calculate existing bonding levels using the state bonding requirements for the deepest wells. Shallower wells will have lower bonding requirements, in which case we have overstated their current bonding levels. Second, we use a premium rate for on-shore bonds that is lower than the actual losses incurred on on-shore policies during the 1989 to 1993 period for which we have data. To remain viable, surety companies must collect enough in premiums to cover losses and earn a profit, which suggests they charge bonding rates higher than the 5.5 percent premium we have assumed for the average firm. Third, we use *average* liabilities as our target for an appropriate bonding level when, in fact, surety requirements

[99] David Garlick notes that many of these operators may be too financially weak to obtain or pay for bonding even if they wanted to. Garlick, personal communication, March 13, 1996.

[100] The contribution of these funds appears inadequate to fully address the total well liability. Only 13,000 wells had been plugged since the start of the funds through the end of 1994, a period of 10 to as many as 40 years depending on the state. Meanwhile, IOGCC estimates the known plugging backlog at nearly 38,000 wells. (IOGCC, 1996, p. 43).

Exhibit 5-1

PUBLIC LIABILITY FOR UNBONDED AND UNDER-BONDED ONSHORE OIL WELLS

		Well Count and Cost Data (Note 1)		Public Liability ($Millions)	
		Low Estimate	**High Estimate**	**Low Estimate**	**High Estimate**
Estimated Full Average Cost to Close an Oil Well					
Estimated plugging, abandonment, and remediation costs per well (Note 2)		$9,584	$19,246		
Historical Legacy of Abandoned Wells - No Bonding, No Current Owner					
Orphaned wells, state jurisdiction		34,147	34,147	$327	$657
Orphaned wells, federal jurisdiction (Note 3)		136	136	$1	$3
Pre-regulatory wells					
Total		425,242	559,812		
Estimated to require public funds	5%	21,262	27,991	$204	$539
Total Orphan Wells with no bonding or known owner		55,546	62,274		
Total Public Liability for Past Well Activity				$532	$1,199
Annual cost, with remediation spread over ten years				$53	$120
Less annual state collections in plugging funds (Note 4)				($9)	($9)
Net Annual Shortfall for Past Oil Activity				**$44**	**$111**
Bonding Shortfall for Existing Stock of Oil Wells					
No Bonding					
Idle wells without state approval		37,934	37,934		
Bonding Shortfall per well		$9,584	$19,246		
Bonding Shortfall, total, wells with no bonding				$364	$730
Partial Bonding					
Idle wells with state approval		81,102	81,102		
Idle wells, federal jurisdiction (Note 3)		5,633	5,633		
Active wells, state jurisdiction		500,628	500,628		
Total Oil Wells with Partial Bonding		587,364	587,364		
Weighted Average Bonding Level Across Oil Producing States (Note 5)		$6,532	$6,532		
Estimated average bonding shortfall per Well		$3,052	$12,714		
Total Underbonding				$1,793	$7,468
Total Bonding Shortfall, Partial and No Bonding				$2,156	$8,198
Estimated Cost of Bonding (Note 6)		5.5%	5.5%		
Net Subsidy					
Annual Subsidy to Existing Well Stock Due to Inadequate Bond Coverage (Note 7)				**$119**	**$451**
Annualized Cost of Remediating and Plugging Orphan Wells (Not included in aggregate estimate)				$44	$111
Total Annual Shortfall in Collections				$163	$562

Notes:

(1) Data on oil and gas wells have been pro-rated to oil based on the ratio of historic oil versus gas plugging activity.

(2) IOGCC estimates for average plugging and abandonment costs do not include remediation for many states. Values shown in this table represent an average high and an average low P&A plus remediation costs for the states within the IOGCC survey that were identified by the study's coordinator as including all necessary cost elements.

(3) The well count has been scaled to eliminate double-counting of an estimated 10 percent of wells under federal jurisdiction that are also under state oversight.

(4) The plugging fund offset was calculated using the average annual spending on well plugging and abandonment by state funds based on data in the IOGCC survey.

(5) Bonding levels vary across states. Using IOGCC survey data, we calculated the weighted average bonding level for oil producing states. The level shown represents an upper bound for two reasons. First, it assumes the highest bonding level, though in reality this level applies only to the deepest wells. Second, many operators will have a blanket bond, translating to a much lower level of coverage per well than is assumed here.

(6) Bonding rates vary by state and producer, with a range of between 1 and 10 percent according to BLM's *Bonding/Unfunded Liability Review. We have used* a simple average in our estimates, which probably understates the average premium cost. Actual national statistical data on onshore bonding losses between 1989 and 1993 shows a loss ratio of 10 percent. Long-term premiums must at least equal loss ratios plus a minimum profit margin if the industry is to remain viable. See Surety Association of America.

(7) We count only the bonding shortfall on *current* operations in our subsidy total figures, as our goal is to measure subsidies to existing operations. For industry to cover remediation and plugging costs at past sites as well, user fees would need to rise an additional $50 to $100 million per year.

Sources:

(1) U.S. Bureau of Land Management, Oil and Gas Program, *Bonding/Unfunded Liability Review*, March 1995, pp. E-16, F-18, F-20.

(2) Interstate Oil and Gas Compact Commission (IOGCC), Ad Hoc Well Committee, *Produce or Plug: The Dilemma over the Nation's Idle Oil and Gas Wells*, December 1996.

(3) James Erb, Chairman, IOGCC Ad Hoc Well Committee, personal communication, October 21, 1997.

(4) The Surety Association of America, "Countrywide Classification Experience Report, 1989-1993," in BLM, *Bonding/Unfunded Liability Review, pp. F-13 - F-15.*

normally aim to protect against above average losses.[101] Nonetheless, we estimate a shortfall in onshore bonding coverage for the current well portfolio of between $2.1 and $8.2 billion per year, which would require an additional $120 to $450 million per year in bonding premiums.

The wide difference between our high and low estimates is driven by the range we use for the total cost of well closure. By including this bonding shortfall in our calculation of federal subsidies, we are making the implicit assumption that the federal government is the insurer of last resort.

5.1.2 Closure of Offshore Oil Platforms

As noted above, the problem with oil platforms is similar to that of onshore wells: operators may not have the funds or the desire to incur substantial costs to properly shut down operations at the end of a facility's operating life. As with many onshore wells, this potential problem is exacerbated by the steady transfer of offshore leases from major oil companies to independents as production declines.[102]

As with onshore wells, possible public liability remains despite bonding requirements for offshore operators. The General Accounting Office conducted a detailed study in 1993 examining offshore drilling platforms in the Gulf of Mexico. These operations are overseen by the Minerals Management Service (MMS), the federal agency responsible for the Outer Continental Shelf (OCS) drilling program. GAO's estimates for the full cost of dismantling platforms and plugging wells under the OCS program ranged from $4.2 to $4.4 billion. Yet, GAO found that the surety bonds in place covered only 1.6 percent of this prospective liability. According to MMS, total offshore liability has since risen to approximately $5.5 billion, of which approximately $1 billion is covered by surety bonds. [103,104] Although the coverage ratio has risen from only 1.6 to 18 percent over the past four years, the potential public exposure tops $4.5 billion.

---

[101] Setting bonding at the average level of losses means that the public sector will inherit liabilities in a substantial fraction of the closures.

[102] Between 1983 and 1992, the number of independent firms operating offshore leases grew from 38 to 92, and their share of total operators grew from 61 to 77 percent. See U.S. House of Representatives, House Committee on Natural Resources, Democratic Staff Report, "Offshore Benefits," in *Taking from the Taxpayer: Public Subsidies for Natural Resource Development*, August 1994, obtained from http://www.house.gov/resources/105cong/democrat/subsidy.htm, October 1997.

[103] Both the GAO and the MMS estimates for closure are in nominal rather than net present value terms. Insurance premiums are based on nominal values as well. Expectations regarding the fraction of wells likely to be abandoned in a given year are reflected in the premium rates.

[104] The total liability includes $1.5 billion in borehole liability, $3.4 billion in platform removal liability, and $650 million in site clearance costs. Totals do not sum due to rounding. Carrol Williams, U.S. Minerals Management Service, personal communications, October 15 and October 28, 1997.

Discussions with the Minerals Management Service suggest that one reason the coverage appears so low is because many of the offshore leases are held by large, multinational oil companies. These firms, due to their financial strength, are able to self-insure for the risks associated with lease abandonment. Although they are not counted in the bonded coverage category, they pose virtually no risk of lease abandonment.

MMS does not adjust its bonding numbers for this factor, but we have tried to do so here. According to MMS, the total number of active leases is a reasonable proxy for the share of total liability held. Statistics for the 1990-96 period show that major oil companies held 1,670 of 4,862 total leases, or 34 percent.[105] Pro-rating total liabilities in the Gulf (the location of the vast majority of offshore activity) suggests that $1.9 billion of total liability is held by the majors, and assumed to be self-insured. Combining bonding levels with self-insurance suggests a total coverage of $2.9 billion and a net shortfall of nearly $2.7 billion.

Unlike the onshore wells, most of the offshore wells continue to operate. Thus, increasing the bonding requirements for owners that are unable to cover the full liability through their financial strength can address nearly all of the public offshore exposure. The cost of offshore bonding varies based on a number of factors, including the number of wells, the age of the drilling equipment, the reserves left underneath the well, the amount of collateral, and the financial strength of the owners. The cost of coverage ranges from one to four percent of the bonded amount depending on these factors. However, the one percent cost applies only to financially strong operators with full collateral for the coverage. A two percent rate is the realistic minimum for the independents.[106] These are the firms likely to make up the bulk of the unfunded liability in the Gulf. Based on a premium rate of two to four percent, addressing the liability shortfall would cost existing producers $53 to $106 million per year (see Exhibit 5-2). Currently, the federal taxpayer bears this liability, and the shortfall constitutes a subsidy to oil. It is unclear how new bonding requirements that took effect at the end of 1997 will affect the level of residual subsidy.[107]

[105] Data on lease counts were reported by MMS based on information assembled by J.M. Dodson, Inc., an independent firm that analyzes data on offshore leases. According to MMS, the share owned by the major oil firms includes all leases with *any* percentage of ownership by the majors. Joint and several liability provisions enable MMS to recover up to 100 percent of the closure and remediation costs from any owner. Williams, personal communications, October 15 and 28, 1997.

[106] Roy Die, Underwriters Indemnity Company, personal communication, November 4, 1997.

[107] MMS published a final rule stipulating higher surety bond coverage on offshore leases. It was supposed to take effect by December 1997. See U.S. Minerals Management Service, "Surety Bond Requirements Amended: MMS Issues Final Rule," May 21, 1997, obtained from http://www.mms.gov/omm/gomr, October 24, 1997.

Exhibit 5-2

PUBLIC LIABILITY FOR OFFSHORE DRILLING
(Millions of Dollars)

Total Liability for Offshore Operations		
Borehole liability	1,500	
Platform removal liability	3,400	
Site clearance cost	650	
Total Liability	5,550	
Estimated Current Bonding	1,000	
Apparent Public Exposure	4,550	
Estimated Role of Self-Insurance by Majors		
Lease Count, 1990-1996		
Major Oil Companies	1,670	
Independents	2,770	
Others	422	
Majors as a percent of total oil companies	34.3%	
Prorated Liability for Majors	1,906	
Public Sector Residual Liability		
Total Liability for the Gulf	5,550	
Coverage through bonding	1,000	
Coverage through self-insurance	1,906	
Residual public liability	2,644	
Cost for Liability Insurance	**Low**	**High**
Annual premium costs for independent producers	2.0%	4.0%
Estimated cost of covering residual public liability through increased bonding	53	106

Sources:

(1) Carrol Williams, Minerals Management Service, personal communications, October 15 and 28, 1997.

(2) Roy Die, Underwriters Indemnity Company, personal communication, November 4, 1997.

5.2 OIL SPILLS

Oil is a globally traded commodity with millions of barrels moved every day. Oil pipelines sometimes leak, and shipping vessels sometimes fail due to human error, natural events, or age.[108] The resulting spills (almost 14,000 are reported in the U.S. each year) contaminate the surrounding ecosystems.[109] While accidents are unlikely to be eliminated entirely, governments can at least ensure that the private entities profiting from the movement and sale of oil bear full liability for any spills that do occur.

The Oil Pollution Act of 1990 (OPA), passed in the wake of the large Exxon Valdez spill, establishes the primary federal requirements for oil spill-related financial assurance and liability. OPA clarified responsible parties' liability, making them directly liable for oil spill cleanups and damages to natural resources. Strict liability limits for tanker vessels were increased to eight times the previous requirements, and tankers operating in U.S. waters were required to purchase a Certificate of Financial Responsibility (COFR), demonstrating their ability to pay potential spill-related costs. While the law clarified issues of liability, it also placed limits on that liability, raising the possibility that liability caps might be too low to cover reasonably expected costs of a spill.

OPA established a two-tiered system of financial responsibility for spills. The first tier includes the COFR, with limits for any particular shipper based on the size of the ship (see Exhibit 5-3 below). Larger vessels are required to have higher coverage because they can cause larger spills. This coverage is strictly limited to the shipper regardless of fault; cargo owners are not held liable for oil spills.[110] The Coast Guard's National Pollution Funds Center administers the Certificate of Financial Responsibility program to certify vessels that provide the necessary financial assurance and to take enforcement actions against violators.

---

[108] An estimated 85 percent of all tanker accidents resulting in oil spills are due to human error. See Odd Auker Hassel, "Smooth Sailing or Rough Waters? The Tanker Industry and the Environmental Challenges," Cambridge, MA: Cambridge Energy Research Associates, 1990, p. 8.

[109] U.S. Environmental Protection Agency, Oil Spill Prevention Preparedness & Response Program, August 26, 1996, obtained from http://www.epa.gov/superfund/oerr/er/oilspill/response.htm, July 14, 1997.

[110] Nina Sankovitch, et al., *Safety at Bay: A Review of Oil Spill Prevention and Cleanup in U.S. Waters*, New York: Natural Resources Defense Council, December 1992, p. 58.

