From:	Jackson, Danna R
To:	Lefton, Amanda B; Knodel, Marissa S
Cc:	Daniel-Davis, Laura E; Sanchez, Alexandra L; Culver, Nada L; Scott, Janea A
Subject:	Re: Scope of Work proposal for contractor for O&G review comments
Date:	Tuesday, March 23, 2021 9:11:25 PM

Looks great. I'm your BLM POC on this.

Get Outlook for iOS

From: Lefton, Amanda B <Amanda.Lefton@boem.gov>
Sent: Tuesday, March 23, 2021 6:40:04 PM
To: Knodel, Marissa S <Marissa.Knodel@boem.gov>
Cc: Daniel-Davis, Laura E <laura_daniel-davis@ios.doi.gov>; Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>; Culver, Nada L <nada_culver@ios.doi.gov>; Jackson, Danna R <djackson@blm.gov>; Scott, Janea A <janea_scott@ios.doi.gov>
Subject: Re: Scope of Work proposal for contractor for O&G review comments

I just got off a long call with Megan about this. I think 6 weeks is the best we can cut it, but we will get weekly reports as part of the process. We need to pull the trigger as soon as we can. Discuss tomorrow?

> On Mar 23, 2021, at 7:51 PM, Knodel, Marissa S <Marissa.Knodel@boem.gov> wrote:
>
> Hello everyone,
>
> See below for an updated timeline with a deliverable 6 weeks after April 15th. BOEM can lead with issuing the request, but will need our sign-off in order to do so **by tomorrow**. They also mentioned that it is typical for additional details to be worked out at the initial post-award meeting, so we see how many "comments" we've received by April 8 and make any necessary adjustments.
>
> **March 25: Comment period opens**
> **April 5:** Award call order
> **April 8:** Deliverable A) Post-Award Meeting, Agenda, and Draft Quality Control Plan (within 3 days of award)
> **April 12:** Deliverable B) Meeting Summary and Final Quality Control Plan (within 4 days of post-award meeting)
> **April 15: Comment period closes**
> **June 3: Deliverable E) Report (within 8 weeks of post-award meeting)**
> **June 17:** Deliverable F) Delivery of Comment Database (within 10 weeks of post-award meeting)
>
> Peace,

Marissa Knodel
Advisor, Bureau of Ocean Energy Management
202.538.2415
Marissa.Knodel@boem.gov

From: Knodel, Marissa S <Marissa.Knodel@boem.gov>
Sent: Monday, March 22, 2021 3:46 PM
To: Daniel-Davis, Laura E <laura_daniel-davis@ios.doi.gov>; Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>; Culver, Nada L <nada_culver@ios.doi.gov>; Jackson, Danna R <djackson@blm.gov>; Scott, Janea A <janea_scott@ios.doi.gov>; Lefton, Amanda B <Amanda.Lefton@boem.gov>
Subject: Scope of Work proposal for contractor for O&G review comments

Hello everyone,

As briefly mentioned this morning, folks from the BOEM team put together a proposal for a Scope of Work for a contractor to help with reviewing and summarizing the feedback we receive between March 25-April 15. Note that the June date is likely later than we'll need for our interim report. The timeline could be shortened, but will require more money. Of course, all of that depends on the volume we receive. **Given the urgency, we need to make a decision on whether or not to pursue a SOW by tomorrow.**

Our suggestions for the SOW are below:

- Contractor to create 3 reports: onshore, offshore, and general (where comments may apply to both BLM and BOEM)
- Contractor to divide comments into several categories based on the TYPE of commentor
- For each type of commentor, those comments would be further divided into general topics/issues
- Reports would separate out suggestions and ideas for what to include in the Comprehensive Review from those types of comments that are supportive or against various activities
- Estimating 500,000 separate comments; if there ends up being more then we would modify the contract (i.e., increase costs)
- Provide database with all comments and analysis for future reporting/queries
- Reports would be delivered to DOI, BLM, and BOEM by end of June 2021 (this gives 10 weeks from end of comment period to conduct the work)

We advocate that because this is a DOI forum, that the costs for the analysis would be covered by DOI. If that is not possible, then we suggest a 50/50 split in costs between BOEM and BLM to keep things as simple as possible for Procurement. This would be a "Fixed Price" workorder, so if you would like to see the cost estimated for fewer number of comments, please let us know ASAP.

Questions to clarify for SOW:

1. What does DOI want this report to look like?
2. What level of detail should be included?
3. Are there any specific metadata that DOI would like to see as part of this analysis for future reference/reports?
4. Please confirm that the contractor for this work would have access to the email box that comments are being submitted to.

Next Steps:

1. Draft SOW created - March 22
2. SOW finalized and PR created - March 24 (pending approvals from DOI?)
    a. Will need cost codes to charge to ASAP
3. Name COR for this work (suggest this be a Regional COR, no one in mind yet) - March 24
4. Kickoff meeting for workorder - March 29
5. Comment period ends - April 15
6. Reports due - June 24

Peace,

Marissa Knodel
Advisor, Bureau of Ocean Energy Management
202.538.2415
Marissa.Knodel@boem.gov

From:	Daniel-Davis, Laura E
To:	Lefton, Amanda B
Cc:	Sanchez, Alexandra L
Subject:	Fw: SCRR Economic Papers
Date:	Sunday, April 18, 2021 1:27:51 PM
Attachments:	BOEM Economic Study on Shallow Water Royalty Relief - Nov 2019 - clean.pdf BOEM Study on Deepwater Royalty Relief - Dec 2020 - clean.pdf

Hi there. We are wanting to better understand how BSEE's SCRR program is currently working, and would want to consider a re-look at this analysis that underpins some of the approach they've been taking over the last 18 months. Who from your econ team could give us a solid overview but also how the conversations developed?

Laura

Bureau of Ocean Energy Management

Recommended Discount Rates and Policies Regarding Special Case Royalty Relief for Oil and Gas Projects in Shallow Water

Bureau of Ocean Energy Management

Economics Division

November 2019

Table of Contents

Summary

The Bureau of Ocean Energy Management (BOEM) has conducted analyses to help inform the Bureau of Safety and Environmental Enforcement's (BSEE) policies and procedures for applying Special Case Royalty Relief (SCRR) for certain shallow water oil and gas projects in the Gulf of Mexico. In this report, BOEM presents its research and recommendations regarding the appropriate discount rates to use when computing the net present value of cash flows within SCRR applications. BOEM recommends that companies should self-report discount rates, but that BSEE should impose a 25 percent upper bound on reported discount rates for shallow water leases. This policy would allow companies to earn appropriate rates of return, and would protect the government's right to receive fair amounts of royalty payments. BOEM also provides some analysis regarding the form of royalty relief. In particular, a Value of Suspended Royalties (VSR) offers some appealing features, and BOEM recommends that BSEE work with BOEM and the Office of Natural Resources Revenue (ONRR) to further examine the potential use of a VSR.

Chapter 1: Introduction

Section 1.1: Project Background

The Bureau of Ocean Energy Management (BOEM) sets royalty rates for oil and gas leases in federal waters. In the most recent Gulf of Mexico (GOM) lease sales, BOEM has set a 12.5% royalty rate for shallow water leases (water depths less than 200 meters) and a 18.75% royalty rate for deepwater leases (water depths of 200 meters or more); existing leases can have royalty rates of 12.5%, 16.67%, or 18.75% (in either shallow or deep water). Royalties help ensure the public receives a fair return for leasing federal submerged lands. However, situations can arise in which companies are unwilling to develop certain oil and gas resources at the prevailing royalty rate because doing so would not yield a sufficient rate of return. In these situations, an operator may apply for certain types of royalty relief.[1] The Bureau of Safety and Environmental Enforcement (BSEE) administers discretionary royalty relief programs.

The oil and gas resources of the federal shallow water GOM region have been explored and developed for more than 65 years. As a result, the most profitable oil and gas projects have been developed, and a number of marginal accumulations are currently leased but may not be profitable (and thus may not be pursued) at current royalty rates. Operators of existing leases may apply to BSEE to obtain SCRR for certain oil and gas development activities. When analyzing SCRR applications, an important consideration is the extent to which the relief shifts the project from being unprofitable to being profitable. Therefore, reviews of SCRR applications often entail calculations of the profitability of the project with and without royalty relief. A key component of these determinations is an interest rate (or discount rate) used to compute the net present value (NPV) of expected cash inflows and outflows. A discount rate accounts for the time value of money, as well as the uncertainty associated with future cash flows. In general, the higher BSEE sets the discount rate, the more royalty relief would be required to make a particular project profitable. Therefore, the appropriate discount rate should facilitate the development of oil and gas resources, while minimizing the loss of government revenue.

This paper provides BOEM's research, analyses, and recommendations regarding the appropriate discount rates to use when evaluating shallow water SCRR applications. BOEM also suggests BSEE consider providing royalty relief in the form of a Value of Suspended Royalties (VSR). A VSR would protect the taxpayer and reduce lessee uncertainty. Section 1.2 provides a numerical illustration of how different discount rates can affect the NPV of an oil and gas project. Chapter 2 provides a theoretical framework for determining and understanding the appropriate discount rate in a particular situation. Chapter 3 describes the available data regarding discount rates. Chapter 4 provides BOEM's analysis regarding the appropriate form of royalty relief. Chapter 5 summarizes BOEM's findings and recommendations.

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[1] More information regarding royalty relief programs is available at: https://www.boem.gov/Royalty-Relief-Information/ (BOEM 2019).

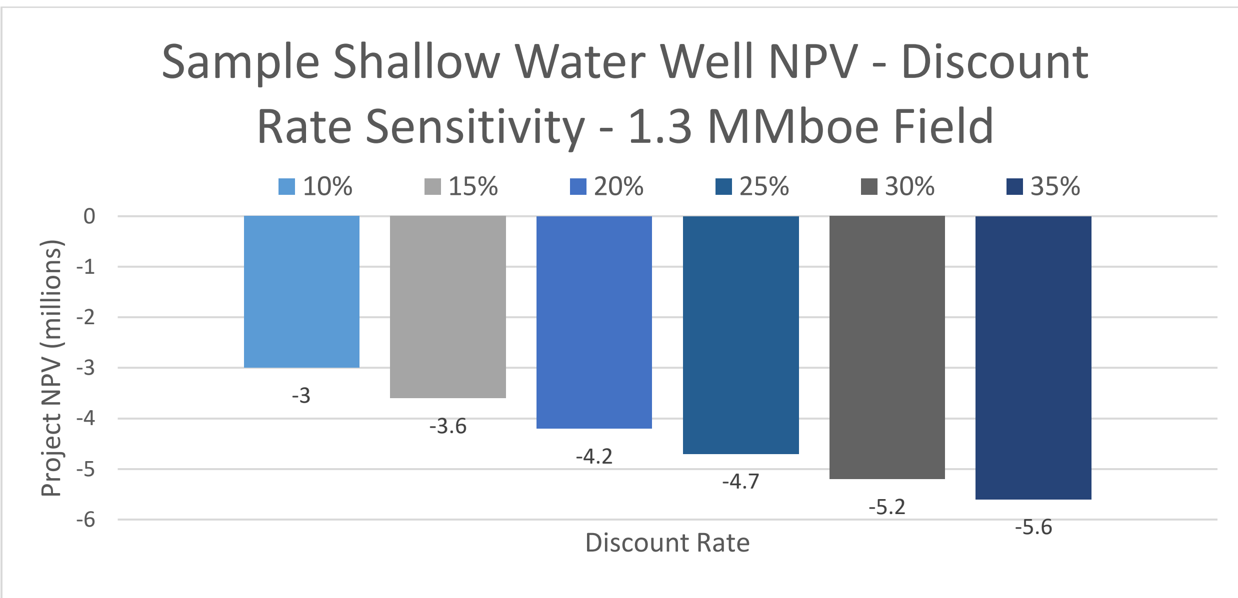
Section 1.2: Numerical Illustration of Discount Rates Impacting Net Present Value

Discount rates have significant impacts on oil and gas project evaluations. This section will present a numerical example of how discount rates can affect profitability, which will inform the analyses in subsequent sections.

$$NPV = \sum_{t=1}^{T} \frac{Expected\ Cash\ Flows}{(1+DR)^t} \qquad \text{(Equation 1)}$$

In Equation 1, NPV is computed by applying a discount rate (DR) to expected cash flows in each time period (t), and then summing the values for each time period. Figure 1 displays the NPV of a hypothetical 1.3 MMboe (million barrels of oil equivalent) shallow water project using discount rates ranging from 10-35%. As the discount rate increases, the NPV of a project decreases. Therefore, more royalty relief would be required to change the project's NPV to zero. For this sample project, each five-percentage point change in the applied discount rate changes the project NPV by roughly one-half of a million dollars.

Figure 1: Example Regarding Discount Rates and NPVs



A higher discount rate will generally reduce the NPV of an oil and gas project and require a larger amount of royalty relief to be economic. However, there is a limitation on the extent to which royalty relief can offset a negative NPV. At very high discount rates, reducing the royalty rate, even to zero percent, may not be sufficient to bring the project NPV to zero. Under Special Case Royalty Relief, royalty relief is provided to turn an uneconomic project economic. That is, BSEE provides royalty relief to change the NPV of a project from being negative to being non-negative. This highlights the importance of applying an optimal discount rate that allows BSEE to assess whether royalty relief is appropriate and, if so, to grant an amount of relief that allows a company to earn an appropriate rate of return (while protecting the government's right to receive fair amounts of royalty payments).

Chapter 2: General Discussion of Discount Rates

Section 2.1: Introduction

This chapter provides a theoretical framework for determining and understanding the appropriate discount rates in the context of SCRR applications[2]. In particular, this chapter describes how various risks faced by shallow water operators influence discount rates.

Businesses typically determine which projects to pursue by assessing the size and timing of expected cash inflows and outflows. The timing of cash flows is important because money received sooner is more valuable than money received later. In addition, the owners of businesses prefer certainty and seek to minimize risk regarding the size and timing of cash flows. However, the cash flows from oil and gas projects are subject to numerous uncertainties. Therefore, businesses need a framework to value these uncertain cash flows. A common framework is to use risk-adjusted discount rates (RADRs), which entails applying higher discount rates for riskier projects.[3]

$$\mathrm{DR} = \mathrm{WACC} + \mathrm{IHR} + \mathrm{SWRA} \qquad \text{(Equation 2)}$$

Inkpen and Moffett (2011) decompose discount rates as shown in Equation 2, where:

- DR: Discount rate applied to expected cash flows
- WACC: Weighted average cost of capital
- IHR: Incremental hurdle rate
- SWRA: Shallow water risk adjustment

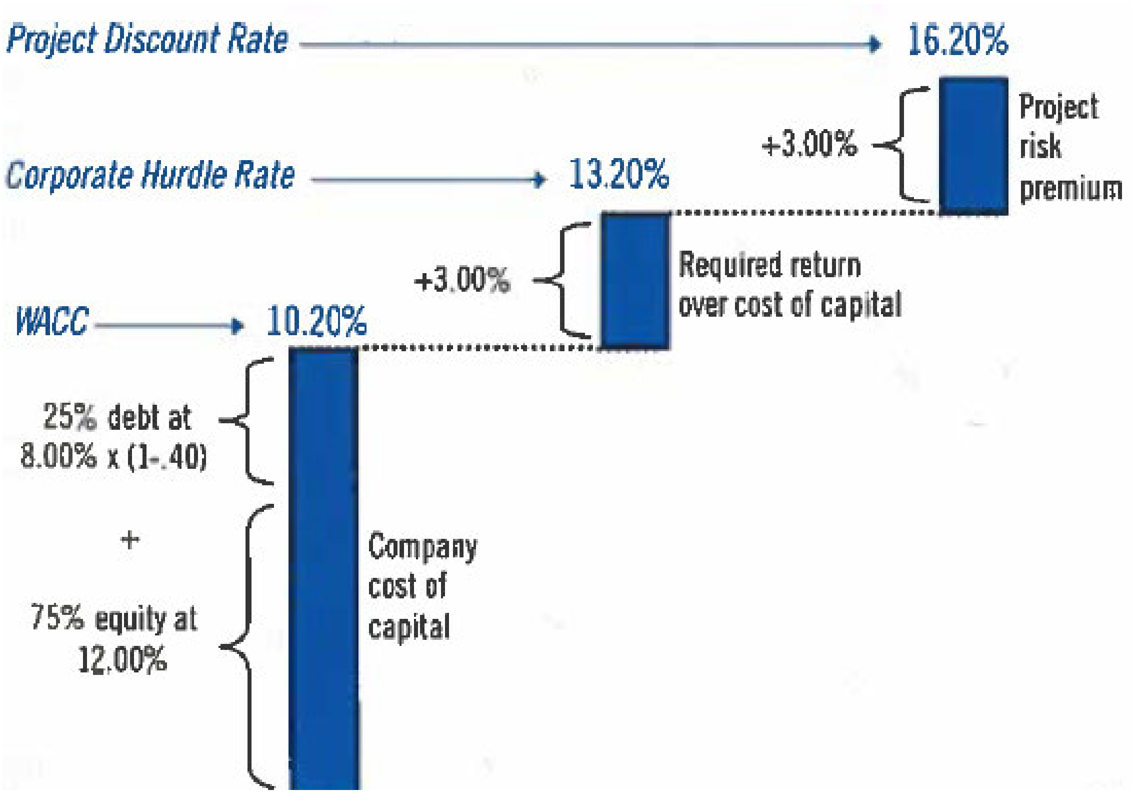
In other words, companies will expect to earn at least as much as their weighted average cost of debt and equity capital. In addition, if companies have multiple profitable investment opportunities (and a limited budget), they will require more than the WACC (an incremental hurdle rate) in order to pursue an average-risk project. Finally, a GOM shallow water project, particularly one for which royalty relief would be requested, likely faces additional risks compared to a company's average project. For example, the probability that a marginal project will be profitable overall is more sensitive to deviations of variables (such as reserves and prices) from their expected values. In addition, the most profitable areas of the shallow water GOM have already been developed, which limits the likelihood of a highly profitable outcome. Therefore, businesses will likely require a higher discount rate to compensate for these risks.

---

[2] This paper generally refers to *nominal* discount rates, which do not remove expected inflation. One can convert nominal discount rates to *real* discount rates (which do remove expected inflation) as:
Real discount rate = [(1+ nominal discount rate)/(1 + expected inflation rate)] -1
(where all variables are entered as decimals).

[3] An alternate approach is to discount cash flows using a lower discount rate than in Equation 2, and to then to decrease the resultant net present value by a reserve adjustment factor (Society of Petroleum Evaluation Engineers 2018). There has also been some research regarding the use of option theory related to oil and gas projects, but these methods are not often used in practice (Dickens and Lohrenz 1996).

Figure 2: Components of a Risk-Adjusted Discount Rate



Source: Inkpen and Moffett (2011)

Figure 2 presents a hypothetical example from Inkpen and Moffett (2011) regarding the components of a risk-adjusted discount rate. In this example, an oil and gas company is analyzing the profitability of a particular project. The company is financed by 75% equity and 25% debt. Suppose the cost of equity is 12%, the cost of debt is 8%, and the corporate tax rate is 40%. The weighted average cost of capital of these funding streams is 10.2% (see Section 2.2 for more information).[4] Due to competing investment projects, this company has an average incremental hurdle rate of 3% (and a total corporate hurdle rate of 13.2%). Finally, the particular project under consideration is riskier than the company's average project, so the company adds a 3% percent risk premium. This yields a total project discount rate of 16.2%. Therefore, this company will use a discount rate of 16.2% to compute the net present value of cash flows from this project. Sections 2 through 4 will describe these components of discount rates in more detail. Section 5 will qualitatively discuss how discount rate policies can affect society as a whole.

[4] The current corporate tax rate is 21%. If this 21% corporate tax rate were applied to the example in Figure 2 (and assuming other variables did not adjust), the WACC would equal 10.58% (and the project discount rate would equal 16.58%). The WACC would increase because there would be less of a tax shield associated with debt financing (see Section 2.2).

Section 2.2: Weighted Average Cost of Capital

When analyzing an oil and gas project, a company will expect to earn at least the weighted average cost of its debt and equity financing in order to undertake the project.

$$WACC = \left(\frac{E}{V}\right) R_E + \left(\frac{D}{V}\right) R_D (1 - T_C) \qquad \text{(Equation 3)}$$

Equation 3 is the formula for the WACC (Corporate Finance Institute 2019), where:

- E: Market value of total equity
- D: Market value of total debt
- V=E+D (the total market value of debt and equity combined)
- R_E: Cost of equity
- R_D: Cost of debt
- T_C: Corporate income tax rate

The first part of Equation 3 represents the portion of a company's cost of capital represented by required returns on equity. In particular, equity investors will require a rate of return commensurate with a company's collective risk profile. There are numerous risks associated with oil and gas projects, such as price volatility, uncertainty regarding reserves, and variability of input costs. Since investors often can diversify their equity holdings, a common assumption is that equity investors will only receive compensation for risks that cannot be eliminated through diversification[5]. However, given the numerous sources of uncertainty for oil and gas companies, as well as the interdependence between energy markets and the broader economy, many of the risks cannot be diversified away. In addition, many shallow water oil and gas operators are privately-held companies, which further limits their ability to diversify risks. Therefore, for most oil and gas companies, the required return on equity capital is high.

The second part of Equation 3 represents the cost of debt financing (since debt interest payments are tax deductible, one considers the after-tax cost of debt financing). One can roughly think of the cost of debt as the sum of a risk-free interest rate, often approximated by the interest rate on a U.S. Treasury bond or bill, plus a premium to compensate lenders for the possibility that some or all of a loan may not be paid back on schedule. U.S. Treasury yields have been low in recent years. However, given the various risks associated with oil and gas development, lenders often require a sizable risk premium. This is particularly the case for smaller companies and companies experiencing financial difficulties. Therefore, the cost of debt (and the overall WACC for oil and gas companies) can be substantial.

[5] This is the core assumption of the Capital Asset Pricing Model, a widely-used framework for determining required rates of return (Sharpe 1964). Other theories of asset prices incorporate additional factors in their models, such as a company's size and the ratio of a company's book equity to its market equity (Fama and French 1993).

Section 2.3: Incremental Hurdle Rate

At any point in time, oil and gas companies likely have several potential projects under consideration. The minimum requirement for these projects is that they yield a return that is greater than (or equal to) the WACC. However, in many cases, a company will have multiple profitable projects under consideration. A company may be able to obtain additional funding to pursue more or all of these projects, but to the extent a company is unable or unwilling to do this, the company will apply a framework for deciding which projects to pursue. In the context of understanding discount rates, an appropriate framework is to think in terms of an incremental hurdle rate that represents the rate of return above the WACC that would induce a company to undertake a particular project relative to other projects. This incremental hurdle rate will thus vary through time given market conditions.

In practice, other factors may influence oil and gas investment decisions. For example, the size of the project (and the resulting overall profits earned) will be an important factor. U.S. shallow water projects are typically smaller than other projects (such as deepwater projects) and thus may not be as lucrative, particularly if certain factors make the projects mutually exclusive. Therefore, all else being equal, an average company will require a higher rate of return for a small shallow water project. However, the size of the oil and gas company may also affect its incremental hurdle rate. In particular, large companies may require a higher incremental hurdle rate than smaller companies because large companies have more (and larger) investment options. This has resulted in a trend of major oil and gas companies leaving the shallow water GOM to focus on larger projects (for example in the deepwater GOM) that offer more potential upside. The remaining operators of shallow water projects are thus smaller companies that are willing to accept smaller overall returns on projects.

Companies may also chose projects that recover their costs more quickly than other projects. In general, shallow water projects recover their costs faster than deepwater projects, but slower than onshore projects. In addition, spillover effects from a particular project to other future projects can influence development decisions. For example, pursuing a particular oil and gas project could position a company to pursue similar projects in the future through cost efficiencies or technological improvements. This issue would tend to lead companies to pursue alternatives to shallow water projects, since the future prospects for GOM shallow water projects are significantly less than for other areas. In addition, the shallow water GOM produces a higher percentage of natural gas (compared to oil) than the deepwater GOM. Natural gas is unlikely to be very profitable given the boom in, and the cost advantages of, onshore natural gas production.

Given the various factors discussed above, the extent to which an average shallow water project requires a higher or lower incremental hurdle rate than other projects will depend on the magnitude of these factors.

Section 2.4: Shallow Water Risk Adjustment

The discount rate for SCRR applications should account for the risks of these shallow water projects. These projects are by definition only marginally economic or uneconomic (often due to their limited oil and gas resources). Therefore, the likelihood that these projects will be profitable is sensitive to any deviations of economic variables (such as market prices, discovered resources, and development costs) from their projected values. A primary determinant of the risk adjustment should be the uncertainty of the oil and gas production likely to arise from a particular project. The risk adjustment should also account for the fact that there is a very low probability of a much higher than expected return because the most resource-rich areas of the shallow water GOM have already been developed. There is a higher probability of a large downside return (if the oil and gas resources turn out not to be present or are unobtainable for some reason). Finally, shallow water operators in the Gulf of Mexico face infrastructure-related risks associated with operating in a declining province. For example, older infrastructure requires more repairs, and longer-term infrastructure gaps (such as the eventual unavailability of certain platforms or pipelines) could arise. Therefore, the discount rate should be adjusted upwards to account for these risks.

Section 2.5: Societal Considerations

The analysis of discount rates in prior sections focused on discount rates used by oil and gas companies when making investment decisions. This is appropriate because companies ultimately determine whether to pursue certain projects, and because federal policy regarding this issue has typically focused on the extent to which royalty payments (and the resulting royalty relief) determine whether a project is economic to pursue. However, when considering policy decisions, it is appropriate to consider the costs and benefits of policy options from the perspective of society as a whole. In the analysis of discount rates, a societal viewpoint highlights the effects of decisions by an oil and gas industry on other actors in an economy. A societal viewpoint also highlights the risks of setting the discount rate too high or too low.

When an oil and gas company undertakes a discounted cash flow analysis in its decision-making process, it does not incorporate numerous effects on society as a whole. Some of these effects are beneficial, such as increased government revenues, lower energy prices, and less dependence on substitute energy sources. On the other hand, some of these effects, such as potential environmental effects, may be negative (depending on the alternatives). An important issue that is not sufficiently captured in an individual company’s analysis is the viability of the shallow water GOM province as a whole, and whether the collective decisions of many companies will leave oil and gas resources undeveloped for the foreseeable future.

The OCS Lands Act authorizes the Secretary of the Department of the Interior to issue regulations in the interest of conservation of OCS natural resources.[6] Conservation of OCS resources promotes economic efficiency, and from an economic perspective, leasing, development, and production activities should be carried out in a manner that will increase the net economic value to society from the development of OCS resources. In the context of GOM shallow water development, conservation of resources is a concern because much of the infrastructure to support shallow water activities, such as production platforms, are required to be removed not long after oil and gas production ceases; BSEE (2018) describes the decommissioning requirements for wells and platforms. Once infrastructure is removed, it is unlikely that similar infrastructure will be re-installed in the future because of the significant costs involved. Therefore, oil and gas companies, and society as a whole, may eventually lose the option to develop these shallow water assets even if economic conditions become more favorable in the future. Therefore, one can view the determination of discount rates as a policy lever to better account for these societal interests. While this is not the core analytical question at issue in this paper, it is useful to keep this perspective in mind.

It is also informative to consider the risks to society of setting discount rates too low or too high. If the government sets discount rates too low, certain projects may not be pursued (that may have been pursued if appropriate discount rates were used). As mentioned previously, society may also lose the value of the option to develop certain shallow water oil and gas resources in the future. If the government sets discount rates too high, it will encourage royalty-relief applications for projects that would have proceeded without royalty relief. Thus, the government would lose a fair amount of royalty revenue. In addition, for very marginal projects, setting the discount rate too high may lead to the conclusion that no amount of royalty relief would make these projects economic (and thus the projects would not be pursued). These effects highlight the need to select optimal discount rates that appropriately balance society's varied interests.

[6] 43 U.S.C. § 1334(a)

Chapter 3: Analysis of Data Sources for Discount Rates

The discount rates the government uses for evaluating SCRR applications should be similar to the rates companies use when evaluating similar upstream oil and gas investment opportunities. Unfortunately, the discount rates companies use, and the evaluation techniques they employ, differ across companies and are proprietary. There are several methods for estimating companies' discount rates. These methods include (1) measuring the cost of capital from financial data, (2) estimating the average return on upstream oil and gas investments, and (3) surveying companies to elicit their discount rates. There are various data and confidentiality limitations regarding methods 1 and 2. Therefore, this Chapter will summarize the available data from surveys and related reports. Section 3.1 will describe discount rate data from the Society of Petroleum Evaluation Engineers (SPEE). Section 3.2 will describe some other relevant data sources.

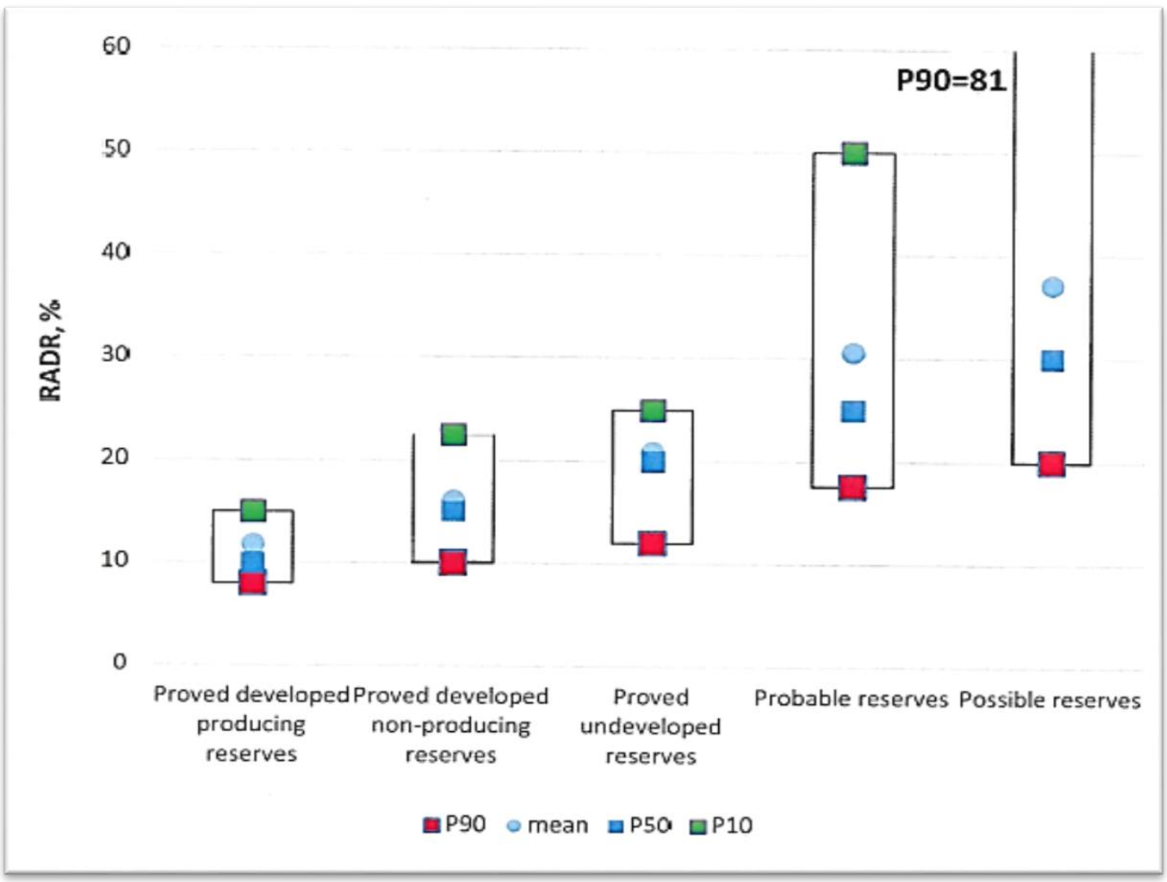
Section 3.1: Society of Petroleum Evaluation Engineers Data

The SPEE conducts an annual survey of their members regarding upstream resource evaluation topics. The survey asks members a wide range of questions, including questions about SPEE member companies' risk-adjusted discount rates (RADRs) used for different types of projects. BOEM acquired reports that summarized the data from the 2016, 2017, and 2018 surveys. The majority of survey responses came from employees of either exploration and production companies or oil and gas consulting companies, whose job functions primarily entail property valuation, reserves estimation, or acquisition and divestiture activities. The surveys do not differentiate between offshore and onshore evaluation methods. In the 2018 SPEE survey, almost 80% percent of respondents were located in the United States, and the vast majority of them spent a significant amount of time evaluating resources in the United States. When asked for reasons why RADRs were used to evaluate assets, 88% of respondents to the 2018 survey stated that reserve risk made the use of RADRs appropriate in their evaluations. Other reasons that were cited in over 33% of responses include price uncertainty, expense uncertainty, mechanical risk, and political regulatory uncertainty.

The 2018 SPEE survey asked members for the actual RADRs used when evaluating projects targeting certain categories of reserves; the results of the survey are presented in Figure 3. As one would expect, the less certainty companies had regarding the volume of recoverable resources, the higher the RADR used to evaluate these projects. Creating asset decline curves and cash flow models is straightforward when the asset being evaluated is proved developed or producing. While there is risk involved with any investment decision, the reserve risk is mitigated when companies are more certain about the recoverable resource. This is why *proved* reserves require a lower RADR than *probable* reserves.

In Figure 3, the 2018 SPEE survey results show that the median RADR used for probable reserves appears to be around 25%. Similarly, the 2016 and 2017 SPEE surveys found that the median RADR used for probable reserves was 25%. The 2016, 2017, and 2018 surveys found that the median RADR for proved developed producing reserves was approximately 10%. These differences illustrate that discount rates used for asset evaluations vary depending on the reserve classifications.

Figure 3: Risk Adjusted Discount Rate by Resource Classification - 2018 SPEE Survey Results



A limitation of the data in Figure 3 is that some of the survey responses relate to RADRs used for purposes somewhat different from oil and gas exploration and development. For example, RADRs are also used for asset acquisitions and overall corporate valuations. The 2017 SPEE survey presented results for the different categories of use (the SPEE data for other years did not provide these breakouts). The 2017 SPEE data found that the mean RADR used for oil and gas field development was 19.5% (sample size=24), and the mean RADR used for decisions to drill exploration wells was 17.4% (sample size=20). However, there were wide ranges of RADRs used.

Section 3.2: Other Data Sources

Other than SPEE data, there is limited alternate survey data regarding discount rates used by oil and gas companies. Below are a few sources that were found.

The Texas Comptroller of Public Accounts (2018) describes the RADRs used to assess oil and gas properties. This report developed an average range of discount rates of 14.62%-20.81%, and described some contexts that would allow for deviations from this range. For example, this study applied a 2 percent increase in RADRs for offshore properties.

Oil and Gas Journal (2018) presents discount rate data from Wood Mackenzie's 2017 and 2018 annual surveys of upstream oil and gas companies. The discount rates for various project categories in 2017 and 2018 were:

- Unconventional projects: 14.0% in 2017; 14.1% in 2018
- Deepwater projects: 15.9% in 2017; 14.8% in 2018
- Exploration projects: 15.8% in 2017; 14.8% in 2018

The Oxford Institute for Energy Studies (2019) emphasizes the risks of oil and gas projects in the context of a long-run transition towards renewable energy sources. This study cites survey results that a deepwater project has an average 18% discount rate (it does not cite a discount rate for shallow water).

Section 3.3: Analysis of Available Data

The SPEE surveys (for 2016, 2017, and 2018) provide the most detailed discount rate data. These surveys report that the median discount rate used for probable reserves was approximately 25%. While informative, some of the survey responses related to discount rates for uses other than oil and gas exploration and field development. The 2017 SPEE survey was the only survey to provide discount rates specifically for these categories. The 2017 SPEE survey found that the mean RADR used for field development was 19.5%, and the mean RADR used for exploration wells was 17.4%. These mean values are roughly consistent with the other data sources found. However, as described in Chapter 2, shallow water projects for which royalty relief would be sought have above-average risks. Therefore, companies will likely apply above-average discount rates when evaluating these projects. However, given the myriad of factors that affect discount rates, there is no formula that BSEE can apply to precisely estimate the appropriate discount rate for a particular SCRR application. Therefore, BSEE needs to set a generally-applicable discount rate policy that accounts for the various factors described in this paper. BOEM recommends that BSEE allow companies to self-report discount rates, but to impose an upper bound of 25%. This 25% upper bound on discount rates allows companies to earn appropriate rates of return, and protects the government's right to receive appropriate royalty payments.

Chapter 4: Form of Royalty Relief

Section 4.1: Royalty Suspension Value, Royalty Suspension Volume, or Lower Royalty Rate?

Although the main purpose of this paper is to provide analyses and recommendations regarding the appropriate discount rates for shallow water SCRR applications, utilizing the appropriate policy to deliver the intended relief to operators is very important. Traditionally, BSEE has provided SCRR in the form of a reduced royalty rate on all production from a lease up to a specific price and production volume threshold. However, as will be described in this chapter, a lower royalty rate is an inefficient form of royalty relief. BSEE has the authority to use a variety of royalty suspension policies as provided in its regulations[7], including (but not limited to):

- A lower royalty rate.
- A Royalty Suspension Volume (RSV): A fixed volume of initial production that is royalty-free as long as prices remain below a pre-determined price threshold.
- A Value of Suspended Royalties (VSR): A predetermined dollar amount that the operator does not pay in royalties. Once the lessee's calculated royalties exceed the VSR, royalty payments resume as provided in the lease.

BOEM recommends that BSEE consider applying royalty relief using a VSR formulation because it provides a number of benefits to operators and the government. A VSR yields the most optimal and timely royalty relief, and provides operators with a consistent benefit in all price cases. Since a VSR is a defined benefit where a value of royalties is the limiting factor, a VSR does not require additional triggers, such as inflation adjustments, price thresholds, or volume limits. When prices deviate from the forecast, only the rate at which the VSR benefit is consumed is affected; the intended value remains constant. By comparison, the amount of relief granted from an RSV or from a lower royalty rate can vary widely if prices or volumes diverge from their projections; the potential of significant price or volume increases also necessitate thresholds to ensure practical limits to royalty benefits. Due to a VSR's design, thresholds are unnecessary and an operator can be certain that they will receive the full amount of the intended benefit at any price, and can build the VSR into their cash flow analyses with confidence.

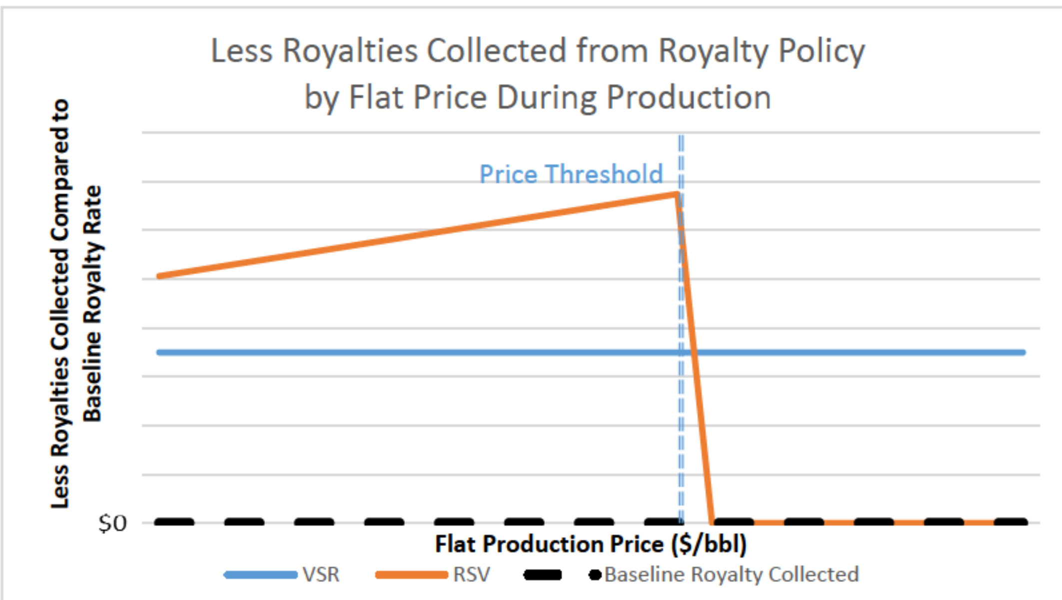
An RSV has been a common form of royalty relief issued by BOEM and BSEE (and their predecessors). However, RSV policies generally suffer from several significant drawbacks due to the necessity of price thresholds to limit the potential royalty relief. A project granted an RSV receives an intended benefit based on a specific price forecast; the derived value of the benefit is calculated by multiplying the royalty rate by the price forecast and the predetermined production volume. The thresholds must be set at the time of the relief determination and are unlikely to reflect actual oil and gas prices or production over time. Price and volume thresholds function as the limits of the royalty suspension benefit. Given the volatility in commodity

[7] 30 CFR Part 203

prices, the actual benefit derived from an RSV policy can vary widely. If actual prices are higher than forecasted, but remain below the price threshold, the benefit granted by the RSV increases beyond the intended benefit. If prices are lower than forecast, the RSV provides less monetary benefit than intended as the amount of paid royalties are lower than forecasted. In either case, the value of the benefit is not as intended.

When prices are above the price threshold, additional undesirable effects occur. First, the value of RSV policies experience a "cliffing" effect, that whenever prices breach the price threshold the value of the project drops sharply as a result. Figure 4 illustrates the "cliffing" effect that RSVs have once the price threshold is breached. In this graph, when the price breaches the threshold, the amount of suspended royalties drops to zero, and the value of the project drops immediately. Second, production that occurs above the price threshold is not royalty free, but continues to count toward the royalty suspension volume, essentially "wasting" the benefit of the RSV. These undesirable effects could cause operators to produce in a suboptimal fashion to avoid these effects.

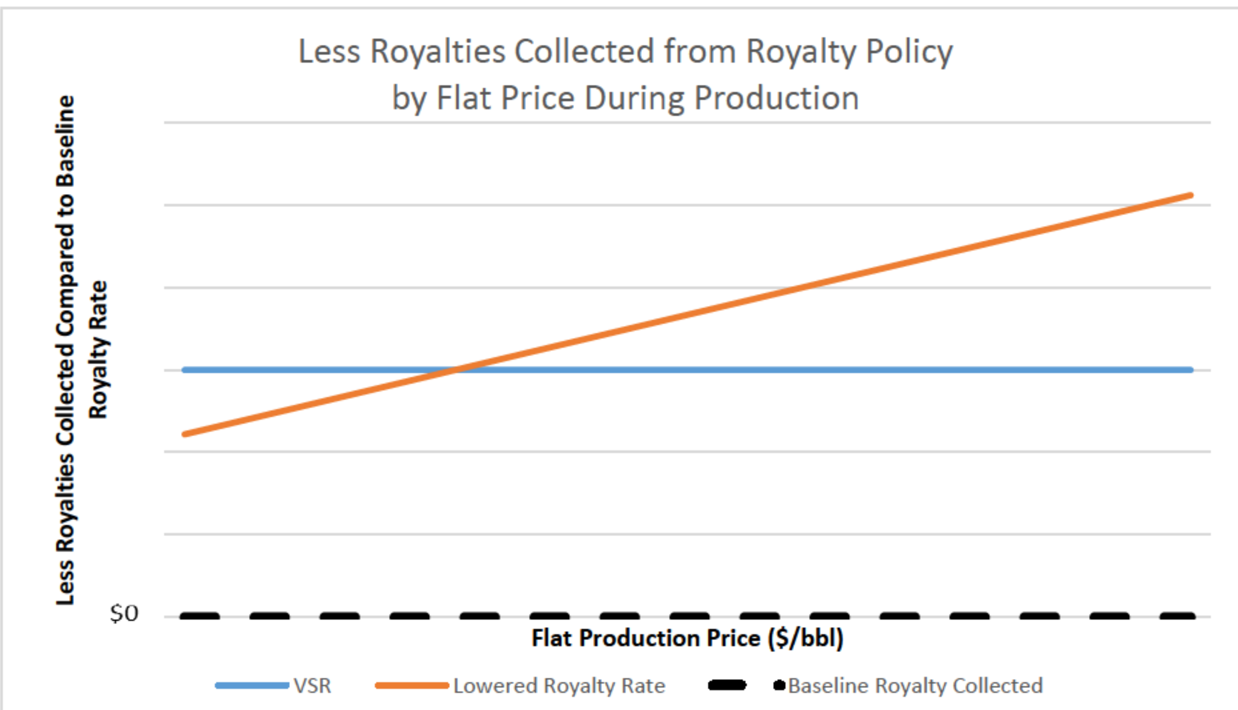
Figure 4 – RSV "cliffing" effect, compared to VSR



On the other hand, a VSR does not require price or volume thresholds and thus does not suffer from the same "cliffing" or "wasting" effects discussed previously. Higher than forecasted prices or production volume simply consumes the intended benefit at a faster rate, which is more beneficial to the operator's cash flow; at lower than forecasted prices or production, the VSR is consumed slower and thus provides more benefit than a royalty suspension policy. Many of the drawbacks of the RSV approach are not applicable, as a VSR provides the intended benefit in any price scenario.

A VSR policy also compares favorably to a lowered royalty rate traditionally used in BSEE royalty relief applications. A lowered royalty rate still requires price and volume thresholds to limit the maximum benefit and inherits all of the related drawbacks (discussed above). A lower royalty rate provides significantly less downside price protection to the operator than a VSR; as prices drop the benefit of a lower royalty rate also drops, whereas a VSR's defined benefit lasts longer at lower prices since it is consumed slower. Another major drawback of a lower royalty rate is that it does not improve cash flow as quickly as a royalty suspension policy. Suspended royalties provide a greater present value on a dollar-for-dollar basis than the remaining paid royalty stream by returning capital as fast as possible; the operator would still pay partial royalties with a lower royalty rate. Figure 5 below illustrates that at low prices a VSR provides more relief to the operator than a lower royalty rate. At high prices, a lower royalty rate delivers significantly more benefit than intended. The use of price and volume thresholds along with a lower royalty rate can limit the over-provision of royalty relief, but use of the thresholds result in the undesirable "cliffing" and "wasting" effects discussed previously.

Figure 5 - Illustration of Less Royalties Collected with VSR vs. Lowered Royalty Rate



A VSR approach could also provide certain administrative benefits to the operator and the government. Price thresholds require annual inflation adjustments, specialized tracking overhead when accounting for suspension volumes, and additional workload if royalties have to be returned to the operator due to prices close to the threshold. A VSR does not require price thresholds or suspension volumes, and thus would not suffer from these issues. However, a VSR could raise other administrative issues and BOEM recommends BSEE discuss this form of royalty incentive with the Office of Natural Resources Revenue.

Section 4.2: VSR Examples

This section uses cash flow data from an SCRR application to illustrate the effects of different discount rates and royalty relief policies. Figure 6 shows the effect that the discount rate has on the NPV of the SCRR project at various royalty rates. Figure 6 displays this relationship for the following royalty rates:

- 16.67%: The baseline royalty rate for the example project.
- 12.50%: The current royalty rate for shallow water leases.
- 7.59%: The royalty rate at which the project would have a zero NPV at a 25% discount rate.
- 0%: A zero royalty example for comparative purposes.

For all royalty rates, the project NPV decreases as the discount rate increases. A VSR policy would entail a VSR amount that would fill the gap between the dashed zero NPV line and the NPV of the project at a particular royalty rate and discount rate. However, since the VSR benefit would be not be received all at once (but rather at the rate royalties would not have to be paid), the amount of the VSR will be slightly higher than this gap. At a 25% discount rate:

- At a 16.67% royalty rate (and no VSR), the project would have an NPV of -$5.42 million.
- At a 12.50% royalty rate (and no VSR), the project would have an NPV of -$2.93 million.

Figure 7 illustrates the amount of VSR required to move up to the dashed black zero NPV line in Figure 6 from either the 16.67% or 12.50% royalty cases over a range of discount rates. Note that above a 34% discount rate, the project is below zero NPV even with a 0% royalty rate. At a 25% discount rate, the following VSR amounts would bring project NPV to zero:

- A $6.63 million VSR at a 16.67% royalty rate
- A $3.45 million VSR at a 12.5% royalty rate

Figure 6 - Project NPV by Discount Rate and Policy

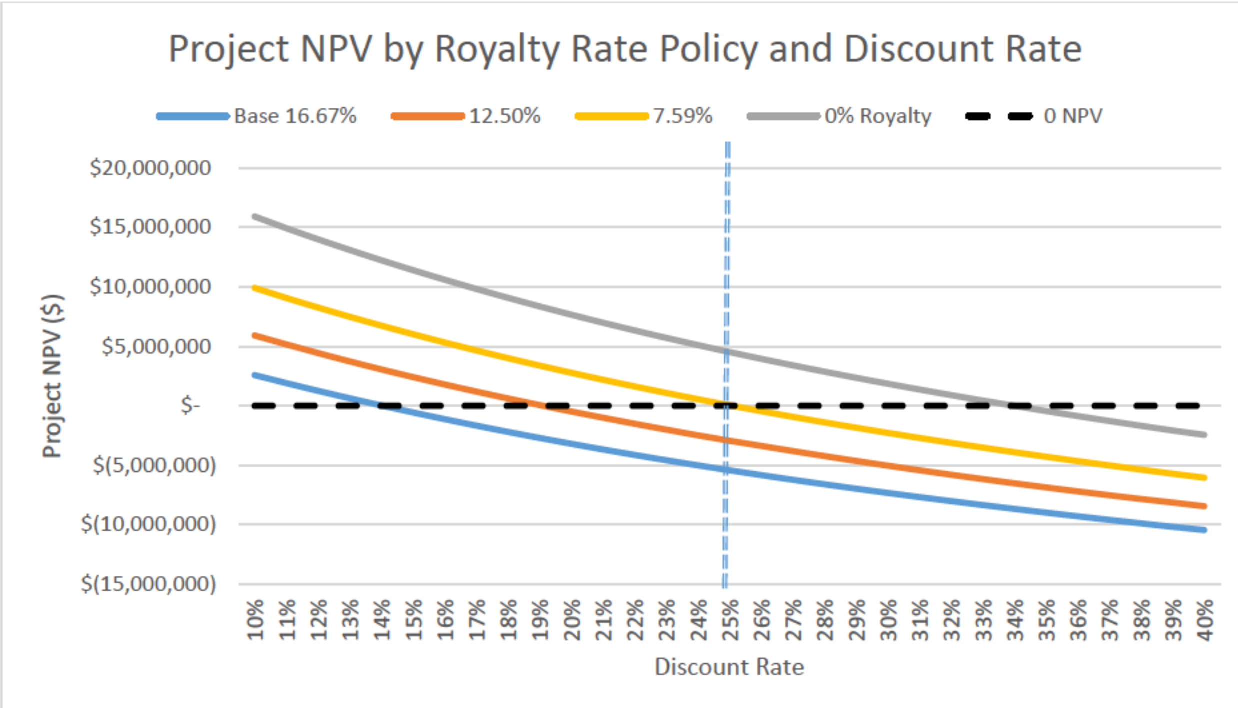


Figure 7 – VSR Required to Reach Zero NPV

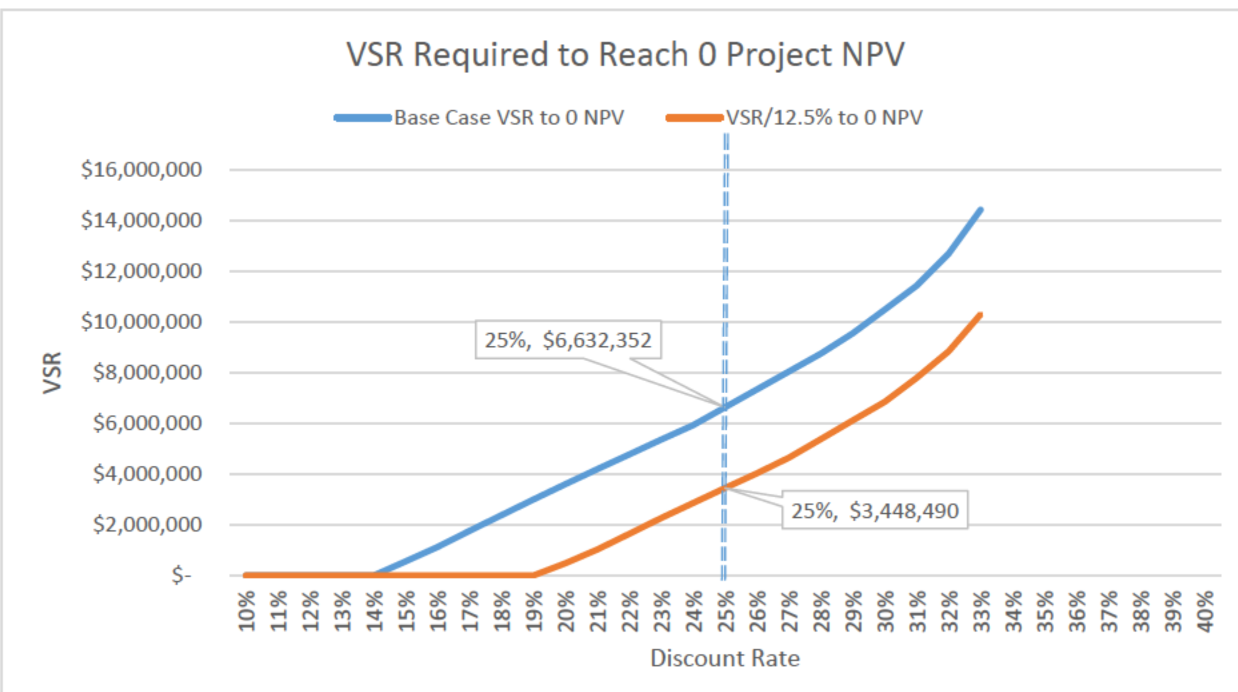


Table 1 compares the results (NPV and royalties collected) of various policy options to the baseline case of a 16.67% royalty rate and no VSR. The rows of Table 1 represent the following policies and royalty rates:

- A 16.67% royalty rate and no VSR (the baseline).
- A 12.5% royalty rate and no VSR.
- A 7.59% royalty rate and no VSR. Note that 7.59% is the royalty rate at which the project NPV is zero (so no VSR is needed to take NPV to zero). This is also the royalty rate that would be applied using a standard formulation of royalty relief.
- A 16.67% royalty rate and a VSR that would take NPV to zero.
- A 12.5% royalty rate and a VSR that would take NPV to zero.

Table 1 - Royalty Breakdown of VSR Policies

Policy @ 25% Discount Rate	Nominal Royalties Paid	Discounted Royalties Paid	VSR Amount	Nominal Less Royalty Collected	Discounted Less Royalty Collected	NPV
16.67% Royalty	$17,299,744	$9,946,349	$0	$0	$0	-$5,418,591
12.5% Royalty	$12,974,808	$7,459,762	$0	$4,324,936	-$2,486,587	-$2,932,003
7.59% Royalty	$7,875,157	$4,527,759	$0	$9,424,587	-$5,418,591	$0
VSR/16.67% Royalty	$10,667,392	$4,527,759	$6,632,352	$6,632,352	-$5,418,591	$0
VSR/12.5% Royalty	$9,526,318	$4,527,759	$3,448,490	$7,773,426	-$5,418,591	$0

The columns of Table 1 represent the following results (assuming a 25% discount rate):

- Nominal royalties paid: The nominal value of royalties paid over the project lifetime.
- Discounted royalties paid: The value of royalties paid discounted to the initial time period.
- VSR amount: The VSR amount for the particular scenario that takes the NPV to zero.
- Nominal less royalty collected: The nominal amount of lower royalties received under a particular scenario compared to the base scenario of 16.67% royalty and no VSR.
- Discounted less royalty collected: The discounted amount of lower royalties received under a particular scenario compared to the base scenario of 16.67% royalty and no VSR.
- NPV: The lifetime NPV of the project.

One can use the *7.59% Royalty* row and the *VSR/16.67% Royalty* row to compare the results of a standard royalty relief policy to a VSR policy. In particular, a VSR policy provides faster relief to the project operator, meaning that the nominal amount of foregone royalties is lower using a VSR policy than using a standard royalty rate reduction (although the discounted loss of royalties are identical under the two policies).

Chapter 5: Conclusions

BOEM has examined the available research and data regarding the appropriate discount rates to use in the context of Special Case Royalty Relief applications for shallow water oil and gas projects. When determining its policy recommendations, BOEM needed to account for the numerous factors that determine discount rates, and the fact that shallow water SCRR projects likely entail above-average risks. BOEM recommends that BSEE allow companies to self-report discount rates, but to impose an upper bound of 25% for shallow water leases. This 25% upper bound for shallow water discount rates allows companies to earn appropriate rates of return, and protects the government's right to receive fair amounts of royalty payments.

BOEM has also provided analyses regarding the use of a VSR, and BOEM recommends that BSEE consider applying royalty relief using a VSR formulation. A VSR provides the operator and the government with certainty regarding cash flows, and avoids some problematic features of other forms of royalty relief. A VSR could also simplify the accounting and tracking for both the lessee and the government. Implementing a VSR could raise administrative issues and require certain adjustments by the Office of Natural Resources Revenue. Therefore, if BSEE elects to examine potential future use of a VSR in its royalty relief decision-making, BOEM recommends that BSEE begin coordinating with BOEM and ONRR to ensure that there is sufficient time to work through any needed process changes.

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Bureau of Ocean Energy Management

Recommended Special Case Royalty Relief Discount Rates for Deepwater Oil and Gas Projects Using Subsea Tiebacks Requiring Enhanced Flow Assurance Technologies

Bureau of Ocean Energy Management

Economics Division

November 2020

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Summary

In November 2019, the Bureau of Ocean Energy Management (BOEM) published a comprehensive report on the appropriate discount rates to use in Special Case Royalty Relief (SCRR) applications for Gulf of Mexico (GOM) shallow water oil and gas projects, *Recommended Discount Rates and Policies Regarding Special Case Royalty Relief for Oil and Gas Projects in Shallow Water* (BOEM 2019), hereafter referred to as the Shallow Water Recommended Discount Rate paper. Subsequently, the Bureau of Safety and Environmental Enforcement (BSEE) has turned its focus to GOM deepwater areas and the potential for stranded resources. Specifically, BSEE requested that BOEM evaluate resources that can be tied-back to existing infrastructure using subsea tieback technology requiring enhanced flow assurance technologies, such as subsea booster pumps, and recommend appropriate discount rates that could be applied to those projects needing special case royalty relief. Prior to this analysis,

the SCRR discount rate for GOM shallow water was a maximum of 25 percent, while the rate for all other GOM areas was 10-15 percent.[1]

The Outer Continental Shelf (OCS) Lands Act provides that the Secretary of the Interior may develop rules and regulations to provide for the conservation of OCS resources. An advantage that the deepwater GOM has over other international basins is the presence of existing infrastructure which facilitates the development of smaller fields through the use of subsea infrastructure that "ties back" to an existing facility. Subsea tiebacks have proven to be an important technology in the GOM, as they facilitate the development of marginal deepwater GOM resources that are potentially at risk of being stranded because their resource bases are too small to justify standalone infrastructure at current economic conditions. However, there are marginal resources that, given the distance and specific reservoir properties, cannot be tied back using traditional tieback methods and may require enhanced flow assurance solutions, such as subsea boosting, to allow for the tieback. This introduces additional complexities. To compensate for the added risks, developers will require a higher rate of return in order to move forward with these projects.

Further complicating the tieback of these marginal resources that may require enhanced flow assurance technology is the fact that many existing GOM production facilities are nearing the end of their permitted design life. While BSEE can extend the permitted life of facilities and their components as long as engineering and safety parameters are met, once infrastructure is removed, it is unlikely that similar infrastructure will be re-installed in the same location in the future because of the significant costs involved.

In this report, BOEM presents its research and recommendations regarding the appropriate discount rates to use when computing the net present value of cash flows within SCRR applications for deepwater subsea tiebacks requiring enhanced flow assurance technologies, as defined in Section 1.1. BOEM recommends that companies should self-report discount rates, but that BSEE should impose a 20 percent upper bound on reported discount rates for new deepwater oil and gas wells that connect to existing production facilities using subsea tieback configurations requiring enhanced flow assurance technologies. This recommendation was developed using preliminary guidance from BSEE regarding what projects would qualify for the higher discount rate. The requirements and evaluation of a project's qualifications for approval will ultimately be determined by BSEE. However, BOEM's evaluation sets the discount rate only for deepwater wells that will be tied back to an existing facility and require enhanced flow assurance technologies, and not other wells that may be associated with the project. This recommended discount rate policy would allow companies to earn appropriate rates of return for these technologically riskier projects while protecting the government's right to receive fair amounts of royalty payments.

[1] BOEM publishes the discount rate recommendations and other economic parameters on its website: https://www.boem.gov/oil-gas-energy/energy-economics/royalty-relief/royalty-relief-information.

Chapter 1: Introduction

Section 1.1: Project Background

BOEM sets royalty rates for oil and gas leases in federal waters. Fiscal terms are set on a sale-by-sale basis and have been adjusted over the years. Both shallow and deepwater leases have historically been issued with royalty rates of 12.5 percent, 16.67 percent, and 18.75 percent. For leases issued from sales held in years 1996 through 2000, Congress provided for royalty suspension volumes (i.e., specified volumes of royalty-free production) in the Deepwater Royalty Relief Act of 1995 for water depths 200 meters or deeper in order to encourage the growth of deepwater development in the GOM. In 2020, both GOM lease sales included a 12.5 percent royalty rate for leases in water depths less than 200 meters and an 18.75 percent royalty rate for leases in water depths of 200 meters or more.

Royalties help ensure the public receives a fair return for the development of OCS conventional energy resources. However, situations can arise in which companies are unwilling to develop certain oil and gas resources at the prevailing royalty rate because doing so would not yield a sufficient rate of return to be considered economic. In these situations, an operator may apply for certain types of royalty relief.[2] BSEE administers discretionary royalty relief programs using the economic parameters outlined by BOEM.[3]

Operators of existing leases may apply to BSEE to obtain SCRR under 30 CFR 203.80 for certain oil and gas development activities. When analyzing SCRR applications, an important consideration is the extent to which royalty relief would make the project viable by shifting it from being uneconomic while paying lease-stipulated royalties to economic with royalty relief. Therefore, reviews of SCRR applications generally include estimates of the profitability of the project with and without royalty relief. A key component of these determinations is an interest rate (or discount rate) used to compute the net present value (NPV) of expected cash inflows and outflows. A discount rate accounts for the time value of money, as well as the uncertainty associated with future cash flows. In general, the higher BSEE sets the discount rate, the more royalty relief would be required to make a particular project profitable. The appropriate discount rate should facilitate the development of oil and gas resources by recognizing the risks of a particular project and of stranding publicly-owned resources, while still providing fair market value to the government.

Significantly more exploration and development occurs in the federal deepwater GOM region than the shallow water region and, unlike in shallow water, significant resources remain in the GOM deepwater area and it remains attractive for bidding and exploration (IHS Markit 2018). However, smaller deepwater resources may not be profitable to develop. Even as technology improves, making these smaller resources accessible at lower costs, they are likely to be bypassed in favor of larger or more lucrative resources. Therefore, such marginal resources may remain stranded.

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[2] More information regarding royalty relief programs is available at: https://www.boem.gov/Royalty-Relief-Information/ (BOEM 2020).

[3] The royalty relief division of duties between BOEM and BSEE are described in the Royalty Relief Memorandum of Agreement, available at: https://www.bsee.gov/sites/bsee.gov/files/interagency-agreements-mous-moas/deepwater/moa-2011-royalty-relief.pdf. The economic parameters are those referenced in footnote 1.

To conserve deepwater marginal resources that would otherwise likely be stranded, as well as extend the useful life of existing GOM infrastructure with idled capacity, these resources can be tied back to existing facilities. However, given distances and specific reservoir properties, some of these subsea tiebacks may require enhanced flow assurance technologies. These complex systems entail risks, such as cost variability and the risk of operational problems, that increase with the tieback length. As such, a higher rate of return may be required to make these marginal projects economic.

BSEE asked BOEM to research the discount rate used in SCRR evaluations for projects including subsea tiebacks that require enhanced flow assurance technologies. In this context, a project would consist solely of any new deepwater development wells (project may also include exploratory wells) connected to an existing production facility using a subsea tieback requiring enhanced flow assurance technologies, even if, from the company's perspective, it was part of a larger, existing project. BSEE suggested that the SCRR program with the correct discount rate could be effective in preventing the stranding of resources, which is described in more detail in Section 3.6. (project may also include exploratory wellsor development)

More specifically, for the purposes of this analysis, "deepwater subsea tiebacks requiring enhanced flow assurance technologies" refer to connections of new wells to existing production facilities that meet the following criteria: (1) there is no closer facility to which the operator has access that can be efficiently utilized; (2) all wells in the project require subsea enhanced flow assurance technology for optimal recovery, as defined and verified by BSEE (for example, subsea pumping); (3) the subsea enhanced flow assurance technology must already be extant (e.g., it cannot be part of a research project); and (4) the water depth at the well location must be greater than 650 feet (200 meters), such that the well(s) must be in deepwater, but the host facility could, in theory, be located in shallow water. Throughout the remainder of this paper, the phrase "deepwater subsea tiebacks requiring enhanced flow assurance technologies" or "deepwater subsea tiebacks requiring EFAT" shall refer to this definition ("EFAT" being shorthand for "enhanced flow assurance technologies").

