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.

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[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]

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[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.

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[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.

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[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.

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[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.

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[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.

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[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.

Exhibit A-6a

DEPARTMENT OF THE INTERIOR
Bureau of Land Management
(millions of dollars)

Program	FY95 Obligations	Estimated FY95 Obligations (Note 1)	Oil & Gas Share	Allocation	Oil Share	Allocation	Description	Source
Management of Land and Resources								
Energy and Minerals	72						Management of onshore oil, gas, coal, and geothermal resources, including resource assessments, use authorization, compliance, and post-use reclamation.	OMB A-549
Oil & Gas		54.7	54.7	All oil and gas	24.2	Oil share of oil and gas value of onshore production from mineral leases		BLM III-4
Other		17.3	0.0	No oil or gas	0.0			BLM III-4
Land Resources	118						Management of rangeland and forest services.	OMB A-549
Soil, Water, & Air		17.9	4.0	Land use spending mix	1.8	Oil share of oil and gas value of onshore production from mineral leases		BLM III-4
Automated Land & Min Records System	76	69.2	15.6	Land use spending mix	6.9	Oil share of oil and gas value of onshore production from mineral leases	Development and implementation of the system	OMB A-549
Workforce and Organizations Support	130						General operations support activities	OMB A-549
Information Systems Operators		16.2	1.8	Management of Land and Resources spending mix	0.8	Oil share of oil and gas value of onshore production from mineral leases		BLM III-4
Administrative Support		50.4	5.5	Management of Land and Resources spending mix	2.4	Oil share of oil and gas value of onshore production from mineral leases		BLM III-4
Bureauwide Fixed Costs		63.4	6.9	Management of Land and Resources spending mix	3.0	Oil share of oil and gas value of onshore production from mineral leases		BLM III-4
Alaska Mineral Assessment	0	0.0	0.0		0.0		Identification, inventory, and evaluation of mineral resources on Federal land in Alaska.	OMB A-549
Realty and Ownership Management	75						Management and processing of authorizations and compliance for realty actions, rights-of-way, surveys, and other land administration.	OMB, A- 549 - A-550
Alaska Conveyance Land		32.4	---	unquantified			Federal land transfers to Alaska natives, native corporations, and the state. (Note 2)	BLM III-4
Cadastral Survey		12.7	2.9	Land use spending mix	1.3	Oil share of oil and gas value of onshore production from mineral leases		BLM III-4
Land & Realty		29.8	6.7	Land use spending mix	3.0	Oil share of oil and gas value of onshore production from mineral leases	Processes land use authorizations (rights-of-way) and land exchanges; manages information on public lands; completes land disposal actions.	BLM III-4
Resource Protection and Maintenance	69						Management of land use planning to balance competing uses	OMB A-549

Exhibit A-6a

DEPARTMENT OF THE INTERIOR
Bureau of Land Management
(millions of dollars)

Program	FY95 Obligations	Estimated FY95 Obligations (Note 1)	Oil & Gas Share	Allocation	Oil Share	Allocation	Description	Source
Resource Management Planning		9.5	2.1	Land use spending mix	0.9	Oil share of oil and gas value of onshore production from mineral leases		BLM III-4
Facilities Maintenance		32.4	1.5	BLM spending mix; Oil and gas share of Land and Resources Management	0.7	Oil share of oil and gas value of onshore production from mineral leases	Maintenance of BLM facilities and infrastructure on public lands. (Includes water, sewers, roads, trails, bridges) (Note 3)	BLM III-4
Resource Protection & Law Enforcement		10.1	2.3	Land use spending mix	1.0	Oil share of oil and gas value of onshore production from mineral leases	Includes investigations of oil and gas theft.	BLM III-4
Hazardous Materials		17.0	3.8	Land use spending mix	1.7	Oil share of oil and gas value of onshore production from mineral leases	Environmental enforcement and compliance activities associated with hazardous materials on public lands. (Note 4)	BLM III-4
Mining Law Administration	27		0.0	No Oil and Gas	0.0	Oil share of oil and gas value of onshore production from mineral leases	Administration of the General Mining Law of 1872, which provides for locating and patenting mining claims for minerals such as gold, silver, copper, nickel, zinc, and lead.	OMB A-549
Reimbursable Program	14							OMB A-549
Subtotal, Management of Land and Resources	**668**		**107.7**		**47.6**		Note: Items don't sum to total because not all programs listed here.	OMB A-549
Construction	17		0.8	BLM spending mix; Oil and gas share of Land and Resources Management	0.3	Oil share of oil and gas value of onshore production from mineral leases	Construction of buildings, recreation facilities, roads, trails, and other facilities	OMB A-551
Total Spending	685		108.5		47.9			
OFFSETTING COLLECTIONS								
Management of Lands and Resources								
Mining Law Administration Fees	27		0.0	No Oil and Gas	0.0	Oil share of oil and gas value of onshore production from mineral leases		OMB A-549
Other Collections	14		3.2	Land use spending mix	1.4	Oil share of oil and gas value of onshore production from mineral leases		OMB A-549
Total Offsets	41		3.2		1.4			

