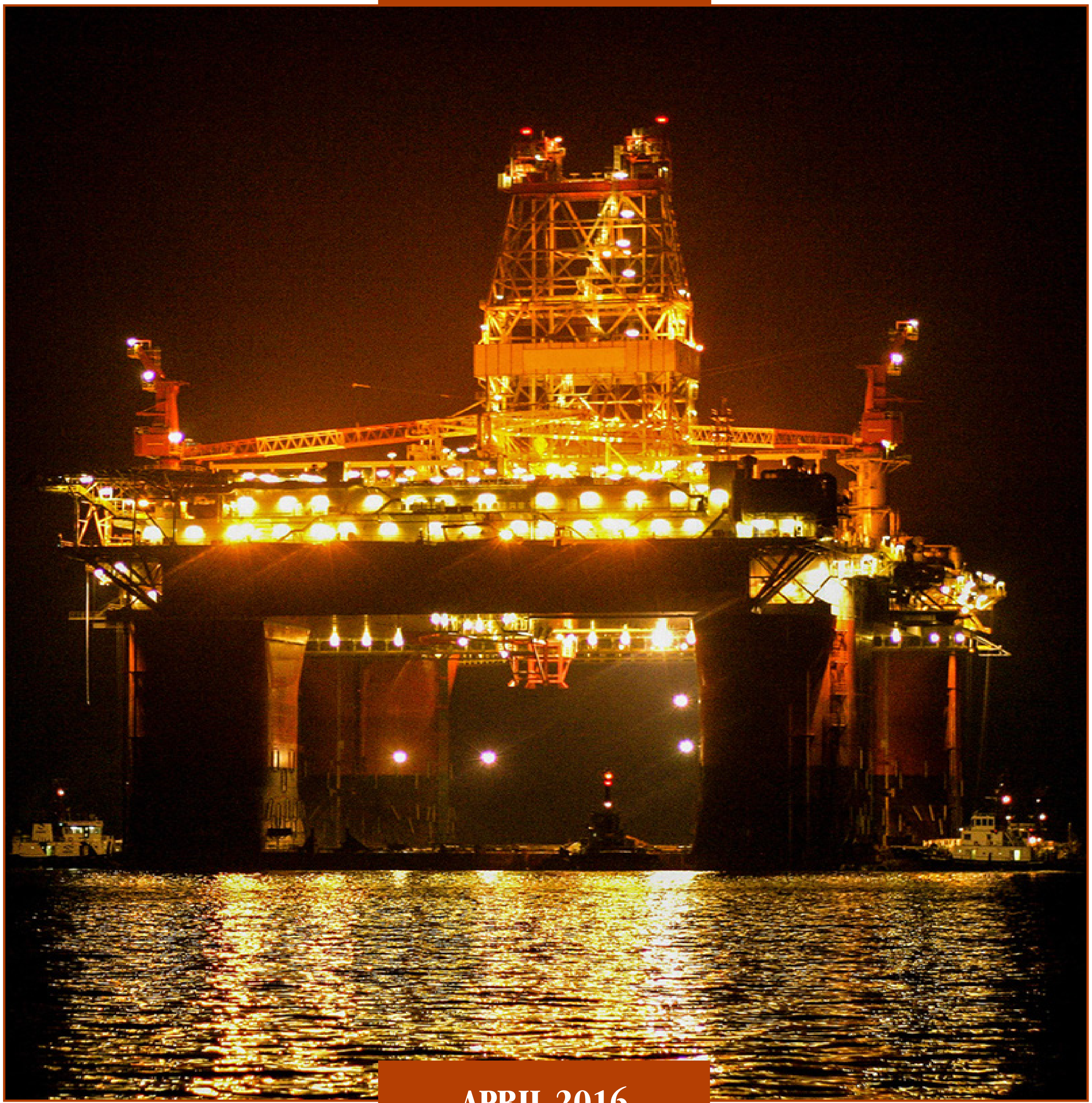
CONGRESS OF THE UNITED STATES
CONGRESSIONAL BUDGET OFFICE

CBO

Options for Increasing Federal Income From Crude Oil and Natural Gas on Federal Lands



APRIL 2016

Notes

Numbers in the text may not add up to totals because of rounding.

Unless otherwise indicated, all years referred to in this report are federal fiscal years, which run from October 1 to September 30 and are designated by the calendar year in which they end.

The photograph on the cover shows the Thunder Horse semisubmersible platform moored in the Gulf of Mexico. The platform is a production and oil drilling facility with crew quarters. The photograph, taken on January 26, 2005, was provided courtesy of BP public affairs staff.

Contents

Summary

The production of oil and natural gas in the United States has increased rapidly over the past decade. As of 2014, domestic production of crude oil had grown to about half of total consumption, and domestic production of natural gas represented almost 95 percent of total consumption. Domestic oil and gas production occurring on federal lands or in federal waters off the coast of the United States represented about one-fifth of total U.S. production in 2014.[1]

Federal lands and waters (referred to collectively as federal lands in this report) are managed by the Department of the Interior (DOI), which allows private firms to compete for the right to produce oil and gas in those areas. The firms that receive those rights make payments to the federal government, which distributes some of the money to states; over the 2005–2014 period, those payments averaged $11 billion per year. (The firms' payments—which are income to the government—are recorded in the federal budget as offsetting receipts, which reduce outlays.) Two types of approaches could be used to increase federal income from oil and gas on federal lands. One approach is to increase the amount of land available for oil and gas production.[2] A second approach, and the one considered in this report, is to revise the rules governing access to the oil and gas resources.

How Does the Government Currently Manage Access to Crude Oil and Natural Gas on Federal Lands?

The Department of the Interior, charged with ensuring that the United States receives a fair return for the oil and gas underlying federal lands, uses a three-stage process (or fiscal regime) to manage private firms' access to those lands.

- *Leasing.* The federal government makes a set of approved parcels available for private leasing and uses an auction to identify the firm willing to pay the most for the right to explore and develop each parcel. The winning firm makes a onetime payment (its bonus bid) in exchange for exclusive access to explore the parcel.
- *Exploration.* Having leased a parcel, the federal government charges an annual rental fee for each year the lease is held without production of oil or gas.
- *Production.* For those parcels that produce oil or gas, the federal government collects royalty payments, which represent a share of the value of the extracted resources.

The maximum length of the exploration period is specified in the lease; once a parcel enters production, the lease continues in effect until production ends, which may be decades later.

Onshore Resources

For development of onshore oil and gas, the Department of the Interior operates under terms set by the Mineral Leasing Act of 1920, as amended, which have remained largely unchanged since 1987. Since that time, the minimum bid in auctions for access to federal lands has been $2 per acre, the rental fee has been $1.50 per acre for the first five years of the 10-year lease term and $2 per acre for the second five years, and the royalty rate has been 12.5 percent of production value.

Between 2003 and 2012, the federal government leased about 25,000 parcels (averaging 1,000 acres in size), about half of which were leased for less than $10 per acre,

1. Federal waters begin 3 marine leagues (about 9 nautical miles) from the low-water line in Texas and parts of Florida, and 3 nautical miles from the low-water line elsewhere.
2. For a discussion, see Congressional Budget Office, *Potential Budgetary Effects of Immediately Opening Most Federal Lands to Oil and Gas Leasing* (August 2012), www.cbo.gov/publication/43527.

including about 4,000 parcels that received no bids and were leased noncompetitively for no fee. Most leased parcels have no exploratory drilling or production during the lease term. For parcels leased between 1996 and 2003, all of which have reached the end of their 10-year exploration period, only about 10 percent of onshore leases issued competitively and 3 percent of those issued noncompetitively entered production.

Offshore Resources

For development of offshore oil and gas resources, the Outer Continental Shelf Lands Act gives the Department of the Interior significant flexibility to adjust the leasing terms. DOI currently sets terms for each lease that are designed to encourage exploration and production. In the leasing stage, the department establishes a minimum bid based on the relative cost of exploration and development; if the highest bid is found to be below estimates of a fair (market-based) return to taxpayers, it is rejected. In the exploration stage, the rental fee is higher for parcels in deep water, reducing slightly a leaseholder's incentive to wait to see whether additional information becomes available before undertaking costly exploratory drilling. (The effect is slight because the fee is very small relative to drilling costs.) For the production stage, DOI has set a royalty rate of 12.5 percent for offshore parcels near Alaska and recently increased the royalty rate to 18.75 percent for newly leased parcels in the Gulf of Mexico; the difference reflects the higher cost of development off the coast of Alaska.

How Much Income Has the Government Collected From Oil and Gas Leasing?

All told, the gross income (before payments to states) from onshore oil and gas resources averaged $3.0 billion annually from 2005 to 2014, comprising the following amounts:

- About $230 million per year in bonus bids,
- $50 million per year in fees for nonproducing leases, and
- $2.7 billion per year in royalties from production.

Total gross income from offshore oil and gas resources averaged $8.0 billion per year over the 2005–2014 period:

- Lease auctions generated about $1.8 billion,
- Rental fees generated about $230 million, and
- Royalties from production yielded about $6.0 billion.

Production from parcels and associated royalty payments can continue for many years, and thus leases issued in any given year represent only a small share of annual royalty income. In 2013, about 6 percent of royalty income from onshore oil and gas came from parcels that were leased in the previous 10 years; in contrast, about half came from parcels that were leased more than 50 years earlier. For offshore resources, about 8 percent of royalty income in 2013 came from parcels that were leased in the previous 10 years, and the majority came from parcels that were leased more than 20 years earlier.

Some of the income collected by the federal government in the three-stage process is shared with the governments of the states where (or nearest to where) the oil and gas were extracted. The states' shares of the income averaged almost 40 percent between 2005 and 2014.

How Could Lawmakers Change the Process to Increase Federal Income?

The Congressional Budget Office analyzed eight ways in which lawmakers could change the fiscal terms for oil and gas development on federal lands so as to increase federal income (see Summary Table 1). Some of the options would change qualitative features of the leasing process, such as auction formats and rules, whereas others would affect quantitative features, such as minimum bids or royalty rates. The specific versions of the quantitative options analyzed here for illustrative purposes are relatively modest, so as not to put federal lands at a competitive disadvantage relative to state-owned or privately owned lands. Smaller or larger versions of those options would yield smaller or larger increases in federal income. (Decreases in production that could result from larger changes would affect more than federal income and raise issues outside the scope of this report, such as possible environmental benefits or concerns about national security.)[3]

3. Such concerns are addressed in Congressional Budget Office, *Energy Security in the United States* (May 2012), www.cbo.gov/publication/43012.

Summary Table 1.

Policy Options for Oil and Natural Gas Production on Federal Lands

Millions of Dollars

Option		Increase in Federal Income Over 10 Years
	Onshore Parcels	
1	Require onshore parcels to be auctioned through a sealed-bid process	100
2	Allow BLM to establish lease-specific fiscal terms	a
3	Increase the minimum bid for auctions and noncompetitive leases	50
4	Impose a fee of $6 per acre on nonproducing parcels	200
5	Increase the royalty rate to 18.75 percent for all new onshore parcels	200
	Offshore Parcels	
6	Require parcels to be nominated for auction	150
7	Impose a fee of $6 per acre on nonproducing parcels	500
8	Increase the royalty rate when the price of oil or gas rises above a threshold	Less Than 25

Source: Congressional Budget Office, using data from the Department of the Interior's Bureau of Land Management and Office of Natural Resources and Revenue.

All estimates represent net federal receipts after distributing appropriate shares of gross proceeds to the states.

BLM = Bureau of Land Management.

a. The effect on receipts would depend on details of the authorizing legislation and its implementation.

For onshore resources, CBO considered the following approaches:

- Lawmakers could direct DOI to adopt an alternative form of auction that would encourage more intense competition between firms; greater competition would probably generate a small increase in the winning bids.
- The prohibition against setting lease-specific fiscal terms could be lifted, allowing DOI to set terms that were more advantageous for the government when there was greater certainty that parcels contained oil or gas reserves.
- Policymakers could instruct DOI to raise the minimum bid, the fee on nonproducing leases, or the royalty rate for all leases.

The options considered here would generate increases of between $50 million and $200 million in net income (after payments to states) over 10 years, CBO estimates. Reductions in production would be small or even negligible over that period or later.

For offshore resources, there are fewer policy options that DOI is not already considering.[4] One such option, designed to increase competition, would require firms to nominate parcels before they can be scheduled for auction, as is the case for onshore parcels. Other policies would impose a new fee on nonproducing leases or adopt a royalty rate that increased if the price of oil or gas rose. Those policies, at commonly discussed magnitudes, would boost net income by amounts ranging from less than $25 million over 10 years to $500 million over that period, CBO estimates. Effects on production would be negligible.

One important factor affecting CBO's estimates of budgetary effects over 10 years is the long lag time between leasing a parcel and beginning production from that parcel. The effects on net income of some options—for example, those that would change royalty rates—could be significantly larger outside of the 10-year period generally used for budget estimates, depending on future prices and other market conditions. But attempts to estimate budgetary effects beyond 10 years are hindered by greater uncertainty about those future conditions.

4. CBO's baseline budget projections account for actions that an agency is likely to take under current law; therefore, CBO's estimates of the budgetary effects of legislation that would merely accelerate such actions or make them more certain to occur may be substantially smaller than if the actions were not under consideration.

CHAPTER

1

The Current Process for Managing Access to Crude Oil and Natural Gas on Federal Lands

Since 2008, the production of oil and natural gas in the United States has increased rapidly (see Figure 1-1). Crude oil production in the United States rose from an average of 5.0 million barrels per day in 2008 to 8.3 million barrels per day in 2014. With that increase, domestic production rose from about 25 percent to about 45 percent of the oil consumed by U.S. households and businesses, and imports of oil fell by 3.6 million barrels per day (or about 30 percent). The production of natural gas rose by a similar amount, climbing from 9.9 million barrels of oil equivalent (BOE) per day in 2008 to 12.4 million BOE per day in 2014, which was almost 95 percent of domestic consumption. The Energy Information Administration (EIA) projects that the United States will become a net exporter of natural gas by 2017.

That growth in production reflected technological developments that allowed the development of shale resources, which are found mainly outside of federal lands.[1] Consequently, the shares of oil and gas production coming from federal lands declined over the past decade, falling below 20 percent for oil and gas production combined in 2014. Specifically, production on federal lands in 2014 accounted for about 2.1 million of the total 8.3 million barrels of oil per day, and about 1.8 million of the total 12.4 million BOE of gas. The rest came from oil or gas underlying lands owned by state governments, private landowners, and Native American tribes (see Figure 1-2). (Offshore resources near the shoreline are owned by state governments; resources in other waters controlled by the United States are owned by the federal government.)[2]

Federally owned resources are managed on behalf of U.S. taxpayers according to a set of rules established in law and, when the law is not specific, by rules adopted by the Department of the Interior. Within that department, the Bureau of Land Management (BLM) manages onshore resources, and the Bureau of Ocean Energy Management (BOEM) manages offshore resources.[3] Those agencies are directed to generate a fair return to taxpayers (one that approximates a market-based return) in exchange for providing private firms with access to those resources.[4] Agencies' gross collections deriving from leasing, exploration, and production averaged $11 billion per year from 2005 to 2014—consisting of $3 billion from onshore resources and $8 billion from offshore resources.

The Three Stages of the Process

The process, sometimes called the fiscal regime, used by the two agencies to govern access to oil and natural gas resources on federal lands has three stages (see Figure 1-3 on page 8):

1. See Department of the Interior, *Economic Report FY 2012*, Chapter 4 (July 2013); and Congressional Budget Office, *The Economic and Budgetary Effects of Producing Oil and Natural Gas From Shale* (December 2014), www.cbo.gov/publication/49815.