Exhibit 5-3

VESSEL AND OFFSHORE OPERATIONS LIABILITY LIMITS ESTABLISHED BY OPA

Vessel Type	Vessel Size (gross tons)	Liability Limit (whichever greater)
Tanker	300<vessel weight<3,000	$2 million or $1,200/gross ton
Tanker	vessel weight>3,000	$10 million or $1,200/gross ton
All Other Vessels	vessel weight>300	$500,000 or $600/gross ton
Offshore Facilities	Not applicable	$35 million

Sources:

(1) U.S. Coast Guard, National Pollution Funds Center, *National Pollution Funds Center 1996 Annual Report*.

(2) Independent Petroleum Association of America, "America's Oil and Gas Producers Praise Reform of Oil Pollution Act," September 30, 1996, obtained from http://www.ipaa.org/departments/communications/1996_press_releases, October 29, 1997.

COFR premiums have cost private shipping interests approximately $70 million annually.[111] However, this first tier coverage restricts their liability to a maximum of $296 million on any single spill.[112] A vessel the size of the Exxon Valdez would have a vessel liability limit of only $142 million on any single spill, far less than the billions of dollars of costs caused by a spill of the Valdez magnitude.[113]

The second tier of coverage is in the form of the Oil Spill Liability Trust Fund (OSLTF). OSTLF incurs cleanup, assessment, and restoration costs in excess of a vessel's liability limit. It also funds immediate work on a spill, allowing a rapid response despite potential problems with collecting funds from responsible parties. OPA established the Oil Spill Liability Trust Fund by

[111] Premium statistics are from U.S. Coast Guard, National Pollution Funds Center, *National Pollution Funds Center 1996 Annual Report*, p. 30. Despite strong concerns by industry that they would be unable to obtain COFR's due to the insurers' fears of unlimited liability, most tankers were able to obtain insurance in advance of the deadline. See Adrian Ladbury, "No crisis in OPA deadline: Alternative markets fill pollution coverage void for ships," *Business Insurance*, December 26, 1994, p. 1.

[112] The largest tankers are 247,000 gross tons, which translates to a liability limit of $296 million ($1,200 per gross ton). Jeff Friedel, COFR Examiner, U.S. Coast Guard, National Pollution Funds Center, personal communication, November 12, 1997.

[113] Dana Compton, U.S. Coast Guard, National Pollution Funds Center, personal communication, November 12, 1997; Darrel Nieley, Chief of Financial Management, U.S. Coast Guard, National Pollution Funds Center, personal communication, October 26, 1997.

consolidating several related precursor funds and instituting a temporary five cents per barrel tax on oil produced in or imported to the United States.[114] The tax was suspended in 1993 once the fund reached its statutory limit of one billion dollars.

The fund may be used for a host of spill-related purposes, including removal, remediation, damage assessments, administration of OPA and the fund, oil spill research and development, and payments of residual damages not recovered from responsible parties. OPA stipulates that expenditures from the fund are limited to one billion dollars for any one incident, with a cap of $500 million on damage assessments and claims. While the fund clearly provides intra-industry cross-subsidies (i.e., the costs of a spill from one transporter in excess of its liability are borne by taxes collected from other parties), it does provide a mechanism for ensuring that the second tier of coverage is provided by the oil industry as a whole rather than by the taxpayer.

The key question from our perspective is whether the combined liability limits for both tiers are sufficient to cover the costs associated with spills. If not, the public sector may bear significant residual risks. The answer to this question depends on the likelihood that a spill will exceed the cap and whether the cap will actually be enforced.

5.2.1 Likelihood of a Spill Exceeding OPA Liability Caps

In addition to financial assurance provisions, OPA included the following elements that have helped to reduce the likelihood and severity of spills.

- **Increased Penalties.** OPA substantially increased administrative, civil, and criminal penalties for oil spills.[115]
- **Improved Tankers.** OPA requires new vessels carrying oil in U.S. waters to have double hulls by 2015.[116]

[114] Congress created OSLTF in 1986, but did not provide the authorization necessary for it to collect or use funds. OSLTF was inactive until Congress granted the necessary authorization following the Exxon Valdez spill. U.S. Coast Guard, National Pollution Funds Center, *National Pollution Funds Center 1996 Annual Report*, p. 13.

[115] Administrative penalties can reach $125,000. The mandatory civil penalty was increased from $5,000 per offense to $25,000 per day and up to $1,000 per barrel of oil disposed. Criminal penalties reach as high as $25,000 per day of violation and/or imprisonment for up to a year. Knowingly discharging oil has penalties of up to $50,000 per day of violation and 3 years imprisonment. (Sankovitch et al., p. 59).

[116] Implementation issues such as the strength of the hull, the space between the hulls, and the allowed single hulling of areas carrying fuel for the ship have reduced the actual protection provided. Sankovitch et al., pp. 15-17.

- **Improved Cleanup Response.** Oil shippers must contract for oil spill cleanup equipment to be positioned and readied at various points around the country, with requirements stipulated in terms of the size of spill that can be addressed in a first, second, and third wave response.

While all of these factors help to reduce the likelihood of spills exceeding the available liability coverage, it does not eliminate the possibility. The Exxon Valdez spill cost $2 billion to clean up, with an additional damage award of billions more.[117] While the costs of an oil spill vary widely, even a much smaller spill than the Valdez could exhaust both the COFR coverage and the entire collection of the Oil Spill Trust Fund.[118] While OPA originally allowed the NPFC to petition Congress for borrowing authority from the U.S. Treasury if the costs incurred for a spill exceeded the capacity of the fund, this authority expired in 1994. Darrel Nieley, NPFC's Chief of Financial Management, was uncertain what would happen currently in such an event.[119] Some risk remains that a portion of the costs of larger spills will be borne by the taxpayer due to the caps on both the liability coverage and the Oil Spill Trust Fund.

5.2.2 Definitiveness of Vessel Liability Caps

A second central issue affecting whether OPA confers residual liabilities to the public sector involves the stringency to which the vessel liability limits are adhered. One industry trade publication noted that while OPA established liability limits, it "severely restricted the limits' applicability."[120] Since the liability limits are not applicable to spills resulting from a violation of a federal regulation or safety standard, industry anticipates that "most spills will breach OPA's defenses."[121] Fears of unlimited liability associated with spills have led to a reduction in lease financing of tankers and other lending for tanker purchases.[122] Up to a point, a higher effective

[117] U.S. Congressional Research Service, June 17, 1992, pp. 55, 58. Olivia Stewart-Liberty, "[OPA]: A Legacy of Confusion," *Asset Finance & Leasing Digest*, May 1995, pp. 24-27.

[118] Based on an analysis by Anderson and Talley, cleanup costs per ton of oil range from $1,610 to $40,880 (1995 dollars). Environmental damage costs add an additional $1,660 to $11,610 per ton spilled (also 1995 dollars). The costs per ton for the Valdez spill appear to have exceeded the upper range value in Anderson and Talley by a wide margin. While the two tiers of liability coverage appear sufficient for most spills, larger releases of over two million gallons (there have been at least five since 1976) risk depleting all available funds. Eric Anderson and Wayne Talley, "The Oil Spill Size of Tanker Barge Accidents: Determinants and Policy Implications," *Land Economics*, Vol. 71, No. 2, May 1995, pp. 216-28.

[119] Darrel Nieley, personal communication, October 26, 1997.

[120] "Tanker Owners Cope with OPA," *Oil and Gas Journal*, July 27, 1992, p. 38.

[121] "Tanker Owners Cope with OPA," *Oil and Gas Journal*, July 27, 1992. p. 38. Oil spills caused by gross negligence, willful misconduct, or a violation of a federal safety, construction, or operating regulation; or failure to report a spill, all result in the loss of the liability cap. Joanne Wojcik, "U.S. Oil Spill Law Rocks the Boat," *Business Insurance*, October 19, 1992, p. 16.

[122] Olivia Stewart-Liberty, "[OPA]: A Legacy of Confusion," *Asset Finance & Leasing Digest*, May 1995, pp. 24-27.

cap could reduce the residual liability borne by the public. However, if concerns over unlimited liability become too severe, insurers may pull out of the market, leaving the public with a much larger exposure than before.

Several spills have exceeded the responsible party's maximum liability. In these cases, the government has tried to recover the full costs of the spill from the oil shipper or its insurer. For example, the federal government has incurred costs of $82 million thus far for a 1994 spill near San Juan, Puerto Rico; however, the liability limit for the responsible vessel was only $10 million.[123] NPFC has attempted to recover the full costs incurred by the government for this and other spills, including costs in excess of the responsible vessels' liability limits. These cases are currently in litigation. Their outcomes may affirm the limitations on financial risk set by OPA or invalidate those limitations, at least under certain circumstances.

State oil spill regulations also play a role in the ultimate liability borne by the private sector. OPA allows states to implement their own liability limits. Using this authority, 30 states have their own oil pollution liability laws, and as many as 19 states impose strict *unlimited* liability on shippers. In addition, although the federal government restricts liability to shippers, some states impose liability on cargo owners and charterers as well.[124]

The impact of state laws on the federal caps also remain to be determined through litigation. A recent court decision seemed to uphold both the priority of federal liability limits over state, and the liability caps established by OPA.[125] If this ruling delineates a trend, large spills, especially if caused by independents with little market visibility and less to lose from adverse publicity following a spill, will likely be borne in part by the general taxpayer. However, given the uncertainty associated with the various ongoing cases, we assume there is no residual public liability from oil spills, and estimate the subsidy to oil to be zero.

[123] Darrel Nieley, personal communication, October 26, 1997.

[124] State rules seem only to apply in state waters. Sankovitch, p. 59; "Tanker Owners Cope with OPA," *Oil and Gas Journal*, July 27, 1992.

[125] *National Shipping Co. of Saudi Arabia v. Moran Trade Corp. of Delaware* affirmed that the shipping company's liability was capped at $500,000 based on OPA, and that the OPA cap could not be bypassed by state laws that allow greater recovery. See "Cleanup Damages for Spills Limited to Those Available Under OPA, Court Says," *Environment Reporter*, September 26, 1997.

5.3 PIPELINE ABANDONMENT[126]

Due to the hazardous material they transport, crude oil pipelines are potential sources of environmental contamination. Current regulations specify response and reporting requirements for contamination events such as oil spills; however, natural resources along pipeline routes may be contaminated from events that pre-date current regulations or from the gradual accumulation of small, unnoticed incidents. State and federal regulatory agencies have requirements for properly closing pipelines so that they do not pose continuing threats to the environment after they are abandoned. However, it is not clear that abandonment regulations fully address possible site contamination or the permanent removal of the lines.[127] Nor do they address the potential problems that may arise when operators are unable to pay for proper closure procedures.

Pipelines are regulated either by state or federal agencies. The U.S. Department of Transportation's Office of Pipeline Safety has regulatory jurisdiction over interstate pipelines, and state agencies regulate pipelines that do not cross state boundaries. Within states, pipeline regulation may fall under the responsibility of more than one agency. For example, two separate offices within the Texas Railroad Commission regulate pipelines in the State of Texas. The Pipeline Safety Office has responsibility for major lines (greater than eight inches in diameter), and the Oil and Gas Office regulates pipelines less than eight inches in diameter, which are typically gathering lines further upstream (i.e., closer to the production sites).

While cases of abandonment involving interstate and major intrastate pipelines are likely to be less common, smaller, upstream gathering pipeline systems are more dynamic, with individual lines closing as wells dry up and production shifts to other locations. We called state and federal agencies responsible for regulating oil pipelines to assess not only their pipeline abandonment requirements, but their provisions for ensuring that operators, and not taxpayers, finance closure and remediation costs. The answer from all levels of the regulatory bureaucracy was that pipeline operators must develop and provide details about their operation and maintenance procedures, including procedures for abandonment. Operators' abandonment procedures must address the issues of safely disconnecting, purging, and sealing pipelines. However, it was not clear whether states and the federal government require environmental site assessments to ensure that possible contamination is identified and remediated at the time of closure, or whether they have guidelines governing the complete removal of defunct pipelines.

[126] Information contained in this section was gathered from telephone conversations with the following people: (a) Bill Dase, Pipeline Safety Office, Railroad Commission of Texas; (b) Buck Furrow, U.S. Office of Pipeline Safety; (c) Marty Mathessen, American Petroleum Institute; (d) Paul McKey, Public Affairs, Federal Energy Regulatory Commission; and (e) John Tintera, Site Remediation Group, Railroad Commission of Texas. Conversations were held on November 6-7, 1997.

[127] The Office of Pipeline Safety (Department of Transportation) does not require pipeline operators to do site assessments and any necessary remediation at the time of abandonment; it is unclear whether some other regulatory body makes these requirements. Linda Dougherty, Compliance Office, U.S. Office of Pipeline Safety, Compliance Office, personal communication, November 10, 1997.

In the event that an operator fails to follow proper abandonment procedures, our contacts agreed that their offices would pursue operators in court, but they were generally unclear what would happen if legal action failed because the operator was insolvent or defunct. In the case of oil spills, pipeline operators must develop and demonstrate their capability to carry out response plans. However, neither the federal government nor the State of Texas requires that operators demonstrate their ability to pay future closure costs with financial assurances such as insurance or bonds. Some states, like Texas, may impose taxes on oil production to finance trust funds capable of paying cleanup and closure costs that are shifted to the state. It is not clear whether the federal government and all states have such mechanisms for shielding taxpayers from pipeline cleanup and closure liability.

Our conversations indicate that the issue of public liability associated with pipeline abandonment is poorly characterized. While regulatory agencies have procedural requirements, they apparently do not have specific financial provisions to ensure that any closure and cleanup costs remain in the private sector. The magnitude of the problem, the historical cost of contamination from pipelines, and the current availability of general trust funds to finance remediation at abandoned or insolvent sites are all unknown.

5.4 SUMMARY

Governments have implemented a number of new requirements over the past ten years to reduce the likelihood that the taxpayer will have to pay for oil-related accidents or facility closures. These are positive steps that should be continued in order to eliminate the remaining liability subsidies. For example, state and federal bonding requirements for offshore well abandonment and remediation costs should be raised to cover the remaining shortfall in coverage. Attention should be given to ongoing litigation that may have impacts on the public's exposure to oil spill liabilities, and the poor characterization of potential liabilities associated with pipeline decommissioning should also be addressed to ensure that environmental liabilities are being adequately internalized.