This paper provides BOEM's research, analyses, and recommendations regarding the appropriate discount rates to use when evaluating SCRR applications for deepwater subsea tiebacks requiring EFAT, as defined above:

- Section 1.2 shows how alternative discount rates can affect the NPV of an oil and gas project;
- Chapter 2 describes subsea tieback and flow assurance technology and how it can be used to address the unique challenges of each project;
- Chapter 3 provides a theoretical framework for determining and understanding the appropriate discount rate and then focuses the framework on the case of marginal resources accessed using deepwater subsea tiebacks requiring EFAT;
- Chapter 4 describes the available data regarding discount rates;
- Chapter 5 provides BOEM's analysis regarding the appropriate discount rate, with Section 5.1 outlining BOEM's recommendations and Section 5.2 describing important considerations for its implementation; and

- Chapter 6 summarizes BOEM's findings and recommendations.

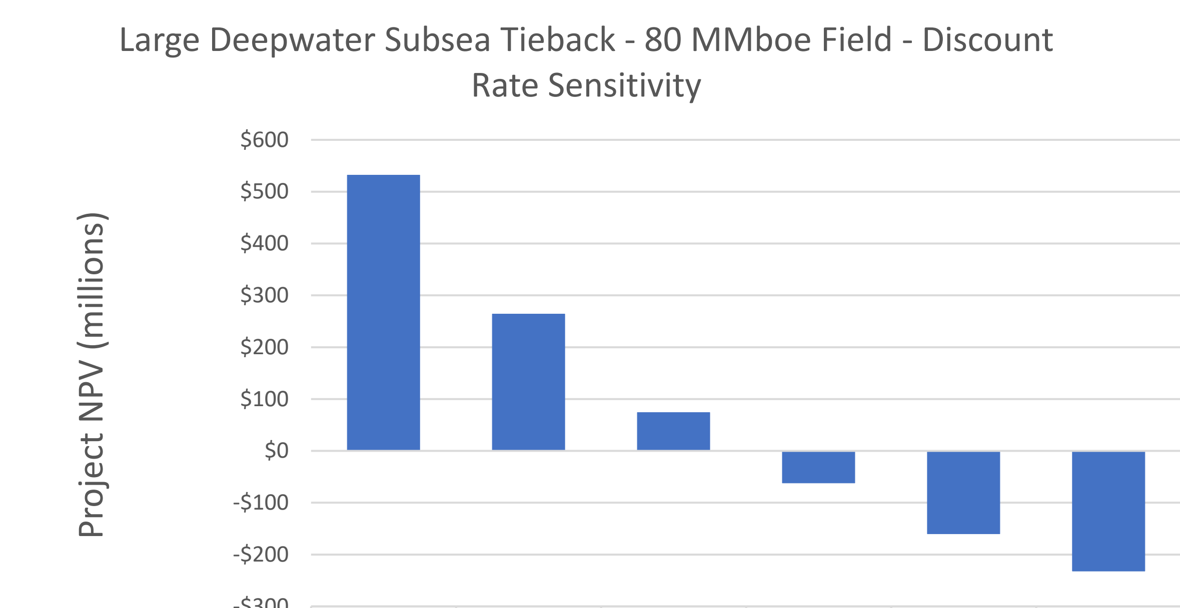
Section 1.2: Numerical Illustration of Discount Rates Impacting Net Present Value

Discount rates have significant impacts on oil and gas project evaluations. This section presents a numerical example of how discount rates can affect profitability, which informs the analyses in subsequent sections.

$$NPV = \sum_{t=1}^{T} \frac{Expected\ Cash\ Flows}{(1+DR)^t} \qquad \text{(Equation 1)}$$

In Equation 1, NPV is computed by applying a discount rate (DR) to expected cash flows in each time period (t), and then summing the values for each time period. Figure 1 displays the NPV of a hypothetical 80 MMboe (million barrels of oil equivalent) deepwater subsea tieback project using discount rates ranging from 5-30 percent. As the discount rate increases, the NPV of a project decreases. Therefore, as higher discount rates are applied to cash flow analysis, more royalty relief would typically be required to change the project's NPV to zero. For the sample project in Figure 1, a five-percentage point change in the applied discount rate can change the project NPV by hundreds of millions of dollars, all else being equal. Though this 80 MMboe tieback represents a larger tieback, the results would be similar regardless of project size.

Figure 1: Example Regarding Discount Rates and NPVs



	5%	10%	15%	20%	25%	30%
NPV with 18.75% Royalty	$532	$264	$74	-$62	-$160	-$232
Royalty Rate*	18.75%	18.75%	18.75%	14.08%	4.39%	0.00%
Lifetime Royalties (millions)	$621	$621	$621	$484	$199	0

*Royalty rate at 20 percent and 25 percent discount rates is the reduced royalty rate required to make this project economic (with an NPV of 0). With a 30 percent discount rate, this project is not economic with any amount of royalty relief.

Royalty relief is granted in the amount necessary to result in a project becoming economic, or more precisely, to have a zero NPV at the designated discount rate. A higher discount rate will generally reduce the NPV of an oil and gas project and require a larger amount of royalty relief to make the project economic. However, there is a limitation on the extent to which royalty relief can offset a negative NPV. At very high discount rates, reducing the royalty rate, even to zero percent, may not be sufficient to bring a project NPV to zero. For the hypothetical project in Figure 1, the project has a positive NPV at 5 percent, 10 percent, and 15 percent discount rates, making it ineligible for royalty relief by regulation. If a 20 percent or 25 percent discount rate is applied to the project with a royalty rate of 18.75 percent, the project would be uneconomic and would necessitate royalty relief. If the project were evaluated with a 20 percent discount rate and royalty relief were provided in the form of a reduced royalty, the royalty would be reduced to 14.08 percent, making the NPV zero. If it were evaluated with the 25 percent discount rate, the relief would be granted by reducing the royalty rate to 4.39 percent. At a 30 percent discount rate, a royalty rate of 0 percent would not be enough to make the project economic (with a 0 NPV). For this example, the hypothetical maximum discount rate that could be used to provide royalty relief to the project would be 27 percent, as it generates a zero NPV with a reduced royalty rate of 0 percent.

Given that revenue and expense forecasts provided by operators are verified by BSEE, royalty relief is provided in the precise amount required to change the NPV of a project from negative to zero NPV. This highlights the importance of applying an appropriate discount rate that allows BSEE to assess whether royalty relief is necessary and if so, to grant an amount of relief that allows a company to earn an appropriate rate of return (while protecting the government's right to receive fair market value from royalty payments). BOEM provides the discount rate as a range, or up to a maximum rate, so that companies can self-report the discount rate at which they would like their project evaluated.

Chapter 2: Subsea Tieback Technology

Generally, a subsea tieback refers to an offshore oil and gas production system designed to move hydrocarbons produced from a subsea well or field of wells over some distance before being lifted to a central fixed or floating surface production facility. They are an alternative solution for gathering production, enabling operators to avoid additional satellite surface infrastructure. It is not a new approach; the first subsea wellhead in the GOM was installed in 1961. However, without additional subsea processing equipment, tieback distances are constrained because flow complications arise over longer distances as the hydrocarbons travel en route to the processing facility. This distance limitation can and has been overcome with additional subsea component technology and strategies. The ability to gather production over extended distances is an attractive strategy for developing discovered, but otherwise marginal, resources (i.e., those that do not meet the criteria for a standalone development), and extending the useful life of existing GOM infrastructure with idled capacity.

Installation and startup of these systems are generally more complicated than installation and startup of conventional facilities. All the components are on the seafloor, requiring service vessels with sufficient crane and ROV capabilities and operators with the relevant expertise. Because the components are generally less accessible once on the seafloor, they are engineered to be more robust and may be designed with modular components and production redundancies so that problems can be isolated and they can remain online in the event of a component failure. Other challenges, such as physical damage due to buckling and spanning for flowlines traversing varied topography over long distances, and infrastructure movement due to thermal cycling, can generally be mitigated in the design but must be monitored over time. Significant downtime can occur during installation or production if redesigned or replacement parts need to be engineered and fabricated. Once operational, the system should require minimal direct intervention, with the operator relying on remote monitoring and interaction with the various components.

Conventional tiebacks generally rely on the native reservoir pressure to produce the oil and gas back to the processing facility. Due to this reliance, the flow distance is physically limited; conventional tie-back distances are highly dependent on the specific properties of the reservoir and its fluids. Produced fluids are not a single homogeneous chemical composition, but a mixture of different hydrocarbon compounds with properties and phase behaviors that change at varying pressures and temperatures. At high reservoir pressures and temperatures, compounds that are normally solid at standard conditions flow as a liquid and those which are normally gaseous are dissolved into the hydrocarbon solution. After exiting the well, these hydrocarbons travel through the subsea flow line, and begin cooling as they are exposed to the low temperature environment of the sea floor. The result of this pressure and temperature decline can lead to changes in some of the hydrocarbon phases, which will often cause hydrate formation, wax deposits, or other solid deposits within the flow line. Shorter tieback distances are able to produce their fluids prior to significant formation of these deposits. However as distances increase, these complications along with multiphase fluid flow instability (aka, slugging) can introduce serious flow assurance challenges.

Industry has, in large part, developed technologies[4] and strategies to overcome these flow assurance challenges. Rather than a single approach, however, these solutions are engineered on a case-by-case basis and generally consist of a combination of technologies used in concert to solve the specific challenges the tieback system is presenting. Though not currently considered proven for use in the Gulf of Mexico, these technologies can include electrically-heated pipe and improved flow line insulation materials to improve thermal performance. Configuring the subsea lines and manifolds with looping capabilities can also be an effective strategy to maintain fluid flow in the system during a production shutdown. Despite these, chemical injection and improved pipeline scraping (aka, pigging) capabilities may still be necessary in some cases to preserve fluid flow. Ultimately, deploying subsea oil and gas separation (subsea processing) may be preferable, as it may address many of the fluid complications early in the production system, before they become an operational problem. However, this approach requires significant additional subsea components, including robust production-handling manifolds and fluid pumping and gas compression capabilities. The subsea system must also have reliable monitoring capabilities, so the operator can effectively manage the various system componentry. Additional considerations must also be given to the host infrastructure, which must be able to support the power, storage, and communication needs of these

[4] The technologies in this chapter are discussed generally and BSEE may or may not consider them proven for use in the United States. If BSEE chooses to implement a SCRR program for deepwater subsea tieback projects with EFAT, operators should defer to BSEE guidance that specifically outlines the acceptable technologies, strategies, and cost requirements necessary for a project to qualify.

system elements, particularly the electrical power requirements for any subsea gas compression and fluid pumping equipment, which can be significant. This becomes further complicated as distances and water depths cause those needs to grow.

Tieback projects which implement some or all these strategies may not be turnkey and could require additional fine-tuning to balance the multiple components of the system to stabilize production within a sustainable operational envelope. Additionally, the production fluid properties may change over time as the reservoir draws down, necessitating further adaptation. Finally, production shutdowns for any reason can cause their own challenges when trying to bring the system of cooled, static fluid back online.

Despite the complexity, subsea tieback systems can be a successful production solution where surface infrastructure is not desired, feasible, or economic. They are particularly attractive in the GOM, where significant areas can be reached from existing surface infrastructure with available capacity using these methods, thereby preventing the stranding of resources and extending the economic life of the surface facilities. Still, they require a thorough understanding of the reservoir fluid properties, and at longer distances require novel technological approaches to implement effectively. At these long distances, performance and reliability may be a source of technological risk and uncertainty for the operator.

Chapter 3: General Discussion of Discount Rates

Section 3.1: Introduction

This chapter provides a theoretical framework for determining and understanding the appropriate discount rates in the context of SCRR applications and describes how various risks faced by deepwater operators targeting marginal resources using subsea tiebacks requiring EFAT influence the discount rate necessary for a company to select a project.[5]

Businesses typically determine which projects to pursue by assessing the size and timing of expected cash inflows and outflows. The timing of cash flows is important because money received sooner is more valuable than money received later. In addition, the owners of businesses prefer certainty and seek to minimize risk regarding the size and timing of cash flows. As the cash flows from oil and gas projects are subject to numerous uncertainties, businesses need a framework for valuing these uncertain cash flows. A common framework is to use risk-adjusted discount rates (RADRs), which entails applying higher discount rates for riskier projects.[6]

$$\mathrm{RADR} = \mathrm{WACC} + \mathrm{IHR} + \mathrm{RA} \qquad \text{(Equation 2)}$$

[5] This paper generally refers to nominal discount rates, which do not remove expected inflation. One can convert nominal discount rates to real discount rates (which do remove expected inflation) as:
Real discount rate = [(1+ nominal discount rate)/(1 + expected inflation rate)] -1
(where all variables are entered as decimals).

[6] An alternate approach is to discount cash flows using a lower discount rate than in Equation 2, and to then to decrease the resultant net present value by a reserve adjustment factor (Society of Petroleum Evaluation Engineers 2020). There has also been some research regarding the use of option theory related to oil and gas projects, but these methods are not often used in practice (Dickens and Lohrenz 1996).

Inkpen and Moffett (2011) decompose discount rates as shown in Equation 2, where:

- RADR: Risk-adjusted discount rate applied to expected cash flows
- WACC: Weighted average cost of capital
- IHR: Incremental hurdle rate
- RA: Risk adjustment

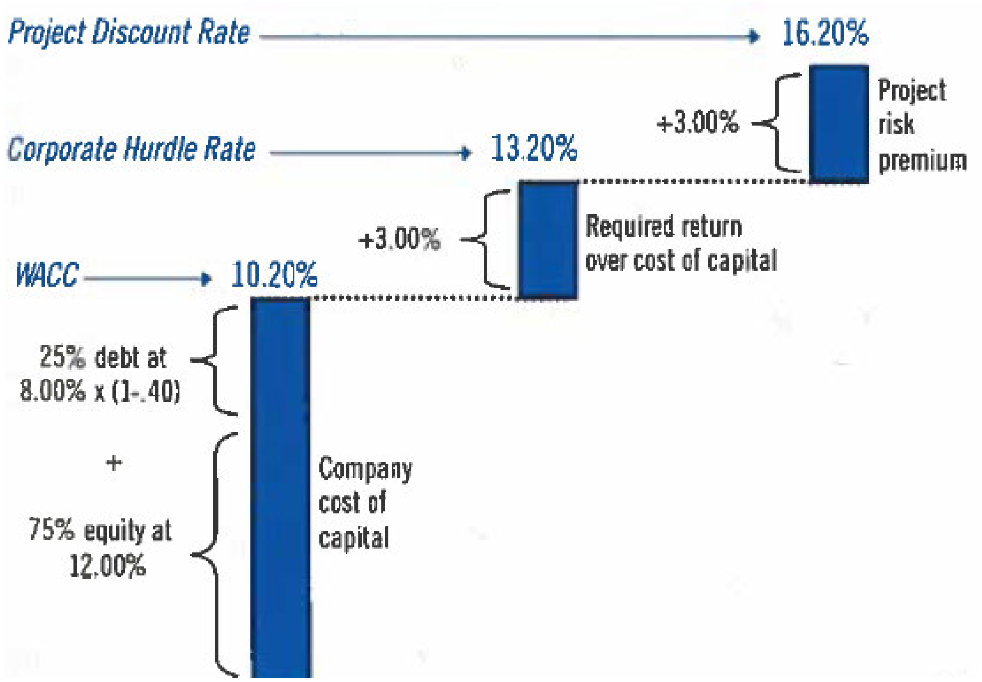
This equation shows that companies will expect to earn at least as much as their weighted average cost of debt and equity capital (WACC). In addition, if companies have multiple profitable investment opportunities (and a limited budget), they will require more than the WACC in order to pursue an average-risk project, which is referred to as the incremental hurdle rate (IHR). Finally, a project, particularly one for which royalty relief would be requested, likely faces additional risks compared to a company's average project. These risk adjustments are project specific, but in general, the probability of profit for any marginal project is more sensitive to variable deviations (such as resource size and prices) from their expected values. This is true for marginal deepwater projects using subsea tiebacks requiring EFAT, as well as other marginal projects.

Additionally, as discussed in Chapter 2, the greater complexity associated with deepwater subsea tiebacks requiring EFAT makes performance and reliability greater sources of risk for operators and these risks generally increase with the tieback length. As a result, marginal resources developed using deepwater subsea tiebacks requiring EFAT will be subject to additional risks due to the technical and economic complexities that require the use of enhanced flow assurance technology in conjunction with subsea tiebacks. Therefore, businesses will likely require a higher discount rate to compensate for these risks.

Figure 2 presents a hypothetical example from Inkpen and Moffett (2011) regarding the components of a risk-adjusted discount rate. In this example, an oil and gas company is analyzing the profitability of a particular project. The company is financed by 75 percent equity and 25 percent debt. If the cost of equity is 12 percent, the cost of debt is 8 percent, and the corporate tax rate is 40 percent, the weighted average cost of capital of these funding streams is 10.2 percent (see Section 3.2 for more information).[7] Due to competing investment projects, this company has an average incremental hurdle rate of 3 percent (and a total corporate hurdle rate of 13.2 percent). Finally, the particular project under consideration is riskier than the company's average project, so the company adds a 3 percent percent risk premium. This yields a total project discount rate of 16.2 percent. Therefore, this company will use a discount rate of 16.2 percent to compute the net present value of cash flows from this project.

[7] The current corporate tax rate is 21%. If this 21% corporate tax rate were applied to the example in Figure 2 (and assuming other variables did not change), the WACC would equal 10.58% (and the project discount rate would equal 16.58%). The WACC would increase because there would be less of a tax shield associated with debt financing (see Section 3.2).

Figure 2: Components of a Risk-Adjusted Discount Rate



Source:Inkpen and Moffett (2011)

Section 3.2: Weighted Average Cost of Capital

The first component in the RADR is the weighted average cost of a company's debt and equity financing, the WACC. A company expects to earn at least the weighted average cost of its debt and equity financing in order to undertake the project. In this circumstance, the project would be low risk (i.e., no RA) and, potentially, one of very few available to the firm if a project's RADR is composed solely of the WACC (i.e., no IHR).

$$WACC = \left(\frac{E}{V}\right) R_E + \left(\frac{D}{V}\right) R_D(1 - T_C) \qquad \text{(Equation 3)}$$

Equation 3 is the formula for the WACC (Corporate Finance Institute 2019), where:

- E: Market value of total equity
- D: Market value of total debt
- V=E+D (the total market value of debt and equity combined)
- RE: Cost of equity
- RD: Cost of debt
- TC: Corporate income tax rate

As discussed in the Shallow Water Recommended Discount Rate paper (BOEM 2019), the first part of Equation 3 is the portion of a company's cost of capital represented by required returns on equity. In particular, equity investors will require a rate of return commensurate with a company's collective risk profile. There are numerous risks associated with oil and gas projects, such as price volatility, uncertainty regarding resources, and variability of input costs. Since investors often can diversify their equity holdings, a common assumption is that equity investors will only receive compensation for risks that cannot be eliminated through diversification.[8] However, given the numerous sources of uncertainty for oil and gas companies, as well as the interdependence between energy markets and the broader economy, many of the risks cannot be diversified away.

The second part of Equation 3 represents the cost of debt financing (since debt interest payments are tax deductible, one considers the after-tax cost of debt financing). One can roughly think of the cost of debt as the sum of a risk-free interest rate, often approximated by the interest rate on a U.S. Treasury bond or bill, plus a premium to compensate lenders for the possibility that some or all of a loan may not be paid back on schedule. U.S. Treasury yields have been low in recent years. However, given the various risks associated with oil and gas development, lenders often require a sizable risk premium.

Both of these components within the WACC equation are different for deepwater subsea projects with flow assurance issues than they are for shallow water projects. First, in regards to the return on equity, companies undertaking deepwater subsea tieback projects requiring EFAT are publicly-held companies, which gives them a greater ability to diversify their risks than companies operating in the shallow water GOM. Therefore, the required return on equity capital for deepwater oil and gas firms is not expected to be as high as for shallow water oil and gas firms.

Similarly, for the second part of the equation, it is likely that companies operating in shallow water have a greater cost of capital due to the riskier nature of shallow prospects, and these smaller-sized companies generally possess less equity, more debt, and fewer assets in their portfolios. This is less likely to be true, however, for larger firms operating in deepwater. Firms that operate in the deepwater GOM are generally large conglomerates with a significant amount of capital, booked reserves, or tangible assets. So, again, one would expect this portion of the WACC to be lower for deepwater companies than for shallow water companies.

Section 3.3: Incremental Hurdle Rate

At any point in time, oil and gas companies are likely considering several potential projects. The minimum requirement for these projects is that they yield a return that is greater than (or equal to) the WACC, assuming there are no risk adjustments necessary. However, in many cases, a company will have multiple profitable projects under consideration. A company may be able to obtain additional funding to pursue more or all of these projects, but to the extent a company is unable or unwilling to do this, the company will apply a framework for deciding which projects to pursue. In the context of understanding discount rates, an appropriate framework is an incremental hurdle rate that represents the rate of return above the WACC that would induce a company to undertake a particular project relative to other projects. This incremental hurdle rate will thus vary through time

[8] This is the core assumption of the Capital Asset Pricing Model, a widely-used framework for determining required rates of return (Sharpe 1964). Other theories of asset prices incorporate additional factors in their models, such as a company's size and the ratio of a company's book equity to its market equity (Fama and French 1993).

given market conditions. For example, given the current low price environment, it is likely that firms have fewer profitable investment projects available to them than they would in a high price environment. It is even possible that some firms may not be willing to take on new projects until prices go up, relying instead on the production of existing projects. Therefore, all else being equal, the incremental hurdle rate will be lower given the low prices currently prevailing because there would be fewer profitable alternatives available.

In practice, many factors may influence oil and gas investment decisions. For example, the size of the project (and the resulting overall profits earned) will be an important factor. Marginal deepwater projects are, by definition, expected to be smaller than other deepwater projects and thus may not be as lucrative, particularly if the projects are mutually exclusive.[9] It is possible that some marginal deepwater projects may never prove profitable enough to induce investment when there are so many other larger or more lucrative resources available in deepwater. Therefore, all else being equal, an average company will require a higher rate of return for a marginal deepwater project. However, the size of the oil and gas company may also affect its incremental hurdle rate. In particular, large companies may require a higher incremental hurdle rate than smaller companies because large companies have more (and larger) investment options. This has resulted in a trend of major oil and gas companies leaving the shallow water GOM to focus on larger projects such as those in the deepwater GOM or elsewhere in the world that offer more potential upside. This further supports the possibility of the large firms that primarily operate in the deepwater GOM permanently bypassing marginal deepwater projects in favor of larger, more profitable projects.

Companies may also choose projects that recover their costs more quickly than other projects. In general, deepwater projects recover their costs more slowly than both shallow water projects and onshore projects, putting them at a relative disadvantage. On the other hand, spillover effects from a particular project to other future projects can influence development decisions. For example, pursuing a particular oil and gas project could position a company to pursue similar or nearby projects in the future through cost efficiencies or technological improvements. Subsea tieback technology is at the cutting edge of innovation in the offshore oil and gas industry. As subsea technology continues to mature, it will allow firms to access resources further from existing host facilities, and more efficiently and inexpensively at any given distance. Additionally, existing subsea tieback structures could potentially be used as part of tiebacks to future wells. In some cases, this could make subsea tieback projects, potentially even deepwater subsea tiebacks requiring EFAT that involve (or are expected to involve, in the case of exploratory wells) marginal resources, more attractive relative to other projects.

Given the various factors discussed above, the extent to which a marginal deepwater project requires a higher or lower incremental hurdle rate than other projects will depend on the unique cirumstances of each project/company combination.

[9] Although, it is possible that some projects expected to be marginal that initially require exploratory wells could instead be larger and more profitable than original anticipated. This cannot be known ex ante, however, only ex post.

Section 3.4: Risk Adjustment

The discount rate for SCRR applications should account for the risks associated with deepwater subsea tiebacks requiring EFAT. Projects that would potentially qualify for royalty relief are, by definition, only marginally economic or uneconomic (due to some combination of limited oil and gas resources and high production costs). Therefore, the likelihood that these projects will be profitable is sensitive to any deviations of economic variables (such as market prices, discovered resources, and development costs) from their projected values.

The risk adjustment considers the uncertainty of the oil and gas resource characteristics, including the size, quality, and costs of extraction. The risk adjustment for deepwater subsea tiebacks requiring EFAT should account for the fact that the marginal resources will require expensive technologies to provide the necessary flow assurance back to host facilities. It should also account for the potential complexity of subsea tieback systems. Compared to shallow water with its small remaining resources, the potential upside to developing a deepwater project is greater. However, the requirements and conditions of the SCRR application process will prevent excessive royalty relief (i.e., more than is truly necessary to make a project economic) from being provided in that event.

Finally, there is an inherent risk with deepwater subsea tiebacks requiring EFAT that increases with length. As discussed in Chapter 2, subsea tiebacks are complex systems that can increase performance and reliability risks, particularly over longer distances. The longer the tieback, the greater the length along which a problem could occur, such as an object damaging the installation. Similarly, greater length increases the risks associated with maintaining flow and the demands on host infrastructure. Additionally, although individual components of a subsea system may be modular, the overall subsea tieback system may be less flexible, particularly more complex systems. System complexity is itself driven, in part, by subsea tieback length. Therefore, when something goes wrong with a deepwater subsea tieback requiring EFAT, there may not be an alternative method to access the production well, increasing the impact of any unscheduled downtime. And, because the equipment is installed primarily on the sea floor, addressing problems can be more difficult and costly.

In summary, the discount rate for deepwater subsea tiebacks requiring EFAT should be adjusted upwards compared to other deepwater projects to account for these risks, yet should be lower than for shallow water projects. The comparisons with shallow water projects have been touched on throughout this section but will be tied together in Section 3.5.

Section 3.5: Shallow Water Comparison

The material presented so far has supported raising the SCRR discount rate for deepwater subsea tiebacks requiring EFAT above the current level for deepwater in general. However, it has also clearly indicated that the appropriate discount rate for deepwater subsea tiebacks requiring EFAT should be lower than the 25 percent rate set for shallow water in the Shallow Water Recommended Discount Rate paper (BOEM 2019).

The type of company operating in shallow water is fundamentally different from deepwater and these differences lead to a different WACC. Companies operating in shallow water differ from those operating in deepwater in two key ways: (1) they tend to be privately-held; and (2) they tend to be significantly smaller. Smaller companies generally possess less equity, more debt, and fewer assets in their portfolios and privately-owned companies are less able to diversify their risks. Both of the factors increase the WACC—(1) requires the return on equity to be higher and (2) requires the return on debt to be higher. Therefore, companies in shallow water require both portions of WACC return to be higher than deepwater firms.

There are competing influences on the IHR. It is possible that marginal deepwater resources may be somewhat more desirable when considering multiple projects than a marginal shallow water project, which has virtually no probability of a large upside return. On the other hand, deepwater projects recover their costs more slowly than shallow water projects and that is generally less desirable to companies. Therefore, it is not entirely clear whether the IHR for deepwater subsea tiebacks requiring EFAT would be significantly different than for shallow water.

The probability of profit due to size of the resource also sets the two types of projects apart, as reflected in the risk adjustment. The probability of profit for a marginal project is sensitive to deviations of variables from their expected values (for example, resource size) regardless of whether the project is in the shallow water GOM or a deepwater GOM project using subsea tiebacks requiring EFAT. However, the possibility of a field being small is much higher in the more mature shallow water GOM, resulting in a higher risk-adjusted discount rate for shallow water than for deepwater subsea tiebacks requiring EFAT.

Based on this, BOEM can conclude that although the SCRR discount rate for deepwater subsea tiebacks requiring EFAT should be raised above the current 10-15 percent level, it should not be as high as the 25 percent rate for shallow water, based on the lower value for the WACC and RA portion of the RADR at minimum. This general understanding is carried into the next Chapter where the available data is presented and discussed.

Section 3.6: Societal Considerations

The analysis of discount rates in prior sections focused on discount rates used by oil and gas companies when making investment decisions. This is appropriate because companies ultimately determine whether to pursue certain projects, and because federal policy regarding this issue has typically focused on the extent to which royalty payments (and the resulting royalty relief) determine whether a project is economic to pursue. However, as discussed in the Shallow Water Recommended Discount Rate paper (BOEM 2019), when considering policy decisions, it is appropriate to consider the costs and benefits of policy options from the perspective of society as a whole. In the analysis of discount rates, a societal viewpoint highlights the effects of oil and gas industry decisions on other actors in the economy. A societal viewpoint also highlights the risks of setting the discount rate too high or too low.

When an oil and gas company undertakes a discounted cash flow analysis in its decision-making process, it does not incorporate numerous effects on society as a whole. Some of these effects are beneficial, such as increased government revenues, lower energy prices, less dependence on substitute energy sources, and less economic inefficiency due to fewer stranded resources. Other effects, such as potential environmental impacts, may be negative (depending on the alternatives). An important issue that is not sufficiently captured in an individual company's analysis is the possibility that marginal resources in deepwater may remain permanently stranded because companies will opt to place limited development resources towards larger or more lucrative deepwater prospects. Additionally, because oil and gas companies are not considering spare capacity at existing facilities, the possible removal of those facilities, or the risk that not using the facilities while they are still operational to access marginal resources, the resources are less likely to be developed in the future.

The OCS Lands Act authorizes the Secretary of the Department of the Interior to issue regulations in the interest of conservation of OCS natural resources.[10] Conservation of OCS resources promotes economic efficiency, and from an economic perspective, it would be preferable for leasing, development, and production activities to be carried out in a manner that increases the net economic value to society from the development of OCS resources.

In the context of marginal GOM deepwater subsea tiebacks requiring enhanced flow assurance development, conservation of resources is a concern because the existing facilities that could host tiebacks are required to be removed at the end of their design life unless an extension is granted, assuming the facility meets engineering and safety parameters. BSEE estimates that 48 percent of GOM average daily oil production from deepwater facilities (facilities in water depths greater than 200 meters) have less than 10 years of remaining permitted design life and that approximately four out of five deepwater facilities are producing at rates less than 50 percent of their daily oil nameplate capacity. Based on that data, BSEE estimates that by 2025, 32 percent of deepwater facilities, representing 24 percent of GOM average daily oil production, are scheduled to reach the end of their permitted design life. Further, BSEE asked BOEM to estimate the contingent resources within 30 to 60 miles of deepwater GOM facilities as these could be targeted by subsea tiebacks with EFAT. BOEM estimates that there are approximately 4.5 billion barrels of oil equivalent (BOE) of contingent resources in this 30 to 60 mile band around existing platforms. Additional information on facility utilization rates is available in Appendix A.

Once infrastructure is removed, it is unlikely that similar infrastructure will be re-installed in the future because of the significant costs involved. Therefore, oil and gas companies, and society as a whole, may eventually lose the option to develop some marginal deepwater resources even if economic conditions become more favorable in the future. To the extent that technology continues to develop toward longer, more efficient subsea tiebacks, more distant facilities could become suitable for tieback. However, in that event, larger deepwater resources would still be relatively more attractive to developers, likely leaving marginal resources undeveloped. Therefore, one can view the determination of discount rates as a policy lever to better account for these societal interests.

It is also important to consider the risks to society of setting discount rates too low or too high. If the government sets discount rates too low, certain projects may not be pursued (that may have

[10] 43 U.S.C. § 1334(a)

been pursued if appropriate discount rates were used) and resources may become stranded. As mentioned previously, society may also lose the value of the option to develop certain marginal deepwater oil and gas resources in the future. If the government sets discount rates too high, it will encourage royalty-relief applications for projects that would have proceeded without royalty relief. Thus, the government could lose royalty revenue. In addition, for very marginal projects, setting the discount rate too high may lead to the conclusion that no amount of royalty relief would make these projects economic, and thus the projects would not be pursued. These effects highlight the need to select discount rates that appropriately balance society's varied interests.

Chapter 4: Analysis of Data Sources for Discount Rates

The discount rates the government uses for evaluating SCRR applications should be similar to the rates companies use when evaluating similar upstream oil and gas investment opportunities. Unfortunately, the discount rates companies use, and the evaluation techniques they employ, differ across companies and are proprietary. There are several methods for estimating companies' discount rates. These methods include (1) measuring the cost of capital from financial data, (2) estimating the average return on upstream oil and gas investments, and (3) surveying companies to elicit their discount rates. There are various data and confidentiality limitations regarding methods 1 and 2. Therefore, this Chapter will summarize the available data from surveys and related reports. Section 4.1 will describe discount rate data from the Society of Petroleum Evaluation Engineers (SPEE). Section 4.2 will discuss other useful data sources. The data sources and data have been re-examined, expanded, and updated where appropriate to reflect new information that has emerged since the Shallow Water Recommended Discount Rate paper (BOEM 2019). Section 4.3 analyzes the entirety of the data presented.

Section 4.1: Society of Petroleum Evaluation Engineers Data

The SPEE conducts an annual survey of their members regarding upstream resource evaluation topics. The survey asks members a wide range of questions, including questions about SPEE member companies' RADRs used for different types of projects. BOEM acquired reports that summarized the data from the 2016, 2017, 2018, and 2020 surveys.[11] The majority of survey responses came from employees of either exploration and production companies or oil and gas consulting companies, whose job functions primarily entail property valuation, reserves estimation, or acquisition and divestiture activities. The surveys do not differentiate between offshore and onshore evaluation methods.

In the 2020 SPEE survey, nearly 81 percent of respondents were located in the United States, and the vast majority of them spent a significant amount of time evaluating resources in the United States. When asked for reasons why RADRs were used to evaluate assets, 78 percent of respondents stated that reserve risk made the use of RADRs appropriate in their evaluations. Other reasons that were cited in over 44 percent of responses include price uncertainty, expense uncertainty, mechanical risk, and political regulatory uncertainty.

[11] BSEE acquired the 2020 SPEE survey on behalf of BOEM.

The 2020 SPEE survey asked members for the actual RADRs used when evaluating projects by the categories of resources they target. As one would expect, the less certainty companies had regarding the volume of recoverable resources, the higher the RADR used to evaluate these projects. Creating asset decline curves and cash flow models is straightforward when the asset being evaluated is proved, developed, or producing. While there is risk involved with any investment decision, the reserve risk is mitigated when companies are more certain about the recoverable resource. This is why proved undeveloped reserves require a lower RADR than probable reserves. BOEM found the discount rate percentage for probable reserves the most applicable for shallow water projects in its Shallow Water Recommended Discount Rate paper (BOEM 2019), but believes that proved reserves provides a better comparison for deepwater resources accessed using subsea tiebacks that require EFAT. This is because there is substantial liklihood that a sufficient quantity of resources exist for deepwater projects that require EFAT. In addition, setting a unique discount rate for subsea tiebacks that require EFAT is a more targeted effort than BOEM's effort to set a general shallow water discount rate. While an operator may occasionally drill an exploratory well for subea tiebacks that require EFAT, BOEM feels it appropriate to develop a discount rate comparison for the primary targets of this policy (reserves that are very likely to exist). Therefore, BOEM used the proved reserves category for comparison purposes. Additionally, as discussed in other parts of this paper, there is strong evidence indicating that the discount rate for deepwater subsea tiebacks requiring EFAT should be lower than for shallow water.

The 2020 SPEE survey results show that the median RADR (the P50 value)[12] used for proved undeveloped reserves is around 20 percent. Similarly, the 2016 and 2017 SPEE surveys found that the median RADR used for proved undeveloped reserves was 20 percent and the 2018 survey shows results that appear to be very close to 20 percent but possibly slightly lower.

A limitation of the SPEE median RADR data is that some of the survey responses relate to RADRs used for purposes somewhat different from oil and gas exploration and development. For example, RADRs are also used for asset acquisitions and overall corporate valuations. The 2017 SPEE survey presented results for the different categories of use (the SPEE data for other years did not provide these breakouts). The 2017 SPEE data found that the mean RADR used for oil and gas field development was 19.5 percent (sample size=24), and the mean RADR used for decisions to drill exploration wells was 17.4 percent (sample size=20). However, there were wide ranges of RADRs used and this would presumably encompass the full range of reserve types.

Section 4.2: Other Data Sources

Limited data is available regarding the discount rates used by oil and gas companies. Apart from SPEE data, most data available comes from Wood Mackenzie, the state of Texas, and other countries.

The Texas Comptroller of Public Accounts (2020) calculates discount rates based on the weighted average cost of capital of 18 petroleum companies. The Texas Comptroller does allow discount rate adjustments for property-specific risk considerations. The average range of discount rates for 2020

[12] The probability that 50 percent of the results will be equal or greater than this result.

was 10.52 percent to 17.79 percent, a decrease from the 2018 rates of 14.62 percent to 20.81 percent. The Texas Comptroller specifies that the discount rate for offshore properties is 2 percentage points higher than the average discount rate, making the range 12.52 percent to 19.79 percent.

Oil and Gas Journal (2018) provides discount rate data from Wood Mackenzie's 2017 and 2018 annual surveys of upstream oil and gas companies.[13] The discount rates for various project categories in 2017 and 2018 were:

- Unconventional projects: 14.0 percent in 2017; 14.1 percent in 2018
- Deepwater projects: 15.9 percent in 2017; 14.8 percent in 2018
- Exploration projects: 15.8 percent in 2017; 14.8 percent in 2018

The Oxford Institute for Energy Studies (2019) emphasizes the risks of oil and gas projects in the context of a long-run transition towards renewable energy sources. This study cites survey results that a deepwater project has an average 18 percent discount rate.

Other countries also use discount rates to help calculate companies' discounted cash flows. The United Kingdom surveyed companies in 2017 and 2018 calculating out a "satisfactory expected commercial return" (SECR). The United Kingdom aims to maximize the expected net value of economically recoverable petroleum. The Oil and Gas Authority (OGA), the U.K.'s regulatory authority, sets discount rates based on the WACC. The current discount rate OGA sets for the U.K. Continental Shelf is between 5 percent and 12.75 percent in nominal terms. The OGA has found this is reflective of companies operating on their Continental Shelf and equivalent to a 10 percent real discount rate.

Section 4.3: Analysis of Available Data

The SPEE surveys (for 2016, 2017, 2018, and 2020) provide the most detailed discount rate data. These surveys report that the median discount rate used for proved undeveloped reserves (the category just below the one used for shallow water) was approximately 20 percent. While informative, some of the survey responses related to discount rates for uses other than oil and gas exploration and field development. The 2017 SPEE survey was the only survey to provide discount rates specifically for these categories. The 2017 SPEE survey found that the mean RADR used for field development was 19.5 percent and the mean RADR used for exploration wells was 17.4 percent, but this likely includes more than just proved undeveloped reserves.

These mean values are roughly consistent with the the rates from the Texas Comptroller (Texas Comptroller of Public Accounts 2018 and 2020), as well as those for deepwater projects cited in the Oxford Institute for Energy Studies (2019). On the other hand, the data from the Oil and Gas Journal (2018) and, particularly, the discount rates cited by the U.K.'s OGA (The Oil and Gas Authority 2015, 2017, and 2018) are much lower than those presented by the SPEE: around 15 percent and 12 percent, respectively, although the latter is for the U.K.'s Continental Shelf.

[13] No data are available for 2019.

Chapter 5: Recommendations

Section 5.1: Discount Rate Recommendation

Deepwater subsea tiebacks that require EFAT have unique characteristics and risks that warrant a somewhat higher rate of return than traditional deepwater projects. These projects entail additional risks associated with both project costs and potential development problems that result from reliance on complex flow assurance technologies. Subsea tiebacks that require EFAT frequently target low- or moderate-sized reservoirs, increasing the economic risk of a project. As the GOM basin matures and the larger reservoirs are developed, the remaining fields become more marginal. Subsea tiebacks utilizing EFAT areessential to developing these increasingly marginal fields, and an above-average discount rate is justified to balance the additional risk these project developers inevitably take on.

BOEM recommends that BSEE allow companies to self-report discount rates, but that BSEE impose an upper bound on reported discount rates. BOEM recommends setting this upper discount rate bound at 20 percent for deepwater subsea tiebacks that require EFAT. This discount rate bound is generally consistent with data from the SPEE and the Texas Comptroller of Public Accounts. This 20 percent discount rate bound is greater than the upper bound for the rest of the deepwater (15 percent) but less than the upper bound for shallow water (25 percent). BOEM believes this is appropriate since deepwater subsea tiebacks that require EFAT typically warrant a somewhat higher rate of return than a standard deepwater project to induce development of a marginal resource with additional technological complexities. However, the risk characteristics of these projects are distinct from those associated with shallow water, and the nature and structure of companies operating in deepwater are such that subsea tiebacks that require EFAT do not require a discount rate as high as shallow water projects. This assessment takes into account typical reservoir sizes, development costs, activity trends, typical company characteristics, and macroeconomic trends. This increase in the upper discount rate bound from 15 percent to 20 percent for deepwater subsea tiebacks that require EFAT should lessen the likelihood of stranding resources, allow companies to earn appropriate rates of return, and allow the federal government to receive appropriate royalty payments.

Section 5.2: Practical Considerations

Defining a subsea tieback that requires EFAT (and thus, identifying the projects that are eligible for a higher discount rate) is a complex issue. In general, BOEM defers to BSEE to develop the appropriate definition. BSEE has provided BOEM with preliminary guidance regarding how it will define these projects. BSEE's definition will center around the enhanced flow assurance technology required and will include conditions regarding what makes projects eligible that will be evaluated when reviewing SCRR applications. BSEE's evaluation of an application for EFAT will consider the complexities involved and ensure that they meet these definitions and conditions as approximations of the risk factors that warrant a higher discount rate.

The technologies referenced in Chapter 2 may or may not be considered by BSEE as proven for use in the United States and operators should defer to BSEE guidance that specifically outlines the acceptable technologies, strategies, and cost requirements necessary for a project to qualify.[14] Therefore, BSEE should monitor operator behavior to see how well their definitions target the intended projects and limit unintended consequences. BSEE should also verify that the enhanced flow assurance technology expenditures outlined in an operator's plan are consistent with the expenditures the operator ultimately makes. In addition, this policy should not reverse the general behavior of companies to target the more profitable remaining resources first, followed by the marginal resources. These considerations lend support to not creating too large of a difference between the general deepwater discount rate and the discount rate for deepwater subsea tiebacks that require EFAT. These considerations also provide support to moving gradually with policy changes to observe operator behavior. BOEM has determined that increasing the upper bound discount rate for subsea tiebacks that require EFAT from 15 percent to 20 percent is consistent with these considerations.

Chapter 6: Conclusions

BOEM has examined the available research and data regarding the appropriate discount rates to use in the context of royalty relief applications for deepwater subsea tiebacks that require EFAT. When determining its policy recommendations, BOEM accounted for the numerous factors that determine discount rates, and the fact that these projects likely entail somewhat above-average risks. BOEM recommends that BSEE allow companies to self-report discount rates, but that BSEE impose an upper bound on reported discount rates of 20 percent for deepwater subsea tiebacks requiring EFAT. This 20 percent upper bound would allow companies to earn appropriate rates of return, help ensure deep water resources are not stranded, and protect the government's right to receive appropriate royalty payments.

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Appendix A

BSEE's analysis of recent production rates on existing deepwater GOM facilities revealed that a majority of the facilities were utilizing less than 50 percent of their average daily production capacity. Tables 1 and 2 show the count of deepwater GOM facilities categorized by average utilization, which is calculated as average daily production rates over a 3-year period (2016-2019) divided by the nameplate capacity of each deepwater facility stated as a percentage.

Table 1

GOM Deepwater Facilities by Average Utilization by Oil Production	
Count of Facilities	Percentage Utilization
7	>65% Utilization
8	50-65% Utilization
15	25-49% Utilization
14	10-24% Utilization
24	<10% Utilization

Source: BSEE

Table 2

GOM Deepwater Facilities by Average Utilization by Gas Production	
Count of Facilities	Percentage Utilization
3	>65% Utilization
6	50-65% Utilization
18	25-49% Utilization
14	10-24% Utilization
27	<10% Utilization

Source: BSEE

From:	Daniel-Davis, Laura E
To:	Sanchez, Alexandra L
Subject:	Daniel-Davis, Laura E left a comment in "DRAFT Report - Onshore"
Date:	Sunday, April 18, 2021 11:14:20 AM
Attachments:	cc8fcff4-0027-4232-990a-3dfd9c6bde65 0b41d3e6-5a39-4915-af0c-173501f9f290 3433f102-bd60-4086-b1db-54b71b8888be c6f87b6b-3363-4fb7-bf5c-070ccbddde87

DRAFT Report - Onshore.docx

Daniel-Davis, Laura E added a comment

Go to comment

Why am I receiving this notification from Office?

From: Daniel-Davis, Laura E
To: Sanchez, Alexandra L
Subject: Daniel-Davis, Laura E left a comment in "DRAFT Report - Onshore"
Date: Sunday, April 18, 2021 10:49:04 AM
Attachments: f75553c0-3939-45d2-8129-a766117fb83e
fbefc1d8-8b20-49d0-840b-6609c7aea711
2fe84e6f-699f-4ace-800e-49077541e87d
8311409e-0415-45bc-88ab-bb10caa4ff33

DRAFT Report - Onshore.docx

Daniel-Davis, Laura E added a comment

Go to comment

Why am I receiving this notification from Office?

From:	Hamilton, Edward A
To:	Macdonald, Cara Lee; Lassiter, Tracie L
Cc:	Sanchez, Alexandra L
Subject:	RE: O&G Report Recs Meeting (1st one)
Date:	Friday, April 16, 2021 5:26:12 PM

I will do so now!

Edward A. Hamilton Jr
Executive Assistant
Assistant Secretary Land & Minerals
Department of Interior
202-208-5954
Telework Cell: 202-494-0861

From: Macdonald, Cara Lee <cara_macdonald@ios.doi.gov>
Sent: Friday, April 16, 2021 4:34 PM
To: Hamilton, Edward A <edward_hamilton@ios.doi.gov>; Lassiter, Tracie L <Tracie_Lassiter@ios.doi.gov>
Cc: Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>
Subject: FW: O&G Report Recs Meeting (1st one)

Boss just said she's good with moving her ASLM pols meeting as needed on the 20th. Grab it before Gareth gives it up

---

From: Macdonald, Cara Lee
Sent: Friday, April 16, 2021 3:31 PM
To: Daniel-Davis, Laura E <laura_daniel-davis@ios.doi.gov>
Cc: Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>
Subject: FW: O&G Report Recs Meeting (1st one)

Ma'am,

The first O&G Recs meeting is on your sked for April 19th 2:15 – 3:00. You said you wanted the second one with the FO two days later, but Kate is out of the office the 21st.
Edward/Tracie are running into some scheduling challenges with Kate on the 20th as well, but Gareth can make April 20, 10:30 to 11:30 work, but we'll need to use half of your daily team check in with the ASLM pols. Is that ok?

V/R,
Cara Lee

From: Hamilton, Edward A <edward_hamilton@ios.doi.gov>
Sent: Friday, April 16, 2021 2:05 PM
To: Macdonald, Cara Lee <cara_macdonald@ios.doi.gov>

Cc: Lassiter, Tracie L <Tracie_Lassiter@ios.doi.gov>
Subject: RE: O&G Report Recs Meeting (1st one)

FYI

Gareth says he can make April 20th, 10:30 -11:30 work; now what to do about the morning huddle and daily teams check in?

Edward A. Hamilton Jr
Executive Assistant
Assistant Secretary Land & Minerals
Department of Interior
202-208-5954
Telework Cell: 202-494-0861

From: Hamilton, Edward A
Sent: Friday, April 16, 2021 2:03 PM
To: Macdonald, Cara Lee <cara_macdonald@ios.doi.gov>
Cc: Lassiter, Tracie L <Tracie_Lassiter@ios.doi.gov>
Subject: O&G Report Recs Meeting (1st one)

Hi Cara Lee,

The first O&G Recs meeting has been scheduled for April 19th 2:15 – 3:00; are there any reference materials that need to be added to the invite?

As far as scheduling the second meeting, I understood that it needed to take place within 2 days of the first but neither Kate or Liz availability lines up.

- Kate availability conflicts with Laura's external on the 20th (2-3), the only other option would be 10:30 – 11:30 and bump the morning huddle and daily teams check in.
- Kate is then out on the 21st
- Still waiting to hear from Gareth on the possibility that Liz is free on the 20th, 10:30 -11:30

I doubt the boss will want to scrape the morning huddle and teams check in.

Edward A. Hamilton Jr
Executive Assistant
Assistant Secretary Land & Minerals

Department of Interior
202-208-5954
Telework Cell: 202-494-0861

From: Macdonald, Cara Lee
To: Hamilton, Edward A; Sanchez, Alexandra L
Cc: Lassiter, Tracie L
Subject: RE: O&G Report Recs Meeting (1st one)
Date: Friday, April 16, 2021 2:35:21 PM

Edward,

Thanks for all the coord on this! I am looping in Alex S. She is the Master Drafter of this doc. (reminds me of the Mad Max movie and hearing Tina Turner say "Master Blaster…"). Anyway, I am guessing that Alex will provide the briefing materials directly herself. But Alex can also help us coord with the boss re whether she agrees to have the below referenced meetings moved on that one day to accommodate this important meeting.

What do you think, Alex? Will you be talking with the boss before me or shall I just send her an email and see if she had time to respond?

Thanks!
Cara Lee

****TELEWORKING CONTACT NUMBER: (Cell) 202.578.4543

Cara Lee Macdonald
Chief of Staff to the Assistant Secretary,
Land and Minerals Management
U.S. Department of the Interior
1849 C Street NW, Room 6624
Washington, D.C. 20240
(Off) 202.208.2654
(Cell) 202.578.4543
cara_macdonald@ios.doi.gov

From: Hamilton, Edward A <edward_hamilton@ios.doi.gov>
Sent: Friday, April 16, 2021 2:05 PM
To: Macdonald, Cara Lee <cara_macdonald@ios.doi.gov>
Cc: Lassiter, Tracie L <Tracie_Lassiter@ios.doi.gov>
Subject: RE: O&G Report Recs Meeting (1st one)

FYI

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Edward A. Hamilton Jr

Executive Assistant
Assistant Secretary Land & Minerals
Department of Interior
202-208-5954
Telework Cell: 202-494-0861

From: Hamilton, Edward A
Sent: Friday, April 16, 2021 2:03 PM
To: Macdonald, Cara Lee <cara_macdonald@ios.doi.gov>
Cc: Lassiter, Tracie L <Tracie_Lassiter@ios.doi.gov>
Subject: O&G Report Recs Meeting (1st one)

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I doubt the boss will want to scrape the morning huddle and teams check in.

Edward A. Hamilton Jr
Executive Assistant
Assistant Secretary Land & Minerals
Department of Interior
202-208-5954
Telework Cell: 202-494-0861

From:	Knodel, Marissa S
To:	Culver, Nada L; Sanchez, Alexandra L; Lefton, Amanda B; Jackson, Danna R
Cc:	Diera, Alexx A
Subject:	Re: O and G reforms
Date:	Friday, April 16, 2021 10:51:08 AM

Amanda and I received the recommendations from the team late last night and haven't had a chance to review in depth with this morning's craziness, but have some edits and additions we want to make.

Thanks for sharing the document, we'll be making additions to it throughout the day.

Marissa Knodel
Advisor, Bureau of Ocean Energy Management
202.538.2415
Marissa.Knodel@boem.gov

From: Culver, Nada L <nculver@blm.gov>
Sent: Friday, April 16, 2021 10:47 AM
To: Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>; Lefton, Amanda B <Amanda.Lefton@boem.gov>; Knodel, Marissa S <Marissa.Knodel@boem.gov>; Jackson, Danna R <djackson@blm.gov>
Cc: Diera, Alexx A <adiera@blm.gov>
Subject: RE: O and G reforms

Let’s take a few minutes on the team call? I think we have a plan for the HNRC madness already.

Nada Wolff Culver
Deputy Director, Policy and Programs
Bureau of Land Management
Cell: 202-255-6979
nculver@blm.gov

From: Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>
Sent: Friday, April 16, 2021 8:46 AM
To: Lefton, Amanda B <Amanda.Lefton@boem.gov>; Knodel, Marissa S <Marissa.Knodel@boem.gov>; Culver, Nada L <nculver@blm.gov>; Jackson, Danna R <djackson@blm.gov>
Cc: Diera, Alexx A <adiera@blm.gov>
Subject: O and G reforms

Friends,

I need help! Linked is the list of proposed reforms that we as a team have put together that I pulled from the report outline, and the onshore section of the report. Also it includes some recs found elsewhere (you'll see what I mean) that we need to figure out if we'd like to incorporate into our reform plan. Also waiting on BOEM additions, as you know and are on top of!

Can you help me organize, and write these up for the meeting on Monday afternoon with the solicitors? Laura would like them put together in a way so we can productively discuss how we can move forward on them, either administratively or through regs. And I need your expertise and guidance there. Happy to jump on a call, or we can bring up at the 11am.

Thanks, as always!
Alex

DRAFT Proposed Reforms.docx

Alexandra Sanchez (she/her)
Special Assistant
Office of the Assistant Secretary
Land and Minerals Management
U.S. Department of the Interior

From:	Diera, Alexx A
To:	Sanchez, Alexandra L
Subject:	Fw: EE - Hearing Readout - HNR EM - Plugging/Reclaiming Orphaned Wells & H.R. 2415, Orphaned Well Cleanup & Jobs Act - 4/15/21
Date:	Friday, April 16, 2021 8:57:04 AM

FYI

Alexx Diera *(she/her)*

Special Assistant

Bureau of Land Management

U.S. Department of the Interior

From: Wilkinson, Patrick <P2Wilkin@blm.gov>
Sent: Friday, April 16, 2021 8:50 AM
To: BLM_WO_100 <BLM_WO_100@blm.gov>
Cc: Douglas, Nicholas E <ndouglas@blm.gov>; Frost, Troy A <tfrost@blm.gov>; BLM_HQ_620 <BLM_HQ_620@blm.gov>; Buffington, Matthew C <mbuffington@blm.gov>; Krauss, Jeff <JKrauss@blm.gov>
Subject: EE - Hearing Readout - HNR EM - Plugging/Reclaiming Orphaned Wells & H.R. 2415, Orphaned Well Cleanup & Jobs Act - 4/15/21

OIL AND GAS

Dems' $8B orphaned well cleanup bill gets GOP blowback

Scott Streater, E&E News reporterPublished: Friday, April 16, 2021

A legacy oil and gas well in Pennsylvania. Pennsylvania Department of Environmental Protection

House Republicans say they will fight an orphan well-plugging bill pushed by Democrats because they oppose bonding requirements and fees designed to ensure oil and gas companies have set aside enough money in the future to pay to clean up abandoned wells instead of taxpayers.

At issue is New Mexico Democratic Rep. Teresa Leger Fernández's **H.R. 2415**. It would authorize $7.25 billion in grants to be administered through a program established by the Interior secretary for orphan well cleanup on state and private lands, where most of the problem wells are located.

It would also authorize grants of $400 million for cleanups on federal lands managed by the Interior and Agriculture departments, and $300 million to clean wells on Native American tribal lands (***E&E Daily***, April 9).

"Because there is no liable owner, the federal government is stepping up now to plug and reclaim the wells to protect our environment," Leger Fernández said during a hearing yesterday of the Natural Resources Subcommittee on Energy and Mineral Resources.

"But we should also take steps to make sure companies live up to their legal obligations to plug abandoned wells, so we're not creating more orphans dropped at the taxpayers' door for cleanup," she added.

But GOP members pushed back. Minnesota Rep. Pete Stauber, the subcommittee's ranking Republican, bemoaned "partisan provisions" in the bill that would require states to adopt "onerous methane restrictions" and impose increased bonding requirements and additional fees on operators if they want to access the grant money.

The bill would increase minimum bonding requirements for oil and gas operators on federal lands, including a bond payment of $150,000 for an operator's wells per lease site or $500,000 for the operator's total wells statewide. Operators would have to pay an "annual, nonrefundable fee" for each idled well they have on federal lands.

"Let's be clear: The intent of this bill is to nickel-and-dime our producers to death," Stauber said, something that would drive operators off federal lands.

That's not going to produce much support from Republicans, said Natural Resources ranking member Bruce Westerman (R-Ark.).

"I think we can come up with a bipartisan bill here if we really wanted to address the problem with the few orphan wells out there," Westerman said. "But to me this bill is swinging a baseball bat at a gnat. We need to do something a little different and more reasonable if we want to get a bipartisan solution."

Hill, White House momentum

The subcommittee hearing came as the Biden administration and Congress have proposed spending potentially billions of dollars to tackle the growing issue.

President Biden's initial fiscal 2022 **budget request**, unveiled last week, would allocate $450 million to the Interior Department, and an additional $100 million to the Department of Agriculture, to "remediate many of the thousands of orphaned oil and gas wells and reclaim abandoned mines on Federal and non-Federal lands." That's more than three times the current spending on orphaned wells and abandoned mines (***Energywire***, April 12).

The president last month proposed allocating $16 billion to clean up orphaned oil and gas wells, as well as abandoned mines, as part of his $2 trillion infrastructure package (***E&E News PM***, March 31).

Leger Fernández's bill is not the only legislation that seeks to address the issue. Sens. Ben Ray Luján (D-N.M.) and Kevin Cramer (R-N.D.) this week introduced a bipartisan bill that would authorize $4.6 billion to plug orphaned wells, mostly through state grants managed by the Interior Department (***E&E Daily***, April 13).

Energy and Mineral Resources Subcommittee Chair Alan Lowenthal (D-Calif.) stressed at yesterday's hearing the importance of plugging the estimated 56,000 abandoned wells that have been documented nationwide.

The Interstate Oil and Gas Compact Commission produced that estimate. Lori Wrotenbery, the commission's executive director, told the subcommittee that a soon-to-be-finalized update will show the number is closer to 70,000.

Although Lowenthal said he is "thrilled" to support Leger Fernández's bill, he also implied yesterday that the bill could be tweaked and "strengthened" to address the concerns from Republicans.

Leger Fernández said the issue is a straightforward one and that the provisions in her bill are needed to address the growing problem.

"Whether it's the impact on public health, or the need for jobs, or the impact on our environment, it's very clear all the witnesses have indicated that orphaned wells present a threat throughout each of the states that we've discussed," she said.

"Despite the benefits of the bill we're looking at today, and the potential to protect communities, put oil and gas workers back to work, I've heard some of [my] colleagues express concerns about the provisions on bonding and idle wells."

She added, "To me it's quite simple: We're just asking industry to clean up after themselves, just like our parents taught us to do when we were kids."

From: Wilkinson, Patrick <P2Wilkin@blm.gov>
Sent: Thursday, April 15, 2021 6:59 PM
To: BLM_WO_100
Cc: Douglas, Nicholas E; Frost, Troy A; BLM_HQ_620; Buffington, Matthew C; Krauss, Jeff
Subject: Hearing Readout - HNR EM - Plugging/Reclaiming Orphaned Wells & H.R. 2415, Orphaned Well Cleanup & Jobs Act - 4/15/21

FYI – On April 15, 2021, the House Natural Resources Subcommittee on Energy and Mineral Resources held a hearing titled: "*Building Back Better: Creating Jobs and Reducing Pollution by Plugging and Reclaiming Orphaned Wells, including the following bill: H.R. 2415, Orphaned Well Cleanup and Jobs Act*." Members attending included Chairman Lowenthal (D-CA-47), full committee Ranking Member Westerman (R-AR-4), Ranking Member Stauber (R-MN-8), and Reps. Leger Fernandez (D-NM-3), Porter (D-CA-45), Herrell (R-NM-2), Cheney (R-WY-AL). DOI was not invited to testify at the hearing, but the BLM is preparing a Statement for the Record to be submitted prior to the hearing record closing in two weeks.

The witnesses for the hearing included Rep. Teresa Leger Fernandez (D-NM-3); Ms. Lori Wrotenbery, Executive Director Interstate Oil and Gas Compact Commission; Dr. Mary Kang, Assistant Professor of Civil Engineering McGill University; Mr. Don Schreiber, Rancher Rio Arriba County, NM; Mr. Ted Boettner, Senior Researcher Ohio River Valley Institute; Mr. Tom Kropatsch Deputy Oil and Gas Supervisor, Wyoming Oil and Gas Conservation Commission; Mr. Tim Tarpley, Senior Vice President for Government Affairs Energy Workforce and Technology Council.

The hearing focused on H.R. 2415, the Orphaned Well Cleanup and Jobs Act, which would establish programs to plug, remediate, and reclaim orphaned oil and gas wells. The BLM was specifically mentioned during the hearing a handful of times, including mention by Ranking Member Stauber of his recent visit to a well plugging operation on BLM lands in New Mexico. The various topics discussed at the hearing included the status of orphaned wells on Federal, Tribal, state and private lands; idle well fees; bonding amounts; and job creation. Members of both parties and all the witnesses were in agreement that orphaned wells are an issue that must be addressed, but there were differences in opinion on the solutions.

Chairman Lowenthal stated that there could be hundreds of thousands of orphaned wells across the country, and that reforms are needed to address the problem. He also said that H.R. 2415 aligns with the Biden Administration's priorities of creating jobs and conserving public lands for future generations. Ms. Wrotenbery claimed that there are about 69,000 orphaned wells in the United States currently, but stated that the number is changing as states are able to do more research and collect better data. Mr. Kropatsch stated that Wyoming has identified over 5,000 orphaned wells and has permanently plugged 4,000 so far. Rep. Leger Fernandez said there were over 700 orphaned wells in New Mexico and Mr. Tarpley mentioned there were 5,400 orphaned wells in California.

Chairman Lowenthal and Rep. Porter repeatedly discussed bonding amounts versus reclamation costs for orphaned wells. Lowenthal mentioned that a $25,000 bond is all that is currently required by law for an operator to cover all the Federal wells in a single state, and Porter added that a lease bond is only $10,000 for Federal wells. Mr. Kropatsch stated that bonds required by the state of Wyoming are $100,000 and they have a $10-per-foot idle well fee. He added that he thought that increasing bonding and adding fees as called for in the bill has the potential to increase the number of orphaned wells with small operators unable to pay the increased amounts, forcing them to walk away from their wells. Dr. Kang also expressed concerns about the methane emissions from orphaned wells.

The costs of plugging wells were mentioned by several witnesses and members. Mr. Boettner stated that bonding covers only 7.6% of the average well plugging costs. Rep. Porter and Mr. Schreiber both mentioned a GAO report (GAO-16-615) that estimated an average cost of plugging a well and reclaiming the surface is about $145,000. Rep. Porter walked through the costs associated with a lease bond on public lands and how an operator could pay less than $900 to cover a lease bond, while leaving the taxpayer on the hook to pay potentially over $140,000 per orphaned well left on a lease if the operator abandoned an operation. She asked Mr. Schreiber how those costs compared throughout his years of experience. Mr Schreiber stated that the bonds for wells on public lands have been the same for longer than his family has written bonds for operators, adding it is the same amount as when he wrote up these bonds in the 1980s and 1990s, as well as when his father wrote these bonds in the 1950s.

Throughout the hearing members on both sides agreed that there was great interest in finding a bipartisan solution to address orphaned wells. The hearing finished with Chairman Lowenthal reiterating that Rep. Leger Fernandez planned to take the information gathered from the hearing to make further modifications to H.R. 2415.

Patrick Wilkinson
Division Chief
Legislative Affairs (HQ 620)
Bureau of Land Management
U.S. Department of the Interior
Cell Phone: (202) 631-6346

From: Hamilton, Edward A
To: Caminiti, Mariagrazia; Anderson, Robert T; Landreth, Natalie A; Sanchez, Alexandra L; Culver, Nada L; Cook, Karla D.; Cordalis, Daniel J
Cc: Lefton, Amanda B; Lassiter, Tracie L; Long, Amanda D
Subject: RE: O&G Report Recs Meeting (schedule 04/19/21)
Date: Thursday, April 15, 2021 5:32:42 PM

Perfect, and will do Marigrace!!