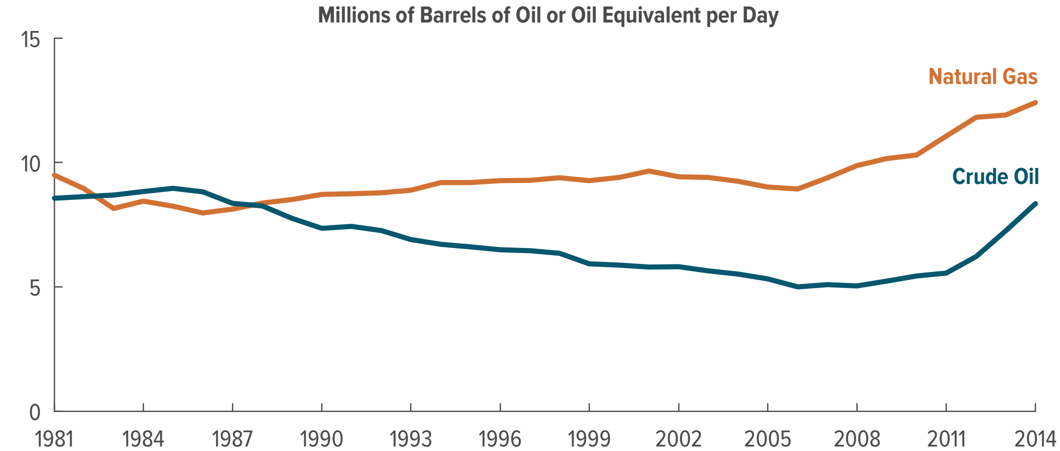
2. State ownership of offshore resources extends to 3 nautical miles from the low-water line except in Texas and parts of Florida, where it extends to 3 marine leagues, or about 9 nautical miles, from the low-water line. Federal waters include the rest of the Outer Continental Shelf, which "would appear to comprise an area extending at least 200 nautical miles from the official U.S. coastline and possibly farther where the geological continental shelf extends beyond that point." See Adam Vann, *Offshore Oil and Gas Development: Legal Framework*, Report for Congress RL33404 (Congressional Research Service, December 30, 2015), p. 2.

3. BLM manages 700 million acres of mineral resources but only about 250 million acres of surface access. The difference represents 400 million surface acres managed by other federal agencies and about 60 million acres owned by state or private landowners.

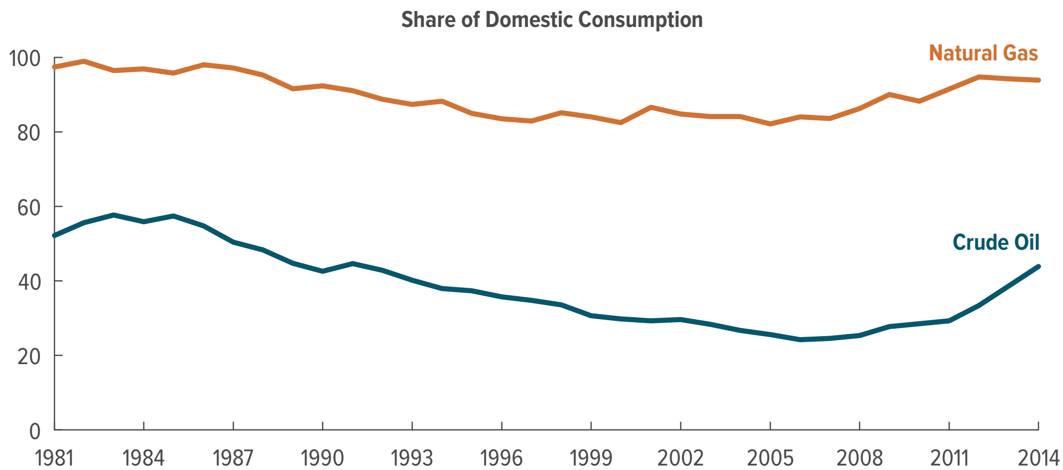
4. For federal waters, the Outer Continental Shelf Lands Act stipulates, "The Secretary [of the Interior] shall establish royalties, fees, rentals, bonuses, or other payments to ensure a fair return to the United States for any lease, easement, or right-of-way granted [for energy and related purposes]" (43 U.S.C. §1337). For onshore lands, the Federal Land Policy and Management Act of 1976 specifies that "the United States receive fair market value of the use of the public lands and their resources" (43 U.S.C. §1701).

Figure 1-1.

Production of Oil and Natural Gas in the United States



The increases in production of natural gas and oil in recent years reflect changes in technology that allowed development of gas and oil from shale resources.



Increased domestic production of natural gas and oil has meant less reliance on imports to supply domestic consumers.

Source: Congressional Budget Office, using data from the Energy Information Administration (EIA).

Production of natural gas before 1997 and consumption of natural gas before 2001 are CBO's estimates, using weighted averages of EIA data for calendar years.

Oil production includes natural gas liquids; gas production excludes those liquids, as well as gas that is flared, reinjected, or lost when extracted.

- *Leasing.* Several times each year, the federal government makes land available to private firms, which compete for the right to explore and develop specific parcels for oil and gas extraction. The firm willing to pay the most for that right (in the form of having the highest bid in an auction) pays its bid, commonly called the bonus bid, and is granted an exclusive lease for a set period of time.

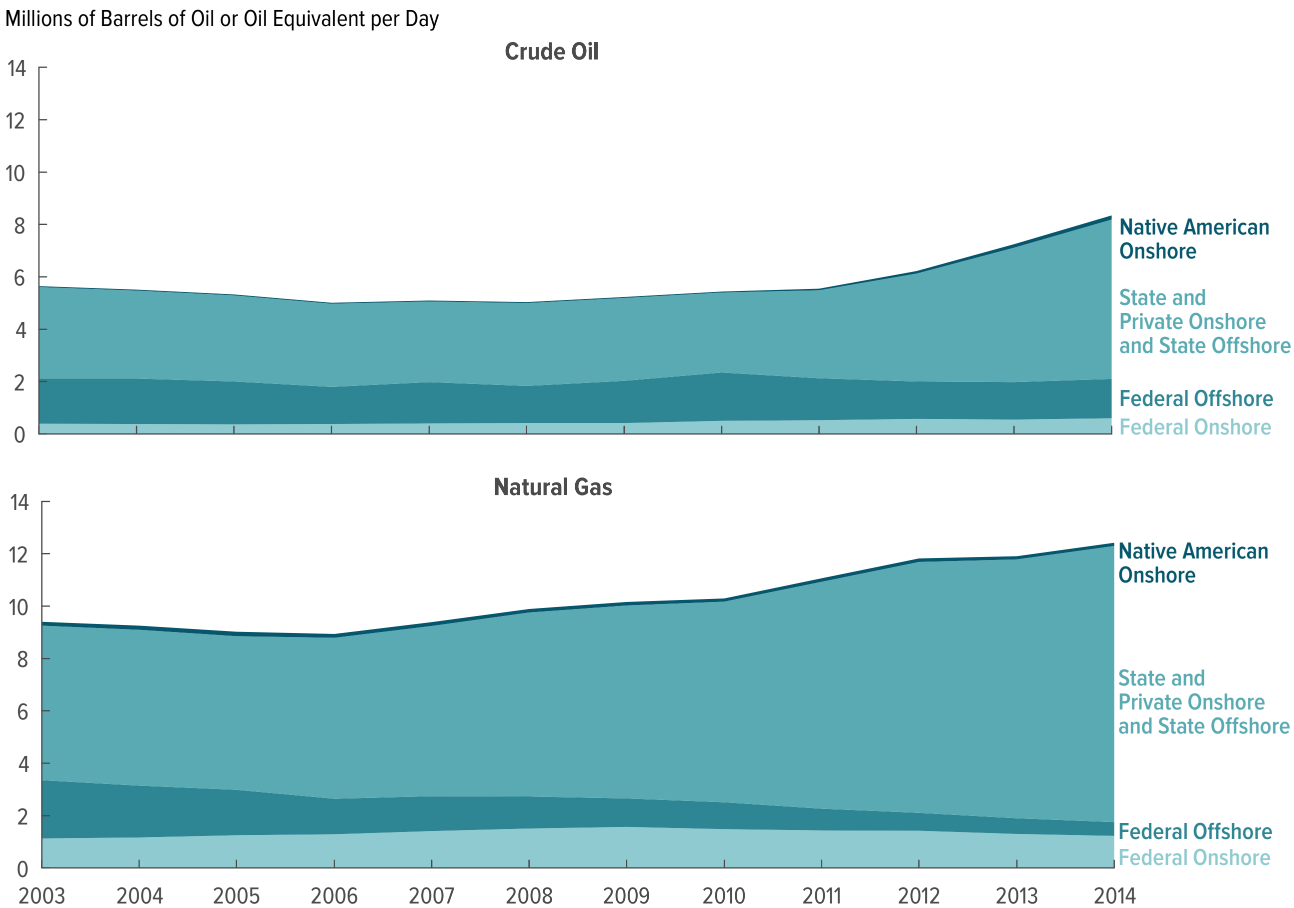
- *Exploration.* The firms that win leases have a set period of time, typically 5 to 10 years, to decide whether to drill one or more exploratory wells on their parcels. For the period of time between the award of the lease and the date on which the parcel begins to produce oil or gas, the leaseholder pays the federal government an annual rental fee. If no production occurs, the leaseholder pays the rental fee until the lease expires or until the leaseholder voluntarily returns the lease to the federal government.

- *Production.* If firms find oil and gas on their leased parcels, they can extract and sell those resources. The leaseholder pays the federal government a share of the income generated from the sales, called a royalty payment. (Royalties are paid on the value of production after taking allowable deductions, such as the cost

Figure 1-2.

Production of Oil and Natural Gas on Federal, State and Private, and Native American Lands

Production of oil and natural gas from federal lands has not increased as it has elsewhere because shale resources are found primarily on lands owned by state governments and private landowners.



Source: Congressional Budget Office, using data from the Energy Information Administration and the Department of the Interior's Office of Natural Resources and Revenue.

Oil production includes natural gas liquids.

State and private production are combined because there is no database of production for only state land or only private land.

of transporting oil and gas to the market.) After production begins, rental payments are no longer made, but firms are required to make at least a minimum royalty payment that is equal to the rental fee. The lease remains in effect indefinitely while production continues; when the leaseholder chooses to end production, it cleans up the site and the lease ends.[5]

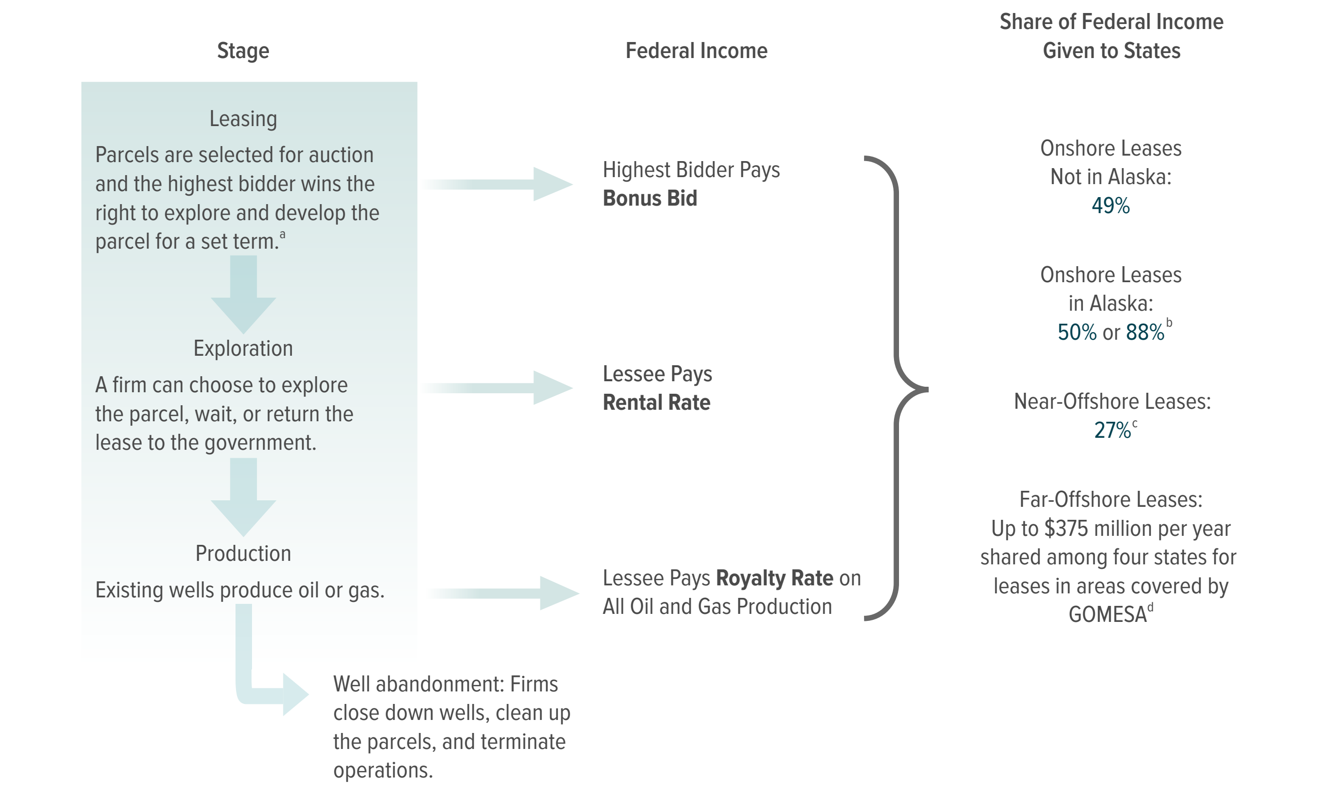
The three stages can be analyzed not only for their contributions to the goal of generating a fair return to taxpayers, but also in terms of the economic incentives they provide and their effects on economic efficiency (see Box 1-1 on page 10).

Despite the similarities in the general structure of the three stages used by BLM and BOEM to manage onshore and offshore oil and gas resources, their processes differ in two important ways.

5. The Department of the Interior has been criticized for problems associated with the reporting and collection of royalty payments for both onshore and offshore federal lands. See the testimony of Frank Rusco, Director, Natural Resources and Environment, Government Accountability Office, before the Subcommittee on Energy Policy, Health Care, and Entitlements of the House Committee on Oversight and Government Reform, *Oil and Gas Management: Continued Attention to Interior's Revenue Collection and Human Capital Challenges Is Needed*, GAO-13-647T (May 2013), www.gao.gov/products/GAO-13-647T.

Figure 1-3.

Process for Managing Access to Federally Owned Oil and Natural Gas Resources



Source: Congressional Budget Office.

a. Onshore parcels are included in an auction if they are nominated by a firm and approved for leasing by the Bureau of Land Management. Offshore parcels are included in an auction if they are part of an area specified for auctioning by the Bureau of Ocean Energy Management.

b. The 50 percent and 88 percent shares apply to leases within and outside of the National Petroleum Reserve in Alaska, respectively (42 U.S.C. 6508).

c. Near-offshore leases are on parcels less than 3 nautical miles seaward of the boundary between state and federal waters. (A nautical mile is 6,080 feet.) That boundary is 3 nautical miles from the low-water line for all states except Texas and the west coast of Florida, where it is 3 marine leagues, or about 9 nautical miles, from the low-water line. Leases within state waters are granted by the respective states.

d. Far-offshore leases are on parcels more than 3 nautical miles from state waters. Under the Gulf of Mexico Energy Security Act (GOMESA), proceeds from certain leases in the Gulf will be shared with Alabama, Louisiana, Mississippi, and Texas, and with the federal Land and Water Conservation Fund (LWCF), starting in 2018. Through 2055, payments from those leases will be subject to caps of $375 million in total for the four states and $125 million for the LWCF; afterward, the caps will be lifted and the four states and the LWCF will receive 37.5 percent and 12.5 percent of the proceeds, respectively. Those percentages are already used to share income received from two other small areas in the Gulf, but the amount of income has not been significant.

First, BLM's governing statute gives it significantly less flexibility to change certain terms associated with the process—such as the duration of leases—than BOEM is afforded by its governing statutes. In addition, BLM has written rules that require it to undertake more rulemaking to change any fiscal terms, whereas BOEM has adopted rules that allow it to adjust various terms by issuing a notice, which is a much simpler process (see Table 1-1 on page 12 and Table 1-2 on page 13). Consequently, BOEM has made many changes to the fiscal terms governing offshore development over the past decade, but those governing onshore development have remained largely unchanged since 1987.

Second, offshore wells, particularly those in deep or ultradeep water (more than 400 or 1,600 meters below sea level, respectively), are much more expensive to drill than onshore wells; that cost differential limits the number and types of firms that can develop offshore parcels. For example, drilling a typical onshore well in Texas and making it ready for production could cost between $3 million and $10 million and be accomplished in a few weeks, but drilling a well in deep water in the Gulf of Mexico could cost $300 million and take many months to complete.[6] In acknowledgment of those higher costs for offshore wells and the resulting limited competition, BOEM attempts to increase competition by allowing smaller firms to submit joint bids for parcels during the leasing stage of the process.[7]

For those reasons, the onshore and offshore processes are discussed separately below.

