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Report to Congressional Committees

June 2017

# OIL, GAS, AND COAL ROYALTIES

# Raising Federal Rates Could Decrease Production on Federal Lands but Increase Federal Revenue

GAO-17-540

GAO Highlights

Highlights of GAO-17-540, a report to congressional committees

June 2017

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## Raising Federal Rates Could Decrease Production on Federal Lands but Increase Federal Revenue

### Why GAO Did This Study

In fiscal year 2016, the federal government collected about $2.5 billion in revenue associated with onshore oil, gas, and coal production on federal lands, including about $2 billion from royalties. Federal royalty rates sometimes differ from the rates states charge for production on state lands. For example, state oil and gas rates tend to be higher than federal royalty rates and state coal rates are generally the same as federal rates in the six states representing more than 90 percent of federal oil, gas, and coal production in fiscal year 2015.

The explanatory statement accompanying the Consolidated Appropriations Act for fiscal year 2016 includes a provision for GAO to review issues related to royalty rates. This report describes what is known about how raising federal royalty rates would affect (1) oil, gas, and coal production on federal lands and (2) the federal revenue associated with such production. GAO reviewed an extensive list of studies and selected for more in-depth review four that modeled the effects of raising federal royalty rates—one study conducted by the Congressional Budget Office, one by the Council of Economic Advisers in the Executive Office of the President, one prepared for the Bureau of Land Management, and one by researchers. GAO also interviewed officials from federal and state agencies, industry groups, non-governmental organizations, academia, and other knowledgeable stakeholders.

GAO is not making recommendations in this report. Interior reviewed a draft of this report and provided technical comments that GAO incorporated as appropriate.

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### What GAO Found

Raising federal royalty rates—a percentage of the value of production paid to the federal government—for onshore oil, gas, and coal resources could decrease oil, gas, and coal production on federal lands but increase overall federal revenue, according to studies GAO reviewed and stakeholders interviewed. However, the extent of these effects is uncertain and depends, according to stakeholders, on several other factors, such as market conditions and prices.

**Production**. One study GAO reviewed found that oil and gas production could decrease by less than 2 percent per year if royalty rates increased from their current 12.5 percent to 22.5 percent, based on fiscal year 2016 production data. Another study stated the effect on production could be “negligible” over 10 years if royalty rates increased to 18.75 percent, particularly if the increased federal royalty rate remained equal to or below the royalty rates for production on state or private lands. Regarding coal, one study suggested that raising the federal royalty rate for coal to 17 percent would decrease production on federal lands by up to 3 percent after changes were fully implemented after 2025, while a second study said that increasing the effective rate—the rate actually paid by companies after processing and transportation allowances have been factored in, along with any royalty rate reductions—might decrease production on federal lands by less than 1 percent per year. Some stakeholders said that several other factors could influence the extent to which oil, gas, and coal production might decline. For example, some stakeholders said current market conditions, the cost advantages of different resources, and the regulatory burden associated with production on federal lands could influence the extent to which production might decline.

**Revenue**. The oil and gas studies that GAO reviewed estimated that raising the federal royalty rate could increase net federal revenue between $5 million and $38 million per year. One of the studies stated that net federal revenue would increase under three scenarios that modeled raising the royalty rate from the current 12.5 percent to 16.67 percent, 18.75 percent, or 22.5 percent, while the other study noted that the effect on federal revenue would initially be small but would increase over time. Both coal studies suggested that a higher royalty rate could lead to an increase in federal revenues. One of the studies suggested that raising the royalty rate to 17 percent or 29 percent might increase federal revenue by up to $365 million per year after 2025. The other study suggested that increasing the effective rate could bring in an additional $141 million per year in royalty revenue. Stakeholders GAO interviewed cited other factors that could influence the extent to which raising federal royalty rates could increase revenues—in particular, how bonus bids, another revenue source, could be affected. Some of the stakeholders stated that companies would be more likely to offer lower bids to obtain a lease for the rights to extract resources if they had to pay higher royalties.

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## Abbreviations

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|---|---|
| BLM | Bureau of Land Management |
| CBO | Congressional Budget Office |
| CEA | Council of Economic Advisers |
| EIA | Energy Information Administration |
| Interior | Department of the Interior |
| ONRR | Office of Natural Resources Revenue |

U.S. GOVERNMENT ACCOUNTABILITY OFFICE
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June 20, 2017

The Honorable Lisa Murkowski
Chairman
The Honorable Tom Udall
Ranking Member
Subcommittee on Interior, Environment, and Related Agencies
Committee on Appropriations
United States Senate

The Honorable Ken Calvert
Chairman
The Honorable Betty McCollum
Ranking Member
Subcommittee on Interior, Environment, and Related Agencies
Committee on Appropriations
House of Representatives

Production of oil, gas, and coal on federal lands is an important part of the nation's energy portfolio and generates billions of dollars annually in revenue for the federal government.[1] In fiscal year 2016, the Department of the Interior (Interior) reported collecting about $2.5 billion associated with onshore oil, gas, and coal production on federal lands.[2] These revenues came primarily from royalties paid on the value of the resources produced. Interior's Bureau of Land Management (BLM) has the responsibility to manage and lease federal lands—about 700 million mineral acres held by BLM, the U.S. Forest Service, and other federal agencies and surface owners.

Since 2011, we have designated Interior's management of federal oil and gas resources as a high-risk area vulnerable to fraud, waste, abuse, and mismanagement. During that time, we have made recommendations to Interior related to oil, gas, and coal royalties. Although it has not met the

[1]The focus of this report is on the onshore production of resources on federal lands and excludes offshore production in federal waters. For the purpose of this report, we refer to money collected from the leasing of federal lands for energy production as revenue. See appendix I for information on offshore production and revenue data.

[2]Approximately half of the revenue collected from the development of onshore resources is to be paid to the state in which the resource was extracted. The exception is Alaska, where the state share is 88 percent for leases outside the National Petroleum Reserve and 50 percent for leases within the reserve. 30 U.S.C. § 191; 42 U.S.C. § 6506a(l).

criteria for removal from our High-Risk List, Interior has taken some steps to strengthen how it manages federal oil and gas resources.[3] For example, Interior adopted regulations that provide BLM with the flexibility to make timely changes to onshore oil and gas royalty rates, as we recommended in December 2013.[4] In addition, after we recommended in December 2013 that BLM revise its guidance regarding management of the coal program, the agency revised its guidance to better ensure it obtains a fair market value for federal coal resources.[5]

Interior has undertaken other actions intended to improve its management of federal oil, gas, and coal resources. For example, in 2016, BLM began preparing a programmatic environmental impact statement of the federal coal program that included reviewing an option to raise the federal royalty rate, among other alternatives.[6] Work on the programmatic environmental impact statement was terminated in March 2017, and in the same month, the Secretary of the Interior signed a charter establishing a Royalty Policy Committee to provide regular advice on the fair market value of federal and Indian mineral and energy leases and the collection of revenues from them.[7] In reexamining aspects of how it collects revenues associated with oil, gas, and coal production on

[3]In our 2017 update, we reported that Interior had implemented some of our recommendations to address these challenges, but needs to do more to meet its responsibilities to manage federal oil and gas resources. See GAO, *High-Risk Series: Progress on Many High-Risk Areas, While Substantial Efforts Needed on Others,* GAO-17-317 (Washington, D.C.: Feb. 15, 2017).

[4]GAO, *Oil and Gas Resources: Actions Needed for Interior to Better Ensure a Fair Return*, GAO-14-50 (Washington, D.C.: Dec. 6, 2013).

[5]GAO, *Coal Leasing: BLM Could Enhance Appraisal Process, More Explicitly Consider Coal Exports, and Provide More Public Information*, GAO-14-140 (Washington, D.C.: Dec. 18, 2013).

[6]Beginning in January 2016, Secretarial Order 3338 placed a “pause” on federal coal leasing, with limited exceptions, during the completion of the programmatic environmental impact statement. However, on March 29, 2017, Secretarial Order 3348 revoked Secretarial Order 3338, lifting the moratorium on federal coal lease sales, and ending work on the programmatic environmental impact statement effective immediately.

[7]According to the charter, the Committee may also advise on the potential impact of proposed policies and regulations related to revenue collection from such development.

federal lands, BLM has solicited and received public comments.[8] In addition, a few stakeholders have stated that current federal royalty rates are too low to ensure a fair return on public resources, while others have stated that raising royalty rates would cause production to shift to state and private lands.

The explanatory statement accompanying the Consolidated Appropriations Act for fiscal year 2016 includes a provision for us to review the potential effects of increasing federal royalty rates for oil, gas, and coal production on federal lands.[9] This report examines what is known about how raising federal royalty rates for oil, gas, and coal could affect (1) production on federal lands and (2) the federal revenue associated with such production.