COST OF ACCESS TO OIL RESOURCES CHAPTER 6

Selling public resources to oil companies below fair market value reduces producers' production costs. This chapter provides a broad overview of oil leasing and the manner in which governments provide subsidies to producers through their leasing processes. In most cases, individual lease decisions will have little or no impact on world oil prices. Rather, subsidized leases increase producers' profits at the taxpayer's expense or allow otherwise uneconomic reserves to be developed. In the extreme, however, a major producing country can affect the global price of oil by allowing widespread leasing below fair market value.[128]

The environmental implications of poor leasing practices can be substantial. Even without affecting world oil prices, subsidized access to oil tends to accelerate the development of particular oil fields, amplifying the direct environmental impacts of production. If the subsidized fields happen to be in parts of the world with weak central governments and poor environmental enforcement, leasing subsidies can also displace more responsible producers in the marketplace. In addition, to the extent that lease terms do contribute to declining prices, oil consumption rises with all of its concomitant environmental impacts. Finally, subsidies in one country may put pressure on competing nations to increase subsidies to their own industries in order to maintain their competitiveness, exacerbating the problem.

The first part of this chapter provides background on leasing. The chapter then discusses the cost of managing oil production on federal lands and identifies potential lease-related subsidies. Little quantitative data are available for estimating leasing subsidies. We have provided estimates of specific subsidies where possible, and evaluate other potential subsidies qualitatively.

6.1 A GENERAL OVERVIEW OF LEASING

A lease is a sale of rights held by the public to another party for exploration and development. Leases allow the buyer to look for oil, to hold the rights for a limited period of

[128] Market prices regularly react to changes in the supply of oil. When Saudi Arabia cuts production, prices often rise. When large new oil fields come on line, prices fall. The terms of access to large new oil regions such as Kazakhstan will affect their supply costs, potentially impacting both the equilibrium price for oil and determining which fields in other parts of the world become relative high cost producers.

time without producing, and to extract and sell oil. The following are the core elements of leases:

- **Location/Size.** Oil leases carefully stipulate the location in which the purchaser may look for oil. Larger leases have higher probabilities (other things being equal) of containing oil. However, leases that are too large (or the combination of too many small ones) are considered monopolistic by the federal government and regulated.

- **Duration.** A lease is an option to look for oil in a certain place for a certain period of time. The owner can generally hold the lease without developing it for up to ten years. Once oil development has begun, the lessee typically retains the lease rights until the oil reserve is exhausted. The time cap on the period a lease can be held without producing ensures that valuable public resources are not held inaccessible by the lessee.

- **Financial Assurance.** The development of oil leases can create liabilities for the public sector owner in the form of environmental contamination, well plugging, and platform removal (for offshore locations). Lessees must post an acceptable form of financial assurance to convince the government of their ability to pay for any necessary cleanup. As discussed in Chapter 5, these assurance requirements are not always set at an adequate level.

- **Payment Terms.** There are three main components of lease pricing: royalties, rentals and bonuses.

    - *Royalties.* Royalties are a percentage of the value of production that is paid to the lease owner. They represent risk sharing between the seller and the buyer. If the well does not produce, the buyer pays no royalties. If the price of oil rises or falls, the royalty payments adjust automatically. Royalty rates vary by lease area and lessor.

    - *Rentals.* Lease rentals are "holding" charges that are paid to owners until lessees begin producing oil. Rental payments compensate owners for the time their resources are not being produced, and help to prevent firms from speculatively holding too many lease tracts. Rental rates sometimes rise as the number of years without development increases, and are sometimes recoverable against royalties owed once production begins. On federal leases, rental payments stop once production and royalties begin.[129]

- *Bonuses.* Where the value of an oil lease appears particularly large, buyers may agree to make an additional cash payment to the seller for rights to a tract. These payments are in addition to rents and royalties. Bonus payments help ensure that the seller is adequately compensated for especially valuable reserves. There is some interplay between royalty levels and bonus levels. For example, lower royalties make tracts more valuable, potentially resulting in higher bonus bids.

6.1.1 Interactions Between Payment Terms

Lease value is primarily driven by three factors: the amount of oil, the market price of oil, and the cost of extracting it from the lease and getting it to market. The projected gross revenues from a particular lease are equal to the quantity of oil to be extracted multiplied by the anticipated price per barrel. To determine the lease value, all direct costs to develop the field, extract the oil, and transport it to market must be deducted from the projected gross revenues. In addition, all levies on production, including local, state, and federal taxes, and all royalty, rental, and bonus payments are figured into the equation. Unless the residual profit is high enough, firms will not be interested in developing a lease.

This simplified overview of leasing illustrates two important points. First, the amount a firm will pay for a lease (generally reflected in the bonus payment since all other terms are fixed by the government) is determined by expected profits *after all levies.* Thus, in a competitive bidding market, charging a higher royalty rate may simply reduce the bid prices by an approximately equal amount. Second, nearly every component in the calculation of expected profits is uncertain. Oil prices may decline, or the actual oil on a site may be less than expected, both reducing the value of the field. Alternatively, extraction costs may be higher than anticipated, or government levies may change (if they have not been fixed for the life of the property in the original lease agreement).

To protect against uncertainties, bidders employ a number of strategies. First, they require a rate of return that adequately compensates them for their risks. Second, they use a portfolio approach, using high profits on successful wells to offset losses on dry ones. Third, they share risks whenever possible with the seller.

[129] Ross Gorte, *Federal Sales of Natural Resources: Allocation and Pricing*, Washington, DC: Congressional Research Service, December 16, 1993, obtained from http://www.cnie.org/nle/nrgen-2.html on October 7, 1997.

The payment terms described above represent a mix of variable payments (royalties and some bonuses) and fixed payments (rentals and some bonuses) that share the risk and rewards from oil exploration between the lessor and the lessee (i.e., the government and private companies). However, this method of risk sharing does not always guarantee an optimal outcome for either party. For example, larger fixed costs increase the risks to the buyer, but reduce the variability in revenues to the government. If a lease has less oil than anticipated, the buyer may lose money on the well.

Lease issues also extend beyond the composition of variable and fixed costs. Royalties themselves can introduce distortions in oil development. Although royalties rise and fall in dollar terms, they remain a fixed percentage of the price of oil. As a well is depleted and the cost of extracting oil rises, the required royalty payments do not change. Thus, well production may be stopped prematurely because the cost of production plus fixed royalties is too high to allow a return on the remaining recoverable oil. Reducing the royalty rate, it is argued, would allow this "marginal" production to continue until additional resources are depleted. Such reductions are commonly implemented at both the state and federal levels.

To avoid premature well closures, another oft-suggested modification to leasing rules is to use variable rather than fixed royalties, linking payments to profitability rather than sale price. Royalties would be set at lower percentages when profits from a particular well are low, and rise to higher than normal percentages when profits rise.

While variable royalties theoretically encourage more complete oil extraction from a reserve, their practical use is challenging. Although production is easy to measure, profits are much more difficult. A profit-based approach allows well operators to deduct a host of expenses from their revenues to calculate the basis of their royalty payments. They have tremendous opportunities to manipulate the calculation in order to reduce their royalties owed. This problem is demonstrated in other sectors of the economy. For example, there have been numerous legal suits in the movie picture industry over movies with hundreds of millions of dollars in "revenues" but zero "profits." To avoid this problem, industries (such as fast food) generally stick to fixed royalty structures in defining payment rates between franchises and parent companies.[130]

In the remainder of this chapter, we first discuss the cost of federal management of oil leases. We then apply the general leasing framework discussed above to identify potential lease-related subsidies for oil production.

[130] The general issue underlying these examples -- the ability for corporations to artificially manipulate profit levels to reduce their financial obligations to other parties -- also plays a central role in the taxation of international corporations. Because these firms buy and sell large quantities of goods and services among their various divisions, and can set the prices for these transactions, they can decide which part of their operations should show the profits. These prices are often set to minimize the firms' tax (or royalty) burden. See U.S. General Accounting Office, *International Taxation: Problems Persist in Determining Tax Effects of Intercompany Prices*, June 1992, and U.S. General Accounting Office, *Tax Administration: Compliance Measures and Audits of Large Corporations Need Improvement*, September 1994.

6.2 MANAGEMENT OF OIL PRODUCTION ON FEDERAL LANDS

Selling oil from public lands requires government expenditures to run lease sales, oversee exploration and drilling activity, ensure sites are cleaned up, and collect the proper royalties from lessees. The Minerals Management Service (MMS) and Bureau of Land Management (BLM) are the agencies primarily responsible for managing and overseeing oil production on public land. Other agencies, such as the Forest Service and the Bureau of Indian Affairs, are involved to a lesser degree. In 1995, MMS and BLM spent approximately $92 and $48 million, respectively, to oversee oil-related activities, of which approximately $12.5 million was collected directly from users.

Within the United States, these management costs are mostly paid from general tax revenues. However, since the federal government also collects oil royalties from the mineral sales, the management costs (net of user fees) can be viewed as the government's "overhead" to collect the revenues from the sale of oil. The question is whether, once these overhead costs are deducted from royalties, the public is receiving a fair return on asset sales. Federal timber sales are instructive. Evaluation of timber sale receipts by independent analysts suggest that the government pays more to make the timber available for sale (including building access roads) than it actually receives from sales.[131]

The overhead on oil sales is not as onerous as for timber, and there does appear to be a healthy net gain from oil concessions. Oil-related overhead costs of MMS and BLM are equivalent to about 10 percent of the $1.3 billion in oil royalties collected at the federal level in 1995.[132] Even once oil oversight activities at other federal agencies are added in, we do not anticipate the overhead rising above 20 percent of sales revenues.

6.3 KEY ARENAS FOR GOVERNMENT CONTROL OVER ACCESS TO OIL

Government involvement with oil leasing includes four main spheres of control: the initial establishment of property rights, setting (or modifying) the terms for existing oil production, setting the terms for new oil production, and ensuring that access to oil resources is competitively determined. Subsidies to producers can be provided in any of these areas. We summarize these subsidies below, and discuss each area in greater detail in the remainder of this chapter.

---

[131] According to the analysis, the government lost $375 million on timber sales held in 116 national forests in 1995. Randall O'Toole, "Forest-by-Forest Timber Sale Accounting for 1995," Thoreau Institute, obtained from http://www.teleport.com/~rot/description95.html, March 17, 1998.

[132] We do not treat oil rents, royalties, and bonuses as subsidy offsets, since they represent payment to the taxpayer for the sale of publicly owned oil assets. Nor, however, do we treat the government cost to manage oil sales as a subsidy to oil. This decision reflects the necessity of incurring some costs in order to earn the oil royalties in the first place, and the relatively low level of overhead costs in comparison to other natural resource areas, such as timber.

- **Establishment of Property Rights.** When and how governments choose to establish mineral rights and rectify competing claims on land can reduce the cost of access to oil resources substantially. Government efforts to resolve property rights disputes can be intensified when oil is at stake, with the results often favorable to oil companies. The Alaska Native Claims Settlement Act is one example where the presence of oil led induced the federal government to actively arbitrate land claims and establish control of key oil reserves and transportation corridors.

- **Subsidies to Existing Oil Production.** Governments can consciously reduce the required payments for existing leases, providing a potential windfall to lease owners or encouraging continued production in the face of worsening extraction economics. Governments may also provide subsidies inadvertently, such as through lapses in oversight.

  - *Failure to Meet Existing Lease Terms*. Poor auditing practices by Federal agencies result in the loss of royalty income, estimated at $50 to $75 million per year for the Bureau of Land Management alone. Oil companies also reduce their contracted royalty payments through the use of artificial transfer prices that understate the true value of oil extracted. This practice costs the Treasury $30 to $130 million per year.

  - *Changes to Existing Terms.* Governments may modify lease terms in the middle of a lease to encourage increased production. Subsidies occur when unnecessary reductions are provided to lease holders.

- **Subsidies to New Production.** Governments may provide special incentives for new production in order to encourage new activity. These subsidies may be targeted at job creation or economic development, and can use a host of different approaches. Examples include royalty relief on certain types of oil deposits, non-competitive conversion of exploration licenses into leases, relaxation of competitive restrictions on lease size, and limited public participation and oversight on leasing decisions.

- **Below-Market Lease Sales Due to Faulty Lease Auctioning Process.** Competitive auctions potentially maximize firms' payments for oil resources, but a lessor's failure to ensure that an auction is truly competitive can enable firms to pay less than the fair value of a lease. Although uncommon in the United States, many countries award oil concessions in a non-competitive and possibly corrupt way. When this occurs, purchasers realize windfall gains, and taxpayers do not receive a fair return on the public assets sold.

6.4 ESTABLISHMENT OF PROPERTY RIGHTS

Developing oil fields, especially remote or inhospitable ones, can cost hundreds of millions of dollars. Without clear property rights, this development will not take place. In addition, resolving property disputes can cause delays that are expensive to industries interested in investing, and may cause them to focus their efforts elsewhere. To minimize delays, governments can establish property rights by brute force. Because oil companies often have an extremely large financial interest in the outcome and tend to be the more powerful parties involved in property disputes, the final property rights allocations can heavily favor them.

A good example of government intervention to resolve oil-related property rights disputes is its resolution of native land claims in Alaska. Native Alaskans claimed much of the land in the state, including land critical to the development of the North Slope's oil fields. When the property rights issues raised by these claims impeded oil development, the United States Congress intervened, resolving the dispute with a combination of its power and taxpayer money. This intervention cleared the way for oil development and likely reduced the cost of acquiring the necessary land.

The Alaska Statehood Act of 1959 triggered property rights disputes between the state and native Alaskans. The Act allowed the new state to select approximately 104 million acres, over one quarter of its total territory, to be considered state land. Although the Act barred the state from selecting land claimed by native Alaskans, Alaskan natives claimed 337 million acres, approximately 90 percent of Alaska.[133] Their claims included what would later become important oil fields and much of the land along the planned Trans Alaskan Pipeline System (TAPS) route. For example, the Arctic Slope Native Association claimed the entire North Slope, including Prudhoe Bay, and several Athabascan communities had filed for a significant portion of the pipeline's route through the Yukon Flats region.[134]

The initial land selections that the state eventually submitted to the Department of the Interior included areas claimed by native Alaskans. Two court decisions upheld native land claims, and the federal government froze land transfers to the state in 1966 until native claims were settled. This land freeze impeded development of Prudhoe Bay and construction of TAPS. Congress and the President removed that obstacle by passing and signing into law the Alaska Native Claims Settlement Act (ANCSA) of 1971, extinguishing all previous claims in return for the transfer of money and 44 million acres of land from the federal government to native

[133] The Statehood Act of 1959 contained a section requiring the State of Alaska and its people to disclaim all right and title to lands held by natives or held in trust for natives by the Unites States. See Mary Clay Berry, *The Alaska Pipeline: The Politics of Oil and Native Land Claims*, Bloomington, IN: Indiana University Press, p. 32.