Effects on Federal and State Budgets

Between 2005 and 2014, gross governmental income from oil and natural gas leases on federal lands—-including bonus bids paid in auctions, rental fees collected during the exploration stage, and royalties paid during the production stage—was $110 billion.[8] Offshore leases generated most of that income; for both onshore and offshore leases, royalty payments were the largest source of income (see Figure 1-4 on page 14). Of the $110 billion, the federal government retained $70 billion, or about 63 percent, and distributed the rest to the states in which the resources were extracted (for onshore leases) or near where they were extracted (for offshore leases). The percentages shared with the states depend on where the extraction occurs:

- *Onshore.* For most onshore parcels, 49 percent of total income (from bonus bids, rents, and royalties) is given to the state in which the resource was extracted. The exception is federal lands in Alaska, where the state's share of receipts is 88 percent for leases outside the National Petroleum Reserve of Alaska (NPR-A) and 50 percent for leases within the NPR-A.[9]
- *Near Offshore.* Federal jurisdiction over offshore parcels starts at the seaward boundary, which is 3 nautical miles from the low-water line for all states except Texas and parts of Florida, where it begins 3 marine leagues, or about 9 nautical miles, from that line.[10] (Leasing of offshore parcels between the low-water line and the seaward boundary is done by the states, which keep 100 percent of the resulting income.) For near-offshore parcels—those no more than 3 nautical miles beyond the seaward boundary—27 percent of all collected income is given to the nearest state.[11]
- *Far Offshore.* Starting in 2018, proceeds from certain leases in the Gulf of Mexico will be shared with Alabama, Louisiana, Mississippi, and Texas, and indirectly with all the states through a mandatory appropriation to the state grants program of the federal Land and Water Conservation Fund (LWCF).[12] Through 2055, payments from the proceeds of those leases will be limited to no more than $375 million in total for the four states and $125 million for the LWCF; afterward, the four states and the LWCF will receive 37.5 percent and 12.5 percent of the proceeds, respectively.[13] Those percentages are already used to share income received from leases in two other small areas in the Gulf, but the amounts have not been significant. Receipts from leases in other far offshore waters are not shared with states.

6. For more on onshore drilling costs, see Trey Cowan, "Costs for Drilling the Eagle Ford," *RigZone* (June 20, 2011); and for offshore drilling costs, see Jennifer Dlouhy, "Gulf's Bounty Commands Attention Amid Shale Drilling Boom," *FuelFix* (May 4, 2014).

7. BOEM publishes a list of bidders that are restricted from entering into joint bidding arrangements, unless bidding is with an affiliate or subsidiary from the same group of restricted bidders. In 2014, the bidders excluded from entering into joint bids were BP, Chevron, Eni, Exxon, Nexen, Petrobras, Shell, Statoil, and Total; see Notice of Outer Continental Shelf Oil and Gas Lease Sales, 78 Fed. Reg. 64243 (October 28, 2013).

8. Those payments from private firms are classified in the federal budget as "offsetting receipts," that is, as a reduction in net outlays; they are not "revenues," like income taxes, because they result from voluntary transactions, rather than from the government's exercise of sovereign authority.

9. 30 U.S.C. §191 and 42 U.S.C. §6506a(l), respectively.

10. Low-water lines in the United States, also called baselines, are defined as "the mean of the lower low tides as depicted on the largest scale NOAA nautical charts." See National Oceanic and Atmospheric Administration, Office of General Counsel, "Maritime Zones and Boundaries" (accessed March 10, 2016), www.gc.noaa.gov/gcil_maritime.html#base.

11. 43 U.S.C. §1337(g)(2).

12. The fund was established by the Land and Water Conservation Act of 1965 to help preserve, develop, and ensure access to outdoor recreation resources. Monies appropriated to the LWCF are used for land acquisition by various federal agencies and for grants to the states. See Carol Hardy Vincent, *Land and Water Conservation Fund: Overview, Funding History, and Issues*, Report for Congress RL33531 (Congressional Research Service, June 17, 2015).

13. See Bureau of Ocean Energy Management, "Gulf of Mexico Energy Security Act (GOMESA)," www.boem.gov/revenue-sharing/.

Box 1-1.

The Effects of the Federal Leasing System on Incentives and Economic Efficiency

Most oil and natural gas development in the United States occurs under contractual agreements between those who own the rights to mineral resources and companies that have the expertise and financial capability to develop those resources. Typically, rights holders are interested in the financial benefit they get from the agreements and in maintaining the value of their land. The federal government has additional interests—including environmental protection, national security, and maximizing economic efficiency, which is a benefit to the economy as a whole. That benefit reflects many factors, including the effects of oil and gas activity on other uses of federal lands, the value of resources left in the ground for production in the future, and the interactions of the leasing system with provisions of the tax code affecting the oil and gas industry. This box considers the narrower question of how the incentives provided by the leasing system affect the economic efficiency of current oil and gas production.

Incentives Provided by the Leasing System

Each of the decisions made by firms that produce oil and gas—where to try to acquire rights, where and when to drill exploratory wells, whether to begin production once oil or gas has been found, and when to stop production at a producing well—is shaped primarily by physical and technical factors and market forces, including the estimated probability of finding oil or gas at a given location, the expected amount of oil or gas available if found, expected or observed extraction costs, current and expected future prices for oil and gas, and firms' costs of capital. But the incentives provided by the leasing system—including the auction rules, rental fees, and royalty rates—can influence those decisions to some degree, particularly to the extent that they make federal lands more or less attractive for leasing than nonfederal lands.

Bidding on Parcels. At the auction stage, firms must decide which available parcels they are interested in and how much to bid for them. To do so, they consider the auction's structure and rules, which affect the amounts firms expect to have to bid, the possibility that winning bids may not be recouped if no oil or gas resources are found during the lease term, the potential profits (influenced to a degree by the lease terms, as discussed below) if resources are found, and the alternatives available for leasing nonfederal lands.[1]

Retaining Parcels and Drilling Exploratory Wells. During the lease term, a firm's decision about whether to drill an exploratory well, return the lease, or wait and revisit those two choices later depends on the physical and economic factors noted above, and also on the configuration of other leases held by that firm. The more parcels the firm has leased that are near one another, the greater the potential value of the information that an exploratory well on one parcel could provide about the prospects for the others.

In addition, three aspects of the leasing system have some bearing on firms' decisions at this stage, though the effects may be small:

- A higher rental fee increases the cost of holding a lease, giving leaseholders an incentive to either explore parcels or return them to the government. In practice, the current incentive is weak because the fees are small relative to the cost of developing a lease. For example, rental fees of $11 to $16 per acre on a deepwater offshore lease cost less than $1 million over a 10-year period, whereas drilling a well costs hundreds of millions of dollars.

- A longer lease gives firms more time to wait for prices to rise or additional information to arrive, at the cost of making more rental payments.

As with other types of operating costs, the higher the royalty rate, the lower the value to firms of any oil or gas that is found, and hence the lesser the incentive to drill exploratory wells or hold on to parcels for possible exploration later.

1. Some changes in lease terms may have little or no effect on bidding decisions: The Department of the Interior found that demand for leases in the Gulf of Mexico remained strong after the royalty rate was increased from 16.67 percent to 18.75 percent in 2008. See Government Accountability Office, *Oil and Gas Resources: Actions Needed for Interior to Better Ensure a Fair Return*, GAO-14-50 (December 2013), p. 14, www.gao.gov/products/GAO-14-50.

Continued

Box 1-1. Continued

The Effects of the Federal Leasing System on Incentives and Economic Efficiency

Beginning Production. Once exploration has indicated the presence of oil or gas, the decision to begin production is typically not sensitive to lease terms except for parcels that appear only marginally valuable—that is, those for which the firm's anticipated rate of return is close to the minimum level it considers acceptable.

Shutting Down a Producing Well. In addition to the dominant physical and economic factors listed above, the royalties charged during production may influence the decision to end production at a well: The higher the royalty rate, the sooner a well with declining production becomes unprofitable, taking into account the cost of closing it. However, producers may apply for an end-of-life reduction in the applicable royalty rate.[2] The incentive effect of a given royalty rate is greater when oil and gas prices are lower, because then the rate represents a larger percentage of profits.[3]

Economic Efficiency

The incentives provided by the leasing system have implications for the extent to which capital and labor are used efficiently—so as to yield the greatest surplus of benefits over costs—in current oil and gas exploration and production. The main implications are as follows:

- Awarding leases to winning auction bidders tends to promote efficiency in current operations because the high bid for a given parcel may reflect better information about the availability of oil or gas, lower-cost production methods, or more leases on nearby parcels.

- The limited time allowed for exploration and the rental fees charged before production begins can promote efficiency by discouraging firms from "warehousing" parcels simply to prevent competitors from exploring them. In principle, if the period is too short or the fees are too high, firms may be discouraged from bidding on some parcels, thus delaying the potential benefits of getting additional information about nearby parcels. But rental fees would have to be far greater than they are now to have such an effect.

- The leasing system does not provide explicit incentives for firms to drill exploratory wells on parcels that could provide information about parcels that are not yet leased or are leased by someone else. Firms may do less exploration on such parcels than would be economically efficient, because they would take little or no account of the potential benefit of information about those nearby parcels.

- Although federal royalty rates may lead firms to shut down wells earlier than they would in the absence of royalties, they may promote efficient decisions about where exploration and production should occur, because state, tribal, and private landowners also typically require compensation for activities on their properties.[4]

Whether the fact that most parcels go unexplored during the term of their leases represents inefficient warehousing is difficult to determine. In some cases, firms that would have made more productive use of given parcels during the lease term may have been outbid by other firms that sought the leases primarily for strategic reasons—that is, to keep the parcels away from competitors. In other cases, leaving a leased parcel unexplored is efficient, because evidence from nearby parcels has suggested that drilling would be unproductive or because drilling would be premature until more information is obtained.

2. See Production Incentives, 43 C.F.R. §3103.4 (2009) for onshore wells and Relief or Reduction in Royalty Rates, 30 C.F.R. §203 (2012) for offshore wells.

3. Conversely, when oil and gas prices are higher, a given royalty rate gives the government a smaller share of profits. Royalty payments as a share of profits would be even more sensitive to those prices if royalty rates were specified in terms of dollars per unit of production. In principle, leases could specify payments as a percentage of profits, but those would be harder for the government to verify.

4. Efficient royalty rates on federal lands reflect many factors and need not equal those charged by other landowners.

Table 1-1.

Statutory and Administrative Governance of Onshore Oil and Natural Gas Leasing

	Statutory Requirements	Regulatory Terms	Subject to Administrative Change?
Leasing			
Auction type	Open outcry[a]	Open outcry[a]	No
Minimum bid per acre	$2 until 1989; may be increased afterward	$2	Yes, by rulemaking
Noncompetitive leases	Payment of a nonrefundable application fee	Fee increased annually ($390 in fiscal year 2013)	No
Lease term	10 years	10 years	No
Exploration			
Annual rental fee per acre	At least $1.50 for the first 5 years and at least $2 thereafter	$1.50 for the first 5 years and $2 thereafter	Yes, by rulemaking
Production			
Royalty rate	Not less than 12.5 percent	12.5 percent	Yes, by rulemaking
Royalty relief	No mechanism specified	n.a.	No

Source: Congressional Budget Office.

Onshore oil and gas legislation is codified at 30 U.S.C. §226, and the corresponding regulations are at 43 C.F.R. Parts 3100–3120.

n.a. = not applicable.

a. The auctions are open outcry because bidders show their interest publicly, specifically by raising their hands or numbered paddles.

The oil and gas income distributed to states can be significant in some state budgets. For example, in 2013 that income accounted for about 5 percent of Wyoming's budget and 3 percent of New Mexico's budget.[14]

Various analysts have compared the combined federal and state share of the value of oil and natural gas resources on federal lands with the shares captured by various state governments for resources on their lands and with the shares captured by the governments of other countries.[15] The three-stage process used in the United States resembles the systems used by countries such as Canada, England, and Norway but differs from those used by countries that operate state-owned national oil companies, such as Saudi Arabia, China, and Russia. In general, analysts find that the combined governmental share—including taxes received from resource producers—of the value of oil and natural gas from federal lands ranks in the lower half of the list of large oil-producing countries and U.S. states for onshore resources and for offshore leases overall (see Box 1-2 on page 16).

Onshore Oil and Gas Leases

The process through which onshore oil and gas resources are developed follows the three stages of leasing, exploration, and production. The fiscal terms for each stage are determined by legislation or by subsequent rulemaking (see Table 1-1).[16] Between 2005 and 2014, the federal government collected, on average, more than $230 million per year at the leasing stage (in the form of bonus bids for auctioned parcels), about $50 million per year

14. According to CBO's calculations, using 2013 data on disbursements to states for all mineral resources from http://statistics.onrr.gov/reporttool.aspx, on shares of federal mineral receipts from oil and gas, by state, from http://useiti.doi.gov, and on states' spending (for state fiscal years starting July 1, 2012) from http://ballotpedia.org/state_budget_and_finance_pages.

15. Government Accountability Office, *Oil and Gas Resources: Actions Needed for Interior to Better Ensure a Fair Return*, GAO-14-50 (December 2013), www.gao.gov/products/GAO-14-50; and Irena Agalliu, *Comparative Assessment of the Federal Oil and Gas Fiscal System* (IHS Cambridge Energy Research Associates, October 2011), http://go.usa.gov/cwznH.

16. The legislation is codified at 30 U.S.C. §226, and the corresponding regulations are at 43 C.F.R. Parts 3100–3120.

Table 1-2.

Statutory and Administrative Governance of Offshore Oil and Natural Gas Leasing

		Administrative Terms		Subject to
	Statutory Requirements	For the Gulf of Mexico[a]	For Waters Near Alaska[b]	Administrative Change?
Leasing				
Auction type	Sealed bid; specifies nine variations with selected variant submitted to the Congress[c]	Sealed bid; bid on bonus	Sealed bid; bid on bonus	Yes, by a new plan submitted to the Congress that is subject to a resolution of disapproval
Minimum bid per acre	Not specified	Depth less than 400 meters, $25; Depth more than 400 meters, $100	$10 ($15 for some leases closer to existing infrastructure)	Yes, in notice of lease sale
Noncompetitive leases	All leases issued competitively	n.a.	n.a.	No
Lease term	5 to 10 years	5, 7, or 10 years, depending on water depth; extensions of 3 years may be earned on 5- and 7-year leases	10 years	Yes (within statutory limits), in notice of lease sale
Exploration				
Annual rental fee per acre	Not specified	For the first 5 years, $7 for parcels less than 200 meters deep and $11 for others; fees higher after 5 years[d]	$5.26	Yes, in notice of lease sale
Production				
Royalty rate	Not less than 12.5 percent	18.75 percent	12.5 percent	Yes, in notice of lease sale
Royalty relief	Various royalty relief programs are required or allowed	None (other than lease terms to implement legislative requirements)	None (other than lease terms to implement legislative requirements)	Yes (within statutory limits), in notice of lease sale

Source: Congressional Budget Office.

Offshore oil and gas legislation is codified at 43 U.S.C. §1337, and the corresponding regulations are at 30 C.F.R. Parts 560 and 556.

n.a. = not applicable.

a. Terms for leases auctioned in August 2014; see Western Gulf of Mexico (WPA) Outer Continental Shelf (OCS) Oil and Gas; Lease Sale 238, 79 Fed. Reg. 42041 (July 18, 2014).

b. Terms are based on the two most recent auctions: Beaufort Sea Sale 202 on April 18, 2007, and Chukchi Sea Sale 193 on February 6, 2008. The minimum bid and rental rate were quoted in dollars per hectare, which CBO converted to acres.