To do this work, we identified an extensive list of studies and other literature through a literature search based on parameters designed to include a wide range of published information about the effects of altering royalty rates for oil, gas, and coal development on federal lands. We supplemented this list with suggestions from knowledgeable stakeholders, including agency officials, and our subject matter experts then narrowed the list to studies directly relevant to our reporting objectives. From the studies identified, we selected for more in-depth review four studies—two that address oil and gas and two that address coal—that we determined used reasonable and comprehensive methodologies and assumptions for describing the range of potential effects of raising federal royalty rates. Three of these studies were conducted by or for federal agencies, and one was conducted by researchers:

- Congressional Budget Office (CBO), *Options for Increasing Federal Income from Crude Oil and Natural Gas on Federal Lands* (Washington, D.C.: April 2016).

[8]In April 2015, BLM issued an Advance Notice of Proposed Rulemaking and sought comment on a number of potential reforms to the oil and gas leasing process, including setting royalty rates. 80 Fed. Reg. 22,148 (Apr. 21, 2015). Regarding coal, as stated above, in January 2016, the Secretary of the Interior announced the preparation of a programmatic environmental impact statement, a comprehensive review of potential leasing and management reforms to the federal coal leasing program.

[9]Section 4 of the Consolidated Appropriations Act, 2016, Pub. L. No. 114-113 (2015), provides that the explanatory statement accompanying the act and printed in the Congressional Record shall have the same effect as if it were a joint explanatory statement of a committee of conference.

- Enegis, LLC, *Benefit-Cost and Economic Impact Analysis of Raising the Onshore Royalty Rates Associated with New Federal Oil and Gas Leasing* (Prepared for BLM, Washington, D.C.: April 2011).
- Executive Office of the President of the United States, Council of Economic Advisers (CEA), *The Economics of Coal Leasing on Federal Lands: Ensuring a Fair Return to Taxpayers* (Washington, D.C.: June 2016).
- Haggerty, Lawson, and Pearcy, *Steam Coal at an Arm's Length: An Evaluation of Proposed Reform Options for U.S. Coal Used in Power Generation* (Working paper, October 2016).

Each of these studies addresses the relationship between royalty rates and production or federal royalty revenue. However, because federal onshore royalty rates for oil, gas, and coal production on federal lands have not changed in decades, no recent historical data exist describing the direct effect of changing royalty rates on oil, gas, and coal production on federal lands or the effect of such changes on federal revenues. In the absence of such data, these studies used simulations with assumptions; therefore, their estimates of the effects of changes in royalty rates depend on various uncertain factors. We determined that these four studies are reasonable for describing what is known about the range of potential effects.

Additionally, we interviewed and summarized the views of knowledgeable stakeholders representing 26 entities—such as officials from federal and state agencies, industry groups, academia, and other nongovernmental organizations—to capture various viewpoints on the potential effects of raising federal royalty rates.[10] We identified stakeholders on the basis of their authorship of studies on the issue, referrals by other stakeholders, or service on relevant panels and advisory groups. We interviewed state and federal officials in states or regions that represented over 95 percent of oil, gas, and coal production on federal lands in fiscal year 2015.[11] We strived to achieve balance by interviewing stakeholders representing different viewpoints, but their views are not generalizable to those we did not interview. Throughout this report, we use the modifiers "a few" to refer to two to five stakeholders and "some" to refer to six to nine stakeholders.

[10]Not all of the stakeholders we interviewed addressed every issue discussed in this report.

[11]We interviewed state and BLM officials from Colorado, Montana, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, Utah, and Wyoming.

We analyzed data from Interior's Office of Natural Resources Revenue (ONRR), the Energy Information Administration (EIA), and the U.S. Extractive Industries Transparency Initiative on trends in oil, gas, and coal production and the associated revenues.[12] We assessed the reliability of these data by analyzing relevant documentation and interviewing officials about the steps they take to maintain the relevant databases. We determined that these data were sufficiently reliable for the purposes of our report.

We conducted this performance audit from June 2016 to June 2017 in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

## Background

BLM leases federal lands to private companies for the production of onshore oil, gas, and coal resources, generally through a competitive bidding process.[13] BLM offers for lease parcels of land nominated by industry and the public, as well as some parcels that BLM itself identifies. If BLM receives any bids, called bonus bids, on an offered lease that are at or above a minimum acceptable bid amount, the lease is awarded to the highest bidder, and, for oil and gas, a lump-sum payment in the amount of the bid is due to ONRR when BLM issues the lease. For coal, the winning bidder pays the bonus bid in five equal payments, with one of the payments being paid at the time of the lease sale. For oil and gas leases, BLM requires a uniform national minimum acceptable bid of $2 per acre.[14] For coal leases, BLM requires a minimum bid of $100 per

[12]ONRR is responsible for managing and collecting revenues from companies that produce or extract resources from federal leases. EIA is a statistical agency within the Department of Energy that provides independent data, forecasts, and analyses. The U.S. Extractive Industries Transparency Initiative is a global standard that promotes open and accountable management of natural resources.

[13]For onshore leases, BLM's current leasing processes were established under the Mineral Leasing Act of 1920, as amended. BLM regulations for oil and gas leasing and coal management are codified at 43 C.F.R. Parts 3100 and 3400, respectively.

[14]43 C.F.R. § 3120.1-2(c). According to Interior officials, most competitive bids for oil and gas are higher than the required minimum. For example, in fiscal year 2015, the average bonus bid per acre for all the acres leased (both competitive and noncompetitive leases) was $139, and for fiscal year 2016, the average bonus bid per acre was $213.

acre, and the bid must meet or exceed BLM's estimate of the fair market value of the lease.[15]

In addition to the competitive bidding process, companies may obtain leases through two additional processes. For oil and gas, tracts of land that do not receive a bid in the initial offer are made available noncompetitively the next day and remain available for noncompetitive leasing for a period of 2 years after the initial competitive auction, with priority given to offers based on the date and time of filing.[16] For coal, companies may request that a certain amount of contiguous land be added to an existing lease in what is called a lease modification process.[17] Lands acquired through lease modification are added to the existing lease without a competitive bidding process, but the federal government must receive the fair market value of the lease of the added lands either by cash payment or adjustment of the royalty applicable to the lands added to the lease.[18]

Leases specify a rental rate—a fixed annual charge until production begins on the leased land, or, when no production occurs, until the end of the period specified in the lease. For oil and gas leases, generally the rental rate is $1.50 per acre for the first 5 years and $2 per acre each year thereafter.[19] For coal, the rental rate is at least $3 per acre.[20] Oil and gas parcels are generally leased for a primary term of 10 years, but lease terms may be extended if, for example, oil or gas is produced in paying quantities.[21] Coal parcels are leased for an initial 20-year period and may be extended if certain conditions are met.[22]

[15]43 C.F.R. § 3422.1(c). Coal bonus bids are based on the recoverable reserves estimate calculated prior to the lease sale and submission of the bonus bid. Coal bonus bids in fiscal year 2015 averaged $940 per acre; and in fiscal year 2016, there were no significant competitive lease sales because of Secretarial Order 3338.

[16]43 C.F.R. § 3110.1(b); 43 C.F.R. § 3110.2.

[17]43 C.F.R. Subpart 3432.

[18]43 C.F.R. § 3432.2(c).

[19]43 C.F.R. § 3103.2-2(a).

[20]43 C.F.R. § 3473.3-1(a).

[21]43 C.F.R. § 3120.2; 43 C.F.R. Part 3107.

[22]43 C.F.R. § 3475.2.

## Royalty Rates for Federal and Nonfederal Lands

Once production of the resource starts, the federal government is to receive royalty payments based on a percentage of the value of production—known as the royalty rate. For onshore oil and gas leases, the Mineral Leasing Act of 1920 sets the royalty rate for competitive leases at not less than 12.5 percent of the amount or value of production.[23] However, until January 2017, BLM regulations generally established a fixed royalty rate of 12.5 percent.[24] For noncompetitive leases, the act, as amended, sets the royalty rate at a fixed rate of 12.5 percent.[25] For coal, royalty rates depend on the type of mine—surface or underground.[26] BLM is authorized to establish royalty rates above 12.5 percent for surface mines, but according to agency officials, BLM generally sets the rate at 12.5 percent, the statutory and regulatory minimum royalty rate.[27] For underground mines, BLM sets the rate at 8 percent, the rate prescribed in regulation.[28] Royalties for oil and gas are calculated based on the value of the resource at the wellhead, and any deductions or allowances are taken after the royalty rate is applied.[29] For coal, certain costs are deducted from the price of coal at the first point of sale, including transportation and processing allowances, before the

[23] 30 U.S.C. § 226(b)(1).