[134] The Arctic Slope Native Corporation held the single largest native land claim, 57 million acres. (Berry, p. 44)

Alaskans. The value of the cash component of ANCSA was $962.5 million (1972 dollars), of which $500 million was earmarked from future oil royalties.[135] The remainder, $462.5 million, was to be paid over an eleven year period.

ANCSA cleared the way for oil development. The settlement permitted the official (although *de facto*) transfer of Prudhoe Bay to the state, and restrictions on native land selections prevented natives from selecting known oil land.[136] In addition, all but 20 of the 800 miles that the pipeline crosses today are controlled by the federal or state government. This settlement officially granted the federal and state governments control over the North Slope's oil development, and allowed development to proceed.

Under ANCSA, the federal government appears to have used its power to underpay claimants, reducing the cost of land acquisition. ANCSA was a unilateral act of Congress. Native Alaskans were involved in ANCSA's development as one lobbying group among many, including oil companies, miners, the state, and environmental groups. Once Congress passed and President Nixon signed ANCSA, the settlement was final; native Alaskans were not given the opportunity to vote to accept it. At least one community with land claims along the pipeline's route voted to reject its land allotment, but the vote was inconsequential. Faced with a "take it or leave it" option, the community took what it could. Likewise, the North Slope natives' regional organization voted against approving the settlement, but, again, such a vote was powerless.

The settlement was distributed among thirteen native Alaskan corporations created by ANCSA. Twelve regional corporations received land and money. A thirteenth corporation comprising native Alaskans who had left the state received only money. One corporation, the Arctic Slope Regional Corporation (ASRC), received approximately $48 million and 4.5 million acres of land in the North Slope region. The Arctic Slope Native Association had previously claimed 15 million acres in that region. Although ANCSA allowed native corporations to select their land, large areas of the North Slope were exempt from consideration by ASRC, including the National Petroleum Reserve, the Arctic Wildlife Refuge, and land previously selected by the state (i.e., Prudhoe Bay).

There is good reason that some of the Alaskan natives rejected the agreement. The payment, less than $800 million in present value terms at the time of the agreement, was equal to less than $3 per acre on which claims were withdrawn. Using the same valuation for the land included in the agreement, the total value of the deal (land plus money, scaled to 1995 dollars) was approximately $2.8 billion. This payment constitutes slightly over 12 percent of the more than $23 billion in oil revenues (1995 dollars) that the State of Alaska collected through the initial lease sale at Prudhoe Bay and the royalties and taxes on oil during the eleven year payment

[135] In effect, this meant that over half of the payment was to come from royalties on oil produced from land (and mineral reserves) that the Alaskan natives believed they owned anyway.

[136] The State of Alaska's initial land selections included Prudhoe Bay and other areas of the North Slope. The Department of the Interior had tentatively approved the selections, but the federal government's 1966 land freeze prevented the official approval and transfer of the selected land to the state. The state ignored that technicality and conducted a North Slope lease sale in 1969, prior to ANCSA, that earned $900 million, nearly as much as the entire ANCSA settlement.

of ANCSA. Once federal royalties and payments from 1983 to the present are included, the low price paid for the settlement becomes ever more apparent.

It is clear that federal intervention accelerated the pace of oil development in Alaska, and reduced the cost of acquiring access to Alaskan oil. This created a windfall that flowed both to governments (Alaska and federal) and to the oil companies themselves, though quantifying the size of the windfall and its distribution among the various parties would be extremely difficult.

6.5 SUBSIDIES TO EXISTING AND NEW PRODUCTION

There are important differences between existing and new production that influence how subsidies are viewed. The central difference is that existing oil production is a fairly perishable commodity. Once a well has been plugged, it rarely makes economic sense to redrill it. Thus, if wells are plugged before the oil has been fully extracted, the oil is lost. In contrast, new production does not age the same way. Reserves can sit for hundreds of years without degrading. Owners of the oil must determine the most opportune time to extract and exhaust their finite resources. The implications of this difference are discussed in the context of royalty reductions.

6.5.1 Subsidies to Existing Production

Subsidies to existing production fall into two main categories: failure to meet set lease terms and changes to existing terms. In the first category, we examine poor royalty auditing practices and the use of artificially low prices for oil "sold" from one division of an oil company to another, both of which can reduce the calculated royalties owed. In the second category, we discuss how reductions in royalty rates and extensions to the durations of existing leases affect government revenues and producer incentives.

6.5.1.1 Failure to Meet Set Lease Terms

In any business activity, lapses in oversight can lead to losses in revenue collection. Royalty payments are no different, and poor auditing practices yield substantial financial losses to the U.S. taxpayer. In addition, a number of oil companies have utilized royalty-avoidance strategies to minimize their payments to both the federal and state governments for public oil resources. Each of these areas is discussed in turn.

6.5.1.1.1 Poor Auditing Practices

The Bureau of Land Management has historically failed to enforce lease terms aggressively. As a result, lease holders who underpaid their royalties were rarely caught. The Committee on Natural Resources of the U.S. House of Representatives estimates that this lax oversight has cost the federal government an estimated $50 to $75 million per year in lost oil royalties.[137]

6.5.1.1.2 Underpayment of Contracted Royalties

In some cases, oil producers have flexibility in how they structure their financial reporting, which enables them to minimize their royalty payments. The use of "posted prices," described below, is one such example that reduced federal royalty collections by hundreds of millions of dollars.

Federal royalties are calculated as a percentage of the value of the oil extracted. When oil is sold to independent buyers, the value of the oil is readily apparent by examining the price at which the crude oil was sold. For integrated oil producers, however, the calculation becomes much more complex because the oil is not sold on an open market. Rather, it is often "sold" from one division of a company to another. Historically, integrated oil companies have used "posted" prices, which are based on corporate decisions rather than the marketplace, to determine the value of the oil sold between divisions.

Increasing evidence gathered over the past four years suggests that major oil companies have used posted prices that systematically understate the real market value of their oil. This practice extends back to 1960, and the resulting underpayment of royalties is substantial, though a matter of fierce disagreement.[138] The Minerals Management Service estimates that the value of royalty underpayments to the federal government from 1960 to 1992 is as much as $422 million (interest included) for California production alone.[139]

---

[137] U.S. House of Representatives, House Committee on Natural Resources, Democratic Staff Report, "Onshore Benefits: Oil and Gas," in *Taking From the Taxpayer: Public Subsidies for Natural Resource Development*, August 1994, obtained from http://www.house.gov/resources/105cong/democrat/subsidy.htm, October 1997.

[138] Danielle Brian, Executive Director, Project on Government Oversight, Written Statement before the House Committee on Resources, Subcommittee on Energy and Mineral Resources, September 18, 1997, obtained from http://www.pogo.org/addit-pr/Brian_RIK.htm, November 9, 1997.

[139] Cynthia Quarterman, Director, U.S. Minerals Management Service, Congressional Testimony prepared for the House Subcommittee on Government Management, Information and Technology of the Committee on Government Reform and Oversight, June 17, 1996, obtained from http://www.mms.gov/testimon/test6176.html on November 9, 1997. An MMS auditing team had originally estimated that California producers could owe as much as $856 million for the 1978-93 period. The amount was reduced following discussions with producers. Patrick Crow, "U.S. industry under attack for alleged royalty underpayments," *The Oil & Gas Journal*, October 28, 1996, p. 19.

The Project on Government Oversight, a non-partisan, non-governmental organization which has tracked this issue for a number of years, puts the figure substantially higher: as much as $1.5 billion (1960 to 1997) for California production, and an additional $1.3 billion (1985 to 1997) for production east of the Rockies (including offshore production).[140] Leveling the unpaid sum plus interest over the number of years of underpayment yields an annual subsidy between $31 and $130 million.[141] This estimate represents *federal* underpayments only. The same issue led to underpayment of state (and often private) royalties as well. For example, the State of Texas recently settled a suit over oil royalties that required Chevron to pay $17.5 million to address claims of past underpayment within the state.[142] We were unable to estimate the subsidy to oil companies that has resulted from underpayment at the state level.

In response to its multi-year investigation, MMS has developed new regulations that use the market exchange price of oil, rather than posted prices, as the basis for royalty calculations on oil that is not sold in arms-length transactions.[143] MMS estimates that the new method will increase annual royalty collections by between $50 and $100 million.[144] In terms of the past underpayments, MMS has issued bills totaling only $275 million, all of which is being challenged in court.[145,146] This sum is considerably less than the estimated value of underpayments for California, suggesting that substantial royalty underpayments remain outstanding.

---

[140] As with the MMS estimates, these figures include interest. Project on Government Oversight, *Drilling for the Truth: More Information Surfaces on Unpaid Oil Royalties*, May 1997, pp. 3-4.

[141] This amount is net of collections on the unpaid royalties. Despite the large difference between the MMS and the Project on Government Oversight estimates of unpaid amounts, even the much lower MMS claims are all being litigated by the oil companies.

[142] "State settles lawsuit over royalties," *Lubbock Avalanche-Journal*, August 22, 1997, obtained from http://www.lubbockonline.com/news/082397/state.htm on November 9, 1997.

[143] U.S. Minerals Management Service, *Final Interagency Report on the Valuation of Oil Produced from Federal Leases In California*, May 16, 1996.

[144] Patrick Crow, "Royalty Valuation Rule Changes Loom," *Oil & Gas Journal*, June 30, 1997, pp. 25-30.

[145] Dale Fazio, Washington Royalty Liaison Office, U.S. Minerals Management Service, personal communication, November 11, 1997. The MMS figure, which applies to the California region for the period 1980 to 1995, includes imputed interest on the unpaid amounts. Fazio did not believe that underpayments prior to 1980, or outside of California, were substantial. However, Cynthia Quarterman of MMS noted in an earlier trade press article that California royalty underpayments "were easier to quantify because the West Coast is a distinct market, while crude is moved in and out of other states more readily." (Crow, October 28, 1996).

[146] Perhaps to avoid future problems with royalty underpayment, the oil companies successfully passed a seven-year statute of limitations on all royalty collections. See Tom DeRocco, "President Signs Federal Oil and Gas Royalty Simplification and Fairness Act into Law," U.S. Minerals Management Service, Office of Communications Press Release, August 13, 1996.

6.5.1.2 Changes to the Terms of the Lease Once Property is Under Production

A second type of subsidy for existing production involves changes to the terms of the lease after the lease has already been issued. Royalties may be reduced or eliminated, and lease duration extended. In addition, lease operators may be given options to expand their activities without having to bid on additional properties. Determining whether these changes constitute subsidies or good business practice is not always easy.

Governments often provide incentives such as royalty reductions to try to prevent marginal wells from closing. To continue producing oil, operators must maintain well bores and well pressures. Changes in market conditions can make marginal wells unprofitable, leading operators to end production and plug the wells, often losing any remaining oil in the ground.[147] Alternatively, production costs may rise as the resource is depleted. To avoid this lost source of royalties, governments offer incentives to reduce the cost of extracting oil and maintain the profitability of marginal wells. This objective forms the basis for scores of incentives at the state and federal level.[148]

The problem with this policy is that royalty reductions are not always needed to avoid premature well closures. In fact, a survey conducted by the Independent Petroleum Association of America suggested that the biggest concern of marginal well operators was the market price for their product.[149] Changes in market prices appear to be much more important in production decisions than reductions in royalties or taxes. Because wells can remain idle for a period of years without necessitating closure, incentives to restart production are not needed immediately to avoid losing the resource, and governments can wait to see if prices recover. However, many marginal well incentives become active after the wells have been idle for only 12 months. The risk of prematurely activating such incentives is that oil prices may rise and the incentives may turn out to have been unnecessary. In such an event, governments lose the discounted portion of normal royalties for all oil depleted while the incentives were unnecessarily in place.

Determining the appropriate time to activate incentives is quite difficult and often leads to imperfect and sometimes inaccurate decisions by government officials. For this reason we consider these incentives as potential subsidies and describe two federal examples here. Time will tell whether active royalty relief policies were good business practices or not.

---

[147] Many small wells pull oil from pools that are not accessible by surrounding wells. Furthermore, the profitability of wells generally decreases as they are depleted. Resuming production would require re-drilling, but the high costs of re-drilling often outweigh the benefit from producing the remaining oil.

[148] See Interstate Oil and Gas Compact Commission, *State Incentives to Maximize Oil and Gas Recovery*, January 1997, for a good summary of state-by-state subsidies to both marginal and new wells.

[149] Independent Petroleum Association of America, "Marginal Wells," in *Profile of Independent Producers 1996*, obtained from http://www.ipaa.org/departments/information/ information_services/profile_of_producers.htm, October 29, 1997.

- **Royalty Relief for Heavy Oil.** In 1996, the Bureau of Land Management implemented a final rule reducing the royalty rate on heavy oil. Heavy oil is less valuable than lighter grades but more expensive to produce, and many wells were idle or were expected to become idle if oil prices fell further. Royalty relief was implemented to help them remain viable.[150] BLM's projections on the economics of the change vary considerably depending on their assumptions regarding the price of oil. However, the combined effect on revenues plus other public sector income (such as severance taxes and corporate income taxes) ranges from a present value gain of $105 million to a present value loss of $25 million. The present value has been calculated over the producing life of properties, around 20 years.[151]

- **Royalty Relief for Stripper Wells.** Stripper wells are low volume oil wells producing less than 15 barrels of oil (on average) per day. These wells tend to have higher unit production costs, and to be adversely affected by low oil prices. To encourage continued operation of these wells (as well as renewed operation of idle stripper wells), the Bureau of Land Management allowed operators to obtain a royalty reduction beginning in the latter part of 1992. At the time, BLM projected somewhat reduced federal revenues and somewhat increased state revenues over the life of the properties. The anticipated net losses are extremely small, less than $1 million per year.[152] The rule is currently being reevaluated for cost and effectiveness.[153]

6.5.2 Subsidies to New Production through Lease Terms

While existing wells must often be used or lost, new wells do not constitute "use-or-lose" situations. Subsidies to new production raise two central questions. The first is whether the subsidy is necessary for the development to take place. This question is the same as we discussed above regarding existing production. The second question is whether it makes sense to encourage the production of high cost oil with public money.