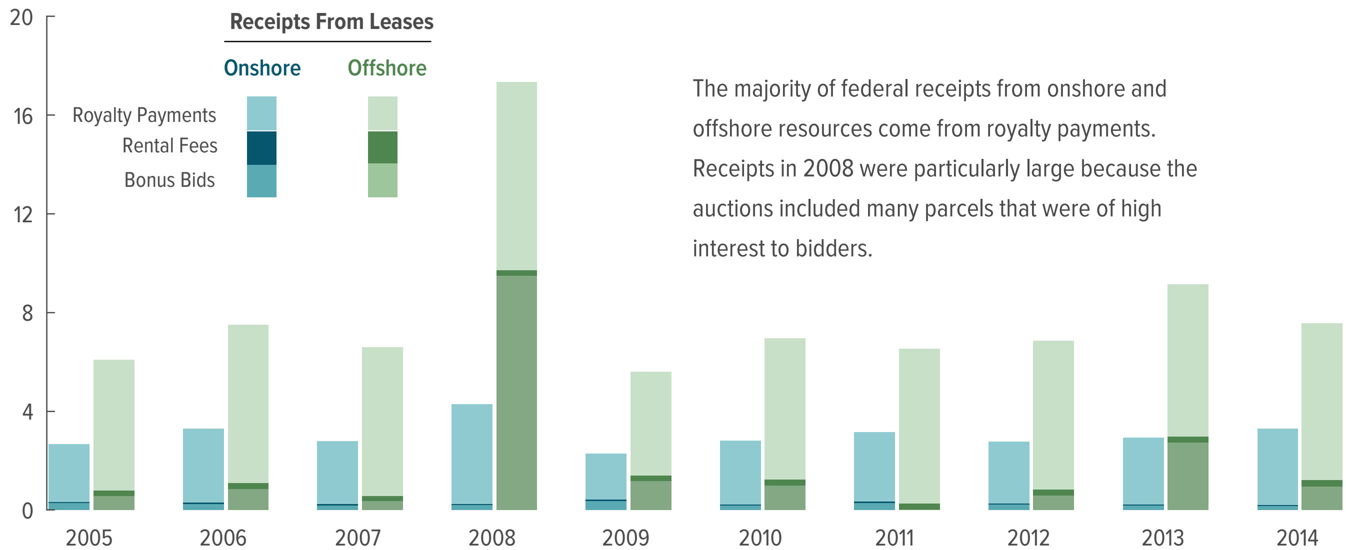
c. The Outer Continental Shelf Lands Act stipulates that the Secretary of Energy can consider nine different types of auction designs. They all involve a sealed bid but can have bidders competing on the bonus bid, royalty rate, and net profit sharing, among other options. The bidding system selected must be submitted by the Secretary to the Congress. If the Congress does not pass a resolution of disapproval within 30 days, the bidding system can be implemented.

d. Holders of leases in water less than 400 meters deep pay higher rates each year of a three-year extension; rates in the final year reach $28 per acre for parcels less than 200 meters deep and $44 per acre for parcels between 200 and 400 meters deep. Holders of leases in deeper water see a single increase to $16 per acre starting in year six.

Figure 1-4.

Gross Federal Receipts From Onshore and Offshore Oil and Natural Gas Resources

Billions of Nominal Dollars



Source: Congressional Budget Office, using data from the Department of the Interior's Office of Natural Resources and Revenue.

at the exploration stage (in rental fees), and about $2.7 billion per year at the production stage (in royalty payments).

Leasing

Before a parcel can be leased in an auction, it must be nominated by a private firm. The nominated parcel can range in size from a few acres up to 2,560 acres in the continental United States or 5,760 acres in Alaska. BLM then conducts an environmental assessment of the parcel to determine what conditions, if any, need to be added to the lease before development can begin. For example, a condition might be added to the lease that any oil or gas development include a plan for avoiding or mitigating damage to endangered species present on the parcel. Once the parcel with its accompanying conditions is approved for leasing, it is offered at one of the BLM auctions held in each state quarterly. (Some states hold auctions for parcels on their own lands more frequently.) The list of parcels approved for auctioning is typically made available to the public at least 90 days before the auction. Leases allow up to 10 years for exploration.

Auctions for onshore parcels are conducted using an open-outcry ascending auction format, which is similar to that commonly used in estate sales or livestock auctions. In that type of auction, an auctioneer offers the parcel at a low starting price, called the minimum bid. The minimum bid for onshore parcels is currently $2 per acre. After a bidder indicates his or her interest in the parcel to the auctioneer at that price, the auctioneer raises the price by small increments until no bidder expresses interest at a higher price. (The auction is described as open-outcry because bidders express their interest publicly by raising their hand or raising a paddle with their bidder number.) The bidder who was last to indicate interest in the parcel pays the amount of his or her highest bid, which is commonly called the bonus bid. If no bidder expresses interest in the parcel at the minimum bid, BLM makes the parcel available the next day on a noncompetitive "first-come, first-served" basis. Such parcels remain available for leasing for two years, and no bonus bid is paid for them.

The amount that any particular bidder is willing to pay for a parcel depends primarily on expectations about the future market price of oil or gas, and expectations about the volume of oil or gas underlying the parcel and the difficulty and cost of extracting it; it also depends to some extent on the terms of the lease. Because all potential bidders know the lease terms stipulated by BLM, those terms can influence the amount that bidders in general are willing to pay to lease a parcel but do not explain why some bidders value a parcel more highly than others do.

Also, bidders tend to have similar expectations about future market prices over the lifetime of a potential new well, based on the same publicly available long-run projections.

In contrast, potential bidders may come to an auction with very different estimates of a parcel's value based on their expectations about the amount of oil or gas underlying it or about extraction costs. Those expectations, which are the main sources of differences in bids, reflect private information from a firm's own experience with nearby parcels as well as three other sources of public and private information:

- The United States Geological Survey (USGS) provides some information, typically on a broad scale, that sheds light on general resource availability but not on the specific potential of any particular parcel.[17]
- Many states' oil and gas commissions collect information about all the wells drilled in their state and the production data from those wells; the states tend to make that information available to the general public. For example, the North Dakota Oil and Gas Division provides well data and production volumes, among other information, to subscribers for an annual fee of $50.[18] Such data can be valuable for determining the resource potential of a particular parcel.
- Potential bidders sometimes pay for seismic surveys, which are conducted by sending sound pulses into the ground and recording information about how they are reflected back. Such surveys provide a type of visual map of the geology underlying a parcel or group of parcels.

17. See, for example, Departments of the Interior, Agriculture, and Energy, *Inventory of Onshore Federal Oil and Natural Gas Resources and Restrictions to Their Development* (2008); and Daniel J. Soeder, Catherine B. Enomoto, and John A. Chermak, "The Devonian Marcellus Shale and Millboro Shale" (GSA Field Guides, 2014), vol. 35, pp. 129–160.

18. Other states, particularly those with significant oil and gas production, offer similar services. For North Dakota's website that provides that information, see www.dmr.nd.gov/oilgas. BLM also requires that firms holding federal leases submit the same information about wells drilled and production from those wells, but the agency does not share the well information and rarely shares with the public production information for particular leases.

Auction results indicate that parcels vary widely in their attractiveness to bidders. Of the more than 25,000 federal leases issued between 2003 and 2012, approximately 85 percent were leased competitively, yielding bonus bids. Of those competitive leases, slightly more than one-quarter were leased at the minimum of $2 per acre.[19] For the other three-quarters, the median bonus bid was $37 per acre, and the average bonus bid was $300 per acre; the average is much higher than the median because some parcels were leased at bids above $5,000 per acre.

Exploration

Holders of onshore leases have the option to explore the parcel for oil and gas for up to the primary term of 10 years, but they are not required to do so. A leaseholder can drill one or more exploratory wells after acquiring the necessary permit; alternatively, the leaseholder can defer deciding whether to drill, or return the lease to BLM. After 10 years, the lease is returned to BLM if no exploratory well has been drilled. If exploration has occurred and production is planned, the leaseholder can apply for a short extension of the primary term to begin production.

To encourage firms to drill exploratory wells and begin production, BLM charges firms a rental fee for parcels that have been leased but have not yet begun production. The rental fee is waived once production begins; at that time, however, firms are required to make a minimum royalty payment set equal to the rental fee. For all onshore federal leases, the rental fee is $1.50 per acre per year for the first five years and $2 per acre per year for the second five years of the primary term, or about $4,000 to $5,000 per year for the largest parcels in the continental United States. Because the fee is small relative to the several million dollars required to drill an exploratory well, firms often wait before drilling to see if other, relevant information—for example, results of drilling activity on a neighboring parcel—becomes available. (When a firm has leased multiple parcels in the same vicinity, an exploratory well on one parcel may yield some benefit to the drilling firm even if it does not reach any oil or gas, by helping the firm redirect additional exploration away from nearby parcels that have become less promising.)

19. Numerical figures in this paragraph are CBO's calculations, using data from BLM.

Box 1-2.

Management of Oil and Gas Resources in Other Countries

Oil and gas resources around the world are managed in various ways. In the United States, Canada, and the United Kingdom, resources are both publicly and privately owned and the governments allow private parties to develop those resources. Conversely, countries such as China, Russia, and the members of the Organization of Petroleum Exporting Countries use state-owned national oil companies almost exclusively to develop their oil and gas resources. The latter countries tend to capture a larger portion of the value of the extracted resources because the government does not share profits with privately owned firms.

The primary components of a government's share vary, but they tend to be based on the amount of resources produced, firms' profits, or the extent of the government's equity participation. Production-based receipts are generated by royalties, severance taxes, and export duties, whereas profit-based receipts are accrued through a share in profit or the collection of windfall taxes. In an equity participation agreement, the government receives a share of income in exchange for partaking in some of a project's risk. In some cases, the government collects additional funds through bonus bids (amounts paid for the right to enter into a lease), rental fees, and research fees.

For countries that allow privately owned firms to develop resources, the financial arrangements can vary widely. For example, some jurisdictions in Canada award licenses to explore parcels not on the basis of cash bonus bids but on the basis of "work proposal bids"—commitments to spend a certain amount of money to develop the parcel. The winning bidder then submits a fraction of that amount to the government as a deposit, which is refunded as exploration costs are incurred.[1] No cash bonus bids are made in the United Kingdom either; licenses there are awarded on the basis of financial and technical criteria.[2]

The basis for determining the government's income associated with production of oil and gas also differs by country. The United Kingdom charges no royalty but levies a standard corporate tax on net income and also a supplementary charge, which together yield a marginal tax rate of 50 percent on net income.[3] In Alberta, Canada, royalties are charged on sliding scales that consider both resource prices and production per well; the royalty rate for oil can be as low as zero or as high as 40 percent, and the rate for gas can range from 5 percent to 36 percent.[4]

In 2011, the Department of the Interior commissioned a study to compare the federal U.S. process for managing access to oil and gas resources with those of selected countries and states in this country.[5] One of the factors considered in the study was the share of the net cash flows—that is, gross revenues from production minus capital and operating expenses—retained by the different governments. (Those shares are not directly comparable to the royalty rates cited in this report, which are percentages of gross revenues minus certain allowable deductions, such as the cost of transporting the oil or gas to the market. The U.S. royalty rate of 12.5 percent for onshore parcels, for example, corresponds to 15.6 percent of the net cash flow if capital and operating expenses equal 20 percent of gross revenues, and to 25 percent if those expenses equal half of gross revenues.) For onshore oil and gas resources on U.S. federal lands,

1. For example, see Northwest Territories Department of Industry, Tourism, and Investment, *NWT Oil and Gas: Annual Report 2014* (June 2, 2015), pp. 6 and 11, http://tinyurl.com/zfcdeu7. Rental fees charged after the first five years are also refundable as costs are incurred.
2. See United Kingdom Oil and Gas Authority, *Applications for Production Licences—General Guidance* (2014), p. 6, http://tinyurl.com/jnhvnj9.
3. United Kingdom Oil and Gas Authority, *Oil and Gas: Taxation* (updated October 9, 2015), http://tinyurl.com/jguo5rk.
4. Irena Agalliu, *Comparative Assessment of the Federal Oil and Gas Fiscal System* (IHS Cambridge Energy Research Associates, October 2011), pp. 189–191, http://go.usa.gov/cwznH.
5. Ibid.

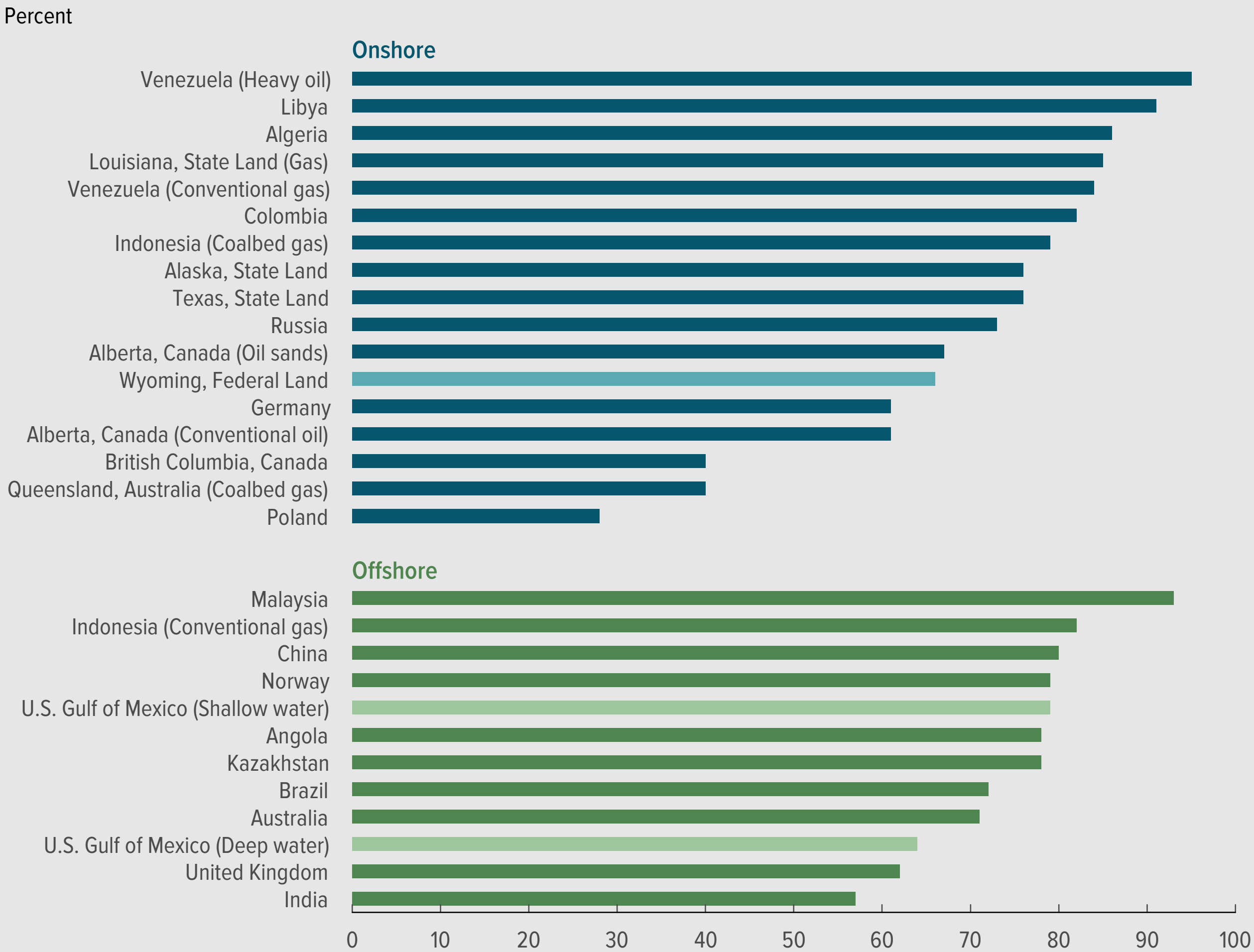
Continued

Box 1-2. Continued

Management of Oil and Gas Resources in Other Countries

the total share of the resources' value (the net cash flow) retained by governments, including federal income taxes and applicable state and local taxes, is about 66 percent; that share ranks in the lower half of nations and states evaluated (see the figure). For offshore resources, the overall share of value retained by governments in the United States is again in the bottom half of the countries evaluated, taking into account the different shares for resources in shallow water (79 percent) and deep water (64 percent).