Exhibit A-6a

DEPARTMENT OF THE INTERIOR
Bureau of Land Management
(millions of dollars)

Program	FY95 Obligations	Estimated FY95 Obligations (Note 1)	Oil & Gas Share	Allocation	Oil Share	Allocation	Description	Source
GROSS SUBSIDY TO OIL					**47.9**			
OFFSETTING COLLECTIONS					**1.4**			
NET SUBSIDY TO OIL					**46.6**			

Breakout by Subsidy Category	Gross	Offsets	Net
Access to resources	47.9	1.4	46.6

NOTES

1) Obligations for sub-categories of certain line items are based on the share of the main line item's FY95 budget authory for which the sub-category accounts.
2) Although the primary focus is on land transfer initiatives, this item includes much of BLM's other activities in Alaska (e.g., land use authorizations; management of Alaska native corporation easements; and issuance of leases, sales, and permits). It is difficult to precisely quantify the extent to which activities in this program may support oil production and transportation because specific activities are not broken out in BLM's Budget Justifications. Further, it is difficult to distinguish between activities supporting BLM's land conveyance responsibilties and its normal program activities.
3) This item appears to involve maintenance operations for all BLM facilities. It was allocated based on all BLM spending, not just the Land and Resources Management division.
4) The allocation of hazardous materials activities may underestimate the proportion for oil because it is based solely on spending for different land use activities and does not factor relative risks. Oil and other energy and mineral activities are more likely to pose hazards than grazing, forestry, and other land uses.
4) Spending for threatened and endangered animals was allocated to oil activities.

SOURCES

United States Department of the Interior, Bureau of Land Management, *Budget Justifications, FY 1997*.
United States Executive Office of the President, Office of Management and Budget, *Budget of the United States Government, Fiscal Year 1997*.

Exhibit A-6b

DEPARTMENT OF THE INTERIOR
Mineral Management Service
(millions of dollars)

PROGRAM	**1995 Obligations**	**Oil Share**	**Allocation**	**Description**	**Source**
Royalty and Offshore Minerals Management					
Outer Continental Shelf Lands	87	39.1	Oil and gas share of 1994 OCS production; oil share of 1995 OCS oil and gas production.	Manages leasing operations and regulates exploration, development, and production on OCS land .	OMB A-559
Royalty Management	68	27.2	Oil and gas share of 1996 receipts; oil share of 1995 oil and gas production on Federal lands.	Activities associated with royalties, rentals, and bonuses due from production on Federal, Indian, alotted, and OCS lands.	OMB A-559
General Administration	33	14.1	Oil share of obligations for direct program spending.		OMB A-559
Reimbursable Program	12	5.1	Oil share of obligations for direct program spending.		
Oil Spill Research	6	6.0	All Oil	Oil pollution research and duties related to spill prevention. Funds appropriated from the Oil Spill Liability Trust Fund.	OMB A-562
Total Spending	206	91.4			
OFFSETTING COLLECTIONS					
Royalty and Offshore Minerals Management					
Reimbursable Program	12	5.1	Oil share of obligations for direct program spending.	Offsetting collections do not include leasing receipts, which reflect the return on the sale of resources.	OMB A-562
Oil Spill Research					
Oil Spill Liability Trust Fund	6	6.0	All Oil		OMB A-562
Total Offsets	18	11.1			

GROSS SUBSIDY TO OIL	**91.4**
OFFSETTING COLLECTIONS	**11.1**
NET SUBSIDY TO OIL	**80.3**

Breakout by Subsidy Category	**Gross**	**Offsets**	**Net Subsidy to Oil**
Access to Resources	85.4	5.1	80.3
Response to Oil Contamination	6.0	6.0	0.0

NOTES

1) Net outlays for Royalty and Offshore Minerals Management were $181 million in FY95.
2) Royalties are counted as a return on asset sales and are not an offset to Mineral Management Service program costs.

SOURCE

United States Department of the Interior, Minerals Management Service, *Budget Justifications, F.Y. 1997*.

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