---

[150] U.S. Bureau of Land Management, "Promotion of Development, Reduction of Royalty on Heavy Oil, Final Rule," *Federal Register*, February 8, 1996, pp. 4748-4752.

[151] *Ibid*., and John Bebout, U.S. Bureau of Land Management, personal communication, November 10, 1997.

[152] R. Michael Rey, U.S. Department of Energy, "Impact of Federal Royalty Relief on Future Oil Recovery from Federal Stripper Leases in the State of New Mexico - Final Report," Memorandum to Hilary Oden, U.S. Bureau of Land Management, May 3, 1991, Table 4.

[153] U.S. Bureau of Land Management, "Royalty Rate Reduction for Stripper Oil Properties," *Federal Register*, August 30, 1996, pp. 45926-45927.

Governments provide lease subsidies for two primary reasons: energy security and economic stability. By encouraging marginal domestic production, the flow of imports can be offset somewhat, at least in the short-term; however, the incremental benefit to energy security is not likely to be large. In the longer term, depleting marginal oil supplies means that the remaining domestic reserves will tend to be more costly to extract, reducing the future ability to develop a domestic response if oil prices begin to rise.

The issue of economic stability is more pernicious. As oil-producing states begin losing oil jobs due to reserve depletion or falling world oil prices, they come under increasing pressure to protect both jobs and government revenues. The problem is more acute if the state's economic and state revenue bases are poorly diversified (as is the case with Alaska). Because the economic shock of industrial decline is potentially large, the government may introduce economically-inefficient policies ("give-aways") to maintain the jobs and revenue *status quo*. The shorter the time frame for response and economic transition, the more likely are decisions that result in short-term economic stimulus but long-term environmental damage -- as well as dubious economic benefits.

A multi-country assessment conducted by Jeffrey Sachs and Andrew Warner of Harvard University comparing nations' economic reliance on natural resources and their long-term economic growth rate illustrates this point. On average, a 17 percentage point increase in the share of primary resource exports in gross domestic product in 1971 corresponded to a 1 percentage point *fall* in average annual growth over the 1971 to 1989 period. In contrast, many natural resource poor countries, such as Taiwan, posted strong growth during that time frame.[154]

We discuss some examples of lease subsidies to new production below.

6.5.2.1 Royalty Relief for Deep Water Oil Drilling

To encourage the development of oil and gas from deeper parts of the outer continental shelf, the federal government gave royalty relief to producers willing to drill new wells in deep water. The Congressional Budget Office estimated the economic impacts of the rule, which became effective in November 1995. In the first five years, the relief was expected to *increase* government revenues through higher bonus bids, as firms would be willing to pay more up-front for drilling rights knowing they would have lower royalty obligations. Yet, relief would reduce government revenues from royalties by $500 million over the life of the properties. The

[154] Jeffrey Sachs and Andrew Warner, "Natural Resource Abundance and Economic Growth," Development Discussion Paper No. 517a, Harvard Institute for International Development, October 1995, as cited in David Roodman, *Paying the Piper: Subsidies, Politics, and the Environment*, Washington, DC: Worldwatch Institute, December 1996, p. 21. The Roodman paper has a number of examples demonstrating the inefficacy of natural resource subsidization as a strategy for development or economic stabilization.

estimated present value loss to the Treasury (net of increased bonuses) was $150 million.[155] Using the interest rate assumptions in the CBO analysis, this translates to an average annual loss to the Treasury of roughly $12.3 million for the 1996-2020 time period of CBO's analysis.

There is substantial evidence that royalty reductions were not needed to encourage exploration in many deeper water locations. New technology, such as three-dimensional imaging and horizontal drilling, have dramatically reduced the costs of finding and producing oil. Average exploration and production costs per barrel have decreased by about 60 percent in real terms over the past 10 years, and exploration costs for one major oil company have fallen by 85 percent over ten years due to improvements in imaging.[156]

Other advances, such as computer-controlled thrusters to stabilize offshore floating rigs, have also brought costs down by eliminating the need for much larger, more expensive installations. Even in colder regions, where icebergs traditionally necessitated massive installations, new options such as floating installations that are tugged out of the path of oncoming icebergs dramatically reduce costs. For example, a floating rig for Canada's Grand Banks and a deep water rig for the U.S. Gulf Coast cost between 50 and 90 percent less than their precursors. They are also faster to design and build, reducing the market risk to the investor.[157] While some deepwater reserves may still be difficult to access, either due to their location or the decline in the market price in oil, it is clear that innovation has made drastic cost reductions in accessing many deepwater reserves. These cost reductions call into question the federal strategy of reducing royalties to encourage production in many of these areas.

6.5.2.2 Other Lease Subsidies to New Production

The federal government and many states have a number of lease-based incentives in place to spur new oil production. We did not have enough information to quantify the revenue losses associated with each one, but their variety demonstrates the many subsidies that can exist for new production.[158] In order to illustrate the variety of policies in place, we have included descriptions of some state programs, though their inclusion does not affect our federal subsidy totals. In addition to these types of incentives, limited public oversight of lease decisions can make lease subsidies more likely.

---

[155] U.S. Congressional Budget Office, Letter from June O'Neill to George Miller, Democratic Leadership, House Committee on Resources, November 2, 1995, providing additional information on the CBO cost estimate for the Outer Continental Shelf Deepwater Royalty Relief Act.

[156] Peter Coy and Gary McWilliams, "The New Economics of Oil," *Business Week*, November 3, 1997, p. 142.

[157] *Ibid*., p. 143.

[158] IOGCC, January 1997. Alaska Oil & Gas Commission, Oil and Gas Policy Council, *Report to the Governor*, February 1996.

- **Large Block Licenses**. Oil companies are sometimes given rights to explore large blocks of land in return for a commitment to invest a pre-specified amount in oil exploration. If oil is found, the license to explore can be converted into a lease at fixed terms, without further bidding. The process can encourage oil exploration in areas in which it might not otherwise occur. However, it can also give specific oil companies valuable rights to large tracts of oil land without having to pay any bonus.

- **Increased Tract Size.** Governments may allow particular oil companies to hold larger than normal tract sizes in order to encourage oil development. Larger sizes increase the chance of finding oil, and enable a single firm or investment group to control an entire oil prospect. This can encourage more rapid oil exploration and development, but may give a company monopolistic or near monopolistic control in a region.

- **Reduction in Taxes and Royalties in Return for Increased Development.** Governments sometimes allow a portion of the costs associated with exploring for new oil to be offset from royalties or taxes owed to the government from other operating sites. The state, in essence, becomes a development partner.

- **Temporary Royalty Reductions for New Wells.** A number of states encourage new well development by excusing production from royalties for the first years of production.

- **Royalty Reductions for New, Higher Cost Fields.** Some states offer reduced royalties for new, “high cost” production sites.

Subsidies to new leases come not only in the form of royalty relief, larger tracts, or the ability to convert licenses into leases at a low cost. Perhaps the most important subsidy comes in the form of limited public participation in leasing decisions. Exploration licenses in Alaska give an oil company the exclusive right to explore up to 500,000 acres for a period of ten years. According to local environmental groups, there is virtually no opportunity for public comment and review of the licenses.[159] Another Alaska program, "area-wide leasing," allows the state to open large areas in certain regions to oil and gas exploration. Once the Alaska Department of Natural Resources (DNR) issues a “best interest finding,” which stipulates a particular lease sale is in the best interest of the state, it can conduct lease sales in the same area for the next ten years without any additional public comment.[160] Others in the state who feel that sales in the adjacent areas are not in the state’s best interest have little recourse to challenge DNR’s decision.

---

[159] Pam Miller, *The Reach of Oil in the Arctic: Alaska, USA,* Washington, DC: Greenpeace USA, August 1997, p. 33.

[160] *Ibid.*

Limited public participation and many of the lease incentives discussed above provide wide discretion to public officials regarding what is a "marginal" well, what regions are high cost, and when data suggest oil reserves are valuable enough to warrant lease auctions rather than large area licenses. With discretion comes the opportunity for arbitrary and capricious decisions and corruption. When these provisions are combined with reduced public oversight, the likelihood of environmentally imprudent decisions rises substantially.

6.6 COMPETITIVENESS OF LEASE AUCTIONS

The final lease-related issue we examine is the process by which lease rights are sold to private parties. Most federal oil leases in the United States are auctioned to the highest bidder. The process used to award leases in many other countries is not always so transparent. If leases are competitive, auctions should theoretically ensure that the government receives full market value for its oil resources. Where sales are corrupt (as sometimes occurs outside of the United States) or non-competitive, subsidies to the purchasers can be enormous. To be truly competitive, auctions require the following components:

- **Sufficient Number of Bidders.** If too few bidders are interested in a property, those that participate will be able to offer substantially less than the true value of the resource. If the auction is not well publicized, or the potential bidders do not have access to information about the tract, fewer bidders are likely.

- **Independence of Each Bidder.** If bidders are able to collude, they can avoid paying a fair market price for the resources being auctioned.

- **Bid Evaluators Not Corrupt.** Government officials award leases based on auction results. If they are corrupt, they can accept kick-backs in return for giving the leases at below-market value to a specific bidder.

6.6.1 Lease Competitiveness In the United States

Offshore leases have been auctioned since 1954, one year after the passage of the Outer Continental Shelf Lands Act. The auctions, which have generally used a bonus bid system, appear to have been fair and competitive. Mead *et al.* evaluated 1,223 offshore leases between 1954 and 1969, and found that the rates of return for winning bids matched that in general industry. They also found no evidence that joint bids, where multiple oil companies team together to bid on a single tract, led to lower winning bids or higher returns.[161] An analysis of OCS leasing activity between 1954 and 1977 by Saidi and Marsden also focused on how joint

[161] Walter Mead, Asbjorn Moseidjord, and Philip Sorenson, "The Rate of Return Earned by Lessees under Cash Bonus Bidding for OCS Oil and Gas Leases," *The Energy Journal*, 1983, v. 4, pp. 37-52.

bids affected the price of leases. They found that the competitiveness of the OCS lease auction was more strongly correlated with the number of bidders than with the number of bids, supporting the hypothesis that joint bidding situations did not lead to unfair auctions.[162]

Onshore leases are a different story. The first federal legislation governing onshore leases was in 1920. While the law called for competitive leasing for oil if the tract lay within a known producing field, less than five percent of federal leases were issued on a competitive basis prior to 1988.[163] Beginning in the 1950s, access to onshore tracts on federal lands was governed less by market value and more by deception and sometimes intimidation.

To rectify these problems, the Bureau of Land Management introduced a lease lottery. In return for a filing fee, the lottery allowed any applicant to file an application for each tract of land up for leasing. The winner was chosen in a random drawing. Valuable leases were then sold by the winner on a secondary market, with little of the economic rent accruing to the government.[164] Problems with the lotteries ultimately led to the Federal Onshore Oil and Gas Leasing Reform Act of 1987. The Act instituted a mixed competitive/non-competitive auctioning approach. All tracts would be offered competitively in an auction; those for which there was no bidding interest would then be put into a lottery. The goal of the approach was to ensure that the higher value tracts were bid competitively.[165]

Early analysis of the reforms suggested that they dramatically increased returns to the federal government, with bids rising from an average of $2.39 per acre in 1988, prior to reform, to $9.96 per acre later that year, under the new auctioning system.[166] While the current onshore leasing system appears to ensure the public sector is adequately compensated for its oil, leasing practices prior to 1988 provided substantial subsidies.

[162] Reza Saidi and James Marsden, "Number of Bids, Number of Bidders and Bidding Behavior in Outer-Continental Shelf Oil Lease Markets," *European Journal of Operational Research*, 1992, v. 58, pp. 335-343.

[163] Abraham Haspel, "Drilling for Dollars: The New and Improved Federal Oil Lease Program," *Regulation*, Fall 1990, p. 62.

[164] An egregious example of lost rents was the Amos Drew region of Wyoming. In 1983, BLM leased 18 tracts non-competitively, receiving $13,000 in annual rental fees plus $1.2 million in lottery filing fees. The tracts, located next to lands currently producing oil and gas, were then resold within weeks on the secondary market for $100 million. U.S. House of Representatives, 1994.

[165] Haspel, 1990, pp. 62-64.

[166] *Ibid*., 67.

6.6.2 Competitive Access to Oil: The World Market Perspective

Despite a rocky history, it appears that leasing is currently fairly competitive at the federal level in the United States. Yet oil is produced in a global market. Low cost producers in other countries increase the pressure on the United States to make concessions for oil development in order to stay competitive. A process known as the "race to the bottom" is in effect. Cost pressures due in part to corruption and lax health, safety, and environmental standards in other oil producing nations influence leasing practices in oil-reliant regions of the United States.

For example, a competitive analysis of Alaska's position as a global oil producer included nations such as Venezuela, Indonesia, Vietnam, Angola, and China in Alaska's list of current or potential competitors.[167] One can hardly count on competitive leasing procedures to fairly price oil reserves in countries such as these. In addition to artificially cheap access to oil reserves, producers in these countries may benefit from government-built or financed transportation infrastructure such as pipelines. To compete, producers such as Alaska are pressured to cut their taxes and royalties and to allow oil companies wider latitude in where they lease. Given the social and environmental costs of oil development in these other countries, the United States should be careful before it tries too hard to win the oil development contest.

6.7 SUMMARY

Leasing and royalty provisions are set at both the state and federal levels and can have a substantial impact on the timing and location of oil development. Decisions regarding the terms of access to limited oil resources have enormous financial implications. Mistakes can cost the public hundreds of millions of dollars per year in well-run countries such as the United States. Mistakes and corruption in countries with fewer government resources and poorer management can cheat them out of billions of dollars per year or more.

The financial implications of a poorly run leasing program require that sound systems of accountability be established that ensure proper public oversight of decisions. This oversight is especially important given the environmental impacts of oil development. Standardized methods for reporting the financial implications of changes to leasing terms should be developed, as is done for tax expenditures. Such methods would enable policy options to be more easily compared, and decisions more easily publicized.

[167] Arthur D. Little, Inc. and John Gault, *Review of International Competitiveness of Alaska's Fiscal System*, prepared for the Alaska Department of Revenue, September 1995.