Governments' Shares of Resources' Value for Oil and Natural Gas Produced on U.S. Federal Lands and Elsewhere

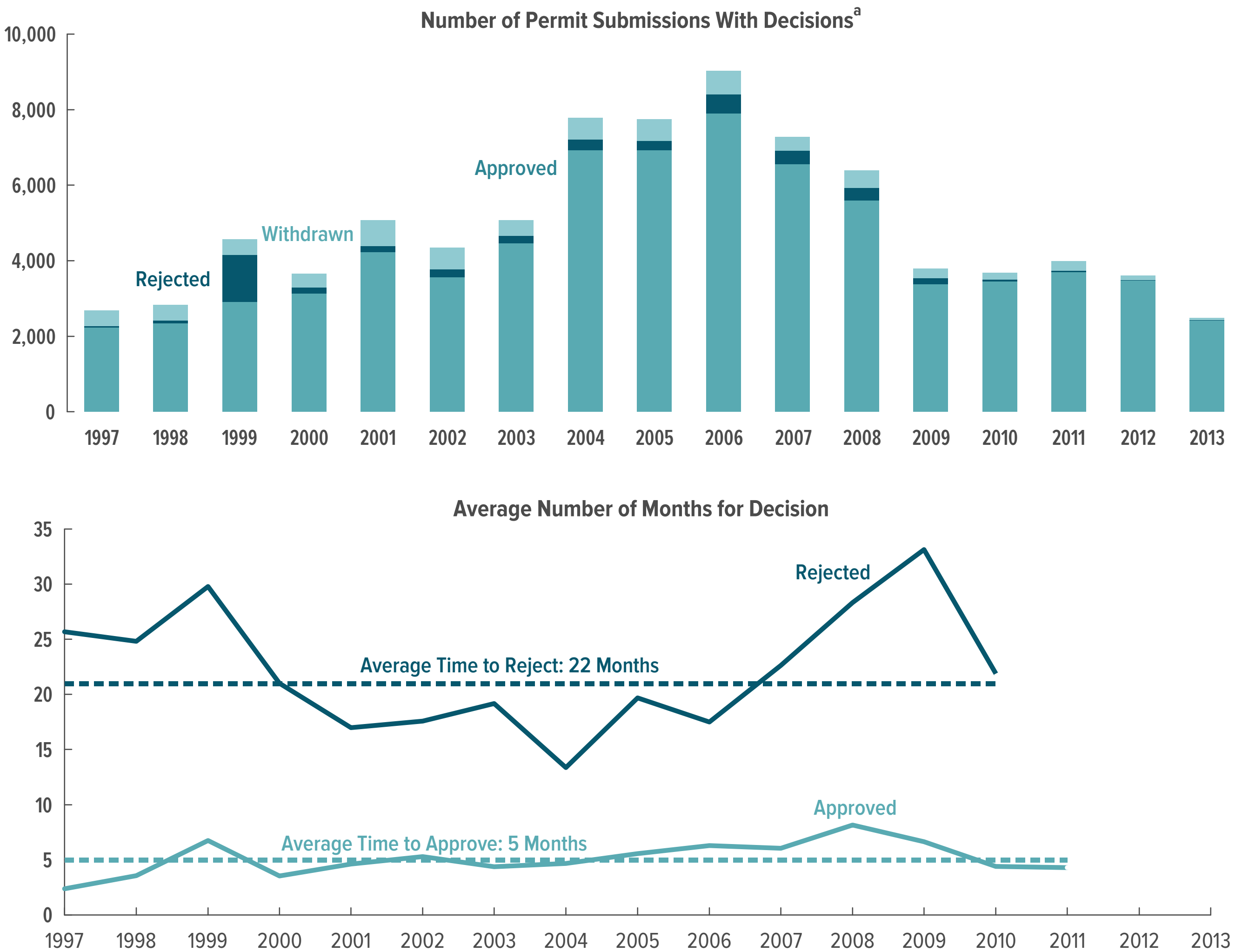


Source: Congressional Budget Office, using data from Irena Agalliu, *Comparative Assessment of the Federal Oil and Gas Fiscal System* (IHS Cambridge Energy Research Associates, October 2011), http://go.usa.gov/cwznH.

The share of resources' value (gross revenues from production minus capital and operating expenses) retained by the government includes income taxes, fees, royalties, and other financial charges associated with oil and natural gas development.

Figure 1-5.

Number of Onshore Drilling Permits Submitted and Average Decision Times



Source: Congressional Budget Office, using data from the Department of the Interior's Bureau of Land Management (BLM) through February 20, 2014.

a. The number of applications with no decision is not shown. After 2005, between 50 and 200 applications each year did not have a decision noted in the database maintained by BLM. That could be the result of recordkeeping errors, an incomplete application, or insufficient time to make a decision. In 2013, there were 887 applications with no action, probably because of insufficient time for BLM to make a decision. For that same reason, in the bottom panel, completion times are shown only through 2010 for rejections and 2011 for approvals.

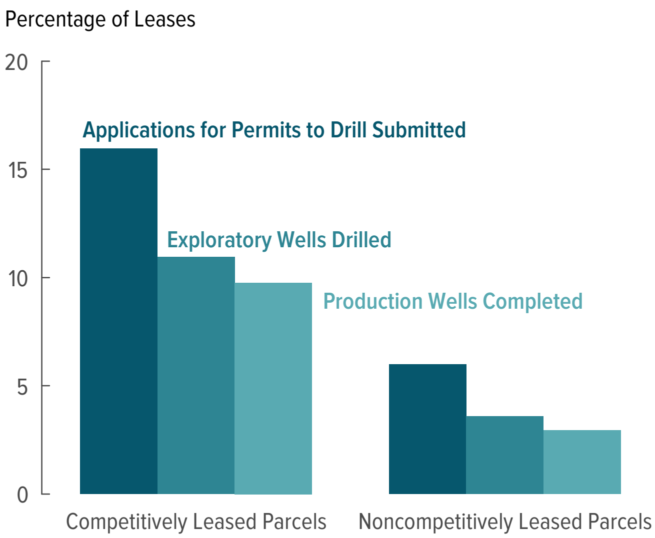
Once a leaseholder decides to drill an exploratory well, the firm must submit an application for a permit to drill (APD). To receive a permit, the leaseholder must provide a plan that complies with the National Environmental Policy Act and all other conditions of the lease, which may include building new roads or pipelines. In addition, a bond of $10,000 is required in case the leaseholder abandons the parcel and the federal government must provide remediation. Since 1997, among applications for which a decision has been made, more than 85 percent of APDs submitted in any year have been approved, typically within about 5 months (see Figure 1-5). About 5 percent of APDs submitted each year have been denied; on average, rejection occurs 22 months after submission. (Before rejecting an application, BLM may request additional information or clarification of a leaseholder's compliance plans.) The other applications have been withdrawn.

Most onshore leases see no activity for the duration of the lease—in some cases, because market conditions prove to be less favorable than the leaseholder had projected, or

Figure 1-6.

Share of Onshore Federal Leases From 1996 Through 2003 With Applications for Drilling and Production

The share of parcels where exploration and production occurred was higher for competitively leased parcels than for noncompetitively leased parcels because the latter are generally those that are considered less likely to contain significant resources.



Source: Congressional Budget Office, using data through February 2014 from the Department of the Interior's Bureau of Land Management and Office of Natural Resources and Revenue.

Well completion is strongly correlated with production, but the share of leases that have started production may be slightly smaller than the share completed.

because exploratory wells on nearby properties reduce expectations of the value of oil or gas available on the unexplored parcel. The Congressional Budget Office analyzed leases issued between 1996 and 2003 and examined all subsequent activity on the leased parcels through February 2014. (Because many leases have no activity until the last few years of the primary term, the analysis focuses on leases for which there is a complete history of activity for the entire 10-year period.) On average, wells are drilled on about 11 percent of parcels leased competitively and less than 4 percent of parcels leased noncompetitively (see Figure 1-6). Production of oil or gas occurs on about 10 percent of the competitively leased parcels and 3 percent of the noncompetitively leased parcels. Most leaseholders do not choose to return the lease to BLM early but instead pay the rental fee and wait to see if new information becomes available that increases the likelihood that the parcel contains oil or gas.

Production

If exploratory drilling finds oil or gas resources on a parcel under conditions believed to be economically viable for production, the leaseholder usually decides to begin production of that oil or gas. In that case, the well is finished by encasing the outside in cement so that oil or gas does not migrate into the surrounding soil as it travels up the well. Once production begins, the leaseholder pays a share of the value of that production—the royalty rate—to the federal government, after deducting certain allowable expenses. For federal onshore leases, the royalty rate is 12.5 percent (set by law and unchanged since 1987), which is less than the royalty rate imposed by many states for production of oil and gas on state-owned land. For example, current state royalty rates are 25 percent in Texas, 18.75 percent in Oklahoma, and 16.67 percent in Colorado, Montana, and Wyoming; New Mexico and North Dakota use both 16.67 percent and 18.75 percent rates.[20]

Although oil and gas resources have been found underlying land in more than 30 states, federally owned oil and gas tends to be concentrated in a few states, particularly New Mexico and Wyoming (see Table 1-3). Since 2005, four states have accounted for about 85 percent of oil production on federal lands, and four states have accounted for about 95 percent of natural gas production on federal lands.

Once production of oil or gas begins, it tends to increase for a time and then decrease as the resources are exhausted. Between 1996 and 2010, resource production from parcels leased in 1996 in Colorado, New Mexico, Utah, and Wyoming (the top four states producing natural gas) climbed for the first decade and then began to fall (see Figure 1-7 on page 21). That pattern of a slow increase in production occurs in part because leaseholders are waiting for more information about potential oil and gas resources before developing their parcels. In addition, once oil and gas reserves are identified, leaseholders drill additional wells over time to extract oil or gas from different areas of the parcel. (Production rates

20. Center for Western Priorities, *A Fair Share: The Case for Updating Oil and Gas Royalties on Our Public Lands—Update* (June 18, 2015), http://tinyurl.com/j296qzt. Some of those royalty rates reflect increases since 2005, as many Western states have changed their lease terms to increase state revenues.

Table 1-3.

Onshore Production of Oil and Natural Gas for the 15 States With the Highest Production on Federal Lands, by Owner, 2005 to 2014

Oil (Millions of barrels)			Natural Gas (Millions of barrels of oil equivalent)		
	Federal Owner	Any Owner		Federal Owner	Any Owner
New Mexico	633	729	Wyoming	2,438	3,637
Wyoming	536	561	New Mexico	1,406	2,486
California	153	2,096	Colorado	493	2,608
Utah	141	250	Utah	447	751
North Dakota	104	1,381	Texas	56	12,020
Colorado	97	395	Montana	44	164
Montana	33	298	Louisiana	41	3,483
Louisiana	7	717	Alaska	38	713
Kansas	4	403	Oklahoma	26	3,377
Oklahoma	4	777	Arkansas	22	1,266
Texas	4	5,522	North Dakota	18	199
Nevada	4	4	Kansas	12	607
Mississippi	3	221	California	11	506
Alaska	3	2,360	Michigan	5	303
South Dakota	2	16	West Virginia	3	704
Total U.S. Onshore Production	**1,731**	**21,355**		**5,064**	**38,280**

Source: Congressional Budget Office, using data from the Energy Information Administration and the Department of the Interior's Office of Natural Resources and Revenue.

Oil totals include natural gas liquids.

from a single well tend not to be controlled by the leaseholder but are instead determined by the geologic conditions and the quantity of oil or gas underlying a parcel.)[21] Production may also increase over time as new methods of drilling, such as hydraulic fracturing (or fracking), become available and cause parcels with declining production to see an increase or cause parcels that were believed to be unprofitable for development to become profitable. Finally, sometimes market conditions, such as a low price for natural gas or oil, may cause a leaseholder to halt further development of a lease or shut in (or close) a producing well until market conditions improve, although reopening a well can be as expensive as drilling a new one.

In general, a productive parcel will continue to produce for much longer than 10 years, the typical period considered by CBO when estimating the income or costs associated with legislation. For leases auctioned in 1996 in the four top natural gas–producing states, about two-thirds of the total production over the first 15 years (through 2010) occurred after the first 10 years (see Figure 1-7). The government receives royalty income while production continues, and that is thus the only source of leasing income that can extend more than a decade after a parcel is auctioned. Of all the royalty payments collected in 2013, about half of those payments came from parcels that were leased more than 50 years earlier, whereas 6 percent came from parcels that were leased in the previous 10 years (see Figure 1-8 on page 22).

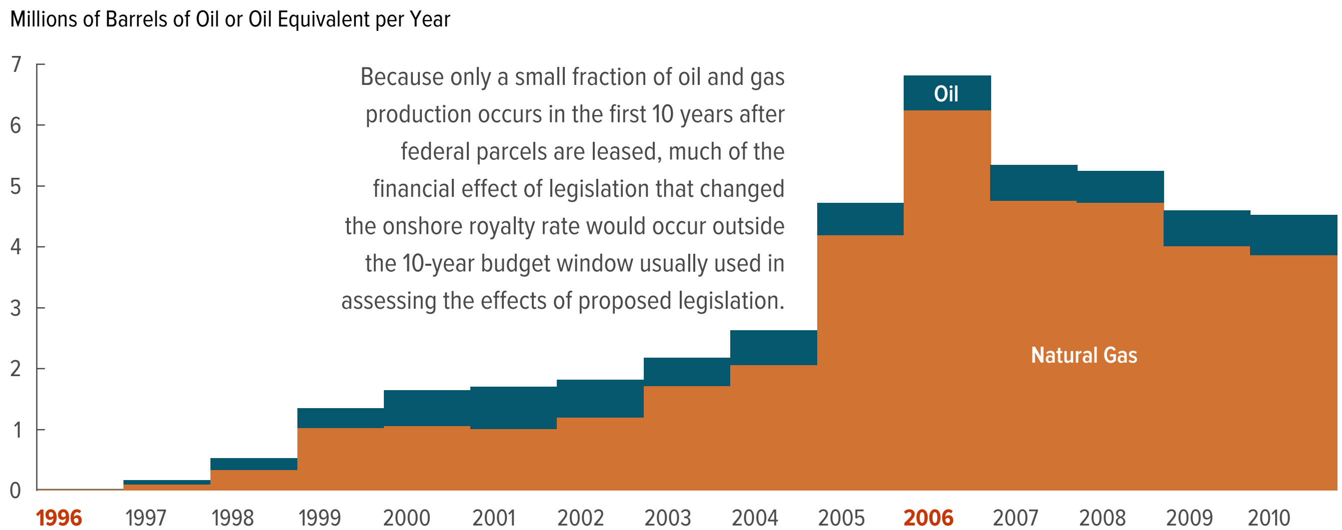
Offshore Oil and Gas Leases

Because the federal government (through BOEM) controls and manages all drilling between the seaward boundary and 200 nautical miles offshore, nearly all offshore production is federal. In 2014, offshore drilling accounted for roughly 70 percent of the oil and 30 percent of the gas produced on federal lands. Nearly all offshore drilling occurs in the central and western Gulf of Mexico and off the coast of California, although no new leases have been issued for areas off the coast of California since 1984. Some activity has occurred elsewhere—such as in the Atlantic Ocean, offshore Alaska, and off the west

21. For more explanation, see Soren T. Anderson, Ryan Kellogg, and Stephen W. Salant, *Hotelling Under Pressure*, Working Paper 20280 (National Bureau of Economic Research, July 2014). According to that report, "oil production from existing wells in Texas does not respond to price incentives. Drilling activity and costs, however, do respond strongly to prices."

Figure 1-7.

Production Profiles Associated With All Leases Issued in 1996 for Federal Lands in Colorado, New Mexico, Utah, and Wyoming



Source: Congressional Budget Office, using data from the Department of the Interior's Bureau of Land Management and Office of Natural Resources and Revenue.

The four states included here account for most of the oil and almost all of the natural gas produced from onshore federal lands; see Table 1-3 for details.

The data extend through December 31, 2010.

coast of Florida—but most of those areas have not been available for leasing since the 1980s; the only exception is certain areas off the coast of Alaska that have been made available for leasing over the past decade.

On average, production of oil and gas from offshore parcels generates more than two-thirds of gross federal income from all domestic oil and gas activities. Between 2005 and 2014, the government collected an annual average of about \$1.8 billion in bonus bids, \$230 million in rental fees, and \$6.0 billion in royalty payments.

Leasing

Offshore leasing is managed through a planning process called the Five-Year Outer Continental Shelf (OCS) Oil and Gas Leasing Program.[22] Each five-year plan describes the areas from which parcels will be auctioned and the dates of each auction. The current plan expires in August 2017; the proposed plan for 2017 through 2022 would offer leases in three areas in the Gulf of Mexico (central, western, and eastern) and three areas off the cost of Alaska (the Chukchi Sea, Beaufort Sea, and Cook Inlet). The acreage offered in the Alaska OCS will be subject to certain exclusion and mitigation zones to protect sensitive areas.