Edward A. Hamilton Jr
Executive Assistant
Assistant Secretary Land & Minerals
Department of Interior
202-208-5954
Telework Cell: 202-494-0861

From: Caminiti, Mariagrazia <Marigrace.Caminiti@sol.doi.gov>
Sent: Thursday, April 15, 2021 5:32 PM
To: Anderson, Robert T <Robert.Anderson@sol.doi.gov>; Hamilton, Edward A <edward_hamilton@ios.doi.gov>; Landreth, Natalie A <natalie.landreth@sol.doi.gov>; Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>; Culver, Nada L <nculver@blm.gov>; Cook, Karla D. <Karla.Cook@boem.gov>; Cordalis, Daniel J <Daniel.Cordalis@sol.doi.gov>
Cc: Lefton, Amanda B <Amanda.Lefton@boem.gov>; Lassiter, Tracie L <Tracie_Lassiter@ios.doi.gov>; Long, Amanda D <adlong@blm.gov>
Subject: Re: O&G Report Recs Meeting (schedule 04/19/21)

Ed - this would work for both Bob and Daniel, and 2:15-2:15 for Natalie- please feel free to include me in scheduling requests for SOL office folks. mg

Mariagrazia Caminiti

Executive Assistant

Office of the Solicitor

1849 C Street, NW, 6352

Washington, DC 20240

Direct: 202-208-3111

Cell: 202-528-0486

WCell: 202-359-2949

From: Anderson, Robert T <Robert.Anderson@sol.doi.gov>
Sent: Thursday, April 15, 2021 4:48 PM
To: Hamilton, Edward A <edward_hamilton@ios.doi.gov>; Landreth, Natalie A <natalie.landreth@sol.doi.gov>; Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>; Culver, Nada L <nculver@blm.gov>; Cook, Karla D. <Karla.Cook@boem.gov>; Cordalis, Daniel J <Daniel.Cordalis@sol.doi.gov>; Caminiti, Mariagrazia <Marigrace.Caminiti@sol.doi.gov>
Cc: Lefton, Amanda B <Amanda.Lefton@boem.gov>; Lassiter, Tracie L <Tracie_Lassiter@ios.doi.gov>; Long, Amanda D <adlong@blm.gov>
Subject: RE: O&G Report Recs Meeting (schedule 04/19/21)

Marigrace, Can you see if this will fit on my calendar?

Robert Anderson
Principal Deputy Solicitor
Department of the Interior
1849 C Street NW
Washington, D.C. 20240
(202) 208-4210

From: Hamilton, Edward A <edward_hamilton@ios.doi.gov>
Sent: Thursday, April 15, 2021 2:34 PM
To: Landreth, Natalie A <natalie.landreth@sol.doi.gov>; Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>; Culver, Nada L <nculver@blm.gov>; Anderson, Robert T <Robert.Anderson@sol.doi.gov>; Cook, Karla D. <Karla.Cook@boem.gov>; Cordalis, Daniel J <Daniel.Cordalis@sol.doi.gov>
Cc: Lefton, Amanda B <Amanda.Lefton@boem.gov>; Lassiter, Tracie L <Tracie_Lassiter@ios.doi.gov>; Long, Amanda D <adlong@blm.gov>
Subject: O&G Report Recs Meeting (schedule 04/19/21)

Good afternoon,

ASLM would like to schedule the O&G Report Recs meeting for Monday, April 19th 2pm – 2:45pm.

Can you all accommodate the time and date?

Edward A. Hamilton Jr
Executive Assistant
Assistant Secretary Land & Minerals
Department of Interior
202-208-5954
Telework Cell: 202-494-0861

From: Hamilton, Edward A
To: Mack-Thompson, Yolando T; Rees, Gareth C
Cc: Sanchez, Alexandra L; Cook, Karla D.; Lassiter, Tracie L
Subject: RE: ASLM O&G Report Recs Meeting (Scheduling to brief Liz and Kate)
Date: Thursday, April 15, 2021 4:25:28 PM

Thank you Yolando, hopefully Gareth's side will match up as well.

Edward A. Hamilton Jr
Executive Assistant
Assistant Secretary Land & Minerals
Department of Interior
202-208-5954
Telework Cell: 202-494-0861

From: Mack-Thompson, Yolando T <yolando_thompson@ios.doi.gov>
Sent: Thursday, April 15, 2021 4:03 PM
To: Hamilton, Edward A <edward_hamilton@ios.doi.gov>; Rees, Gareth C <Gareth_Rees@ios.doi.gov>
Cc: Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>; Cook, Karla D. <Karla.Cook@boem.gov>; Lassiter, Tracie L <Tracie_Lassiter@ios.doi.gov>
Subject: RE: ASLM O&G Report Recs Meeting (Scheduling to brief Liz and Kate)

Kate is available the following dates and times:

19th – 11:00 – 12:00

20th – 10:30 – 11:30 or 2:00 – 3:00

23rd - 10:30 – 11:30, 1:00 – 2:00 or 4:00 – 5:00

From: Hamilton, Edward A <edward_hamilton@ios.doi.gov>
Sent: Thursday, April 15, 2021 3:59 PM
To: Mack-Thompson, Yolando T <yolando_thompson@ios.doi.gov>; Rees, Gareth C <Gareth_Rees@ios.doi.gov>
Cc: Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>; Cook, Karla D. <Karla.Cook@boem.gov>; Lassiter, Tracie L <Tracie_Lassiter@ios.doi.gov>
Subject: RE: ASLM O&G Report Recs Meeting (Scheduling to brief Liz and Kate)

How about the 20th with:

- 3pm to 3:45pm

OR

- 3:45 to 4:30pm

Edward A. Hamilton Jr
Executive Assistant
Assistant Secretary Land & Minerals
Department of Interior
202-208-5954
Telework Cell: 202-494-0861

From: Mack-Thompson, Yolando T <yolando_thompson@ios.doi.gov>
Sent: Thursday, April 15, 2021 3:56 PM
To: Hamilton, Edward A <edward_hamilton@ios.doi.gov>; Rees, Gareth C <Gareth_Rees@ios.doi.gov>
Cc: Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>; Cook, Karla D. <Karla.Cook@boem.gov>; Lassiter, Tracie L <Tracie_Lassiter@ios.doi.gov>
Subject: RE: ASLM O&G Report Recs Meeting (Scheduling to brief Liz and Kate)

Good Afternoon,

Kate is not available on the 21st.

From: Hamilton, Edward A <edward_hamilton@ios.doi.gov>
Sent: Thursday, April 15, 2021 3:52 PM
To: Rees, Gareth C <Gareth_Rees@ios.doi.gov>; Mack-Thompson, Yolando T <yolando_thompson@ios.doi.gov>
Cc: Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>; Cook, Karla D. <Karla.Cook@boem.gov>; Lassiter, Tracie L <Tracie_Lassiter@ios.doi.gov>
Subject: ASLM O&G Report Recs Meeting (Scheduling to brief Liz and Kate)

Good afternoon Yolando and Gareth,

ASLM would like to schedule a meeting with Kate and Liz on O&G Report Recs; do you all have availability for either:

- 04/21/21 (April 21st) 3pm to 3:45pm?

- 04/21/21 (April 21st) 3:45 to 4:30pm?

Edward A. Hamilton Jr

Executive Assistant
Assistant Secretary Land & Minerals
Department of Interior
202-208-5954
Telework Cell: 202-494-0861

From:	Culver, Nada L
To:	Hamilton, Edward A; Landreth, Natalie A; Sanchez, Alexandra L; Anderson, Robert T; Cook, Karla D.; Cordalis, Daniel J
Cc:	Lefton, Amanda B; Lassiter, Tracie L; Long, Amanda D
Subject:	RE: O&G Report Recs Meeting (schedule 04/19/21)
Date:	Thursday, April 15, 2021 3:40:19 PM

Yes.

Nada Wolff Culver
Deputy Director, Policy and Programs
Bureau of Land Management
Cell: 202-255-6979
nculver@blm.gov

From: Hamilton, Edward A <edward_hamilton@ios.doi.gov>
Sent: Thursday, April 15, 2021 1:34 PM
To: Landreth, Natalie A <natalie.landreth@sol.doi.gov>; Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>; Culver, Nada L <nculver@blm.gov>; Anderson, Robert T <Robert.Anderson@sol.doi.gov>; Cook, Karla D. <Karla.Cook@boem.gov>; Cordalis, Daniel J <Daniel.Cordalis@sol.doi.gov>
Cc: Lefton, Amanda B <Amanda.Lefton@boem.gov>; Lassiter, Tracie L <Tracie_Lassiter@ios.doi.gov>; Long, Amanda D <adlong@blm.gov>
Subject: O&G Report Recs Meeting (schedule 04/19/21)

Good afternoon,

ASLM would like to schedule the O&G Report Recs meeting for Monday, April 19th 2pm – 2:45pm.

Can you all accommodate the time and date?

Edward A. Hamilton Jr
Executive Assistant
Assistant Secretary Land & Minerals
Department of Interior
202-208-5954
Telework Cell: 202-494-0861

From:	Macdonald, Cara Lee
To:	Sanchez, Alexandra L
Subject:	RE: meeting with ASLM and SOL
Date:	Thursday, April 15, 2021 2:21:15 PM

Good! I'll let Tracie and Edward know. THANK YOU!

From: Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>
Sent: Thursday, April 15, 2021 2:16 PM
To: Macdonald, Cara Lee <cara_macdonald@ios.doi.gov>
Subject: FW: meeting with ASLM and SOL

Aha! See below about Daniel!

From: Daniel-Davis, Laura E <laura_daniel-davis@ios.doi.gov>
Sent: Wednesday, April 14, 2021 9:26 PM
To: Macdonald, Cara Lee <cara_macdonald@ios.doi.gov>; Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>
Subject: meeting with ASLM and SOL

Let's talk on our huddle tomorrow about finding a time for me, Alex, Nada, Amanda, Bob A, Natalie, Daniel to have a first discussion about the o&g report recs. Friday or Monday.

From:	Lefton, Amanda B
To:	Jackson, Danna R; Diera, Alexx A; Culver, Nada L; Scott, Janea A; Daniel-Davis, Laura E; Knodel, Marissa S; Sanchez, Alexandra L
Subject:	RE: House Natural Resources Committee Remarks for Review
Date:	Wednesday, April 14, 2021 2:47:12 PM
Attachments:	House Natural Resources Cmtte 4-14-21AL.docx

I am so sorry that I did not include you on my first email!

A

From: Jackson, Danna R <djackson@blm.gov>
Sent: Wednesday, April 14, 2021 2:41 PM
To: Diera, Alexx A <adiera@blm.gov>; Lefton, Amanda B <Amanda.Lefton@boem.gov>; Culver, Nada L <nculver@blm.gov>; Scott, Janea A <janea_scott@ios.doi.gov>; Daniel-Davis, Laura E <laura_daniel-davis@ios.doi.gov>; Knodel, Marissa S <Marissa.Knodel@boem.gov>; Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>
Subject: RE: House Natural Resources Committee Remarks for Review

Can you send me the TP so I can make Nada's "matchy matchy?"

From: Diera, Alexx A <adiera@blm.gov>
Sent: Wednesday, April 14, 2021 2:33 PM
To: Lefton, Amanda B <Amanda.Lefton@boem.gov>; Culver, Nada L <nculver@blm.gov>; Scott, Janea A <janea_scott@ios.doi.gov>; Daniel-Davis, Laura E <laura_daniel-davis@ios.doi.gov>; Knodel, Marissa S <Marissa.Knodel@boem.gov>; Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>; Jackson, Danna R <djackson@blm.gov>
Subject: Re: House Natural Resources Committee Remarks for Review

Thank you, Amanda. Looping in @Danna too who is working on Nada's remarks.

Marissa and I met with OCL to plan logistics of the meeting. Paniz will open the meeting to introduce Nada and Amanda, then Sarina Weiss and Ashley Nichols will emcee Democratic and Republican House members respectively (3 min/House member).

Marissa, please jump in if I'm missing anything.

Alexx Diera
Special Assistant
Bureau of Land Management
She/Her

Sent via Outlook for iOS

From: Lefton, Amanda B <Amanda.Lefton@boem.gov>
Sent: Wednesday, April 14, 2021 2:27:54 PM
To: Culver, Nada L <nculver@blm.gov>; Scott, Janea A <janea_scott@ios.doi.gov>; Daniel-Davis, Laura E <laura_daniel-davis@ios.doi.gov>; Knodel, Marissa S <Marissa.Knodel@boem.gov>; Diera, Alexx A <adiera@blm.gov>; Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>
Subject: House Natural Resources Committee Remarks for Review

Team—Attached are draft comments for the listening session on Friday. Nada—we likely need to coordinate who is going first, how to open the session, etc. These are intentionally brief.

We will send these through normal ASLM hallway channels too

House Natural Resources Committee Listening Session

April 16, 2021

Time 12: 45-2:00 p.m. (Eastern)

Via Zoom

Amanda Lefton, BOEM Director

INTRO/ACKNOWLEDGEMENTS

- Chairman Grijalva, Ranking Member Westerman, and members of the Committee, I am pleased to speak with you today to discuss the Bureau of Ocean Energy Management, or BOEM's, role in developing America's energy resources on the Outer Continental Shelf, or OCS.

- My name is Amanda Lefton and I am the Director of BOEM. I am proud to have assumed this role and I am eager pursue the Bureau's mission in developing America's offshore natural resources in an environmentally and economically sustainable way.

E.O. 14008 & THE COMPREHENSIVE OIL AND GAS REVIEW

- President Biden has made tackling the climate crisis a centerpiece of his agenda. In January he issued *Executive Order 14008: Tackling the Climate Crisis at Home and Abroad*.

- This E.O. directs DOI to pause new oil and gas leasing on public lands and offshore waters pending completion of a comprehensive review of oil and gas leasing and permitting activities, and an evaluation of royalty rates and fiscal terms to ensure a fair return to taxpayers.

    - This E.O. does not impact existing operations or permits for valid, existing leases. Work will continue on existing leases and we will continue to review and approve plans and permits.

- BOEM is currently undertaking that review to ensure that our offshore leasing and permitting programs serve the public interest and balance our nation's energy needs with our climate goals to benefit current and future generations.

- During this review we will:

    - Consider whether the royalties and other monies paid to the federal government amount to a fair return for the American taxpayer.

    - Account for the corresponding costs to the climate.

    - Ensure that our actions respect our government-to-government relationships with Tribal nations and commit to principles of environmental justice in our decision making.

- E.O. 14008 also directs federal agencies to elevate certain priorities in federal leasing, including:

    - Controlling greenhouse gas emissions and promoting economic growth and family-supporting jobs.

- BOEM will need to supplement the analyses it historically performs to ensure proper consideration of such priorities.

- The National OCS Program will be part of the comprehensive review. However, we are currently reviewing all options and have not made any final decisions regarding next steps for the National OCS Program.

- Throughout the review we are committed to engaging in extensive outreach to hear from a diverse set of perspectives.

- Information gathered will inform a report outlining recommendations and actions for moving the nation toward an equitable energy future.

- We expect the review to be done in a timely fashion, but we don't have an exact timeframe at this point. We will keep you informed as the review progresses.

- The Administration is also committed to beginning the nation's transition to a cleaner energy future. Offshore wind is expected to contribute significantly to this goal.

OFFSHORE WIND

- Section 207 of President Biden's E.O. 14008 called for a review of offshore renewable energy siting and permitting processes, with the goal of doubling offshore wind by 2030.

- BOEM will play a critical role in implementing the White House's offshore wind strategy. To date, we have leased approximately 1.7 million acres in the OCS for offshore wind development and have 17 commercial leases on the Atlantic, from Cape Cod to Cape Hatteras.

- During a White House forum on March 29th, the Departments of Interior, Energy, and Commerce committed to a target to deploy 30 gigawatts of offshore wind by 2030, which would create nearly 80,000 jobs. Meeting this target could:

  - Trigger more than 12 billion/year in capital investments in project on both coasts.
  - Employ more than 44,000 workers in offshore wind by 2030.
  - Create nearly 33,000 additional jobs in communities supported by offshore wind activity.
  - Generate enough power for 10 million American homes for a year.
  - Avoid 78 million metric tons of CO_2 emissions.

- To help the Administration meet the 2030 target, BOEM plans to advance new lease sales and complete the review of at least 16 Construction and Operations Plans (COPs) by 2005. This represents more than 19 GW of new clean energy for the nation.

- During the White House forum, we announced that we have identified the final Wind Energy Areas in the New York Bight.

- The New York Bight Wind Energy Areas are approximately 800,000 acres of shallow water between Long Island and the New Jersey coast.

- We also announced that we are initiating an environmental review for Ocean Wind, a proposed wind energy facility off the New Jersey coast, the third commercial scale offshore wind project.

- We previously announced environmental reviews for Vineyard Wind offshore Massachusetts and South Fork offshore Rhode Island and anticipate initiating environmental reviews for up to 10 additional projects later this year.

- In addition to the important announcements made by the Interior, the Departments of Commerce, Energy and Transportation all advanced initiatives on offshore wind at the forum.

- These announcements represent a sea change for our offshore wind process, demonstrating an all-of-government approach that will catalyze the industry in the United States.

CONCLUSION

- The climate crisis is before us now. Transitioning to clean energy is critical to tackle climate change for us and for future generations.

- But the full environmental and economic benefits of offshore energy can only be realized if we – as a nation – come together to ensure all potential development is considered and advanced responsibly.

- Moving forward, robust stakeholder outreach and scientific integrity will continue to be important components of our nation's offshore energy program development. All of our decisions will be transparent and rely on the best available data.

- We will continue to listen to all of our partners and consider your perspectives as we move forward. BOEM will work with industry, tribes, government partners, the fishing community, conservation organizations, and labor unions to ensure that any future offshore energy and mineral development is done in a safe and responsible manner.

- We look forward to receiving your input on the best ways to advance the Administration's climate and renewable energy goals and to help create a cleaner, more equitable energy future for our nation. Thank you.

SUPPLEMENTAL INFORMATION

Marine Minerals (if asked)

- BOEM partners with communities to address serious erosion along the Nation's coastal beaches, dunes, barrier islands, and wetlands. Erosion affects coastal habitat, tourism and energy, defense, and public infrastructure.

- Making sand and sediment resources from the Outer Continental Shelf (OCS) available to coastal communities helps them improve their resiliency in the face of climate change and contribute to the Administration's goal of climate change resilience (EO 14008).

- We are preparing to execute an agreement with St. Johns County, Florida, granting the county up to 1.1 million cubic yards of sand from Federal waters for shoreline restoration along 5 miles of South Ponte Vedra Beach.

- The project will address critical erosion caused by Hurricanes Matthew and Irma, two powerful storms that struck the area in 2016 and 2017, respectively.

- BOEM supports President Biden's Executive Order on America's Supply Chains by working with other Federal agencies to identify potential offshore sources of critical minerals that could bolster domestic supplies.

From:	Knodel, Marissa S
To:	Sanchez, Alexandra L
Subject:	Fw: Follow-up from Alex Sanchez request, re: O&G review report
Date:	Saturday, April 10, 2021 10:44:19 AM
Attachments:	gao-16-40.pdf Info Request Royalty Relief-Decom Abandoned Assets Attachments.zip Outline of BOEM Interim Comprehensive Report.docx Royalty Relief Decom Abandoned Assets Information_04-08-21.docx 2020_0210_RoyaltyPresentation_Final.pptx BOEM Propose Rule - Financial Assurance Background.docx Financial Assurance Bankruptcy and Proposed Rule Briefing - Public Information v2.pptx Sources and References for Offshore interim report 4-9-2021.docx Outlook-4sazcthv.png

Good morning Alex!

This morning I received the resources we requested earlier this week. This is a great compilation, I hope it's helpful! Please let us know if you have any questions.

Peace,

Marissa Knodel
Advisor, Bureau of Ocean Energy Management
202.538.2415
Marissa.Knodel@boem.gov

From: Carr, Megan E <megan.carr@boem.gov>
Sent: Saturday, April 10, 2021 8:44 AM
To: Knodel, Marissa S <Marissa.Knodel@boem.gov>
Cc: Frank, Wright J <Wright.Frank@boem.gov>
Subject: Follow-up from Alex Sanchez request, re: O&G review report

Hello Marissa,

The team has collected more background materials in response to your request on Monday.

The request:

- References to resources and reports: These are contained in “Sources and References for Offshore Interim Report 4-9-2021.”
- Resources illustrating where we are on Royalties; Royalty Relief; Bonding; Financial Assurances; Decommissioning; and Abandoned Assets. These are contained in a variety of presentations and briefing documents that I collected.
- Draft/Outline of where we are on the BOEM Interim Report. We’re still doing the drafting of sections, so the draft isn’t ready to share yet, but the file, “Outline of BOEM Interim Comprehensive Report” gives a Table of Contents level description of our progress, similar to what we shared on the call last week.

Note—we collected the information for BOEM, and BSEE sent me a zip file containing their responses, which is attached. All BSEE's responses are in the zip file.

Please let us know if you have any questions.

Thank you,

Megan Carr, PhD, CPG
Pronouns: she, her, hers
Chief, Office of Strategic Resources
Bureau of Ocean Energy Management
U.S. Department of the Interior
1849 C Street NW
Washington, D.C. 20240

Mobile: (907) 250-1840

BOEM
Bureau of Ocean Energy Management

From: Knodel, Marissa S <Marissa.Knodel@boem.gov>
Sent: Monday, April 5, 2021 2:23 PM
To: Frank, Wright J <Wright.Frank@boem.gov>; Carr, Megan E <megan.carr@boem.gov>
Subject: Follow-up from Alex Sanchez re: O&G review report

Hello Wright and Megan,

I heard back from Alex today, and she really appreciated our meeting last Thursday to get an overview of our report so we can make sure the BOEM info included in the DOI interim report for the comprehensive review is aligned.

She had a couple follow-up asks for our team:

- As part of her literature review, she said if you all know of or are referencing or citing to any external resources (e.g. reports from the GAO, IG, CRS), she would greatly appreciate those references (or a list of them).
- Any data or resources that illustrates where we are on the following, and may be helpful

for consideration during the second phase of the review:

  - Royalties
  - Royalty relief
  - Bonding
  - Financial assurances
  - Decommissioning
  - "Abandoned" assets

- To the extent you feel comfortable, she said she would also appreciate any drafts of the report or outline you are willing to share. I don't think she intends to copy-and-paste anything, I think the intent is to cross-reference and make sure we are aligned in how we're characterizing BOEM's leasing programs.

Please let me know if this makes sense and if you have any questions. Is Thursday or Friday of this week reasonable for pulling together the resources Alex requested?

Peace,

Marissa

Marissa Knodel
Advisor, Bureau of Ocean Energy Management
202.538.2415
Marissa.Knodel@boem.gov

United States Government Accountability Office

Report to Congressional Requesters

December 2015

OFFSHORE OIL AND GAS RESOURCES

Actions Needed to Better Protect Against Billions of Dollars in Federal Exposure to Decommissioning Liabilities

GAO-16-40

GAO Highlights

Highlights of GAO-16-40, a report to congressional requesters

December 2015

OFFSHORE OIL AND GAS RESOURCES

Actions Needed to Better Protect Against Billions of Dollars in Federal Exposure to Decommissioning Liabilities

Why GAO Did This Study

Oil and gas produced on federal leases in the Gulf of Mexico are important to the U.S. energy supply. Historically, most offshore production was in shallow water, but more than two-thirds of the more than 5,000 active oil and gas leases in the Gulf are now located in deep water. When oil and gas infrastructure is no longer in use, Interior requires lessees to decommission it so that it does not pose safety and environmental hazards. Decommissioning can include plugging wells and removing platforms, which can cost millions of dollars. Interior requires lessees to provide bonds or other financial assurances to demonstrate that they can pay these costs; however, if lessees do not fulfill their decommissioning obligations, the federal government could be liable for these costs.

GAO was asked to review Interior's management of liabilities from offshore oil and gas production. This report examines Interior's (1) procedures for overseeing decommissioning and estimating its costs, (2) procedures for obtaining financial assurances for these liabilities, and (3) challenges managing these liabilities. GAO reviewed agency regulations and procedures and interviewed officials from Interior, credit rating agencies, academia, and trade associations.

What GAO Recommends

GAO recommends that Interior take several steps to improve its data system, complete plans to revise its financial assurance procedures, and revise its cost reporting regulations, among other things. Interior concurred with GAO's recommendations.

View GAO-16-40. For more information, contact Frank Rusco at (202) 512-3841 or ruscof@gao.gov.

What GAO Found

The Department of the Interior (Interior) has developed procedures to oversee the decommissioning of offshore oil and gas infrastructure and estimate costs associated with decommissioning liabilities but has not addressed limitations with its system for tracking cost estimates. According to officials, Interior's procedures include (1) identifying and tracking unused infrastructure, (2) reviewing lessee plans to decommission infrastructure, and (3) using different cost estimates for decommissioning in shallow and deep water. However, inconsistent with internal control standards, Interior officials must manually enter cost estimates into Interior's main data system to override inaccurate estimates automatically calculated by the system. Without a more accurate data system, Interior does not have reasonable assurance that it will consistently estimate the costs associated with decommissioning.

Interior's procedures for obtaining financial assurances for decommissioning liabilities pose financial risks to the federal government, and Interior is planning to revise its procedures to address these risks but has not finalized its approach. As of October 2015, for an estimated $38.2 billion in decommissioning liabilities in the Gulf, Interior officials identified about $2.3 billion in liabilities that may not be covered by financial assurances. However, these officials were unable to determine the extent to which these data were valid due to limitations with Interior's data system, among other things. Of the remaining $35.9 billion in decommissioning liabilities, Interior held or required about $2.9 billion in bonds and other financial assurances, and had foregone requiring about $33.0 billion in bonds for the remaining liabilities. Interior has procedures that allow it to waive its requirement for a lessee to provide a bond if the lessee passes a financial strength test. Prior GAO work has shown that the use of financial strength tests in lieu of bonds poses risks to the federal government. Interior recognizes the risks associated with its procedures, and Interior officials stated that they issued draft guidance to clarify their procedures in September 2015. Interior has not issued any final revisions to its procedures; therefore, it is too soon to evaluate the details of these proposed changes. Until Interior improves its ability to obtain valid data from its data system and revises and implements its financial assurance procedures, the federal government remains at increased risk of incurring costs should lessees fail to decommission oil and gas infrastructure.

Interior faces challenges managing potential decommissioning liability. For example, until December 2015, Interior did not have a requirement for lessees to report on costs associated with decommissioning activities in the Gulf. Instead, Interior contracted studies to obtain data on decommissioning costs, but some data were decades old. Federal internal control standards call for agencies to obtain information from external stakeholders that may significantly affect their ability to achieve agency goals. However, in December 2015, Interior issued final regulations (proposed in 2009) requiring lessees to report data on most, but not all, decommissioning costs to Interior. Unless and until Interior obtains accurate and complete data on decommissioning costs, Interior may not have reasonable assurance that its cost estimates of decommissioning liabilities in the Gulf are accurate, or that it is requiring sufficient amounts of financial assurance based on these estimates.

Contents

Abbreviations

BOEM	Bureau of Ocean Energy Management
BSEE	Bureau of Safety and Environmental Enforcement
Gulf	Gulf of Mexico
Interior	Department of the Interior
TIMS	Technical Information Management System

U.S. GOVERNMENT ACCOUNTABILITY OFFICE
441 G St. N.W.
Washington, DC 20548

December 18, 2015

The Honorable Raúl M. Grijalva
Ranking Member
Committee on Natural Resources
House of Representatives

The Honorable Alan Lowenthal
Ranking Member
Subcommittee on Energy and Mineral Resources
Committee on Natural Resources
House of Representatives

The Honorable Peter A. DeFazio
House of Representatives

Oil and gas resources located on federal leases on the outer continental shelf are an important component of the nation's energy supply.[1] Wells on federal leases on the outer continental shelf accounted for over 16 percent of the nation's crude oil production in 2014 and about 5 percent of natural gas production in 2013. The vast majority of this production occurred on federal leases in the Gulf of Mexico (Gulf). Historically, most offshore oil and gas activities have occurred in shallow water,[2] but in recent decades these activities have moved into deep water. More than two-thirds of the more than 5,000 active oil and gas leases in the Gulf are now located in deep water.

The Department of the Interior (Interior) manages oil and gas activities on offshore federal leases, including activities associated with thousands of wells, platforms, and miles of pipelines on the outer continental shelf. When this infrastructure is no longer useful for operations or otherwise

[1]The outer continental shelf refers to the submerged lands outside the territorial jurisdiction of all 50 states, but within U.S. jurisdiction and control. The portion of the North American continental edge that is federally designated as the outer continental shelf generally extends seaward 3 geographical miles off the coastline to at least 200 nautical miles.

[2]In this report, unless other specified, we use the term "shallow" water to refer to depths of less than 400 feet and "deep" water to refer to depths of greater than 400 feet.

becomes idle,[3] or when a lease has been expired for more than 1 year, Interior requires oil and gas lessees to decommission it so that it does not pose potential safety hazards to marine vessels and environmental hazards to sea life and humans.[4] Decommissioning refers to the process of plugging wells, removing platforms and other structures, removing or cleaning out pipelines, and clearing sites of debris. According to Interior estimates, in shallow water, decommissioning infrastructure can cost tens of millions of dollars per lease, depending on the number of wells and types of structures present. In deep water, decommissioning can cost hundreds of millions of dollars per lease. In addition, infrastructure damaged by hurricanes is significantly more expensive to decommission than nondamaged infrastructure.

According to Interior's regulations, all lessees are liable for decommissioning costs that accrue during their ownership.[5] Before lessees drill wells or install platforms and other structures, Interior requires them to provide financial assurance to ensure that they are capable of meeting their decommissioning obligations. This financial assurance may be in the form of a financial asset provided by the lessee, such as a bond, or a determination that a lessee has the financial strength and ability to fulfill decommissioning obligations. According to Interior officials, the federal government has not incurred costs associated with offshore decommissioning since 1989, when a lessee declared bankruptcy.[6] In response to this bankruptcy, Interior promulgated regulations in 1993 requiring some lessees to provide bonds specifically for offshore decommissioning.[7] Nonetheless, Interior refers to oil and gas infrastructure on offshore federal leases as potential liabilities because

[3]Interior refers to wells and platforms as "idle" if they have not been used in the past 5 years for oil and gas exploration or development and production activities.

[4]For the purposes of this report, we use the term "lessee" to refer to owners of record title and owners of operating rights on offshore leases, designated operators acting on behalf of record title and operating rights owners, and right-of-way holders.

[5]30 C.F.R. § 250.1701.

[6]According to Interior officials, this company entered into an agreement to fund two decommissioning trusts using cash, services performed, acceptable forms of security, and royalty reductions. As part of this agreement, Interior reduced the company's royalty payments by about $13 million, which was spent on decommissioning.

[7]30 C.F.R. § 556.53(d).

the federal government may have to pay for decommissioning if lessees do not.

You asked us to review Interior's management of potential federal liabilities associated with the decommissioning of offshore oil and gas infrastructure. This report examines (1) Interior's procedures for overseeing the decommissioning of offshore oil and gas infrastructure and estimating costs associated with decommissioning liabilities; (2) Interior's procedures for obtaining financial assurances for decommissioning liabilities; and (3) challenges, if any, Interior faces in managing potential decommissioning liabilities. We focused our work on the Gulf, where most oil and gas infrastructure is located.

To conduct this work, we reviewed Interior's regulations regarding its management of leases for offshore oil and gas production. To examine Interior's procedures for overseeing the decommissioning of offshore oil and gas infrastructure and estimating decommissioning costs, we interviewed officials from Interior's Bureau of Safety and Environmental Enforcement (BSEE) in their Washington, D.C., headquarters office and Gulf regional office in New Orleans, Louisiana, and reviewed and summarized relevant BSEE guidance, procedures, and related documentation.[8] We also compared BSEE's actions to implement its procedures to standards for internal control in the federal government.[9] In addition, to better understand the decommissioning process and the costs involved, we spoke with a nongeneralizable sample of officials and stakeholders from trade associations and academia. We identified these officials and stakeholders from our prior work, published academic and technical articles, our attendance at a decommissioning conference, and interviews with BSEE officials, and we selected them based on their knowledge in this area.

To examine Interior's procedures for obtaining financial assurances for decommissioning liabilities, we interviewed officials from Interior's Bureau of Ocean Energy Management (BOEM) in their Washington, D.C.,

[8]For the purposes of this report, we use the term "procedure" to include Interior's notices to lessees, which are supposed to clarify, supplement, or provide more details about Interior's regulations; standard operating procedures; and other related documents describing Interior's processes. *See* 30 C.F.R. § 250.103.

[9]GAO, *Standards for Internal Control in the Federal Government*, GAO/AIMD-00-21.3.1 (Washington, D.C.: November 1999).

headquarters office and Gulf regional office in New Orleans, Louisiana, and reviewed and summarized relevant BOEM guidance, procedures, and related documentation. We compared actions that BOEM took to implement its procedures to standards for internal control in the federal government. In addition, to better understand financial assurance and bonding issues, we spoke with a nongeneralizable sample of analysts from the three largest credit rating agencies,[10] officials from bonding companies, and stakeholders from trade associations. We identified these organizations from our prior work and interviews with BOEM officials and selected them based on their knowledge in this area.

To examine challenges Interior faces in managing potential decommissioning liabilities, we used the information collected from our first two objectives. We also spoke with a nongeneralizable sample of stakeholders from trade associations about their views on challenges; we identified these stakeholders from our prior work and selected them based on their knowledge in this area.

We conducted this performance audit from October 2014 to December 2015 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

This section provides information on (1) the types of wells and structures in the Gulf, (2) offshore leasing, (3) financial assurance requirements, (4) decommissioning requirements, and (5) oil and gas infrastructure installed and removed in the Gulf.

Types of Wells and Structures in the Gulf

Lessees drill wells to access and extract oil and gas from geologic formations. According to an Interior publication, “exploratory” wells are drilled in an area with potential oil and gas reserves, while “development”

[10]The three largest credit rating agencies are Moody’s Investors Services, Standard and Poor’s, and Fitch Ratings, as reported by the Securities and Exchange Commission.

wells are drilled to produce oil and gas from a known reserve.[11] An exploratory well may not actually produce any oil or gas, while a successful development well produces oil or gas. Wellheads that are located on a fixed platform (typically in shallow water) are referred to as “dry tree” wells, and wellheads that are located on the seafloor (typically in deep water) are referred to as “subsea” or “wet tree” wells.

Offshore oil and gas structures in the Gulf vary in size and complexity. The simplest structures are found in shallow water and include caissons and well protectors. A caisson is a cylindrical or tapered large diameter steel pipe enclosing a well conductor and is the minimum structure for offshore development. A well protector provides support to one or more wells with no production equipment and facilities. A more complex structure in shallow water is a fixed platform, which uses a jacket and pilings to support the superstructure, or deck.[12] The deck is the surface where work is performed and provides space for crew quarters, a drilling rig, and production facilities. Most of the large fixed platforms have living quarters for the crew, a helicopter pad, and room for drilling and production equipment.[13] A typical platform is designed so that multiple wells may be drilled from it. Wells from a single platform may have bottom-hole locations many thousands of feet (laterally displaced) from the surface location.

Structures in deep water rely on other methods to anchor to the ocean floor. For example, a “compliant tower” structure supports the deck using a narrow, flexible tower and a piled foundation. According to an industry publication, the flexible nature of the compliant tower allows it to withstand large wind and wave forces associated with hurricanes. Other common deep-water structures include the tension leg platform, floating

[11]According to BSEE officials, lessees sometimes drill other types of wells, such as relief wells and core test wells. However, these types of wells represent a very small portion of the wells drilled in the Gulf.

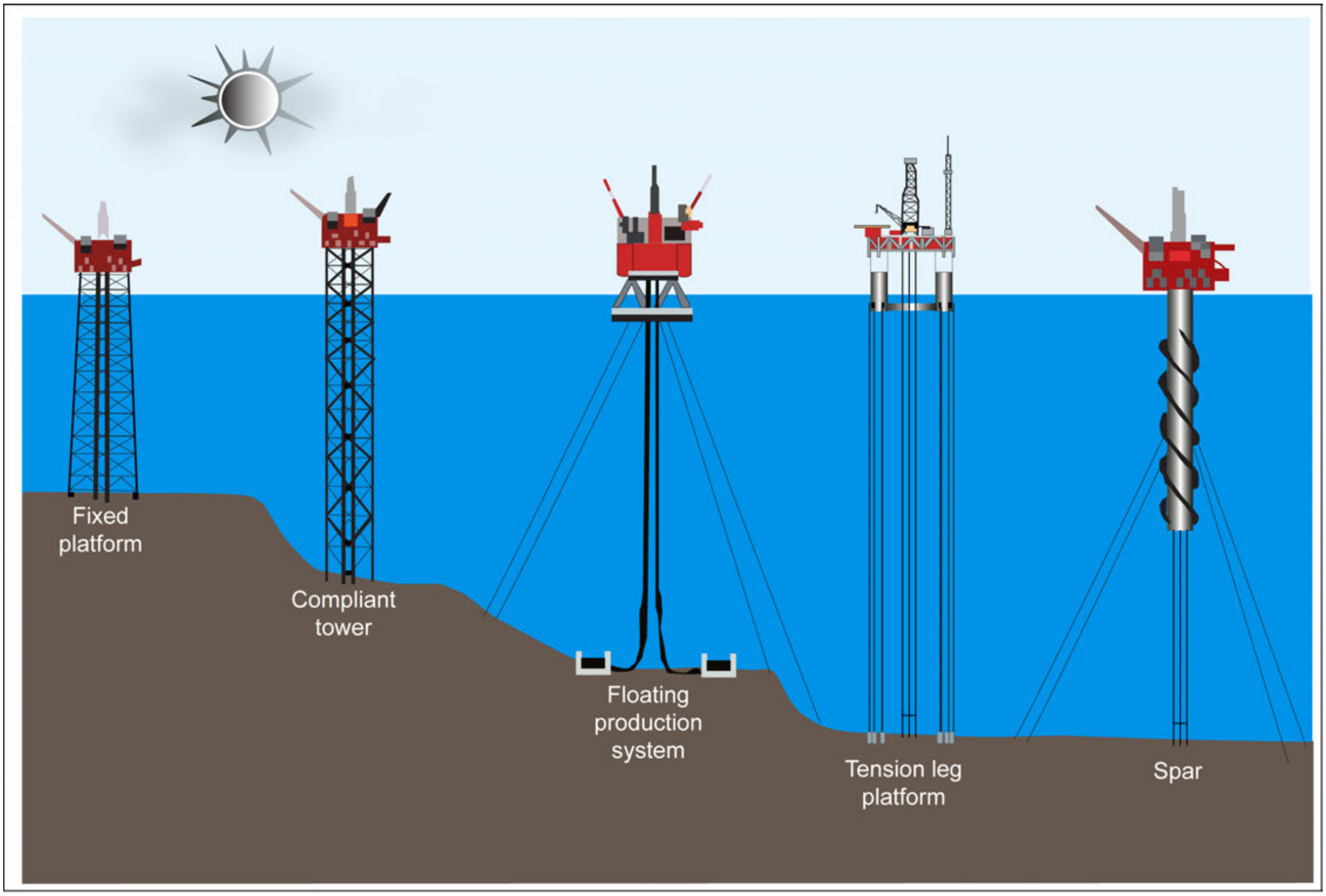
[12]A jacket is a steel structure that rests on the ocean’s floor and has columns, or legs. Pilings are driven through the legs of the jacket into the seafloor to hold the jacket in place.

[13]According to BSEE officials, fixed platforms are typically found in shallow water, but some fixed platforms are used in water depths between 400 feet and 1,400 feet.

production system, and spar platform.[14] Illustrations of these structures are shown in figure 1.

[14]A tension leg platform structure supports a floating deck using vertical steel "tendons" or a chain and wire system anchored to the seafloor by pilings. A floating production system uses a floating, semisubmersible hull equipped with drilling and production equipment. It can be anchored in place with a chain and wire system or dynamically positioned using rotating thrusters. A spar platform supports a floating deck using a long, slender column that extends far below the ocean surface. Vertical steel tendons anchor the column to the seafloor (using pilings), and guy-wires extend out diagonally to seafloor anchors for horizontal stability.

Figure 1: Examples of Oil and Gas Structures in the Gulf of Mexico



Source: GAO analysis of industry reports. | GAO-16-40

Offshore Leasing

Management of offshore oil and gas resources is primarily governed by the Outer Continental Shelf Lands Act, which sets forth procedures for leasing,[15] exploration, and development and production of those resources. The act calls for the preparation of an oil and gas leasing

[15]For the purposes of this report, we use the term "lease" to include leases, grants of right of way, and right of use and easements.

program designed to meet the nation's energy needs while also taking into account a range of principles and considerations specified by the act. Specifically, the act provides that "[m]anagement of the outer Continental Shelf shall be conducted in a manner which considers economic, social, and environmental values of the renewable and nonrenewable resources contained in the outer Continental Shelf, and the potential impact of oil and gas exploration on other resource values of the outer Continental Shelf and the marine, coastal, and human environments."[16]

The Outer Continental Shelf Lands Act also requires the Secretary of the Interior to prepare a 5-year schedule of proposed lease sales, indicating the size, timing, and location of leasing activity as precisely as possible. Every 5 years, Interior selects the areas that it proposes to offer for leasing and establishes a schedule for individual lease sales. These leases may be offered for competitive bidding, and all eligible companies are invited to submit written sealed bids for the lease and rights to explore, develop, and produce oil and gas resources on these leases. These rights last for a set period of time, referred to as the initial period of the lease,[17] and vary depending on the water depth.[18]

Historically, Interior's Minerals Management Service managed offshore federal oil and gas activities and collected royalties for all producing leases. In May 2010, in an effort to separate major functions of offshore oil and gas management, Interior announced the reorganization of the Minerals Management Service into the Bureau of Ocean Energy Management, Regulation, and Enforcement, responsible for offshore oil and gas management, and the Office of Natural Resources Revenue, responsible for revenue collections. Subsequently, in October 2011, the

[16]43 U.S.C. §1344(a)(1).

[17]If a discovery is made within the initial period of the lease, the lease is extended for as long as oil and/or natural gas is produced in paying quantities or approved drilling operations are conducted. The term of the lease may also be extended if a suspension of production or suspension of operations has been granted or directed.

[18]In the Gulf, in a notice of sale in 2012, BOEM offered leases with an initial term of 5 years extended to 8 years if drilling begins during the initial 5-year period targeting hydrocarbons below a depth of at least 25,000 feet subsea for leases in less than 400 meters of water. For leases in 400 to 800 meters of water, the initial term was 5 years extended to 8 years if drilling begins during the initial 5-year period. For leases in 800 to 1,600 meters of water, the initial period was 7 years extended to 10 years if drilling begins during the initial 7-year period. For leases in over 1,600 meters of water, the initial period was 10 years.

Bureau of Ocean Energy Management, Regulation, and Enforcement was separated into BOEM and BSEE. BOEM oversees resource management activities, including preparing the 5-year outer continental shelf oil and gas leasing program; reviews oil and gas exploration and development plans and environmental studies; and conducts National Environmental Policy Act analyses. BSEE oversees operations and environmental compliance, including reviewing drilling permits, inspecting offshore drilling rigs and production platforms, assessing civil penalties, developing regulations and standards for offshore drilling (including those related to decommissioning), and ensuring the conservation of natural resources.

Financial Assurance Requirements

The Outer Continental Shelf Lands Act authorizes the Secretary of the Interior to promulgate regulations necessary to administer the outer continental shelf leasing program, including regulations concerning financial assurance. Under this authority, Interior promulgated regulations and developed financial assurance procedures to protect the government from incurring costs if a lessee fails to meet its lease obligations, including its obligation to decommission offshore infrastructure. Under these regulations and procedures, BOEM regional directors may require a lessee to provide a bond —referred to as a “supplemental bond”—that covers the estimated costs of decommissioning for a lease.[19] BSEE is responsible for estimating costs associated with decommissioning liabilities. If a lessee is unable to accomplish decommissioning obligations as required, the federal government can use the bond to cover decommissioning costs.[20] However, if BOEM determines that at least one lessee has sufficient financial strength to accomplish decommissioning

[19]To satisfy the requirement to provide bonds, BOEM accepts surety bonds, U.S. Treasury notes, and other financial instruments if the government’s interests are protected. A surety bond is a third-party guarantee that a lessee purchases from a private insurance company or other entity approved by the Department of the Treasury (i.e., listed on Circular No. 570). The lessee must pay a premium to the surety company to maintain the bond.

[20]In addition to a supplemental bond that may be required from a lessee, under BOEM regulations, every offshore oil and gas lease must be covered by a general bond that could be used to ensure a lessee complies with regulatory and lease requirements such as inspection fees, civil penalties, decommissioning, and rents and royalties. The general bond is not relied on to cover oil spill response, because those activities are covered by BOEM’s Oil Spill Financial Responsibility regulations (30 C.F.R. § 553) as well as the Oil Spill Liability Trust Fund. General bonds vary in amount, from $50,000 to $3 million, depending on the geographical area and phase of operation covered by the bond. As of June 10, 2015, lessees had provided 604 general bonds with a value of $517 million.

obligations on the lease, BOEM may waive the requirement for a supplemental bond.[21]

Under BOEM and BSEE regulations, lessee liability is “joint and several”—that is, each lessee is liable for all decommissioning obligations that accrue on the lease during its ownership, including those that accrued prior to its ownership but had not been performed. In addition, a lessee that transfers its ownership rights to another party will continue to be liable for the decommissioning obligations it accrued. According to BOEM officials, BOEM ensures that all decommissioning obligations on offshore leases are required to be covered by either a supplemental bond or a current lessee that has the financial ability to conduct decommissioning.

Decommissioning Requirements

According to Interior regulations, lessees must permanently plug all wells, remove all platforms and other structures, decommission all pipelines, and clear the seafloor of all obstructions created by the lease and pipeline operations when this infrastructure is no longer useful for operations.[22] Lessees must also permanently plug wells and remove platforms within 1 year after a lease terminates. BSEE refers to infrastructure that is no longer useful for operations on active leases as idle infrastructure (or “idle iron”) and infrastructure on expired leases as terminated lease infrastructure. In general, BSEE’s guidance defines idle infrastructure as follows: [23]

[21]Each lease may have numerous lessees that have various rights to the lease, including lessees that are record title holders and lessees that are operating rights holders. BOEM requires that all lessees agree to one designated operator, and the designated operator generally provides BOEM with the required bonding.

[22]According to BSEE, permanent well abandonment includes installing a surface plug and severing the casing at least 15 feet below the mudline, among other requirements. Temporary well abandonment includes all plugging and testing requirements imposed by BSEE to permanently abandon a well, except a surface plug is not required, and the lessee need not sever the casing, remove the wellhead, or clear the site. BSEE regulations also allow a lessee to either leave a pipeline in place after performing certain activities (e.g., cleaning it and flushing with seawater) or remove it from the seafloor. *See* 30 C.F.R. § 250.

[23]Department of the Interior, *Notice to Lessees and Operators of Federal Oil and Gas Leases and Pipeline Right-of-way Holders in the Outer Continental Shelf, Gulf of Mexico OCS Region: Decommissioning Guidance for Wells and Platforms*, NTL No. 2010-G05 (Sept. 15, 2010). This guidance expired Oct. 14, 2013, but BSEE continues to use it.

- A well is considered idle if it has not been used in the past 5 years for operations associated with exploration or development and production of oil or gas, and if the lessee has no plans for such operations.
- A platform is considered idle if it has been toppled or otherwise destroyed, or it has not been used in the past 5 years for operations associated with exploration or development and production of oil or gas.

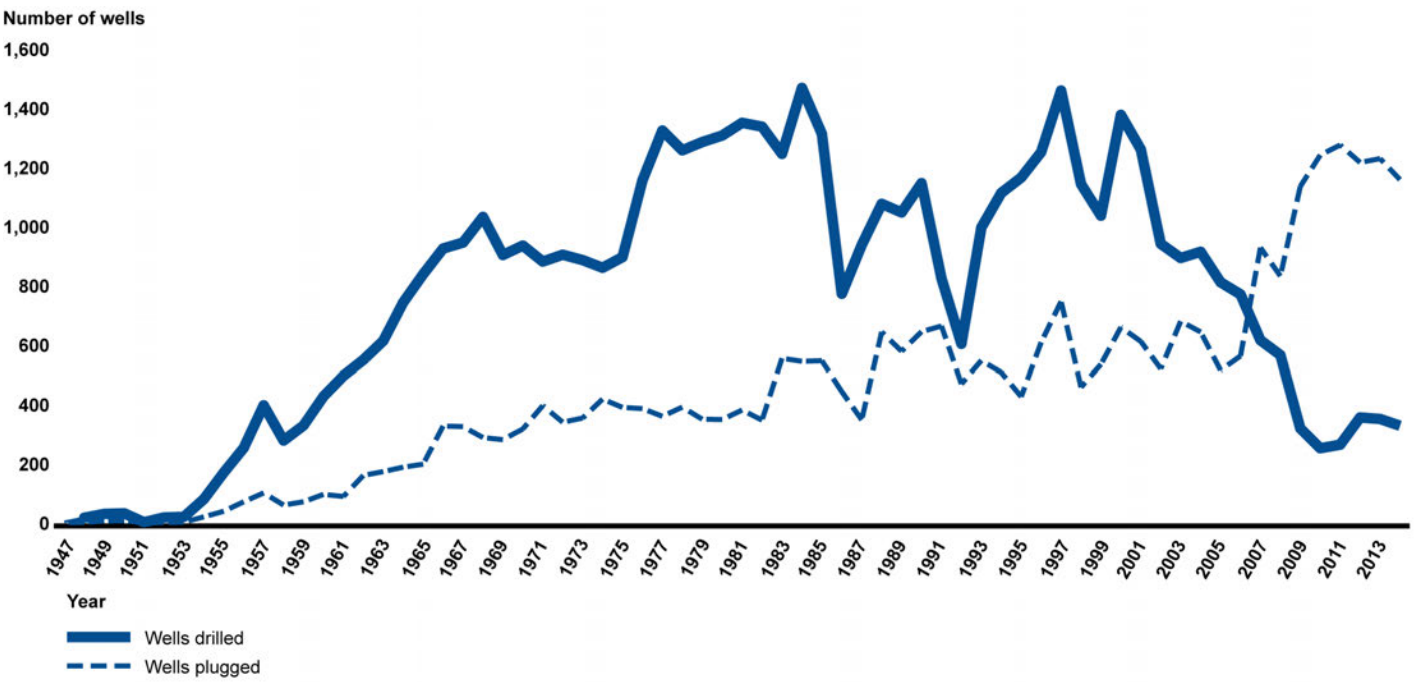
Companies may postpone decommissioning idle wells and platforms to defer the cost of removal, increase the opportunity for resale, or reduce decommissioning costs through economies of scale and scheduling, among other reasons. However, postponing decommissioning can be costly because the longer a structure is present in the Gulf the greater the likelihood it will be damaged by a hurricane. According to Interior documentation, decommissioning a storm-damaged structure may cost 15 times or more the cost of decommissioning an undamaged structure. In 2005, Hurricanes Katrina and Rita destroyed 116 structures and significantly damaged another 163 structures and 542 pipelines in the Gulf, according to Interior documentation. According to BSEE officials, as of April 2015, the Gulf contained 13 destroyed structures with 16 associated wells.

Storm-damaged or toppled structures present a greater risk to safety and require difficult and time-consuming salvage work. After preliminary salvage work that can take weeks, divers cut and remove structural components while crane assemblies remove the components and place them on a barge for transport and disposal. Additionally, when working in areas with strong currents and unconsolidated material, coffer dams are often constructed on the seabed to prevent material from slumping back in on the dive crews and equipment.

Oil and Gas Infrastructure Installed and Removed in the Gulf

Figure 2 shows the annual number of wells drilled and plugged in the Gulf from 1947 through 2014. During this time period, lessees drilled a total of 52,223 wells in the Gulf (including 18,447 exploratory wells and 33,776 development wells) and plugged a total of 29,879 wells (including 4,017 temporarily abandoned wells and 25,862 permanently abandoned wells).

Figure 2: Annual Number of Wells Drilled and Plugged in the Gulf of Mexico, 1947-2014

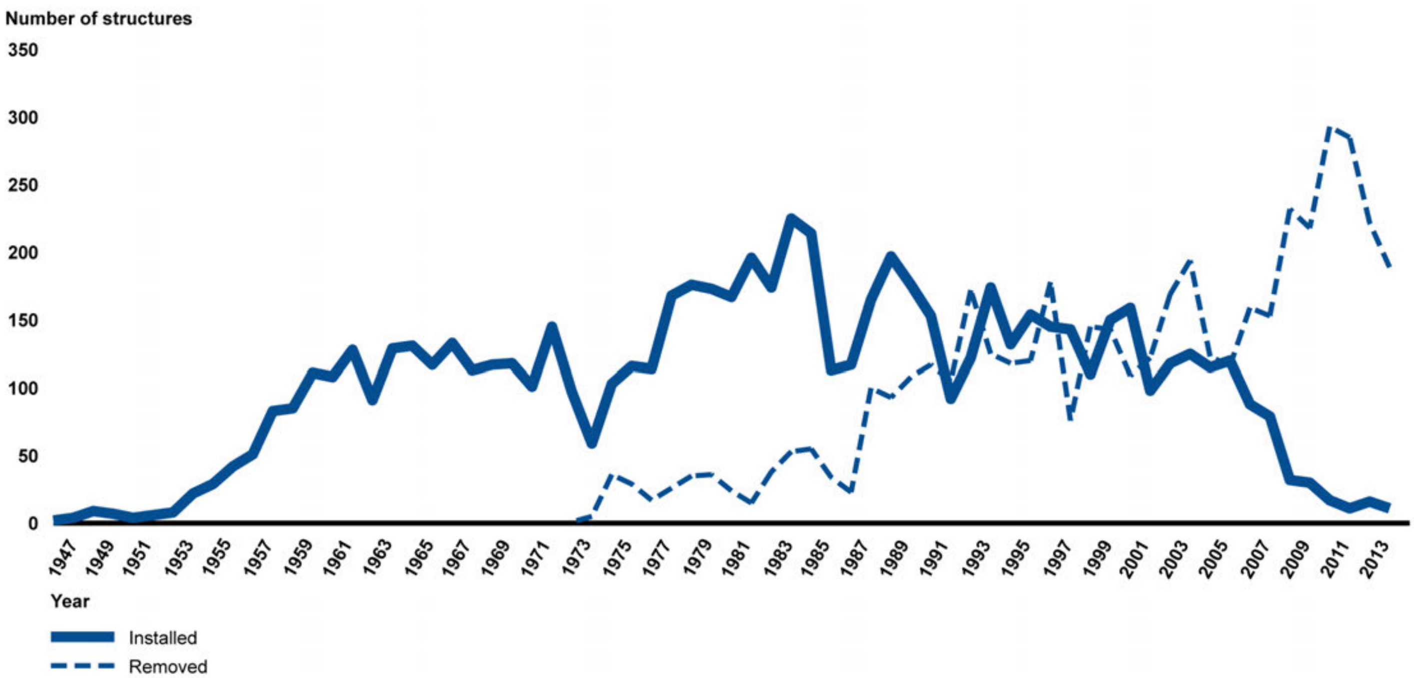


Source: GAO analysis of Bureau of Safety and Environmental Enforcement (BSEE) data. | GAO-16-40

Note: Wells drilled include exploratory and development wells. Wells plugged include temporary and permanent well abandonments.

Figure 3 shows the annual number of structures installed and removed in the Gulf from 1947 through 2014. During this time period, lessees installed a total of 7,038 structures in the Gulf. In addition, starting in the 1970s, lessees began removing structures from the Gulf. Specifically, lessees removed a total of 4,611 structures from 1973 through 2014. Most of the structures installed and removed were fixed platforms and caissons installed in shallow water.

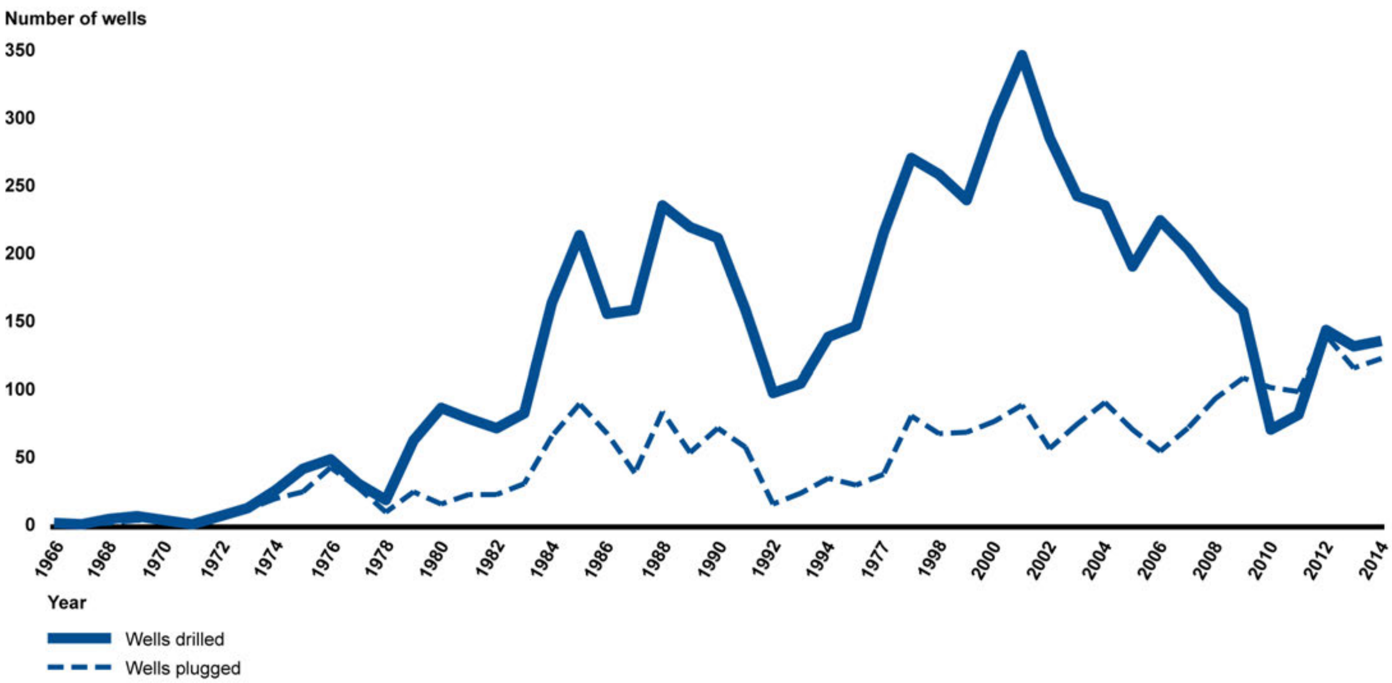
Figure 3: Annual Number of Structures Installed and Removed in the Gulf of Mexico, 1947-2014



Source: GAO analysis of Bureau of Safety and Environmental Enforcement (BSEE) data. | GAO-16-40

Between the late 1940s and early 1960s, lessees only drilled wells in shallow water. However, starting in the mid-1960s, lessees began drilling wells in deep water. Figure 4 shows the annual number of wells drilled and plugged in deep water in the Gulf from 1966 through 2014. During this time period, lessees drilled a total of 6,468 wells (including exploratory and development wells) and plugged a total of 2,489 wells (including temporary and permanently abandoned wells) in deep water. Lessees also installed 112 structures—mostly fixed platforms, spar, tension leg platforms, and floating production systems—and removed 19 structures in deep water during this time period.

Figure 4: Annual Number of Deepwater Wells Drilled and Plugged in the Gulf of Mexico, 1966-2014



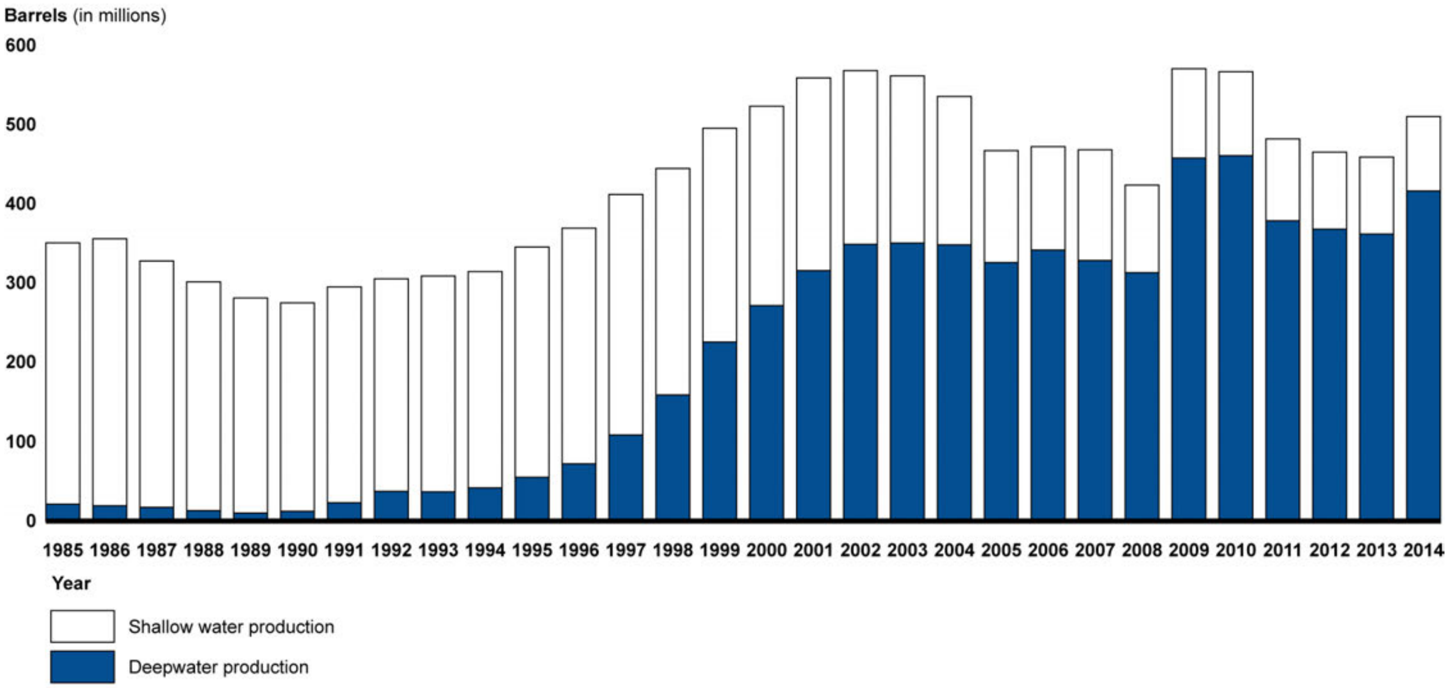
Source: GAO analysis of Bureau of Safety and Environmental Enforcement (BSEE) data. | GAO-16-40

Note: Wells drilled include exploratory and development wells drilled in greater than 400 feet of water. Wells plugged include temporary and permanent well abandonments in greater than 400 feet of water.

Since 1985, oil production from deepwater wells has increased significantly, as shown in figure 5. While the number of wells drilled has decreased in recent years, offshore production has increased as lessees have drilled wells in deep water that are more productive than wells in shallower water. In 2014, over 80 percent of Gulf oil production occurred in deep water, up from 6 percent in 1985.[24] According to BSEE officials, activities in deep water, including drilling and decommissioning, are significantly more expensive than those in shallow water because of the technology required and challenges associated with deep water, such as very high pressures at significant water and well depths.

[24]For these data, Interior defined deep water as depths of greater than 1,000 feet. According to Interior's data, gas production in deep water also increased dramatically over this period, from less than 1 percent of total Gulf production in 1985 to over 50 percent in 2014.

Figure 5: Oil Production in the Gulf of Mexico, 1985-2014



Source: GAO analysis of Bureau of Ocean Energy Management (BOEM) data. | GAO-16-40

Interior Has Procedures to Oversee Decommissioning and Estimate Related Costs but Faces Data System Limitations and Has Not Documented Some Procedures

Interior's BSEE has developed procedures to oversee the decommissioning of offshore oil and gas infrastructure and estimate costs associated with decommissioning liabilities, but limitations in its data system may affect the accuracy and completeness of some cost estimates. In addition, BSEE has not documented some of its procedures for identifying and tracking infrastructure that needs to be decommissioned and for estimating the related costs.

BSEE Has Procedures to Oversee Decommissioning and Estimate Costs, but Data System Limitations May Affect the Accuracy and Completeness of Some Cost Estimates

Officials in BSEE's Gulf regional office have developed procedures for overseeing the activities of lessees in decommissioning oil and gas infrastructure in the Gulf and estimating the costs of doing so, but limitations in its data system for estimating costs may affect the accuracy and completeness of some cost estimates.

Procedures for Overseeing Decommissioning

Under BSEE's regulations, lessees must apply for approval before plugging wells, removing platforms and clearing sites, and decommissioning pipelines. According to BSEE regional officials, they review applications to ensure that they contain the required information (see table 1 below). Once this process is complete, BSEE officials approve a lessee's application, which authorizes the lessee to begin decommissioning activities.