[24] 43 C.F.R. § 3103.3-1 (2015). In November 2016, BLM issued regulations amending this section to mirror BLM's statutory authority for competitive leases, providing BLM with the flexibility to set royalty rates at or above 12.5 percent. This rule became effective in January 2017. Department of the Interior, Bureau of Land Management, *Waste Prevention, Production Subject to Royalties, and Resource Conservation*, Final Rule, 81 Fed. Reg. 83008, (Nov. 18, 2016). As of March 2017, BLM officials said they had not yet used this flexibility to increase royalty rates above 12.5 percent.

[25] 30 U.S.C. § 226(c).

[26] Two primary methods are used to mine coal: surface mining and underground mining. In surface mining, where coal deposits are buried within a few hundred feet of the surface, soil and rock above the coal are blasted with explosives and removed using large equipment, and the uncovered coal is then extracted. Deeper coal resources require use of underground mining, which entails digging a series of mine entries and shafts and using equipment to extract the coal and transport it to the surface. Underground mining is more expensive than surface mining. Mining on federal leases involves both surface and underground mining.

[27] 30 U.S.C § 207 (a); 43 C.F.R. § 3473.3-2(a)(1).

[28] 43 C.F.R. § 3473.3-2(a)(2).

[29] An allowance is an allowable deduction from the value of a mineral for royalty purposes.

amount is calculated for royalty purposes.[30] The royalty rate paid by the coal company after such allowable deductions have been factored in, along with any royalty rate reductions, is called the effective royalty rate.[31]

Federal royalty rates differ from the royalty rates that state governments charge for production on state lands and the rates that companies pay for production on private lands. Table 1 shows federal royalty rates and rates for six states that represented more than 90 percent of federal oil, gas, and coal production in fiscal year 2015. According to state officials, as of March 2017, royalty rates for oil and gas production charged by these states vary but tend to be higher than federal royalty rates, while royalty rates for coal production charged by these states are generally the same as federal rates. Less is known about the royalty rates for production on private lands because of the proprietary nature of lease contracts, but a few published reports suggest that private royalty rates range from 12.5

[30]On July 1, 2016, ONRR issued a final rule amending its regulations concerning valuation, for royalty purposes, of oil and gas produced from federal onshore and offshore leases and coal produced from federal and Indian leases. Department of the Interior, Office of Natural Resources Revenue, *Consolidated Federal Oil and Gas and Federal and Indian Coal Valuation Reform*, Final Rule, 81 Fed. Reg. 43338 (2016) (2017 Valuation Rule). The rule, effective January 1, 2017, addressed, among other things, royalty valuation for transactions between affiliated parties. On Feb. 27, 2017, ONRR postponed the effective date of the 2017 Valuation Rule citing, among other things, pending litigation over the rule that had been initiated in December 2016. Department of the Interior, Office of Natural Resources Revenue, *Postponement of Effectiveness of the Consolidated Federal Oil and Gas and Federal and Indian Coal Valuation Reform 2017 Valuation Rule,* 82 Fed. Reg. 11823 (2017). On April 4, 2017, ONRR issued a proposed rule proposing to repeal in its entirety the 2017 Valuation Rule. Department of the Interior, Office of Natural Resources Revenue, *Repeal of Consolidated Federal Oil and Gas and Federal and Indian Coal Valuation Reform,* Proposed Rule, 82 Fed. Reg. 16323 (2017). Concurrently with the proposed repeal, ONRR published an Advance Notice of Proposed Rulemaking seeking public comment on whether revisions are needed to the pre-existing regulations governing royalty values, including whether the 2017 Valuation Rule should be retained or re-promulgated, in whole or in part. 82 Fed. Reg. 16325 (2017).

[31]Royalty rate reductions may be approved by BLM in cases where a reduction is needed to promote mining development. In 2013, we found that the effective rate averaged about 11 percent from fiscal year 1990 through fiscal year 2012 (see GAO-14-140).

percent to 25 percent for oil and gas production and from 3 percent to 10 percent for coal production.[32]

**Table 1: Federal and State Royalty Rates for New Onshore Oil, Gas, and Coal Leases, as of March 2017**

Percentages

| Federal rate | Oil and gas | Coal surface | Coal underground |
|---|---|---|---|
| Onshore | 12.5[a] | 12.5 | 8 |
| **Selected state rates** | | | |
| Colorado | 20.0 | 12.5 | 8 |
| Montana | 16.67 | 12.5[b] | 10 |
| New Mexico | 12.5 to 20.0[c] | 12.5 | 8 |
| North Dakota | 16.67 or 18.75 | Varies[d] | Varies[d] |
| Utah | 12.5 to 16.67[e] | 8.0[f] | 8[f] |
| Wyoming | 12.5 or 16.67[g] | 12.5 | 8 |

Sources: GAO analysis of federal laws and regulations, and state officials. | GAO-17-540

Notes: These six states represented over 90 percent of total federal oil, gas, and coal production in fiscal year 2015. Other aspects of federal and state leasing processes, such as rental rates, allowances, and deductions, are not included in this table.

[a]As of January 2017, BLM regulations permit royalty rates of not less than 12.5 percent for competitive leases, giving BLM the flexibility to issue a rate over 12.5 percent. All noncompetitive leases have a fixed rate of 12.5 percent. In March 2017, officials told us that BLM had not yet used this flexibility and that all leases issued since the regulations have been at 12.5 percent.

[b]The Montana royalty rate is generally set at 12.5 percent for surface coal mining, but is not less than 10 percent.

[c]The oil and gas royalty rates in New Mexico are on a sliding scale based on the geographic location of the lease.

[d]The coal royalty rates in North Dakota are determined on a mine-by-mine basis and assessed on fair market price.

[e]The oil and gas royalty rates in Utah can change with the approval of the Director of the Utah Trust Lands Administration.

[f]The coal royalty rate in Utah is generally 8 percent, though there are currently two exploration agreements for surface mining at 12 percent.

[32]In 2015, BLM's Advance Notice of Proposed Rulemaking stated that private royalty rates for oil and gas generally were between 12.5 percent and 25 percent. A 2016 Federal Reserve Bank of Kansas City study, which analyzed private lease data from the data source DrillingInfo, found private royalty rates for oil and gas varied from 13.2 percent to 21.2 percent in 2014. A 2016 National Mining Association report, suggested private royalty rates for coal are generally between 3 percent and 10 percent. See Federal Reserve Bank of Kansas City, *Capturing Rents from Natural Resource Abundance: Private Royalties from U.S. Onshore Oil and Gas Production* (Kansas City, MO: July 2016) and National Mining Association, *Federal Coal Leasing Moratorium: An Examination of the Reasons Driving a Disruptive Policy* (Washington, D.C.: July 2016).

[9]The oil and gas royalty rates vary in Wyoming based on demand.

## Production on Federal and Nonfederal Lands

In fiscal year 2016, approximately 157 million barrels of oil, 3.14 trillion cubic feet of gas, and 295 million tons of coal were produced on federal lands, according to ONRR data.[33] These numbers represented about 6 percent of total U.S. onshore oil production, 10 percent of total U.S. onshore gas production, and 40 percent of total U.S. coal production, according to our analysis of EIA data.[34] The federal government collected approximately $2.5 billion in gross revenue from the production of these resources on federal lands in fiscal year 2016.[35] The majority of this revenue generally has come from royalties—about $2 billion, or 80 percent of total revenues in fiscal year 2016.[36] As figure 1 shows, royalties comprised a larger percentage of the total revenue from oil and gas production than from coal production in 2016. (See appendix I for additional data on production and revenues from oil, gas, and coal development on federal and American Indian lands from fiscal year 2007 through 2016.)

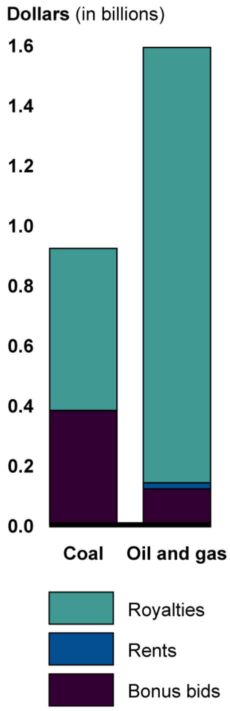
[33]ONRR gas production numbers include natural gas liquids. Natural gas liquids are not produced at the wellhead; they are a byproduct of processing that produces revenue for the lessees, according to ONRR. For coal, these production numbers include coal, leonardite (a low rank coal with lower energy content), and coal waste.

[34]Both ONRR and EIA gas production data include natural gas liquids. ONRR data are reported by fiscal year, which runs from October through September. EIA data are reported monthly and can be added together in fiscal years or calendar years. To compare EIA data with ONRR data, we added EIA monthly data by fiscal year.