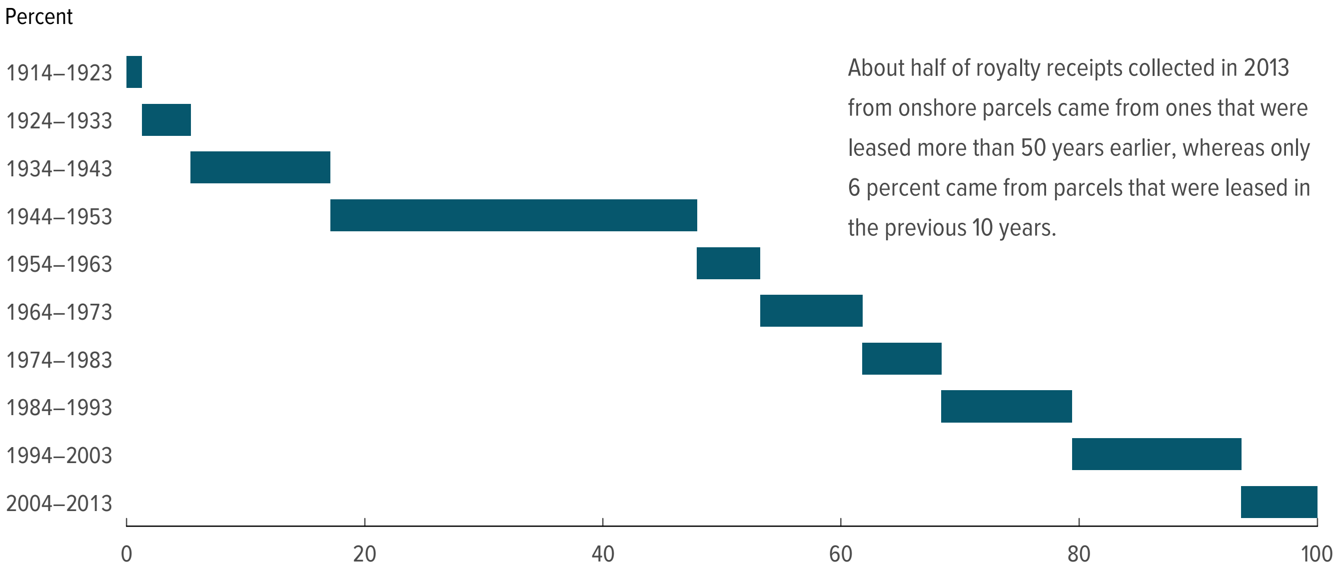
Recognizing the increased complexity of drilling wells in certain offshore areas and wanting to encourage development of parcels, BOEM sets different terms for leases based on the parcels' location. For example, leases for parcels in areas of the Gulf of Mexico that are less than 400 meters deep have a primary term of five years plus an additional three years for drilling if the bottom of the well is more than 7,600 meters below sea level; leases for parcels in ultradeep water in the Gulf of Mexico or anywhere off the coast of Alaska have a 10-year primary term. In addition, parcels off the coast of Alaska that are closer to existing infrastructure, and thus less expensive to develop, tend to have a higher minimum bid.

Auctions for offshore parcels use a sealed-bid format in which all bidders simultaneously submit bids for all the parcels they would like to lease in an area. Most parcels are 5,760 acres and have a minimum bid (set by BOEM) of \$25 to \$100 per acre depending on the depth of the

22. For more details on how the program was created, see Adam Vann, *Offshore Oil and Gas Development: Legal Framework*, Report for Congress RL33404 (Congressional Research Service, December 30, 2015).

Figure 1-8.

Shares of Royalty Receipts Collected in 2013 From Onshore Parcels, by Decade of Original Lease



Source: Congressional Budget Office, using data from the Department of the Interior's Office of Natural Resources and Revenue.

The total amount collected in 2013 was $2.7 billion.

ocean floor in that area; deeper parcels have higher minimums to discourage less serious bidders. After all bids are received, BOEM determines the highest bidder for each parcel and then evaluates whether that bid equals or exceeds the fair value of the parcel (an amount above the minimum bid). To make that determination, BOEM relies on the bids of other firms and on seismic data collected by private firms and confidentially shared with BOEM as a condition of collection. Because such surveys offshore can cost more than $100 million, multiple firms will often commission a survey and share the results. BOEM stipulates that such surveys can be done, as long as the results are also shared with the agency. (BOEM does not release the surveys to the public for 25 years.) The agency uses the surveys to determine whether the highest bid for an auctioned parcel exceeds its fair value and for large-scale assessments of resources' availability (as USGS uses seismic surveys onshore).

If the highest bid exceeds the fair value, then the lease is awarded. If the highest bid does not exceed the fair value, which tends to happen for a few parcels in each auction, then the parcel is returned for leasing at the next scheduled auction. In general, less than 12 percent of the total acreage available in any given auction is leased in that auction. In the Gulf of Mexico, that rate of leasing means that about a third of total available parcels were under lease at the end of 2014.

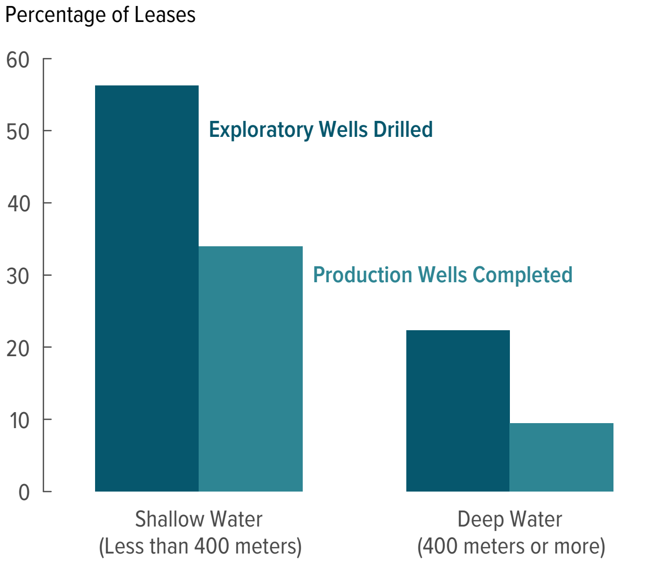
As with auctions for onshore parcels, four factors largely determine the amount a firm is willing to pay to lease a parcel: the terms of the lease, the firm's expectations about the future market price of oil or gas, its expectations about the amount of oil or gas underlying a parcel, and its expectations about the difficulty and cost of extracting oil or gas from the parcel. Differences in the amounts firms are willing to pay for a lease arise mainly from differences in the last two factors.

Federal income from offshore bonus bids can vary significantly over time. In 2008, for example, income from bonus bids spiked to almost $10 billion (see Figure 1-4 on page 14), much higher than the 2005–2014 average of $1.8 billion. Three factors contributed to that surge in auction income. First, the five-year plan included a lease sale for parcels underlying the Chukchi Sea, an area in the Arctic that was thought to contain significant oil and gas reserves and for which leases had not been made available since 1991. Second, delay of a fiscal year 2007 auction resulted in two auctions for leases in the central Gulf of Mexico in fiscal year 2008, both of which contained

Figure 1-9.

Share of Federal Leases in the Gulf of Mexico From 1980 Through 2000 With Drilling and Production Activity

Exploration and development rates for offshore parcels vary by location; parcels in deep water are less likely to be explored because costs are higher there.



Source: Congressional Budget Office, using data from Kenneth Hendricks, University of Wisconsin.

Shallow and deep waters each include about half of all parcels leased in the Gulf between calendar years 1980 and 2000.

numerous parcels believed to be highly valuable.[23] Third, oil prices in 2008 peaked at $140 per barrel, so firms selling oil had more cash to spend on auctions. Those high oil prices also may have increased firms' expectations about future oil prices and thus about the profitability of new discoveries.

Exploration

During the primary term of a lease, the leaseholder can pursue one of three options, which are identical to those for onshore leases: drill an exploratory well (after securing BOEM's approval for its exploration and development plans), wait, or return the lease.

The rental fees on offshore parcels that have been leased but not yet begun production depend on the parcel's location, ranging initially from about $5 per acre to $11 per acre (increased from $3 per acre in the mid-1990s); fees on parcels in the Gulf of Mexico increase after five years (see Table 1-2 on page 13). The high cost of developing offshore parcels, particularly those in deep water, gives leaseholders an incentive to wait to see if additional information—from newly commissioned seismic surveys or other wells drilled on neighboring parcels—becomes available before drilling. The higher rental rate for deepwater parcels reduces that incentive to wait, but only slightly, because the annual fee is small—typically less than 0.1 percent of the costs of exploration.

Exploration and development rates for offshore parcels vary by location. In the Gulf of Mexico, 56 percent of parcels in shallow water leased between 1980 and 2000 were explored during their initial lease term, compared with 22 percent of parcels in deep water, even though the term for parcels in shallow water is shorter (see Figure 1-9). About a third of all leases in the Gulf of Mexico since 1983 have been voluntarily returned to the government before their initial term expired; those leases were then offered for sale in subsequent auctions, during which 60 percent of them attracted bids.[24]

Production

If an exploratory well identifies oil or gas resources of sufficient volume to make a completed well economically viable, the leaseholder usually decides to build the infrastructure necessary to begin production. Only 34 percent of shallow-water parcels and 9 percent of deepwater parcels leased between 1980 and 2000 have produced oil or gas (see Figure 1-9). The construction of offshore infrastructure can be expensive; the leaseholder requires an oil or gas platform in addition to a mechanism to transport the recovered oil or gas to a processing facility on land. Sometimes firms build a pipeline that connects the producing well to onshore facilities. At other times, firms rely on large ships to transport the oil to land.

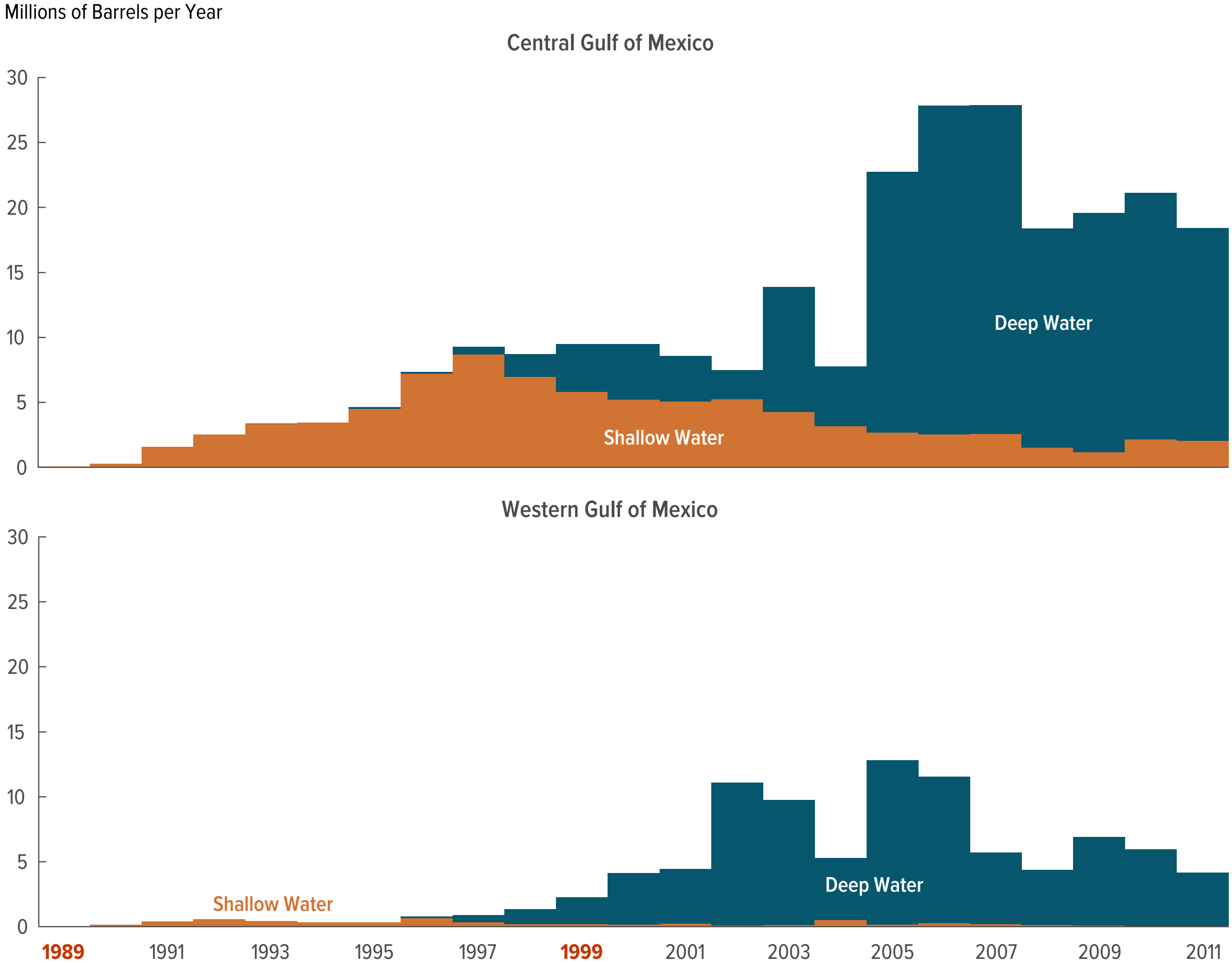
23. The 2007 Central Gulf of Mexico auction was delayed until October 3, 2007, which was in fiscal year 2008. Both auctions included many parcels that were up for re-auction after having first been leased between 1996 and 2000, under legislation that eliminated royalties on production (below certain volume limits) from parcels in water more than 200 meters deep leased during those years. That legislation led firms to lease many more parcels than could be developed during the 10-year primary term. See the Outer Continental Shelf Deep Water Royalty Relief Act of 1995, title III of Public Law 104-58, 109 Stat. 563.

24. Bureau of Ocean Energy Management data as of June 23, 2014, provided to the Congressional Budget Office, on leases with completed initial terms.

Figure 1-10.

Oil Production From All Parcels Leased in Two 1989 Auctions in the Gulf of Mexico

Of the oil production occurring within 22 years of these auctions, production in the first 10 years (through 1999) represented about half of the total for wells in shallow water and very little of the total for wells in deep water.



Source: Congressional Budget Office, using data from the Department of the Interior's Bureau of Land Management and Office of Natural Resources and Revenue.

Deep water is defined as an average parcel depth greater than 400 meters.

The data extend through December 31, 2011.

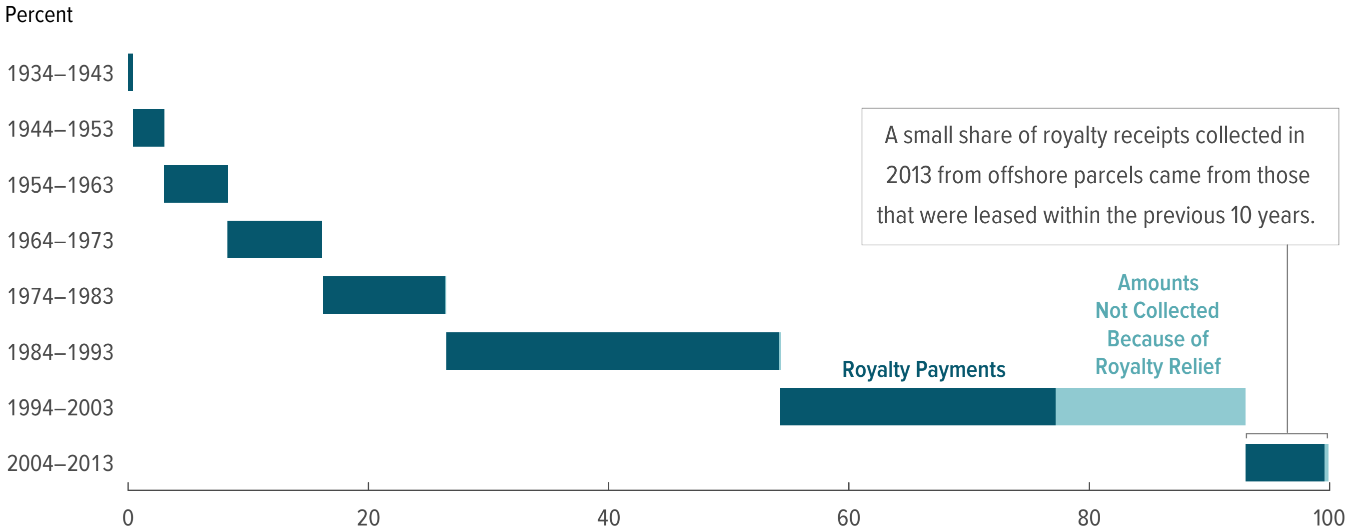
Once production begins, the lease specifies a royalty rate that must be paid to the federal government based on the market value of the oil or gas after certain allowable costs are deducted. The current royalty rates for offshore parcels are 18.75 percent for the Gulf of Mexico and 12.5 percent for Alaska, although BOEM waives royalty payments for some leases if the market price of oil or gas falls below certain thresholds, as it has for gas in the past few years.[25]

For all types of offshore parcels, much of the production—and hence much of royalty income—occurs more than 10 years after the parcel was leased. The production

25. The thresholds are adjusted annually for inflation; a preliminary estimate of the adjustment for 2015 showed that the thresholds for oil remained below the average price for that year. See Bureau of Ocean Energy Management, "Prices Above Which Full Royalties Are Due Notwithstanding Any Remaining Royalty Suspension Volumes" (accessed on March 7, 2016), www.boem.gov/current-price-thresholds-determination (PDF, 100 KB).