Table 1: Bureau of Safety and Environmental Enforcement (BSEE) Requirements for Decommissioning Applications for Offshore Oil and Gas Infrastructure

Type of application	Description
Plugging wells[a]	Lessees must provide the following information: (1) reason for plugging the well; (2) recent well test and pressure data; (3) maximum possible surface pressure; (4) type and weight of well-control fluid to be used; (5) description of work; (6) current and proposed well schematic and description; and (7) certification by a registered professional engineer of the well abandonment design and procedures, and that all plugs meet BSEE requirements.
Removing platforms or other facilities	Lessees must provide the following information: (1) identification and description of the structure to be removed; 2) description of vessel(s) used to remove structure; (3) identification of purpose for removing structure; (4) description of removal method (e.g., explosives); (5) plans for transportation and disposal or salvage of removed platform; (6) if available, results of any recent biological surveys conducted in vicinity of structure; (7) and plans to protect archaeological and sensitive biological features during removal operations, among other things.
Decommissioning pipelines	If decommissioning a pipeline in place, lessees must submit information on the proposed decommissioning procedures and the length of the segment to be decommissioned and left in place, among other things. If removing a pipeline, lessees must submit information on the proposed removal procedures and length of segment to be removed, among other things.

Source: GAO analysis of BSEE documentation. | GAO-16-40

[a]BSEE has established requirements for an application to permanently plug a well and to temporarily abandon a well. This table reflects requirements for an application to permanently plug a well.

After lessees complete all planned decommissioning, they are required to report to BSEE on the outcome of these activities so that BSEE may verify that all their decommissioning obligations have been met, including clearing the seafloor around wells, platforms, and other facilities.

According to BSEE regional officials, they review lessee reports on decommissioning activities to ensure that the results are consistent with the information presented as part of the application process. Table 2 summarizes BSEE's reporting requirements related to the results of decommissioning activities.

Table 2: Bureau of Safety and Environmental Enforcement (BSEE) Requirements for Reporting on Decommissioning Results for Offshore Oil and Gas Infrastructure

Type of report	Description
Plugging wells	Lessees must submit a report within 30 days after plugging a well. This report must include the following information: (1) information included with request submitted before permanently plugging the well along with a final well schematic; (2) description of plugging work; (3) nature and quantities of material used in plugs; and (4) description of methods used for casing removal (including information on explosives, if used), among other things.
Removing platforms or other facilities	Lessees must submit a report within 30 days after removing a platform or other facility. This report must include the following information: (1) summary of removal operations including completion date; (2) description of any mitigation measures taken; and (3) signed statement certifying that the types and amounts of explosives used in removing the platform were consistent with those set forth in the approved removal application.
Decommissioning pipelines	Lessees must submit a report within 30 days after decommissioning a pipeline. This report must include the following information: (1) summary of the decommissioning operation including completion date; (2) description of any mitigation measures taken; and (3) signed statement certifying that the pipeline was decommissioned according to the approved application.
Clearing sites around wells, platforms, and other facilities	Lessees must verify that a site is clear of obstructions within 60 days of plugging a well or removing a platform or other facility. Lessees then must submit a report within 30 days after verifying site clearance to certify to BSEE that all site clearance activities are completed. For wells, this report must include the following information: (1) signed certification that the well site area is cleared of all obstructions; (2) date the verification work was performed and the vessel used; (3) extent of the area surveyed; (4) survey method used; and (5) results of the survey, among other things. For platforms and other facilities, this report must include the following information: (1) letter (signed by the lessee) certifying that the platform or area is cleared of all obstructions and that a company representative witnessed the activities; (2) letter (signed by contractor) certifying that it cleared the platform or area of all obstructions; (3) date that work was performed and vessel used; (4) extent of area surveyed; (5) survey method used; and (6) survey results, among other things.

Source: GAO analysis of BSEE documentation. | GAO-16-40

According to BSEE regional officials, during the process of reviewing lessee reports, BSEE may issue a notice of an "incident of noncompliance" in cases where lessees have not provided all of the required information or when lessee activities are not consistent with BSEE regulations. If BSEE officials determine that the violation is not severe or threatening, they will issue a "warning" notice that requires the lessee to correct the violation within a specified period of time. If BSEE officials determine that the violation is more serious, they will issue a "shut-in" notice that requires the lessee to correct the violation before resuming activities. In addition, BSEE officials can assess a civil penalty of up to $40,000 per violation per day if the lessee fails to correct the violation in the period of time specified in the notice, or if the violation resulted in a threat of serious harm to human life or damage to the environment.

In addition to reviewing lessee applications and reports, the BSEE Gulf region identifies and tracks idle and terminated lease infrastructure. According to BSEE regional officials, the BSEE Gulf region began identifying and tracking idle lease infrastructure in 2010 and currently updates a list of this infrastructure on an annual basis. BSEE began identifying and tracking terminated lease infrastructure prior to 2010, according to BSEE regional officials. At the beginning of each calendar year, BSEE regional officials obtain data from Interior's main data system—the Technical Information Management System (TIMS)—on wells and structures on leases that meet the criteria for idle and terminated lease infrastructure.[25] Based on these data, BSEE sends a list of idle and terminated lease infrastructure to each lessee, requesting a decommissioning plan and schedule for decommissioning the lessee's inventory. According to BSEE regional officials, BSEE works with lessees to verify the accuracy of their inventory of idle and terminated lease infrastructure, and BSEE tracks lessees' progress in meeting their schedules.[26]

Procedures for Estimating Costs

According to BSEE regional officials, BSEE estimates the costs associated with decommissioning liabilities by counting the number and types of wells, pipeline segments, and structures on a lease and using

[25]According to the Federal IT Dashboard, TIMS is a computerized information system that automates many of the business and regulatory functions of BSEE and BOEM. TIMS enables staff of the regional and headquarters offices of both BSEE and BOEM to share and combine data; create and print maps; standardize processes, forms, and reports; and promote the electronic submission of data.

[26]According to BSEE data, lessees have made progress in decommissioning idle infrastructure in the Gulf. Specifically, in 2010, there were 3,233 idle wells and 617 idle platforms in the Gulf and, as of June 15, 2015, there were 1,082 idle wells and 245 idle platforms in the Gulf.

data on the water depth associated with this infrastructure.[27] Using these data, BSEE then calculates the costs associated with (1) plugging and abandoning wells, (2) removing platforms and other structures, (3) decommissioning pipelines, and (4) clearing debris from the site.

In general, the cost to plug wells and remove structures increases as the water depth increases. For example, according to BSEE's current methodology, its estimate of the cost to plug a dry tree well attached to a fixed structure in shallow water is $150,000, while its estimate of the cost to plug a subsea well in deep water is a minimum of about $21 million. Likewise, BSEE's estimates of the costs to remove fixed platforms in shallow water range from approximately $85,000 to $4.6 million, while its estimate of the cost to remove a floating structure (and associated equipment) in deep water is a minimum of $30 million.

According to BSEE regional officials, a number of events can trigger BSEE's review of the costs associated with decommissioning liabilities on a lease. Examples of these events include the following:

- BSEE determines that a lessee is planning a potential sale or acquisition of leases.
- BOEM or BSEE detect indications of financial stress for a lessee.
- BOEM requests a review of a pending request for lease assignment and bond cancellations.
- A lessee requests a review from BSEE when some but not all infrastructure is decommissioned on a lease.

BSEE enters and stores its cost estimates of decommissioning liabilities in TIMS. However, according to BSEE regional officials, TIMS is limited in its ability to accurately and completely record cost estimates of decommissioning liabilities, as follows:

- TIMS contains three data fields to record cost estimates for each offshore lease—one for estimates of the cost of removing existing structures, one for estimates of the cost of plugging existing wells, and one for estimates of the cost of clearing debris from sites. TIMS uses algorithms developed in the 1990s to calculate cost estimates for

[27] The BSEE Gulf regional office established a Decommissioning Support Section in December 2013 to estimate costs associated with decommissioning liabilities in the Gulf. Prior to that date, BSEE officials in other sections within the Gulf regional office were assigned the responsibilities associated with estimating these costs.

each of these data fields. However, BSEE officials said that the cost estimates are too low compared to BSEE's current estimates. For example, TIMS calculates the cost to plug a well is $100,000, regardless of water depth or the type of well, while BSEE estimates the cost to plug a subsea well in deep water is approximately $21 million.

- TIMS does not contain separate data fields for recording the estimated cost to plug a planned well (as opposed to an existing well) or to decommission pipelines. BSEE officials said that both of these costs are important to consider and to estimate a lessee's potential decommissioning liability.

Because of these limitations, BSEE regional officials said that, in 2009, they began investing more time and resources into manually updating cost estimates of decommissioning liabilities in TIMS. Currently, BSEE officials use separate spreadsheets—containing updated methodologies for estimating costs in shallow and deep water—to estimate costs to decommission leases. They then manually enter the cost estimates into TIMS using separate data fields entitled "adjusted decommissioning liability" for each type of cost estimate; for example, plugging wells, removing structures, and site clearance. In addition, they add estimated costs for (1) plugging planned wells into the "adjusted decommissioning liability" data field for existing wells and (2) decommissioning pipelines into the "adjusted decommissioning liability" data field for site clearance. Once they enter these data, TIMS automatically populates the date of that entry into an "updated" data field.

According to BSEE regional officials, they have manually entered updated cost estimates for most leases in the Gulf. Specifically, as of July 8, 2015, BSEE officials said that they had entered updated cost estimates for 3,460 (86 percent) of the 4,021 leases in the Gulf with decommissioning liabilities. BSEE officials characterized their efforts to update cost estimates as an "ongoing process" and said that their activities related to cost estimating have increased dramatically over the past decade. Officials said that while there was no set time frame by which they plan to update cost estimates for all the leases in the Gulf, the number of leases changes over time, and BSEE prioritizes its efforts on those leases that BOEM and BSEE determine pose higher financial risk.

BSEE regional officials told us that Interior is transitioning to a new data system (the National Consolidated Information System) to manage offshore oil and gas activities and that BSEE plans to use the new data system to improve how decommissioning liabilities are calculated and recorded. However, officials were unable to provide details on how the new data system will address the existing data limitations in TIMS or when they expect to implement these improvements in the new data system. Internal control standards in the federal government call for agencies to ensure that all transactions and events are completely and accurately recorded.[28] Without the ability to completely and accurately record data on decommissioning costs, some of BSEE's estimates of decommissioning liabilities may not be complete or accurate, and BOEM may not have reasonable assurance that it is requiring sufficient amounts of financial assurance based on BSEE's estimates.

BSEE Does Not Have Finalized, Documented Procedures for Identifying and Tracking Infrastructure That Needs to Be Decommissioned or for Estimating Costs

BSEE officials in the Gulf regional office told us BSEE does not have documented procedures for identifying and tracking idle and terminated lease infrastructure or finalized documented procedures for estimating costs associated with decommissioning liabilities. Specifically, BSEE regional officials told us the bureau did not have documentation, such as standard operating procedures or operating manuals that described their process for identifying and tracking infrastructure. BSEE regional officials provided draft documentation outlining their approach to estimating costs associated with plugging wells, removing structures, and decommissioning pipelines; however, they told us that these documents had not been finalized and were a "work in progress." According to these officials, these documents replace an older policy manual and were developed in 2014 after BSEE established the Decommissioning Support Section within the Gulf regional office.[29]

In addition, BSEE's draft documents outlining its approach to estimating the costs of decommissioning liabilities do not address how BSEE regional officials plan to periodically assess the methodology for estimating costs, as recommended by an internal Interior review. Specifically, in fiscal year 2009, Interior conducted an internal review of its procedures related to its financial accountability and risk management

[28] GAO/AIMD-00-21.3.1.

[29] Department of the Interior, Minerals Management Service, *Policy Manual Part 640.1 - Financial Accountability and Risk Management (FARM) Program* (Washington, D.C.: July 22, 2008).

program. In an internal report,[30] Interior stated that program officials estimated costs using data that had not been updated in over 14 years. The report recommended that the program develop and implement a formal policy to review and revise all assessments at least once every 5 years for all regions.[31] It also recommended that program officials consider adjusting assessments to reflect the cost of inflation during the period between the 5-year updates. To date, BSEE regional officials have not developed and implemented formal procedures addressing these recommendations.

Internal control standards in the federal government call for agencies to clearly document internal controls, and the documentation should appear in management directives, administrative policies, or operating manuals.[32] According to BSEE regional officials, they plan to establish documented procedures to identify and track idle and terminated lease infrastructure and estimate costs, but have not done so due to competing priorities, among other reasons. Without finalized, documented procedures, BSEE does not have reasonable assurance that it will consistently conduct such activities in the future, which could limit the effectiveness of Interior's oversight of the decommissioning process and its ability to obtain sufficient financial assurances to cover decommissioning liability.

[30]Department of the Interior, Minerals Management Service, *Offshore Energy and Minerals Management, Supplemental Bonding Process, Fiscal Year 2009 Internal Control Review* [publication date not listed].

[31]In keeping with this recommendation, BSEE's Pacific regional office customarily prepares a decommissioning cost report every 5 years to determine estimated decommissioning costs for its region and to support decisions regarding bonding requirements.

[32]GAO/AIMD-00-21.3.1.

Interior's Procedures for Obtaining Financial Assurances for Decommissioning Liabilities Pose Risks to the Federal Government, and Interior Plans to Revise Them

Interior's procedures for obtaining financial assurances for offshore decommissioning liabilities pose financial risks to the federal government. Officials from Interior's BOEM told us that the bureau plans to revise its procedures that determine how much financial assurance a lessee must provide, and that they expect these procedures to reduce the risk that the government could incur costs associated with decommissioning.

BOEM's Procedures for Obtaining Financial Assurances for Decommissioning Liabilities Pose Risks to the Federal Government

BOEM's procedures for obtaining financial assurances for offshore decommissioning liabilities pose financial risks to the federal government in three ways. First, as of October 2015, according to BOEM officials, BOEM had identified approximately $2.3 billion in decommissioning liabilities in the Gulf that may not be covered by financial assurances but was unable to determine in a timely manner the extent to which these liabilities were valid. Specifically, after identifying data on potentially uncovered decommissioning liabilities in TIMS, BOEM officials analyzed these data over several months to determine their validity. That is, BOEM officials tried to determine the extent to which these liabilities were accurate and the extent to which valid liabilities were covered by financial assurances. BOEM officials told us that, based on their analyses, some of the $2.3 billion in decommissioning liabilities may be valid and uncovered by financial assurances.[33]

However, according to BOEM officials, they were unable to quantify how much of the $2.3 billion in decommissioning liabilities were valid and uncovered by financial assurances due to limitations with the TIMS data system and inaccurate data, among other things. For example, BOEM officials stated that existing reports generated by the TIMS data system

[33]For example, according to BOEM officials, BSEE recently began updating its estimates of decommissioning liabilities associated with pipelines in the TIMS data system. As a result, BOEM officials said that data associated with these decommissioning liabilities may be valid.

did not provide all the necessary information for determining the validity of data on decommissioning liabilities and financial assurances. As a result, officials said that they had to create new reports to access additional data stored in TIMS, and that these efforts were time consuming. In addition, BOEM officials said that they identified leases that did not have wells or platforms but for which TIMS contained estimates of decommissioning liabilities. BOEM officials said that data associated with these decommissioning liabilities may not be valid but that they would need to consult with BSEE officials to determine their validity, which would take additional time.

BOEM officials stated that, in order to determine the validity of the data in TIMS, they plan to consult with BSEE officials and continue to analyze relevant data. Once they have determined the validity of the data, they said that they will take steps to obtain financial assurances for any uncovered decommissioning liabilities. However, officials were unable to provide details on how or when they planned to address existing limitations with the TIMS data system or determine the accuracy of data on decommissioning liabilities. Internal control standards in the federal government call for agencies to ensure that pertinent information is identified, captured, and distributed in a form and time frame that permits people to perform their duties efficiently.[34] Without timely access to valid data on decommissioning liabilities in the Gulf and associated financial assurances, BOEM does not have reasonable assurance that it has sufficient financial assurances in place, putting the federal government at risk.

Second, under BOEM's procedures, less than 8 percent of estimated decommissioning liabilities in the Gulf are covered by financial assurance mechanisms such as bonds. Specifically, as of October 2015, according to BOEM officials, for an estimated $38.2 billion in decommissioning liabilities in the Gulf, BOEM held or required about $2.9 billion in bonds and other financial assurances.[35] For $33.0 billion in decommissioning liabilities, BOEM waived 47 lessees from the requirement to provide

[34]GAO/AIMD-00-21.3.1.

[35]As of October 2015, BOEM held about $1.8 billion in bonds (including supplemental and general bonds) and about $500 million in trust agreements. In addition, BOEM had issued letters requiring lessees to provide about $600 million in financial assurances.

supplemental bonds based on BOEM's reviews of the lessees' financial strength, according to BOEM officials.[36, 37]

Under BOEM's current financial assurance procedures,[38] each offshore lease with a decommissioning liability must be covered by a supplemental bond unless BOEM determines that a lessee has the financial ability to fulfill its decommissioning obligations. BOEM staff evaluate the financial ability of a lessee to fulfill its decommissioning obligations by means of a financial strength test. BOEM's financial strength test requires a lessee to meet the following criteria:

- provide an independently audited financial statement indicating a net worth greater than $65 million;
- possess a total decommissioning liability (as determined by BSEE) of less than or equal to 50 percent of its audited net worth;
- possess total company liabilities of no more than 2 to 3 times the value of the adjusted net worth;[39, 40] and

[36]For the purposes of ensuring that there is at least one responsible party with the financial ability to fulfill lease decommissioning obligations, BOEM attributes all lease decommissioning liabilities to any waived lessee on a lease (even if other responsible parties are present on the lease). The waived lessee is, with all other lessees, jointly and severally liable for decommissioning and relies on its financial strength to secure the costs of this decommissioning, on behalf of all the jointly and severally liable parties.

[37]Under Interior regulations, regional directors may determine that a supplemental bond is necessary to ensure compliance with a lessee's obligations. According to Interior officials, supplemental bonding becomes a requirement once the regional director determines that it is necessary.

[38]Department of the Interior, Minerals Management Service, *Notice to Lessees and Operators of Federal Oil, Gas, and Sulfur Leases and Pipeline Right-of-way Holders in the Outer Continental Shelf: Supplemental Bond Procedures*, NTL No. 2008-N07 (Aug. 28, 2008).

[39]Adjusted net worth includes a percentage of a lessee's proven oil and gas reserves added to a lessee's audited net worth. BOEM varies the total liability ratio it will accept based on adjusted net worth—for example, a lessee with between $65 million and $100 million in adjusted net worth can possess total lessee liabilities of no more than 2 or 2.5 times its adjusted net worth, depending on the size of the company's potential decommissioning liability.

[40]Alternatively, BOEM allows a lessee to use a substitute criterion—the lessee must demonstrate that it produces in excess of an average of 20,000 barrels of oil equivalent per day on its leases. However, according to BOEM officials, of the 51 waived lessees only 1 or 2 chose to use this alternative criterion.

- demonstrate reliability, as shown by a record of compliance with laws, regulations and lease terms, among other factors.

If a lessee passes the financial strength test by demonstrating its financial ability to pay for decommissioning on its leases, BOEM waives its requirement for the lessee to provide supplemental bonds. Other responsible parties on the lease will also be waived from the requirement to provide supplemental bonds.[41] According to BOEM officials, BOEM waives these parties as well because the waived lessee could be held responsible if another party on a lease does not fulfill its decommissioning obligations. In addition, a waived lessee may provide financial assurance in the form of a corporate guarantee of the lease obligations of a lessee on another lease.[42]

After BOEM waives a lessee from the requirement to provide supplemental bonding, it monitors the financial strength of the lessee to ensure it continues to pass BOEM's financial strength test. BOEM conducts quarterly financial reviews for the first 2 years after a lessee receives a waiver and then an annual review thereafter.[43] In addition, on a weekly basis, BOEM compares the decommissioning obligations (as determined by BSEE) of all waived lessees with the financial information provided by lessee audited financial statements.[44] If BOEM finds that a lessee no longer passes its financial strength test, BOEM will conduct a more in-depth review of a lessee's financial status by reviewing financial statements, credit ratings, and other financial information. BOEM may also conduct an unscheduled financial review if: (1) BSEE revises its estimate of a lessee's decommissioning liability, (2) a lessee's financial status changes as reported by credit rating agencies, or (3) a lessee does

[41]In addition to bonds required by BOEM, some lessees that transfer leases or rights may require the party acquiring the lease to provide a surety bond. This bond protects the transferring party from paying decommissioning costs it may be liable for if the purchasing party is unable to fulfill its decommissioning obligations. According to BOEM officials, these bonds are generally not reported to BOEM, and BOEM does not consider them as financial assurance because BOEM is not a beneficiary of such bonds.

[42]According to BOEM officials, nearly all corporate guarantees are between parent companies and subsidiaries.

[43]These reviews evaluate the same criteria that BOEM officials used during the initial financial strength test.

[44]As part of these reviews, BOEM determines whether the waived lessee has the ability to pay for all decommissioning costs on leases where the lessee is an owner.

not pay the required royalties to the federal government. According to BOEM officials, these reviews could cause BOEM to revoke a lessee's waiver from the requirement to provide supplemental bonding. For example, in May 2015, BOEM revoked the waiver of one lessee and, according to BOEM officials, the waived lessee and related parties could be required to provide as much as $1 billion in supplemental bonds.[45]

Our prior reports have found that the use of financial strength tests and corporate guarantees in lieu of bonds poses financial risks to the federal government. Specifically, we found, in August 2005, that the financial assurance mechanisms that impose the lowest costs on the companies using them— such as financial strength tests and corporate guarantees—also typically pose the highest financial risks to the government entity accepting them.[46] In that report, we found that, if a company passes a financial strength test but subsequently files for bankruptcy or becomes insolvent, the company in essence is no longer providing financial assurance because it may no longer have the financial capacity to meet its obligations. Such financial deterioration can occur quickly. While companies no longer meeting the financial test are to obtain other financial assurance, they may not be able to obtain or afford to purchase it. In addition, in May 2012, we found that, according to the Bureau of Land Management and the Environmental Protection Agency, corporate guarantees are potentially risky because they are not covered by a specific financial asset such as a bond.[47] BOEM's use of the financial strength test and corporate guarantees in lieu of bonds raises the risk that the federal government may have to pay for offshore decommissioning if lessees do not.

The third way BOEM's procedures pose financial risks to the federal government is that BOEM's financial strength test relies on measures that may not provide an accurate indication of a lessee's ability to pay for

[45]In cases where BOEM revokes a lessee's waiver from the requirement to provide supplemental bonding, the lessee or other responsible parties on a lease or recipients of corporate guarantees would be required to provide supplemental bonds to cover decommissioning obligations that are no longer covered by a waiver or guarantee.

[46]GAO, *Environmental Liabilities: EPA Should Do More to Ensure That Liable Parties Meet Their Cleanup Obligations,* GAO-05-658 (Washington, D.C.: Aug. 17, 2005).

[47]GAO, *Phosphate Mining: Oversight Has Strengthened, but Financial Assurances and Coordination Still Need Improvement,* GAO-12-505 (Washington, D.C.: May 4, 2012).

decommissioning. As described above, BOEM uses net worth (from a lessee's audited financial statements) as a key measure in its financial strength test. However, according to representatives from credit rating agencies we spoke to, net worth provides limited value to assess a company's financial strength and ability to pay future liabilities. Specifically, these representatives said that net worth is "backward looking" and can be skewed by the volatile nature of commodity prices, among other factors. Credit rating agencies use financial measures that emphasize the evaluation of cash flow, such as debt-to-earnings and debt-to-funds from operations to evaluate whether a company will be able to pay its liabilities. Without the use of similar measures in its financial assessments, BOEM may not have reasonable assurance that the lessees it waives from the requirement to provide supplemental bonds have the financial abilities to fulfill decommissioning obligations, which may increase the financial risk to the government.

BOEM Plans to Revise Its Procedures to Reduce Financial Risks

According to BOEM officials, BOEM recognizes the financial risks associated with its current financial assurance procedures and plans to revise its procedures to reduce risk. Specifically, BOEM officials told us that BOEM's planned revisions would eliminate the use of financial strength tests to completely waive lessees from the requirement to provide supplemental bonding. Instead, BOEM plans to conduct financial reviews of lessees' financial status and, based on those reviews, assign lessees an amount of credit that may be used to reduce required bonding associated with decommissioning liabilities on leases. Lessees would be able to apportion this credit to leases, in coordination with other responsible parties on those leases, to ensure that lease decommissioning liabilities are fully covered by apportioned credit or supplemental bonds. As part of BOEM's financial review of lessees, these officials told us that BOEM plans to use criteria that emphasize the use of measures such as cash flow and company liquidity while deemphasizing the use of net worth. In addition to these planned revisions, in August 2014, BOEM announced its intent to update its regulations and program oversight for offshore financial assurance requirements.[48] BOEM solicited stakeholder comments in response to this proposal and has held industry

[48]79 Fed. Reg. 49027 (Aug. 19, 2014). According to BOEM officials, BOEM expects to promulgate these new regulations in 2017.

forums to discuss potential changes to its financial assurance regulations and procedures.

According to BOEM officials, if BOEM were to use these criteria as part of its financial strength test, some of the lessees currently waived from the requirement to provide supplemental bonds could lose their waivers. BOEM officials also stated that, if the revised procedures are implemented as planned, lessees could be required to provide several billion dollars in additional supplemental bonds. BOEM officials told us they plan to update the bureau's financial assurance procedures in late 2015 or early 2016. In commenting on a draft of this report, Interior officials stated that on September 22, 2015, BOEM issued proposed guidance to clarify its financial assurance procedures. However, it is too soon to evaluate the specific details of BOEM's proposed changes to its financial assurance procedures because BOEM has not issued any final revisions to its procedures. Until BOEM revises and implements new procedures, the federal government remains at greater risk of incurring costs should lessees fail to decommission offshore oil and gas infrastructure as required.

Interior Faces Two Key Challenges Managing Potential Decommissioning Liabilities

Interior faces two key challenges managing potential decommissioning liabilities. First, BSEE does not have access to all relevant data from lessees on costs associated with decommissioning activities in the Gulf. Second, BOEM's requirements for reporting the transfers of lease rights may impair its ability to manage decommissioning liabilities.

BSEE Does Not Have Access to All Relevant Data on Decommissioning Costs

BSEE does not have access to all relevant current data on costs associated with decommissioning activities in the Gulf. Internal control standards in the federal government call for agencies to obtain information from external stakeholders that may significantly affect their abilities to achieve agency goals.[49] Obtaining accurate and complete information on the decommissioning costs is critical to Interior being able

[49] GAO/AIMD-00-21.3.1.

to achieve its goals. Specifically, BSEE needs accurate and complete information on decommissioning costs to estimate decommissioning liabilities in the Gulf, and BOEM relies on BSEE's estimates to ensure that it is requiring sufficient amounts of financial assurance to cover decommissioning liabilities.

However, BSEE generally has not had access to current data on decommissioning costs. Prior to December 2015, under BSEE's regulations, lessees were not required to report costs associated with decommissioning activities to BSEE. According to BSEE regional officials, data on decommissioning costs were considered proprietary, and companies generally did not share this information with BSEE. Instead, BSEE regional officials relied on other sources of data—some of which are decades old and, as a result, likely inaccurate—to estimate costs associated with decommissioning liabilities. According to BSEE regional officials, their estimates for decommissioning liabilities in shallow water were based on data provided by the oil and gas industry in 1995.[50] For decommissioning liabilities in water depths of 400 to 1,400 feet, their estimates were based on information in a 2009 report that Interior contracted.[51] For decommissioning liabilities for subsea wells, BSEE officials said that they had developed their own models for estimating costs based on an analysis of a variety of factors, such as the daily cost of hiring a vessel in the Gulf to plug wells.

During the course of our audit, BSEE regional officials told us that they planned to improve this process and the resulting data by issuing a regulation requiring such data to be submitted. Specifically, Interior issued a proposed rule in May 2009 to establish new requirements for lessees to submit expense information on costs associated with plugging and abandonment, platform removal, and site clearance.[52] In December 2015, BSEE issued a final rule establishing these requirements.[53] However,

[50]BSEE officials told us that they are preparing to request proposals to fund a new study to evaluate the costs associated with structure removal in shallow water in the Gulf and have proposed studies to evaluate costs associated with pipeline decommissioning and well plugging in shallow water.

[51]Proserv Offshore, *Gulf of Mexico Deep Water Decommissioning Study: Final Report*, prepared for Interior's Minerals Management Service (Houston, Tex: October 2009).

[52]74 Fed. Reg. 25177 (May 27, 2009).

[53]80 Fed. Reg. 75806 (Dec. 4, 2015) (effective Jan. 4, 2016).

according to BSEE regional officials, the rule does not require lessees to submit expense information on costs associated with decommissioning pipelines, and officials were unable to provide details as to when or whether BSEE would issue a new rule to require the reporting of such costs. Unless and until BSEE obtains all relevant cost data, BSEE may continue to use outdated information to assess decommissioning liabilities. Without access to accurate and complete information on decommissioning costs, BSEE may not have reasonable assurance that its estimates of decommissioning liabilities in the Gulf are accurate, and BOEM may not have reasonable assurance that it is requiring sufficient amounts of financial assurance based on BSEE's estimates.

Absence of a Clear Reporting Deadline for Transfers of Revenue Rights May Impair BOEM's Ability to Manage Decommissioning Liabilities

The absence of a clear deadline for reporting transfers of rights to lease production revenue may impair BOEM's ability to manage decommissioning liabilities. Under BOEM's financial assurance procedures, BOEM must obtain accurate information on a lessee's financial status to determine whether the lessee has sufficient financial strength to meet its decommissioning obligations, and BOEM may waive its requirement for the lessee to provide supplemental bonds based on this information. However, the transfer of rights to a lease may affect a lessee's financial status. For example, lessees may transfer lease ownership and the right to operate on a lease, which also obligates the new owner to decommission infrastructure on the lease. Under Interior regulations, these transfers must be approved by BOEM.[54]

Lessees can also transfer rights to lease production revenue.[55] Transfers of these revenue rights generally allow the receiving party to obtain a portion of the revenue from oil and gas production over a period of time and the lessee, in turn, is paid in advance of production. The more revenue rights a lessee transfers to other parties, the less revenue the lessee has to cover its other obligations, including decommissioning. However, unlike transfers of lease ownership and operating rights, transfers of revenue rights do not obligate the new owner to decommission, and lessees are not required to obtain BOEM's approval for these transfers. BOEM requires lessees to report these transfers, but

[54] 30 C.F.R. § 556.64(a).

[55] For the purposes of this report, we use the term "revenue rights" in place of "overriding royalty interests" and "payments out of production."

its regulations do not establish a clear deadline for the reporting.[56] As a result, BOEM is not always aware of such transfers in a timely manner.

For example, in one recent case, a waived lessee that had previously transferred most of its revenue rights to other parties subsequently declared bankruptcy. BOEM was unaware of these transfers until bankruptcy court proceedings. Had BOEM been aware of these transfers during its weekly review of the waived lessee, it could have revoked the lessee's waiver if it determined the lessee no longer passed the financial strength test. Consequently, BOEM then could have required the lessee or its co-lessees to provide supplemental bonds to cover its decommissioning obligations. In this case, the transfer of revenue rights left the lessee with insufficient assets to pay all of its liabilities during bankruptcy, including decommissioning. Though other lessees were held liable for decommissioning costs under joint and several liability, the government was at increased risk of incurring costs if the other lessees had been unwilling or unable to perform decommissioning.

BOEM officials told us that they created an internal group to help improve BOEM's knowledge of revenue rights transfers and the effect of transfers on a lessee's financial status. In commenting on a draft of this report, BOEM officials stated that they believe that current regulations could be interpreted as imposing a reporting deadline but recognize the need to clarify the regulations. Without a clear reporting deadline, lessees have little incentive to report revenue rights transfers to BOEM in a timely manner, and this could limit BOEM's ability to effectively evaluate a lessee's financial strength.

Conclusions

Decommissioning offshore oil and gas infrastructure is expensive and poses potential financial liabilities to the federal government. BSEE officials in the Gulf region have developed procedures for reviewing idle and terminated lease infrastructure to ensure that this infrastructure is decommissioned. In addition, in December 2015, BSEE issued final regulations (proposed in 2009) requiring lessees to report decommissioning costs directly to BSEE. However, several problems

[56] The regulations at 30 C.F.R. § 556.64 establish a 90-day deadline for the reporting of transfers of interest but do not define the term "interest." In discussions with BOEM officials in the Gulf regional office, BOEM officials did not interpret these regulations as imposing a reporting deadline for transfers of lease production revenue.

remain. First, BSEE's recent regulations do not require lessees to report costs associated with decommissioning pipelines. Unless and until BSEE obtains all relevant cost data, it may continue to use outdated data to assess decommissioning liabilities. Second, limitations of Interior's current data system restrict BSEE's ability to record estimates of decommissioning costs, and it is unclear how BSEE's new data system will address these limitations or when it will be available. Without access to complete data on decommissioning costs, and without the ability to accurately and completely record data in Interior's main data system, BSEE does not have reasonable assurance that its estimates of decommissioning liabilities in the Gulf are accurate, and BOEM may not have reasonable assurance that it is requiring sufficient amounts of financial assurance based on BSEE's estimates. Third, BSEE does not have finalized, documented procedures for identifying and tracking idle and terminated lease infrastructure and estimating decommissioning liabilities. Without such documented procedures, BSEE does not have reasonable assurance that it will consistently conduct such activities in the future, which could limit the effectiveness of BSEE's oversight of the decommissioning process.

Moreover, while BOEM is taking important steps to ensure that the financial assurance procedures used by the federal government are reducing the government's exposure to decommissioning costs by updating its procedures to assess the financial strength of lessees, we continue to have three concerns. First, BOEM identified roughly $2.3 billion in decommissioning liabilities in the Gulf that may not be covered by financial assurances but was unable to determine the extent to which these liabilities were valid after several months of analysis due to limitations with the TIMS data system and inaccurate data. As a result, it is unclear whether BOEM has obtained sufficient financial assurances to cover decommissioning liabilities in the Gulf. Without timely access to valid data on decommissioning liabilities and associated financial assurances, BOEM cannot ensure that it has sufficient financial assurances in place, putting the federal government at financial risk. Second, to date BOEM has not taken concrete steps to revise its current procedures. As a result, it is unclear whether BOEM's planned revisions will improve its procedures and the extent to which these revisions will increase the amount of bonding that lessees provide. Until BOEM revises its financial assurance procedures, the federal government remains at increased risk of incurring costs should lessees fail to decommission oil and gas infrastructure. Third, BOEM is not always aware when lessees transfer rights to lease production revenue. While BOEM's current regulations require lessees to report such transfers, these regulations do not clearly establish a deadline for reporting. Without a clear reporting deadline, lessees have little incentive to report revenue rights transfers to BOEM in a timely manner, and this could limit BOEM's ability to effectively evaluate a lessee's financial strength.

Recommendations for Executive Action

To improve the effectiveness of Interior's oversight of the decommissioning process, we recommend that the Secretary of the Interior direct BSEE to establish documented procedures for identifying and tracking idle and terminated lease infrastructure.

To better ensure that the government obtains sufficient financial assurances to cover decommissioning liabilities in the event of lessee default, we recommend that the Secretary of the Interior take the following six actions:

- Ensure that BSEE collects all relevant data associated with decommissioning from lessees.
- Direct BSEE to establish documented procedures for estimating decommissioning liability.
- Develop a plan and set a time frame to ensure that Interior's data system for managing offshore oil and gas activities includes processes to accurately and completely record estimated decommissioning liabilities.
- Develop a plan and set a time frame to ensure that Interior's data system for managing offshore oil and gas activities will be able to identify, capture, and distribute data on decommissioning liabilities and financial assurances in a timely manner.
- Ensure that BOEM completes its plan to revise its financial assurance procedures, including the use of alternative measures of financial strength.
- Revise BOEM's regulations to establish a clear deadline for the reporting of transfers to require that lessees report the transfer of rights to lease production revenue.

Agency Comments and Our Evaluation

We provided a draft of this report to Interior for review and comment. Interior provided written comments, which are reproduced in appendix I, and generally agreed with our findings and concurred with our recommendations.

As agreed with your offices, unless you publicly announce the contents of this report earlier, we plan no further distribution until 30 days from the report date. At that time, we will send copies of this report to the appropriate congressional committees, the Secretary of the Interior, and other interested parties. In addition, this report will be 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 members who made major contributions to this report are listed in appendix II.

Frank Rusco
Director, Natural Resources and Environment

Appendix I: Comments from the Department of the Interior

United States Department of the Interior

OFFICE OF THE SECRETARY
Washington, DC 20240

NOV 30 2015

Mr. Frank Rusco
Director
Natural Resources and Environment
Government Accountability Office
441 G Street, NW
Washington, DC 20548

Dear Mr. Rusco:

Thank you for the opportunity to review and comment on the Government Accountability Office (GAO) draft report entitled, *Offshore Oil and Gas Resources – Actions Needed to Better Protect Against Billions of Dollars in Federal Exposure to Decommissioning Liabilities* (GAO-16-40). Thank you also for incorporating the technical edits we recommended in our letter dated October 13, 2015.

The Department of the Interior (Department) generally agrees with the findings and concurs with the recommendations directed to the Bureau of Ocean Energy Management (BOEM) and the Bureau of Safety and Environmental Enforcement (BSEE). The Department is implementing GAO's recommendations to document procedures, improve its data system, and revise financial assurance procedures and regulations.

BOEM is updating its financial assurance requirements for Outer Continental Shelf (OCS) leases and facilities to mitigate risks associated with decommissioning liability. BOEM's goal is to ensure the taxpayer never has to pay to decommission an OCS facility. Updating the financial assurance policies will better reflect current business practices and the increased cost of decommissioning OCS facilities.

On September 22, 2015, BOEM issued proposed guidance to clarify procedures for oil and gas companies operating on the OCS. Specifically, the guidance contains updated financial criteria for determining a lessee's ability to meet its financial obligations, including decommissioning liabilities, in whole or part, and the potential need for additional security. BOEM will no longer consider the combined financial strength and reliability of co-lessees or operating rights holders when determining a lessee's ability to carry out its obligations with respect to decommissioning.

BOEM intends to update its data system and create comprehensive procedures designed to decrease risks to taxpayers while providing industry flexibility to negotiate adaptive solutions and utilize tailored financial plans to meet financial assurance needs. Next year, BOEM expects to publish a Notice to Lessees and Operators, which will clarify the process BOEM will use to develop tailored plans and financial assurance requirements.

In the draft report, GAO states that BOEM regulations do not include a deadline by which filings of transfer of revenue interests must be submitted to BOEM. BOEM believes that its regulation found at 30 CFR section 556.64(a)(2) requiring submittal of the creation or transfer of an interest within 90 days of the last date that a party executes the transfer agreement could be interpreted to impose such a deadline. Nonetheless, BOEM is working to finalize a leasing rule that will clarify the deadline.

In recent years, BSEE has made considerable progress in improving its capabilities with regard to estimating decommissioning costs for OCS facilities in the Gulf of Mexico. Over the past few years, BSEE has updated cost data, revised estimation methodologies, begun consolidating decommissioning-related activities into a single program office, worked to develop new regulations, and generated thousands of updated decommissioning cost estimates for offshore wells and structures, which greatly reduced BSEE's backlog of leases requiring an updated estimate.

Despite these improvements, BSEE acknowledges that more needs to be done. BSEE intends to continue to focus on systematizing the process of updating decommissioning estimates and finalizing policy and procedures related to estimating decommissioning costs and overseeing idle infrastructure. BSEE's upcoming rule, *Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Decommissioning Costs*, will require the submission of summary decommissioning expenditures from operators, greatly improving the bureau's ability to ensure that estimates reflect actual decommissioning costs. BSEE recently received approval from the Office of Management and Budget, and anticipates publishing the rule in the *Federal Register* soon.

Once the final rule is effective, BSEE will begin collecting expenditure data on decommissioning activities as early as 120 days after the effective date. As data are collected, BSEE will review and analyze the submissions to revise current cost data and estimation techniques, and develop algorithms that will automatically generate more reliable decommissioning cost estimates for wells and structures on leases. Until that time, BSEE will continue to use existing estimation techniques, where cost estimates must be built for each lease. Additionally, BSEE will seek available opportunities to refine cost data. BSEE is currently working toward procuring contracted services to improve data quality related to costs associated with decommissioning fixed structures in under 400 feet of water. BSEE plans to undertake additional research on decommissioning costs in the current fiscal year.

Enclosed are a few additional general and technical comments for your consideration when finalizing the report. If you have any questions about this response, please contact Andrea Nygren, BOEM Audit Liaison Officer, at 202-208-4343, or Linh Luu, BSEE Audit Liaison Officer, at 202-208-4120.

Sincerely,

Janice M. Schneider
Assistant Secretary
Land and Minerals Management

Enclosure

Appendix II: GAO Contact and Staff Acknowledgments

GAO Contact

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

Staff Acknowledgments

In addition to the individual named above, Christine Kehr (Assistant Director), Jason Holliday, and David Messman made key contributions to this report. Also contributing to this report were Philip Farah, Cindy Gilbert, Paul Kinney, Risto Laboski, Alison O’Neill, and Barbara Timmerman.

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OFFICE OF
INSPECTOR GENERAL
U.S. DEPARTMENT OF THE INTERIOR

November 23, 2020

Memorandum

To: Scott A. Angelle
Director, Bureau of Safety and Environmental Enforcement

From: Amy R. Billings Amy R Billings
Regional Manager, Central Region

Subject: Announcement – Inspection of the Bureau of Safety and Environmental Enforcement's Royalty Relief Program During COVID-19
Assignment No. 2021-CR-006

We are initiating an inspection of the Bureau of Safety and Environmental Enforcement's (BSEE's) Royalty Relief Program to determine whether BSEE consistently and appropriately evaluated and processed royalty relief applications submitted as a result of COVID-19. Our review will focus on gaining an understanding of the program; evaluating policies, procedures, and laws relevant to the program; and sampling applications to evaluate compliance with such criteria. We appreciate the cooperation of BSEE officials in making staff available during this inspection.

We will work with your audit liaison officer to schedule an entrance conference, which we would like to schedule the week of December 7, 2020. An information request is attached to expedite our work. Please forward the request to the appropriate offices and provide each item as it becomes available. We appreciate receiving all information by December 4, 2020. Please note that we will begin work on the inspection immediately following the entrance conference. Due to the COVID-19 pandemic the team does not plan to visit Department offices or sites. Any limitations such as records verification, accessibility, and site visits posed by our inability to travel will be reflected in the scope and methodology sections of the report.

Colleen Kotzmoyer, Regional Supervisor, will supervise the inspection, and Paul Burns will be the team lead. If you have any questions regarding this inspection, please contact me at 303-236-9243.

Attachment

cc: Linh Luu, Audit Liaison Officer, Bureau of Safety and Environmental Enforcement
Ambria Moore, Audit Liaison Officer, Bureau of Safety and Environmental Enforcement
Molly Madden, Chief, Office of Policy and Analysis, Bureau of Safety and Environmental Enforcement
Alexis Vann, Audit Liaison Officer, Office of Financial Management
Preston Wong, Audit Liaison Officer, Office of Financial Management

OIG INFORMATION REQUEST
Inspection of BSEE's Royalty Relief Program During COVID-19

Please provide each item listed below as it becomes available. We appreciate receiving all information by December 4, 2020. Please identify the information you provide with the corresponding request number and send it to paul_burns@doioig.gov. If you have any questions or concerns regarding the data request, please email or contact Paul Burns at 720-830-8735.

1. Organization chart for the royalty relief program, to include contact information and position descriptions for those who process relief applications

2. All policies, procedures, laws, and regulations related to the royalty relief program, to include any temporary guidance that exists because of COVID-19

3. A listing of all royalty relief applications received from March 1, 2020, through September 30, 2020. The listing should include:

    a. Current status of the application

    b. Name of the lessee/applicant

    c. Requested duration of relief

    d. Requested amount of relief

4. An example of an approved royalty relief application submitted between March 1, 2020, through September 30, 2020, and all supporting documentation associated with the application, to include:

    a. Documentation provided by the lessee

    b. Documentation used by BSEE personnel to support approval of the relief

5. All training program materials and procedures provided to BSEE personnel responsible for evaluating and processing royalty relief applications

6. Evidence of any royalty relief program training that has taken place since March 1, 2020, and a listing of all BSEE attendees

UNITED STATES DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE

NTL No. 2009-N08

Effective Date: September 14, 2009
Expiration Date: September 14, 2014

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES ON THE OUTER CONTINENTAL SHELF

Application and Audit Fees for Requests for Royalty Relief or Adjustment Under 30 CFR Part 203

This Notice to Lessees (NTL) replaces NTL No. 98 5N and details information on fees for royalty relief or adjustment applications and possible audits, as well as when and how you make payments to the Minerals Management Service (MMS). We will periodically update the files to reflect changes in costs as well as provide information needed for administering the royalty relief program. The only changes from the previous NTL are: the inclusion of the authority under the Energy Policy Act of 2005, and the name of the type of request from "Pre-Act relief" to "Development project" associated with a pre-production royalty relief application.

Operators on the Federal Outer Continental Shelf (OCS) who apply for reductions, suspensions, or change of royalty or net profit share on their oil and gas leases must obtain approval from the MMS (30 CFR part 203). The OCS Deep Water Royalty Relief Act (Public Law 104-58 (DWRRA)) and section 346 of the Energy Policy Act of 2005, Pub. L. No. 109–58) clarified and expanded the Secretary of the Interior's authority in 43 U.S.C. 1337(a)(3) to reduce royalty rates on existing leases in order to promote development, increase production, and encourage production of marginal resources on producing or nonproducing leases. This NTL does not apply to royalty relief associated with producing gas from deep or ultra-deep wells on shallow water leases in the Gulf of Mexico.

The omnibus Appropriations Bill (PL. 104-134, 110 Stat. 13221, April 26, 1996) specifically authorized collection of fees. It provides:

> That beginning in fiscal year 1996 and thereafter, fees for royalty rate relief applications shall be established (and revised as needed) in Notices to Lessees, and shall be credited to this account in the program areas performing the function, and remain available until expended for the costs of administering the royalty rate relief authorized by 43 U.S.C. 1337(a)(3).

There are six types of applications/assessment requests. Different fees apply to the various categories initially. Some applicants will be eligible for significant refunds if we reject their deepwater relief applications as incomplete within the first 20 business days after receipt. A supplemental fee will be charged if, during the review period, we either initiate an audit or identify the need for an audit. Those applicants who choose to submit a draft application for deepwater royalty relief (i.e., a nonbinding assessment request) will pay less than those submitting a complete application, because we will not perform a completeness review.

The following instructions do not supersede, but are supplemental to, the procedures for royalty relief to increase production and for pre-enactment deepwater leases specified in regulations at 30 CFR part 203.

I. TYPES OF APPLICATIONS

Q. What types of royalty relief applications are available under 30 CFR 203.

A. There are five different categories:

(1) development project -- an initial request for a volume suspension on a lease or unit on a field that has not produced;

(2) redetermination of royalty relief -- a request for a redetermination of our findings before start of new production if one of three changes specified in the rule occurs;

(3) expansion project -- a request for a volume suspension on a producing deepwater lease or unit proposing development in a supplemental Development Operations Coordination Document (DOCD) approved after November 28, 1995, that will expand production significantly beyond the level anticipated in an earlier DOCD;

(4) nonbinding assessment for relief -- a draft request for a nonbinding assessment for a volume suspension on a lease or unit on a field that has not produced; and

(5) abbreviated application -- a request to add a pre-Act lease to a field with an approved volume suspension.

Q. What other type of royalty relief is available under the regulations?

A. MMS provides end-of-life relief to marginal producing leases anywhere on the OCS. Royalties are halved when lessees can show they have inadequate revenues to continue production. Special case requests to adjust royalty terms to increase ultimate recovery of the resources on the lease may also be considered.

II. FEES

Q. How much do I have to pay to apply for MMS to evaluate my royalty relief request?

A. It depends on the type of application. The following table lists the application fees by category of relief:

Fees to Cover Cost of Processing Royalty Relief Requests *		
Type of Request/Audit	**Request Fee**	**Audit Fee**
Development project	$34,000	$37,500
Redetermination of relief finding	$16,000	$37,500
Expansion project	$19,500	$18,750
Nonbinding assessment for pre-production relief	$28,500	0
Abbreviated application to add a lease to a field with an approved volume suspension	$1,000	0
End-of-life relief for marginal leases	$8,000	$12,500

* MMS may periodically update these fees to reflect changes in costs for processing requests.

Q. Under what conditions do I pay a fee?

A. You must pay an application fee when you file for royalty relief or request a nonbinding assessment or royalty adjustment. You will also pay an audit fee if we notify you that we will conduct an audit during the application evaluation process or if we notify you at approval of relief that we will conduct a later audit.

Q. How do I pay an application fee?

A. You must submit the appropriate fee by an Automated Clearing House (ACH) payment to MMS for settlement on or before the day you file your application for royalty relief or your request for a nonbinding assessment. You must file your royalty relief application or your nonbinding assessment request with the MMS Regional Director of the OCS Region where the lease(s) are located. Contact the OCS Regional Office for wiring instructions.

Q. If my application is rejected, do I get a refund?

A. Ordinarily, no refund is given when we reject an application. The one exception applies to the first three categories of deepwater royalty relief listed above. If we reject these applications for incompleteness during the first 20 business days after receiving the application, then we will refund all but $5,500 of the initial application fee. We will attempt to get any missing information from the applicants before rejecting an application as incomplete.

Q. What circumstances would trigger the need to perform an audit?

A. We may initiate an audit or identify the need to conduct an audit during the evaluation period, if we determine that additional information, clarification, or interpretation could materially affect our decision to grant royalty relief. We expect that, in most cases, audits will be completed during the evaluation period. Applications may be audited when: significant historical costs are claimed, there appear to be inconsistencies in the data, or the economic viability of the field approaches the qualification threshold.

Q. How do I pay an audit fee?

A. When we notify you that an audit will be performed, you will be sent an invoice. You must pay the invoice on or before the due date by an ACH payment to MMS.

This NTL is also on the MMS worldwide website at http://www.mms.gov.

Paperwork Reduction Act Statement: Any collection of information that we mention in this NTL provides clarification, description, or interpretation of requirements contained in 30 CFR part 203. The Office of Management and Budget has approved our collection of information required by these regulations and assigned OMB Control Number 1010-0071. This NTL does not impose additional information collection requirements that would be subject to the Paperwork Reduction Act of 1995.

Dated: AUG 27 2009

Chris Oynes

Chris Oynes
Associate Director for
Offshore Energy and Minerals Management

OFFICE OF
INSPECTOR GENERAL
U.S.DEPARTMENT OF THE INTERIOR

The Bureau of Safety and Environmental Enforcement's Decommissioning Program

Assignment No.: 2016-EAU-063

March 2019

OFFICE OF
INSPECTOR GENERAL
U.S.DEPARTMENT OF THE INTERIOR

MAR 26 2019

Memorandum

To: Scott A. Angelle
Director, Bureau of Safety and Environmental Enforcement

From: Kimberly McGovern Kimberly McGovern
Assistant Inspector General for Audits, Inspections, and Evaluations

Subject: Closeout Memorandum – The Bureau of Safety and Environmental Enforcement's Decommissioning Program
Assignment No. 2016-EAU-063

We reviewed the Bureau of Safety and Environmental Enforcement (BSEE) to determine if it was overseeing and enforcing offshore oil and gas decommissioning[1] requirements for idle infrastructure[2] on the Outer Continental Shelf (OCS). Overall, we learned that BSEE has not yet implemented decommissioning policies and procedures at the national level. We plan to initiate a review within the next 2 years, which will allow BSEE the opportunity to develop and implement a bureauwide decommissioning policy.

We found that while BSEE established policies and procedures on reviewing idle infrastructure in the Gulf of Mexico Region, the policies and procedures were never implemented. The Pacific Region did not have policies and procedures for decommissioning idle infrastructure and is not currently requiring operators to do so. Staff in the Pacific Region did not actively identify idle infrastructure, but instead relied on operators to notify them when they are ready to decommission.

BSEE senior management told us the policies have not been implemented because there are concerns that requiring operators to decommission infrastructure will force many into bankruptcy. This happened, in part, because of (1) insufficient headquarters and regional management oversight; (2) BSEE staff's need for training on enforcement procedures; and (3) regional management's concern that enforcing the Federal regulations, by forcing operators to decommission, will push additional operators into bankruptcy.

The senior staff we interviewed in the Pacific Region admitted that they never exercised their authority, while staff in the Gulf of Mexico Region did not believe BSEE had the authority to enforce decommissioning regulations. BSEE's authority for decommissioning comes from the Code of Federal Regulations (30 C.F.R. § 250.1711(b)), which states that BSEE "will order" a lessee or operator to decommission a well if it is not useful for lease operations and is not

[1] Decommissioning means ending oil, gas, or sulfur operations, removing idle infrastructure, and returning the environment to a condition that meets Federal regulations and BSEE's requirements.
[2] Idle infrastructure is a term BSEE uses for wells, platforms, and pipelines on active leases that are unused or no longer viable.

capable of production in paying quantities.[3] BSEE also has the authority to issue regulatory guidance in the form of Notices to Lessees and Operators (NTLs) to clarify and supplement existing requirements in accordance with 30 C.F.R. § 250.103.

The NTL 2010-G05, "Decommissioning Guidance for Wells and Platforms," clarifies and provides additional information on the regulatory requirements for decommissioning idle infrastructure. BSEE issued the NTL in response to an internal control review that estimated approximately one out of every three structures in the Gulf of Mexico were classified as idle. The NTL states that this idle infrastructure poses a potential threat to the environment if destroyed or damaged, which creates a greater financial liability for the regulated companies and potentially the Federal Government.

Once BSEE has the opportunity to implement decommissioning policies, we will perform our review. We appreciate the cooperation and assistance provided by your staff during our review. If you have any questions regarding this memorandum, please contact me at 202-208-5745.

[3] The production of enough oil, gas, sulfur, or other minerals to yield a positive stream of income after subtracting normal expenses.

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United States Government Accountability Office

Testimony

Before the Subcommittee on Energy and Mineral Resources, Committee on Natural Resources, House of Representatives

For Release on Delivery
Expected at 10 a.m. ET
Wednesday, May 17, 2017

OFFSHORE OIL AND GAS RESOURCES

Information on Infrastructure Decommissioning and Federal Financial Risk

Statement of Frank Rusco, Director,
Natural Resources and Environment

GAO-17-642T

GAO Highlights

Highlights of GAO-17-642T, testimony before the Subcommittee on Energy and Mineral Resources, Committee on Natural Resources, House of Representatives

May 2017

OFFSHORE OIL AND GAS RESOURCES

Information on Infrastructure Decommissioning and Federal Financial Risk

Why GAO Did This Study

Oil and gas produced on federal leases in the Gulf are important to the U.S. energy supply. When oil and gas infrastructure is no longer in use, Interior requires lessees to decommission it so that it does not pose safety and environmental hazards. Decommissioning can include plugging wells and removing platforms, which can cost millions of dollars. Interior requires lessees to provide bonds or other financial assurances to demonstrate that they can pay these costs; however, if lessees do not fulfill their decommissioning obligations, the federal government may be liable for these costs.

This statement describes offshore oil and gas infrastructure in the Gulf and Interior's requirements and procedures for overseeing decommissioning, and the risks posed by its financial assurances procedures. This statement is based on GAO-16-40 from December 2015. For that report, GAO reviewed agency regulations and procedures and interviewed officials from Interior, credit rating agencies, academia, and trade associations. GAO also followed up on the implementation status of the report's recommendations.

What GAO Recommends

Among other recommendations, GAO recommended in GAO-16-40 that Interior complete plans to revise its financial assurance procedures to address risks posed by these procedures. Interior concurred with GAO's recommendations and has taken or described planned actions to address the recommendations, which GAO will continue to monitor.

View GAO-17-642T. For more information, contact Frank Rusco at (202) 512-3841 or ruscof@gao.gov.

What GAO Found

As GAO reported in December 2015, offshore oil and gas infrastructure in the Gulf of Mexico (Gulf) varies in size and complexity, and lessees have installed and removed thousands of structures over the past half century. The simplest structures are found in shallow water and include a caisson, which is a cylindrical, large diameter steel pipe enclosing a well. A more complex structure in shallow water is a fixed platform, which uses a jacket and pilings to support the superstructure, or deck. A typical platform is designed so that multiple wells may be drilled from it. Structures in deep water rely on other methods to anchor to the ocean floor, such as using a narrow, flexible tower and a piled foundation. From 1947 through 2014, lessees drilled over 50,000 wells and installed over 7,000 structures in the Gulf. Over the same time period, lessees plugged almost 30,000 of these wells and removed about 5,000 of these structures. Oil production from deepwater wells increased significantly in recent decades, and in 2014, over 80 percent of Gulf oil production occurred in deep water.

The Department of the Interior (Interior) requires lessees to decommission offshore oil and gas infrastructure, and according to GAO's December 2015 report, Interior developed procedures for overseeing the decommissioning of offshore oil and gas infrastructure and estimating costs associated with decommissioning liabilities. According to Interior regulations, lessees must permanently plug all wells, remove all platforms and other structures, decommission all pipelines, and clear the seafloor of all obstructions created by the lease and pipeline operations when the lessee's facility is no longer useful for operations. Lessees must also permanently plug wells and remove platforms within 1 year after a lease terminates. According to officials GAO interviewed for its December 2015 report, Interior's procedures for overseeing decommissioning and estimating costs associated with decommissioning liabilities included (1) identifying and tracking unused infrastructure, (2) reviewing lessee plans to decommission infrastructure, and (3) using different cost estimates for decommissioning in shallow and deep water.

Interior requires financial assurances from lessees to cover decommissioning liabilities, but GAO's December 2015 report found that Interior's financial assurance procedures in place at that time posed risks to the federal government. Under Interior's financial assurance procedures in place at the time, each offshore lease with a decommissioning liability had to be covered by a bond unless Interior determined that a lessee had the financial ability to fulfill its decommissioning obligations. Interior's procedures allowed it to waive its requirement for a lessee to provide a bond if the lessee passed a financial strength test. However, GAO found that of $38.2 billion in decommissioning liabilities as of October 2015, Interior held or required about $2.9 billion in bonds and other financial assurances, and had foregone requiring about $33.0 billion in bonds for most of the remaining liabilities. Prior GAO work has shown that the use of financial strength tests in lieu of bonds poses risks to the federal government. GAO recommended that Interior address this risk by following through on plans to revise its financial assurance procedures. Interior issued revised financial assurance procedures in July 2016 but, according to Interior, delayed implementing them in 2017 pending a six-month review process.

Chairman Gosar, Ranking Member Lowenthal, and Members of the Subcommittee:

I am pleased to be here today to discuss our work on the decommissioning of offshore oil and gas infrastructure on federal leases. As you know, oil and gas resources located on federal leases on the outer continental shelf are an important component of the nation's energy supply.[1] The vast majority of the nation's crude oil and natural gas production on the outer continental shelf occurs in the Gulf of Mexico (Gulf). Historically, most offshore oil and gas activities have occurred in shallow water,[2] but in recent decades these activities have moved into deep water. Most active oil and gas leases in the Gulf are now located in deep water.

Management of offshore oil and gas resources is primarily governed by the Outer Continental Shelf Lands Act, which authorizes leasing,[3] exploration, development, and production of those resources. The Department of the Interior (Interior) is responsible for establishing procedures and managing oil and gas activities on offshore federal leases, including activities associated with thousands of wells, platforms, and miles of pipelines on the outer continental shelf. When this infrastructure is no longer useful for operations or otherwise becomes idle,[4] or when a lease has been expired for more than 1 year, Interior requires oil and gas lessees to decommission it so that it does not pose potential safety hazards to marine vessels and environmental hazards to sea life and humans.[5]

[1]The outer continental shelf refers to the submerged lands outside the territorial jurisdiction of all 50 states, but within U.S. jurisdiction and control. The portion of the North American continental edge that is federally designated as the outer continental shelf generally extends seaward 3 geographical miles off the coastline to at least 200 nautical miles.

[2]In this testimony, unless otherwise specified, we use the term "shallow" water to refer to depths of less than 400 feet and "deep" water to refer to depths of greater than 400 feet.

[3]For the purposes of this testimony, we use the term "lease" to include leases, grants of right of way, and right of use and easements.

[4]Interior refers to wells and platforms as "idle" if they have not been used in the past 5 years for oil and gas exploration or development and production activities.

[5]For purposes of this testimony, we use the term "lessees" to refer to owners of record title and owners of operating rights on offshore leases, designated operators acting on behalf of record title and operating rights owners, and right-of-way holders.

Decommissioning refers to the process of plugging wells, removing platforms and other structures, removing or cleaning out pipelines, and clearing sites of debris. According to Interior estimates, in shallow water, decommissioning infrastructure can cost tens of millions of dollars per lease, depending on the number of wells and types of structures present. In deep water, decommissioning can cost hundreds of millions of dollars per lease. In addition, infrastructure damaged by hurricanes is significantly more expensive to decommission than undamaged infrastructure.

Two bureaus within Interior are responsible for managing offshore oil and gas infrastructure. Interior's Bureau of Ocean Energy Management (BOEM) oversees resource management activities, including preparing the 5-year outer continental shelf oil and gas leasing program; reviews oil and gas exploration and development plans and environmental studies; and conducts National Environmental Policy Act analyses. Interior's Bureau of Safety and Environmental Enforcement (BSEE) oversees operations and environmental compliance, including reviewing drilling permits, inspecting offshore drilling rigs and production platforms, assessing civil penalties, developing regulations and standards for offshore drilling (including those related to decommissioning), and ensuring the conservation of natural resources.

My testimony today discusses information presented in our December 2015 report on potential federal liabilities associated with the decommissioning of offshore oil and gas infrastructure.[6] In particular, I will discuss (1) oil and gas infrastructure in the Gulf, (2) Interior's requirements and procedures for overseeing the decommissioning of oil and gas infrastructure, and (3) Interior's requirements and procedures for obtaining financial assurances for decommissioning liabilities and the risks posed by these procedures.

For that report, we reviewed Interior's regulations regarding its management of leases for offshore oil and gas production. We interviewed BSEE officials in their Washington, D.C., headquarters office and Gulf regional office in New Orleans, Louisiana, and reviewed and summarized relevant BSEE procedures, guidance, and related

[6]GAO*, Offshore Oil and Gas Resources: Actions Needed to Better Protect Against Billions of Dollars in Federal Exposure to Decommissioning Liabilities,* GAO-16-40 (Washington, D.C.: Dec. 18, 2015).

documentation.[7] We also interviewed BOEM officials in their Washington, D.C., headquarters office and Gulf regional office in New Orleans, Louisiana, and reviewed and summarized relevant BOEM guidance, procedures, and related documentation. Our December 2015 report includes a more detailed explanation of the scope and methodology we used to conduct our work. We also followed up on the implementation status of the report's recommendations.

We conducted the work on which this testimony is based 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.

[7]For the purposes of this testimony, we use the term "procedure" to include Interior's notices to lessees, which are intended to clarify, supplement, or provide more details about Interior's regulations; standard operating procedures; and other related documents describing Interior's processes. See 30 C.F.R. § 250.103.

Offshore Oil and Gas Infrastructure in the Gulf Varies in Size and Complexity, and Lessees Have Installed and Removed Thousands of Structures Over the Past Half Century

As we reported in December 2015, offshore oil and gas infrastructure in the Gulf varies in size and complexity, and lessees have installed and plugged or removed thousands of wells and structures over the past half century.[8] The simplest structures are found in shallow water and include caissons and well protectors. A caisson is a cylindrical or tapered large diameter steel pipe enclosing a well conductor and is the minimum structure for offshore development. A well protector provides support to one or more wells with no production equipment and facilities. Lessees drill wells to access and extract oil and gas from geologic formations. According to an Interior publication, “exploratory” wells are drilled in an area with potential oil and gas reserves, while “development” wells are drilled to produce oil and gas from a known reserve.[9] An exploratory well may not actually produce any oil or gas, while a successful development well produces oil or gas. Some wellheads are located on a fixed platform (typically in shallow water), while other wellheads are located on the seafloor (typically in deep water).

A more complex structure in shallow water is a fixed platform, which uses a jacket and pilings to support the superstructure, or deck.[10] The deck is the surface where work is performed and provides space for crew quarters, a drilling rig, and production facilities. Most of the large fixed platforms have living quarters for the crew, a helicopter pad, and room for drilling and production equipment.[11] A typical platform is designed so that multiple wells may be drilled from it. Wells from a single platform may have bottom-hole locations many thousands of feet (laterally displaced) from the surface location.