[35]This figure includes revenue associated with natural gas liquids production.

[36]Although total royalty, rental, and bonus revenues were lower in fiscal year 2016 than in recent years, mainly because of decreased prices or decreased production, the percentage that royalty revenues constituted of total royalty, rental, and bonus revenues has been fairly constant for oil, gas, and coal over the last 10 years: around 83 percent.

**Figure 1: Royalty Revenue, Rental Payments, and Bonus Bids Associated with Onshore Oil, Gas, and Coal Production on Federal Lands, Fiscal Year 2016**




Source: GAO analysis of Office of Natural Resources Revenue data. | GAO-17-540

Note: Oil and gas royalties include amounts associated with natural gas liquids production.

Private companies develop oil, gas, and coal on federal lands within the context of broader energy markets, and conditions in those markets have changed. Overall oil and gas production has increased after decades of decline or general stability—between 2008 and 2016, total U.S. oil production increased by 77 percent and gas production increased by 35 percent.[37] During that same period, federal onshore oil production increased by 59 percent while federal onshore gas production declined by 18 percent.[38] According to EIA, almost all of the increase in overall oil and gas production has centered on oil and gas plays located in shale and other tight rock formations, spurred by advances in production technologies such as horizontal drilling and hydraulic fracturing.[39] However, as figure 2 shows, major tight oil and shale gas plays—those plays that, according to EIA data, have represented more than 90 percent of growth in oil and gas development from 2011 to 2016—are mostly located on nonfederal lands. In 2016, about 15 percent of the major tight oil and shale gas plays in the contiguous United States overlapped federal lands, according to our analysis of EIA and the U.S. Geological Survey data.[40]

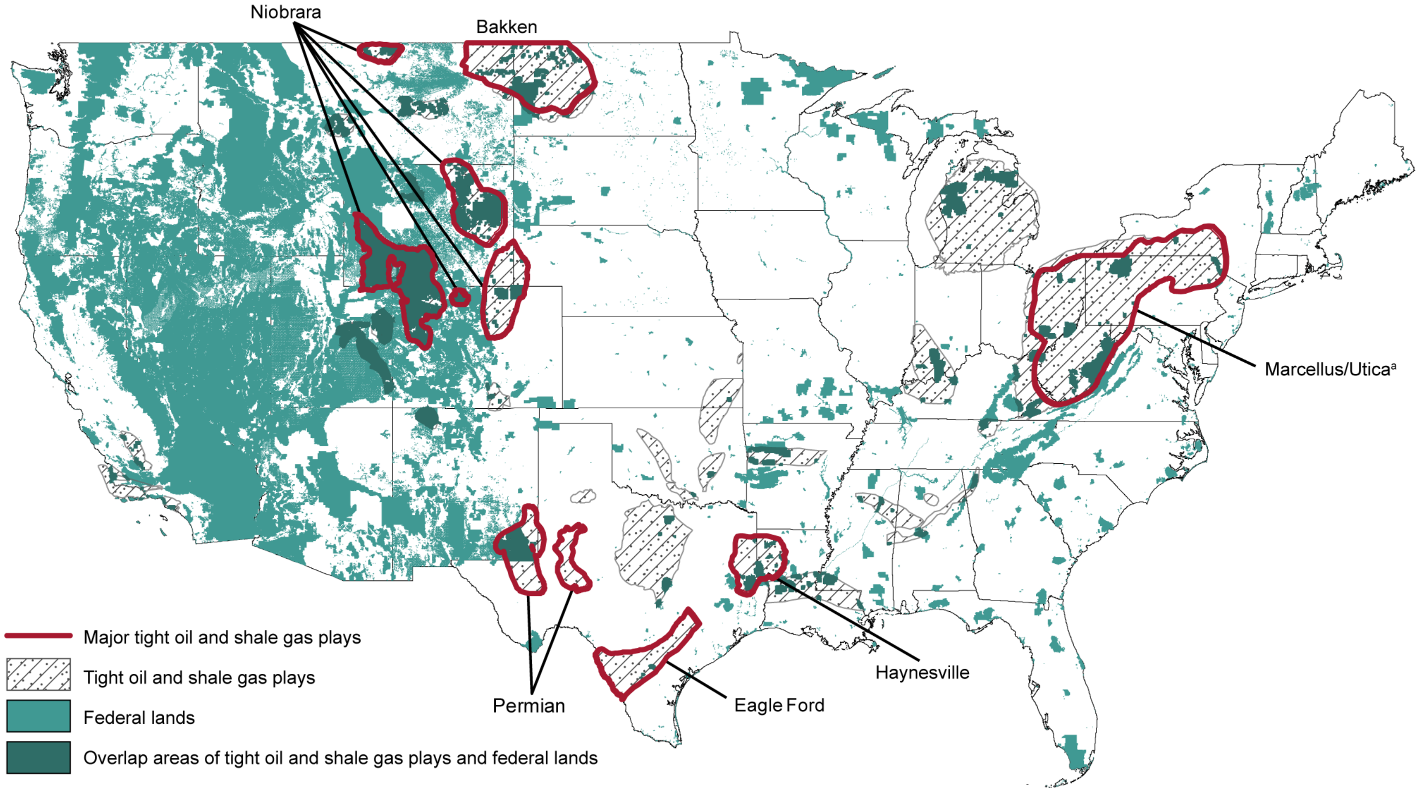
[37]Total U.S. oil and gas production numbers are from EIA and are presented in calendar years.

[38]Federal onshore oil and gas production numbers are from ONRR and are presented in fiscal years.

[39]According to EIA, a play is a set of known or postulated oil and gas accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration pathway, and hydrocarbon type. Oil and natural gas are found in a variety of geologic formations distributed across the country, such as shale or tight sandstone formations—also referred to as "tight oil" or "shale gas." Shale is a sedimentary rock that is predominantly composed of consolidated clay-sized particles. Hydraulic fracturing (also known as fracking) is commonly defined as an oil or gas well completion process that directs pressurized fluids to penetrate tight rock formations, such as shale or coal formations, in order to stimulate and extract the oil or gas in the formation. The fluids typically contain a combination of water, proppant, and added chemicals.

[40]The percentage is approximate because the federal lands mapping layer provided by EIA represents those federal lands where the government holds surface land ownership of mineral rights. This does not include 57 million acres, or about 9 percent of the lands mapped, where the federal government owns mineral resources on or below state and private lands.

**Figure 2: Federal Lands and Major Tight Oil and Shale Gas Plays**




| Major tight oil and shale gas plays | Oil production in play as a percentage of total U.S. onshore production, 2016 | Gas production in play as a percentage of total U.S. onshore production, 2016 | Percentage of play that is on federal lands |
|---|---|---|---|
| Bakken | 15.0 | 2 | 8.0 |
| Eagle Ford | 17.0 | 8 | 0.4 |
| Haynesville | 0.6 | 7 | 9.0 |
| Marcellus/Utica[a] | 1.0 | 26 | 7.0 |
| Niobrara | 6.0 | 5 | 38.0 |
| Permian | 28.0 | 8 | 15.0 |

Sources: GAO analysis of Energy Information Administration data and U.S. Geological Survey data; MapInfo (map). | GAO-17-540

Notes: These major tight oil and shale gas plays constituted more than 90 percent of oil and gas production growth from 2011 to 2016, according to Energy Information Administration data, although there is production from conventional resources in other plays and basins. The federal lands mapped here represent federal surface land ownership and do not include 57 million acres, or about 9 percent of the lands mapped, where the federal government owns mineral resources below private lands. Alaska and Hawaii are not depicted because they contain no major tight oil or shale plays.