Figure 1-11.

Shares of Royalty Receipts Collected in 2013 From Offshore Parcels, by Decade of Original Lease



Source: Congressional Budget Office, using data from the Department of the Interior's Bureau of Land Management and Office of Natural Resources and Revenue.

The amount collected in 2013 totaled $6.0 billion. Another $1.2 billion was excluded from collection because of the royalty relief program of 1996, which eliminated royalty payments for all leases sold between 1996 and 2000, and smaller relief programs in other decades.

history for parcels in the Gulf of Mexico following two representative auctions in 1989 illustrates that pattern: For shallow-water parcels, between 40 percent and 50 percent of production occurred more than 10 years after the auctions; for deepwater parcels, more than 98 percent of production occurred more than 10 years after the auctions (see Figure 1-10). Conversely, about two-thirds of the royalty income collected in 2013 was generated from parcels leased more than 20 years earlier. That figure was higher than it would have been otherwise because the government leased a large number of parcels between 1996 and 2000 on a royalty-free basis: If production from those parcels had occurred at the observed levels and been subject to the royalty rate included in leases before and after that period, then parcels leased more than 20 years earlier would have accounted for about 55 percent of royalty income in 2013 (see Figure 1-11). In either case, parcels leased from 2004 to 2013 generated less than 10 percent of that income.

CHAPTER

2

Selected Policy Options to Increase Federal Income

Legislative and administrative proposals to amend the rules governing access to oil and natural gas on federal lands often involve changes intended to raise additional federal income. In this report, the Congressional Budget Office focuses on policies that would increase the income associated with development and extraction of given volumes of oil and gas, by changing either the qualitative rules for the auctions—in particular, the auction type and nomination process—to increase the competition for available parcels, or the quantitative terms of the auctions and leases, such as the minimum bid, the rental fee, and the royalty rate. The policies analyzed here would generate additional income to the federal government (net of payments to states) ranging from less than $25 million to $500 million over 10 years, CBO estimates, with negligible effects on production over that period or later. For comparison, CBO's March 2016 current-law baseline includes $20 billion in net federal income from onshore oil and gas leasing between fiscal years 2017 and 2026 and $72 billion from offshore leasing over that period.

Quantitative lease terms can be changed to a lesser or greater degree, so CBO selected particular changes to illustrate the potential effects on federal income. The options considered here are relatively small changes, chosen to minimize the likelihood that oil and gas producers would be induced to shift operations from federal to nonfederal lands. Larger or smaller changes could have larger or smaller budgetary effects; larger changes could lead to decreases in production, which could affect other policy objectives that are beyond the scope of the analysis. One such objective—increasing the ability of U.S. households and businesses to accommodate disruptions of supply in energy markets—was evaluated in another CBO report.[1] Other objectives include increasing the flexibility to choose not to import oil from countries associated with terrorism or from countries that might seek to use their exports of oil to influence international affairs; reducing the price of oil or gas in the United States; and avoiding negative environmental consequences that may result from greater production of oil and gas. Estimates of the budgetary effects of larger changes would be subject to greater uncertainty because the size of any decreases in production would depend on future market conditions (for example, a particular change might have little effect on production when prices are high but a large effect when they are low) and on responses by other parties (including states and private landowners).

Two other approaches to increasing federal income from oil and gas produced on federal lands are outside the scope of this report. One approach would be to immediately open additional onshore and offshore federal lands for leasing; in 2012, CBO estimated that doing so would increase receipts (before any revenue sharing with the states) by about $7 billion over 10 years (see Box 2-1).[2] The government could also attempt to promote oil and gas production in general—on private, state, and tribal lands as well as federal lands—by changing the tax treatment of oil and gas development (for a brief examination of that approach, see Box 2-2 on page 30).

Options for Onshore Oil and Gas

The fiscal process governing onshore oil and gas production was largely promulgated in 1987 under an amendment to the Mineral Leasing Act and has not been changed since (see Table 1-1 on page 12). Recent advances in technology and changes in the terms offered by state agencies and other governments for access to their oil and gas resources may offer the Bureau of Land Management an opportunity to increase federal income, albeit by small amounts, with minor or negligible negative effects on production (see Table 2-1 on page 31). One category of policies would change the process by which BLM leases parcels. For example, BLM could be authorized to do the following:

1. See Congressional Budget Office, *Energy Security in the United States* (May 2012), www.cbo.gov/publication/43012.

2. Congressional Budget Office, *Potential Budgetary Effects of Immediately Opening Most Federal Lands to Oil and Gas Leasing* (August 2012), www.cbo.gov/publication/43527.

Box 2-1.

Increasing Production by Opening New Federal Lands

One approach to increasing oil and gas production on federal lands and thus boosting federal income from bonus bids, rental payments, and royalties would be to immediately open additional federal lands to oil and gas leasing. Doing that would entail making changes to two categories of lands now closed to development:

- Lands where leasing is now statutorily prohibited, notably, the Arctic National Wildlife Refuge (ANWR), and
- Lands that are unavailable for leasing under current administrative policies, such as sections of the Outer Continental Shelf (OCS) and certain onshore areas in which oil and gas leasing is either restricted or temporarily prohibited.[1]

In August 2012, the Congressional Budget Office estimated that immediately opening most federal lands to oil and gas leasing would generate $7 billion in additional gross receipts to the federal government, before any sharing with the states, between 2012 and 2022.[2] The $7 billion comprised about $5 billion associated with opening federal lands in ANWR and about $2 billion from expanded development in areas affected by current administrative policies. (Most of that $2 billion was expected to come from the OCS leases; a portion of the proceeds would be shared with the states. Most legislative proposals related to ANWR have specified that a significant portion of receipts from leases there would be shared with Alaska.)

In its 2012 report, CBO estimated that most of the $5 billion in additional receipts obtained between 2012 and 2022 as a result of opening ANWR to development would take the form of bonus bids. The federal government also would collect royalties on oil and natural gas eventually produced from those lands, but most royalty payments would not be collected until much later because of the long lag time between

1. The Outer Continental Shelf consists of submerged lands that are within 200 nautical miles of the official U.S. coastline and may include additional lands where the geological continental shelf extends beyond 200 nautical miles. It does not include waters under state jurisdiction, which extends either 3 or 9 nautical miles from the coastline. See Adam Vann, *Offshore Oil and Gas Development: Legal Framework,* Report for Congress RL33404 (Congressional Research Service, December 30, 2015), p. 2.

2. Congressional Budget Office, *Potential Budgetary Effects of Immediately Opening Most Federal Lands to Oil and Gas Leasing* (August 2012), www.cbo.gov/publication/43527.

Continued

- Adopt an alternative form of auction that would encourage more intense competition between firms for parcels and thus generate more income, or
- Use discretion to set terms that are more advantageous for the government on parcels that are more likely to have oil or gas reserves underlying them. If implemented similarly to approaches used by state governments, that option could allow BLM to increase the minimum bid, rental fee, or royalty rate only when such increases were most likely to boost federal income with negligible effects on production.

A second category of policies could require BLM to adjust the specific terms of the leasing process—for example, by making these changes:

- Increasing the minimum bid,
- Establishing a new fee for nonproducing leases, or
- Raising the royalty rate for all leases.

In addition to the option-specific arguments noted below, two general arguments are commonly made against the eight options discussed here, despite the increase in federal income they would produce. First, increased federal income would necessarily reduce the profitability of holding a lease, which would lessen the returns to shareholders and employees of firms that produce oil and gas from federal lands. Second, increased income in the near term could be offset by lower bidding (because expected returns would be smaller) and less production in later years: If firms cut back on their leasing and exploration of speculative parcels (those for which the availability of oil

Box 2-1. Continued

Increasing Production by Opening New Federal Lands

the initial leasing agreement and the time when production began. Thus, most of the receipts eventually collected would probably occur outside of the 10-year period generally used for budget estimates. Using estimates of potential resources from the Energy Information Administration and taking into account a range of probable oil prices, CBO estimated in 2012 that gross royalties from leasing in ANWR would probably total between $25 billion and $50 billion (in 2010 dollars) during the 13-year period from 2023 to 2035, or roughly $2 billion to $4 billion a year.

If CBO were to revisit its August 2012 analysis today, the estimates of federal receipts would be affected by the significant reduction in the price of oil, which was about $100 per barrel then and is currently about $40 per barrel. The effect of the change in oil prices on CBO's estimates would be proportionately smaller, because most of the receipts collected within the 10-year budget window would come from bonus bids, not royalty payments, and bids depend more on expected future oil prices than on current prices.

One argument in favor of opening more federal lands to oil and gas production is that preparing the newly available parcels for development could boost employment and economic output, especially in the affected regions. Additional leasing could also raise income for state and local governments; the exact amounts would depend on states' tax policies, the amounts of oil and gas expected to be available in each leasing area and the amounts actually produced, and the formulas for distributing portions of federal oil and gas proceeds to the states. The primary argument against expanded leasing is that the areas involved are environmentally sensitive, and exploration and production of oil and natural gas could pose a threat to wildlife, fisheries, and tourism. Another argument against expanded leasing is that increased development of resources in the near term would reduce the oil and gas available for production in the future, when prices might be higher and the resources might be valued more highly by households and businesses.[3]

3. For those and other arguments for and against oil and gas development, see Robert B. Jackson and others, "The Environmental Costs and Benefits of Fracking," *Annual Review of Environment and Resources*, vol. 39 (October 2014), pp. 327–362, http://tinyurl.com/kq4endz.

or gas is particularly uncertain), less information would be generated about the resources on nearby parcels, potentially reducing bidding on those parcels in future auctions and delaying production from them once leased.

However, CBO expects that the effects on production and federal income of reduced activity on speculative parcels would be small, for two reasons. First, the parcels not leased would be among those most likely to remain unexplored even if leased. Second, the parcels not leased would be available for leasing in the future, and some of them would become more valuable because of oil or gas discoveries on nearby parcels or information from new seismic surveys. Thus, any losses in production and income in the near term might be offset or outweighed by gains in later years.

Option 1. Require Onshore Parcels to Be Auctioned Through a Sealed-Bid Process

Onshore parcels are leased through an open-outcry auction, as mandated by the authorizing legislation. In some settings, such a design has been found to be vulnerable to collusion, particularly when the number of bidders is small.[3] Maybe more important, when there is only a single bidder, as is often the case in auctions for onshore parcels, the open-outcry format has no mechanism to

3. See, for example, R. Preston McAfee and John McMillan, "Bidding Rings," *American Economic Review*, vol. 82, no. 3 (June 1992), pp. 579–599, www.jstor.org/stable/2117323; and Daniel A. Graham and Robert C. Marshall, "Collusive Bidder Behavior at Single-Object Second-Price and English Auctions," *Journal of Political Economy*, vol. 95, no. 6 (December 1987), pp. 1217–1239, http://dx.doi.org/10.1086/261512.

Box 2-2.

Increasing Income by Repealing Tax Preferences

In addition to changing the leasing system associated with development of oil and gas on federal lands, lawmakers could consider reducing the tax preferences that are available to private firms that develop oil and gas resources, regardless of whether the lands are owned by the federal government. Two primary tax preferences are available to those firms.[1] One allows producers of oil, gas, coal, and minerals to expense (or deduct) some of the costs associated with exploration and development as they are incurred, rather than waiting for those activities to generate income. In 2014, the staff of the Joint Committee on Taxation (JCT) estimated that repealing that provision that year would increase revenues by $15 billion between 2015 and 2024. The other tax preference allows producers of oil, gas, coal, and minerals to deduct from their taxable income between 5 percent and 22 percent of the dollar value of oil and gas extracted during the year. (The precise amount of the deduction depends on the type of resource and applies only up to certain limits.) JCT estimated that repealing that tax preference would increase revenues by $21 billion over the 2015–2024 period.

An argument in favor of reconsidering the tax preferences available for firms that produce oil or gas is that they distort the allocation of resources between the extractive industries and other industries. When making investment decisions, companies consider the tax advantages associated with those decisions. By favoring extractive industries, tax preferences encourage some investments in drilling and mining that produce a smaller market value of output than the investments would produce elsewhere. In addition, the preferences encourage producers to extract more resources in a shorter time, accelerating the depletion of the nation's oil and gas resources and causing greater reliance on foreign producers in the long run.

An argument against making such changes is that the current system treats exploration and development costs for extractive industries similarly to research and development costs for other industries, which can be expensed by all businesses. Another argument against making changes is that such tax benefits increase the profitability of exploring and developing domestic energy resources, which can increase economic growth in the United States.

1. For an analysis of some aspects of the tax treatment for extractive industries, including the estimates of revenue effects cited in the text, see Congressional Budget Office, "Option 65: Repeal Certain Tax Preferences for Extractive Industries," in *Options for Reducing the Deficit: 2015 to 2024* (November 2014), p. 43, www.cbo.gov/budget-options/2014/49647.

cause the bid to rise above the minimum amount. Conversely, sealed-bid auctions (such as those that are used for offshore parcels) are less vulnerable to collusion and maintain an incentive for participants to bid above the minimum amount, because they do not know how many other participants might be bidding on the same parcel when they submit their bid.

Changing to a sealed-bid design would increase net federal income by $100 million over the subsequent 10 years, the Congressional Budget Office estimates, by increasing competition between firms for parcels. That additional competition would probably increase the amount that firms would have to pay to lease more valuable parcels and, as a result, could reduce the funds available in firms' exploration budgets for bidding on less valuable parcels. But CBO expects that any reduction in the number of parcels leased would have a negligible effect on production. Again, the parcels that firms would not lease under the new design would probably have gone unexplored even if leased. And they would be available for leasing in the future, when they might be more valuable and more likely to be developed.

An argument against the option might be this: Because the value of resources underlying a parcel is unknown, the open-outcry format allows firms to learn something about the estimates of other firms on the basis of their decision to remain in or exit the auction. However, the open-outcry approach currently used by BLM does not

Table 2-1.

Policy Options for Oil and Natural Gas Production on Federal Lands

Millions of Dollars

	Option	Increase in Federal Income Over 10 Years
	Onshore Parcels	
1	Require onshore parcels to be auctioned through a sealed-bid process	100
2	Allow BLM to establish lease-specific fiscal terms	a
3	Increase the minimum bid for auctions and noncompetitive leases	50
4	Impose a fee of $6 per acre on nonproducing parcels	200
5	Increase the royalty rate to 18.75 percent for all new onshore parcels	200
	Offshore Parcels	
6	Require parcels to be nominated for auction	150
7	Impose a fee of $6 per acre on nonproducing parcels	500
8	Increase the royalty rate when the price of oil or gas rises above a threshold	Less Than 25

Source: Congressional Budget Office, using data from the Department of the Interior's Bureau of Land Management and Office of Natural Resources and Revenue.

All estimates represent net federal receipts after distributing appropriate shares of gross proceeds to the states.

BLM = Bureau of Land Management.

a. The effect on receipts would depend on details of the authorizing legislation and its implementation.

allow firms to observe the number of other firms that exit the auction at a particular price, only whether the firm willing to pay the highest bid continues to bid when the price increases. That information is less valuable, particularly if some firms are waiting until the end of the auction before submitting a bid.[4]

Option 2. Allow BLM to Establish Lease-Specific Terms

Under current law, BLM is prohibited from considering the quality of a parcel in setting any of the terms of the leasing process. If that restriction was eliminated by legislation, BLM could keep the terms unchanged for parcels about which little is known or that are unlikely to be developed but make the terms more advantageous to the government for parcels that are most likely to contain oil or gas resources.

Giving BLM such flexibility would probably increase net federal income, particularly if the legislation prohibited changes that would tend to lower income, such as reductions in rental fees. Because the amount of increased income would depend on what the legislation required and how BLM implemented it, CBO has not estimated the amount of additional income that might result. If the terms were changed only for parcels with a high likelihood of development, the effect on production would probably be negligible.

One argument against this option is that implementation would be administratively expensive and difficult for BLM. However, other federal agencies and states already are establishing such parcel-specific terms. For example, BOEM sets different primary terms, rental fees, and minimum bids for offshore parcels on the basis of water depth (see Table 1-2 on page 13). Also, the state of North Dakota auctions leases with a royalty rate of 16.67 percent in counties where the presence of oil and gas is more speculative and a rate of 18.75 percent elsewhere.[5] As a more complex example, New Mexico categorizes all state leases into one of five types, each of which has a different rental rate, minimum bid, and royalty rate.[6] BLM could start by implementing a fairly simple rule and add complexity as managerial resources permitted.