Structures in deep water rely on other methods to anchor to the ocean floor. For example, a “compliant tower” structure supports the deck using

[8]GAO-16-40.

[9]According to BSEE officials interviewed for our December 2015 report, lessees sometimes drill other types of wells, such as relief wells and core test wells. However, these types of wells represent a very small portion of the wells drilled in the Gulf.

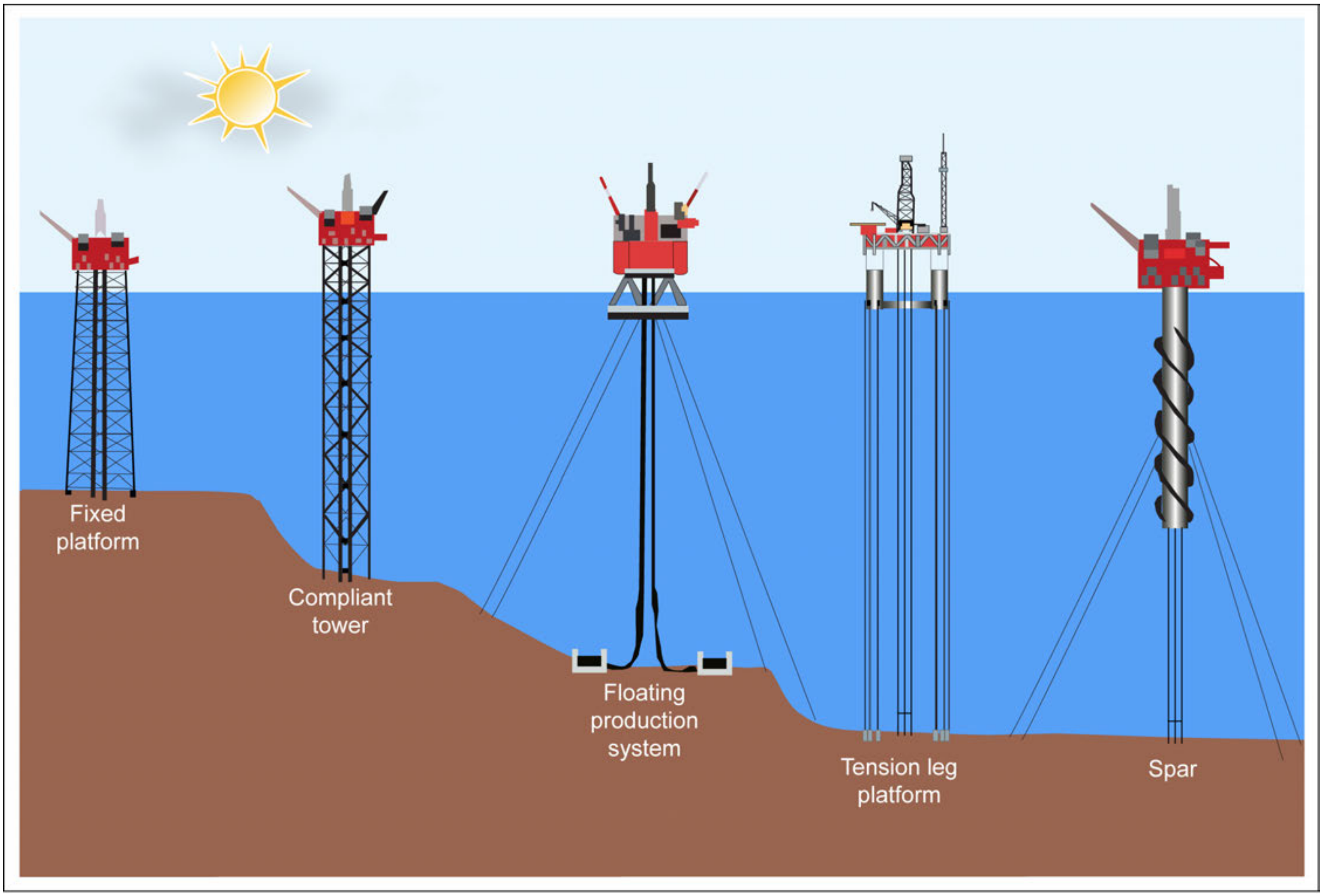
[10]A jacket is a steel structure that rests on the ocean’s floor and has columns, or legs. Pilings are driven through the legs of the jacket into the seafloor to hold the jacket in place.

[11]According to BSEE officials we interviewed for our December 2015 report, fixed platforms are typically found in shallow water, but some fixed platforms are used in water depths between 400 feet and 1,400 feet.

a narrow, flexible tower and a piled foundation. According to an industry publication, the flexible nature of the compliant tower allows it to withstand large wind and wave forces associated with hurricanes. Other common deep-water structures include the tension leg platform, floating production system, and spar platform.[12] Illustrations of these structures are shown in figure 1.

[12]A tension leg platform structure supports a floating deck using vertical steel “tendons” or a chain and wire system anchored to the seafloor by pilings. A floating production system uses a floating, semisubmersible hull equipped with drilling and production equipment. It can be anchored in place with a chain and wire system or dynamically positioned using rotating thrusters. A spar platform supports a floating deck using a long, slender column that extends far below the ocean surface. Vertical steel tendons anchor the column to the seafloor (using pilings), and guy-wires extend out diagonally to seafloor anchors for horizontal stability.

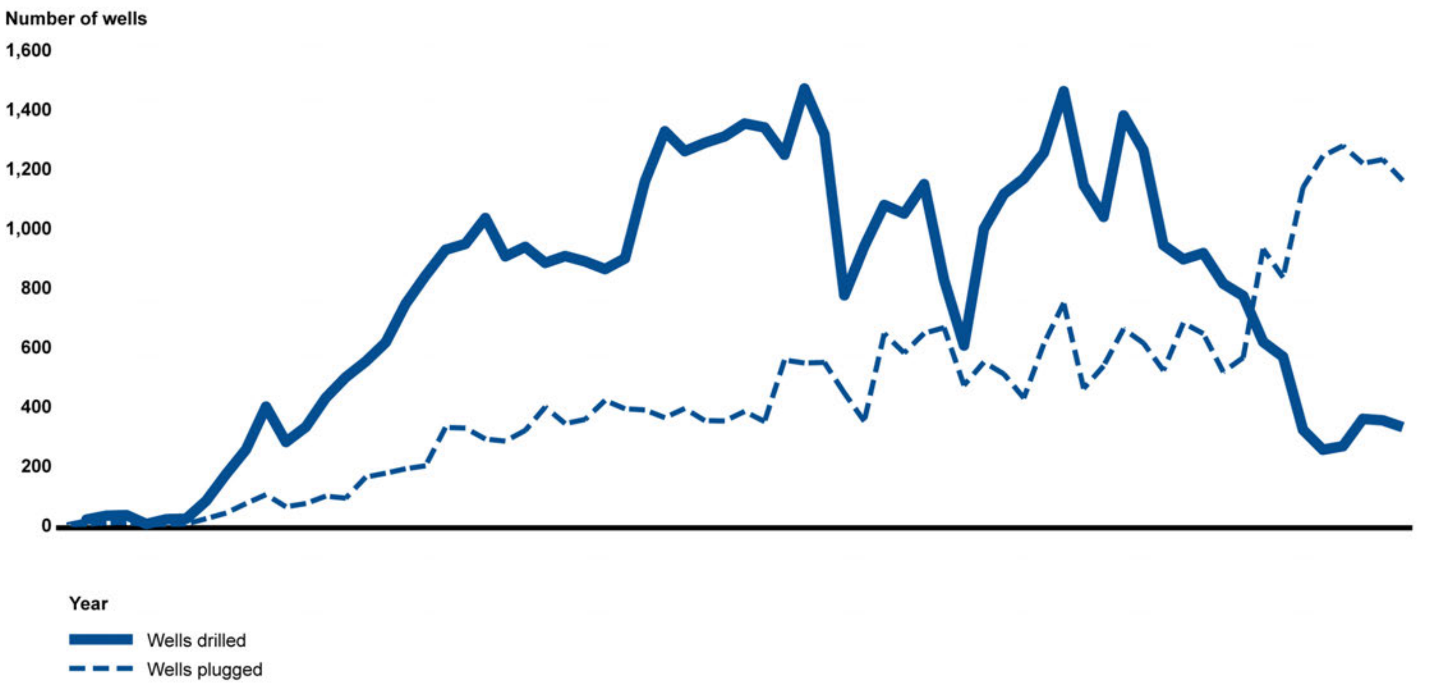
Figure 1: Examples of Oil and Gas Structures in the Gulf of Mexico



Source: GAO analysis of industry reports. | GAO-17-642T

In our December 2015 report, we also discussed the oil and gas infrastructure installed and removed in the Gulf over time. Figure 2 shows the annual number of wells drilled and plugged in the Gulf from 1947 through 2014. During this period, lessees drilled a total of 52,223 wells in the Gulf (including 18,447 exploratory wells and 33,776 development wells) and plugged a total of 29,879 wells (including 4,017 temporarily abandoned wells and 25,862 permanently abandoned wells).

Figure 2: Annual Number of Wells Drilled and Plugged in the Gulf of Mexico, 1947-2014

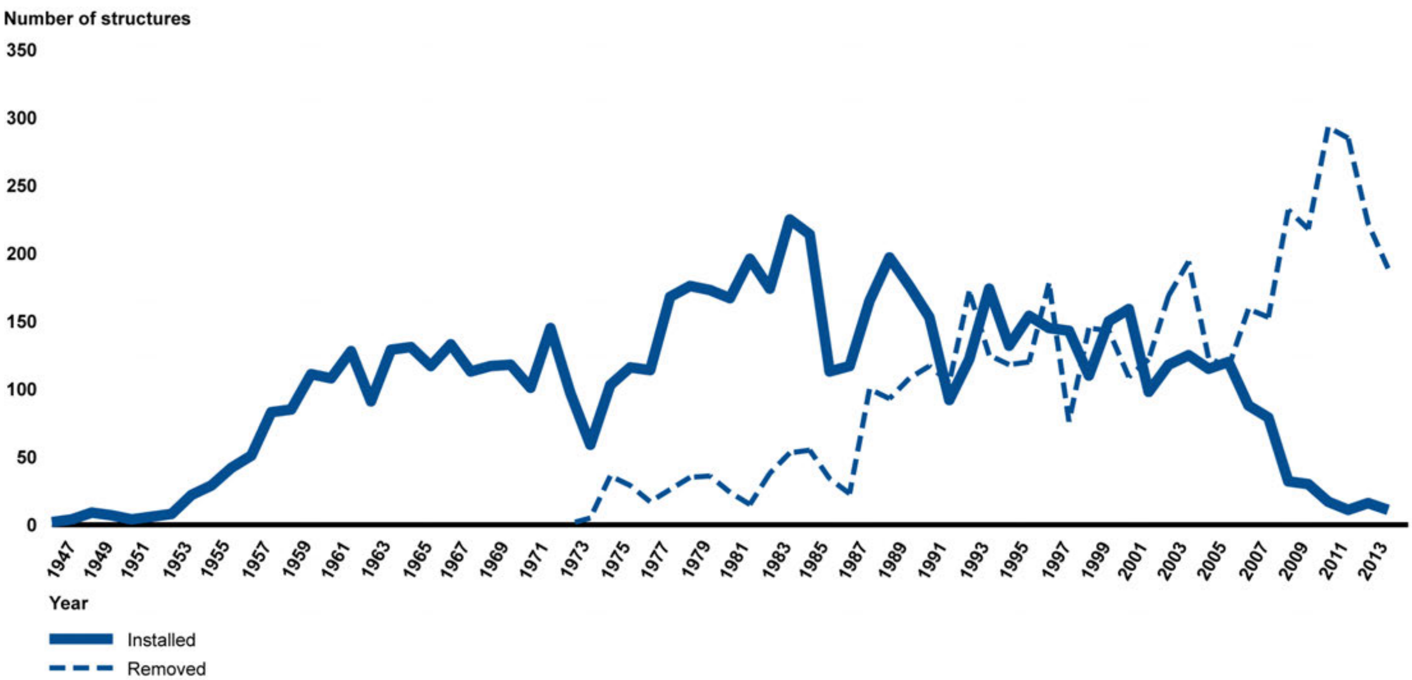


Source: GAO analysis of Bureau of Safety and Environmental Enforcement (BSEE) data. | GAO-17-642T

Note: Wells drilled include exploratory and development wells. Wells plugged include temporary and permanent well abandonments.

Figure 3 shows the annual number of structures installed and removed in the Gulf from 1947 through 2014. During this period, lessees installed a total of 7,038 structures in the Gulf. In addition, starting in the 1970s, lessees began removing structures from the Gulf. Specifically, lessees removed a total of 4,611 structures from 1973 through 2014. Most of the structures installed and removed were fixed platforms and caissons installed in shallow water.

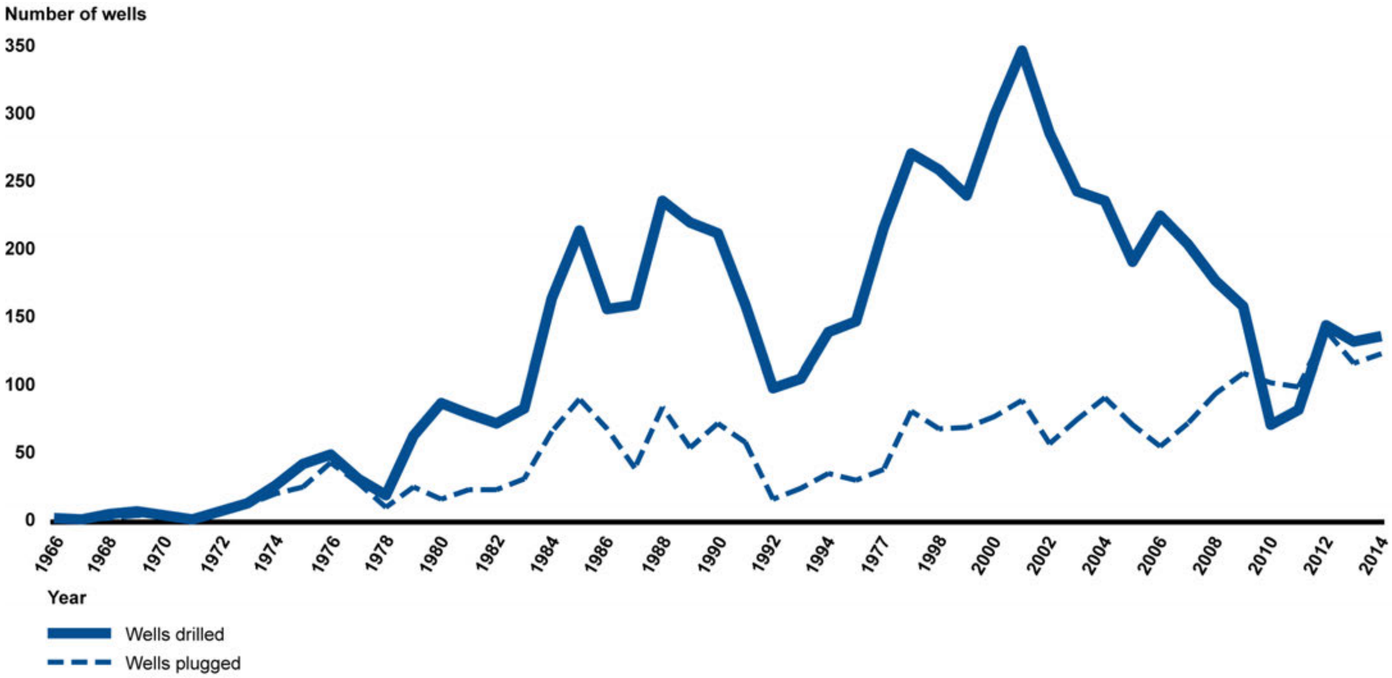
Figure 3: Annual Number of Structures Installed and Removed in the Gulf of Mexico, 1947-2014



Source: GAO analysis of Bureau of Safety and Environmental Enforcement (BSEE) data. | GAO-17-642T

From the late 1940s through the early 1960s, lessees only drilled wells in shallow water. However, starting in the mid-1960s, lessees began drilling wells in deep water. Figure 4 shows the annual number of wells drilled and plugged in deep water in the Gulf from 1966 through 2014. During this period, lessees drilled a total of 6,468 wells (including exploratory and development wells) and plugged a total of 2,489 wells (including temporary and permanently abandoned wells) in deep water. Lessees also installed 112 structures—mostly fixed platforms, spar, tension leg platforms, and floating production systems—and removed 19 structures in deep water during this period.

Figure 4: Annual Number of Deepwater Wells Drilled and Plugged in the Gulf of Mexico, 1966-2014



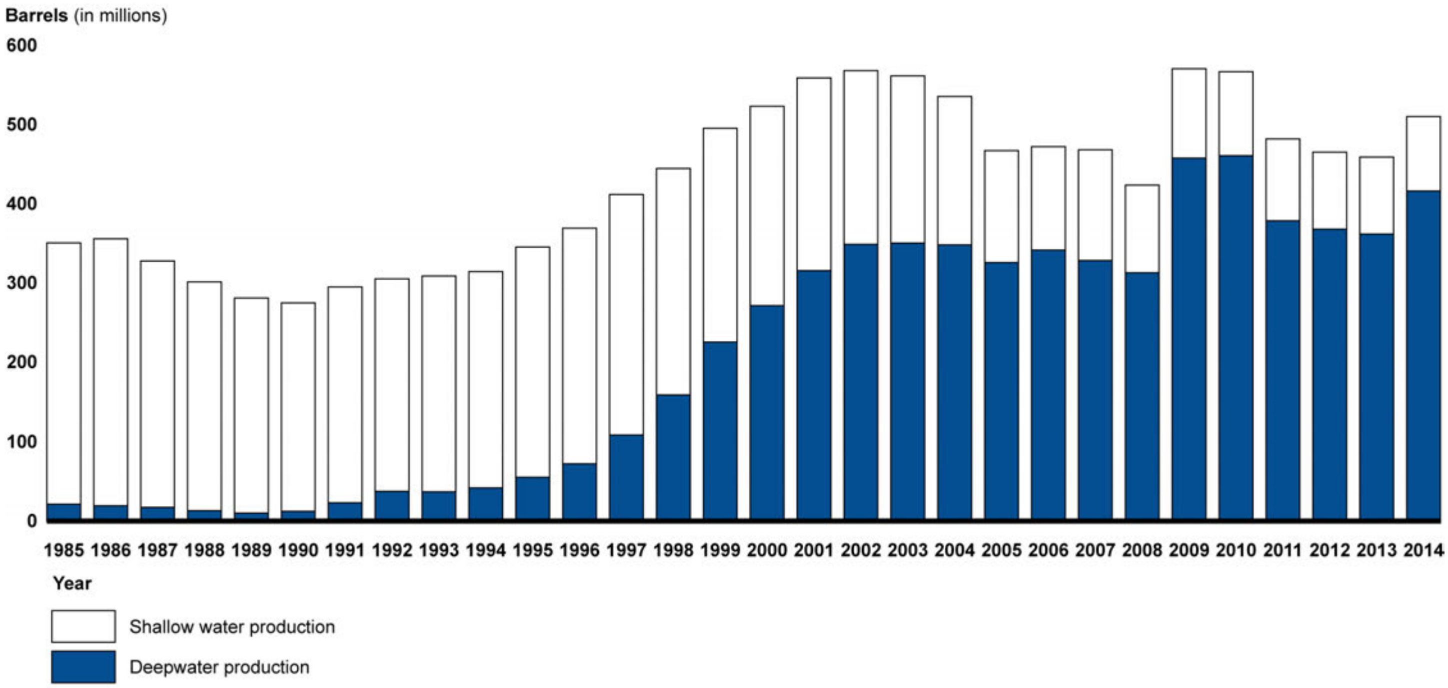
Source: GAO analysis of Bureau of Safety and Environmental Enforcement (BSEE) data. | GAO-17-642T

Note: Wells drilled include exploratory and development wells drilled in greater than 400 feet of water. Wells plugged include temporary and permanent well abandonments in greater than 400 feet of water.

From 1985 through 2014, oil production from deepwater wells has increased significantly, as shown in figure 5. While the number of wells drilled decreased in recent years, offshore production increased as lessees drilled wells in deep water that are more productive than wells in shallower water. In 2014, over 80 percent of Gulf oil production occurred in deep water, up from 6 percent in 1985.[13] According to BSEE officials we interviewed for our December 2015 report, activities in deep water, including drilling and decommissioning, are significantly more expensive than those in shallow water because of the technology required and challenges associated with deep water, such as very high pressures at significant water and well depths.

[13]For these data, Interior defined deep water as depths of greater than 1,000 feet. According to Interior's data, gas production in deep water also increased dramatically over this period, from less than 1 percent of total Gulf production in 1985 to over 50 percent in 2014.

Figure 5: Oil Production in the Gulf of Mexico, 1985-2014



Source: GAO analysis of Bureau of Ocean Energy Management (BOEM) data. | GAO-17-642T

Interior Requires Lessees to Decommission Offshore Infrastructure and Developed Procedures to Oversee the Process and Estimate the Associated Costs

As we reported in December 2015, Interior requires lessees to decommission offshore oil and gas infrastructure, and Interior's BSEE developed procedures to oversee the decommissioning process for offshore oil and gas infrastructure and to estimate costs associated with decommissioning liabilities.[14] According to Interior regulations, lessees must permanently plug all wells, remove all platforms and other structures, decommission all pipelines, and clear the seafloor of all obstructions created by the lease and pipeline right-of-way operations when the lessee's facility is no longer useful for operations.[15] Generally, lessees must permanently plug wells and remove platforms within 1 year after a lease terminates.[16] As we reported in December 2015, BSEE referred to infrastructure that was no longer useful for operations on active leases as idle infrastructure (or "idle iron") and infrastructure on expired leases as terminated lease infrastructure. In general, BSEE's guidance defined idle infrastructure as follows:[17]

- A well is considered idle if it has not been used in the past 5 years for operations associated with exploration or development and production of oil or gas, and if the lessee has no plans for such operations.
- A platform is considered idle if it has been toppled or otherwise destroyed, or it has not been used in the past 5 years for operations associated with exploration or development and production of oil or gas.

According to BSEE officials we spoke with as part of our December 2015 report, companies may postpone decommissioning idle wells and platforms to defer the cost of removal, increase the opportunity for resale, or reduce decommissioning costs through economies of scale and scheduling, among other reasons. However, they said that postponing decommissioning can be costly because the longer a structure is present

[14] GAO-16-40.

[15] 30 C.F.R. § 250.1703 (b)-(e).

[16] Lessees may temporarily abandon a well when it is necessary for proper development and production of a lease, subject to certain requirements and procedures. 30 C.F.R. § 250.1721.

[17] Department of the Interior, *Notice to Lessees and Operators of Federal Oil and Gas Leases and Pipeline Right-of-way Holders in the Outer Continental Shelf, Gulf of Mexico OCS Region: Decommissioning Guidance for Wells and Platforms*, NTL No. 2010-G05 (Sept. 15, 2010). This guidance expired Oct. 14, 2013, but BSEE continued to use it at the time of our December 2015 report.

in the Gulf the greater the likelihood it will be damaged by a storm. According to Interior documentation, decommissioning a storm-damaged structure may cost 15 times or more the cost of decommissioning an undamaged structure. In 2005, Hurricanes Katrina and Rita destroyed 116 structures and significantly damaged another 163 structures and 542 pipelines in the Gulf, according to Interior documentation. According to BSEE officials, as of April 2015, the Gulf contained 13 destroyed structures with 16 associated wells.

Storm-damaged or toppled structures present a greater risk to safety and require difficult and time-consuming salvage work. After preliminary salvage work that can take weeks, divers cut and remove structural components while crane assemblies remove the components and place them on a barge for transport and disposal. Additionally, when working in areas with strong currents and unconsolidated material, coffer dams are often constructed on the seabed to prevent material from slumping back in on the dive crews and equipment.

In December 2015, we reported that BSEE had developed procedures for overseeing the decommissioning of offshore oil and gas infrastructure and estimating costs associated with decommissioning liabilities. Under BSEE's regulations, lessees must apply for approval before plugging wells, removing platforms or other facilities, and decommissioning pipelines. According to BSEE regional officials, they reviewed applications to ensure that they contained the required information (see table 1 below). Once this process was complete, BSEE officials approved a lessee's application, which authorized the lessee to begin decommissioning activities.

Table 1: Bureau of Safety and Environmental Enforcement (BSEE) Requirements for Decommissioning Applications for Offshore Oil and Gas Infrastructure, as of December 2015

Type of application	Description
Plugging wells[a]	Lessees must provide the following information: (1) reason for plugging the well; (2) recent well test and pressure data; (3) maximum possible surface pressure; (4) type and weight of well-control fluid to be used; (5) description of work; (6) current and proposed well schematic and description; and (7) certification by a registered professional engineer of the well abandonment design and procedures, and that all plugs meet BSEE requirements.
Removing platforms or other facilities	Lessees must provide the following information: (1) identification and description of the structure to be removed; 2) description of vessel(s) used to remove structure; (3) identification of purpose for removing structure; (4) description of removal method (e.g., explosives); (5) plans for transportation and disposal or salvage of removed platform; (6) if available, results of any recent biological surveys conducted in vicinity of structure; (7) and plans to protect archaeological and sensitive biological features during removal operations, among other things.
Decommissioning pipelines	If decommissioning a pipeline in place, lessees must submit information on the proposed decommissioning procedures and the length of the segment to be decommissioned and left in place, among other things. If removing a pipeline, lessees must submit information on the proposed removal procedures and length of segment to be removed, among other things.

Source: GAO analysis of BSEE documentation. | GAO-17-642T

[a]BSEE has established requirements for an application to permanently plug a well and to temporarily abandon a well. This table reflects requirements for an application to permanently plug a well.

After lessees completed all planned decommissioning, they were required to report to BSEE on the outcome of these activities so that BSEE could verify that all their decommissioning obligations had been met, including clearing the seafloor around wells, platforms, and other facilities. According to BSEE regional officials we spoke with as part of our December 2015 report, they reviewed lessee reports on decommissioning activities to ensure that the results were consistent with the information presented as part of the application process. Table 2 summarizes BSEE's reporting requirements related to the results of decommissioning activities, as of December 2015.

Table 2: Bureau of Safety and Environmental Enforcement (BSEE) Requirements for Reporting on Decommissioning Results for Offshore Oil and Gas Infrastructure, as of December 2015

Type of report	Description
Plugging wells	Lessees must submit a report within 30 days after plugging a well. This report must include the following information: (1) information included with request submitted before permanently plugging the well along with a final well schematic; (2) description of plugging work; (3) nature and quantities of material used in plugs; and (4) description of methods used for casing removal (including information on explosives, if used), among other things.
Removing platforms or other facilities	Lessees must submit a report within 30 days after removing a platform or other facility. This report must include the following information: (1) summary of removal operations including completion date; (2) description of any mitigation measures taken; and (3) signed statement certifying that the types and amounts of explosives used in removing the platform were consistent with those set forth in the approved removal application.
Decommissioning pipelines	Lessees must submit a report within 30 days after decommissioning a pipeline. This report must include the following information: (1) summary of the decommissioning operation including completion date; (2) description of any mitigation measures taken; and (3) signed statement certifying that the pipeline was decommissioned according to the approved application.
Clearing sites around wells, platforms, and other facilities	Lessees must verify that a site is clear of obstructions within 60 days of plugging a well or removing a platform or other facility. Lessees then must submit a report within 30 days after verifying site clearance to certify to BSEE that all site clearance activities are completed. For wells, this report must include the following information: (1) signed certification that the well site area is cleared of all obstructions; (2) date the verification work was performed and the vessel used; (3) extent of the area surveyed; (4) survey method used; and (5) results of the survey, among other things. For platforms and other facilities, this report must include the following information: (1) letter (signed by the lessee) certifying that the platform or area is cleared of all obstructions and that a company representative witnessed the activities; (2) letter (signed by contractor) certifying that it cleared the platform or area of all obstructions; (3) date that work was performed and vessel used; (4) extent of area surveyed; (5) survey method used; and (6) survey results, among other things.

Source: GAO analysis of BSEE documentation. | GAO-17-642T

In addition to reviewing lessee applications and reports, the BSEE Gulf region identified and tracked idle and terminated lease infrastructure. According to BSEE regional officials we spoke with as part of our December 2015 report, the BSEE Gulf region began identifying and tracking idle lease infrastructure in 2010 and updated a list of this infrastructure on an annual basis. BSEE began identifying and tracking terminated lease infrastructure prior to 2010, according to BSEE regional officials. At the beginning of each calendar year, BSEE regional officials obtained data from Interior's main data system—the Technical Information Management System—on wells and structures on leases that meet the criteria for idle and terminated lease infrastructure.[18] Based on these data, BSEE sent a list of idle and terminated lease infrastructure to each lessee, requesting a decommissioning plan and schedule for decommissioning the lessee's inventory. According to BSEE regional officials, BSEE worked with lessees to verify the accuracy of their inventory of idle and terminated lease infrastructure, and BSEE tracked lessees' progress in meeting their schedules.[19]

According to BSEE regional officials we spoke with for our December 2015 report, BSEE estimated the costs associated with decommissioning liabilities by counting the number and types of wells, pipeline segments, and structures on a lease and using data on the water depth associated with this infrastructure.[20] Using these data, BSEE then calculated the costs associated with (1) plugging and abandoning wells, (2) removing platforms and other structures, (3) decommissioning pipelines, and (4) clearing debris from the site.

In general, the cost to plug wells and remove structures increases as the water depth increases. For example, according to BSEE's methodology at the time of our December 2015 report, its estimate of the cost to plug a dry tree well attached to a fixed structure in shallow water was $150,000, while its estimate of the cost to plug a subsea well in deep water was a minimum of about $21 million. Likewise, BSEE's estimates of the costs to remove fixed platforms in shallow water ranged from approximately $85,000 to $4.6 million, while its estimate of the cost to remove a floating structure (and associated equipment) in deep water was a minimum of $30 million.

[18]According to the Federal IT Dashboard, the Technical Information Management System is a computerized information system that automates many of the business and regulatory functions of BSEE and BOEM. This system enables staff of the regional and headquarters offices of both BSEE and BOEM to share and combine data; create and print maps; standardize processes, forms, and reports; and promote the electronic submission of data.

[19]According to BSEE data, lessees made progress in decommissioning idle infrastructure in the Gulf. Specifically, in 2010, there were 3,233 idle wells and 617 idle platforms in the Gulf and, as of June 15, 2015, there were 1,082 idle wells and 245 idle platforms in the Gulf.

[20]The BSEE Gulf regional office established a Decommissioning Support Section in December 2013 to estimate costs associated with decommissioning liabilities in the Gulf. Prior to that date, BSEE officials in other sections within the Gulf regional office were assigned the responsibilities associated with estimating these costs.

In our December 2015 report, we found that BSEE generally did not have access to current data on decommissioning costs but had taken steps to address this issue. Prior to December 2015, under BSEE's regulations, lessees were not required to report costs associated with decommissioning activities to BSEE. According to BSEE regional officials, data on decommissioning costs were considered proprietary, and companies generally did not share this information with BSEE. Instead, BSEE regional officials told us that they relied on other sources of data—some of which were decades old and, as a result, likely inaccurate—to estimate costs associated with decommissioning liabilities. For example, according to BSEE regional officials, their estimates for decommissioning liabilities in shallow water were based on data provided by the oil and gas industry in 1995. However, in December 2015, BSEE issued a final rule requiring establishing new requirements for lessees to submit expense information on costs associated with plugging and abandonment, platform removal, and site clearance.[21]

[21]Department of the Interior, Bureau of Safety and Environmental Enforcement, *Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Decommissioning Costs, Final Rule*, 80 Fed. Reg. 75806 (Dec. 4, 2015) (effective Jan. 4, 2016).

Interior Requires Lessees to Provide Financial Assurances for Decommissioning Liabilities, but Our December 2015 Report Found that Interior's Procedures Posed Risks to the Federal Government

As we reported in December 2015, Interior's BOEM requires financial assurances from lessees to cover decommissioning liabilities, but we found that Interior's financial assurance procedures in place at that time posed risks to the federal government.[22] Under The Outer Continental Shelf Lands Act, Interior has issued regulations and developed financial assurance procedures to protect the government from incurring costs if a lessee fails to meet its lease obligations, including its obligation to decommission offshore infrastructure.

Under the regulations and procedures in place at the time of our December 2015 report, BOEM regional directors could require a lessee to provide a bond —referred to as a "supplemental bond"—that covers the estimated costs of decommissioning for a lease.[23] BSEE is responsible for estimating costs associated with decommissioning liabilities. If a lessee was unable to accomplish decommissioning obligations as required, the federal government could use the bond to cover decommissioning costs.[24] However, where there are co-lessees or prior lessees, if BOEM determined that at least one lessee had sufficient financial strength to accomplish decommissioning obligations on the lease, BOEM might waive the requirement for a supplemental bond.[25]

[22]GAO-16-40.

[23]According to our December 2015 report, to satisfy the requirement to provide bonds, BOEM accepted surety bonds, U.S. Treasury notes, and other financial instruments if the government's interests were protected. A surety bond is a third-party guarantee that a lessee purchases from a private insurance company or other entity approved by the Department of the Treasury (i.e., listed on Circular No. 570). The lessee must pay a premium to the surety company to maintain the bond.

[24]In addition to a supplemental bond that may be required from a lessee, under BOEM regulations and procedures, every offshore oil and gas lease must be covered by a general bond that could be used to ensure a lessee complies with regulatory and lease requirements such as inspection fees, civil penalties, decommissioning and rents and royalties. General bonds vary in amount, from $50,000 to $3 million, depending on the geographical area and phase of operation covered by the bond. As of June 10, 2015, lessees had provided 604 general bonds with a value of $517 million.

[25]Each lease may have numerous lessees that have various rights to the lease, including lessees that are record title holders and lessees that are operating rights holders. At the time of our December 2015 report, BOEM required that all lessees agree to one designated operator, and the designated operator generally provides BOEM with the required bonding.

Under BOEM and BSEE regulations, lessee liability is “joint and several”—that is, each lessee is liable for all decommissioning obligations that accrue on the lease during its ownership, including those that accrued prior to its ownership but had not been performed. In addition, a lessee that transfers its ownership rights to another party will continue to be liable for the decommissioning obligations it accrued. According to BOEM officials we spoke with as part of our December 2015 report, BOEM ensured that all decommissioning obligations on offshore leases were required to be covered by either a supplemental bond or a current lessee that had the financial ability to conduct decommissioning.

Under BOEM’s financial assurance procedures in place at the time of our December 2015 report,[26] each offshore lease with a decommissioning liability had to be covered by a supplemental bond unless BOEM determined that a lessee had the financial ability to fulfill its decommissioning obligations. BOEM staff evaluated the financial ability of a lessee to fulfill its decommissioning obligations by means of a financial strength test. BOEM’s financial strength test required a lessee to meet the following criteria:

- provide an independently audited financial statement indicating a net worth greater than $65 million;
- possess a total decommissioning liability (as determined by BSEE) of less than or equal to 50 percent of its audited net worth;
- possess total company liabilities of no more than 2 to 3 times the value of the adjusted net worth;[27],[28] and

[26]Department of the Interior, Minerals Management Service, *Notice to Lessees and Operators of Federal Oil, Gas, and Sulfur Leases and Pipeline Right-of-way Holders in the Outer Continental Shelf: Supplemental Bond Procedures*, NTL No. 2008-N07 (Aug. 28, 2008).

[27]Adjusted net worth includes a percentage of a lessee’s proven oil and gas reserves added to a lessee’s audited net worth. According to our December 2015 report, BOEM varied the total liability ratio it would accept based on adjusted net worth—for example, a lessee with between $65 million and $100 million in adjusted net worth could possess total lessee liabilities of no more than 2 or 2.5 times its adjusted net worth, depending on the size of the company’s potential decommissioning liability.

[28]Alternatively, according to our December 2015 report, BOEM allowed a lessee to use a substitute criterion—the lessee had to demonstrate that it produced in excess of an average of 20,000 barrels of oil equivalent per day on its leases. However, according to BOEM officials, of the 51 waived lessees only 1 or 2 chose to used this alternative criterion.

- demonstrate reliability, as shown by a record of compliance with laws, regulations and lease terms, among other factors.

According to our December 2015 report, if a lessee passed the financial strength test by demonstrating its financial ability to pay for decommissioning on its leases, BOEM waived its requirement for the lessee to provide supplemental bonds. Other responsible parties on the lease would also be waived from the requirement to provide supplemental bonds.[29] According to BOEM officials, BOEM waived these parties as well because the waived lessee could be held responsible if another party on a lease did not fulfill its decommissioning obligations. In addition, a waived lessee might provide financial assurance in the form of a corporate guarantee of the lease obligations of a lessee on another lease.[30]

According to our December 2015 report, after BOEM waived a lessee from the requirement to provide supplemental bonding, it monitored the financial strength of the lessee to ensure it continued to pass BOEM's financial strength test. BOEM conducted quarterly financial reviews for the first 2 years after a lessee received a waiver and then an annual review thereafter.[31] In addition, on a weekly basis, BOEM compared the decommissioning obligations (as determined by BSEE) of all waived lessees with the financial information provided by lessee audited financial statements.[32] If BOEM found that a lessee no longer passed its financial strength test, BOEM conducted a more in-depth review of a lessee's financial status by reviewing financial statements, credit ratings, and other financial information. BOEM might also conduct an unscheduled financial review if: (1) BSEE revised its estimate of a lessee's decommissioning

[29]In addition to bonds required by BOEM, according to our December 2015 report, some lessees that transferred leases or rights might require the party acquiring the lease to provide a surety bond. This bond protected the transferring party from paying decommissioning costs it might be liable for if the purchasing party was unable to fulfill its decommissioning obligations. According to BOEM officials, these bonds were generally not reported to BOEM, and BOEM did not consider them as financial assurance because BOEM was not a beneficiary of such bonds.

[30]According to BOEM officials we spoke with for our December 2015 report, nearly all corporate guarantees were between parent companies and subsidiaries.

[31]According to our December 2015 report, these reviews evaluated the same criteria that BOEM officials used during the initial financial strength test.

[32]According to our December 2015 report, as part of these reviews, BOEM determined whether the waived lessee had the ability to pay for all decommissioning costs on leases where the lessee was an owner.

liability, (2) a lessee's financial status changed as reported by credit rating agencies, or (3) a lessee did not pay the required royalties to the federal government. According to BOEM officials, these reviews could have caused BOEM to revoke a lessee's waiver from the requirement to provide supplemental bonding. For example, in May 2015, BOEM revoked the waiver of one lessee and, according to BOEM officials, the waived lessee and related parties could have been required to provide as much as $1 billion in supplemental bonds.[33]

However, in our December 2015 report, we found that BOEM's financial assurance procedures posed financial risks to the federal government in several ways. In particular, under BOEM's procedures in place at the time, less than 8 percent of estimated decommissioning liabilities in the Gulf were covered by financial assurance mechanisms such as bonds. Specifically, as of October 2015, according to BOEM officials, for an estimated $38.2 billion in decommissioning liabilities in the Gulf, BOEM held or required about $2.9 billion in bonds and other financial assurances.[34] For $33.0 billion in decommissioning liabilities, BOEM had waived 47 lessees from the requirement to provide supplemental bonds based on BOEM's reviews of the lessees' financial strength, according to BOEM officials.[35],[36]

[33]According to our December 2015 report, in cases where BOEM revoked a lessee's waiver from the requirement to provide supplemental bonding, the lessee or other responsible parties on a lease or recipients of corporate guarantees would have been required to provide supplemental bonds to cover decommissioning obligations that were no longer covered by a waiver or guarantee.

[34]As of October 2015, BOEM held about $1.8 billion in bonds (including supplemental and general bonds) and about $500 million in trust agreements. In addition, BOEM issued letters requiring lessees to provide about $600 million in financial assurances.

[35]According to our December 2015 report, for the purposes of ensuring that there was at least one responsible party with the financial ability to fulfill lease decommissioning obligations, BOEM attributed all lease decommissioning liabilities to any waived lessee on a lease (even if other responsible parties were present on the lease). The waived lessee was, with all other lessees, jointly and severally liable for decommissioning and relied on its financial strength to secure the costs of this decommissioning, on behalf of all the jointly and severally liable parties.

[36]Under Interior regulations and procedures in place at the time of our December 2015 report, regional directors might determine that a supplemental bond was necessary to ensure compliance with a lessee's obligations. According to Interior officials, supplemental bonding became a requirement once the regional director determined that it was necessary.

As we have found in prior GAO reports, the use of financial strength tests and corporate guarantees in lieu of bonds pose financial risks to the federal government. Specifically, we found, in August 2005, that the financial assurance mechanisms that impose the lowest costs on the companies using them—such as financial strength tests and corporate guarantees—also typically pose the highest financial risks to the government entity accepting them.[37] In that report, we found that, if a company passes a financial strength test but subsequently files for bankruptcy or becomes insolvent, the company in essence is no longer providing financial assurance because it may no longer have the financial capacity to meet its obligations. Such financial deterioration can occur quickly. While companies no longer meeting the financial test are to obtain other financial assurance, they may not be able to obtain or afford to purchase it. In addition, in May 2012, we found that, according to the Bureau of Land Management and the Environmental Protection Agency, corporate guarantees are potentially risky because they are not covered by a specific financial asset such as a bond.[38] Therefore, in our December 2015 report, we concluded that BOEM's use of the financial strength test and corporate guarantees in lieu of bonds raised the risk that the federal government would have to pay for offshore decommissioning if lessees did not.

According to BOEM officials we spoke with for our December 2015 report, BOEM recognized the financial risks associated with its financial assurance procedures and planned to revise its procedures to reduce risk. Specifically, BOEM officials told us that BOEM's planned revisions would eliminate the use of financial strength tests to completely waive lessees from the requirement to provide supplemental bonding. Instead, BOEM planned to conduct financial reviews of lessees' financial status and, based on those reviews, assign lessees an amount of credit that may be used to reduce required bonding associated with decommissioning liabilities on leases. Lessees would be able to apportion this credit to leases, in coordination with other responsible parties on those leases, to ensure that lease decommissioning liabilities are fully covered by apportioned credit or supplemental bonds. However, because it was unclear whether BOEM's planned revisions would improve its

[37] GAO, *Environmental Liabilities: EPA Should Do More to Ensure That Liable Parties Meet Their Cleanup Obligations,* GAO-05-658 (Washington, D.C.: Aug. 17, 2005).

[38] GAO, *Phosphate Mining: Oversight Has Strengthened, but Financial Assurances and Coordination Still Need Improvement,* GAO-12-505 (Washington, D.C.: May 4, 2012).

procedures and the extent to which these revisions would increase the amount of bonding that lessees provide, we recommended in our December 2015 report, that BOEM complete its plans to revise its financial assurance procedures, and Interior concurred.

Since the issuance of our December 2015 report, BOEM revised its financial assurance procedures. Specifically, on July 12, 2016, BOEM issued revised procedures, effective on September 12, 2016, containing several changes to BOEM's policy concerning additional financial security requirements for leases, pipeline rights-of-way, and rights-of-use and easement, including the use of alternative measures of financial strength.[39] In December 2016, BOEM issued orders to sole liability lessees requiring them to provide additional security.[40] In January 2017, BOEM delayed implementation of its revised financial assurance procedures for 6 months. The following month, BOEM withdrew its December 2016 orders to sole liability lessees, stating that these orders will be discussed as part of the six-month review process related to the financial assurance procedures. We have not evaluated the extent to which these financial assurance procedures and orders, if fully implemented, would address the concerns we have identified about the financial risks to the federal government. We will continue to monitor Interior's actions to address our recommendations.

Chairman Gosar, Ranking Member Lowenthal, and Members of the Subcommittee, this completes my prepared statement. I would be pleased to respond to any questions that you may have at this time.

[39]Department of the Interior, Bureau of Ocean Energy Management, *Notice to Lessees and Operators of Federal Oil and Gas, and Sulfur Leases, and Holders of Pipeline Right-of-Way and Right-of-Use and Easement Grants in the Outer Continental Shelf: Requiring Additional Security*, NTL No. 2016-NO1 (July 12, 2016).

[40]Sole liability properties are leases, rights-of-way, or rights of use and easements for which the holder is the only liable party, i.e., there are no co-lessees, operating rights owners and/or other grant holders, and no prior interest holders liable to meet the lease and/or grant obligations.

GAO Contact

If you or your staff have any questions about this testimony, please contact Frank Rusco, Director, Natural Resources and Environment, 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 statement.

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United States Government Accountability Office

Report to Congressional Requesters

December 2015

OFFSHORE OIL AND GAS RESOURCES

Actions Needed to Better Protect Against Billions of Dollars in Federal Exposure to Decommissioning Liabilities

GAO-16-40

GAO Highlights

Highlights of GAO-16-40, a report to congressional requesters

December 2015

OFFSHORE OIL AND GAS RESOURCES

Actions Needed to Better Protect Against Billions of Dollars in Federal Exposure to Decommissioning Liabilities

Why GAO Did This Study

Oil and gas produced on federal leases in the Gulf of Mexico are important to the U.S. energy supply. Historically, most offshore production was in shallow water, but more than two-thirds of the more than 5,000 active oil and gas leases in the Gulf are now located in deep water. When oil and gas infrastructure is no longer in use, Interior requires lessees to decommission it so that it does not pose safety and environmental hazards. Decommissioning can include plugging wells and removing platforms, which can cost millions of dollars. Interior requires lessees to provide bonds or other financial assurances to demonstrate that they can pay these costs; however, if lessees do not fulfill their decommissioning obligations, the federal government could be liable for these costs.

GAO was asked to review Interior's management of liabilities from offshore oil and gas production. This report examines Interior's (1) procedures for overseeing decommissioning and estimating its costs, (2) procedures for obtaining financial assurances for these liabilities, and (3) challenges managing these liabilities. GAO reviewed agency regulations and procedures and interviewed officials from Interior, credit rating agencies, academia, and trade associations.

What GAO Recommends

GAO recommends that Interior take several steps to improve its data system, complete plans to revise its financial assurance procedures, and revise its cost reporting regulations, among other things. Interior concurred with GAO's recommendations.

View GAO-16-40. For more information, contact Frank Rusco at (202) 512-3841 or ruscof@gao.gov.

What GAO Found

The Department of the Interior (Interior) has developed procedures to oversee the decommissioning of offshore oil and gas infrastructure and estimate costs associated with decommissioning liabilities but has not addressed limitations with its system for tracking cost estimates. According to officials, Interior's procedures include (1) identifying and tracking unused infrastructure, (2) reviewing lessee plans to decommission infrastructure, and (3) using different cost estimates for decommissioning in shallow and deep water. However, inconsistent with internal control standards, Interior officials must manually enter cost estimates into Interior's main data system to override inaccurate estimates automatically calculated by the system. Without a more accurate data system, Interior does not have reasonable assurance that it will consistently estimate the costs associated with decommissioning.

Interior's procedures for obtaining financial assurances for decommissioning liabilities pose financial risks to the federal government, and Interior is planning to revise its procedures to address these risks but has not finalized its approach. As of October 2015, for an estimated $38.2 billion in decommissioning liabilities in the Gulf, Interior officials identified about $2.3 billion in liabilities that may not be covered by financial assurances. However, these officials were unable to determine the extent to which these data were valid due to limitations with Interior's data system, among other things. Of the remaining $35.9 billion in decommissioning liabilities, Interior held or required about $2.9 billion in bonds and other financial assurances, and had foregone requiring about $33.0 billion in bonds for the remaining liabilities. Interior has procedures that allow it to waive its requirement for a lessee to provide a bond if the lessee passes a financial strength test. Prior GAO work has shown that the use of financial strength tests in lieu of bonds poses risks to the federal government. Interior recognizes the risks associated with its procedures, and Interior officials stated that they issued draft guidance to clarify their procedures in September 2015. Interior has not issued any final revisions to its procedures; therefore, it is too soon to evaluate the details of these proposed changes. Until Interior improves its ability to obtain valid data from its data system and revises and implements its financial assurance procedures, the federal government remains at increased risk of incurring costs should lessees fail to decommission oil and gas infrastructure.

Interior faces challenges managing potential decommissioning liability. For example, until December 2015, Interior did not have a requirement for lessees to report on costs associated with decommissioning activities in the Gulf. Instead, Interior contracted studies to obtain data on decommissioning costs, but some data were decades old. Federal internal control standards call for agencies to obtain information from external stakeholders that may significantly affect their ability to achieve agency goals. However, in December 2015, Interior issued final regulations (proposed in 2009) requiring lessees to report data on most, but not all, decommissioning costs to Interior. Unless and until Interior obtains accurate and complete data on decommissioning costs, Interior may not have reasonable assurance that its cost estimates of decommissioning liabilities in the Gulf are accurate, or that it is requiring sufficient amounts of financial assurance based on these estimates.

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Abbreviations

BOEM	Bureau of Ocean Energy Management
BSEE	Bureau of Safety and Environmental Enforcement
Gulf	Gulf of Mexico
Interior	Department of the Interior
TIMS	Technical Information Management System

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December 18, 2015

The Honorable Raúl M. Grijalva
Ranking Member
Committee on Natural Resources
House of Representatives

The Honorable Alan Lowenthal
Ranking Member
Subcommittee on Energy and Mineral Resources
Committee on Natural Resources
House of Representatives

The Honorable Peter A. DeFazio
House of Representatives

Oil and gas resources located on federal leases on the outer continental shelf are an important component of the nation's energy supply.[1] Wells on federal leases on the outer continental shelf accounted for over 16 percent of the nation's crude oil production in 2014 and about 5 percent of natural gas production in 2013. The vast majority of this production occurred on federal leases in the Gulf of Mexico (Gulf). Historically, most offshore oil and gas activities have occurred in shallow water,[2] but in recent decades these activities have moved into deep water. More than two-thirds of the more than 5,000 active oil and gas leases in the Gulf are now located in deep water.

The Department of the Interior (Interior) manages oil and gas activities on offshore federal leases, including activities associated with thousands of wells, platforms, and miles of pipelines on the outer continental shelf. When this infrastructure is no longer useful for operations or otherwise

[1]The outer continental shelf refers to the submerged lands outside the territorial jurisdiction of all 50 states, but within U.S. jurisdiction and control. The portion of the North American continental edge that is federally designated as the outer continental shelf generally extends seaward 3 geographical miles off the coastline to at least 200 nautical miles.

[2]In this report, unless other specified, we use the term "shallow" water to refer to depths of less than 400 feet and "deep" water to refer to depths of greater than 400 feet.

becomes idle,[3] or when a lease has been expired for more than 1 year, Interior requires oil and gas lessees to decommission it so that it does not pose potential safety hazards to marine vessels and environmental hazards to sea life and humans.[4] Decommissioning refers to the process of plugging wells, removing platforms and other structures, removing or cleaning out pipelines, and clearing sites of debris. According to Interior estimates, in shallow water, decommissioning infrastructure can cost tens of millions of dollars per lease, depending on the number of wells and types of structures present. In deep water, decommissioning can cost hundreds of millions of dollars per lease. In addition, infrastructure damaged by hurricanes is significantly more expensive to decommission than nondamaged infrastructure.

According to Interior's regulations, all lessees are liable for decommissioning costs that accrue during their ownership.[5] Before lessees drill wells or install platforms and other structures, Interior requires them to provide financial assurance to ensure that they are capable of meeting their decommissioning obligations. This financial assurance may be in the form of a financial asset provided by the lessee, such as a bond, or a determination that a lessee has the financial strength and ability to fulfill decommissioning obligations. According to Interior officials, the federal government has not incurred costs associated with offshore decommissioning since 1989, when a lessee declared bankruptcy.[6] In response to this bankruptcy, Interior promulgated regulations in 1993 requiring some lessees to provide bonds specifically for offshore decommissioning.[7] Nonetheless, Interior refers to oil and gas infrastructure on offshore federal leases as potential liabilities because

[3]Interior refers to wells and platforms as "idle" if they have not been used in the past 5 years for oil and gas exploration or development and production activities.

[4]For the purposes of this report, we use the term "lessee" to refer to owners of record title and owners of operating rights on offshore leases, designated operators acting on behalf of record title and operating rights owners, and right-of-way holders.

[5]30 C.F.R. § 250.1701.

[6]According to Interior officials, this company entered into an agreement to fund two decommissioning trusts using cash, services performed, acceptable forms of security, and royalty reductions. As part of this agreement, Interior reduced the company's royalty payments by about $13 million, which was spent on decommissioning.

[7]30 C.F.R. § 556.53(d).

the federal government may have to pay for decommissioning if lessees do not.

You asked us to review Interior's management of potential federal liabilities associated with the decommissioning of offshore oil and gas infrastructure. This report examines (1) Interior's procedures for overseeing the decommissioning of offshore oil and gas infrastructure and estimating costs associated with decommissioning liabilities; (2) Interior's procedures for obtaining financial assurances for decommissioning liabilities; and (3) challenges, if any, Interior faces in managing potential decommissioning liabilities. We focused our work on the Gulf, where most oil and gas infrastructure is located.

To conduct this work, we reviewed Interior's regulations regarding its management of leases for offshore oil and gas production. To examine Interior's procedures for overseeing the decommissioning of offshore oil and gas infrastructure and estimating decommissioning costs, we interviewed officials from Interior's Bureau of Safety and Environmental Enforcement (BSEE) in their Washington, D.C., headquarters office and Gulf regional office in New Orleans, Louisiana, and reviewed and summarized relevant BSEE guidance, procedures, and related documentation.[8] We also compared BSEE's actions to implement its procedures to standards for internal control in the federal government.[9] In addition, to better understand the decommissioning process and the costs involved, we spoke with a nongeneralizable sample of officials and stakeholders from trade associations and academia. We identified these officials and stakeholders from our prior work, published academic and technical articles, our attendance at a decommissioning conference, and interviews with BSEE officials, and we selected them based on their knowledge in this area.

To examine Interior's procedures for obtaining financial assurances for decommissioning liabilities, we interviewed officials from Interior's Bureau of Ocean Energy Management (BOEM) in their Washington, D.C.,

[8]For the purposes of this report, we use the term "procedure" to include Interior's notices to lessees, which are supposed to clarify, supplement, or provide more details about Interior's regulations; standard operating procedures; and other related documents describing Interior's processes. *See* 30 C.F.R. § 250.103.

[9]GAO, *Standards for Internal Control in the Federal Government*, GAO/AIMD-00-21.3.1 (Washington, D.C.: November 1999).

headquarters office and Gulf regional office in New Orleans, Louisiana, and reviewed and summarized relevant BOEM guidance, procedures, and related documentation. We compared actions that BOEM took to implement its procedures to standards for internal control in the federal government. In addition, to better understand financial assurance and bonding issues, we spoke with a nongeneralizable sample of analysts from the three largest credit rating agencies,[10] officials from bonding companies, and stakeholders from trade associations. We identified these organizations from our prior work and interviews with BOEM officials and selected them based on their knowledge in this area.

To examine challenges Interior faces in managing potential decommissioning liabilities, we used the information collected from our first two objectives. We also spoke with a nongeneralizable sample of stakeholders from trade associations about their views on challenges; we identified these stakeholders from our prior work and selected them based on their knowledge in this area.

We conducted this performance audit from October 2014 to December 2015 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

This section provides information on (1) the types of wells and structures in the Gulf, (2) offshore leasing, (3) financial assurance requirements, (4) decommissioning requirements, and (5) oil and gas infrastructure installed and removed in the Gulf.

Types of Wells and Structures in the Gulf

Lessees drill wells to access and extract oil and gas from geologic formations. According to an Interior publication, “exploratory” wells are drilled in an area with potential oil and gas reserves, while “development”

[10]The three largest credit rating agencies are Moody’s Investors Services, Standard and Poor’s, and Fitch Ratings, as reported by the Securities and Exchange Commission.

wells are drilled to produce oil and gas from a known reserve.[11] An exploratory well may not actually produce any oil or gas, while a successful development well produces oil or gas. Wellheads that are located on a fixed platform (typically in shallow water) are referred to as "dry tree" wells, and wellheads that are located on the seafloor (typically in deep water) are referred to as "subsea" or "wet tree" wells.

Offshore oil and gas structures in the Gulf vary in size and complexity. The simplest structures are found in shallow water and include caissons and well protectors. A caisson is a cylindrical or tapered large diameter steel pipe enclosing a well conductor and is the minimum structure for offshore development. A well protector provides support to one or more wells with no production equipment and facilities. A more complex structure in shallow water is a fixed platform, which uses a jacket and pilings to support the superstructure, or deck.[12] The deck is the surface where work is performed and provides space for crew quarters, a drilling rig, and production facilities. Most of the large fixed platforms have living quarters for the crew, a helicopter pad, and room for drilling and production equipment.[13] A typical platform is designed so that multiple wells may be drilled from it. Wells from a single platform may have bottom-hole locations many thousands of feet (laterally displaced) from the surface location.

Structures in deep water rely on other methods to anchor to the ocean floor. For example, a "compliant tower" structure supports the deck using a narrow, flexible tower and a piled foundation. According to an industry publication, the flexible nature of the compliant tower allows it to withstand large wind and wave forces associated with hurricanes. Other common deep-water structures include the tension leg platform, floating

[11]According to BSEE officials, lessees sometimes drill other types of wells, such as relief wells and core test wells. However, these types of wells represent a very small portion of the wells drilled in the Gulf.

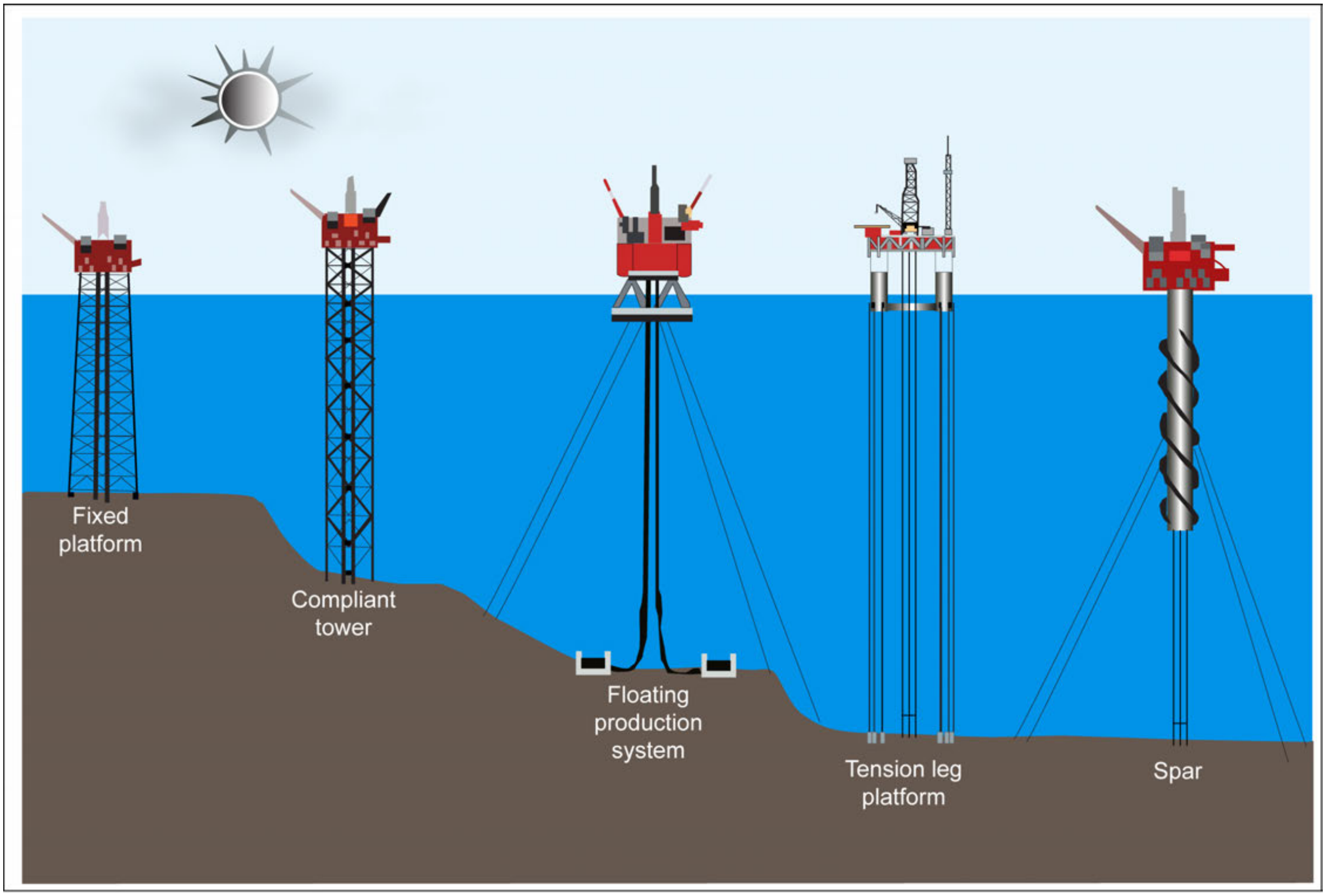
[12]A jacket is a steel structure that rests on the ocean's floor and has columns, or legs. Pilings are driven through the legs of the jacket into the seafloor to hold the jacket in place.

[13]According to BSEE officials, fixed platforms are typically found in shallow water, but some fixed platforms are used in water depths between 400 feet and 1,400 feet.

production system, and spar platform.[14] Illustrations of these structures are shown in figure 1.

[14]A tension leg platform structure supports a floating deck using vertical steel “tendons” or a chain and wire system anchored to the seafloor by pilings. A floating production system uses a floating, semisubmersible hull equipped with drilling and production equipment. It can be anchored in place with a chain and wire system or dynamically positioned using rotating thrusters. A spar platform supports a floating deck using a long, slender column that extends far below the ocean surface. Vertical steel tendons anchor the column to the seafloor (using pilings), and guy-wires extend out diagonally to seafloor anchors for horizontal stability.

Figure 1: Examples of Oil and Gas Structures in the Gulf of Mexico



Source: GAO analysis of industry reports. | GAO-16-40

Offshore Leasing

Management of offshore oil and gas resources is primarily governed by the Outer Continental Shelf Lands Act, which sets forth procedures for leasing,[15] exploration, and development and production of those resources. The act calls for the preparation of an oil and gas leasing

[15] For the purposes of this report, we use the term "lease" to include leases, grants of right of way, and right of use and easements.

program designed to meet the nation's energy needs while also taking into account a range of principles and considerations specified by the act. Specifically, the act provides that "[m]anagement of the outer Continental Shelf shall be conducted in a manner which considers economic, social, and environmental values of the renewable and nonrenewable resources contained in the outer Continental Shelf, and the potential impact of oil and gas exploration on other resource values of the outer Continental Shelf and the marine, coastal, and human environments."[16]

The Outer Continental Shelf Lands Act also requires the Secretary of the Interior to prepare a 5-year schedule of proposed lease sales, indicating the size, timing, and location of leasing activity as precisely as possible. Every 5 years, Interior selects the areas that it proposes to offer for leasing and establishes a schedule for individual lease sales. These leases may be offered for competitive bidding, and all eligible companies are invited to submit written sealed bids for the lease and rights to explore, develop, and produce oil and gas resources on these leases. These rights last for a set period of time, referred to as the initial period of the lease,[17] and vary depending on the water depth.[18]

Historically, Interior's Minerals Management Service managed offshore federal oil and gas activities and collected royalties for all producing leases. In May 2010, in an effort to separate major functions of offshore oil and gas management, Interior announced the reorganization of the Minerals Management Service into the Bureau of Ocean Energy Management, Regulation, and Enforcement, responsible for offshore oil and gas management, and the Office of Natural Resources Revenue, responsible for revenue collections. Subsequently, in October 2011, the

[16]43 U.S.C. §1344(a)(1).

[17]If a discovery is made within the initial period of the lease, the lease is extended for as long as oil and/or natural gas is produced in paying quantities or approved drilling operations are conducted. The term of the lease may also be extended if a suspension of production or suspension of operations has been granted or directed.

[18]In the Gulf, in a notice of sale in 2012, BOEM offered leases with an initial term of 5 years extended to 8 years if drilling begins during the initial 5-year period targeting hydrocarbons below a depth of at least 25,000 feet subsea for leases in less than 400 meters of water. For leases in 400 to 800 meters of water, the initial term was 5 years extended to 8 years if drilling begins during the initial 5-year period. For leases in 800 to 1,600 meters of water, the initial period was 7 years extended to 10 years if drilling begins during the initial 7-year period. For leases in over 1,600 meters of water, the initial period was 10 years.

Bureau of Ocean Energy Management, Regulation, and Enforcement was separated into BOEM and BSEE. BOEM oversees resource management activities, including preparing the 5-year outer continental shelf oil and gas leasing program; reviews oil and gas exploration and development plans and environmental studies; and conducts National Environmental Policy Act analyses. BSEE oversees operations and environmental compliance, including reviewing drilling permits, inspecting offshore drilling rigs and production platforms, assessing civil penalties, developing regulations and standards for offshore drilling (including those related to decommissioning), and ensuring the conservation of natural resources.