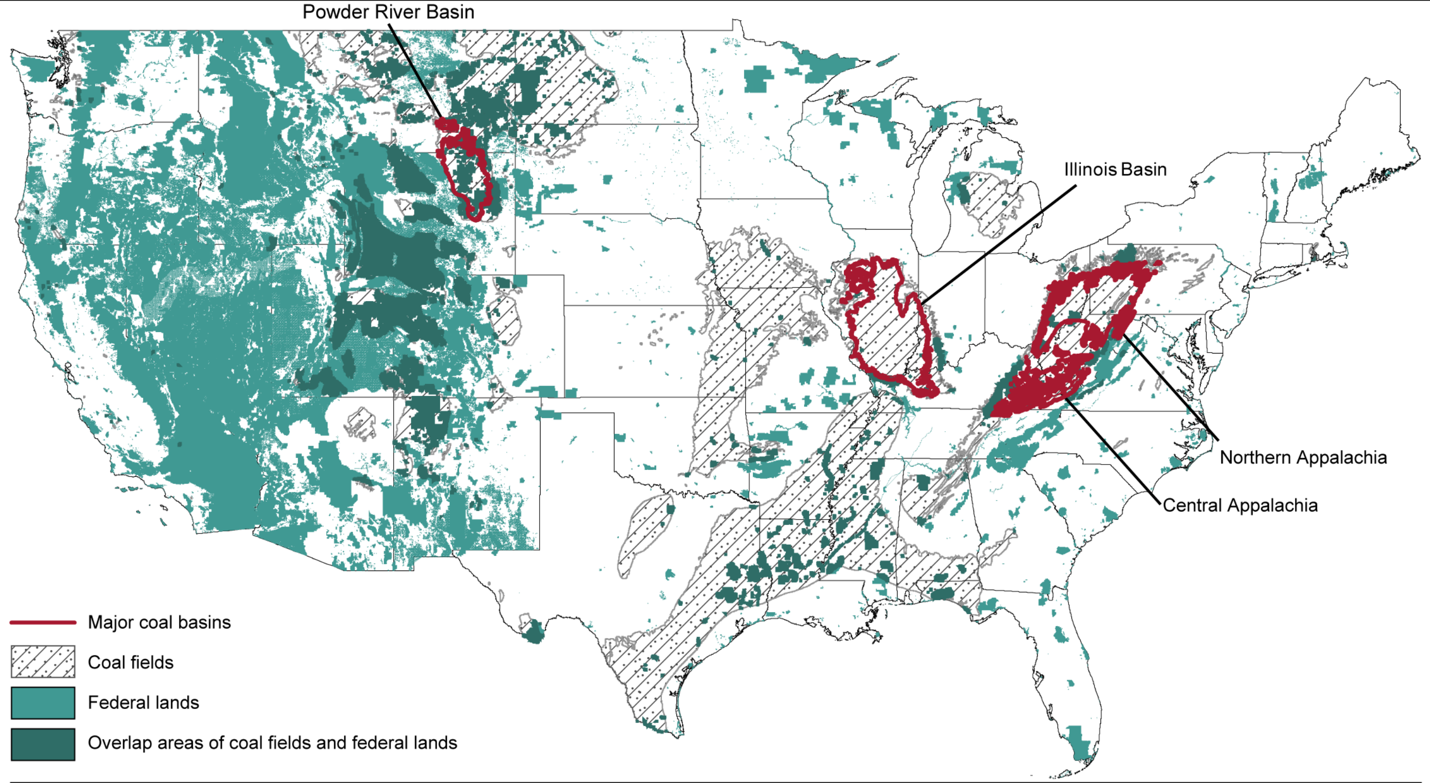
[a]The Marcellus and Utica plays geographically overlap to some degree and are therefore reported together.

In contrast to oil and gas production, both federal and total U.S. coal production have declined since 2008. Federal coal production declined 19 percent from 2008 to 2015, while total U.S. coal production declined more than 23 percent in the same period.[41] According to EIA, the decline in total U.S. coal production can be attributed to a lower international demand for coal, increased environmental regulations, and low natural gas prices (natural gas is an alternative for coal in the electricity market). As figure 3 shows, about 5 percent of the major coal basins in the contiguous United States overlapped federal lands in 2013, according to our analysis of EIA and U.S. Geological Survey data.[42] Major coal basins that overlap with federal lands are primarily concentrated in the Powder River Basin in parts of Wyoming and Montana.

[41]Federal coal production numbers are from ONRR and are presented in fiscal years, while total U.S. coal production numbers are from EIA and are presented in calendar years.

[42]The coal fields mapping layer is provided by the U.S. Geological Survey, and the latest version of the layer is from 2013. The percentage is approximate because the mapping layer represents federal lands where the government holds surface land ownership of mineral rights. The federal lands mapped here represent federal surface land ownership and do not include 57 million acres, or about 9 percent of the lands mapped, where the federal government owns mineral resources on or below state and private lands.

**Figure 3: Federal Lands and Major Coal Basins**




| Major coal basins | Coal production in basin as a percentage of total U.S. production, 2015 | Percentage of basin that is on federal lands |
|---|---|---|
| Northern Appalachia | 13 | 5.0 |
| Central Appalachia | 10 | 9.0 |
| Illinois | 14 | 0.2 |
| Powder River | 44 | 19.0 |

Sources: GAO analysis of Energy Information Administration data and U.S. Geological Survey data; MapInfo (map). | GAO-17-540

Note: These four coal basins represented more than 80 percent of total U.S. coal production in 2015, based on Energy Information Administration data. Federal lands mapped here represent federal surface land ownership. However, for an additional 57 million acres, or about 9 percent of the lands mapped, the federal government owns mineral resources below private lands. We did not include Alaska or Hawaii because they had no federal coal production in the last 10 years.

## Studies and Stakeholders Suggest Raising Federal Royalty Rates Could Decrease Production on Federal Lands

Raising federal royalty rates for onshore oil, gas, and coal could decrease production on federal lands, according to studies we reviewed and stakeholders we interviewed. Increasing royalty rates would increase the total costs for producers, thus making production on federal lands less attractive to companies, according to some stakeholders. Companies may respond by producing less on federal lands and more on nonfederal lands. However, stakeholders disagreed about the extent to which production could decrease because they said other factors may influence energy companies' development decisions.

**Oil and gas.** We identified two studies—one by the CBO and one by Enegis, LLC—that modeled the effects of different policy scenarios on oil and gas production on federal lands.[43] Both studies suggested that a higher royalty rate could decrease production on federal lands by either a small amount or not at all.[44] The CBO study concluded that raising the royalty rate to 18.75 percent would lead to "reductions in production [that] would be small or even negligible" over 10 years, particularly if the increased federal royalty rate remained equal to or below the royalty rates for production on state or private lands.[45] As discussed above, the current 12.5 percent federal royalty rate is generally the same or lower than rates charged by the six states in which more than 90 percent of federal oil and gas was produced in fiscal year 2015. In addition, the Enegis, LLC, study showed that demand for new federal competitive leases—or the extent to which oil and gas companies would compete for new leases—would generally decrease over 25 years if the royalty rate were raised to 16.67 percent, 18.75 percent, or 22.5 percent. For each of these three royalty rate increases, the study examined several different scenarios that varied with respect to key factors, including company costs and company

[43]Congressional Budget Office, *Options for Increasing Federal Income From Crude Oil and Natural Gas on Federal Lands* (Washington, D.C.: April 2016) and Enegis, LLC, *Benefit-Cost and Economic Impact Analysis of Raising the Onshore Royalty Rates Associated with New Federal Oil and Gas Leasing* (Washington, D.C.: April 2011). The Enegis, LLC, report was completed under a contract for BLM.

[44]The studies discuss results 10 or more years into the future. A royalty rate increase would apply only to new leases, and production on a new lease might not begin until near the end of the lease term. Therefore, the effects of a royalty rate increase on production and revenue would only begin to be realized within the first 10 years, according to CBO.

[45]The CBO study included other policy scenarios not related to a change in the royalty rate, including (1) auctioning leases through a sealed-bid process, (2) allowing Interior to set lease-specific fiscal terms for leases with great potential for oil and gas reserves, (3) increasing the minimum bid, and (4) imposing a fee on non-producing leases.

responses.[46] The study showed declines in production under all scenarios except those in which companies completely absorbed the higher costs resulting from higher royalty rates. In scenarios in which companies could absorb the costs—potentially in market conditions in which higher oil and gas prices help buffer companies from the effects of increased royalty rates—there would be no change in production levels. The three increased royalty rates modeled resulted in oil production declines ranging from 0 barrels to approximately 70 million barrels over 25 years (or, about 2.8 million barrels per year—the equivalent of about 1.8 percent of fiscal year 2016 onshore federal oil production). The three increased royalty rates modeled also resulted in gas production declines over 25 years ranging from 0 cubic feet to 85 billion cubic feet (or about 3.4 billion cubic feet per year—the equivalent of less than 1 percent of onshore federal gas production in fiscal year 2016).

**Coal.** We also identified two studies that analyzed the effects of different policy scenarios on coal production on federal lands. The first study, by the CEA, examined how raising the federal royalty rate could affect coal production on federal lands after 2025 using a series of scenarios.[47] Under the first scenario, equivalent to raising royalty rates to 17 percent in 2025, the study predicted that federal production would decrease by 3 percent once the changes were fully implemented. The other two scenarios, each equivalent to raising royalty rates to 29 percent in 2025,

[46]In addition to the flat-rate increases to the royalty rate (i.e., 16.67 percent, 18.75 percent, or 22.5 percent), the Enegis study also included 24 sliding-scale royalty rate scenarios that modeled how changes to royalty rates would be triggered by future commodity price thresholds.