RESULTS AND RECOMMENDATIONS CHAPTER 7

The U.S. government provided net subsidies of between $5.2 and $11.9 billion to the oil sector during 1995, excluding the cost of defending Persian Gulf oil supplies. We estimate defense of oil supplies to be worth an additional $10.5 to $23.3 billion, demonstrating the magnitude of this specific subsidy element. Thus, our estimate for net federal subsidies to oil, including defense, is $15.7 to $35.2 billion for 1995. Because of the sensitivity of our totals to the defense subsidy, we present our results both with and without this item.

The large range between our high and low estimates is indicative of the uncertainty surrounding some of the data inputs needed to estimate specific subsidies. Factors contributing to this range include differences between the cost of subsidies to taxpayers versus their value to the oil industry, differences between data sources, and the use of multiple methodological approaches to assess certain subsidies.

This chapter begins with a summary of the largest individual subsidies to oil. We then summarize subsidies by the type of activity supported. Next, we develop a number of metrics to evaluate the subsidies in a broader market context. Finally, we present policy recommendations suggested by our work.

7.1 LARGEST INDIVIDUAL SUBSIDIES TO OIL

Exhibit 7-1 lists the fifteen largest sources of subsidy to the oil fuel cycle at the federal level. As shown in the exhibit, the largest non-defense subsidies are worth between $4.5 and $11 billion, over 85 percent of our total non-defense estimates. Including defense, the fifteen largest subsidies are worth $15 to $34 billion, more than 95 percent of our totals. The most significant of these subsidies, grouped by topic, are described below. A complete listing of subsidy elements can be found in Appendix Exhibit A-1.

- **Defense of Persian Gulf Oil Supplies.** Defense of Persian Gulf oil shipments and infrastructure comprises two-thirds of the total high estimate, conferring a subsidy of $10.5 to $23.3 billion per year. The range represents the variation in analytical approaches used by defense analysts (described in detail in Chapter 4).

Exhibit 7-1

15 LARGEST SUBSIDIES TO OIL
(sorted in descending order)

	Subsidy	Subsidy Amount (Oil Share, $Millions)	Percent Share: Excluding Defense Low	Excluding Defense High	Including Defense Low	Including Defense High	Description
1.	Oil Defense	$10,459 - $23,333	NA	NA	66.8%	66.3%	Defense operations to protect and secure Persian Gulf oil shipments and infrastructure.
2.	Strategic Petroleum Reserve	$1,560 - $5,427	30.0%	45.8%	10.0%	15.4%	Storage of crude oil to be sold during price shocks and supply disruptions to stabilize domestic supply.
3.	Foreign Tax Credit	$486 - $1,057	9.3%	8.9%	3.1%	3.0%	Allows a portion of foreign tax payments to be credited against, rather than deducted from, U.S. taxes due.
4.	Accelerated depreciation of machinery and equipment	$720 - $976	13.9%	8.2%	4.6%	2.8%	Allows machinery and equipment within the oil industry to be depreciated more quickly than their actual service lives.
5.	Excess of percentage over cost depletion	$335 - $746	6.5%	6.3%	2.1%	2.1%	Allows firms to deduct more than their investment in oil properties from their taxes.
6.	Public liability for plugging, abandoning, and remediating onshore wells	$119 - $451	2.3%	3.8%	0.8%	1.3%	Annualized shortfall in bonding levels needed to cover existing liabilities on on-going operations.
7.	Accelerated depreciation of buildings other than rental housing	$234 - $355	4.5%	3.0%	1.5%	1.0%	Allows buildings owned by the oil industry to be depreciated more quickly than their actual service lives.
8.	U.S. Coast Guard	$308 - $308	5.9%	2.6%	2.0%	0.9%	Water infrastructure (maintenance of coastal shipping; provision of navigational support; ice clearing).
9.	Deferral of income from controlled foreign corporations	$62 - $303	1.2%	2.6%	0.4%	0.9%	Allows oil companies to delay payment of U.S. taxes due on earnings from certain foreign corporations.
10.	Low Income Home Energy Assistance	$274 - $274	5.3%	2.3%	1.8%	0.8%	Assistance for low income energy consumers to buy oil.
11.	U.S. Army Corps of Engineers	$239 - $259	4.6%	2.2%	1.5%	0.7%	Maintenance of waterways heavily used by oil tankers and barges.
12.	Expensing of exploration and development costs	($146) - $243	-2.8%	2.0%	-0.9%	0.7%	Allows expenses related to multi-year oil well assets to be deducted from taxes in the current year rather than capitalized.
13.	U.S. Export-Import Bank	$197 - $241	3.8%	2.0%	1.3%	0.7%	Subsidized loans and insurance to support the sale of oil-related equipment and consulting services abroad by U.S. corporations.
14.	Royalty Undercollection due to Artificially Low Posted Prices	$31 - $130	0.6%	1.1%	0.2%	0.4%	Undercollection due to use of below-market prices in computation of production value by integrated companies.
15.	Tax break from federal/state interaction	$56 - $119	1.1%	1.0%	0.4%	0.3%	State revenue losses from federal tax breaks due to basing state taxable income calculations on federal tax returns.
-	All other subsidies	$724 - $970	13.9%	8.2%	4.6%	2.8%	
	TOTAL VALUE OF TOP 15 SUBSIDIES						
	Excluding Defense*	**$4,477 - $10,889**	**86.1%**	**91.8%**			
	Including Defense*	**$14,936 - $34,223**			**95.4%**	**97.2%**	
	TOTAL SUBSIDIES						
	Excluding Defense	**$5,200 - $11,859**	**100%**	**100%**			
	Including Defense	**$15,660 - $35,192**			**100%**	**100%**	

* Numbers do not add due to rounding.

- **Provision of the Strategic Petroleum Reserve.** Stockpiling oil to protect against supply disruptions provided between $1.6 and $5.4 billion in subsidies to oil markets in 1995 (see Chapter 4). The high estimate includes the 1995 increment of compounded interest incurred on the many years of unrepaid debt.

- **Tax Breaks for Domestic Oil Exploration and Production.** Despite reforms intended to narrow the applicability of tax breaks for oil and gas, the industry continues to benefit substantially from tax subsidies, as described in Chapter 2. Three tax breaks benefiting oil exploration and production (the expensing of exploration and development costs, excess of percentage over cost depletion, and accelerated depreciation of oil-related capital) reduced oil industry tax payments by between $1.1 and $2.3 billion during 1995.

- **Support for Oil-related Exports and Foreign Production.** Tax credits for foreign royalties paid, deferrals of U.S. income taxes due for multinational oil companies, and credit subsidies through the Export-Import Bank and the Overseas Private Investment Corporation, provide between $0.8 and $1.6 billion per year in subsidies for exports and foreign production. These provisions are presented in detail in Chapters 2 and 3.

- **Provision and Maintenance of Coastal and Inland Shipping Routes.** With a large share of the total tonnage shipped through the nation's waterways and ports, oil benefits disproportionately from subsidies to water infrastructure (see Chapter 3). Reforms over the past ten years have increased the share of infrastructure costs borne by shippers; however, substantial subsidies remain. Tax exemptions for bonds used for harbor construction and spending by the U.S. Coast Guard and the Army Corps of Engineers continue to provide subsidies worth $600 to $650 million per year to oil.

- **Unfunded and Underfunded Liabilities.** Inadequate bonding and user fees for the current stock of onshore and offshore oil operators shift $170 to $550 million in liability insurance premiums from oil companies to the public each year. These subsidies are described in Chapter 5.

- **Royalty Losses.** Due to creative accounting by oil producers and lapses in auditing practices by some government agencies, the federal government loses at least $80 and $200 million per year in royalties (see Chapter 6). Adequate data were not available to quantify the full value of royalty-related subsidies.

7.2 AGGREGATE FEDERAL SUBSIDIES FOR OIL, BY ACTIVITY SUPPORTED

Individual subsidies can be classified by the type of activity they encourage, ranging from support to oil exploration and development to providing regulatory oversight to the oil industry. As shown in Exhibit 7-2, the security of oil supply is by far the largest activity supported by the federal government. Security concerns, which include the two largest individual subsidies (the Strategic Petroleum Reserve and defense of Persian Gulf oil supplies), comprise over 75 percent of our estimates if defense of Persian Gulf oil is included, and at least 30 percent of all non-defense subsidies. Incentives for oil exploration and production, at over 35 percent of the total, are the largest category of support for non-defense subsidies in our low estimate, and second largest in our high.

The third largest subsidy activity is support for oil-related transportation, a category often overlooked. This support primarily involves maintenance of oil shipping routes and infrastructure, and is worth as much as $775 million per year. It is important to remember that this category includes only the transport of oil; subsidies to transportation systems that rely on oil (and which therefore increase the demand for oil) are not included in our analysis.

The remaining subsidy categories each comprise between one and six percent of our total estimates. Though small on a percentage basis, the dollar value of these categories is still substantial. For example, transfers to the public sector of liability for properly closing oil drilling operations were worth as much as $500 million in 1995.

7.3 SUBSIDIES IN CONTEXT

In this section we evaluate our subsidy estimates in the context of the oil production and consumption that they support. We discuss the value of these subsidies relative to the number of barrels of oil consumed and consumer expenditures for that oil. While not all subsidies affect prices, these comparisons offer a better idea of the impact subsidies have on consumption behavior than the aggregate subsidy values alone.

We also discuss the results of our subsidy analysis in the context of two major policy initiatives within the past decade to modify oil demand patterns. The first is the issue of carbon taxes currently being debated. The second policy is the Btu-tax that was proposed early in the Clinton administration's first term. This discussion underscores the importance of integrating subsidy removal into ongoing policy reform efforts.

The subsidy metrics are evaluated using three scenarios, reflecting the complexity associated with U.S. government subsidies that partly benefit foreign rather than domestic petroleum:

Exhibit 7-2

AGGREGATE FEDERAL SUBSIDIES FOR OIL, BY ACTIVITY SUPPORTED
(Millions of 1995 Dollars, Net of User Fees)*‡

	Low Estimate			High Estimate		
	Subsidy	% Share, excluding Defense	% Share, including Defense	Subsidy	% Share, excluding Defense	% Share, including Defense
Research and Development / Provision of Basic Market Information	$215	4%	1%	$243	2%	1%
Cost of Access to Oil Resources	$81	2%	1%	$205	2%	1%
Exploration and Production	$2,005	39%	13%	$4,093	35%	11%
Support for Oil-related Transportation	$690	13%	4%	$776	6%	2%
Security of Oil Supply						
Excluding Defense Costs	$1,560	30%		$5,427	46%	
Including Defense Costs	$12,019		77%	$28,760		82%
Regulatory Oversight and Response to Oil Contamination	$147	3%	1%	$166	1%	0%
Transfer of Oil-related Liability to Public Sector	$171	3%	1%	$557	5%	2%
Assistance for Energy Consumers	$274	5%	2%	$274	2%	1%
Crosscutting Tax Provisions	$56	1%	0%	$119	1%	0%
Subsidy Offsets*	$0	0%	0%	$0	0%	0%
TOTAL, excluding Defense	**$5,200**	**100%**		**$11,859**	**100%**	
TOTAL, including Defense	**$15,660**		**100%**	**$35,192**		**100%**

*Many federal programs benefiting oil are partially funded by user fees levied on program beneficiaries. The subsidy figures shown in this exhibit have already deducted user fees. Detailed data on user fees and gross subsidy values are provided in the Appendix exhibits. The final category in this exhibit, "Subsidy Offsets," allows for adjustments to account for any additional fees on oil that are not program specific, yet appropriately deducted from gross subsidies. No such adjustments were appropriate in 1995. Exhibit 2-1 further explains our treatment of federal levies.

‡Numbers do not add due to rounding.

- **Scenario 1** evaluates domestic subsidies only, excluding credit subsidies to international banks, defense of Persian Gulf oil supplies, and tax breaks for foreign operations.

- **Scenario 2** allocates a portion of the foreign subsidies to the domestic market, reflecting the fact that some of the foreign oil supported by these programs is imported into the United States.

- **Scenario 3** sets an upper bound by assuming all subsidies benefit domestic markets. Although in reality not all the oil supported by internationally oriented programs reaches U.S. markets, foreign tax breaks and lending programs primarily benefit U.S. corporations, and supply shocks in the Persian Gulf affect the price of *all* U.S. oil, regardless of its origin.

In each scenario, we have adjusted both the subsidy value and the denominator (consumption, consumer spending, carbon emissions, and Btus) to best approximate the scope of the subsidies included. The consumption figures used for Scenario 1 are for domestic petroleum only, and consumer expenditures exclude the value of imported oil prior to domestic refining. Scenarios 2 and 3 include total U.S. consumption and expenditure data. The specific metrics are shown in Exhibit 7-3; more detail on their derivation can be found in Appendix Exhibit A-7a.

7.3.1 Subsidies as a Percent of Oil Prices

Subsidies to domestic oil are worth between $1.20 and $2.80 per barrel of domestic crude consumed. This range is equivalent to roughly 3 to 6.5 percent of consumer expenditures on petroleum products in 1995.[196] The range is slightly lower in our second scenario, although the uncertainty associated with the values suggests that the differences would probably not be statistically significant.

Total federal subsidies for oil are worth as much as 17 percent of 1995 retail petroleum prices. Were all, or even most, of the benefits of the subsidies to foreign production to flow back to the U.S. oil sector, the impact on consumption decisions would be considerable. Under this scenario, the subsidy intensity of imported oil is much higher than domestic production. Were these subsidies eliminated, we would expect the relative competitive position of domestic versus imported oil to improve, with some marginal oil wells again becoming economic.

[196] Because our subsidy estimates are net of user fees, we have adjusted expenditure data to eliminate the portion of prices attributable to the various fees on oil.