Financial Assurance Requirements

The Outer Continental Shelf Lands Act authorizes the Secretary of the Interior to promulgate regulations necessary to administer the outer continental shelf leasing program, including regulations concerning financial assurance. Under this authority, Interior promulgated regulations and developed financial assurance procedures to protect the government from incurring costs if a lessee fails to meet its lease obligations, including its obligation to decommission offshore infrastructure. Under these regulations and procedures, BOEM regional directors may require a lessee to provide a bond —referred to as a “supplemental bond”—that covers the estimated costs of decommissioning for a lease.[19] BSEE is responsible for estimating costs associated with decommissioning liabilities. If a lessee is unable to accomplish decommissioning obligations as required, the federal government can use the bond to cover decommissioning costs.[20] However, if BOEM determines that at least one lessee has sufficient financial strength to accomplish decommissioning

[19]To satisfy the requirement to provide bonds, BOEM accepts surety bonds, U.S. Treasury notes, and other financial instruments if the government’s interests are protected. A surety bond is a third-party guarantee that a lessee purchases from a private insurance company or other entity approved by the Department of the Treasury (i.e., listed on Circular No. 570). The lessee must pay a premium to the surety company to maintain the bond.

[20]In addition to a supplemental bond that may be required from a lessee, under BOEM regulations, every offshore oil and gas lease must be covered by a general bond that could be used to ensure a lessee complies with regulatory and lease requirements such as inspection fees, civil penalties, decommissioning, and rents and royalties. The general bond is not relied on to cover oil spill response, because those activities are covered by BOEM’s Oil Spill Financial Responsibility regulations (30 C.F.R. § 553) as well as the Oil Spill Liability Trust Fund. General bonds vary in amount, from $50,000 to $3 million, depending on the geographical area and phase of operation covered by the bond. As of June 10, 2015, lessees had provided 604 general bonds with a value of $517 million.

obligations on the lease, BOEM may waive the requirement for a supplemental bond.[21]

Under BOEM and BSEE regulations, lessee liability is “joint and several”—that is, each lessee is liable for all decommissioning obligations that accrue on the lease during its ownership, including those that accrued prior to its ownership but had not been performed. In addition, a lessee that transfers its ownership rights to another party will continue to be liable for the decommissioning obligations it accrued. According to BOEM officials, BOEM ensures that all decommissioning obligations on offshore leases are required to be covered by either a supplemental bond or a current lessee that has the financial ability to conduct decommissioning.

Decommissioning Requirements

According to Interior regulations, lessees must permanently plug all wells, remove all platforms and other structures, decommission all pipelines, and clear the seafloor of all obstructions created by the lease and pipeline operations when this infrastructure is no longer useful for operations.[22] Lessees must also permanently plug wells and remove platforms within 1 year after a lease terminates. BSEE refers to infrastructure that is no longer useful for operations on active leases as idle infrastructure (or “idle iron”) and infrastructure on expired leases as terminated lease infrastructure. In general, BSEE’s guidance defines idle infrastructure as follows: [23]

[21]Each lease may have numerous lessees that have various rights to the lease, including lessees that are record title holders and lessees that are operating rights holders. BOEM requires that all lessees agree to one designated operator, and the designated operator generally provides BOEM with the required bonding.

[22]According to BSEE, permanent well abandonment includes installing a surface plug and severing the casing at least 15 feet below the mudline, among other requirements. Temporary well abandonment includes all plugging and testing requirements imposed by BSEE to permanently abandon a well, except a surface plug is not required, and the lessee need not sever the casing, remove the wellhead, or clear the site. BSEE regulations also allow a lessee to either leave a pipeline in place after performing certain activities (e.g., cleaning it and flushing with seawater) or remove it from the seafloor. *See* 30 C.F.R. § 250.

[23]Department of the Interior, *Notice to Lessees and Operators of Federal Oil and Gas Leases and Pipeline Right-of-way Holders in the Outer Continental Shelf, Gulf of Mexico OCS Region: Decommissioning Guidance for Wells and Platforms*, NTL No. 2010-G05 (Sept. 15, 2010). This guidance expired Oct. 14, 2013, but BSEE continues to use it.

- A well is considered idle if it has not been used in the past 5 years for operations associated with exploration or development and production of oil or gas, and if the lessee has no plans for such operations.
- A platform is considered idle if it has been toppled or otherwise destroyed, or it has not been used in the past 5 years for operations associated with exploration or development and production of oil or gas.

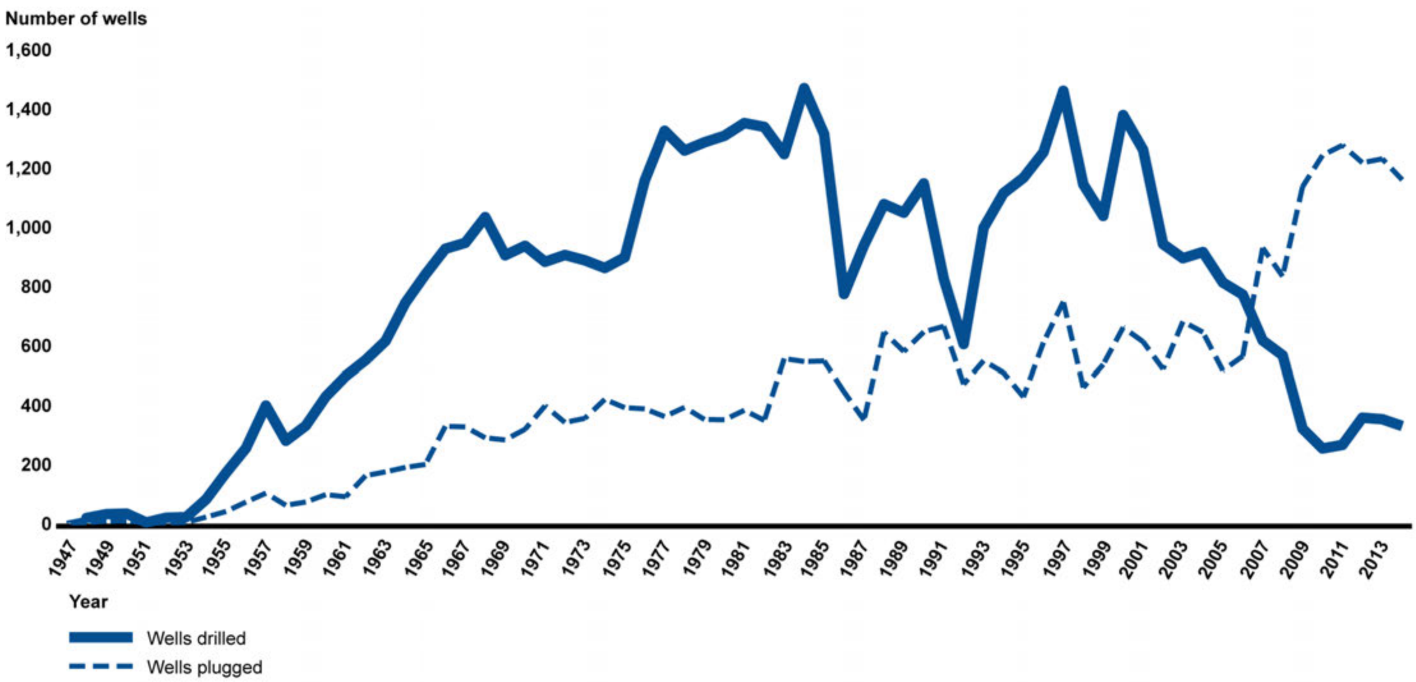
Companies may postpone decommissioning idle wells and platforms to defer the cost of removal, increase the opportunity for resale, or reduce decommissioning costs through economies of scale and scheduling, among other reasons. However, postponing decommissioning can be costly because the longer a structure is present in the Gulf the greater the likelihood it will be damaged by a hurricane. According to Interior documentation, decommissioning a storm-damaged structure may cost 15 times or more the cost of decommissioning an undamaged structure. In 2005, Hurricanes Katrina and Rita destroyed 116 structures and significantly damaged another 163 structures and 542 pipelines in the Gulf, according to Interior documentation. According to BSEE officials, as of April 2015, the Gulf contained 13 destroyed structures with 16 associated wells.

Storm-damaged or toppled structures present a greater risk to safety and require difficult and time-consuming salvage work. After preliminary salvage work that can take weeks, divers cut and remove structural components while crane assemblies remove the components and place them on a barge for transport and disposal. Additionally, when working in areas with strong currents and unconsolidated material, coffer dams are often constructed on the seabed to prevent material from slumping back in on the dive crews and equipment.

Oil and Gas Infrastructure Installed and Removed in the Gulf

Figure 2 shows the annual number of wells drilled and plugged in the Gulf from 1947 through 2014. During this time period, lessees drilled a total of 52,223 wells in the Gulf (including 18,447 exploratory wells and 33,776 development wells) and plugged a total of 29,879 wells (including 4,017 temporarily abandoned wells and 25,862 permanently abandoned wells).

Figure 2: Annual Number of Wells Drilled and Plugged in the Gulf of Mexico, 1947-2014

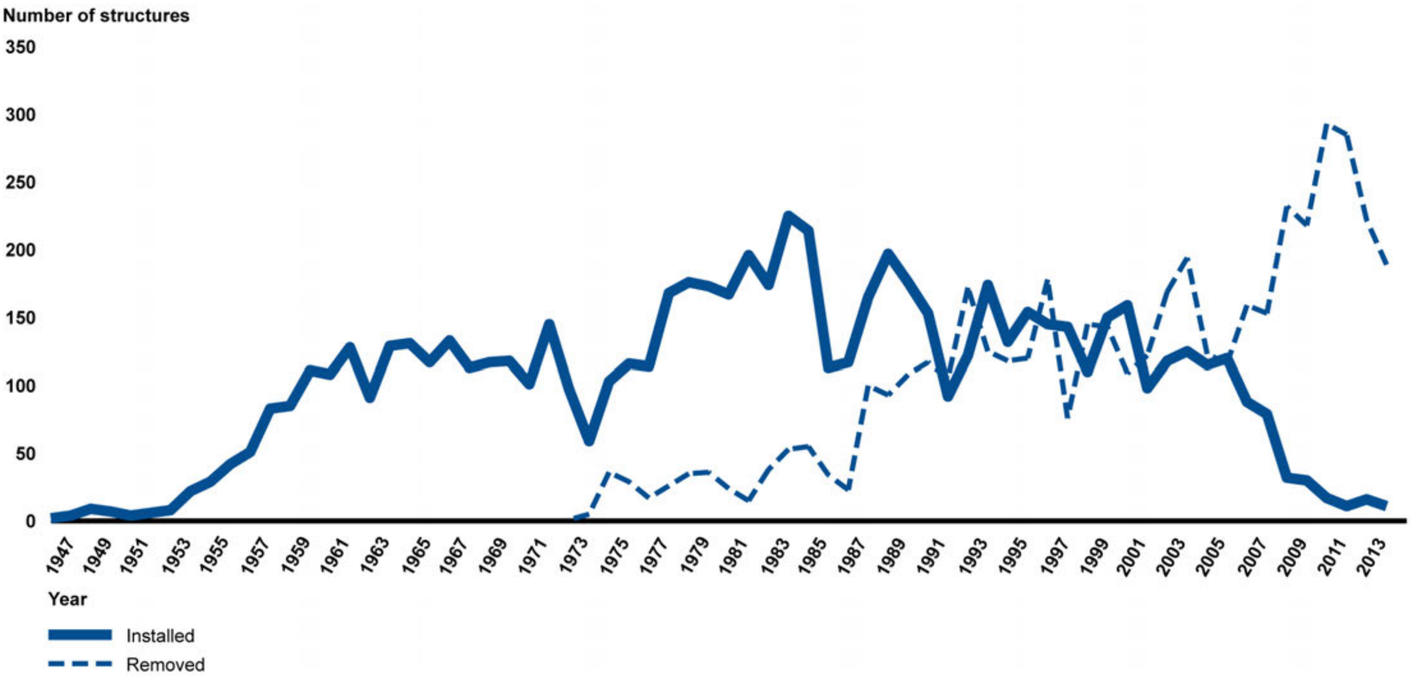


Source: GAO analysis of Bureau of Safety and Environmental Enforcement (BSEE) data. | GAO-16-40

Note: Wells drilled include exploratory and development wells. Wells plugged include temporary and permanent well abandonments.

Figure 3 shows the annual number of structures installed and removed in the Gulf from 1947 through 2014. During this time period, lessees installed a total of 7,038 structures in the Gulf. In addition, starting in the 1970s, lessees began removing structures from the Gulf. Specifically, lessees removed a total of 4,611 structures from 1973 through 2014. Most of the structures installed and removed were fixed platforms and caissons installed in shallow water.

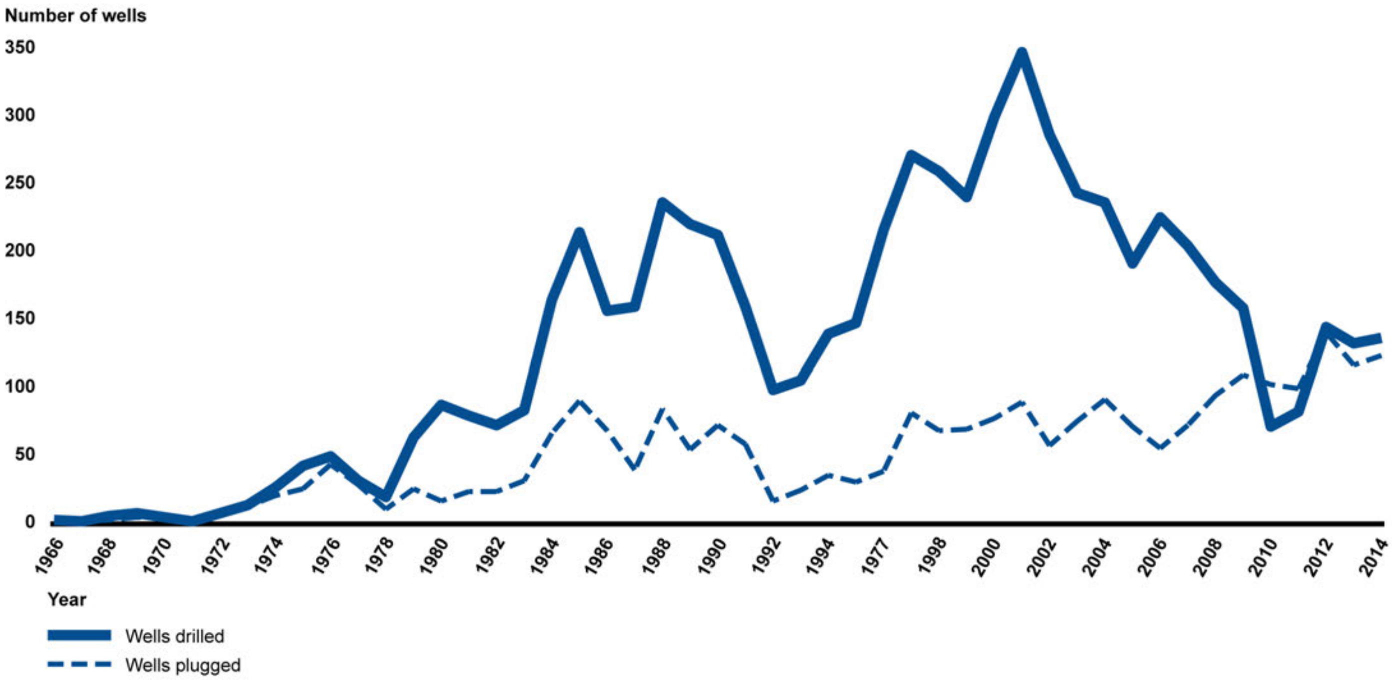
Figure 3: Annual Number of Structures Installed and Removed in the Gulf of Mexico, 1947-2014



Source: GAO analysis of Bureau of Safety and Environmental Enforcement (BSEE) data. | GAO-16-40

Between the late 1940s and early 1960s, lessees only drilled wells in shallow water. However, starting in the mid-1960s, lessees began drilling wells in deep water. Figure 4 shows the annual number of wells drilled and plugged in deep water in the Gulf from 1966 through 2014. During this time period, lessees drilled a total of 6,468 wells (including exploratory and development wells) and plugged a total of 2,489 wells (including temporary and permanently abandoned wells) in deep water. Lessees also installed 112 structures—mostly fixed platforms, spar, tension leg platforms, and floating production systems—and removed 19 structures in deep water during this time period.

Figure 4: Annual Number of Deepwater Wells Drilled and Plugged in the Gulf of Mexico, 1966-2014



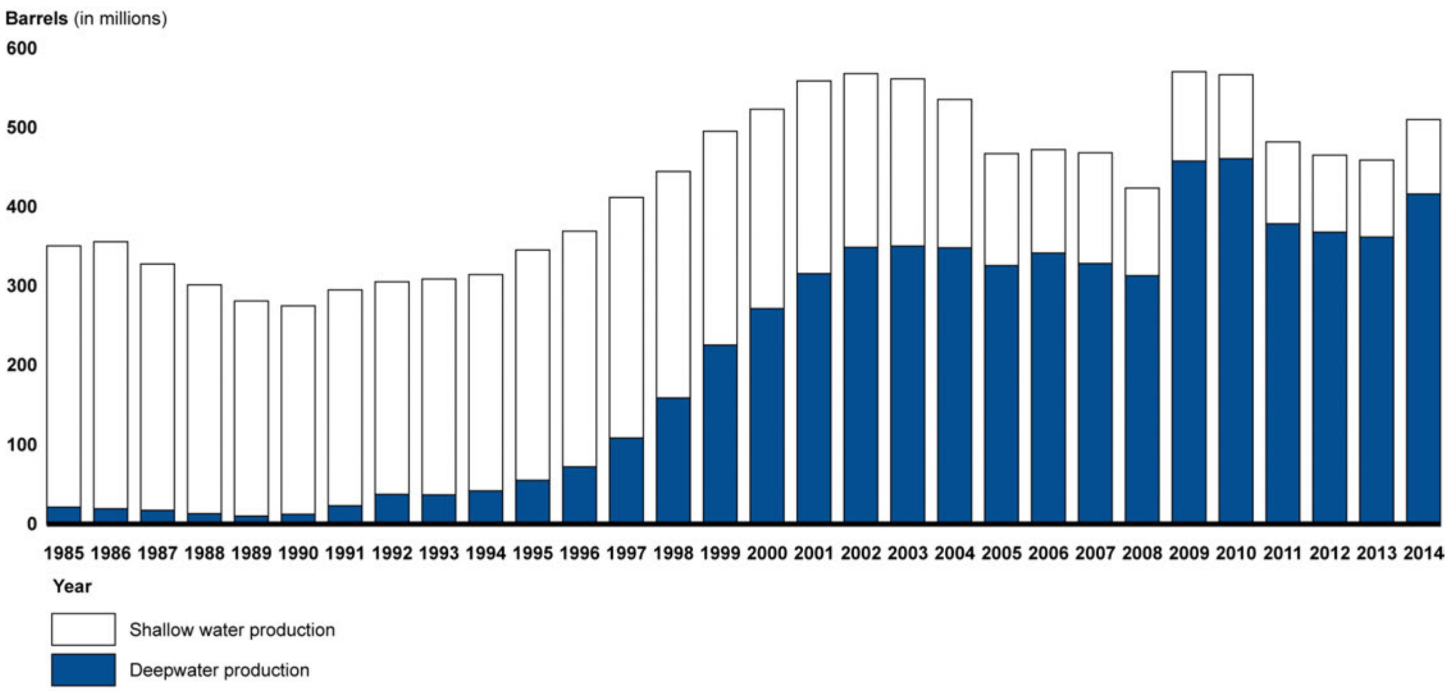
Source: GAO analysis of Bureau of Safety and Environmental Enforcement (BSEE) data. | GAO-16-40

Note: Wells drilled include exploratory and development wells drilled in greater than 400 feet of water. Wells plugged include temporary and permanent well abandonments in greater than 400 feet of water.

Since 1985, oil production from deepwater wells has increased significantly, as shown in figure 5. While the number of wells drilled has decreased in recent years, offshore production has increased as lessees have drilled wells in deep water that are more productive than wells in shallower water. In 2014, over 80 percent of Gulf oil production occurred in deep water, up from 6 percent in 1985.[24] According to BSEE officials, activities in deep water, including drilling and decommissioning, are significantly more expensive than those in shallow water because of the technology required and challenges associated with deep water, such as very high pressures at significant water and well depths.

[24]For these data, Interior defined deep water as depths of greater than 1,000 feet. According to Interior's data, gas production in deep water also increased dramatically over this period, from less than 1 percent of total Gulf production in 1985 to over 50 percent in 2014.

Figure 5: Oil Production in the Gulf of Mexico, 1985-2014



Source: GAO analysis of Bureau of Ocean Energy Management (BOEM) data. | GAO-16-40

Interior Has Procedures to Oversee Decommissioning and Estimate Related Costs but Faces Data System Limitations and Has Not Documented Some Procedures

Interior's BSEE has developed procedures to oversee the decommissioning of offshore oil and gas infrastructure and estimate costs associated with decommissioning liabilities, but limitations in its data system may affect the accuracy and completeness of some cost estimates. In addition, BSEE has not documented some of its procedures for identifying and tracking infrastructure that needs to be decommissioned and for estimating the related costs.

BSEE Has Procedures to Oversee Decommissioning and Estimate Costs, but Data System Limitations May Affect the Accuracy and Completeness of Some Cost Estimates

Officials in BSEE's Gulf regional office have developed procedures for overseeing the activities of lessees in decommissioning oil and gas infrastructure in the Gulf and estimating the costs of doing so, but limitations in its data system for estimating costs may affect the accuracy and completeness of some cost estimates.

Procedures for Overseeing Decommissioning

Under BSEE's regulations, lessees must apply for approval before plugging wells, removing platforms and clearing sites, and decommissioning pipelines. According to BSEE regional officials, they review applications to ensure that they contain the required information (see table 1 below). Once this process is complete, BSEE officials approve a lessee's application, which authorizes the lessee to begin decommissioning activities.

Table 1: Bureau of Safety and Environmental Enforcement (BSEE) Requirements for Decommissioning Applications for Offshore Oil and Gas Infrastructure

Type of application	Description
Plugging wells[a]	Lessees must provide the following information: (1) reason for plugging the well; (2) recent well test and pressure data; (3) maximum possible surface pressure; (4) type and weight of well-control fluid to be used; (5) description of work; (6) current and proposed well schematic and description; and (7) certification by a registered professional engineer of the well abandonment design and procedures, and that all plugs meet BSEE requirements.
Removing platforms or other facilities	Lessees must provide the following information: (1) identification and description of the structure to be removed; 2) description of vessel(s) used to remove structure; (3) identification of purpose for removing structure; (4) description of removal method (e.g., explosives); (5) plans for transportation and disposal or salvage of removed platform; (6) if available, results of any recent biological surveys conducted in vicinity of structure; (7) and plans to protect archaeological and sensitive biological features during removal operations, among other things.
Decommissioning pipelines	If decommissioning a pipeline in place, lessees must submit information on the proposed decommissioning procedures and the length of the segment to be decommissioned and left in place, among other things. If removing a pipeline, lessees must submit information on the proposed removal procedures and length of segment to be removed, among other things.

Source: GAO analysis of BSEE documentation. | GAO-16-40

[a]BSEE has established requirements for an application to permanently plug a well and to temporarily abandon a well. This table reflects requirements for an application to permanently plug a well.

After lessees complete all planned decommissioning, they are required to report to BSEE on the outcome of these activities so that BSEE may verify that all their decommissioning obligations have been met, including clearing the seafloor around wells, platforms, and other facilities.

According to BSEE regional officials, they review lessee reports on decommissioning activities to ensure that the results are consistent with the information presented as part of the application process. Table 2 summarizes BSEE's reporting requirements related to the results of decommissioning activities.

Table 2: Bureau of Safety and Environmental Enforcement (BSEE) Requirements for Reporting on Decommissioning Results for Offshore Oil and Gas Infrastructure

Type of report	Description
Plugging wells	Lessees must submit a report within 30 days after plugging a well. This report must include the following information: (1) information included with request submitted before permanently plugging the well along with a final well schematic; (2) description of plugging work; (3) nature and quantities of material used in plugs; and (4) description of methods used for casing removal (including information on explosives, if used), among other things.
Removing platforms or other facilities	Lessees must submit a report within 30 days after removing a platform or other facility. This report must include the following information: (1) summary of removal operations including completion date; (2) description of any mitigation measures taken; and (3) signed statement certifying that the types and amounts of explosives used in removing the platform were consistent with those set forth in the approved removal application.
Decommissioning pipelines	Lessees must submit a report within 30 days after decommissioning a pipeline. This report must include the following information: (1) summary of the decommissioning operation including completion date; (2) description of any mitigation measures taken; and (3) signed statement certifying that the pipeline was decommissioned according to the approved application.
Clearing sites around wells, platforms, and other facilities	Lessees must verify that a site is clear of obstructions within 60 days of plugging a well or removing a platform or other facility. Lessees then must submit a report within 30 days after verifying site clearance to certify to BSEE that all site clearance activities are completed. For wells, this report must include the following information: (1) signed certification that the well site area is cleared of all obstructions; (2) date the verification work was performed and the vessel used; (3) extent of the area surveyed; (4) survey method used; and (5) results of the survey, among other things. For platforms and other facilities, this report must include the following information: (1) letter (signed by the lessee) certifying that the platform or area is cleared of all obstructions and that a company representative witnessed the activities; (2) letter (signed by contractor) certifying that it cleared the platform or area of all obstructions; (3) date that work was performed and vessel used; (4) extent of area surveyed; (5) survey method used; and (6) survey results, among other things.

Source: GAO analysis of BSEE documentation. | GAO-16-40

According to BSEE regional officials, during the process of reviewing lessee reports, BSEE may issue a notice of an "incident of noncompliance" in cases where lessees have not provided all of the required information or when lessee activities are not consistent with BSEE regulations. If BSEE officials determine that the violation is not severe or threatening, they will issue a "warning" notice that requires the lessee to correct the violation within a specified period of time. If BSEE officials determine that the violation is more serious, they will issue a "shut-in" notice that requires the lessee to correct the violation before resuming activities. In addition, BSEE officials can assess a civil penalty of up to $40,000 per violation per day if the lessee fails to correct the violation in the period of time specified in the notice, or if the violation resulted in a threat of serious harm to human life or damage to the environment.

In addition to reviewing lessee applications and reports, the BSEE Gulf region identifies and tracks idle and terminated lease infrastructure. According to BSEE regional officials, the BSEE Gulf region began identifying and tracking idle lease infrastructure in 2010 and currently updates a list of this infrastructure on an annual basis. BSEE began identifying and tracking terminated lease infrastructure prior to 2010, according to BSEE regional officials. At the beginning of each calendar year, BSEE regional officials obtain data from Interior's main data system—the Technical Information Management System (TIMS)—on wells and structures on leases that meet the criteria for idle and terminated lease infrastructure.[25] Based on these data, BSEE sends a list of idle and terminated lease infrastructure to each lessee, requesting a decommissioning plan and schedule for decommissioning the lessee's inventory. According to BSEE regional officials, BSEE works with lessees to verify the accuracy of their inventory of idle and terminated lease infrastructure, and BSEE tracks lessees' progress in meeting their schedules.[26]

Procedures for Estimating Costs

According to BSEE regional officials, BSEE estimates the costs associated with decommissioning liabilities by counting the number and types of wells, pipeline segments, and structures on a lease and using

[25]According to the Federal IT Dashboard, TIMS is a computerized information system that automates many of the business and regulatory functions of BSEE and BOEM. TIMS enables staff of the regional and headquarters offices of both BSEE and BOEM to share and combine data; create and print maps; standardize processes, forms, and reports; and promote the electronic submission of data.

[26]According to BSEE data, lessees have made progress in decommissioning idle infrastructure in the Gulf. Specifically, in 2010, there were 3,233 idle wells and 617 idle platforms in the Gulf and, as of June 15, 2015, there were 1,082 idle wells and 245 idle platforms in the Gulf.

data on the water depth associated with this infrastructure.[27] Using these data, BSEE then calculates the costs associated with (1) plugging and abandoning wells, (2) removing platforms and other structures, (3) decommissioning pipelines, and (4) clearing debris from the site.

In general, the cost to plug wells and remove structures increases as the water depth increases. For example, according to BSEE's current methodology, its estimate of the cost to plug a dry tree well attached to a fixed structure in shallow water is $150,000, while its estimate of the cost to plug a subsea well in deep water is a minimum of about $21 million. Likewise, BSEE's estimates of the costs to remove fixed platforms in shallow water range from approximately $85,000 to $4.6 million, while its estimate of the cost to remove a floating structure (and associated equipment) in deep water is a minimum of $30 million.

According to BSEE regional officials, a number of events can trigger BSEE's review of the costs associated with decommissioning liabilities on a lease. Examples of these events include the following:

- BSEE determines that a lessee is planning a potential sale or acquisition of leases.
- BOEM or BSEE detect indications of financial stress for a lessee.
- BOEM requests a review of a pending request for lease assignment and bond cancellations.
- A lessee requests a review from BSEE when some but not all infrastructure is decommissioned on a lease.

BSEE enters and stores its cost estimates of decommissioning liabilities in TIMS. However, according to BSEE regional officials, TIMS is limited in its ability to accurately and completely record cost estimates of decommissioning liabilities, as follows:

- TIMS contains three data fields to record cost estimates for each offshore lease—one for estimates of the cost of removing existing structures, one for estimates of the cost of plugging existing wells, and one for estimates of the cost of clearing debris from sites. TIMS uses algorithms developed in the 1990s to calculate cost estimates for

[27] The BSEE Gulf regional office established a Decommissioning Support Section in December 2013 to estimate costs associated with decommissioning liabilities in the Gulf. Prior to that date, BSEE officials in other sections within the Gulf regional office were assigned the responsibilities associated with estimating these costs.

each of these data fields. However, BSEE officials said that the cost estimates are too low compared to BSEE's current estimates. For example, TIMS calculates the cost to plug a well is $100,000, regardless of water depth or the type of well, while BSEE estimates the cost to plug a subsea well in deep water is approximately $21 million.

- TIMS does not contain separate data fields for recording the estimated cost to plug a planned well (as opposed to an existing well) or to decommission pipelines. BSEE officials said that both of these costs are important to consider and to estimate a lessee's potential decommissioning liability.

Because of these limitations, BSEE regional officials said that, in 2009, they began investing more time and resources into manually updating cost estimates of decommissioning liabilities in TIMS. Currently, BSEE officials use separate spreadsheets—containing updated methodologies for estimating costs in shallow and deep water—to estimate costs to decommission leases. They then manually enter the cost estimates into TIMS using separate data fields entitled "adjusted decommissioning liability" for each type of cost estimate; for example, plugging wells, removing structures, and site clearance. In addition, they add estimated costs for (1) plugging planned wells into the "adjusted decommissioning liability" data field for existing wells and (2) decommissioning pipelines into the "adjusted decommissioning liability" data field for site clearance. Once they enter these data, TIMS automatically populates the date of that entry into an "updated" data field.

According to BSEE regional officials, they have manually entered updated cost estimates for most leases in the Gulf. Specifically, as of July 8, 2015, BSEE officials said that they had entered updated cost estimates for 3,460 (86 percent) of the 4,021 leases in the Gulf with decommissioning liabilities. BSEE officials characterized their efforts to update cost estimates as an "ongoing process" and said that their activities related to cost estimating have increased dramatically over the past decade. Officials said that while there was no set time frame by which they plan to update cost estimates for all the leases in the Gulf, the number of leases changes over time, and BSEE prioritizes its efforts on those leases that BOEM and BSEE determine pose higher financial risk.

BSEE regional officials told us that Interior is transitioning to a new data system (the National Consolidated Information System) to manage offshore oil and gas activities and that BSEE plans to use the new data system to improve how decommissioning liabilities are calculated and recorded. However, officials were unable to provide details on how the new data system will address the existing data limitations in TIMS or when they expect to implement these improvements in the new data system. Internal control standards in the federal government call for agencies to ensure that all transactions and events are completely and accurately recorded.[28] Without the ability to completely and accurately record data on decommissioning costs, some of BSEE's estimates of decommissioning liabilities may not be complete or accurate, and BOEM may not have reasonable assurance that it is requiring sufficient amounts of financial assurance based on BSEE's estimates.

BSEE Does Not Have Finalized, Documented Procedures for Identifying and Tracking Infrastructure That Needs to Be Decommissioned or for Estimating Costs

BSEE officials in the Gulf regional office told us BSEE does not have documented procedures for identifying and tracking idle and terminated lease infrastructure or finalized documented procedures for estimating costs associated with decommissioning liabilities. Specifically, BSEE regional officials told us the bureau did not have documentation, such as standard operating procedures or operating manuals that described their process for identifying and tracking infrastructure. BSEE regional officials provided draft documentation outlining their approach to estimating costs associated with plugging wells, removing structures, and decommissioning pipelines; however, they told us that these documents had not been finalized and were a "work in progress." According to these officials, these documents replace an older policy manual and were developed in 2014 after BSEE established the Decommissioning Support Section within the Gulf regional office.[29]

In addition, BSEE's draft documents outlining its approach to estimating the costs of decommissioning liabilities do not address how BSEE regional officials plan to periodically assess the methodology for estimating costs, as recommended by an internal Interior review. Specifically, in fiscal year 2009, Interior conducted an internal review of its procedures related to its financial accountability and risk management

[28] GAO/AIMD-00-21.3.1.

[29] Department of the Interior, Minerals Management Service, *Policy Manual Part 640.1 - Financial Accountability and Risk Management (FARM) Program* (Washington, D.C.: July 22, 2008).

program. In an internal report,[30] Interior stated that program officials estimated costs using data that had not been updated in over 14 years. The report recommended that the program develop and implement a formal policy to review and revise all assessments at least once every 5 years for all regions.[31] It also recommended that program officials consider adjusting assessments to reflect the cost of inflation during the period between the 5-year updates. To date, BSEE regional officials have not developed and implemented formal procedures addressing these recommendations.

Internal control standards in the federal government call for agencies to clearly document internal controls, and the documentation should appear in management directives, administrative policies, or operating manuals.[32] According to BSEE regional officials, they plan to establish documented procedures to identify and track idle and terminated lease infrastructure and estimate costs, but have not done so due to competing priorities, among other reasons. Without finalized, documented procedures, BSEE does not have reasonable assurance that it will consistently conduct such activities in the future, which could limit the effectiveness of Interior's oversight of the decommissioning process and its ability to obtain sufficient financial assurances to cover decommissioning liability.

[30]Department of the Interior, Minerals Management Service, *Offshore Energy and Minerals Management, Supplemental Bonding Process, Fiscal Year 2009 Internal Control Review* [publication date not listed].

[31]In keeping with this recommendation, BSEE's Pacific regional office customarily prepares a decommissioning cost report every 5 years to determine estimated decommissioning costs for its region and to support decisions regarding bonding requirements.

[32]GAO/AIMD-00-21.3.1.

Interior's Procedures for Obtaining Financial Assurances for Decommissioning Liabilities Pose Risks to the Federal Government, and Interior Plans to Revise Them

Interior's procedures for obtaining financial assurances for offshore decommissioning liabilities pose financial risks to the federal government. Officials from Interior's BOEM told us that the bureau plans to revise its procedures that determine how much financial assurance a lessee must provide, and that they expect these procedures to reduce the risk that the government could incur costs associated with decommissioning.

BOEM's Procedures for Obtaining Financial Assurances for Decommissioning Liabilities Pose Risks to the Federal Government

BOEM's procedures for obtaining financial assurances for offshore decommissioning liabilities pose financial risks to the federal government in three ways. First, as of October 2015, according to BOEM officials, BOEM had identified approximately $2.3 billion in decommissioning liabilities in the Gulf that may not be covered by financial assurances but was unable to determine in a timely manner the extent to which these liabilities were valid. Specifically, after identifying data on potentially uncovered decommissioning liabilities in TIMS, BOEM officials analyzed these data over several months to determine their validity. That is, BOEM officials tried to determine the extent to which these liabilities were accurate and the extent to which valid liabilities were covered by financial assurances. BOEM officials told us that, based on their analyses, some of the $2.3 billion in decommissioning liabilities may be valid and uncovered by financial assurances.[33]

However, according to BOEM officials, they were unable to quantify how much of the $2.3 billion in decommissioning liabilities were valid and uncovered by financial assurances due to limitations with the TIMS data system and inaccurate data, among other things. For example, BOEM officials stated that existing reports generated by the TIMS data system

[33]For example, according to BOEM officials, BSEE recently began updating its estimates of decommissioning liabilities associated with pipelines in the TIMS data system. As a result, BOEM officials said that data associated with these decommissioning liabilities may be valid.

did not provide all the necessary information for determining the validity of data on decommissioning liabilities and financial assurances. As a result, officials said that they had to create new reports to access additional data stored in TIMS, and that these efforts were time consuming. In addition, BOEM officials said that they identified leases that did not have wells or platforms but for which TIMS contained estimates of decommissioning liabilities. BOEM officials said that data associated with these decommissioning liabilities may not be valid but that they would need to consult with BSEE officials to determine their validity, which would take additional time.

BOEM officials stated that, in order to determine the validity of the data in TIMS, they plan to consult with BSEE officials and continue to analyze relevant data. Once they have determined the validity of the data, they said that they will take steps to obtain financial assurances for any uncovered decommissioning liabilities. However, officials were unable to provide details on how or when they planned to address existing limitations with the TIMS data system or determine the accuracy of data on decommissioning liabilities. Internal control standards in the federal government call for agencies to ensure that pertinent information is identified, captured, and distributed in a form and time frame that permits people to perform their duties efficiently.[34] Without timely access to valid data on decommissioning liabilities in the Gulf and associated financial assurances, BOEM does not have reasonable assurance that it has sufficient financial assurances in place, putting the federal government at risk.

Second, under BOEM's procedures, less than 8 percent of estimated decommissioning liabilities in the Gulf are covered by financial assurance mechanisms such as bonds. Specifically, as of October 2015, according to BOEM officials, for an estimated $38.2 billion in decommissioning liabilities in the Gulf, BOEM held or required about $2.9 billion in bonds and other financial assurances.[35] For $33.0 billion in decommissioning liabilities, BOEM waived 47 lessees from the requirement to provide

[34]GAO/AIMD-00-21.3.1.

[35]As of October 2015, BOEM held about $1.8 billion in bonds (including supplemental and general bonds) and about $500 million in trust agreements. In addition, BOEM had issued letters requiring lessees to provide about $600 million in financial assurances.

supplemental bonds based on BOEM's reviews of the lessees' financial strength, according to BOEM officials.[36, 37]

Under BOEM's current financial assurance procedures,[38] each offshore lease with a decommissioning liability must be covered by a supplemental bond unless BOEM determines that a lessee has the financial ability to fulfill its decommissioning obligations. BOEM staff evaluate the financial ability of a lessee to fulfill its decommissioning obligations by means of a financial strength test. BOEM's financial strength test requires a lessee to meet the following criteria:

- provide an independently audited financial statement indicating a net worth greater than $65 million;
- possess a total decommissioning liability (as determined by BSEE) of less than or equal to 50 percent of its audited net worth;
- possess total company liabilities of no more than 2 to 3 times the value of the adjusted net worth;[39, 40] and

[36]For the purposes of ensuring that there is at least one responsible party with the financial ability to fulfill lease decommissioning obligations, BOEM attributes all lease decommissioning liabilities to any waived lessee on a lease (even if other responsible parties are present on the lease). The waived lessee is, with all other lessees, jointly and severally liable for decommissioning and relies on its financial strength to secure the costs of this decommissioning, on behalf of all the jointly and severally liable parties.

[37]Under Interior regulations, regional directors may determine that a supplemental bond is necessary to ensure compliance with a lessee's obligations. According to Interior officials, supplemental bonding becomes a requirement once the regional director determines that it is necessary.

[38]Department of the Interior, Minerals Management Service, *Notice to Lessees and Operators of Federal Oil, Gas, and Sulfur Leases and Pipeline Right-of-way Holders in the Outer Continental Shelf: Supplemental Bond Procedures*, NTL No. 2008-N07 (Aug. 28, 2008).

[39]Adjusted net worth includes a percentage of a lessee's proven oil and gas reserves added to a lessee's audited net worth. BOEM varies the total liability ratio it will accept based on adjusted net worth—for example, a lessee with between $65 million and $100 million in adjusted net worth can possess total lessee liabilities of no more than 2 or 2.5 times its adjusted net worth, depending on the size of the company's potential decommissioning liability.

[40]Alternatively, BOEM allows a lessee to use a substitute criterion—the lessee must demonstrate that it produces in excess of an average of 20,000 barrels of oil equivalent per day on its leases. However, according to BOEM officials, of the 51 waived lessees only 1 or 2 chose to use this alternative criterion.

- demonstrate reliability, as shown by a record of compliance with laws, regulations and lease terms, among other factors.

If a lessee passes the financial strength test by demonstrating its financial ability to pay for decommissioning on its leases, BOEM waives its requirement for the lessee to provide supplemental bonds. Other responsible parties on the lease will also be waived from the requirement to provide supplemental bonds.[41] According to BOEM officials, BOEM waives these parties as well because the waived lessee could be held responsible if another party on a lease does not fulfill its decommissioning obligations. In addition, a waived lessee may provide financial assurance in the form of a corporate guarantee of the lease obligations of a lessee on another lease.[42]

After BOEM waives a lessee from the requirement to provide supplemental bonding, it monitors the financial strength of the lessee to ensure it continues to pass BOEM's financial strength test. BOEM conducts quarterly financial reviews for the first 2 years after a lessee receives a waiver and then an annual review thereafter.[43] In addition, on a weekly basis, BOEM compares the decommissioning obligations (as determined by BSEE) of all waived lessees with the financial information provided by lessee audited financial statements.[44] If BOEM finds that a lessee no longer passes its financial strength test, BOEM will conduct a more in-depth review of a lessee's financial status by reviewing financial statements, credit ratings, and other financial information. BOEM may also conduct an unscheduled financial review if: (1) BSEE revises its estimate of a lessee's decommissioning liability, (2) a lessee's financial status changes as reported by credit rating agencies, or (3) a lessee does

[41]In addition to bonds required by BOEM, some lessees that transfer leases or rights may require the party acquiring the lease to provide a surety bond. This bond protects the transferring party from paying decommissioning costs it may be liable for if the purchasing party is unable to fulfill its decommissioning obligations. According to BOEM officials, these bonds are generally not reported to BOEM, and BOEM does not consider them as financial assurance because BOEM is not a beneficiary of such bonds.

[42]According to BOEM officials, nearly all corporate guarantees are between parent companies and subsidiaries.

[43]These reviews evaluate the same criteria that BOEM officials used during the initial financial strength test.

[44]As part of these reviews, BOEM determines whether the waived lessee has the ability to pay for all decommissioning costs on leases where the lessee is an owner.

not pay the required royalties to the federal government. According to BOEM officials, these reviews could cause BOEM to revoke a lessee's waiver from the requirement to provide supplemental bonding. For example, in May 2015, BOEM revoked the waiver of one lessee and, according to BOEM officials, the waived lessee and related parties could be required to provide as much as $1 billion in supplemental bonds.[45]

Our prior reports have found that the use of financial strength tests and corporate guarantees in lieu of bonds poses financial risks to the federal government. Specifically, we found, in August 2005, that the financial assurance mechanisms that impose the lowest costs on the companies using them— such as financial strength tests and corporate guarantees—also typically pose the highest financial risks to the government entity accepting them.[46] In that report, we found that, if a company passes a financial strength test but subsequently files for bankruptcy or becomes insolvent, the company in essence is no longer providing financial assurance because it may no longer have the financial capacity to meet its obligations. Such financial deterioration can occur quickly. While companies no longer meeting the financial test are to obtain other financial assurance, they may not be able to obtain or afford to purchase it. In addition, in May 2012, we found that, according to the Bureau of Land Management and the Environmental Protection Agency, corporate guarantees are potentially risky because they are not covered by a specific financial asset such as a bond.[47] BOEM's use of the financial strength test and corporate guarantees in lieu of bonds raises the risk that the federal government may have to pay for offshore decommissioning if lessees do not.

The third way BOEM's procedures pose financial risks to the federal government is that BOEM's financial strength test relies on measures that may not provide an accurate indication of a lessee's ability to pay for

[45]In cases where BOEM revokes a lessee's waiver from the requirement to provide supplemental bonding, the lessee or other responsible parties on a lease or recipients of corporate guarantees would be required to provide supplemental bonds to cover decommissioning obligations that are no longer covered by a waiver or guarantee.

[46]GAO, *Environmental Liabilities: EPA Should Do More to Ensure That Liable Parties Meet Their Cleanup Obligations,* GAO-05-658 (Washington, D.C.: Aug. 17, 2005).

[47]GAO, *Phosphate Mining: Oversight Has Strengthened, but Financial Assurances and Coordination Still Need Improvement,* GAO-12-505 (Washington, D.C.: May 4, 2012).

decommissioning. As described above, BOEM uses net worth (from a lessee's audited financial statements) as a key measure in its financial strength test. However, according to representatives from credit rating agencies we spoke to, net worth provides limited value to assess a company's financial strength and ability to pay future liabilities. Specifically, these representatives said that net worth is "backward looking" and can be skewed by the volatile nature of commodity prices, among other factors. Credit rating agencies use financial measures that emphasize the evaluation of cash flow, such as debt-to-earnings and debt-to-funds from operations to evaluate whether a company will be able to pay its liabilities. Without the use of similar measures in its financial assessments, BOEM may not have reasonable assurance that the lessees it waives from the requirement to provide supplemental bonds have the financial abilities to fulfill decommissioning obligations, which may increase the financial risk to the government.

BOEM Plans to Revise Its Procedures to Reduce Financial Risks

According to BOEM officials, BOEM recognizes the financial risks associated with its current financial assurance procedures and plans to revise its procedures to reduce risk. Specifically, BOEM officials told us that BOEM's planned revisions would eliminate the use of financial strength tests to completely waive lessees from the requirement to provide supplemental bonding. Instead, BOEM plans to conduct financial reviews of lessees' financial status and, based on those reviews, assign lessees an amount of credit that may be used to reduce required bonding associated with decommissioning liabilities on leases. Lessees would be able to apportion this credit to leases, in coordination with other responsible parties on those leases, to ensure that lease decommissioning liabilities are fully covered by apportioned credit or supplemental bonds. As part of BOEM's financial review of lessees, these officials told us that BOEM plans to use criteria that emphasize the use of measures such as cash flow and company liquidity while deemphasizing the use of net worth. In addition to these planned revisions, in August 2014, BOEM announced its intent to update its regulations and program oversight for offshore financial assurance requirements.[48] BOEM solicited stakeholder comments in response to this proposal and has held industry

[48]79 Fed. Reg. 49027 (Aug. 19, 2014). According to BOEM officials, BOEM expects to promulgate these new regulations in 2017.

forums to discuss potential changes to its financial assurance regulations and procedures.

According to BOEM officials, if BOEM were to use these criteria as part of its financial strength test, some of the lessees currently waived from the requirement to provide supplemental bonds could lose their waivers. BOEM officials also stated that, if the revised procedures are implemented as planned, lessees could be required to provide several billion dollars in additional supplemental bonds. BOEM officials told us they plan to update the bureau's financial assurance procedures in late 2015 or early 2016. In commenting on a draft of this report, Interior officials stated that on September 22, 2015, BOEM issued proposed guidance to clarify its financial assurance procedures. However, it is too soon to evaluate the specific details of BOEM's proposed changes to its financial assurance procedures because BOEM has not issued any final revisions to its procedures. Until BOEM revises and implements new procedures, the federal government remains at greater risk of incurring costs should lessees fail to decommission offshore oil and gas infrastructure as required.

Interior Faces Two Key Challenges Managing Potential Decommissioning Liabilities

Interior faces two key challenges managing potential decommissioning liabilities. First, BSEE does not have access to all relevant data from lessees on costs associated with decommissioning activities in the Gulf. Second, BOEM's requirements for reporting the transfers of lease rights may impair its ability to manage decommissioning liabilities.

BSEE Does Not Have Access to All Relevant Data on Decommissioning Costs

BSEE does not have access to all relevant current data on costs associated with decommissioning activities in the Gulf. Internal control standards in the federal government call for agencies to obtain information from external stakeholders that may significantly affect their abilities to achieve agency goals.[49] Obtaining accurate and complete information on the decommissioning costs is critical to Interior being able

[49] GAO/AIMD-00-21.3.1.

to achieve its goals. Specifically, BSEE needs accurate and complete information on decommissioning costs to estimate decommissioning liabilities in the Gulf, and BOEM relies on BSEE's estimates to ensure that it is requiring sufficient amounts of financial assurance to cover decommissioning liabilities.

However, BSEE generally has not had access to current data on decommissioning costs. Prior to December 2015, under BSEE's regulations, lessees were not required to report costs associated with decommissioning activities to BSEE. According to BSEE regional officials, data on decommissioning costs were considered proprietary, and companies generally did not share this information with BSEE. Instead, BSEE regional officials relied on other sources of data—some of which are decades old and, as a result, likely inaccurate—to estimate costs associated with decommissioning liabilities. According to BSEE regional officials, their estimates for decommissioning liabilities in shallow water were based on data provided by the oil and gas industry in 1995.[50] For decommissioning liabilities in water depths of 400 to 1,400 feet, their estimates were based on information in a 2009 report that Interior contracted.[51] For decommissioning liabilities for subsea wells, BSEE officials said that they had developed their own models for estimating costs based on an analysis of a variety of factors, such as the daily cost of hiring a vessel in the Gulf to plug wells.

During the course of our audit, BSEE regional officials told us that they planned to improve this process and the resulting data by issuing a regulation requiring such data to be submitted. Specifically, Interior issued a proposed rule in May 2009 to establish new requirements for lessees to submit expense information on costs associated with plugging and abandonment, platform removal, and site clearance.[52] In December 2015, BSEE issued a final rule establishing these requirements.[53] However,

[50]BSEE officials told us that they are preparing to request proposals to fund a new study to evaluate the costs associated with structure removal in shallow water in the Gulf and have proposed studies to evaluate costs associated with pipeline decommissioning and well plugging in shallow water.

[51]Proserv Offshore, *Gulf of Mexico Deep Water Decommissioning Study: Final Report*, prepared for Interior's Minerals Management Service (Houston, Tex: October 2009).

[52]74 Fed. Reg. 25177 (May 27, 2009).

[53]80 Fed. Reg. 75806 (Dec. 4, 2015) (effective Jan. 4, 2016).

according to BSEE regional officials, the rule does not require lessees to submit expense information on costs associated with decommissioning pipelines, and officials were unable to provide details as to when or whether BSEE would issue a new rule to require the reporting of such costs. Unless and until BSEE obtains all relevant cost data, BSEE may continue to use outdated information to assess decommissioning liabilities. Without access to accurate and complete information on decommissioning costs, BSEE may not have reasonable assurance that its estimates of decommissioning liabilities in the Gulf are accurate, and BOEM may not have reasonable assurance that it is requiring sufficient amounts of financial assurance based on BSEE's estimates.

Absence of a Clear Reporting Deadline for Transfers of Revenue Rights May Impair BOEM's Ability to Manage Decommissioning Liabilities

The absence of a clear deadline for reporting transfers of rights to lease production revenue may impair BOEM's ability to manage decommissioning liabilities. Under BOEM's financial assurance procedures, BOEM must obtain accurate information on a lessee's financial status to determine whether the lessee has sufficient financial strength to meet its decommissioning obligations, and BOEM may waive its requirement for the lessee to provide supplemental bonds based on this information. However, the transfer of rights to a lease may affect a lessee's financial status. For example, lessees may transfer lease ownership and the right to operate on a lease, which also obligates the new owner to decommission infrastructure on the lease. Under Interior regulations, these transfers must be approved by BOEM.[54]

Lessees can also transfer rights to lease production revenue.[55] Transfers of these revenue rights generally allow the receiving party to obtain a portion of the revenue from oil and gas production over a period of time and the lessee, in turn, is paid in advance of production. The more revenue rights a lessee transfers to other parties, the less revenue the lessee has to cover its other obligations, including decommissioning. However, unlike transfers of lease ownership and operating rights, transfers of revenue rights do not obligate the new owner to decommission, and lessees are not required to obtain BOEM's approval for these transfers. BOEM requires lessees to report these transfers, but

[54] 30 C.F.R. § 556.64(a).

[55] For the purposes of this report, we use the term "revenue rights" in place of "overriding royalty interests" and "payments out of production."

its regulations do not establish a clear deadline for the reporting.[56] As a result, BOEM is not always aware of such transfers in a timely manner.

For example, in one recent case, a waived lessee that had previously transferred most of its revenue rights to other parties subsequently declared bankruptcy. BOEM was unaware of these transfers until bankruptcy court proceedings. Had BOEM been aware of these transfers during its weekly review of the waived lessee, it could have revoked the lessee's waiver if it determined the lessee no longer passed the financial strength test. Consequently, BOEM then could have required the lessee or its co-lessees to provide supplemental bonds to cover its decommissioning obligations. In this case, the transfer of revenue rights left the lessee with insufficient assets to pay all of its liabilities during bankruptcy, including decommissioning. Though other lessees were held liable for decommissioning costs under joint and several liability, the government was at increased risk of incurring costs if the other lessees had been unwilling or unable to perform decommissioning.

BOEM officials told us that they created an internal group to help improve BOEM's knowledge of revenue rights transfers and the effect of transfers on a lessee's financial status. In commenting on a draft of this report, BOEM officials stated that they believe that current regulations could be interpreted as imposing a reporting deadline but recognize the need to clarify the regulations. Without a clear reporting deadline, lessees have little incentive to report revenue rights transfers to BOEM in a timely manner, and this could limit BOEM's ability to effectively evaluate a lessee's financial strength.

Conclusions

Decommissioning offshore oil and gas infrastructure is expensive and poses potential financial liabilities to the federal government. BSEE officials in the Gulf region have developed procedures for reviewing idle and terminated lease infrastructure to ensure that this infrastructure is decommissioned. In addition, in December 2015, BSEE issued final regulations (proposed in 2009) requiring lessees to report decommissioning costs directly to BSEE. However, several problems

[56] The regulations at 30 C.F.R. § 556.64 establish a 90-day deadline for the reporting of transfers of interest but do not define the term "interest." In discussions with BOEM officials in the Gulf regional office, BOEM officials did not interpret these regulations as imposing a reporting deadline for transfers of lease production revenue.

remain. First, BSEE's recent regulations do not require lessees to report costs associated with decommissioning pipelines. Unless and until BSEE obtains all relevant cost data, it may continue to use outdated data to assess decommissioning liabilities. Second, limitations of Interior's current data system restrict BSEE's ability to record estimates of decommissioning costs, and it is unclear how BSEE's new data system will address these limitations or when it will be available. Without access to complete data on decommissioning costs, and without the ability to accurately and completely record data in Interior's main data system, BSEE does not have reasonable assurance that its estimates of decommissioning liabilities in the Gulf are accurate, and BOEM may not have reasonable assurance that it is requiring sufficient amounts of financial assurance based on BSEE's estimates. Third, BSEE does not have finalized, documented procedures for identifying and tracking idle and terminated lease infrastructure and estimating decommissioning liabilities. Without such documented procedures, BSEE does not have reasonable assurance that it will consistently conduct such activities in the future, which could limit the effectiveness of BSEE's oversight of the decommissioning process.

Moreover, while BOEM is taking important steps to ensure that the financial assurance procedures used by the federal government are reducing the government's exposure to decommissioning costs by updating its procedures to assess the financial strength of lessees, we continue to have three concerns. First, BOEM identified roughly $2.3 billion in decommissioning liabilities in the Gulf that may not be covered by financial assurances but was unable to determine the extent to which these liabilities were valid after several months of analysis due to limitations with the TIMS data system and inaccurate data. As a result, it is unclear whether BOEM has obtained sufficient financial assurances to cover decommissioning liabilities in the Gulf. Without timely access to valid data on decommissioning liabilities and associated financial assurances, BOEM cannot ensure that it has sufficient financial assurances in place, putting the federal government at financial risk. Second, to date BOEM has not taken concrete steps to revise its current procedures. As a result, it is unclear whether BOEM's planned revisions will improve its procedures and the extent to which these revisions will increase the amount of bonding that lessees provide. Until BOEM revises its financial assurance procedures, the federal government remains at increased risk of incurring costs should lessees fail to decommission oil and gas infrastructure. Third, BOEM is not always aware when lessees transfer rights to lease production revenue. While BOEM's current regulations require lessees to report such transfers, these regulations do not clearly establish a deadline for reporting. Without a clear reporting deadline, lessees have little incentive to report revenue rights transfers to BOEM in a timely manner, and this could limit BOEM's ability to effectively evaluate a lessee's financial strength.

Recommendations for Executive Action

To improve the effectiveness of Interior's oversight of the decommissioning process, we recommend that the Secretary of the Interior direct BSEE to establish documented procedures for identifying and tracking idle and terminated lease infrastructure.

To better ensure that the government obtains sufficient financial assurances to cover decommissioning liabilities in the event of lessee default, we recommend that the Secretary of the Interior take the following six actions:

- Ensure that BSEE collects all relevant data associated with decommissioning from lessees.
- Direct BSEE to establish documented procedures for estimating decommissioning liability.
- Develop a plan and set a time frame to ensure that Interior's data system for managing offshore oil and gas activities includes processes to accurately and completely record estimated decommissioning liabilities.
- Develop a plan and set a time frame to ensure that Interior's data system for managing offshore oil and gas activities will be able to identify, capture, and distribute data on decommissioning liabilities and financial assurances in a timely manner.
- Ensure that BOEM completes its plan to revise its financial assurance procedures, including the use of alternative measures of financial strength.
- Revise BOEM's regulations to establish a clear deadline for the reporting of transfers to require that lessees report the transfer of rights to lease production revenue.

Agency Comments and Our Evaluation

We provided a draft of this report to Interior for review and comment. Interior provided written comments, which are reproduced in appendix I, and generally agreed with our findings and concurred with our recommendations.

As agreed with your offices, unless you publicly announce the contents of this report earlier, we plan no further distribution until 30 days from the report date. At that time, we will send copies of this report to the appropriate congressional committees, the Secretary of the Interior, and other interested parties. In addition, this report will be 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 members who made major contributions to this report are listed in appendix II.

Frank Rusco
Director, Natural Resources and Environment

Appendix I: Comments from the Department of the Interior

United States Department of the Interior

OFFICE OF THE SECRETARY
Washington, DC 20240

NOV 30 2015

Mr. Frank Rusco
Director
Natural Resources and Environment
Government Accountability Office
441 G Street, NW
Washington, DC 20548

Dear Mr. Rusco:

Thank you for the opportunity to review and comment on the Government Accountability Office (GAO) draft report entitled, *Offshore Oil and Gas Resources – Actions Needed to Better Protect Against Billions of Dollars in Federal Exposure to Decommissioning Liabilities* (GAO-16-40). Thank you also for incorporating the technical edits we recommended in our letter dated October 13, 2015.

The Department of the Interior (Department) generally agrees with the findings and concurs with the recommendations directed to the Bureau of Ocean Energy Management (BOEM) and the Bureau of Safety and Environmental Enforcement (BSEE). The Department is implementing GAO's recommendations to document procedures, improve its data system, and revise financial assurance procedures and regulations.

BOEM is updating its financial assurance requirements for Outer Continental Shelf (OCS) leases and facilities to mitigate risks associated with decommissioning liability. BOEM's goal is to ensure the taxpayer never has to pay to decommission an OCS facility. Updating the financial assurance policies will better reflect current business practices and the increased cost of decommissioning OCS facilities.

On September 22, 2015, BOEM issued proposed guidance to clarify procedures for oil and gas companies operating on the OCS. Specifically, the guidance contains updated financial criteria for determining a lessee's ability to meet its financial obligations, including decommissioning liabilities, in whole or part, and the potential need for additional security. BOEM will no longer consider the combined financial strength and reliability of co-lessees or operating rights holders when determining a lessee's ability to carry out its obligations with respect to decommissioning.

BOEM intends to update its data system and create comprehensive procedures designed to decrease risks to taxpayers while providing industry flexibility to negotiate adaptive solutions and utilize tailored financial plans to meet financial assurance needs. Next year, BOEM expects to publish a Notice to Lessees and Operators, which will clarify the process BOEM will use to develop tailored plans and financial assurance requirements.

In the draft report, GAO states that BOEM regulations do not include a deadline by which filings of transfer of revenue interests must be submitted to BOEM. BOEM believes that its regulation found at 30 CFR section 556.64(a)(2) requiring submittal of the creation or transfer of an interest

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within 90 days of the last date that a party executes the transfer agreement could be interpreted to impose such a deadline. Nonetheless, BOEM is working to finalize a leasing rule that will clarify the deadline.

In recent years, BSEE has made considerable progress in improving its capabilities with regard to estimating decommissioning costs for OCS facilities in the Gulf of Mexico. Over the past few years, BSEE has updated cost data, revised estimation methodologies, begun consolidating decommissioning-related activities into a single program office, worked to develop new regulations, and generated thousands of updated decommissioning cost estimates for offshore wells and structures, which greatly reduced BSEE's backlog of leases requiring an updated estimate.

Despite these improvements, BSEE acknowledges that more needs to be done. BSEE intends to continue to focus on systematizing the process of updating decommissioning estimates and finalizing policy and procedures related to estimating decommissioning costs and overseeing idle infrastructure. BSEE's upcoming rule, *Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Decommissioning Costs*, will require the submission of summary decommissioning expenditures from operators, greatly improving the bureau's ability to ensure that estimates reflect actual decommissioning costs. BSEE recently received approval from the Office of Management and Budget, and anticipates publishing the rule in the *Federal Register* soon.

Once the final rule is effective, BSEE will begin collecting expenditure data on decommissioning activities as early as 120 days after the effective date. As data are collected, BSEE will review and analyze the submissions to revise current cost data and estimation techniques, and develop algorithms that will automatically generate more reliable decommissioning cost estimates for wells and structures on leases. Until that time, BSEE will continue to use existing estimation techniques, where cost estimates must be built for each lease. Additionally, BSEE will seek available opportunities to refine cost data. BSEE is currently working toward procuring contracted services to improve data quality related to costs associated with decommissioning fixed structures in under 400 feet of water. BSEE plans to undertake additional research on decommissioning costs in the current fiscal year.

Enclosed are a few additional general and technical comments for your consideration when finalizing the report. If you have any questions about this response, please contact Andrea Nygren, BOEM Audit Liaison Officer, at 202-208-4343, or Linh Luu, BSEE Audit Liaison Officer, at 202-208-4120.

Sincerely,

Janice M. Schneider
Assistant Secretary
Land and Minerals Management

Enclosure

Appendix II: GAO Contact and Staff Acknowledgments

GAO Contact

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

Staff Acknowledgments

In addition to the individual named above, Christine Kehr (Assistant Director), Jason Holliday, and David Messman made key contributions to this report. Also contributing to this report were Philip Farah, Cindy Gilbert, Paul Kinney, Risto Laboski, Alison O'Neill, and Barbara Timmerman.

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A Report by a Study Team of the

NATIONAL ACADEMY OF PUBLIC ADMINISTRATION

for the Bureau of Safety and Environmental Enforcement

Bureau of Safety and Environmental Enforcement: Strategic Organizational Assessment

March 2017

National Academy of Public Administration ®

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A Report by a Study Team of the

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for the Bureau of Safety and Environmental Enforcement

March 15, 2017

Bureau of Safety and Environmental Enforcement: Strategic Organizational Assessment

Study Team

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FOREWORD

The Outer Continental Shelf (OCS) of the United States extends over 1.7 billion acres and holds vast reserves of oil and natural gas. The nation relies upon the U.S Department of the Interior's Bureau of Safety and Environmental Enforcement (BSEE) to ensure that this energy is effectively developed in a safe and environmentally sustainable manner. BSEE was created in October 2011 after the Deepwater Horizon incident that took 11 lives and caused significant damage to the economy and Gulf of Mexico ecosystem. BSEE works with other federal agencies and the private sector to fulfill its responsibilities to protect worker safety, ensure oil spill preparedness, protect coastal and marine resources, and develop energy resources with a fair return for the American public.

BSEE's efforts to enable the development of energy resources significantly contribute to the nation's economy. The OCS produced about 16 percent of the nation's domestic oil production, about 5 percent of domestic natural gas production, and $4.4 billion in revenues in FY 2015. Effective management of the OCS ensures the viability of local economies and sustains half a million jobs.