[47]Executive Office of the President of the United States, Council of Economic Advisers, *The Economics of Coal Leasing on Federal Lands: Ensuring a Fair Return to Taxpayers* (Washington, D.C.: June 2016). The CEA study used results from a series of Integrated Planning Model scenarios with higher royalty rates. The Integrated Planning Model is a well-established energy and electricity system model that the U.S. government has used extensively for many years in support of rulemakings. The CEA study consisted of four scenarios that looked at calculating the market value of coal for royalty purposes based on per-Btu (British thermal unit) market prices of (1) nearby regional coal, (2) nationwide nonfederal coal and (3) natural gas. The fourth scenario looked at maximizing the return to taxpayers; this scenario was used to illustrate how high the royalty rate could go before royalty revenues began to decrease because of reduced production. We are not discussing the results for this scenario because it was not meant as a policy suggestion.

predicted that federal production would decrease by 7 percent.[48] The second study, by Mark Haggerty, Megan Lawson, and Jason Pearcy, modeled an increase in the effective royalty rate, which is the rate companies actually pay after processing and transportation allowances are factored in.[49] The study found that the modeled increase in the effective royalty rate led to a decrease in federal coal production of less than 1 percent per year.[50]

Results of the two studies differed in how an increase in coal royalty rates might affect nonfederal coal production. The CEA study determined that an increase in federal royalty rates would raise the national price of coal, improving the competitiveness of nonfederal coal and slightly increasing nonfederal coal production. According to the CEA study, coal mines in Wyoming and Montana—representing more than 86 percent of federal coal production in fiscal year 2015—are some of the largest, most productive, and lowest-cost mines. According to EIA, in 2015 the average market price of coal from the Appalachian region, which comes primarily from production on state and private lands, was $60.61 per ton, while the average market price of coal from the Powder River Basin, where the majority of federal coal is produced, was $13.12 per ton.[51]

We previously reported that underground mining, which is mostly concentrated in the eastern region, is more costly than surface mining,

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[48]According to CEA officials, the results of the study assumed that the Clean Power Plan would take effect beginning in 2022, which is set to reduce emissions from the electric power sector through many compliance approaches, including switching fuel sources from coal and other carbon intensive fuels to less carbon intensive ways to produce electricity. Without the Clean Power Plan, officials stated that the modeled production effects might change.

[49]Haggerty, Lawson, and Pearcy, *Steam Coal at an Arm's Length: An Evaluation of Proposed Reform Options for U.S. Coal Used in Power Generation* (Working paper, October 2016). This study examines the impact of an effective increase in the royalty rate. The authors generate an effective rate increase by positing a change in the valuation point of coal royalties from a lower effective rate based on delivered prices to a potentially higher statutory rate based on reported prices. Our focus is on the hypothetical effect on production and royalties of an increase in the effective royalty rate. We did not assess the validity of the empirical valuation methodology that is claimed by the authors to generate a higher effective royalty rate.

[50]This study calculated the average difference in the effective and statutory rates for nine states from 2008 to 2014, which ranged between 0 and 3.6 percent.

[51]These average market prices do not include captive market transactions, or sales between two affiliated parties.

resulting in a higher sale price.[52] At the same time, eastern coal has more heat, or energy, content per ton than western coal, which raises the value of eastern coal. CEA concluded that raising the royalty rate would decrease this price gap between Appalachian and Powder River Basin coal, thus making Appalachian and other nonfederal coal slightly more competitive.

The study by Haggerty, Lawson, and Pearcy states that substitution between federal and nonfederal coal could occur, but is unlikely for several reasons, including federal ownership in western states and the inherent difference in the qualities of coal. The study states that substitution between federal and nonfederal coal could occur if federal and nonfederal coal are in close proximity. However, the authors note that where federal ownership of coal dominates, in states like Wyoming, Montana, and Colorado where the majority of federal coal is produced, states tend to adopt federal policy changes. Also according to the study, transportation from the mine to the power plant is highly specialized, and power plants are engineered to maximize efficiency of the specific type of coal in the region. Switching from one type of coal to another could involve substantial conversion costs for coal power plants.

Stakeholders we interviewed suggested that several factors could influence the extent to which oil, gas, and coal production might be affected if federal royalty rates were increased, including the following.

- **Market conditions and prices.** Some stakeholders noted that market conditions and prices play an important role in determining whether raising federal royalty rates could affect production on federal lands. BLM officials suggested that raising federal royalty rates is less likely to have a negative effect on production when oil and gas prices are high. For example, increasing royalty rates from 12.5 percent to 16.67 percent would increase the cost of producing oil by about $2 a barrel at oil prices as of March 2017.[53] In addition, according to a few stakeholders we interviewed and a 2015 report by the Congressional

[52]GAO-14-140.

[53]More specifically, oil prices averaged $101 per barrel in March 2014 compared with an average of $50 per barrel in March 2017. Increasing royalty rates from 12.5 percent to 16.67 percent would raise the cost of production by about $4 per barrel at oil prices as of March 2014 and $2 per barrel at oil prices prevailing in March 2017. If nothing else had changed, producers in March 2014 would still be receiving a net additional $49 per barrel because of the higher price.

Research Service, any negative effect on production from higher rates could be limited to or affect areas with marginal oil and gas wells, which are usually wells with low production rates and/or higher production costs.[54] As for coal, some stakeholders said that in an already challenging market, increased costs could further discourage production. According to EIA data, total U.S. coal production declined 23 percent from 2008 to 2015. In a 2012 report, we found that various market and regulatory factors may influence the future use of coal, including the price of natural gas, demand for electricity, and environmental regulations.[55] A few stakeholders we interviewed said there has been little interest in further coal development in their regions, which include the western and midwestern regions of the country. Since fiscal year 2012, the number of coal lease sales on federal lands has generally declined.[56] We previously reported that there was limited competition for coal leases because of the significant capital investment and time required; additionally, from January 2016 to March 2017 the Secretary of the Interior placed a pause on significant new federal coal leasing decisions, with limited exemptions and exclusions.[57]

- **Cost advantages of different resources.** A few stakeholders told us that the competitiveness of federal lands for development depends less on the royalty rate charged and more on the location of the best resources—such as areas with low exploration and production costs. For example, as discussed above, most of the areas with major U.S. tight oil and shale gas plays and major U.S. coal basins do not overlap with federal lands. A few stakeholders suggested that an increase in the federal royalty rates for coal would not cause companies to switch from federal to nonfederal coal because of the cost advantages of federal coal, which is primarily concentrated in surface mines in the West. According to EIA data, all coal extracted from the Powder River Basin in 2015 was from surface mining, which

[54]Congressional Research Service, *Mineral Royalties on Federal Lands: Issues for Congress* (Washington, D.C.: January 2015). This report specifically states that a higher royalty rate coupled with low oil and gas prices could negatively impact high-cost marginal producers.

[55]GAO, *Electricity: Significant Changes Are Expected in Coal-Fueled Generation, but Coal Is Likely to Remain a Key Fuel Source*, GAO-13-72 (Washington, D.C.: Oct. 29, 2012).

[56]In fiscal year 2012, there were six coal lease sales; in fiscal year 2013, two; in fiscal year 2014, one; and in fiscal year 2015, two. According to BLM officials, there were no successful coal lease sales in fiscal year 2016.

[57]GAO-14-140.

we previously reported has lower extraction and production costs.[58] In contrast, the majority of coal production from the Appalachian region in 2015 was from underground production, which we previously reported is more costly to extract.[59] Increasing the royalty rate on federal lands would not cause operators to switch from federal to nonfederal coal, according to a few stakeholders, because companies producing coal on federal lands would still have a cost advantage over companies producing coal on nonfederal lands.

- **Regulatory burden of federal development.** Some stakeholders we spoke with stated that there is already a higher regulatory burden for oil and gas companies to develop resources on federal lands than on nonfederal lands, and one stakeholder noted that an increase in federal royalty rates would decrease the competitiveness of federal lands versus state or private lands. In addition, BLM officials noted that about half the public comments BLM received through its 2015 Advance Notice of Proposed Rulemaking also noted there is a higher regulatory burden on federal lands. According to BLM officials, when federal and nonfederal coal are located on adjoining tracts the cost of production will be identical unless the nonfederal land has a different royalty rate, which officials say is unlikely. Assuming the royalty rate is the same, officials stated that the main difference between federal and nonfederal coal is the additional regulatory burden of producing on federal lands. In addition, a few stakeholders stated that companies may avoid mining federal lands for coal when possible in order to avoid the required environmental assessments, which add time to the leasing process.