Exhibit 7-3

OIL SUBSIDIES IN CONTEXT
(All figures reflect 1995 values)

	Scenario 1 Domestic Subsidies Only (Note 1)	**Scenario 2** Domestic and Pro-rated Share of Foreign Subsidies (Note 2)	**Scenario 3** Total U.S. Subsidies for Domestic and Foreign Oil (Note 3)
Subsidy Value ($million) (Note 4)	$4,445 - $10,226	$5,430 - $12,417	$15,660 - $35,192
Per Barrel of Domestic Consumption ($/bbl)	$1.2 - $2.8	$0.8 - $1.9	$2.4 - $5.4
As % of U.S. consumer expenditures, net of user fees	2.9% - 6.6%	2.7% - 6.1%	7.7% - 17.3%
Per Btu ($/mmBtu)	$0.25 - $0.57	$0.16 - $0.36	$0.45 - $1.02
Per Metric Ton of Carbon ($/ton carbon)	$7.41 - $17.06	$9.06 - $20.71	$26.12 - $58.70

Notes:

1) Does not include subsidies for foreign oil (i.e., foreign lending, foreign tax breaks, and Persian Gulf defense). Consumption data (both barrels and Btus) were adjusted to exclude net imports since they do not benefit from domestic subsidies. Consumer expenditure data were adjusted to exclude the value of net imports upon arrival to U.S. refineries, again because that value is not impacted by domestic subsidies.
2) Subsidy value includes the pro-rated share of foreign subsidies that benefit net imports. Foreign tax breaks and lending subsidies are pro-rated by U.S. net imports' share of total foreign petroleum products supplied. Persian Gulf defense spending is pro-rated by the percentage of total Persian Gulf production imported by the U.S. Total U.S. consumption and expenditure figures are used.
3) Includes all subsidies for domestic and foreign oil. Total U.S. consumption and expenditure figures are used
4) See Appendix Exhibit A-7a for additional detail on the derivation of adjusted subsidy values and the subsidy metrics.

7.3.2 Subsidy Intensity in the Context of Proposed Oil Taxes

Tremendous attention has focused on efficient mechanisms to reduce the impact of climate change. Taxes on carbon are an oft-suggested tool to "get the prices right" (i.e., to internalize environmental externalities) in energy markets. A number of economists have estimated economically efficient carbon tax levels that would begin the transition to lower-carbon fuels. Their results suggest median values of between $9 and $14 per ton.[197]

Our three subsidy scenarios suggest that federal oil subsidies are worth $7.50 to nearly $60 per ton of carbon emitted from U.S. petroleum consumption. While subsidy removal should not be substituted for a carbon tax, since the latter is aimed specifically at mitigating externalities associated with fossil fuels, the comparison is instructive. The relative size of the values suggests that even without the political will to implement a carbon tax, phasing out oil subsidies could help to improve the price signals that now exist within oil markets. In addition, the fact that the subsidy intensity actually exceeds these carbon tax values underscores the market distortions that would remain if carbon taxes were implemented without concurrent subsidy reform.

A comparison to proposed taxes on Btus (British thermal units) illustrates a similar point. Btus measure the heat content of a fuel. During 1992 and 1993 the U.S. Congress proposed a Btu-based tax on energy. In addition to raising revenues, proponents argued that the tax would ensure that energy prices reflected the environmental impacts associated with the production and consumption of particular fuels. The proposed tax rate set for oil was $0.31 per million Btu (scaled to 1995 dollars). In comparison, oil subsidies for 1995 ranged from 50 to 325 percent of the proposed tax value, depending on the scenario. Had the tax been implemented, much of the hoped for benefit in terms of price signals would merely have offset distortions already in place from federal subsidies to oil. Environmental externalities would still not have been reflected in oil prices.

7.3.3 Summary of Subsidy Intensity

The evaluation of subsidies in the context of the oil market demonstrates that subsidies to oil are important and probably impact oil consumption decisions. Eliminating subsidies throughout the fuel cycle will help clarify price signals throughout the production chain,

[197] The tax values calculated are set at a rate such that the marginal cost of carbon-emitting activities reflects the (estimated) damage these activities cause the environment. We chose a median carbon tax estimate over an average because the source of our data contained an outlier, $142.50 per metric ton of carbon (1995 dollars), that exceeded all of the other estimates by more than a factor of six. Data on the optimal tax rate on carbon are from five studies (Nordhaus, Cline, Peck and Tiesberg, Fankauser, and Maddison) summarized in the Intergovernmental Panel on Climate Change, *Climate Change 1995: Economic and Social Dimensions of Climate Change*, Contribution of Working Group III to the Second Assessment Report of the IPCC, Cambridge University Press, 1996, Table 6.1, p. 215.

improving economic efficiency. In conjunction with externality-based taxes, the price of oil would begin to provide suppliers, consumers, and governments much more accurate information with which to adjust their economic decision making.

7.4 RECOMMENDATIONS

The impacts of oil subsidies merit greater attention as the world tries to shape a global climate change strategy and address the many competing needs for scarce government funds. While it has long been recognized that oil prices do not reflect the environmental costs of petroleum consumption, our analysis shows that prices do not even reflect the direct costs of petroleum production. At a time of tight fiscal constraints and cuts to social programs, the government should not spend billions of dollars every year to subsidize oil and the environmental problems that result from its consumption.

The costs of supplying oil should fall on the user, not on the general taxpayer. Continued subsidization of oil makes little sense. Subsidies to the oil fuel cycle distort oil exploration, production and consumption decisions; reduce the incentive to develop substitutes; intensify environmental degradation; and cost taxpayers billions of dollars per year. Our analysis suggests that subsidy reform can be a positive force in achieving environmental improvements and substantial fiscal savings, while also eliminating the price distortions that hinder economic efficiency. Furthermore, our analysis suggests that the magnitude of subsidies is large enough that they can impede the efficacy of other policy reform efforts (such as carbon taxes) if ignored.

The historically low oil prices now in effect provide a tremendous opportunity for governments to phase out their oil subsidies with minimal inflationary risks. To help this process, efforts to characterize, report, and remove oil subsidies need to be intensified. Based on our analysis, we make the following recommendations for structural change. To reduce the economic dislocations, many of these reforms should be phased in over time.

1) **Decouple oil subsidies from rural economic development.** Many subsidies to oil exploration and production are justified on the grounds that they provide jobs and livelihoods for isolated rural populations. Data suggest that development policies focused on natural resource extraction have rarely been successful. In addition, rapid advances in telecommunications and computer technology provide an increasing range of development options for geographically-isolated communities. By decoupling oil development and jobs, governments can stop subsidizing environmental degradation and work to create cleaner, higher value job opportunities for rural populations.

2) **Internalize oil-related defense costs into market prices.** Where governments choose to intervene in oil markets to ensure the security of supplies, the costs of this intervention should be recovered through a user fee on oil consumers. Given the magnitude of these costs, excluding them from the price of oil creates significant and undesirable distortions in consumption behavior.

3) **Treat Strategic Petroleum Reserve like a formal government enterprise.** SPR costs taxpayers billions of dollars per year in direct costs and foregone interest. The Reserve should be treated as a government enterprise, financed through taxes on oil consumption and formally held responsible for repayment of invested capital plus interest.

4) **Include subsidy reform as an integral element in strategies to mitigate the impacts of climate change.** Taxing emissions makes little sense if governments simultaneously continue to subsidize fossil fuels. Subsidy identification, reporting, and removal should be an integral part of climate change mitigation programs.

5) **Improve the transparency of oil leases on public lands so terms can be easily compared.** Subsidized lease terms can provide large benefits to oil producers at the taxpayers' expense, and the resulting acceleration in oil development creates or aggravates environmental problems. Leasing of public oil reserves should be done in a transparent manner at both the federal and state levels. Environmental groups should work with the relevant government agencies to develop a standard disclosure form to be completed for each sale. Modification of lease terms should also be reported in a standardized, publicly available format. This disclosure form will ensure that lease-related subsidies are visible and that lease terms are comparable across sales. Given the international nature of oil markets, the goal of this disclosure system should be to allow international comparisons of lease terms.

REFERENCES

"Administration Begins Crafting Plan to Cut Greenhouse Emissions." *Inside EPA.* October 31, 1997, p. 10.

Alaska Oil & Gas Commission, Oil and Gas Policy Council. *Report to the Governor.* February 1996.

Anderson, Eric and Wayne Talley. "The Oil Spill Size of Tanker and Barge Accidents: Determinants and Policy Implications." *Land Economics*. Vol. 71, No. 2. May 1995, pp. 216-28.

Apucoin, Mary P. "Tapping into the History of the Trans-Alaska Pipeline." *Oil & Gas Journal*. June 1997, p. 46.

Arctic Circle Virtual Classroom. "Corporate Strategies and Village Values." Obtained from http://www.lib.uconn.edu/ArcticCircle/VirtualClassroom/case2a/case2avc.html. September 29, 1997.

Arctic Circle. "Indigenous Rights and Northern Lands: Who Should Own the Land?" Obtained from http://www.lib.uconn.edu/ArcticCircle/SEEJ/ancsa5.html. September 29, 1997.

Arctic Perspectives. "Arctic National Wildlife Refuge: Prudhoe Bay and the North Slope." Obtained from http://www.arcticpersp.org/ANWR/APanwrPrudhoe.html. September 29, 1997.

Arthur D. Little, Inc. and John Gault. *Review of International Competitiveness of Alaska's Fiscal System.* Prepared for the Alaska Department of Revenue. September 1995.

Barthold, Tom. Joint Committee on Taxation. Personal communication. February 20, 1998.

Barubie, Ed. Comptroller, U.S. Department of Defense, Alaska Command. Personal communication. September 10, 1997.

Bebout, John. U.S. Bureau of Land Management. Personal communication. November 10, 1997.

Ben Johnson Associates, Inc. "Costing Definitions and Concepts." Obtained from http://www.microeconomics.com/essays/cost_def/cost_def.htm. January 27, 1998.

Berry, Mary Clay. *The Alaska Pipeline: The Politics of Oil and Native Land Claims*. Bloomington, IN: Indiana University Press. 1975.

Biro, Zolton. London Economics, Ltd. "Cost Allocation in Principle and Practice." October 1994. Obtained from http://www.londecon.co.uk/pubs/comp/costall.htm. January 27, 1998.

Blake, Leslie R. Manager. U.S. Department of Defense, Defense Investigative Service, Office of FOIA & Privacy. Personal communication. September 12, 1997.

Bohi, Douglas and Michael Toman. *The Economics of Energy Security*. Boston: Kluwer Academic Publishers. 1996.

Bosie, Jerry. Joint Pipeline Office. Personal communication. September 3, 1997.

Braathen, Nils Axel. OECD. Personal communication. December 11, 1997.

Brian, Danielle. Executive Director, Project on Government Oversight. Written Statement before the House Committee on Resources, Subcommittee on Energy and Mineral Resources. September 18, 1997. Obtained from http://www.pogo.org/addit-pr/Brian_RIK.htm. November 9, 1997.

Brian, Danielle. Project on Government Oversight. Personal communication. November 12, 1997.

"Cleanup Damages for Spills Limited to Those Available Under OPA, Court Says." *Environment Reporter*. September 26, 1997.

Cohen, William S. Secretary of Defense, U.S. Department of Defense. *Annual Report to the President and the Congress*. April 1997.

Compton, Dana. U.S. Coast Guard, National Pollution Funds Center. Personal communication. November 12, 1997.

Cone, B. W., et al. *An Analysis of Federal Incentives Used to Stimulate Energy Production*. Richland, WA: Battelle Memorial Institute. Prepared for the U.S. Department of Energy. December 1978.

Copulos, Milt. *Answering America's Energy and Environmental Dilemma*. National Defense Council Foundation. 1990.

Copulos, Milt. National Defense Council Foundation. Personal communication. October 16, 1997.

Coy, Peter and Gary McWilliams. "The New Economics of Oil." *Business Week*. November 3, 1997, p. 142.

Crow, Patrick. "Royalty Valuation Rule Changes Loom." *Oil & Gas Journal*. June 30, 1997, pp. 25-30.

Crow, Patrick. "U.S. industry under attack for alleged royalty underpayments." *The Oil & Gas Journal*. October 28, 1996, p. 19.

Dase, Bill. Railroad Commission of Texas, Pipeline Safety Office. Personnel communication. November 6, 1997.

Delucchi, Mark and James Murphy. "U.S. Military Expenditures to Protect the User of Persian-Gulf Oil for Motor Vehicles." Report #15 in the series *The Annualized Social Cost of Motor-Vehicle Use in the United States, based on 1990-91 Data*. UCD-ITS-RR-93-3 (15). April 1996.

DeRocco, Tom. "President Signs Federal Oil and Gas Royalty Simplification and Fairness Act into Law." U.S. Minerals Management Service, Office of Communications, Press Release. August 13, 1996.

Die, Roy. Underwriters Indemnity Company. Personal communication. November 4, 1997.

Dougherty, Linda. U.S. Office of Pipeline Safety, Compliance Office. Personal communication. November 10, 1997.

Dougherty, Stanley J., Lieutenant Colonel, U.S. Department of Defense, Alaska Command. Personal communication. August 27, 1997.

Dreissen, Pat. Joint Committee on Taxation. Personal communication. February 24, 1998.

Erb, James. Pennsylvania Department of Environmental Protection. Personal Communication. October 21, 1997.

Fazio, Dale. U.S. Minerals Management Service, Washington Royalty Liaison Office. Personal communication. November 11, 1997.

Friedel, Jeff. COFR Examiner, U. S. Coast Guard Nation Pollution Funds Center. Personal communication. November 12, 1997.

"From fur trading to portfolios: Alaska (economics of the 1971 Alaska Native Claims Settlement Act)." *The Economist*. Vol. 339, No. 7967. May 25, 1996, p. 31.

Fuller, Graham and Ian Lesser. "Persian Gulf Myths." *Foreign Affairs*. May/June 1997.

Furrow, Buck. U.S. Office of Pipeline Safety. Personnel communication. November 6, 1997.

Gorte, Ross. *Federal Sales of Natural Resources: Allocation and Pricing*. Washington, DC: Congressional Research Service, December 16, 1993. Obtained from http://www.cnie.org/nle/nrgen-2.html. October 7, 1997.

Gotbaum, Joshua. Assistant Secretary of Defense for Economic Security, U.S. Department of Defense. *United States Dependence on Foreign Oil*. Hearing before the U.S. Senate Committee on Foreign Relations. Senate Hearing 104-21. March 27, 1995, pp. 24-25.

"H.R. 1648: The National Energy Security Act of 1997." Provided by the Office of Wes Watkins (R-Oklahoma). November 6, 1997.

Haspel, Abraham. "Drilling for Dollars: The New and Improved Federal Oil Lease Program." *Regulation*. Fall 1990, pp. 62-68.