To assess its organizational progress over the past five years, BSEE contracted with the National Academy of Public Administration (the Academy), which assembled a study team assisted by an Expert Advisory Group of Academy Fellows, to review BSEE's organizational structure, relationships, systems, policies, and processes. This report presents the Academy's assessment results and a series of recommendations to build on the progress that BSEE has already made. Overall, the Academy study team concluded that BSEE has made significant progress, including aligning its organization and activities, developing management structures and systems, implementing a modernized regulatory framework, and building relationships to promote OCS resource stewardship. The team's recommendations to the U.S. Department of the Interior are intended to help address broader policy issues outside of the bureau's direct control, such as decommissioning facilities and equipment in the OCS, and those to BSEE are intended to increase the bureau's functioning and sustainability.

As a congressionally chartered non-partisan and non-profit organization with over 850 distinguished Fellows, the Academy's members and staff assist public organizations address their most critical challenges. We were pleased to conduct this review and appreciate the support of BSEE's managers and stakeholders. I thank members of the Academy Expert Advisory Group and the professional study team, led by Pamela Haze, for their work on this important project.

Teresa Gerton
President and Chief Executive Officer
National Academy of Public Administration

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TABLE OF CONTENTS

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ACRONYMS AND ABBREVIATIONS

Academy	National Academy of Public Administration
A-CER	Abbreviated Categorical Exclusion Review
APD	Application for Permit to Drill
AK	Alaska Region
APM	Application for Permit to Modify
ASLM	Assistant Secretary for Land and Minerals Management
ASPMB	Assistant Secretary for Policy, Management and Budget
BAST	Best Available and Safest Technology
BID	Bureau Interim Directive
BOP	Blow Out Preventer
BOEM	Bureau of Ocean Energy Management
BOEMRE	Bureau of Ocean Energy Management, Regulation, and Enforcement
BSEE	Bureau of Safety and Environmental Enforcement
CAA	Clean Air Act
CANUS	Canada-US Joint Marine Pollution Contingency
CER	Categorical Exclusion Review
CVA	Certified Verification Authorities
CWA	Clean Water Act
CZMA	Coastal Zone Management Act
DHC	Downhole Commingling
DNA	Determination of NEPA Adequacy
DOCD	Development Operations Coordination Documents
DOE	Department of Energy
DPP	Development/ Production Plans
DOI	Department of the Interior
DWH	Deepwater Horizon
DWOP	Deepwater Operations Plans
EAG	Expert Advisory Group
EC	Extraordinary Circumstance
ECD	Environmental Compliance Division
EDRC	Effective Daily Recovery Capacity
EED	Environmental Enforcement Division
EIS	Environmental Impact Statement
EP	Exploration Plan
EPA	Environmental Protection Agency
ERM	Enterprise Risk Management
ESA	Endangered Species Act
ESP	Environmental Studies Program
ETAC	Engineering Technology Assessment Center
FCC	Federal Communications Commission
FEVS	Federal Employee Viewpoint Survey

FLETC	Federal Law Enforcement Training Center
FOGRMA	Federal Oil and Gas Royalty Management Act of 1982
FONSI	Finding of No Significant Impact
FTE	Full-Time Equivalent
FWS	U.S. Fish and Wildlife Service
FY	Fiscal Year
GAO	Government Accountability Office
G&G	Geological and Geophysical
GCP	Gas Cap Productions
GOMR	Gulf of Mexico Region
ICCOPR	Interagency Coordinating Committee on Oil Pollution Research
ICR	Internal Control Review
INC	Incident of Non-Compliance
IPD	Interim Policy Document
IPRA	Integrity and Professional Responsibility Advisor
IRU	Investigations and Review Unit
ISM	International Safety Management Code
KM	Knowledge Management
LP	Office of Leasing and Plans, BOEM
MC	Management Council
MEXUS	Joint Mexico-US Marine Pollution Contingency
MLA	Mineral Leasing Act of 1920
MMPA	Marine Mammal Protection Act
MMS	Minerals Management Service
MODU	Mobile Offshore Drilling Unit
MOP	Management of Operations and Policy
MOU	Memorandum of Understanding
MSFCMA	Magnuson-Stevens Fishery Conservation and Management Act
NASA	National Aeronautics and Space Administration
NEPA	National Environmental Policy Act
NHPA	National Historic Preservation Act
NMFS	National Marine Fisheries Service
NOAA	National Oceanic and Atmospheric Administration
NPMM	National Program Management Model
NTL	Notice to Lessees or Operators
NUT	New and Unusual Technology
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act
OE	Office of the Environment, BOEM
OESI	Ocean Energy Safety Institute
OIG	Office of Inspector General
OIR	Offshore Incident Reporting

OMB	Office of Management and Budget
ONRR	Office of Natural Resources Revenue
OORP	Office of Offshore Regulatory Programs
OPA	Oil Pollution Act
OPAA	Office of Policy and Analysis
OPM	Office of Personnel Management
OSPD	Oil Spill Preparedness Division
OSRO	Oil Spill Response Organization
OSRP	Oil Spill Response Plan
PAC	Pacific Region
PHMSA	Pipelines and Hazardous Materials Safety Administration
PINC	Potential Incident of Non-Compliance
RBI	Risk Based Inspections
RHA	Rivers and Harbors Act
ROD	Record of Decision
ROW	Right of Way
RPM	Revised Application for Permit to Modify
RPS	Renewable Portfolio Standard
RRI	Response Resource Inventory
RTM	Real Time Monitoring
SEA	Site- Specific Environmental Assessment
SED	Safety Enforcement Division
SEMS	Safety and Environmental Management System
SIID	Safety and Incident Investigations Division
SOP	Suspension of Production
SOPs	Standard Operating Procedures
SRI	Sensitive Reservoir Information
TIMS	Technical Information Management System
USCG	U.S. Coast Guard
USCOE	U.S. Corps of Engineers

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EXECUTIVE SUMMARY

The Department of the Interior's Bureau of Safety and Environmental Enforcement (BSEE) was established on October 1, 2011 after an exacting process that reformed the Department of the Interior's (DOI) management of outer continental shelf (OCS) energy development. The 2010 Deepwater Horizon explosion, fire, and oil spill in the Gulf of Mexico coalesced support for the separation of functions authorized by the Outer Continental Shelf Lands Act (OCSLA) into three separate entities: BSEE, the Bureau of Ocean Energy Management (BOEM), and the Office of Natural Resources Revenue (ONRR).

Today, DOI's management of energy development and production on the OCS is a closely coordinated effort in which BOEM manages the exploration and development of the nation's offshore energy and marine mineral resources; BSEE ensures the safe and responsible development of offshore energy resources; and ONRR collects, disburses, and verifies federal and Indian energy and other natural resources revenues. These agencies carry out the mandate of the Outer Continental Shelf Lands Act (OCSLA)[1] to conduct orderly development of the OCS, in an economically and environmentally responsible manner.

In the five years since its creation, BSEE has developed and strengthened programs and capacities to fulfill its mission. BSEE's organization, people, processes, and technology reflect maturation and all show improvement, though in varying amounts. BSEE issued its first strategic plan in October 2012 and, in December of 2015, issued its 2016-2019 Strategic Plan that includes a clear vision, goals, and strategies and is the basis for the bureau's ongoing initiatives for operational and organizational excellence. Guided by its 2013 Human Capital Management Strategic Plan, the bureau has achieved ambitious goals for recruitment and hiring, expansion of training programs, and special pay rates needed to attract and retain a highly skilled workforce. BSEE is modernizing its regulatory framework and issued guidance needed to promote high levels of safety for OCS workers and the environment. BSEE has also advanced its technological capacity, developing partnerships with academia and others to improve knowledge transfer and stay abreast of technology advances. BSEE has substantially addressed all of the areas of reform that were called for in DOI's 2010 implementation plan which set the goals the new bureau was intended to accomplish.[2]

In order to be best prepared for the challenges ahead, BSEE contracted with the National Academy of Public Administration (Academy) to assess its readiness and capability and inform the bureau's efforts to establish and institutionalize effective processes and practices. The Academy formed a study team that conducted a strategic organizational assessment, with input from an Expert Advisory Group. The Academy study team focused

[1] ***Outer Continental Shelf Lands Act***, 43 U.S.C. §§ 1331 et seq.

[2] U.S. Department of the Interior, ***Implementation Plan in Response to the Outer Continental Shelf Oversight Board's September 1, 2010 Report to the Secretary of the Interior***, issued September 4, 2010, p.6.

on BSEE's mission execution and operability as a separate bureau and its relationship with BOEM and other federal entities; its regulatory framework; emerging policy and operational issues; the results of a recent organizational realignment; strategic planning and organizational performance management; human capital management; governance, communication, and collaboration; and budgetary challenges.

In conducting this assessment, the Academy's study team received and reviewed an extensive array of documentation, including internal studies, reviews, and plans demonstrating a commitment for ongoing maturation and improvement. The study team also conducted numerous interviews with officials throughout BSEE and in several other government offices that interact extensively with the bureau. The assessment identifies and describes BSEE's completed improvements and those it has underway, charting the bureau's progress relative to its status at the time it was stood up in 2011. The study team also evaluated BSEE's current state as compared to its desired future state, and, based in part on recommendations made by other authorities and on best practices, the study team identified a number of opportunities for improvement.

Overview of the Report

The study team's analyses, findings, and related recommendations offered in this report are organized as follows:

- **Chapter 1: Introduction** – Includes an introduction to BSEE, an overview of the Academy study team's organizational assessment and summary results.
- **Chapter 2: Background** – Briefly reviews the history of oil and natural gas production on the OCS, the legislative authority for federal OCS energy management, reforms of DOI's OCS program leading to the creation of BSEE and its current role.
- **Chapter 3: A Mission for Safety, Environmental Protection, and Conservation** – Reviews BSEE's deconflicted mission and functionality as a separate bureau; the regulatory framework, policies, and processes; alignment of BOEM and BSEE in general and with regard to environmental compliance and renewable energy; coordination with other federal agencies and the Rigs to Reefs Program; and decommissioning.
- **Chapter 4: Strategic Alignment of the Organization** – Reviews BSEE's realignment to a national program management model; offices and programs including the Safety and Incident Investigations Program, Safety Enforcement Program, Integrity and Professional Responsibility Advisor, Environmental Compliance Program, Engineering Technology Assessment Center, and Data Stewardship Program; and knowledge management.
- **Chapter 5: Operational and Organizational Excellence** – Reviews BSEE's FY 2016-2019 Strategic Plan, organizational performance management, and enterprise risk management.
- **Chapter 6: Overcoming Human Resource Challenges** – Reviews BSEE's 2013 Human Capital Management Strategic Plan; human capital management including

accomplishments in recruitment, hiring, and training; succession planning; 2016 Federal Employee Viewpoint Survey results; and fostering an inclusive workplace.

- **Chapter 7: Adequate Resources for Safety, Environmental Protection, and Conservation Offshore** – Reviews BSEE's budget, inspection fees, rental receipts, cost recovery, and budgetary challenges.
- **Chapter 8: Facilitating Organizational and Cultural Change** – Reviews BSEE's organizational and cultural transformation efforts, leadership, governance structures and processes, communication, collaboration, and change management.

BSEE's leadership and employees are attentive to improvement and reform in pursuit of mission and management excellence. The Academy study team was impressed by the commitment of BSEE's employees to the organization and its mission. These valuable assets and the accomplishments made since 2011 are a sound foundation of support for BSEE's pursuit of strategic operational and organizational excellence goals. BSEE's continued diligence is needed to sustain and improve regulatory and enforcement capability for oversight of an oil and gas industry that is focusing on deep water operations and deploying cutting edge technology. BSEE will need to acquire or develop competencies to address new duties in regulating renewable energy offshore and continue to support a key role in the decommissioning of offshore infrastructure. BSEE also needs to continue to focus on people and processes to promote a unified inclusive and collaborative culture.

Recommendations

In the course of conducting the organizational assessment and evaluating BSEE's strengths, the Academy study team developed a set of recommendations to assist BSEE in improving operation of a sustainable and effectively functioning bureau. The majority of the recommendations are associated with areas where correction and/or mitigation are within the control of BSEE. Several recommendations, however, require heightened awareness and action by DOI, the Office of Management and Budget (OMB), and Congress.

3.1 Maintain a Deconflicted Mission

Background: DOI instituted reforms to its OCS energy program in 2010-2011 to address long-standing weaknesses and shortcomings and in consideration of extensive expert advice, including presidentially appointed commissions and review boards. Key among the reforms was the separation of DOI's OCSLA responsibilities, to avoid critical responsibilities being compromised by being combined in an entity with contradictory roles. Three entities – BOEM, BSEE, and ONNR – were created to effectively deliver on DOI's responsibilities for (1) managing the mineral resources on the OCS, (2) oversight and enforcement of safety and environmental regulations, and (3) collecting, accounting for, and verifying natural resources and energy revenues. Restructuring to combine these entities would risk reversing the gains made while also causing disruption, uncertainty, and delay.

Objective**:** *To ensure that safety, the environment, and conservation of OCS resources are effectively promoted by an entity that can focus on vigorous regulatory oversight and enforcement.*

Recommendation: BSEE should remain a separate entity with high levels of coordination with BOEM and ONRR.

3.2 Complete the Inventory and Updating of Bureau Guidance

Background: BSEE has been conducting an extensive inventory of policies, procedures, and guidance (including handbooks, directives, and Notices to Lessees), much of which was created before BSEE existed and dates back to the 1980s, in order to have a complete record. It has also been updating and creating new policies, procedures, and guidance and automating to facilitate their use internally and externally (by industry and others). BSEE has created a system of interim policies, procedures, and guidance for organization of current materials while it continues these efforts.

Objective**:** *To maintain an internal focus on completing the inventory; moving to a permanent set of policies, procedures, and guidance; and ensuring priority materials are updated and or created promptly.*

Recommendation: BSEE should continue its efforts to inventory, organize, and update policies, procedures, and guidance. It should assign realistic and enforceable timeframes to managers for updating these materials.

3.3 Support the Environmental Compliance Mission

Background: BOEM is responsible for environmental review under the National Environmental Policy Act (NEPA), including completion of environmental impact statements and environmental assessments. BSEE uses these materials to inform permit reviews and compliance and enforcement efforts.

Objective**:** *To ensure that BSEE has adequate environmental information on which to base permit reviews, development of mitigating actions, and conduct inspections and compliance reviews and enforcement actions.*

Recommendation: In instances when BSEE does not have adequate information needed to support environmental decisions associated with permitting and enforcement, this situation should be communicated to BOEM. The Memoranda of Agreement (MOA) and Standard Operating Procedures (SOPs) that BOEM and BSEE operate under should be revised or supplemented by the establishment of processes with timelines to ensure that expectations are clearly understood. These processes established by revision or supplementation of the MOAs and SOPs should also include robust procedures for the elevation of matters for resolution, when necessary, and for the periodic review of the process by which BSEE obtains needed information from BOEM to identify systemic issues and needed improvements.

3.4 Transfer Renewable Energy Compliance and Enforcement Responsibilities
Background: When BOEM and BSEE were created, BOEM was given the responsibility for management of the OCS renewable energy program. BSEE is working with BOEM to assume responsibility for safety and environmental oversight and regulation of OCS renewable energy.

***Objective*:** *To ensure that BSEE has the capacity and capability in place for an OCS renewable energy compliance and enforcement program, has the ability to fulfill responsibilities based on scheduled projects coming on line, and is planning and preparing for projected future program growth.*

Recommendation: BSEE should work with BOEM to accelerate the transfer of environmental oversight, facility inspection, and regulatory enforcement responsibilities for the OCS renewable energy program and develop a schedule to be monitored by the Assistant Secretary for Land and Minerals Management (ASLM). BSEE should consider these new responsibilities in the development of workforce plans and should ensure that resources are available for these efforts and, as necessary, requested in future budgets.

3.5 Maintain Alignment with BOEM
Background: BOEM and BSEE were created to separate conflicting OCSLA responsibilities and allow BSEE to develop and operate an effective safety and environmental compliance program. The two bureaus remain closely interconnected, by design, to ensure that each adequately supports the other, primarily in environmental compliance.

***Objective*:** *To establish sustainable mechanisms that enable BSEE and BOEM to more effectively provide mutual support in interdependent areas and to resolve issues timely and in a manner that best supports DOI goals.*

Recommendation: ASLM should establish formal, regularly scheduled reviews of ongoing BOEM and BSEE alignment, processes, and linkages. Among the most important issues to address immediately are updates to the Environmental Compliance MOA and SOPs, and transfer of environmental oversight, facility inspection, and regulatory enforcement responsibilities for the OCS renewable program from BOEM to BSEE. ASLM should seek assistance from the Assistant Secretary for Policy, Management and Budget (ASPMB), as needed, to provide support in matters that require a DOI-wide policy or economic review and in convening working groups to address specific matters.

3.6 Elevate Decommissioning Issues
Background: Operators in the OCS are required to plug wells, remove structures and pipelines, and take other actions to decommission once production has ended. When they enter into a lease, operators are required to demonstrate their financial ability to conduct these activities to ensure the OCS is returned to its original condition either through bonding or self-insuring for these costs. Under this complex regulatory program, which is administered in part by BSEE and in part by BOEM, financial-assurance and decommissioning requirements and the enforcement of these requirements are intended to ensure that facilities are decommissioned at no cost to the government. However,

depending on the policies applied, certain approaches to regulation and enforcement might have the unintended consequence of undermining some operators' financial stability, thereby increasing the risk that neither a responsible operator nor adequate bonding might be available to cover decommissioning costs in certain instances.

Objective*: *To inform DOI leadership and national policy officials of the potential risks of unfunded decommissioning costs, and to facilitate consideration of options – including choices involving BOEM or BSEE regulatory or enforcement policies, or including possible proposed legislation – that might help mitigate those risks.

Recommendation: BSEE should work with BOEM, ASLM, DOI's Office of the Solicitor, and others to elevate issues and provide supporting analyses related to the risk that financial stress in the oil and gas industry might result in some failure to conduct or fund needed decommissioning – issues include (1) choices in BOEM or BSEE regulatory or enforcement policy that might help mitigate those risks, and (2) the absence of a funding source for decommissioning in the event an operator is unable to pay these costs.

4.1 Improve Alignment with the National Program Manager Model

Background: BSEE implemented an organizational realignment based on the national program management model on November 4, 2015 that is intended to bring clarity, consistency, predictability, and accountability to BSEE's operations. Several successful models of national program implementation within BSEE demonstrate high levels of communication, collaboration, and understanding of the roles of headquarters and the regions. Other programs and initiatives have not progressed to a comparable level of national program management performance.

Objective*: *To effectively implement BSEE's realignment and facilitate efforts to bring consistency to processes and practices based on the national program management model.

Recommendation: BSEE should complete implementation of the national program management model incorporating best practices for organizational transformation tailored to the needs of individual programs and initiatives; the effort should be coordinated by a single individual or entity reporting to the Director or Deputy Director. The effort should incorporate lessons learned from the Safety and Incident Investigation and Data Stewardship Programs, in particular the high levels of collaboration, effective governance structures and processes, and training.

4.2 Complete the Environmental Compliance National Program Design

Background: BSEE's realignment to the national program management model changed the reporting relationship for regional environmental compliance staff that were direct reports to the headquarters Division Director and now report to the regional directors. This deviates from historical documents that were the basis for organization of the BSEE environmental enforcement function (now renamed environmental compliance). BSEE has not implemented a systematic approach to environmental stewardship as was envisioned in the establishment of the Environmental Stewardship Collaboration Group, which could optimize agency expertise and outcomes and improve compliance and enforcement. In addition, there are differing views about the nature of the work and role of inspections in the Environmental Compliance Program.

Objective: *To (1) formulate an Environmental Compliance Program design that engages headquarters and the regions and considers the original design of the environmental enforcement function and the results of the Environmental Stewardship Collaboration Group's work, (2) make final decisions about the appropriate staffing and workforce composition, and (3) complete implementation of the national program and ensure high levels of collaboration and communication.*

Recommendation: BSEE should produce a program management design for the Environmental Compliance Program that considers the history of the program's organization and functions as well as the work of the Environmental Stewardship Core Group. The design should detail the activities, work streams, outputs, and outcomes. The design should include workforce plans for headquarters and the regions that can be the basis for staffing decisions, addressing gaps in competencies, and effective implementation of the national program. The process should include an assessment of risk related to reporting relationships as well as appropriate internal controls and risk mitigation measures to ensure the function can effectively achieve mission goals.

4.3 Improve Utilization of the Engineering Technology Assessment Center

Background: BSEE established the Engineering Technology Assessment Center (ETAC) to assist regions with maintaining up-to-date knowledge about emerging technology and support standards setting.

Objective: *To effectively utilize ETAC's resources for standards setting and national policy development and ensure high levels of knowledge transfer to and from the regions to inform operations, inspections, and permitting.*

Recommendation: BSEE should improve the linkage between ETAC and the regions by expanding outreach and engagement and developing a formal governance body and process to ensure high levels of two-way communication between the regions and the Office of Offshore Regulatory Programs (OORP).

4.4 Strengthen Data Stewardship with Knowledge Management

Background: BSEE's Data Stewardship Program is effectively working toward goals to increase the quality and consistency of data, but information and knowledge is not being effectively shared across all of BSEE's organizational units.

Objective: *To promote more effective information and knowledge sharing.*

Recommendation: BSEE should develop a knowledge management (KM) strategy that complements the existing Data Stewardship Program and IT program with tools that enable knowledge sharing and close gaps in the knowledge cycle. As part of this strategy, BSEE should consider establishing communities of practice for critical areas of knowledge to facilitate organizational knowledge retention, knowledge sharing, and learning. A KM pilot for a critical area of knowledge can be used to demonstrate the benefits of KM and inform the strategy prior to full-scale implementation.

5.1 Reactivate the Strategic Plan Working Group

Background: BSEE convened a working group comprised of a cross-section of BSEE employees that participated in development of the 2016-2019 Strategic Plan, but disbanded the working group after the plan was completed.

***Objective*:** *To expand awareness of the plan and its use as the basis for ongoing strategic alignment of the organization, resources, priorities, and actions; to create a conduit for continuing input for strategic planning and management; and to facilitate collaboration.*

Recommendation: Establish a working group comprised of program and regional representatives, in order to promote improved awareness of and engagement in strategic planning, inform the process for annual priority setting, and expand the use of risk management. Selection of the members of the group should consider the ability of the members to be advocates and change agents within their organizations and the team should be operational in time to assist with BSEE's participation in the development of a new DOI strategic plan.

5.2 Continue the Foresight Initiative

Background: BSEE established the Foresight Initiative to help understand how changes in the energy landscape, geopolitics, technology shifts, workforce, and other factors may impact future activities and programs.

***Objective*:** *To inform strategic planning, program and budget development, and workforce planning and to better prepare for changes and challenges in the future.*

Recommendation: BSEE should institutionalize its Foresight Initiative to provide input to strategic planning and risk assessment and to help anticipate and guide BSEE's programs and operations.

5.3 Enhance Annual and Multi-year Planning

Background: BSEE conducts annual and multi-year planning to drive continuous improvement, advance operational and organizational strategic goals, and respond to stakeholders.

***Objective*:** *To effectively manage BSEE's annual and multi-year planning and thereby maintain momentum and focus on priority activities.*

Recommendation: BSEE should enhance its annual and multi-year planning to include prioritization and sequencing of tasks taking risk assessment into account, assignment of roles and responsibilities for leadership and participation, tracking of progress, and following up.

5.4 Expand Understanding and Use of Enterprise Risk Management

Background: BSEE developed an Enterprise Risk Management Program (ERM) to inform strategic planning and decision-making, strengthen internal controls, and clarify priorities. However, the program is not uniformly accepted, understood, or utilized because there are different conceptual approaches to management of risk found within existing program based initiatives, and there currently is not a common lexicon for risk communication.

Objective**:** *To improve the capacity to systematically address organizational and operational risks.*

Recommendation: BSEE should establish communities of practice for management of strategic risks and develop a common lexicon that can be used for risk communication. To this end, the ERM program should incorporate learning from the results of the inspection pilot underway and other areas where risk management pilots can expand its use and improve capability. BSEE should also incorporate ERM into its planning (see recommendation 5-3).

6.1 Conduct Targeted Succession Planning for Senior Leadership

Background: BSEE's senior management cadre comprised of senior executives and GS-15's is small, with a number of individuals who are now or soon will be retirement eligible. BSEE established its Leadership Development Program to develop future leaders, but more targeted efforts are needed to prepare a cadre of individuals that could potentially assume senior leadership roles.

Objective**:** *To help ensure effective succession in senior leadership.*

Recommendation: BSEE should continue to develop opportunities for GS-14 and GS-15 employees who can gain experience in order to be prepared to assume senior leadership positions and ensure continuity.

6.2 Increase Integration of Training Programs

Background: Training programs are conducted by four BSEE entities to support mission needs. Improvements in effectiveness and efficiency are possible with consolidation of training programs, or program components. The Training Governance Board oversees technical training, but does not oversee the other training programs.

Objective**:** *To holistically address training needs for BSEE employees, to achieve improved effectiveness and efficiency, to improve tracking and reporting, and to increase integration of these programs.*

Recommendation: BSEE should create a training governance structure that encompasses oversight of all of BSEE's training programs, not just technical training, and should assess the benefits of consolidating or leveraging aspects of its training programs to ensure the highest levels of integration and efficiency across the bureau.

7.1 Increase Fees and Collections
Background: BSEE's resources are at risk due to declining collections that comprise approximately 57 percent of its budget and limitations on inspection fees charged to industry.

Objective: *To address a potential budget shortfall due to declining collections and inflexibilities in the inspection fee.*

Recommendation: BSEE, in cooperation with DOI and OMB, should finalize the cost recovery regulation and continue to seek proposed changes in inspection fees to align them with current program requirements. BSEE, in cooperation with BOEM, should formulate proposals to submit to DOI and OMB that fund the shortfall in collections. Timely action is needed so these additional regulatory fees can be included in future OCS leases and avoid impacts to BSEE's budget.

7.2 Budget for Renewable Energy Compliance and Enforcement
Background: BSEE is assuming responsibility for safety and environmental oversight of renewable energy projects that may require additional staff and competencies.

Objective: *To be prepared to assume renewable energy program safety and environmental oversight responsibilities.*

Recommendation: BSEE should consider funding requirements for the renewable program as part of FY 2018 budget formulation and in future budgets.

7.3 Budget for Decommissioning
Background: BSEE's decommissioning workload is increasing.

Objective: *To address an expanding workload in decommissioning.*

Recommendation: BSEE should consider funding requirements for the decommissioning program as part of FY 2018 budget formulation and in future budgets.

8.1 Implement a Change Management Strategy
Background: BSEE is actively working on operational and organizational reform aligned with the strategic plan, but lacks an integrated organizational change management program or strategy.

Objective: *To bring greater cohesiveness to BSEE's organizational and cultural change efforts and foster greater collaboration, employee engagement, and communication.*

Recommendation: BSEE should develop and utilize a more comprehensive change management strategy to support the development of a more unified, collaborative and proactive organizational culture, using tools that can strengthen capabilities for engagement, knowledge sharing, collaboration, and communication. The strategy should consider best practices and specific guidance provided by the study team, and address special challenges with respect to leadership, culture, governance, collaboration, and communication. The study team suggests that a full-time change management advocate should lead this effort.

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CHAPTER 1: INTRODUCTION

The Department of the Interior's Bureau of Safety and Environmental Enforcement (BSEE) is responsible for promoting safety, protecting the environment, and conserving resources in federal offshore waters. BSEE executes this mission through vigorous oversight and enforcement of energy exploration and development activities that are conducted by industry across a large geographic area, and in close coordination with other federal agencies.

BSEE was established as a new federal entity on October 1, 2011,[3] approximately 18 months after the April 20, 2010 explosion, fire, and sinking of the Deepwater Horizon mobile offshore drilling unit 49 miles off the coast of Louisiana in the Gulf of Mexico. The incident led to the death of 11 men and injury of 16 others working on the Deepwater Horizon rig followed by the release of nearly 5 million barrels of oil into the Gulf of Mexico. The release of oil and gas continued for 87 days, ending on July 15, 2010 when the well, which was 3,000 feet below the water's surface, was capped.[4] Despite a focused response effort by federal trustees, states and others, an estimated 1,100 miles of shoreline were polluted and the impacts to the environment, and economy are still being compiled.[5]

Shortly after the Deepwater Horizon (DWH) incident, on May 19, 2010, Secretary of the Interior Ken Salazar announced the dissolution of the federal entity responsible for OCS energy management, the Minerals Management Service (MMS). He ordered the separation of MMS's functions into three separate entities to create clear lines of responsibility for planning and leasing, oversight and regulation, and revenue management. Over the next 18 months a deliberate and careful process was conducted to create three new entities to manage DOI's responsibilities in the OCS: BSEE, BOEM and ONRR.

To identify necessary reforms to DOI's OCS program and ensure effective functioning of these new entities, Secretary Salazar created the Outer Continental Shelf Safety Oversight Board[6] (Board) to provide recommendations for improved management and administration. The results of the Board's review, in conjunction with a Department of the Interior Office of Inspector General (OIG) investigation of management, regulation, and oversight of OCS operations,[7] were considered in the creation of BSEE. Other reviews and

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[3] BSEE began to operate on October 1, 2011; this was subsequent to the May 19, 2010 Secretarial Order that directed the creation of BSEE as part of reforms to DOI's OCS program.

[4] National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, ***Deep Water: The Gulf Disaster and the Future of Offshore Drilling***, January 2011, available at https://www.gpo.gov/fdsys/pkg/GPO-OILCOMMISSION/pdf/GPO-OILCOMMISSION.pdf.

[5] Encyclopaedia Brittanica, ***Deepwater Horizon Oil Spill of 2010***, May, 9, 2016 .

[6] U.S. Department of the Interior, ***Outer Continental Shelf Safety Oversight Board Report to Secretary of the Interior Ken Salazar,*** September 1, 2010, available at http://www.noia.org/wp-content/uploads/2015/12/DOI-OCS-Safety-Oversight-Board-Report.pdf.

[7] Office of the Inspector General, U.S. Department of the Interior, ***A New Horizon: Looking to the Future of the Bureau of Ocean Energy Management, Regulation and Enforcement***, Report No. CR-EV-MMS-0015-2010, December 2010, available at https://www.doioig.gov/sites/doioig.gov/files/A-New-Horizon-Public.pdf.

recommendations were also considered, including the results of a joint investigation of the DWH incident by the Departments of the Interior and Homeland Security,[8] and the review conducted by the Presidentially-convened National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling.[9]

These investigations and reviews brought attention to significant gaps and shortcomings in MMS. They pointed primarily to MMS's challenge in balancing the competing statutorily directed requirements set by OCSLA to expedite offshore oil and gas production, regulate and enforce safety and environmental requirements, ensure the effective conservation of the nation's resources, and maximize revenues. The President's Commission concluded that balancing these conflicting and complex responsibilities for regulating a highly technical and sophisticated industry was unattainable because of the conflicting mission, insufficient funding, staffing, and technical expertise.[10] The gap in industry growth versus federal oversight is demonstrated by the numbers; industry exploration and development of offshore oil and gas increased by 200 percent from 1982 to 2007, while staffing for MMS declined by 6 percent during the same time period.[11]

BSEE's Creation

BSEE is the regulatory and enforcement authority that works in conjunction with BOEM to manage and protect 1.7 million acres of the OCS. BOEM is responsible for managing development of the nation's offshore resources, while BSEE is responsible for oversight of industry compliance with requirements to ensure the safety of offshore workers, environmental protection, and the effective recovery and measurement of OCS resources. These two bureaus oversee a vast potential for energy and minerals development. In Fiscal Year (FY) 2015, oil and gas development activities under their jurisdiction resulted in the production of over 550 million barrels of oil and 1.3 trillion cubic feet of natural gas, accounting for about 16 percent of the nation's oil production and about 5 percent of domestic natural gas production, the equivalent of the energy needed to power about 119 million U.S. households for one year.[12] The bureaus also help protect a wealth of natural resources – the OCS includes rich, productive marine ecosystems with fish and other species of significant commercial importance.[13]

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[8]U.S. Department of the Interior and Department of Homeland Security, ***Joint Investigation of the Marine Casualty, Explosion, Fire, Pollution, and Sinking of Mobile Offshore Drilling Unit Deepwater Horizon***, April 20-22, 2010, available at https://www.uscg.mil/hq/cg5/cg545/dw/exhib/DWH%20ROI%20-%20USCG%20-%20April%2022,%202011.pdf.

[9] National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, ***Deep Water: The Gulf Disaster and the Future of Offshore Drilling***, January 2011, available at https://www.gpo.gov/fdsys/pkg/GPO-OILCOMMISSION/pdf/GPO-OILCOMMISSION.pdf.

[10] Ibid

[11]Stuart Theriot, ***Changing Direction: How Regulatory Agencies Have Responded to the Deepwater Horizon Oil Spill***, LSU J. Energy L. & Res. *Currents*, November 19, 2014.

[12] U.S. Department of the Interior, ***FY 2017 Budget in Brief, Departmental Highlights***, available at https://edit.doi.gov/sites/doi.gov/files/uploads/FY2017_BIB_DH035.pdf.

[13] U.S. Department of the Interior, ***Economic Report FY 2015***, June 17, 2016, available at: https://www.doi.gov/sites/doi.gov/files/uploads/fy2015_doi_econ_report_2016-06-17.pdf.

A third entity within DOI, the Office of Natural Resources Revenue, oversees and manages the revenues collected from OCS development. In FY 2015 receipts collected into the U.S. Treasury from OCS oil and gas totaled $4.4 billion.[14] Because of the efforts of BSEE, BOEM and ONNR, DOI can claim direct economic contributions to the Nation's economy of over $40 billion for FY 2015 from the oversight of OCS energy production and over $86 billion including secondary economic benefits gained from spending on goods and services.[15]

Strategic Organizational Assessment

BSEE contracted with the Academy to perform a strategic organizational assessment, identify gaps in capabilities, and provide recommendations to help improve functionality and sustainability. The strategic organizational assessment considered the following elements:

- Systems, structures, and people;
- Organizational resources and capabilities that enable execution of the strategic framework;
- Processes that deliver the organizational mission requirements;
- Technical programs (such as permitting, environmental enforcement, inspections) establishment and functioning; and
- Organizational technological solutions.

Scope and Methodology: The Academy formed a study team that received input from an Expert Advisory Group (EAG) of National Academy Fellows. The study team undertook a structured assessment of BSEE's organization, processes, people, technology, and culture by examining extensive documentation, conducting research, synthesizing results from evaluations conducted by others, and conducting structured interviews. BSEE provided over 2,500 pages of documents including reports, plans, presentation materials, and recorded notes of meetings. Over 40 structured interviews were held with BSEE leadership officials, managers, employees, and former employees, as well as the Government Accountability Office (GAO), the OIG, BOEM, and ASLM. Interviews were conducted on a not-for-attribution basis.

The study team assessed BSEE's current state to evaluate progress made since creation of the bureau and relative to BSEE's desired future state. The study team assessed BSEE's internal strengths and weaknesses that may be helping or hindering progress toward achievement of the mission and strategic goals. The team also assessed opportunities and threats in the external environment. In its assessment of BSEE the study team gauged progress on a continuum of maturity based on the degree to which the organization,

[14] U.S. Department of the Interior, ***FY 2017 Budget in Brief, Receipts by Source (Appendix I)***, available at https://edit.doi.gov/sites/doi.gov/files/uploads/FY2017_Appendix_I0001.pdf.
[15] U.S. Department of the Interior, ***Economic Report FY 2015***, June 17, 2016 available at https://www.doi.gov/sites/doi.gov/files/uploads/fy2015_doi_econ_report_2016-06-17.pdf

processes, culture, and other aspects of BSEE are institutionalized, sustainable, and effectively supporting mission goals.

BSEE's programs and activities are technically complex and geographically dispersed and the scope and timeframe for the organizational assessment did not allow the study team to assess all of BSEE's efforts. Following a review of documentation provided by BSEE and other sources and interviews, the study team identified key issues and challenges that BSEE faces in transitioning to the future state, which formed the basis for a gap analysis and roadmap that guided more in-depth research, consideration of best practices, and the development of detailed recommendations. The analysis identified and focused on the following priority areas:

- **Achieving strategic outcomes for safety, environmental protection, and conservation** through operation as a separate bureau focused on a deconflicted mission;
- **Strategic alignment of the organization** with continued implementation of BSEE's national program management model;
- **Advancing BSEE's strategic goals for operational and organizational excellence** through organizational program management that promotes integration and risk management;
- **Management of human resources** guided by the Human Capital Management Strategic Plan and implementation of strategies to improve hiring, retention, and training, and create an inclusive workplace;
- **Resolving budgetary challenges** to ensure that BSEE has stable and adequate resources to support mission accomplishment; and
- **Facilitating organizational and cultural change** through leadership, governance, communication, and collaboration.

Summary Results: BSEE has established itself as a new federal entity; strengthened programs for the protection of safety and the environment and the conservation of OCS resources; improved core mission responsibilities for inspection and permitting; enhanced relationships with other federal entities; modernized and addressed gaps in regulations and policy; realigned the organization to promote consistency and transparency internally and with stakeholders; nearly achieved recruitment and hiring goals to attract highly skilled employees; and established partnerships to promote technical competencies.

Although a relatively new organization, BSEE has taken major strides in formulating and using strategic direction to guide priorities. It has issued two strategic plans and a Human Capital Management Strategic Plan, deployed enterprise risk management, and developed a series of action plans to drive operational and organizational improvements. BSEE promoted ongoing reforms responsive to GAO and OIG recommendations, put in place an integrated information technology and business enterprise architecture, significantly expanded training to promote professional and leadership development and technical competencies, and implemented data stewardship to improve the accuracy and utility of information used internally and by industry.

BSEE's efforts have substantially addressed areas of reform identified in the 2010 implementation plan prepared by DOI in response to the recommendations of the Outer Continental Shelf Safety Oversight Board.[16] The areas are:

- Building new systems for processing and analyzing data;
- Performing risk assessments for permitting and environmental reviews;
- Designing and implementing a robust, effective, and aggressive safety and environmental enforcement regime;
- Creating new policies and guidance for both federal personnel and industry;
- Developing training programs and curricula;
- Recruiting of scores of new professionals;
- Establishing efficient, modern information systems; and
- Developing management structures and systems appropriate to the scale and missions of the new organization.

Conclusion

The creation of BSEE as a separate bureau significantly strengthened the federal government's ability to effectively oversee industry as it develops OCS resources. BSEE's establishment has helped ensure high levels of protection for worker safety and the environment and utilization of OCS resources in a manner that is in the best interests of the nation.

BSEE's creation also provides a strong foundation for improving what had previously been insufficient federal oversight of compliance monitoring (permitting and inspection), investigation and enforcement, and oil spill response preparedness. Over the past five years, BSSE has made significant headway in building capacity and competencies to support its mission. In addition, BSEE has developed an information technology infrastructure and business area that supports both BOEM and BSEE and developed capacity and infrastructure in order to deliver shared services to BOEM, BSEE and others in DOI in areas including human resources, acquisition, and financial services. BSEE demonstrates commitment to its mission; achievement of operational and organizational excellence; and transformation, maturation, and modernization.

The study team's recommendations are primarily focused on advancing and improving the efforts that BSEE has undertaken thus far, which are within BSEE's control. There are a few notable exceptions. These are areas that require the assistance of DOI, OMB, and the Congress:

- Most importantly, the study team recommends that BSEE should continue to operate as a separate entity to ensure a strong federal role.

[16] U.S. Department of the Interior, ***Implementation Plan in Response to the Outer Continental Shelf Oversight Board's September 1, 2010 Report to the Secretary of the Interior***, issued September 4, 2010, p.6.

- The study team recommends a more institutionalized process involving ASLM and potentially others in DOI for ensuring the alignment of BOEM and BSEE; the team also suggests that BOEM and BSEE accelerate the transfer of environmental oversight, facility inspection, and regulatory enforcement responsibilities for the OCS renewable program.
- The study team suggests that DOI should continue to address policy issues surrounding the decommissioning program, including risks associated with potential bankruptcies.
- BSEE faces budgetary challenges due to declining revenue collections and insufficient inspection fees that are a significant component of the budget. This issue requires actions by DOI, OMB and Congress. In addition, BSEE should address the budgetary implications of decommissioning and ensure there are adequate budgetary resources to enable the bureau to assume a larger role in oversight of renewable projects.

CHAPTER 2: BACKGROUND

The history of offshore drilling for oil and natural gas begins in the late 1800s with simultaneous development in the Pacific Ocean off the California Coast, the Gulf of Mexico, and the Great Lakes. As early as 1891, the first submerged oil wells were drilled from platforms built on piles in Grand Lake St. Marys, about 60 miles north of Dayton, Ohio.[17] Offshore development began in California in 1894 when Henry L. Williams drilled two wells on a beach near Santa Barbara. Observing promising results, Williams and his associates went on to develop a production platform in 1896 with a rig located on a 300-foot wooden pier connected to the shoreline. In 1911 the Gulf Refining Company used tugboats, barges, and floating pile drivers to drill on Caddo Lake, Louisiana. The first Caddo Lake Well, which was untethered to land, was drilled to a depth of 2,185 feet and produced 450 barrels of oil a day.[18]

Since the earliest discoveries of oil, industrious operators have pushed the boundaries of technology and geography. Today, offshore oil and gas production and exploration takes place in ultra-deep waters in the Gulf of Mexico and in frigid Arctic environments. In September 2016, Shell started production at Stones, the world's deepest oil and gas project, operating in 9,500 feet of water and connected to reservoirs nearly 30,000 feet below sea level.[19] Hilcorp Alaska operates Northstar on a five-acre, man-made island located in the Beaufort Sea, 12 miles northwest of Prudhoe Bay and six miles offshore. Renewable energy production on the OCS is now a reality as well. In late 2016, the first commercial offshore United States wind farm, Block Island, came on line, located in state waters three miles off the coast of Rhode Island.

The history of offshore energy development is a testament to American ingenuity and the ability of industry to overcome the challenges of remote locations, inhospitable climates, and unpredictable geological formations to extract energy to meet the nation's energy needs. The history of offshore development also includes reminders of the risks involved in energy exploration and development, the potential for disaster that can cost lives, wreak havoc on the OCS environment, and impact economies. Scientists are still investigating the effects of the Deepwater Horizon oil spill on the Gulf ecosystem. Recent studies found evidence of wetland loss accelerated by the oil spill, significant oil contamination in bottom sediments in the Gulf impacting marine ecosystems that may take decades to recover, and declines in annual oyster harvests.[20]

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[17] American Oil & Gas Historical Society, ***Ohio Offshore Wells***, available at http://aoghs.org/offshore-history/ohio-offshore-wells//.
[18] Ibid
[19] Offshore Technology.com, ***Stones Field, Gulf of Mexico, United States of America***, available at http://www.offshore-technology.com/projects/stones-field-gulf-mexico//.
[20] National Wildlife Federation, ***Five Years and Counting: Gulf Wildlife in the Aftermath of the Deepwater Horizon Disaster***, available at http://www.nwf.org/News-and-Magazines/Media-Center/Reports/Archive/2015/03-30-2015-Five-Years-And-Counting.aspx.

These reminders underscore the need for rigorous protections to ensure adequate safety for offshore workers, sustain sensitive and economically important marine environments, and effectively manage OCS resources that are held in trust by the federal government.[21]

The Outer Continental Shelf Lands Act

The drilling conducted offshore was regulated and managed by states until the 1930s, when a series of legal battles began between coastal states and the federal government for control over offshore oil and gas development.[22] In 1945, President Harry Truman proclaimed federal authority over the subsoil of the U.S. continental shelf in its entirety. [23] Congress clarified OCS ownership and control on May 22, 1953 with enactment of the Submerged Lands Act. The Act reaffirmed states' authority to grant leasing rights within state waters, generally three miles from shore (9 nautical miles for Texas and western Florida due to historical claims).[24]

Three months later, on August 7, 1953, Congress passed OCSLA, which affirms federal control of the OCS seaward of the state's offshore boundaries.[25] OCSLA provides direction for development of the OCS, stating that "the outer continental shelf is a vital national resource reserve held by the Federal Government for the public, which should be made available for expeditious and orderly development, subject to environmental safeguards, in a manner which is consistent with the maintenance of competition and other national needs"[26] Congress tasked the Secretary of the Interior with the administration of a leasing system for the outer continental shelf.[27] Congress did not specify how DOI should balance expeditious development with high levels of safety and environmental protection. The first leases of the OCS under OCSLA began in September of 1954, with the announcement of rights to explore 748,000 acres off the coast of Louisiana. Half of the available acreage was leased in the sale with winning bids totaling $130 million.[28] Federal OCS leasing continued and by 1970, 16.7 percent of domestic oil production and 15 percent of gas production was coming from offshore wells. By the end of 1970, over 7 million offshore acres had been

[21] National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, ***Deep Water: The Gulf Disaster and the Future of Offshore Drilling, January 2011***, available at https://www.gpo.gov/fdsys/pkg/GPO-OILCOMMISSION/pdf/GPO-OILCOMMISSION.pdf.

[22] Craig, Robin Kundis, ***Treating Offshore Submerged lands as Public Lands: A Historical Perspective***, *Public Land and Resources Law Review*, Vol. 34, 2013.

[23] Proclamation 2667-Policy of the United States With Respect to the Natural Resources of the Subsoil and Sea Bed of the Continental Shelf, September 28, 1945.

[24] Submerged Lands Act of 1953, 43 U.S.C. § §1301 et seq..

[25] Outer Continental Shelf Lands Act, 43 U.S.C. § 1331§ et seq.

[26] 43 U.S.C. § 1332(3)).

[27] 43 U.S.C. § 1334.

[28] National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, ***Deep Water: The Gulf Disaster and the Future of Offshore Drilling***, January 2011, available at https://www.gpo.gov/fdsys/pkg/GPO-OILCOMMISSION/pdf/GPO-OILCOMMISSION.pdf.

auctioned by the federal government for more than $5.6 billion in bonus bids, royalty payments, and rental fees.[29]

DOI's management of OCS leasing, development, and production remained largely unchanged until the Santa Barbara Oil Spill in 1969. The spill led DOI to toughen its rules and helped to further congressional awareness of environmental issues leading to enactment of sweeping new environmental protection and resource conservation laws, starting with the National Environmental Policy Act (NEPA). Enactment of NEPA in 1970 changed the federal role in overseeing offshore oil and gas development requiring the disclosure and consideration of relevant information about proposed federal actions and reasonable alternatives. Amid these changes, Congress began to consider changes to OCSLA. [30]

The 1973 oil embargo caused nationwide shortages, price increases, and rationing, which prompted Congress to hold hearings on revamping the federal offshore leasing program.[31] In the process, Congress began to consider balancing of the potential for oil and gas discovery with environmental impacts. The hearings and discussions led to consideration and passage of the OCSLA Amendments of 1978. Reflecting congressional attempts to find a balance between the policy goals of energy independence and environmental protection, the amendments added detailed procedures governing leasing of rights to explore, develop, and produce OCS resources, defining four distinct stages: formulation of a leasing plan, leasing based on a five-year plan, exploration plans submitted by lessees for approval, and development and production plans submitted by lessees upon discovery of oil and gas for approval.[32]

The amendments required that lessees apply for approval before drilling any wells, pursuant to an approved exploration plan or, in most areas, pursuant to a development and production plan. The statute also underscored the importance of environmental safeguards, directing the Secretary of the Interior "to obtain a proper balance between the potential for environmental damage, the potential for discovery of oil and gas, and the potential for adverse impact on the coastal zone." Congress authorized an environmental studies program for the OCS. Congress also addressed the safety of workers, requiring the DOI and the U.S. Coast Guard to promulgate safety regulations and use of the Best and Safest Technology (BAST) to protect safety, health and the environment.[33] The regulations

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[29] Kenneth Hendricks, Robert H. Porter, and Bryan Boudreau, Information, Returns, and Bidding Behavior in OCS Auctions: 1954-1969, The Journal of Industrial Economics, Vol. XXXV, June 1987.

[30] National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, ***Deep Water: The Gulf Disaster and the Future of Offshore Drilling***, January 2011, available at https://www.gpo.gov/fdsys/pkg/GPO-OILCOMMISSION/pdf/GPO-OILCOMMISSION.pdf.

[31] U.S. Department of State, Office of the Historian, ***Oil Embargo 1973-1974,*** available at https://history.state.gov/milestones/1969-1976/oil-embargo.

[32] National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, ***Deep Water: The Gulf Disaster and the Future of Offshore Drilling***, January 2011, https://www.gpo.gov/fdsys/pkg/GPO-OILCOMMISSION/pdf/GPO-OILCOMMISSION.pdf.

[33] Outer Continental Shelf Lands Act, 43 U.S.C. §§ 1334(ee), 1347(b), as amended by the Outer Continental Shelf Lands Act Amendments of 1978.

issued under the OCSLA Amendments require offshore operators to use BAST whenever practical on all exploration, development, and production operations when failure of equipment would have a significant effect on safety, health, or the environment.[34] To implement this requirement, BSEE evaluates the performance of equipment and determines an appropriate performance level that technology must meet or exceed.[35]

Minerals Management Service

In 1981, an investigation of allegations of irregularities in oil and gas royalty payments led to appointment of a Commission on Fiscal Accountability of the Nation's Resources. The Commission called for an overhaul of royalty collection from federal and Indian lands, including submerged lands in the OCS.[36] Up until this time two entities within DOI were responsible for OCS energy management: the U.S. Geological Survey was responsible for oversight of offshore exploration and energy production while the Bureau of Land Management was responsible for collection of royalties for drilling on federal lands and waters.[37] Using the Commission's report as the basis for restructuring DOI's OCS management functions, on January 19, 1982, Secretary of the Interior James Watt created the Minerals Management Service (MMS).[38] The consolidation of offshore functions was accomplished under authority of Reorganization Plan No. 3 of 1950.[39]

Deepwater Horizon and Reorganization of DOI's OCS Programs

Beginning in 1982 and through 2010, DOI's MMS was the federal entity with primary responsibility for energy development in federal waters. Based on authority granted by OCSLA,[40] MMS had a broad scope of responsibilities (see Figure 2-1 below), including:

- Management and regulation of OCS activities;
- Administration of OCS leases;
- Compliance and enforcement related to the safety of offshore facilities;
- Protection of coastal and marine environments;
- Development of a renewable energy program to allow leasing on the OCS;[41]

[34] 30 CC.F.R. § 250.107(c)).
[35] Bureau of Safety and Environmental Enforcement, ***Best Available and Safest Technology,*** https://www.bsee.gov/BAST.
[36] U.S. Department of the Interior, ***Fiscal Accountability of the Nation's Energy Resources***, January 1982, https://www.doi.gov/sites/doi.opengov.ibmcloud.com/files/T-2264.pdf.
[37] National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, ***Deep Water: The Gulf Disaster and the Future of Offshore Drilling,*** January 2011, available at https://www.gpo.gov/fdsys/pkg/GPO-OILCOMMISSION/pdf/GPO-OILCOMMISSION.pdf.
[38] U.S. Department of the Interior, ***Secretarial Order 3071***, January 19, 1982.
[39] Congressional Research Service, ***Reorganization of the Minerals Management Service in the Aftermath of the Deepwater Horizon Oil Spill,*** November 10, 2010.
[40] Outer Continental Shelf Lands Act, 43 U.S.C. §§ 1331 et seq..
[41] U.S Department of the Interior, ***Budget Justifications and Performance Information, Fiscal Year 2011: Minerals Management Service,*** pp. 3-4.

- Oil spill response and research under authority of the Oil Pollution Act;[42] and
- Collection, accounting and disbursement of revenues from energy and mineral leases on the OCS and onshore federal and American Indian lands.[43]

Assistant Secretary – Land and Minerals Management	
Minerals Management Service	
Offshore Energy and Minerals Management	**Minerals Revenue Management**
5- Year Program (Oil and Gas)	Offshore/ Onshore Revenue Collection
Leasing Process Management	Audits/ Enforcement
Environmental Analysis and NEPA	State and Tribal Audits
Development, Exploration, Production Plan Management	Accounting/ Financial Reporting
Safety and Technical Review of Plans	Asset Valuation
Production Development Operations/ Resources Management	Economic and Market Analysis
Safety and Technical Inspections and Enforcement	
Environmental Inspections and Enforcement	
Safety and Environmental Research	
Oil Spill Response and Research	

Figure 2-1. Distribution of MMS Functions[44]

The April 20, 2010 explosion and fire that occurred on the Deepwater Horizon drilling rig and the resulting oil spill focused the nation's attention on MMS and was the catalyst for major reorganization and reforms in the manner in which DOI managed OCS energy development. Congress attempted to permanently authorize a reorganization of MMS and institute reforms. The congressional proposals, many of which were supported by the Executive Branch, sought to address long-standing issues, bureaucratic inadequacies, and shortcomings that undercut MMS's ability to ensure safe operations and insulate compliance and regulatory functions from industry pressures.[45] Bills were introduced in the House and Senate during the 111th Congress. Four of the bills, described below, proposed to separate out MMS's three conflicting missions of (1) managing the mineral resources on the OCS, (2) oversight and enforcement of safety and environmental regulations, and (3) collecting, accounting for, and verifying natural resources and energy revenues.

[42] Oil Pollution Act of 1990, 33 U.S.C. § 2701 et seq.
[43] U.S Department of the Interior, ***Budget Justifications and Performance Information, Fiscal Year 2011: Minerals Management Service***, p.4.
[44] U.S. Department of the Interior, ***Implementation Report: Reorganization of the Minerals Management Service***, issued July 14, 2010, with the addition of Oil Spill Response and Research omitted from original.
[45] Mulligan, James S., ***Case Study: Minerals Management Service***, *Institute for Environmental Diplomacy and Security at the University of Vermont*, September 2011 and Hayley Carpenter, ***Deepwater Horizon: Agency Reorganization and Appropriations in Offshore Oil Regulation,*** *Ecology Law Quarterly*, Vol. 42, Issue 2, November 1, 2015.

- H.R. 3534, the Consolidated Land, Energy, and Aquatic Resources Act of 2009 passed by the House on July 30, 2010. The bill would have abolished MMS and created three new units in DOI; one to manage the leasing and permitting of onshore and offshore federal lands, a second to carry out safety and environmental regulatory activities on all onshore and offshore federal lands, and a third to collect and disburse royalties and revenues from energy and mineral activities on onshore and offshore federal lands.
- S. 3516, the Outer Continental Shelf Reform Act of 2010 was reported out of committee and placed on the Senate calendar on July 28, 2010. The bill would have directed the Secretary of the Interior to use administrative authority to establish a new entity responsible for revenue and royalty management and two new entities dividing responsibilities for leasing, permitting, and safety and environmental regulatory functions and eliminate "to the maximum extent practicable…potential organizational conflicts of interest related to leasing, revenue creation, environmental protection, and safety.
- S. 3643, the Oil Spill Response Improvement Act, was placed on the Senate Legislative Calendar on July 22, 2010. The bill included the provisions of S. 3516 discussed above.
- S3663, the Clean Energy Jobs and Oil Company Accountability Act of 2010 was placed on the Senate Legislative Calendar on July 28, 2010. The bill included the provisions of S. 3516 discussed above.

These legislative proposals did not progress to enactment, and the Secretary of the Interior created three separate entities under the authority of a Secretarial Order.[46] Issued on May 19, 2010, Secretarial Order No. 3299 directed the division of MMS into three new entities: BOEM, BSEE and ONRR. As a first step, the largely intact revenue function that was MMS's Minerals Revenue Management Division moved to the Office of the Secretary under the supervision of the Assistant Secretary for Policy, Management and Budget and became ONRR effective October 1, 2010 (Figure 2-2).[47] ONRR's mission is to ensure the full and fair return to the American people of royalties and other monies owed for the utilization of public resources in the production of conventional and renewable energy and mineral resources both onshore and in the OCS.[48]

[46] U.S. Department of the Interior, ***Secretarial Order 3299***, May 19, 2010 executed under authority of Reorganization Plan No.3 of 1950.
[47] U.S. Department of the Interior, ***Secretarial Order 3299***, May 19, 2010.
[48] Department of the Interior, ***Implementation Report: Reorganization of the Minerals Management Service,*** July 14, 2010.

Assistant Secretary – Land and Minerals Management		Assistant Secretary- Policy, Management and Budget
Bureau of Ocean Energy Management	**Bureau of Safety and Environmental Enforcement**	**Office of Natural Resources Revenue**
Environmental Analysis and NEPA	Safety, Technical, and Environmental Review of Plans	Revenue Collections
5- Year Program (Oil and Gas)	Safety and Technical Inspections and Enforcement	Revenue Collections and Projections
Leasing Process Management	Production and Development Operations	Enforcement
Development/ Exploration/ Production Plan Management	Environmental Inspections and Enforcement	Accounting/ Financial Reporting
Resource Management	Rulemaking (for Safety and Environment)	Asset Valuation
Rulemaking (for Resource Utilization)	Safety and Environmental Research	Economic and Market Analysis
Environmental Studies	Oil Spill Response and Research	

Figure 2- 2. Post- Reorganization of OCS Functions Formerly in MMS[49]

The Secretary directed the restructuring of the remaining MMS functions that were at that point included in a newly named Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE).[50] The Secretary directed the creation of two entities: BOEM would exercise the conventional and renewable energy related management functions including, but not limited to activities involving resource evaluation, planning, and leasing. BSEE would exercise the safety and environmental enforcement functions of the MMS including, but not limited to the authority to inspect, investigate, summon witnesses and produce evidence, levy penalties, cancel or suspend activities, and oversee safety, response, and removal preparedness.[51]

After issuance of the Secretarial Order, the creation of BOEM and BSEE proceeded through a long and deliberate process that led to the design of the two bureaus. This design would allow the two bureaus to achieve mission separation, establish appropriate checks and balances, and ensure rigorous oversight while maintaining high levels of communication and coordination. This process progressed over the course of 18 months, and considered best practices gained from reviewing oil and gas management in other countries, multiple external reviews, and evaluation of other federal regulatory functions.

Two separate bureaus – BOEM and BSEE – reporting to the Assistant Secretary for Land and Minerals Management began operations on October 1, 2011 with defined and distinct

[49] U.S. Department of the Interior, ***Implementation Report: Reorganization of the Minerals Management Service***, issued July 14, 2010 with the addition of Oil Spill Response and Research omitted from original.
[50] U.S. Department of the Interior, ***Secretarial Order 3302***, June 18, 2010.
[51] U.S. Department of the Interior, ***Secretarial Order 3299***, May 19, 2010 executed under authority of Reorganization Plan No.3 of 1950.

missions. The actions taken by the Department in restructuring MMS addressed long-standing issues arising from three competing and conflicting missions. Under this design, BSEE has the responsibility to protect and improve worker safety, environmental compliance, and conservation of resources.

BSEE's Organizational Structure and Responsibilities

BSEE operates from a headquarters located in Washington, D.C. and through regional offices that oversee OCS development in the Gulf of Mexico, the Pacific Ocean, and waters off of Alaska. The three regions manage very different programs because of the environments in which they operate and the nature of energy development and production activities in the areas they oversee.

The Gulf of Mexico Region, headquartered in New Orleans, Louisiana, operates the largest program with 3,108 active leases including over 16 million acres.[52] The vast majority of OCS production comes from the Gulf of Mexico. Over 539 million barrels of oil were produced from the Gulf in 2015. Despite reduced oil and gas prices in recent years, production has steadily increased as new projects have come on line including five deep water projects that began production during 2015. The Gulf Region conducted 19,462 inspections in 2015 related to well operations, production facilities, pipelines, meters, and environmental compliance. Ensuring decommissioning and abandonment of facilities (once production has ended) are conducted in a safe and environmentally responsible manner is a significant component of the Gulf of Mexico Region's (GOMR) responsibilities.

The Pacific Region (PAC), headquartered in Camarillo, California, manages a program comprised of mature fields and aging infrastructure including 43 active leases and 217,669 acres.[53] PAC conducted 299 inspections in 2015 and is preparing for eventual decommissioning of multiple platforms and long-term preservation issues associated with shutdown of the main onshore arterial pipeline that transports 65 percent of the region's production for processing.[54] PAC is also involved in renewable energy projects off the coasts of Oregon and Hawaii.

The Alaska Region, headquartered in Anchorage, Alaska, manages 43 active leases and 204,949 acres where operations face unique issues related to operations in the Arctic environment.[55] BSEE's Alaska Region conducted 270 inspections in 2015 and currently oversees, in coordination with State regulators, production activities at the Northstar unit, located in the Beaufort Sea. Two primary interests for exploration in the Alaska Region (AK) are the Beaufort and Chukchi Seas, where there is an estimated 23 billion barrels of

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[52] U.S. Department of the Interior, ***Bureau of Ocean Energy Management Combined Leasing Report***, February 1, 2017, available at: https://www.boem.gov/2017-02-Combined-Leasing-Report//.
[53] Ibid
[54] Bureau of Safety and Environmental Enforcement, ***Annual Report 2015,*** available at https://www.bsee.gov/annual-report/safety/bsee-2015-annual-report.
[55] U.S. Department of the Interior, ***Bureau of Ocean Energy Management Combined Leasing Report***, November 1, 2015, https://www.boem.gov/Combined-Leasing-Reports-2015//.

technically recoverable oil and nearly 106 trillion cubic feet of natural gas. There is no exploration underway in these two areas and on December 20, 2016 President Barack Obama designated portions of U.S. waters in the Chukchi and Beaufort Seas as indefinitely off limits to offshore oil and gas leasing.[56] [57]

BSEE's Role in the OCS

BSEE's responsibilities are defined by OCSLA, which prescribes federal responsibility to promote safety, protect the environment, and conserve energy.[58] In carrying out these responsibilities, BSEE also ensures compliance with NEPA,[59] the Clean Air Act (CAA),[60] the Federal Oil and Gas Royalty Management Act (FOGRMA),[61] and the Oil Pollution Act of 1990 (OPA),[62] and others. BSEE uses the full range of authorities, policies, and technical knowledge to oversee OCS activities and perform the following functions:

- Oversight of production operations to ensure sound conservation, engineering, and economic practices to prevent waste and maximize recovery;
- Offshore regulation that establishes standards that emphasize a culture of safety;
- A technical review process that ensures risks are identified and minimized;
- Inspections of facilities, plans, and systems;
- Oil spill preparedness assessment that verifies operators have adequate plans and equipment in place;
- Technical and scientific research to enhance information and technology to sustain organizational, technical, and intellectual capacity;
- Investigation of incidents and allegations of unsafe and/or illegal conduct;
- Oversight to ensure that operators adhere to the stipulations of approved leases, plans and permits; and
- Monitoring compliance with and enforcement of applicable operational and environmental law, regulations, and policies.

BSEE's efforts in these areas are performed by highly skilled engineers, geoscientists, inspectors, biologists, investigators, and others who work with industry to evaluate plans, inspect facilities and equipment, verify operatory and contractor competencies, complete announced and unannounced inspections and exercises, apply standards and the results of research and development, and support ongoing refinement and improvement of

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[56] BSEE, ***Alaska Regional Operations***, 12-20-16, available at https://www.bsee.gov/whoweare/our-organization/regional-offices/alaska/ak-regional-operations.

[57] The White House, ***United States-Canada Joint Arctic Leaders' Statement***, December 20, 2016, available at https://www.whitehouse.gov/the-press-office/2016/12/20/united-states-canada-joint-arctic-leaders-statement.

[58] Outer Continental Shelf Lands Act, 43 U.S.C. §§ 1331 et seq..

[59] National Environmental Policy Act, 42 U.S.C. §§ 4321 et seq.

[60] Clean Air Act, 42 U.S.C. § 7401 et seq.

[61] Federal Oil and Gas Royalty Management Act of 1982, 30 U.S.C. § 1701 et seq.

[62] Oil Pollution Act of 1990, 33 U.S.C. 40 § 2701 et seq.

technologies.

To implement its mission, BSEE works with other federal agencies, states, and local entities and other countries. Within DOI, BSEE works closely with BOEM promoting energy independence, environmental protection, and economic development through responsible science-based management of offshore conventional and renewable energy and marine mineral resources. BOEM studies the environment and leases resources on the OCS, while BSEE enforces the terms of the leases. BOEM and BSEE also collaborate on decommissioning and the Rigs to Reefs Program, which is explained in Chapter 3. BSEE works closely with ONRR in their efforts to collect and disburse royalty revenues generated by energy production on federal lands, including the OCS. BSEE performs meter inspections on behalf of ONRR to ensure companies are accurately reporting production totals. BSEE works closely with many other federal entities in the fulfillment of their mission. A summary of relationships with other federal entities is included in Appendix E.