Officials from two state offices we interviewed said that the history of increasing royalty rates for oil and gas production on state lands suggests that increasing the federal royalty rate would not have a clear impact on production. In particular, officials from Colorado and Texas said that they have raised their state royalty rates without a significant effect on production on state lands. In February 2016, Colorado increased its royalty rate for oil and gas production from 16.67 percent to 20 percent, and, according to state officials, there had been no slowdown in interest in new leases as of August 2016. In fact, Colorado state officials said they were unsure whether the higher royalty rate played much of a role in companies' decision making. Additionally, Texas officials told us that over 30 years ago, Texas began charging a 25-percent royalty for most oil and

[58]EIA's data include coal production from federal, state, and private lands. GAO-14-140.

[59]GAO-14-140.

gas leases on state lands, and this increase has not had a noticeable impact on production or leasing. Officials at BLM said about half of the public comments they received through BLM's 2015 Advance Notice of Proposed Rulemaking suggested that an increase in royalty rates would not have a clear impact on production.

## Studies and Stakeholders Suggest Raising Federal Royalty Rates Could Increase Federal Revenues

Raising federal royalty rates for onshore oil, gas, and coal could increase overall federal revenues, according to studies we reviewed and stakeholders we interviewed. Higher rates could have two opposing effects on federal revenues. First, as discussed above, raising royalty rates could lead to decreased production on federal lands, and, consequently, decreased revenues. Second, revenues would increase on any production that does occur because of higher royalty rates on that production. The studies we reviewed show that raising federal royalty rates could increase federal revenues for oil, gas, and coal. Some stakeholders we interviewed said any effects on federal revenue would depend on how increasing royalty rates for oil, gas, and coal would affect bonus bid revenue, while others said overall market conditions, among other factors, need to be considered.

**Oil and gas.** The studies we reviewed for oil and gas estimate that raising the federal royalty rate could increase net federal revenue between $5 million and $38 million per year (equivalent to around 0.7 percent to around 5.2 percent of net oil and gas royalties in fiscal year 2016).[60] According to the CBO study, the effect on federal revenue would initially be small but would increase over time because a change in the royalty rate would apply only to new leases and the affected parcels would not go into production immediately. For example, CBO found that 6 percent of royalties collected in 2013 came from leases issued in the previous 10 years. CBO estimated that if the royalty rate for onshore oil and gas parcels were raised from 12.5 percent to 18.75 percent, net federal revenue would increase by $200 million over the first 10 years, and potentially by much more over the following decade, depending on market conditions. Similarly, according to the Enegis study, net federal revenues would increase under the scenarios that modeled raising the

[60]Net federal revenue is the revenue retained by the federal government after approximately half of revenues are returned to the states in which the resources were produced, and after any other disbursements.

royalty rate to 16.67 percent, 18.75 percent, or 22.5 percent.[61] Under these scenarios, estimated increases in net federal revenue range from $125 million to $939 million over 25 years.

**Coal.** Both studies for coal also suggested that a higher royalty rate could lead to an increase in federal revenues. For example, the modeling scenarios in the CEA study that raised the royalty rate to the equivalent of 17 percent or 29 percent predicted a range of increases in government revenues from $0 to $730 million annually after 2025, with approximately half of that revenue going to the federal government.[62] By comparison, in fiscal year 2016, the federal government collected more than $536 million in coal royalty payments, according to ONRR data. The revenue range included zero to take into account the possibility that bonus bids could be lost entirely, but the study stated that this was an extremely conservative assumption, and that the increase in royalty revenue would be vastly larger than any decrease in bonus bid revenue. The study by Haggerty, Lawson, and Pearcy suggested that total average royalty revenues could increase by $141 million per year if the effective royalty rate were raised. This study did not consider the effect on bonus bid revenue from a royalty rate increase.

Stakeholders we interviewed also suggested that the effect on bonus bid revenue could influence the extent to which raising federal royalty rates would increase revenues from oil, gas, and coal production. For example, some stakeholders stated that companies would be more likely to offer lower bonus bids if they had to pay higher royalty payments, but a few stakeholders believed that the net impact on federal revenue would be minimal because royalties are a more significant portion of total revenues than bonus bids. For oil and gas, royalties could offset losses from other revenue sources, such as bonus bids and rents. Although royalties also constitute the majority of revenue for coal, bonus bids represent a larger percentage of total revenue in comparison with oil and gas revenue. For example, in fiscal year 2016 only 8 percent of total revenue from oil and gas development on federal lands was from bonus bids, while in the

[61]Net changes to state and federal revenues were also positive under the sliding scale scenarios in the Enegis study.

[62]Under the other scenario, which maximized the return to taxpayers, the study estimated that government revenue would increase by up to $3.1 billion annually after 2025. As noted earlier, according to CEA officials, this study assumed that the Clean Power Plan would take effect in 2022. Without the Clean Power Plan, the federal revenue effects may vary.

same year the comparable figure for coal was 42 percent. However, a few stakeholders said that any decrease in bonus bids from an increase in coal royalty rates would likely be offset by a larger increase in royalty revenue.

In addition, BLM officials stated that raising the royalty rate could make some federal coal uneconomical to mine, resulting in fewer royalty payments to the federal government. BLM officials stated that an operator can justify a capital investment to produce coal on federal lands if the potential for revenue outweighs the cost of production. According to officials, increasing the royalty rate would add to the cost of production, which could cause an operator to bypass federal coal, thus causing the government to miss out on revenue. As discussed above, some stakeholders said any effects on federal revenue would depend on how increasing royalty rates for oil, gas, and coal would affect bonus bid revenue, and others said overall market conditions, among other factors, need to be considered.

## Agency Comments

We provided a draft of this report to Interior for review and comment. The agency provided technical comments, which we incorporated as appropriate.

We are sending copies of this report to the appropriate congressional committees, the Secretary of the Interior, and other interested parties. In addition, the report is available at no charge on the GAO website at http://www.gao.gov.

If you or your staff members have any questions about this report, please contact me at (202) 512-3841 or ruscof@gao.gov. Contact points for our Offices of Congressional Relations and Public Affairs may be found on the last page of this report. GAO staff who made key contributions to this report are listed in appendix II.

Frank Rusco

Frank Rusco
Director, Natural Resources and Environment

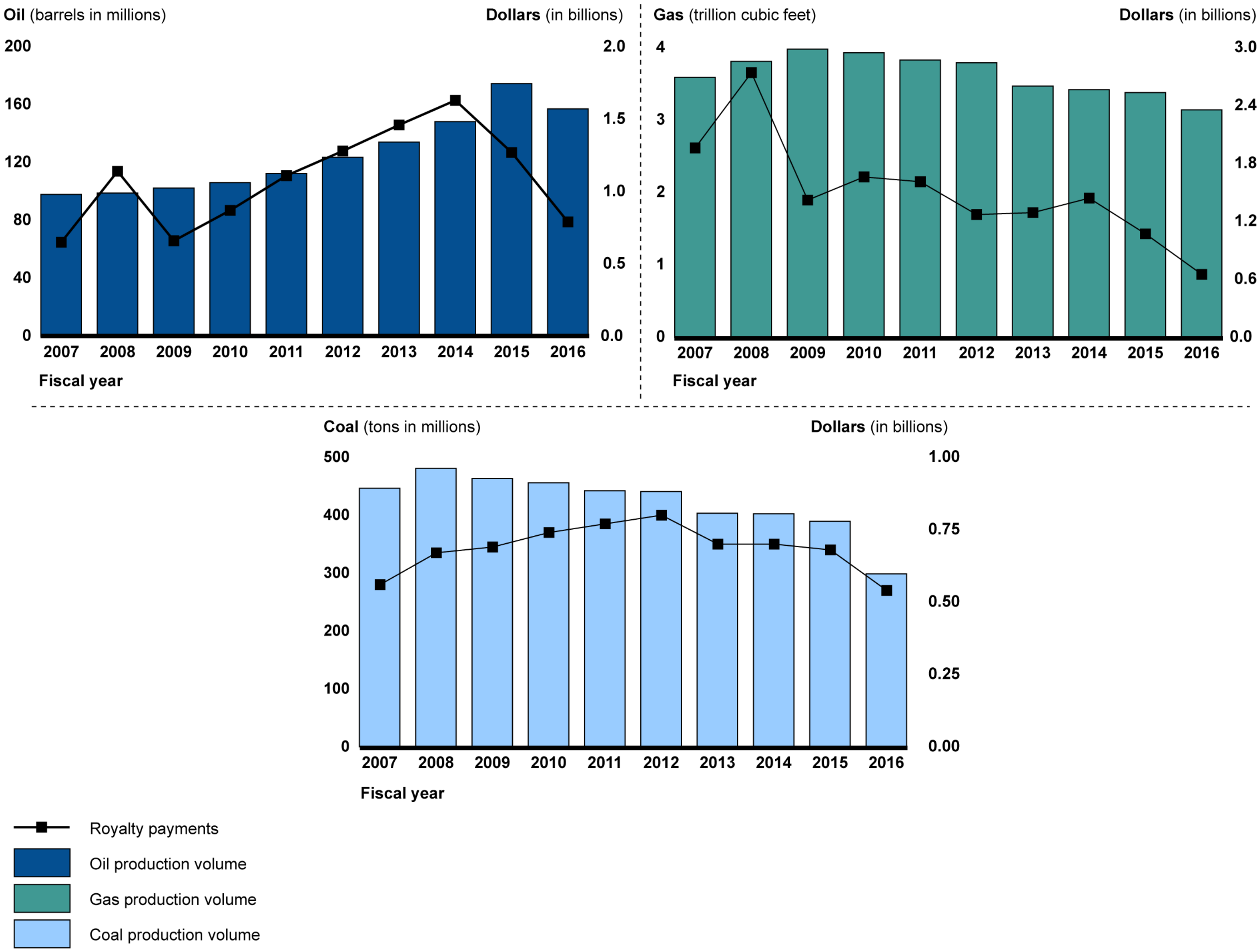
# Appendix I: Federal and Indian Production and Revenue Data from Oil, Gas, and Coal Development