Hassel, Odd Auker. "Smooth Sailing or Rough Waters? The Tanker Industry and the Environmental Challenges." Cambridge, MA: Cambridge Energy Research Associates. 1990.

Hirsch, Brian. Doctoral Student, University of Wisconsin-Madison. Personal communication. September 1997.

Hirsch, Brian. *Indigenous Protest and Community Development in the Arctic: A Case Study of the Gwich'in Nation in Alaska*. Master's Thesis. University of Wisconsin-Madison. 1996.

Hochheiser, William. U.S. Department of Energy. Personal communication. January 13, 1998.

Horngren, Charles and George Foster. *Cost Accounting: A Managerial Emphasis, 7th Edition*. Englewood Cliffs. NJ: Prentice Hall. 1991.

Hwang, Roland. *Money Down the Pipeline: Uncovering the Hidden Subsidies to the Oil Industry*. Union of Concerned Scientists. September 1995.

Independent Petroleum Association of America. "Domestic Oil and Natural Gas Producers Call on Congress for Fairer, More Competitive Tax System." July 31 1996. Obtained from http://www.ipaa.org. October 29, 1997.

Independent Petroleum Association of America. "Marginal Wells." in *Profile of Independent Producers 1996*. Obtained from http://www.ipaa.org/departments/information/information_services/profile_of_producers.htm. October 29, 1997.

Intergovernmental Panel on Climate Change. *Climate Change 1995: Economic and Social Dimensions of Climate Change*. Contribution of Working Group III to the Second Assessment Report of the IPCC, Cambridge University Press. 1996.

Interstate Oil and Gas Compact Commission (IOGCC), Ad Hoc Idle Well Committee. *Produce or Plug: The Dilemma over the Nation's Idle Oil and Gas Wells*. December 1996.

Interstate Oil and Gas Compact Commission. *State Incentives to Maximize Oil and Gas Recovery*. January 1997.

Joint Committee on Taxation. "Estimated Budget Effects of the Conference Agreement on the Revenue Provisions of H.R. 2014, the 'Taxpayer Relief Act of 1997': Fiscal Years 1997-2007." JCX-39-97, July 30, 1997.

Jones, Mike. Sergeant, Elmendorf Air Force Base, Public Affairs Office. Personal communication. September 10, 1997.

Kaufmann, William W. and John D. Steinbruner. *Decisions for Defense: Prospects for a New Order.* Washington, DC: The Brookings Institution. 1991.

Koplow, Douglas. "Energy Subsidies and the Environment." In OECD, *Subsidies and Environment: Exploring the Linkages*. 1996.

Koplow, Douglas. *Federal Energy Subsidies: Energy, Environmental, and Fiscal Impacts -- Main Report and Technical Appendix*. Washington, DC: Alliance to Save Energy. 1993.

Ladbury, Adrian. "No crisis in OPA deadline: Alternative markets fill pollution coverage void for ships." *Business Insurance*. December 26, 1994, p. 1.

Loper, Joe. *State and Local Taxation: Energy Policy by Accident*. Washington, DC: The Alliance to Save Energy. June 1994.

Mathessen, Marty. American Petroleum Institute. Personnel communication. November 7, 1997.

McKenney, Bruce and Douglas Koplow. *Improving Access-to-Capital, Site Transition, and Brownfield Redevelopment Through More Effective Environmental Risk Management.* Cambridge, MA: Industrial Economics, Inc. Prepared for the U.S. Environmental Protection Agency. February 1998.

McKey, Paul. U.S. Federal Energy Regulatory Commission, Office of Public Affairs. Personnel communication. November 6, 1997.

Mead, Walter, Asbjorn Moseidjord, and Philip Sorenson. "The Rate of Return Earned by Lessees under Cash Bonus Bidding for OCS Oil and Gas Leases." *The Energy Journal*. Vol. 4, 1983, pp. 37-52.

Miller, George. "Unjustified Giveaway to the Oil Industry." *Albion Monitor*. September 2, 1995. Obtained from http://www.monitor.net/monitor. September 1997.

Miller, Lloyd B. "Federal court open door to improved tribal-state relations." *Alaska Business Monthly*. Vol. 13, No. 6. June 1997, p. 26.

Miller, Pam. *The Reach of Oil in the Arctic: Alaska, USA.* Washington, DC: Greenpeace USA. August 1997.

Moler, Elizabeth Anne. Deputy Secretary, U.S. Department of Energy, Testimony Before the House Subcommittee on Energy and Power of the Committee on Commerce, September 16, 1997. Obtained from http://www.fe.doe.gov/remarks/916moler.html. February 25, 1998.

Morgan, Richard. *Federal Energy Tax Policy and the Environment*. Washington, DC: Environmental Action Foundation. April 1, 1985.

National Association of State Budget Officers. "State Tax Expenditure Reports." Obtained from http://www.nasbo.org/pubs/infobrf/v02n03.htm. July 3, 1997.

National Science Foundation. *Science and Engineering Indicators - 1996*.

Natural Resources Defense Council. *No Safe Harbor: Tanker Safety in America's Ports*. 1990.

Neiley, Darrel. Chief of Financial Management. U.S. Coast Guard, National Pollution Funds Center. Personnel communication. October 26, 1997.

Nockels, Joan M. "Redefining federal public lands in Alaska." *Environmental Law*. Vol. 26, No. 2. Summer 1996.

Pollack, Gerald. "Promoting the U.S. Flag Merchant Marine." *Business Economics*. April 1991, pp. 45-50.

Project on Government Oversight. *Drilling for the Truth: More Information Surfaces on Unpaid Oil Royalties*. May 1997.

Quarterman, Cynthia. Director, U.S. Minerals Management Service. Congressional Testimony Prepared for the House Subcommittee on Government Management, Information and Technology of the Committee on Government Reform and Oversight. June 17, 1996. Obtained from http://www.mms.gov/testimon/test6176.html. November 9, 1997.

Randall O'Toole. "Forest-by-Forest Timber Sale Accounting for 1995." Thoreau Institute, obtained from http://www.teleport.com/~rot/description95.html. March 17, 1998.

Ravenal, Earl C. *Designing Defense for a New World Order: The Military Budget in 1992 and Beyond*. Washington, DC: Cato Institute. 1991.

Ravenal, Earl C. Georgetown University School of Foreign Service. Personal communication, March 1998.

Ravenal, Earl C. "The 1998 Defense Budget," Chapter 7 in the *Cato Handbook for Congress*. Washington, D.C.: The Cato Institute. 1997. Obtained from http://www.www.cato.org/pubs/handbook/hb105-7.html. February 20, 1998.

Rey, R. Michael. U.S. Department of Energy. "Impact of Federal Royalty Relief on Future Oil Recovery from Federal Stripper Leases in the State of New Mexico - Final Report." Memorandum to Hilary Oden, U.S. Bureau of Land Management. May 3, 1991.

Richard Neu. RAND Corporation. Personal communication. March 11, 1998.

Rogers, George W., ed. *Change in Alaska: People, Petroleum, and Politics*. College, AK: University of Alaska Press. 1970.

Roodman, David. *Paying the Piper: Subsidies, Politics, and the Environment.* Washington, DC: Worldwatch Institute. December 1996.

Rothschild, Edwin. *Oil Imports, Taxpayer Subsidies and the Petroleum Industry*. Washington, DC: Citizen Action. May 1995.

Ruijgrok, Elisabeth and Frans Oosterhuis. *Energy Subsidies in Western Europe.* Amsterdam: Greenpeace International. May 1997.

Saida, Reza and James Marsden. "Number of Bids, Number of Bidders and Bidding Behavior in Outer-Continental Shelf Oil Lease Markets." *European Journal of Operational Research*. Vol. 58. 1992, pp. 335-343.

Sankovitch, Nina, et al. *Safety at Bay: A Review of Oil Spill Prevention and Cleanup in U.S. Waters*. New York: Natural Resources Defense Council. December 1992.

Shannahan, Marycarol. Strategic Petroleum Reserve, personal communication. April 27, 1998.

"State settles lawsuit over royalties." *Lubbock Avalanche-Journal*. August 22, 1997. Obtained from http://www.lubbockonline.com/news/082397/state.htm. November 9, 1997.

Steenblik, Ronald. OECD. Personal communication. February 25, 1998.

Stewart-Liberty, Olivia. "[OPA]: A Legacy of Confusion." *Asset Finance & Leasing Digest*. May 1995, pp. 24-27.

"Tanker Owners Cope with OPA." *Oil and Gas Journal*. July 27, 1992, p. 38.

Tintera, John. Railroad Commission of Texas, Site Remediation Group. Personnel communication. November 6, 1997.

U.S. General Accounting Office. *International Taxation: Problems Persist in Determining Tax Effects of Intercompany Prices*. June 1992.

U.S. Army Corps of Engineers. *Waterborne Commerce of the Unites States, 1995*. "Part 5 - Waterways and Harbors, National Summaries."

U.S. Bureau of Land Management, Oil and Gas Program. *Bonding/Unfunded Liability Review*. March 1995.

U.S. Bureau of Land Management. "Promotion of Development, Reduction of Royalty on Heavy Oil, Final Rule." *Federal Register*. Vol. 61. February 8, 1996, pp. 4748-52.

U.S. Bureau of Land Management. "Royalty Rate Reduction for Stripper Oil Properties." *Federal Register*. Vol. 61. August 30, 1996, pp. 45926-27.

U.S. Coast Guard. National Pollution Funds Center. *National Pollution Funds Center 1996 Annual Report*.

U.S. Coast Guard. National Pollution Funds Center. *Statement of Mr. Daniel F. Sheehan on the Economic Impact of Vessel Certificates of Financial Responsibility*. Obtained from http://www.dot.gov/dotinfo/uscg/hq/npfc/cofr_sp.htm. October 20, 1997.

U.S. Congressional Budget Office. Letter from June O'Neill to George Miller, Democratic Leadership, House Committee on Resources. November 2, 1995.

U.S. Congressional Research Service. *Tax Expenditures: Compendium of Background Material on Individual Provisions*. Senate Committee on the Budget. December 1996.

U.S. Congressional Research Service. *The External Costs of Oil Used in Transportation*. 92-574 ENR. June 17, 1992.

U.S. Department of Defense. "Active Duty Military Personnel Strengths by Regional Area and by Country." June 30, 1995. Obtained from http://web1.whs.osd.mil/mmid/military/309a695.htm. September 11, 1997.

U.S. Department of Defense. Directorate for Information Operations and Reports. "Active Duty Military Personnel Strengths by Regional Area and by Country." Obtained from http://web1.whs.osd.mil/mmid/military/309hist.htm. February 13, 1998.

U.S. Department of Defense. Office of the Under Secretary of Defense (Comptroller). *National Defense Budget Estimates for FY 1998*. March 1997.

U.S. Department of Energy. "FY1996 Internal Statistical Table by Appropriation." November 8, 1995.

U.S. Department of Energy. Office of Strategic Petroleum Reserve. "Opportunity for Public Comment on Strategic Petroleum Reserve Policy." *Federal Register*. April 24, 1997. Obtained from http://www.fe.doe.gov/spr/sprfedrg.html. March 5, 1998.

U.S. Department of Energy. *Strategic Petroleum Reserve Annual Report*. February 15, 1996.

U.S. Energy Information Administration. *Federal Energy Subsidies: Direct and Indirect Interventions in Energy Markets*. November 1992.

U.S. Energy Information Administration. *International Energy Annual. 1995*. December 1996.

U.S. Energy Information Administration. *International Petroleum Statistics Report.* September 1997.

U.S. Energy Information Administration. *Performance Profiles of Major Energy Producers 1995*.

U.S. Environmental Protection Agency. "Oil Spill Prevention Preparedness & Response Program." August 26, 1996. Obtained from http://www.epa.gov/superfnd/oerr/er/oilspill/response.html. July 14, 1997.

U.S. General Accounting Office. *Adequacy of Preparation and Response Related to Exxon Valdez Oil Spill*. August 10, 1989.

U.S. General Accounting Office. *Credit Reform: Review of OMB's Credit Subsidy Model*. GAO/AIMD-97-145. August 1997.

U.S. General Accounting Office. *Drinking Water: Safeguards are not Preventing Contamination from Injected Oil and Gas Wastes*. GAO/RCED-89-97. July 1989.

U.S. General Accounting Office. *Export-Import Bank: Options for Achieving the Possible Budget Reductions*. GAO/NSIAD-97-7. December 1996.

U.S. General Accounting Office. *Mineral Resources: Interior's Use of Oil and Gas Development Contracts.* GAO/RCED-91-1. September 1991.

U.S. General Accounting Office. *Overseas Presence: More Data and Analysis Needed to Determine Whether Cost-Effective Alternatives Exist.* GAO/NSIAD-97-133. June 3, 1997.

U.S. General Accounting Office. *Southwest Asia: Costs of Protecting U.S. Interests.* GAO/NSIAD-91-250. August 1991.

U.S. General Accounting Office. *Tax Administration: Compliance Measures and Audits of Large Corporations Need Improvement*. September 1994.

U.S. General Accounting Office. *Trans-Alaska Pipeline: Actions to Improve Safety Are Under Way*. GAO/RCED-95-162. August 1995

U.S. General Accounting Office. *Trans-Alaska Pipeline: Ensuring the Pipeline's Security*. GAO/RCED-92-58BR. November 1991, p. 5.

U.S. House of Representatives. House Committee on Natural Resources, Democratic Staff Report. *Taking from the Taxpayer: Public Subsidies for Natural Resource Development*. August 1994. Obtained from http://www.house.gov/resources/105cong/democrat/subsidy.htm. October 1997.

U.S. Minerals Management Service. "Surety Bond Requirements Amended: MMS Issues Final Rule." May 21, 1997. Obtained from http://www.mms.gov/omm/gomr. October 24, 1997.

U.S. Minerals Management Service. *Final Interagency Report on the Valuation of Oil Produced from Federal Leases In California*. May 16, 1997.

Wahl, Jenny. *Oil Slickers: How Petroleum Benefits at the Taxpayer's Expense*. Washington, DC: Institute for Local Self Reliance. August, 1997.

Williams, Carrol. U.S. Minerals Management Service. Personal communications. October 15 and October 28, 1997.

Wojcik, Joanne. "U.S. Oil Spill Law Rocks the Boat." *Business Insurance*. October 19, 1992, p. 16.