Option 3. Increase the Minimum Bid for Onshore Auctions and Noncompetitive Leases

As set by BLM, the current minimum bonus bid for onshore parcels is $2 per acre, an amount that could be

4. Analysts have examined other types of multiround auctions that could be less susceptible to collusion than open-outcry auctions and yet give bidders more information about the potential value of a parcel than sealed-bid auctions. See, for example, Kenneth Hendricks and Robert H. Porter, "Auctioning Resource Rights," *Annual Review of Resource Economics,* vol. 6 (2014), pp. 175–190, http://dx.doi.org/10.1146/annurev-resource-091912-151752; and Peter Cramton, "How Best to Auction Oil Rights," in Macartan Humphreys, Jeffrey D. Sachs, and Joseph E. Stiglitz, eds., *Escaping the Resource Curse* (Columbia University Press, 2007).

5. Diane Nelson, North Dakota Department of Trust Lands, Minerals Management Division, personal communication (October 28, 2015).

6. New Mexico State Land Office, *Oil and Gas Manual* (May 2013), www.nmstatelands.org/oil-and-gas-manual.aspx.

increased through future rulemaking or legislation. If a parcel is leased noncompetitively, no bonus bid is paid; adding a minimum bonus bid for noncompetitive leases could also be done through rulemaking or legislation. Only a small share of parcels leased noncompetitively or for prices near the minimum bid are explored and developed: Among onshore parcels leased between 1996 and 2003, for instance, drilling permits were submitted for 8 percent of parcels leased for less than $10 per acre, compared with 25 percent of parcels leased for more than $10 per acre.[7]

Raising the minimum bid in an auction to $10 per acre and requiring that same amount to be paid for parcels leased noncompetitively would boost net federal income by an estimated $50 million over 10 years, CBO estimates. That effect is the net result of increases in federal income from higher bonus bids for some parcels, including all parcels leased noncompetitively, and decreases in rental and royalty income for parcels that attract no bids (though such parcels would have generated relatively little production and royalty income).

Notwithstanding that estimated increase in federal income, the general arguments against all of the options apply here: Returns to producing firms would be lower; and reductions in the number of parcels leased could mean that new information about the locations of oil and gas resources would become available more slowly, in turn reducing future production. Again, experience suggests that the latter effect would be negligible, in part because parcels that go unleased as a result of the higher minimum bid would have had relatively little exploration in any case.

Option 4. Impose a Fee on Nonproducing Parcels

The current rental fee for nonproducing onshore parcels is $1.50 per acre for the first five years and $2 per acre for the next five years; legislation that established a separate new fee of $6 per acre on nonproducing leases would increase net federal income by $200 million over 10 years, CBO estimates.[8] That effect is the net result of increases in income from fees and decreases in income from bonus bids, because the new fee would slightly reduce the amount private firms would be willing to bid in an auction for leases. That fee might also give firms a financial incentive to be more selective in acquiring parcels and to explore and develop those parcels more quickly (as discussed in Box 1-1 on page 10), although that effect is probably small because fees would typically be less than 1 percent of the costs of development. For that reason, CBO anticipates that such a fee would have a negligible effect on production.

Option 5. Increase the Royalty Rate

The royalty rate for onshore oil and gas production is 12.5 percent, which is the lowest royalty rate allowed under current law. That rate is lower than the 18.75 percent charged for offshore oil and gas production, and lower than the rates charged by many key Western states, including Wyoming, New Mexico, Colorado, and Utah.[9] (Many states have increased their royalty rates over the past decade.) Although BLM has the statutory authority to increase the royalty rate, it has not done so.

Raising the royalty rate for onshore parcels to 18.75 percent to match the rate for offshore parcels would generate $200 million in net federal income over the next 10 years, CBO estimates. Income generated in the following decade could be much greater, depending on market conditions: Because the higher rate would apply only to new leases and the affected parcels would not go into production immediately, the effect on federal income would be small initially but increase over time as the number of producing parcels subject to the new rate grew.

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7. Offshore leases won with low bids also have low rates of development. In analysis supporting a 2011 increase in the minimum bid for offshore leases in the Gulf of Mexico from $37.50 per acre to $100 per acre, BOEM stated, “the last 15 years of lease sales in the Gulf of Mexico showed that deep water leases that received high bids of less than $100 per acre, adjusted for energy prices at the time of each sale, experienced virtually no exploration and development drilling.” See Department of the Interior, *Oil and Gas Lease Utilization, Onshore and Offshore: Updated Report to the President* (May 2012), p. 9, http://go.usa.gov/ctCgW (PDF, 1.25 MB).

8. The estimate reflects an assumption that receipts from the new fee could not be spent without subsequent appropriations. If some or all of the receipts were available for direct spending (for example, to be distributed to the states), the net effect on the budget would be smaller or zero.

9. Center for Western Priorities, *A Fair Share: The Case for Updating Oil and Gas Royalties on Our Public Lands—Update* (June 18, 2015), http://tinyurl.com/j296qzt. From 2005 through 2014, those states were the top four producers of gas and four of the top six producers of oil from federal lands onshore; see Table 1-3 on page 20.

The effect on income is the net result of increases in royalty receipts and decreases in income from bonus bids. Such an increase in the royalty rate would also reduce the profitability of exploring speculative parcels compared with parcels owned by other jurisdictions, so CBO expects that some exploration would shift away from federal lands. But the subsequent decrease in production on federal lands would in all likelihood be small or negligible, particularly if the federal royalty rate remained equal to or below the royalty rates that apply to nearby state and private lands.[10] In addition, the higher royalty rate would probably cause firms to end production at wells with declining volumes earlier than they would with a lower royalty rate. That effect would probably also be small or negligible and occur several decades in the future.

Although federal income is estimated to increase under this option, one argument against it is that the effect on production could be large if oil or gas prices were very low, as they currently are. To address that issue, BLM could establish separate royalty rates for oil and gas that increased or decreased as the prices of those commodities rose or fell. That approach would give firms some relief in periods of low prices but would generate more federal income when prices rose; however, it could be more difficult and costly for BLM to implement.

Options for Offshore Oil and Gas

CBO evaluated three policy options for offshore oil and gas production (see Table 2-1 on page 31).[11]

- Requiring parcels to be nominated before auctioning (as are onshore parcels),
- Imposing a fee on nonproducing parcels, and
- Increasing royalty rates when the price of oil or gas rises.

In CBO's estimation, the options as specified below would increase federal income by relatively small amounts and have negligible effects on production.

Not included in the analysis are changes already under consideration by BOEM. (The legislation authorizing the leasing process for offshore oil and gas production gives BOEM significant flexibility, which the agency has used to change the process several times over the past decade, on the basis of its research and analysis.)[12] CBO's baseline takes into account administrative actions that are likely to occur under current law; therefore, estimates of the budgetary effects of legislation directing BOEM to take actions that were likely to occur in any event would reflect only changes in the timing or certainty of those actions.

The two general arguments often made against the options for onshore parcels discussed earlier can also apply to the options for offshore parcels. First, the options would reduce income to shareholders and employees of oil and gas producers. Second, production (and thus government income) could be reduced over time: As lease-related costs increased, firms would probably reduce their inventory of the most speculative parcels, which would slow the accumulation of new information about those parcels and hence the identification of some oil and gas reserves.

For the changes considered in this report, the effects on production would probably be negligible because the relatively few parcels that would go unleased are those that would have been least likely to be explored under current law. Moreover, some of those parcels would be leased and developed later, after discoveries of oil or gas on nearby parcels made them more attractive. Larger changes to the fiscal terms could affect production, however, as happened when BOEM eliminated the royalty rate for deepwater leases issued between 1996 and 2000. That change most likely contributed to increased leasing of speculative parcels, which were then explored and developed when oil prices rose from less than $50 per barrel in the late 1990s to more than $100 per barrel a decade later.

10. For a review of the effects that increases in royalty rates can have on oil and gas production, see Ujjayant Chakravorty, Shelby Gerking, and Andrew Leach, "State Tax Policy and Oil Production: The Role of the Severance Tax and Credits for Drilling Expenses," in Gilbert E. Metcalf, ed., *U.S. Energy Tax Policy* (Cambridge University Press, 2011), pp. 305–337.

11. For an analysis of other options, see Economic Analysis, Inc., and Marine Policy Center, *Policies to Affect the Pace of Leasing and Incomes in the Gulf of Mexico Technical Report*, OCS Study BOEMRE 2011-014 (December 2010), http://go.usa.gov/cAEWF.

12. See Department of the Interior, *Oil and Gas Lease Utilization, Onshore and Offshore: Updated Report to the President* (May 2012), http://go.usa.gov/ctCgW (PDF, 1.25 MB).

Option 6. Require Parcels to Be Nominated for Auction

Starting in 1983, BOEM began leasing parcels through an approach called areawide leasing, which divides all offshore acreage into discrete areas and then makes most parcels within each area available for auction according to the schedule devised in each five-year leasing program. That approach represented a change from a system in which BOEM (known as the Mineral Management Service at the time) largely determined which offshore parcels would be made available for leasing. Areawide leasing was adopted as a more efficient way to allow the private market to allocate expenditures for exploration, development, and production across acreage. That change increased the average number of auctioned parcels from 175 offered and 80 leased per auction before 1983 to several thousand offered and 400 leased per auction between 1983 and 2006.[13] The increase in acreage available for auction reduced competition for any single parcel and contributed to decreases in the price of each parcel and in total income from auction bids. Legislation that required BOEM to implement a nomination process to determine which parcels were auctioned, instead of including all parcels under areawide leasing, would probably increase competition for the nominated parcels.[14] In addition, firms would be more likely to bid on nominated parcels because they would assume that such parcels had a higher likelihood of containing oil and gas reserves.

Requiring nomination of offshore parcels could generate an additional $150 million over 10 years in net federal income, CBO estimates, depending on what the legislation required and how BOEM implemented it.

CBO's analysis incorporates an assumption that BOEM would charge a small fee to nominate parcels, which would discourage firms from nominating many parcels as a way of distracting other bidders from their targeted parcels. Again, arguments against the option are that it would reduce earnings for leaseholders and decrease production, but the effect on production would probably be negligible.

Option 7. Impose a Fee on Nonproducing Parcels

As of the end of 2014, only about 17 percent of offshore parcels were producing oil or gas.[15] Some analysts speculate that firms are not gathering much information about parcels until after they have acquired leases for them.[16] A new fee on nonproducing parcels could encourage firms to gather more information before an auction, to focus on the most promising parcels, and to bid more competitively for those parcels. The effects would be similar to those of an increase in rental rates; in recent years, BOEM has raised base rental rates and established rate schedules that increase over the course of a lease to encourage faster exploration and development of parcels, as well as earlier decisions to return parcels that current leaseholders do not plan to explore.[17]

Legislation that established a new fee of $6 per acre on nonproducing parcels would increase net federal income by $500 million over 10 years, CBO estimates.[18] That effect is the net result of increases in income from fees and decreases in income from bonus bids, because the new fee would slightly reduce the amount firms would be

13. See Kenneth Hendricks and Robert H. Porter, "Auctioning Resource Rights," *Annual Review of Resource Economics*, vol. 6 (2014), pp. 175–190, http://dx.doi.org/10.1146/annurev-resource-091912-151752; and Philip Haile, Kenneth Hendricks, and Robert Porter, "Recent U.S. Offshore Oil and Gas Lease Bidding: A Progress Report," *International Journal of Industrial Organization*, vol. 28, no. 4 (July 2010), pp. 390–396, http://dx.doi.org/10.1016/j.ijindorg.2010.02.010.

14. In the five-year leasing plan for 2012 to 2017, BOEM adopted a policy of "targeted leasing" for waters off the coast of Alaska. That policy requires that an interested party "provide specific information to support its nominations of areas to be considered for leasing"; see Bureau of Ocean Energy Management, "Enhancements to Alaska Outer Continental Shelf Lease Sales Process" (accessed March 18, 2016), http://go.usa.gov/cAmhw. The policy differs from the option considered here in that it does not require nominations of individual parcels to be auctioned.

15. See Bureau of Ocean Energy Management, "Combined Leasing Report as of January 1, 2015" (January 1, 2015).

16. See Kenneth Hendricks and Robert H. Porter, "Auctioning Resource Rights," *Annual Review of Resource Economics*, vol. 6 (2014), pp. 175–190, http://dx.doi.org/10.1146/annurev-resource-091912-151752.

17. Statement of Tommy P. Beaudreau, Director, Bureau of Ocean Energy Management, before the Subcommittee on Interior, Environment, and Related Agencies, Committee on Appropriations (March 7, 2012), http://go.usa.gov/cAyq5. In the August 2014 auction of parcels in the Gulf of Mexico, the initial rental fee for parcels in water over 200 meters deep was $11 per acre; in contrast, the fee was $7.50 per acre a decade ago and $3 per acre in the 1990s.

18. The estimate incorporates the assumption that receipts from the new fee could not be spent without subsequent appropriations. If some or all of the receipts were available for direct spending (for example, to be distributed to the states), the net effect on the budget would be smaller or zero.

willing to bid at auction. Again, an argument against the option is that those increases in federal income would be decreases in income to the oil and gas firms. The fee's effects on production would probably be small, because the fee would typically be less than 0.1 percent of the costs of development.

Option 8. Increase the Royalty Rate When the Price of Oil or Gas Rises Above a Threshold

BOEM imposes a single royalty rate for all offshore leases, regardless of whether the parcel is producing oil, gas, or both. Various laws have reduced or eliminated royalty payments in certain areas if prices fall below a particular threshold: In 2014, for parcels in deep water or deep wells in shallow water, the threshold was set at about $5 per thousand cubic feet for gas and about $40 per barrel for oil.[19] In addition, BOEM has the authority to waive royalty payments for leaseholders who request such a waiver. The value of a productive parcel decreases as the price of oil or natural gas falls; however, when a parcel is leased in an auction, bidders do not know the future market price of oil or natural gas and thus bid on the basis of their best estimates of future prices. If prices fall unexpectedly, the leaseholder makes less profit than anticipated; conversely, if prices rise unexpectedly, the leaseholder makes more profit than anticipated. The current approach offers some leaseholders protection from falling oil and gas prices but does not benefit the government if prices rise. One alternative would be to create a royalty schedule that increased with prices.

If the royalty rate for oil rose to 25 percent when the real (inflation-adjusted) price of oil climbed above $100 per barrel and the rate for natural gas rose to 25 percent when its real price rose above $8 per thousand cubic feet, additional net federal income would be less than $25 million over the next decade, CBO estimates; it could be significantly larger in the following decade, depending on market conditions. That effect is the net result of increases in income from royalties and decreases in income from bonus bids, because the option would reduce slightly the expected profitability of leases. Because leases become more profitable for the firm holding the lease at higher oil or gas prices, the option would probably have a negligible effect on production.

In addition to the above general arguments, a specific argument against this option is that a tiered royalty system would be more complicated for BOEM to administer. But such systems have been implemented elsewhere: For example, Alberta, Canada, has set royalties for conventional oil that depend on both price and well production.[20]

19. The price of natural gas is currently below that threshold of $5 per thousand cubic feet. To qualify as a deep well in shallow water, the well must be more than 15,000 feet below sea level. For more information on the program and specific thresholds, see Department of the Interior, "Prices Above Which Full Royalties Are Due Notwithstanding Any Remaining Royalty Suspension Volumes," www.boem.gov/current-price-thresholds-determination (PDF, 100 KB).

20. For an evaluation, see Irena Agalliu, *Comparative Assessment of the Federal Oil and Gas Fiscal System* (IHS Cambridge Energy Research Associates, October 2011), pp. 189–191, http://go.usa.gov/cwznH.

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About This Document

This report was prepared in response to a request from the Ranking Member of the House Committee on Natural Resources. In keeping with the Congressional Budget Office's mandate to provide objective, impartial analysis, the report makes no recommendations.

Andrew Stocking (formerly of CBO) and Perry Beider wrote the report with guidance from Joseph Kile and Chad Shirley. Jeff LaFave prepared the estimates for the policy options for onshore leasing, and Kathleen Gramp prepared the estimates for the policy options for offshore leasing. Terry Dinan, Kathleen Gramp, Jeff LaFave, Mark Lasky, Chayim Rosito, Kurt Seibert, and Rebecca Verreau provided useful comments. Lydia Cox and Andre Barbe (both formerly of CBO) provided help with data analysis. Tristan Hanon fact-checked the document.

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Keith Hall
Director

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