Figure 4 shows trends in onshore oil, gas, and coal production and revenue on federal lands over the last 10 years. Tables 2 and 3 show which federal agencies have ownership over the associated federal surface lands that overlap the major tight oil and shale gas plays and major coal basins, as well as which major plays and basins are on tribal lands.[1] Tables 4, 5, and 6 show royalty and other revenues and oil, gas, and coal production on federal lands; on American Indian lands; and, for comparison, in federal offshore areas for fiscal years 2015 and 2016.[2]

[1]The tribal lands overlap was determined using a U.S. Census map layer.

[2]The Office of Natural Resources Revenue (ONRR) reports data on oil, gas, and coal production on American Indian lands, but these numbers are not included in federal onshore totals.

**Figure 4: Production and Royalty Payments from Onshore Oil, Gas, and Coal Development on Federal Lands, Fiscal Year 2007 through 2016**




Source: Office of Natural Resources Revenue data. | GAO-17-540

**Table 2: Major Tight Oil and Shale Gas Plays, Federal Agency Ownership, and Overlap of Federal and Tribal Lands, 2016**

| Play | Percentage of federal land overlap | Agency ownership | Percentage of tribal land overlap |
|---|---|---|---|
| Bakken | 9 | Interior, Forest Service | 15.5 |
| Eagle Ford | 0 | Interior, other | 0.0 |
| Haynesville | 9 | Interior, Forest Service, other | 1.5 |
| Marcellus/Utica | 6 | Interior, Forest Service, other | 0.0 |
| Niobrara | 39 | Interior, Forest Service, other | 0.0 |
| Permian | 15 | Interior, other | 0.0 |

Sources: GAO analysis of Energy Information Administration data, U.S. Geological Survey data, and U.S. Census Bureau data. | GAO-17-540

Notes: The Marcellus and Utica plays geographically overlap to some degree and are therefore reported together. “Other” in the agency ownership column represents all other federal agencies apart from Department of the Interior and the U.S. Forest Service. The percentage of tribal land overlap reflects those boundaries reported to the U.S. Census Bureau and in effect as of January 1, 2010. These boundaries are for Census Bureau statistical data collection and tabulation purposes only; their depiction and designation for statistical purposes do not constitute a determination of jurisdictional authority or rights of ownership or entitlement.

**Table 3: Major Coal Basins, Federal Agency Ownership, and Overlap of Federal and Tribal Lands, 2013**

| Basin | Percentage of federal land overlap | Agency ownership | Percentage of tribal land overlap |
|---|---|---|---|
| Northern Appalachia | 4.7 | Interior, Forest Service | 0.0 |
| Central Appalachia | 8.7 | Forest Service | 0.0 |
| Illinois | 0.2 | Forest Service, other | 0.0 |
| Powder River | 19.2 | Interior, Forest Service | 0.1 |

Sources: GAO analysis of Energy Information Administration data, U.S. Geological Survey data, and U.S. Census Bureau data. | GAO-17-540

Note: “Other” in the agency ownership column represents all other federal agencies apart from the Department of the Interior and the U.S. Forest Service. The percentage of tribal land overlap reflects those boundaries reported to the U.S. Census Bureau and in effect as of January 1, 2010. These boundaries are for Census Bureau statistical data collection and tabulation purposes only; their depiction and designation for statistical purposes do not constitute a determination of jurisdictional authority or rights of ownership or entitlement. The most recent coal layer data available are from 2013.

**Table 4: Federal Offshore, Onshore, and American Indian Royalties, Fiscal Years 2015 and 2016**

Dollars in millions

| Resource | Fiscal Year 2015 royalties | Fiscal Year 2016 royalties |
|---|---|---|
| **Oil** | | |
| Federal offshore | 3,734.14 | 2,216.47 |
| Federal onshore | 1,269.60 | 793.12 |
| American Indian | 601.84 | 379.27 |
| **Gas** | | |
| Federal offshore | 516.11 | 253.52 |
| Federal onshore | 1,069.31 | 653.35 |
| American Indian | 149.98 | 96.25 |
| **Coal** | | |
| Federal onshore | 682.70 | 536.46 |
| American Indian | 74.39 | 58.49 |

Source: Office of Natural Resources Revenue data. | GAO-17-540

Notes: The revenue data for gas include natural gas liquids revenues. The Office of Natural Resources Revenue reports data on oil, gas, and coal production on American Indian lands, but these numbers are not included in federal onshore totals.

**Table 5: Federal Offshore, Onshore, and American Indian Bonus Bids and Rental Revenue, Fiscal Years 2015 and 2016**

Dollars in millions

| Resource | Fiscal Year 2015 | Fiscal Year 2016 |
|---|---|---|
| **Oil and gas** | | |
| Federal offshore—bonus bids | 642.04 | 159.86 |
| Federal offshore—rentals | 225.51 | 158.03 |
| Federal onshore—bonus bids | 112.65 | 122.91 |
| Federal onshore—rentals | 30.89 | 21.47 |
| American Indian—bonus bids | 0[a] | 0[a] |
| American Indian—rentals | 4.06 | 4.06 |
| **Coal** | | |
| Federal onshore—bonus bids | 453.87 | 384.07 |
| Federal onshore—rentals | 1.29 | 1.31 |
| American Indian—bonus bids | 0.20 | 5.50 |
| American Indian—rentals | 0.06 | 0.21 |

Source: Office of Natural Resources Revenue data. | GAO-17-540

Notes: Production of natural gas liquids does not produce bonus bid or rental revenues and natural gas liquids therefore are not included in these revenue data. The Office of Natural Resources Revenue reports data on oil, gas, and coal production on American Indian lands, but these numbers are not included in federal onshore totals.

[a]There were no bonus bids reported for oil and gas on American Indian lands in fiscal year 2015 or 2016.

**Table 6: Federal Offshore, Onshore, and American Indian Oil, Gas, and Coal Production, Fiscal Years 2015 and 2016**

| Resource | Fiscal Year 2015 | Fiscal Year 2016 |
|---|---|---|
| **Oil (barrels)** | | |
| Federal offshore | 554,720,979 | 553,683,961 |
| Federal onshore | 174,555,096 | 157,030,533 |
| American Indian | 63,899,859 | 57,732,193 |
| **Gas (thousand cubic feet)** | | |
| Federal offshore | 1,357,562,938 | 1,255,384,917 |
| Federal onshore | 3,378,237,142 | 3,138,734,185 |
| American Indian | 316,435,483 | 316,841,943 |
| **Coal (tons)** | | |
| Federal onshore | 389,606,150 | 295,871,233 |
| American Indian | 19,101,776 | 13,857,277 |

Source: Office of Natural Resources Revenue data. | GAO-17-540

Notes: Gas production numbers include natural gas liquids volumes. The Office of Natural Resources Revenue reports data on oil, gas, and coal production on American Indian lands, but these numbers are not included in federal onshore totals.

# Appendix II: GAO Contact and Staff Acknowledgments

## GAO Contact

Frank Rusco, (202) 512-3841 or ruscof@gao.gov

## Staff Acknowledgments

In addition to the contact named above, Quindi Franco (Assistant Director), Richard Burkard, Greg Campbell, Colleen Candrl, Tara Congdon, Cindy Gilbert, Michael Kendix, Courtney Lafountain, Jessica Lewis, John Mingus, Cynthia Norris, Caroline Prado, Sara Sullivan, Kiki Theodoropoulos, Barbara Timmerman, and Amy Ward-Meier made key contributions to this report.