BSEE's role in regulating offshore energy exploration, production, and development demands close productive relationships with industry and standards setting authorities to ensure that regulations, guidance, and oversight incorporate the latest technological requirements. BSEE participates in nearly 100 different standards development committees with organizations including the American Petroleum Institute (API), the American Society for Testing and Materials International, the American Society of Mechanical Engineers, and the National Association of Corrosion Engineers International.[63]

BSEE also engages with stakeholders from academia, industry, non-governmental organizations, and other governmental agencies to enhance the knowledge base of BSEE's programs and technical personnel. In 2013, BSEE established the Ocean Energy Safety Institute (OESI), a forum for dialogue, shared learning, and cooperative research in offshore-related technologies and activities to promote environmentally safe and responsible offshore operations. BSEE also established the Engineering Technology Assessment Center (ETAC), located in Houston, Texas, to assess novel and emerging technologies and enable BSEE to stay abreast of an increasingly complex industry. Through ETAC, the bureau works closely with original equipment manufacturers and standards-setting bodies.

BSEE's Oil Spill Preparedness Program advances research and development into new innovative methods to respond to oil spills and identify best available technologies for mechanical and alternative spill response, by engaging with the U.S. Coast Guard and other partners. BSEE operates the National Oil Spill Response Research and Renewable Energy Test Facility. Located in Ohmsett, New Jersey, the facility is designed to test and evaluate full-scale equipment for the detection of and response to spilled oil. It plays an important role in developing response technologies and preparing responders by training in a realistic setting.

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[63] U.S Department of the Interior, ***Budget Justifications and Performance Information, Fiscal Year 2017: Bureau of Safety and Environmental Enforcement***, p. 21.

BSEE's Budget and Staffing Profile

BSEE has an annual budget of $204.7 million, which represents nearly 1.7 percent of the DOI budget of $12.0 billon.[64] This includes $88.5 million in appropriations and $116.2 million in offsetting collections. BSEE is currently funded through the Further Continuing and Security Assistance Appropriations Act, 2017, P.L. 114-254 enacted on December 10, 2016. This authority extends funding levels and terms and conditions based on the FY 2016 Appropriations Act[65] through April 28, 2017 or until regular appropriations are enacted. The FY 2017 budget submitted to Congress on February 9, 2016 represents the most current proposal for BSEE (as of the time of the release of this report) and includes a request of $204.9 million, including $81.4 million in appropriations and $108.5 million in offsetting collections.

BSEE's staffing component totaled 802 Full-Time Equivalents (FTE) as of September 17, 2016. An FTE translates annual hours worked by BSEE's employees into an equivalent number of full time work years. There were 852 full-time employees on board as of September 17, 2016 and 871 employees in total.

[64] BSEE current authority for FY 2016, including offsetting collections, as compared to DOI current authority, regular appropriations.
[65] ***Consolidated Appropriations Act***, 2016, P.L. 114-113, Dec. 18, 2015.

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Chapter 3: A Mission for Safety, Environmental Proection, and Conservation

BSEE was created with a distinct mission focused on ensuring that industry operates in a manner that ensures high levels of worker safety, is compatible with protection of the environment, and effectively recovers and measures OCS resources. BSEE's creation reformed OCS management, establishing for the first time since Congress passed OCSLA in 1953 an authority that is deconflicted from the other OCSLA federal responsibilities to promote development and maximize revenues.

DOI's action to create three separate entities to administer its OCS program and undertake numerous reforms established a foundation for and precipitated a wide range of other improvements. These include the issuance of new and updated guidance to improve drilling safety, blowout preventer and well control, production safety systems, and Arctic drilling. In both regulatory and compliance initiatives, BSEE has applied modern regulatory concepts such as performance and risk-based requirements and advanced near-miss reporting, real-time monitoring, and third-party certification.

These actions and others have improved BSEE's capability to focus on attainment of strategic goals to advance a culture of safety, promote environmental stewardship, and conserve energy resources and maintain effective relationships with operators and the offshore energy industry. In FY 2015, BSEE conducted 20,031 inspections on more than 2,300 OCS facilities covering well operations, pipelines, meters, and environmental compliance and issued 2,483 violations for Incidents of Noncompliance. BSEE collected over $6 million in fines as a result of 57 civil penalty cases and initiated 71 investigations spanning multiple categories of oversight. In 2015, BSEE also reviewed 238 Oil Spill Response Plans, and completed 170 oil spill preparedness inspections, audits, verifications, or exercises.[66]

In FY 2015, BSEE launched its SafeOCS program, which collects and analyzes near-miss data from industry to save lives, reduce injuries, and help prevent potentially devastating environmental events on the OCS. BSEE's data collection protects confidentiality, promoting voluntary reporting to encourage learning and reporting within the offshore community and fosters a culture of transparency with industry and other stakeholders. BSEE closely tracks trends in industry-reported data and uses the results to inform and improve compliance, including the data reported below in Figure 3-1.

[66] Bureau of Safety and Environmental Enforcement, ***Annual Report 2015,*** available at https://www.bsee.gov/annual-report/safety/bsee-2015-annual-report.

	2007	2008	2009	2010	2011	2012	2013	2014	2015
Fatalities	5	12	4	12	3	1	4	2	1
Injuries	322	263	260	253	221	280	276	285	206
Loss of Well Control	6	7	7	4	5	3	8	5	3
Fires/Explosions	145	141	148	134	113	132	116	135	105
Collisions	26	28	26	14	11	13	21	16	9
Spills (greater than 50 barrels)[67]	7	33	7	9	4	5	10	5	7
Lifting	180	185	243	118	110	167	197	210	161
Gas/Hydrogen Sulfide Releases	14	22	33	20	17	27	21	21	21
Evacuation Musters	33	43	55	31	36	48	68	52	70
Total	738	734	783	595	520	676	721	731	583

Figure 3-1 Recordable Incidents Occurring in the OCS from FY 2007-2015[68]

BSEE's attainment of its strategic goals is also reliant on sustained, high levels of collaboration and cooperation with its federal partners. Alignment of BSEE and BOEM is of particular importance for successful collaboration of functions and systems relating to OCS energy and mineral development. BSEE's close collaboration with BOEM ensures high levels of information sharing, effectively functioning programs for environmental protection, and joint efforts to implement decommissioning responsibilities. The two bureaus are currently working to transfer the renewable energy responsibilities of environmental oversight, facility inspections, and regulatory enforcement from BOEM to BSEE.

BSEE shares jurisdiction in the management of OCS resources and regulation of activities on the OCS with multiple other federal partners, including, most prominently the U.S. Coast Guard (USCG), which shares responsibility in multiple areas including inspections and incident response and investigations. BSEE's long-standing relationships with the USCG and other federal partners promote efficient and consistent regulation and enhance information reporting and sharing.

A Deconflicted Mission

The establishment of BSEE was an exacting, multi-year undertaking. The nearly 18-month-long process included interviewing employees; collecting and analyzing data involving relevant processes, systems, and regulatory metrics; and developing and evaluating various models and options for restructuring and reforming the functions being assigned to the

[67] An oil barrel defined as 42 U.S. gallons.
[68] Bureau of Safety and Environmental Enforcement, ***Annual Report 2015,*** available at https://www.bsee.gov/annual-report/safety/bsee-2015-annual-report.

new bureau.[69] This deliberative process engaged teams of subject matter experts from MMS's offshore programs and included interviews with over 300 staff; surveys of all 1,000 MMS employees; analyses of and interviews with other nations' energy programs; and reviews of the structure and functioning of other federal programs involved in the regulation of industry. Through a process that included extensive working sessions led by a facilitator, decisions were made about the division of OCSLA-authorized functions. Ultimately the organization, reporting structure, and division of responsibilities were reviewed and approved by the senior officials in DOI and plans were developed to guide the implementation process. The Assistant Secretary for Policy, Management and Budget and a Senior Advisor to the Secretary were tasked with overseeing the reorganization.[70] A budget amendment submitted to the Congress on September 13, 2010 laid the groundwork for the reorganization, requesting additional resources and authority to proceed to reorganize OCS functions. Additional submissions[71] and reports about the ongoing restructuring were presented to Congress, which approved of the reorganization in appropriations legislation.[72]

BSEE was split off as a separate bureau in order to ensure that critical functions would not be compromised by being combined in an entity with contradictory missions. In their reviews following DWH, the OIG and others found troubling patterns where managers seemed to prioritize the dominant mission of meeting development targets at the expense of regulatory compliance functions.[73] Environmental and safety functions had been "historically slighted and underfunded within MMS", where management of OCS resources and enforcement of regulatory compliance were combined in a single entity; and "separating resource management from safety oversight" was seen as essential to the creation of BSEE as "an aggressive, tough-minded but fair regulator" with greater independence, more budgetary autonomy, and clearer senior leadership focus."[74] Although

[69] See, generally, remarks of then-BOEMRE Director Michael R. Bromwich, available as "BOEMRE Director Discusses Future of Offshore Oil and Gas Development in the U.S. at Gulf Oil Spill Series, BOEMRE Office of Public Affairs, for release April 19, 2011, https://www.boem.gov/boem-newsroom/press-releases/2011/press0419-pdf.aspx.

[70] U.S. Department of the Interior, ***Salazar Names Interior Officials to Lead Minerals Management Service Restructuring,*** press release, May 13, 2010, available at https://www.doi.gov/news/pressreleases/Salazar-Names-Senior-Interior-Officials-to-Lead-Minerals-Management-Service-Restructuring.

[71] The White House, ***FY 2011 Budget Amendments for the Department of the Interior***, September 13, 2010, available at https://www.doi.gov/sites/doi.gov/files/migrated/budget/appropriations/2011/upload/BOEMRE_Budget_Amendment_09_13_10.pdf.

[72] Congressional Research Service, ***Reorganization of the Minerals Management Service in the Aftermath of the Deepwater Horizon Oil Spill*** (R41485, Nov. 10, 2010), https://fas.org/sgp/crs/misc/R41485.pdf; U.S. Congress, ***Department of Defense and Full-Year Continuing Appropriations Act***, 2011, Public Law 112-10, Div. A, sec. 1726, 125 Stat. 151 (April 15, 2011).

[73] U.S. Department of the Interior, Office of Inspector General, ***A New Horizon: Looking to the Future of the Bureau of Ocean Energy Management, Regulation and Enforcement,*** Report No. CR-EV-MMS-0015-2010, December 2010, pages 33-37.

[74] Bureau of Ocean Energy Management, Regulation, and Enforcement, Office of Public Affairs, ***BOEMRE Director Discusses Future of Offshore Oil and Gas Development in the U.S. at Gulf Oil Spill Series***, April 19, 2011, available at https://www.boem.gov/BOEM-Newsroom/Press-Releases/2011/press0419-pdf.aspx.

the hard work to fully establish all of BSEE's functions and processes is ongoing, and some regional personnel express nostalgia for the simpler chains-of-command that preceded the separation of BOEM and BSEE, the consensus view is that BSEE has established a substantially more robust and focused compliance program than existed before the separation. In interviews with the study team, employees who had worked in MMS explained that the separation allowed employees to more adequately conduct regulation and enforcement and operate in an environment free from these historical conflicts.

BSEE's efforts to mature the organization are evident and are consistent with the expectation early in the separation process that creation of the new OCS management authorities would take sustained effort over a number of years. Establishment of BSEE as a high-functioning separate organization was understood to be a complex, long-term process requiring ongoing support and adequate resources. For example, the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling suggested that reorganization of MMS into three offices and enhancing their technical expertise would require a sustained effort over a period of years.[75]

Experts on public administration and government management consistently advise that it is extremely difficult to effectively implement a reorganization and that doing so requires close coordination with those inside and outside of the agency, including Congress, and takes many years to accomplish.[76] This puts in perspective criticisms of BSEE's shortcomings with regard to still maturing processes. In 2011, GAO designated DOI's OCS programs as high risk due, in part, to the challenges of restructuring.[77] GAO removed restructuring from the list of factors contributing to the high-risk designation for DOI's OCS programs in 2013 based on its assessment of progress made.[78] GAO's most recent high risk report issued on February 2017 broadens the areas under consideration adding back reorganization as an area of potential risk based on GAO's belief that BSEE has made limited progress addressing long-standing deficiencies in investigative, environmental compliance, and enforcement capabilities.[79] GAO based this conclusion on the findings in its

[75] National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, ***Deepwater: The Gulf Oil Disaster and the Future of Offshore Drilling***, p. 254, January 2011, available at https://www.gpo.gov/fdsys/pkg/GPO-OILCOMMISSION/pdf/GPO-OILCOMMISSION.pdf.

[76] See, e.g., GAO, ***Government Efficiency and Effectiveness: Opportunities for Improvement and Considerations for Restructuring***, GAO-12-454T, March 21, 2012, page 10 ("implementation of a new organization is an extremely complex task that can take years to accomplish"); Alan Lomax, NAPA/ASPA Memos to National Leaders, ***Reorganizing the Federal Government,*** Oct. 25, 2012; NAPA forum, ***Government Reorganization? Why? How?*** March 8, 2011 (described in "The Rocky Road to Reorganization, from Nixon to Obama" GovExec.com, March 8, 2011); GAO, ***Results-Oriented Cultures: Implementation Steps to Assist Mergers and Organizational Transformations,*** GAO-03-669, July 2003.

[77] Government Accountability Office, ***GAO's 2011 High-Risk Series, An Update***, GAO-11-394T, February 17, 2011.

[78] Government Accountability Office***, High Risk Series, An Update, NGA-***13-283, February 2013..

[79] Government Accountability Office. ***High-Risk Series: Progress on Many High-Risk Areas, While Substantial Efforts Needed on Others,*** GAO-17-317, Feb. 15, 2017.

February 10, 2016 report.[80] In response to the findings in this report, BSEE put plans in place to address GAO's nine recommendations, of which four have already been completed.

Just as BSEE's maturation requires a continued commitment to addressing gaps and challenges, orderly development of energy resources in the OCS requires a regulatory environment that is sufficiently stable to be conducive to an ongoing commitment from industry. The business decisions of industry to invest in exploration and development of energy resources must consider market forces, the outlook for energy prices, and the ability to work within a stable and predictable business and regulatory environment. As BSEE continues to pursue strategic goals for operational and organizational excellence, it will be able to contribute to greater predictability and stability. And, although oil production is projected to increase to record high levels in 2017, decreasing profit margins and reduced expectations for a quick oil price recovery have prompted many operators to pull back on future deep water exploration spending.[81] Thus, a stable OCS environment with certainty and predictability could be a significant consideration in OCS development planning, arguing for continuation of the current alignment of responsibilities among BOEM, BSEE, and ONRR and continued deliberate efforts to mature these entities.

Further restructuring would most certainly reverse the gains made while also causing disruption and uncertainty for federal programs and industry. Although well-conceived and effectively implemented reorganizations can yield benefits, at least in the long run, reorganizations generally increase costs and disrupt operations in the near term, and reorganization is better thought of as a last-resort, rather than a first-resort, to address institutional challenges.[82] Reorganization can generally be expected to particularly impact the agency's stakeholders, due to the turbulence and decreased productivity that are likely during restructuring. Attention is diverted from the organization's longer-term mission goals, and employees become distracted by uncertainty and concerns about their own positions.[83]

Recommendation 3.1

BSEE should remain a separate entity with high levels of coordination with BOEM and ONRR.

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[80] Government Accountability Office, ***Oil and Gas Management: Interior's Bureau of Safety and Environmental Enforcement Restructuring Has Not Addressed Long-Standing Oversight Deficiencies,*** GAO-16-245, February 10, 2016.
[81] U.S. Energy Information Administration, ***Today in Energy***, February 18, 2016.
[82] Posner, Paul, ***Paul Posner, George Mason University***, Interview, Federal News Radio, Feb. 9, 2015, available at http://federalnewsradio.com/in-depth/2015/02/paul-posner-george-mason-university/; Alan Lomax, NAPA/ASPA Memos to National Leaders, op. cit.; NAPA forum on Government Reorganization, op. cit.
[83] Government Accountability Office, ***Government Efficiency and Effectiveness: Opportunities for Improvement and Reconsiderations for Restructuring***, March 12, 2012.

Regulations, Policies, and Processes

The Deepwater Horizon incident continues to shape the environment within which BSEE operates. BSEE responded to findings and recommendations from nine reviews that were conducted in the wake of DWH.[84] BSEE adopted recommendations and addressed concerns expressed by GAO, OIG, and many others, evidencing areas of transformation and improvement. As of October 2016, BSEE had completed actions on 79 recommendations for corrective actions resulting from GAO and OIG reviews and was tracking the 14 that remain, of which, 13 are scheduled for closure in 2017 and 1 is scheduled for closure in 2018. BSEE's strategic performance review that is conducted on a regular basis keeps focus on these efforts.

The evaluations conducted in the immediate aftermath of the Deepwater Horizon incident identified very substantial gaps and deficiencies in MMS's regulatory and procedural framework and recommended that major improvement would be necessary to adequately protect safety and the environment. These reforms were complex and many involved the development of capacities that did not exist or were inadequate. For example, the report of the Outer Continental Shelf Safety Oversight Board (Board) issued on September 1, 2010,[85] and the "New Horizon" report of the OIG issued in December 2010[86] addressed these areas:

- **OIG's Finding:** Gulf of Mexico district offices lacked a standardized protocol for reviewing their large number of complex permit applications.
- ***Recommendation:*** The development and compilation of standardized policies and practices.

[84] National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, ***Deep Water: The Gulf Disaster and the Future of Offshore Drilling***, January 2011, available at https://www.gpo.gov/fdsys/pkg/GPO-OILCOMMISSION/pdf/GPO-OILCOMMISSION.pdf; and U.S. Department of the Interior Outer Continental Shelf Safety Oversight Board, ***Report to Secretary of the Interior Ken Salazar***, September 1, 2010; U.S. Department of the Interior Office of Inspector General, ***A New Horizon: Looking to the Future of the Bureau of Ocean Energy Management, Regulation and Enforcement,*** Report No.: CR-EV-MMS-0015-2010, December 2010; Ocean Energy Safety Advisory Committee, Federal Advisory Committee to the Secretary of the U.S. Department of the Interior, April 2011-January 2013; Transportation Safety Board Report 309, ***Evaluating the Effectiveness of Offshore Safety and Environmental Management Systems,*** 2012; and U.S. Chemical Safety and Hazard Investigation Board, ***Investigation Report Vol. 4, Drilling Rig and Explosion and Fire at the Macondo Well***, April 20, 2010; National Academy of Engineering and National Research Council, ***Macondo Well-Deepwater Horizon Blowout***, December 14, 2011; Joint Industry Subsea Well Control and Containment Task Force, ***Final Report on Industry Recommendations to Improve Subsea Well Control and Containment,*** March 13, 2012; and Bureau of Ocean Energy Management, Regulation and Enforcement/U.S. Coast Guard Joint Investigation Team, ***Deepwater Horizon Joint Investigation Team Report,*** September 14, 2011.

[85] U.S. Department of the Interior Outer Continental Shelf Safety Oversight Board, ***Report to Secretary of the Interior Ken Salazar***, September 1, 2010.

[86] U.S. Department of the Interior Office of Inspector General, ***A New Horizon: Looking to the Future of the Bureau of Ocean Energy Management, Regulation and Enforcement,*** Report No.: CR-EV-MMS-0015-2010, December 2010.

- **OIG's Finding:** There was no formal, bureau-wide compilation of rule, policies, or practices pertinent to inspection.
- ***Recommendation:*** A comprehensive handbook should be compiled of all policies and practices to assist inspectors, including clarification of policies under which unannounced inspections can be performed.

- **OIG's Finding:** There was no standard practice to address operators' ability to "shop around" for a favorable engineer or office to gain an advantage for regulatory approval.
- ***Recommendation:*** Procedures should be established to prevent such "engineer shopping."

- **OIG's Finding:** There was no adequate standardized protocol for activities of incident investigation and evidence-gathering, so that investigations lacked consistency and might be inadequate for serious accidents.
- ***Recommendation:*** The development and implementation of internal procedures, including basic investigation and evidence-gathering protocol, to fully conduct and document investigations.

- **OIG's Finding:** Substantive regulations generally did not distinguish between operations in deep water and in shallow water and regulations specifically addressing deep water activities were scattered and had gaps and inconsistencies.
- ***Recommendation:*** The development of a regulatory framework that addresses gaps and inconsistencies, and that is comprehensive and well organized.

Both before and soon after these findings and recommendations were issued, rules and procedures were already being developed and issued to fill the most significant gaps that had been identified.[87] In recognition of the role that well design, casing, and cementing had in the Deepwater Horizon disaster and future potential risks, a Drilling Safety Rule was issued, on an emergency basis, establishing standards for these and other elements of well-control, including blowout preventers. A Workplace Safety Rule was also put into place, requiring operators to systematically identify risks and establish measures to mitigate those risks. Work was also initiated to develop a comprehensive handbook of policies and practices for permit review and approval, risk-based inspection programs, investigative procedures, and other initiatives to improve and modernize the regulatory program.[88]

In the intervening five years, BSEE has continued to make substantial progress in its regulatory and procedural framework. BSEE's efforts include issuance of new or revised rules on drilling safety, decommissioning-costs reporting, blowout preventer and well

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[87] Bureau of Ocean Energy Management, Regulation, and Enforcement, ***BOEMRE Director discusses future of Offshore Oil and Gas Development in the U.S. at Gulf Oil Spill Series,*** April 19, 2011, available at https://www.boem.gov/Boem-Newsroom/Press-Releases/2011/press0419-pdf.aspx.

[88] Bureau of Ocean Energy Management, Regulation, and Enforcement, ***BOEMRE Director discusses future of Offshore Oil and Gas Development in the U.S. at Gulf Oil Spill Series,*** January 13, 2011,available at https://csis-prod.s3.amazonaws.com/s3fs-public/legacy_files/files/attachments/110113_prepared_remarks.pdf .

control, production safety systems, and Arctic drilling. In both regulations and compliance initiatives, BSEE has been incorporating modern regulatory concepts such as performance- and risk-based requirements, near-miss reporting, real-time monitoring, and third-party certification.

Remaining gaps include national beneficial-use guidance and requirements as identified by the OIG in a June 11, 2009 Advisory issued to MMS;[89] renewable energy program regulations; measures on installation, maintenance, and decommissioning of pipelines; updating oil spill planning and response requirements; improvements in Safety and Environmental Management System (SEMS) rules regarding process safety; performance of audit and sharing of information; safety requirements related to helicopters and helipads on fixed platforms; and updated regulations for cranes.

There is, in addition, a significant workload for BSEE to implement recently issued regulations, establish a consistent performance-based and transparent process for determining BAST, and strengthen capability for estimating potential decommissioning costs to be covered in the event of operator bankruptcy or other contingencies.

BSEE also needs to finalize and codify national policies and procedures and to strengthen mechanisms for issuing and managing interpretations and exceptions. Policies and procedures governing certain key compliance functions have not been completed and nationally applied. GAO and the OIG continue to focus on gaps in BSEE's national policies for incident investigation, environmental compliance, safety enforcement, and permit review. Greater efforts to review and publish regulatory interpretations and guidance should also help foster consistent national policy and procedures, including in the issuance of Notices to Lessees and Operators (NTLs) and in the exercise of regional authority to approve exceptions. Improved collaboration and decision-making processes with balanced headquarters and regional involvement are vital for these efforts, to ensure that the regions are able to make guidance available to operators in a timely manner and to manage the significant workload associated with these efforts.

BSEE has evaluated its development and issuance of policies and implemented changes to improve the efficiency of these processes. Rulemaking efforts are prioritized based on a comprehensive review of existing oil and gas regulations, safety and environmental risks, new developments in industry practices and technology, research results, and information about changing circumstances. BSEE's ongoing collaboration with industry and industry groups on the development of industry standards also informs BSEE's regulatory development. BSEE's hybrid approach to regulating industry means that performance-based regulations will be used in lieu of standard checklists wherever performance-based regulations can be effectively implemented. This approach relies on industry use of SEMS, which is a performance-based tool to enhance the safety of operations by focusing operator

[89] U.S. Department of the Interior, Office of Inspector General, ***Inspection Report: BLM and MMS Beneficial Use Deductions,*** Report No. CR-IS-MOA-0004-2009, March 2010, available at https://www.doioig.gov/sites/doioig.gov/files/2010-I-00171.pdf.

attention and resources on recognizing and managing the impacts of human behavior; organizational structure; leadership; monitoring of critical equipment and processes; adoption of standards, processes and procedures; and an underlying safety culture to promote continuous improvements in safety and environmental performance.

BSEE inherited a legacy of guidance and other documentation that was not effectively organized or easily located. BSEE has a process underway to both inventory and update these policies, directives, and other policy statements. This is a significant workload, since legacy MMS directives date back to the 1980s and were not archived appropriately. BSEE's Office of Policy and Analysis (OPAA) has an organized approach to assist BSEE managers in this effort and BSEE instituted a transitional directives system to allow for continuous updating of the bureau's policy, procedures, and guidance. Senior managers should be given specific assignments with realistic timeframes in order to ensure that program offices with primary responsibility for updating the directives or that are still relying on legacy directives are engaged in this process and take the actions necessary for this process to be successful.

Recommendation 3.2

BSEE should continue its efforts to inventory, organize, and update policies, procedures, and guidance. It should assign realistic and enforceable timeframes to managers for updating these materials.

BOEM and BSEE Alignment and Coordination

BOEM and BSEE were created as separate bureaus for the overarching purpose of "separating resource management from safety oversight."[90] In the division of responsibilities between the two bureaus, BSEE was established as "an aggressive, tough-minded but fair regulator" that "can properly carry out the critical safety and environmental protection functions that are central to its mission" with "greater independence, more budgetary autonomy, and clearer senior leadership focus."[91] BOEM received the balance of the environmental science and environmental analysis resources to create "an organizational structure that ensures that thorough environmental analyses are conducted and that potential environmental effects of proposed operations are given appropriate weight during decision-making related to resource management," so that "leasing and plan approval activities are properly balanced and that environmental considerations are fully taken into account at early stages of the process."[92]

[90] Bureau of Ocean Energy Management, Regulation, and Enforcement, Office of Public Affairs, ***BOEMRE Director Discusses Future of Offshore Oil and Gas Development in the U.S. at Gulf Oil Spill Series,*** April 19, 2011, available at https://www.boem.gov/BOEM-Newsroom/Press-Releases/2011/press0419-pdf.aspx .
[91] Ibid.
[92] Ibid.

In implementing the separation, it was emphasized that BSEE and BOEM would have to remain interdependent, and that addressing "information-sharing and other linkages between BSEE and BOEM" would be "essential to ensure that the business and regulatory processes related to offshore leasing, plan approval, and permitting are not plagued by bureaucratic paralysis."[93] To achieve effective collaboration, BSEE and BOEM negotiated and agreed to a substantial body of Memoranda of Understanding (MOU), MOA, and associated standard operating procedures (SOPs). Many were developed in 2011 and two more were developed in 2014. This documentation spells out in detail the policies and procedures for BSEE's and BOEM's interactions in key areas such as: information sharing, enforcement, environmental assessments and NEPA, approval of plans and permits, bonding, and reimbursable administrative services to be provided by BSEE to BOEM.[94]

The framework established in these agreements was designed to be self-sustaining through the peer-to-peer efforts by the two bureaus. Appropriate officials within the two bureaus may modify the documentation. Any disputes are to be resolved by the two bureaus at the lowest organizational level possible. When all other options have been exhausted, the bureaus may elevate the issue to the Assistant Secretary for Land and Minerals Management for resolution.

Because BOEM and BSEE are interdependent, they must work together to effectively manage the OCS. Given the importance of maintaining close and functional relationships and ensuring close alignment, issues between the bureaus need to be resolved quickly. In addition to the MOU, MOA, and SOPs, linkages between the bureaus are maintained through individual relationships, coordination, and informal efforts. Moreover, issues that are not resolved at the staff level are elevated within BSEE and ultimately raised to the Deputy Director to resolve with BOEM's Deputy Director. Such dialogue between the BOEM and BSEE leadership frequently leads to resolution. However, areas of disagreement between the bureaus can remain without resolution because they are not elevated to the Assistant Secretary. An institutionalized process to address the divergence in views or to examine impacts of actions by one bureau on the other bureau's processes, workload, staffing, and budget would create additional opportunities to maintain the close and functional relationship.

Supporting the Environmental Compliance Mission: The challenges in the management of the BOEM and BSEE relationship and processes seem to have the greatest impact on BSEE's

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[93] Department of the Interior, Press release, ***Fact Sheet: The BSEE and BOEM Separation: An Independent Safety, Enforcement and Oversight Mission***, January 19, 2011, available at https://www.doi.gov/sites/doi.gov/files/migrated/news/pressreleases/upload/01-19-11_Fact-Sheet-BSEE-BOEM-separation-2.pdf .

[94] See, generally, Bureau of Safety and Environmental Enforcement, ***Interagency Collaboration***, available at https://www.bsee.gov/newsroom/partnerships/interagency . Documentation referenced through that website include: a 2014 MOU between BOEM, BSEE, and ONRR on information sharing; a 2014 MOA between BOEM and BSEE on enforcement activities, a 2011 MOU between BOEM and BSEE providing an overall framework for the two bureaus to minimize duplication, promote consistency, and resolve disputes, and a series of 2011 MOAs, SOPs, etc., between BOEM and BSEE on specific functions and topics.

Environmental Compliance Program. In the creation of BOEM and BSEE, the decision was made to assign responsibility for NEPA compliance to BOEM. BOEM is responsible for environmental review under NEPA, the National Historic Preservation Act and other statutory and regulatory requirements, including the completion of environmental impact statements, environmental assessments, and other actions related to the development of the 5-year plan and lease sales, as well as in support of permits issued by BSEE. Differences can arise between the bureaus in implementing this process and if not resolved at the field or regional level, these differences can cause friction, additional workload, and additional costs.

Critically important decisions are made in the NEPA analyses supporting planning, leasing, and permitting, which are all functions of BOEM. Operational protocols are outlined in MOA and procedures are described in SOPs that were developed in 2011. The MOA may need to be refreshed to address maturation of process and areas of divergence between the two bureaus. As part of the refresh, BSEE needs to define information that is necessary to support environmental decisions associated with permitting and enforcement. There may need to be a process for mitigation, if BOEM is not able to provide this information or if the information is not adequate. In the current state, BSEE indicated that they may be filling these voids and assuming additional work and costs. In at least one instance where sufficient information was not available from BOEM, BSEE funded the completion of an environmental assessment. This approach will not be sustainable with tightening budgets.

Recommendation 3.3

In instances when BSEE does not have adequate information needed to support environmental decisions associated with permitting and enforcement, this situation should be communicated to BOEM. The Memoranda of Agreement (MOA) and Standard Operating Procedures (SOPs) that BOEM and BSEE operate under should be revised or supplemented by the establishment of processes with timelines to ensure that expectations are clearly understood. These processes established by revision or supplementation of the MOAs and SOPs should also include robust procedures for the elevation of matters for resolution, when necessary, and for the periodic review of the process by which BSEE obtains needed information from BOEM to identify systemic issues and needed improvements.

<u>Renewable Energy Program Transition:</u> BSEE is working with BOEM to transition the renewable energy program, as BSEE assumes responsibilities for environmental oversight, facility inspections, and regulatory enforcement. There were a small number of renewable projects in the initial planning stages in 2011 and the responsibility for renewable energy was assigned to BOEM. Since then, however, the extent and pace of OCS renewable energy development has changed and recent changes by a number of states to increase renewable energy as a component of their energy portfolio have the potential to expand renewable energy development.

Currently there are eleven commercial wind energy leases on the east coast. The first offshore wind farm—the Block Island Wind Farm—is operating in state waters although the subsea cable is in federal waters. Several more wind energy projects are scheduled to be completed and begin operations in 2019. In December of 2016, BOEM held a wind energy lease sale for an area offshore New York. BOEM is also processing floating wind lease requests for offshore Hawaii and one offshore California, and is evaluating a lease request for a floating wind demonstration project offshore of Oregon. There is significant potential for future growth in renewable energy development on the OCS. On June 8, 2016, Hawaii updated its renewable portfolio standard (RPS) to set a goal for 100 percent renewable energy by 2045. In October 2015, California modified its RPS to require that retail sellers and publicly owned utilities procure 50 percent of their electricity from eligible renewable energy resources by 2030. In 2016, Oregon adopted a 50 percent RPS and requires that half of the state's electricity is to come from renewable sources by 2040.

BSEE has taken steps to prepare for assuming renewable energy related duties and addressed the increased momentum for renewable energy in its Foresight Initiative (discussed in Chapter 5). In order to prepare for the reassignment of responsibilities, a BOEM/BSEE team is re-designating renewable energy regulations between the two agencies. Once this is complete, BOEM and BSEE will revise regulations and update the MOA for the renewable energy program. BSEE has been involved in the review of the Block Island subsea cable facility designs and review of Department of Energy offshore demonstration projects, including oil spill response plans. BSEE is also developing a methodology for inspection of renewable energy facilities.

Based on the accelerating pace and potential for OCS renewable energy development, the study team suggests that the timeline for transition of the regulatory aspects of the program should be accelerated. In addition, a schedule for the transition should be developed and both bureaus and ASLM should be monitoring progress. Lastly, BSEE should be identifying the necessary competencies for the renewable program in its revised Human Capital Management Strategic Plan, incorporating additional needs for specialized expertise it will need in its workforce planning, and considering additional budgetary requirements for its budget. Chapter 8 addresses the budget issue in more detail.

Recommendation 3.4

BSEE should work with BOEM to accelerate the transfer of environmental oversight, facility inspection, and regulatory enforcement responsibilities for the OCS renewable energy program and develop a schedule to be monitored by ASLM. BSEE should consider these new responsibilities in the development of workforce plans and should ensure that resources are available for these efforts and, as necessary, requested in future budgets.

<u>Virtual Organization and Collaboration:</u> Much has been written about the increasing complexity of problems that government must address, including the prevalence of issues that cut across organizational boundaries and the quandaries this poses for managers. An approach of establishing effective and sustainable collaborative mechanisms among governmental entities is sometimes referred to as "virtual reorganization." For example, GAO's Managing Director for Strategic Issues has written that "in many cases today, concerns with federal organization should be less interested in ripping apart existing

agencies and creating new organizations in an endless and largely futile quest to find some theoretically right structural fit of related programs and initiatives. Rather, federal reorganization should be more focused on creating and sustaining what has been referred to as virtual organizations that use collaboration mechanisms to knit together various related programs and efforts...."[95]

To foster more effective and consistent coordination between BSEE and BOEM, the study team recommends that leadership in improved coordination be exercised at the Departmental level by ASLM. At a minimum, there should be periodic scheduled meetings between top leadership of BSEE and BOEM, convened by the Assistant Secretary to review ongoing processes and linkages between the two bureaus. This would also be a useful venue to revisit the consequences of decisions made by the bureaus and to assess resource demands. ASLM could draw on the resources available to the Assistant Secretary for Policy, Management and Budget (ASPMB) including economic and policy analysis and mediation and coordination specialists.

Recommendation 3.5

ASLM should establish formal, regularly scheduled reviews of ongoing BOEM and BSEE alignment, processes, and linkages. Among the most important issues to address immediately are updates to the Environmental Compliance MOA and SOPs, and transfer of environmental oversight, facility inspection, and regulatory enforcement responsibilities for the OCS renewable program from BOEM to BSEE. ASLM should seek assistance from ASPMB, as needed, to provide support in matters that require a DOI-wide policy or economic review and in convening working groups to address specific matters.

Rigs to Reefs and Other Interagency Collaboration

BSEE is the principal regulator of offshore exploration and production activities; however, numerous other agencies have significant overlapping regulatory roles, most prominently USCG. BSEE has strengthened and clarified relationships with many of these agencies to fulfill important initiatives, employing memoranda of understanding or agreement and interagency agreements to align roles and responsibilities. One of the most complex initiatives with extensive relationships is the Rigs to Reefs program, which deals with the disposition of unused drilling platforms.

Rigs to Reefs: Fish and other marine life congregate around the underwater portions of unused structures, which provide habitat in the same way as natural reefs.[96] MMS worked with the National Marine Fisheries Service (NMFS), state agencies, and the oil and gas industry to explore how decommissioned platforms and other structures might be

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[95] Christopher J. Mihm, ***Virtual Reorganization: Results Mapping and Collaboration***, The Public Manager, June 15, 2011, available at: https://www.td.org/Publications/Magazines/The-Public-Manager/Archives/2011/Summer/Virtual-Reorganization-Results-Mapping-and-Collaboration.

[96] Bureau of Safety and Environmental Enforcement, ***ECD Rigs to Reefs*** (providing a general description of the reefs program), available at https://www.bsee.gov/what-we-do/environmental-focuses/rigs-to-reefs.

converted into beneficial artificial reefs. In 1984, NMFS published a National Artificial Reef Plan to guide the program. BSEE can approve the use of an obsolete structure as a reef if several conditions are satisfied:

- The state has a plan that complies with the National Artificial Reef Plan.
- The state agency obtains a permit from the U.S. Army Corps of Engineers (USCOE) for the obsolete structure to become part of the state program, and the state accepts title to and liability for the structure once it is situated to serve as a reef.
- The operator satisfies USCG navigational requirements.
- The proposal satisfies BSEE's engineering and environmental standards.

As of July 2015, 450 platforms had been converted to artificial reefs in the Gulf of Mexico. A typical large structure provides two to three acres of habitat, accommodating 12,000 to 14,000 fish and hundreds of different marine species.[97]

All of the Gulf of Mexico coastal states have approved artificial reef plans and have incorporated platforms into their programs, but Louisiana and Texas have the most incorporated platforms.[98] California also has adopted statutory authority for Rigs to Reefs, but, due to concerns expressed about the environmental impact of leaving rigs permanently on the OCS, no active Rigs to Reefs program exists in the state.

<u>Other Interagency Collaboration:</u> BSEE's role as the principal regulator of offshore exploration and production activities on the OCS requires effective collaboration and coordination with a number of other federal agencies. These relationships are supported by memoranda of understanding or agreement and interagency agreements as well as through ongoing coordination at headquarters and regional levels. BSEE continues to work on improving these relationships, which are described below and in additional detail in Appendix E.[99]

- **USCG**: The U.S. Coast Guard's responsibilities for oversight of safety and environmental protection overlap with BSEE's. While BSEE is focused primarily on the drilling and production aspects of OCS activity, the USCG focuses on maritime systems. Each agency has a relationship with industry and efforts to collaborate have helped to harmonize regulatory regimes to ensure consistency in standards and enforcement.
- **U.S. Department of Energy** (DOE): BSEE and DOE work closely together, primarily in areas of energy-related research, including through agreements with two of DOE's national laboratories.
- **U.S. Department of Transportation, Pipelines and Hazardous Materials Safety Administration** (PHMSA): Oil and gas produced on the OCS are generally

[97] Ibid.
[98] Bureau of Safety and Environmental Enforcement, ***ECD Rigs to Reefs*** (providing a general description of the reefs program), available at https://www.bsee.gov/what-we-do/environmental-focuses/rigs-to-reefs.
[99] Bureau of Safety and Environmental Enforcement, ***Interagency Collaboration***, available at https://www.bsee.gov/newsroom/partnerships/interagency.

transported to shore through pipelines regulated by PHMSA, and BSEE collaborates with PHMSA on safety, spill prevention and response, and pipeline rights-of-way.

- **U.S. Environmental Protection Agency** (EPA): BSEE and EPA work cooperatively to protect the environment using their respective statutory authorities.
- **U.S. Fish and Wildlife Service** (FWS) and the **U.S. Department of Commerce, National Oceanic and Atmospheric Administration** (NOAA): BSEE operates the Protected Species Program and monitors and protects species identified under the Endangered Species Act, which is administered by FWS and NOAA.

A report prepared in July 2013 by then-USCG Vice Admiral Brian Salerno, who was BSEE's Director from August 2013 through January 2017, includes a series of recommendations to strengthen and improve these interagency relationships.[100] It is primarily focused on BSEE's relationships with USCG but includes other helpful recommendations with regard to interactions between agencies and strategies to promote efficiency and effectiveness in the manner in which they carry out their responsibilities.

Decommissioning Responsibilities and Liabilities

When wells and pipelines become inactive or idle, federal regulations require that lessees and operators must permanently plug all wells, remove all platforms and other structures, clean or remove all pipelines, and otherwise clear the seafloor of obstructions created by operations.[101] Successful decommissioning is essential to avoid release of oil and gas and to otherwise maintain the ocean environment.

The potential cost of decommissioning facilities and equipment in the OCS is enormous. Approximately 2,996 active platforms exist in the OCS, more than 40 percent of which are more than 25 years old and approaching the end of their useful life.[102] The cost of decommissioning a deep water facility can run in the hundreds of millions of dollars. BSEE estimates that the liabilities for decommissioning facilities in the Gulf of Mexico would approximate \$33 billion,[103] and, according to BOEM, the liability for decommissioning in the entire OCS could reach approximately \$40 billion.[104]

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[100] Bureau of Safety and Environmental Enforcement, ***Building Stronger Connections, An Independent Look at BSEE's Interagency Partnerships and Their Regulatory Effectiveness***, July 5, 2013.

[101] See, generally, Bureau of Safety and Environmental Enforcement, ***Decommissioning,*** https://www.bsee.gov/site-page/decommissioning; Bureau of Safety and Environmental Enforcement, ***Decommissioning Liability Assessment Workshop***, available at https://www.bsee.gov/what-we-do/environmental-focuses/decommissioning; Government Accountability Office***, Offshore Oil and Gas Resources: Actions Needed to Better Protect Against Billions of Dollars in Federal Exposure to Decommissioning Liabilities,*** GAO-16-40, December 2015.

[102] Bureau of Safety and Environmental Enforcement, ***Environmental Focus: Decommissioning***, available at https://www.bsee.gov/what-we-do/environmental-focuses/decommissioning.

[103] Bureau of Safety and Environmental Enforcement, ***Fact Sheet, "Decommissioning Costs"***, November 2016, available at https://www.bsee.gov/sites/bsee.gov/files/fact-sheet//fact-sheet-decommissioning-costs-with-kevin-karl-and-jeremy-williams-revisions-october-27-2016-mbmns.pdf.

[104] Bureau of Ocean Energy Management, ***BOEM Announces Updated Financial Assurance and Risk Management Requirements for Offshore Leases: Notice To Lessees addresses facility decommissioning liabilities,*** July 14, 2016, available at https://www.boem.gov/press07142016//.

A regulatory program, administered in part by BSEE and in part by BOEM, seeks to ensure that lessees and operators fulfill their decommissioning obligations. When a company enters a lease or easement in the OCS, BOEM requires that the lessee provide financial assurance that it will be able to cover the estimated cost of decommissioning. This may require providing a bond or demonstrating the ability to self-insure. Then, when use of the facility is discontinued, it is BSEE's responsibility to ensure that wells are plugged, obsolete structures are cleared from the site, and pipelines are removed or cleaned. BSEE allows some platforms that meet stringent requirements to be toppled in place or towed for use as artificial reefs under the Rigs to Reefs program to attract and provide habitat for fish and other marine life.[105] Due to its role in overseeing decommissioning, BSEE is also responsible for estimating the costs and liabilities associated with decommissioning. BOEM relies on these estimates in determining the amount of bonding or self-insurance to require from lessees.

DOI considers platforms and other infrastructure on the OCS as potential liabilities, because, if lessees or operators cannot pay for decommissioning, the federal government might have to do so.[106] The risk of insolvency for some participants in the industry is exacerbated because continued low oil and gas prices have placed many operators under financial stress; and, while energy forecasts indicate that the oil and gas industry will eventually recover from its recent stagnation, this is not likely to happen quickly.[107] To protect the OCS and the taxpayer, both BSEE and BOEM have been taking a number of steps to reduce the risk of unfunded decommissioning costs:

- In December 2015, BSEE issued rules requiring operators to report summaries of their actual decommissioning costs for platforms, and in November 2016, BSEE issued rules to extend similar requirements for pipelines.[108] This information should allow BSEE to provide more accurate estimates of decommissioning costs, enabling BOEM to establish more realistic financial assurance requirements for lessees and operators.
- BSEE is updating its information management system and associated algorithms to generate more accurate cost estimates.

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[105] Bureau of Safety and Environmental Enforcement, ***What is Rigs-to-Reefs?,*** https://www.bsee.gov/faqs/what-is-rigs-to-reefs.

[106] Government Accountability Office, ***Offshore Oil and Gas Resources: Actions Needed to Better Protect Against Billions of Dollars in Federal Exposure to Decommissioning Liabilities***, GAO-16-40, December 2015, at pages 2-3.

[107] U.S. Energy Information Administration, ***Energy Forecast 2017***, January 5, 2017, http://www.eia.gov/outlooks/aeo/pdf/0383(2017).pdf.

[108] Bureau of Safety and Environmental Enforcement, ***BSEE Decommissioning Costs Reporting Rule Finalized***, December 3, 2015, available at https://www.bsee.gov/newsroom/latest-news/statements-and-releases/press-releases/bsee-decommissioning-costs-reporting; Bureau of Safety Environmental Enforcement, ***BSEE Releases Decommissioning Cost Reporting for Pipelines Rule,*** November 16, 2016, available at https://www.bsee.gov/newsroom/latest-news/statements-and-releases/press-releases/bsee-releases-decommissioning-cost.

- BOEM recently issued an NTL updating and clarifying its procedures and criteria for requiring financial assurance, in order to minimize the risk that inadequately bonded lessees and operators will be financially unable to pay decommissioning costs, which may have to be paid by the taxpayer.[109]
- BSEE is collaborating with BOEM, ONRR, DOI's Office of the Solicitor, and the Department of Justice to develop strategies for responding to potential or actual bankruptcy filings and to identify ways to reduce the risks to the OCS.

Even with these efforts, BSEE officials are concerned about potentially significant risks associated with operator bankruptcy and the potential consequences if operators are unable to fund the decommissioning for which they are responsible. Indeed, some industry representatives and consultants have stated that, while BOEM's tighter financial assurance guidance is intended to protect the OCS and the taxpayer against the consequences of operator bankruptcy, the new guidance "could possibly cause the very thing that it's trying to hedge against."[110] Moreover, the lack of funds to decommission OCS infrastructure may pose a particularly stark risk because no statutory funding mechanism is available to fill the void if no solvent operator can be identified to fund the decommissioning of infrastructure on the OCS. This contrasts with oil spills, for which cleanup can be funded through the Oil Spill Liability Trust Fund,[111] and hazardous contamination on land, for which cleanup can be funded through Superfund.[112]

The interplay of factors that must considered and balanced in addressing the risks posed by underfunded decommissioning costs, and the benefits and potential unintended consequences of possible measures to address those risks, pose substantial, national policy issues that are outside BSEE's mandate to resolve. Accordingly, the study team recommends that BSEE elevate these issues and possible solutions for the awareness and consideration by DOI and other national policy officials.

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[109] Bureau of Ocean Energy Management, Notice to Lessees and Operators***, Requiring Additional Security***, NTL No. 2016-N01, Effective Date: September 12, 2016, https://www.boem.gov/BOEM-NTL-2016-N01/. BOEM recently extended the effective date of the new requirements as to certain classes of lessees for several months. Bureau of Ocean Energy Management, ***BOEM Prioritizes Implementation of Risk Management and Financial Assurance Program: Provides Additional Time and Welcomes Stakeholder Engagement,*** January 06, 2017, available at https://www.boem.gov/note01062017//.

[110] Gallay, Annie, ***Gulf of Mexico: Shelf Life***, *Oil and Gas Investor,* January 5, 2017, available at http://www.oilandgasinvestor.com/gulf-mexico-shelf-life-1456941; ***Experts Predict Trouble Ahead for Gulf of Mexico Oil & Gas Operators,*** *Oil & Gas 360*, September 20, 2016, http://www.oilandgas360.com/experts-predict-trouble-ahead-for-gulf-of-mexico-oil-gas-operators; Josh Sherman, ***New BOEM Regulations Threaten Independent Gulf of Mexico Operators,*** *Offshore,* Sept. 12, 2016, available at http://www.offshore-mag.com/articles/print/volume-76/issue-9/departments/regulatory-perspectives/new-boem-regulations-threaten-independent-gulf-of-mexico-operators.html.

[111] Environmental Protection Agency, ***Oil Spill Liability Trust Fund***, available at https://www.epa.gov/oil-spills-prevention-and-preparedness-regulations/oil-spill-liability-trust-fund.

[112] Environmental Protection Agency, ***Superfund***, https://www.epa.gov/superfund.

Recommendation 3.6

BSEE should work with BOEM, ASLM, DOI's Office of the Solicitor, and others to elevate issues and provide supporting analyses related to the risk that financial stress in the oil and gas industry might result in some failure to conduct or fund needed decommissioning – issues include (1) choices in BOEM or BSEE regulatory or enforcement policy that might help mitigate those risks, and (2) the absence of a funding source for decommissioning in the event an operator is unable to pay these costs.

CHAPTER 4: STRATEGIC ALIGNMENT OF THE ORGANIZATION

BSEE is organized into national programs that align with its mission "to promote safety, protect the environment and conserve resources offshore through vigorous regulatory oversight and enforcement."[113] Program managers, located in headquarters offices and divisions, oversee and direct activities for offshore operations and regulation, environmental compliance, safety enforcement, safety and incident investigations, oil spill preparedness, and administration. National program managers are also assigned to key initiatives for data stewardship, permitting, inspections, and SEMS.

BSEE's organizational alignment by program brings consistency to headquarters and regional structures and functions so they can be managed in a coordinated way to achieve strategic goals and provides a foundation for efforts to optimize and integrate activities. Effective program management, by design, integrates and aligns functions and stakeholders toward the common end of managing change.[114]

In 2015, BSEE completed an organizational realignment to put national program managers in place for all of the bureau's major functions. In doing so it standardized the organization and reporting relationships, and clarified roles and responsibilities for headquarters functions and three regions. In so doing, BSEE followed many generally accepted best practices for organizational transformations, sought and secured approval from appropriate stakeholders for organizational changes, and addressed a number of long-standing recommendations from external reviews.

The realignment included the addition of two new divisions to focus on responsibilities for safety enforcement and safety and incident investigations. This will help BSEE to realize its full potential to ensure accountability for "a robust, effective, and aggressive safety and environmental enforcement regime based on rigorous analysis of best practices and the challenges presented by industry" that was envisioned when BSEE was created.[115]

BSEE also restructured its internal and external investigatory functions to improve their effectiveness, expanded capability for developing expertise in technological innovations, and undertook a data stewardship initiative to effectively manage and use data.

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[113] Bureau of Safety and Environmental Enforcement, ***Strategic Plan FY 2016-FY2019,*** December 21, 2015, available at https://www.bsee.gov/sites/bsee.gov/files/agendas/public-engagement/2016-2019-bsee-strategic-plan.pdf.

[114] National Academy of Public Administration, ***Improving Program Management in the Federal Government,*** A White Paper by a Panel of the National Academy of Public Administration, Sponsored by the Project Management Institute, July 2015.

[115] U.S. Department of the Interior, ***Implementation Plan In Response to the Outer Continental Shelf Safety Oversight Board's September 1, 2010 Report to the Secretary of the Interior***, September 4, 2010.

Realignment of the Organization

In 2015, BSEE created two new organizations: the Safety Enforcement Division and the Safety and Incident Investigations Division. BSEE also changed the name of the Environmental Enforcement Division to the Environmental Compliance Division and changed the reporting relationship for the regional environmental compliance functions. Although the realignment made minimal changes to the organization chart, it significantly changed the manner in which programs are operated on a national basis. The current organization depicted in Figure 4-1 below includes these changes.

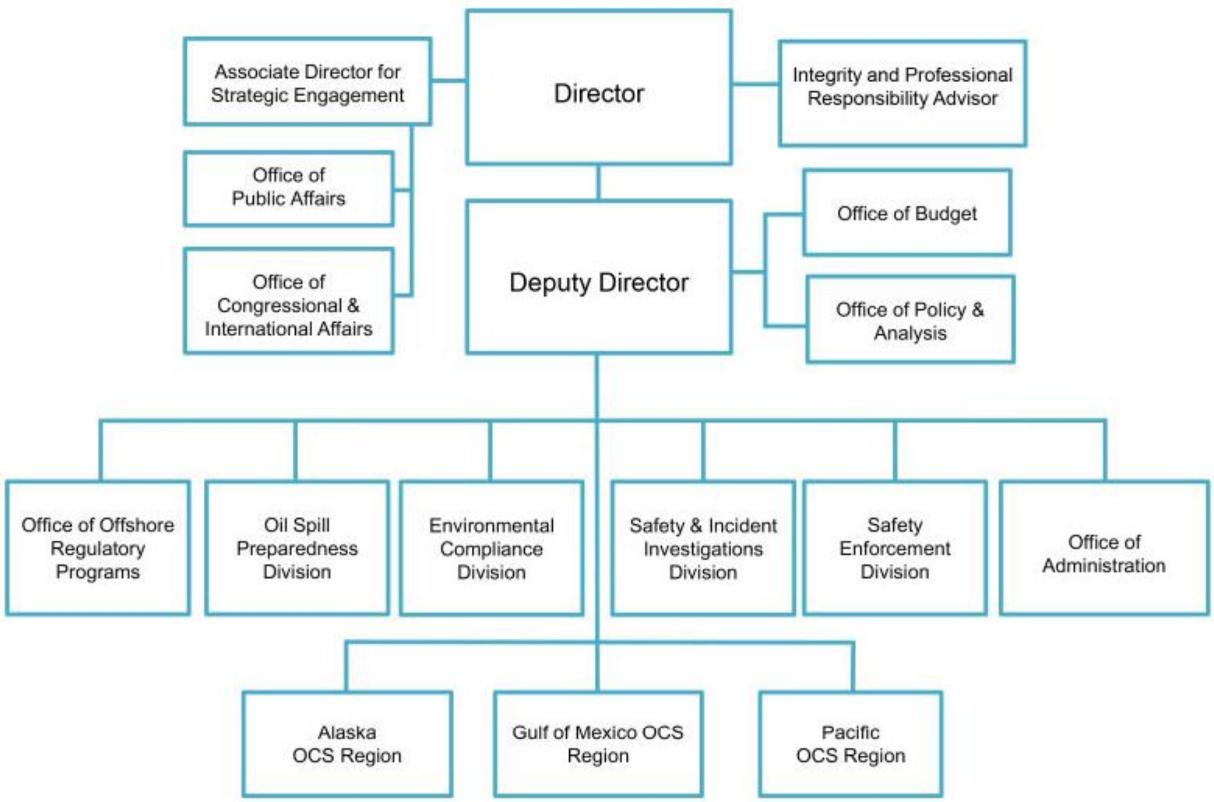

Figure 4-1 BSSE Organizational Chart 2016

The realignment implemented a national program management model to achieve consistent operations with national policy offices and regional operational entities. The realignment was the outcome of a deliberate process to modify the organization structure, roles and responsibilities, relationships, and processes in order to:

- Strengthen headquarters' policy development and strengthen field implementation across multiple BSEE divisions and mission areas.
- Establish clear roles and responsibilities in the divisions and enhance the organizational culture.
- Strengthen BSEE's capabilities to operate based on the guiding principles of BSEE's mission: transparency, consistency, predictability, and accountability.

BSEE's initial discussion of realignment began in December of 2013, when senior management used a structured process to systematically assess risks facing the bureau and align priorities for the future. The outcome of this process led to agreement on the need for better vertical alignment between headquarters and the regions on roles and responsibilities and better horizontal alignment among the regions. The discussion also identified the need to focus bureau efforts on key outcomes and create national programs for investigations, enforcement, technology, and data.

From these early discussions, BSEE began a process that involved extensive collaboration and consensus building with national and regional leaders and involvement of employees to refine plans for the realignment. A project team of subject matter experts led the effort, working with BSEE program and regional offices, to identify functional realignment options for data stewardship, investigations, and enforcement. Technology was addressed through a separate effort with creation of the Engineering Technology Assessment Center (ETAC), discussed later in this chapter.

Data stewardship was a focus area due to the importance of informed decision making that could be facilitated with modernized data systems, standardized data definition, and increased data accessibility. For investigations, the team identified a goal for more consistency through the increased use of data and clearly defined policy and standard operating principles—a key factor here was the use of information from the investigations to inform enforcement and inspection. The goals for enforcement included clear national policies and criteria for enforcement actions to increase consistency in taking action such as civil penalties and debarments. BSEE's project team evaluated the standard practices of private sector entities and other federal agencies with similar missions and functions and formulated organizational structure alternatives and courses of action.

In a June 2014 meeting, BSEE's leadership reviewed alternatives for restructuring and decided to adopt a national program management model. The model assigns to national program managers the responsibility for developing policy that would be consistently applied in the regions and field, while regional directors would be responsible for program execution in line with national policy. The decision was made to proceed with realignment planning for data stewardship, investigations, and enforcement programs and implementation planning teams were established to undertake the planning and design based on a set of milestones. Collaboration was specifically identified as a functional requirement for policy development in these national programs. The team completed their work and reported their results to BSEE leadership in September 2014.

As BSEE's implementation of the realignment progressed through the fall of 2014 and into the spring of 2015, Environmental Compliance was incorporated into the bureau's realignment planning and implementation efforts. BSEE leadership, interim program managers, and teams tracked and monitored the progress for implementation of the model for four programs: data stewardship, investigations, enforcement, and environmental compliance. The teams developed a management and governance dashboard that was used to guide decision making, monitor implementation progress, and identify and respond to project risks. BSEE modified timelines and adapted the implementation process to incorporate briefings of stakeholders. During the spring of 2015 policies and procedures were drafted and reviewed and the Director communicated high-level details of the realignment to keep bureau employees informed. BSEE developed a change management plan to promote strategic communication, leadership engagement, employee engagement, and training, as well as a change impact assessment to track change management activities.

Based on decisions made at a March 31-April 2, 2015 Senior Management Team Meeting, employees were assigned to work on program-specific teams to help with completion of priority actions, while regional implementation liaisons facilitated collection of field input to the teams. In the summer of 2015 the teams participated in the development of internal bureau guidance in the form of Bureau Interim Directives (BIDs) for the Safety and Incident Investigations Division (SIID), Environmental Compliance Division (ECD), and Safety Enforcement Division (SED) that were completed in April 2016. The teams produced detailed direction for model implementation, next steps to guide future work, and progress reports. In this same timeframe, BSEE established the Data Steward position to lead the Data Stewardship Program and the Data Stewardship Council to oversee and govern the program. BSEE also established the Integrity and Professional Responsibility Advisor (IPRA), discussed later in this chapter. A number of BSEE's FY 2016 priority action plans included implementation of national programs that were tracked through quarterly status updates with BSEE leadership. Managers committed to work plans and the Management Council reviewed quarterly progress in achieving work plan milestones.

The realignment became effective on November 4, 2015 with the creation of two new divisions, SIID and SED; renaming of the Environmental Compliance Division (ECD); and realignment of regional environmental compliance staffs who became direct reports to the regional directors. In the current organization, SIID, SED, and ECD, along with the Office of Offshore Regulatory Programs (OORP), Oil Spill Preparedness Division (OSPD), and the Office of Administration (ADA), house the national program managers. There are also designated national program managers assigned to key initiatives for data stewardship, permitting, inspections, and SEMS. The realignment also formally eliminated the Investigations and Review Unit (IRU), and divided its responsibilities into two components: the investigation of OCS incidents assigned to SIID and investigations of internal personnel matters assigned to IPRA.

BSEE's national program management model is based on the structure and functioning of other federal agencies that oversee multiple programs operated by geographically dispersed regional and/or local entities such as the USCG. Implementation of the model has the potential to standardize program direction and operations across BSEE's three regions for consistent application to operators and to facilitate ongoing coordination with other federal agencies thereby achieving principles defined in BSEE's strategic plan – clarity, consistency, predictability, and accountability.

The national program managers are tasked with leading a collaborative effort with the regions to develop policies, procedures, and business rules and to implement data-driven oversight of program operations in the regions. With these designated responsibilities they have the ability to become better informed; maintain current programmatic knowledge; represent and express the views of regional program experts in discussions at the bureau, Department and other levels; elevate important issues to bureau leadership; ensure adequate regional representation in establishing consistent national policy; and create a better melding of programs at the national and regional levels. This improved capacity for national oversight at the headquarters level addresses criticisms of MMS that headquarters had limited influence over regional and district operations.

Implementation of the National Program Management Model

During planning and preparation for the realignment, BSEE's Director maintained communications with employees to keep them informed about the status. Once the formal proposal for restructuring moved into the approval process in the summer and fall of 2015, the need to preserve decision-making space for DOI, OMB, and congressional stakeholders made it difficult for BSEE leadership to keep the organization fully informed.

Once the realignment was approved, BSEE did not provide the necessary support and follow through to ensure effective implementation in all programs and program initiatives By the time the realignment was approved, BSEE had disbanded its teams, discontinued use of the dashboard, and was not using tools that were developed during the early stages of the realignment including a change management strategy and a change impact assessment. Personnel changes in program leadership roles added to the implementation challenges in some of the programs.

Thus, BSEE's development of the national program management model and realignment efforts did not fully follow generally accepted best practices for managing change, which could have helped ease the transition to the new organizational structure and to changing roles and responsibilities.[116]

BSEE did follow best practices in the early phases of realignment planning, but implementation has faltered in some areas. An effective transformation process is important because employees and organizations need ongoing support for completing the realignment, which threatens the status quo and requires that employees break from traditional roles and practices. In interviews, the study team was told of continuing resistance to model implementation by some organizations and some individuals. This is likely due, in part, to inconsistent implementation, which makes it difficult for organizations and employees to assume their new roles. Even with fully effective implementation there can be resistance to organizational change. In a review of lessons learned from mergers and transformations, GAO found that there tend to be a relatively small group of employees in every organization who will resist change, refusing to engage

[116]Cohen, Dan and John Kotter, ***The Heart of Change,*** Boston: Harvard Business School Press, 2002; Government Accountability Office, ***Results-Oriented Cultures: Implementation Steps to Assist Mergers and Organizational Transformations***, GAO-03-669, July 2003; Marc A. Abrahamson and Paul R. Lawrence, ***Transforming Organizations***, Lanham, MD: Rowman and Littlefield Publishers, 2001.

in transformation regardless of how compelling the case for change may be. This group of employees may try to "wait it out" in the hopes that the transformation will pass without taking hold.[117]

BSEE should take steps to uniformly implement the model throughout the bureau, provide support to organizations and individuals that are not successfully adapting to new roles, and ensure high levels of collaboration. Successful implementation of the model requires that individuals and organizations collaborate and adhere to consistent roles and responsibilities and understand the consequences of departing from bureau direction. A set of actions tailored to each program and initiative that are coordinated at a bureau level could help BSEE to re-energize implementation, assist organizations and employees who are having difficulty shifting to new roles, overcome resistance, and identify where areas of intransigence remain. Ultimately, successful implementation of the national program model also requires a shift in organizational culture away from the former organization and processes and toward support for and a common understanding of BSEE's strategic vision and principles and operations based on modified roles and responsibilities and processes. As described in Chapter 8, a change management strategy would advance cultural change and increase the organization's capacity for collaboration, communication, and knowledge sharing. Implementation of the model should be a focus of BSEE's change management efforts.

BSEE's actions should incorporate effective practices that are demonstrated by two programs. The Academy study team heard in multiple interviews that the Division Chief for SIID was able to effectively implement the model for a national incident investigations program. The Division Chief worked collaboratively with the regions, provided effective leadership, and made a convincing case for change. The extensive consultation involving the regions and stakeholders required time and effort on the part of the participants, however, the resulting program is one in which the headquarters, regions, and districts appear to have ownership and should be sustainable and effective. SIID augmented high levels of collaboration and two-way communication with the development of a training program focused on program requirements including the investigatory processes and procedures. The Data Stewardship Program is also considered to be a successful model for national program implementation. It has effectively deployed a formalized governance structure with clear roles for headquarters and regional components, with effective communications about the goals and purpose, and maintains high levels of engagement.

Per best practices guidance for organizational transformations (included as Attachment G), a focused effort by a single individual or entity reporting to the Director or Deputy Director is needed to manage the process. This central point of coordination can facilitate other key practices, which include keeping senior executives and program managers engaged in leading the effort, using the strategic plan mission and goals to guide the process,

[117] Government Accountability Office, Comptroller General of the U.S., ***Highlights of a GAO Forum Mergers and Transformation: Lessons Learned from the Department of Homeland Security and Other Agencies***, GAO-03-293SP, November 2002.

establishing a schedule with milestones, using performance management to define organizational and individual responsibilities and ownership, and communication to internal and external stakeholders with the compelling reasons for adopting new roles and responsibilities.

While leadership, communications, performance management, tracking and reporting need to be consistently managed at the bureau level, specific actions necessary for implementation and the tools used by each program will vary. Bureau-wide communications should inform employees and stakeholders. For example, a summary of national programs modeled on Appendix F could be posted on the internet, with more detailed SOPs for each program made available on the intranet. Performance management should be used consistently bureau-wide to define expectations and ensure accountability for organizations and individuals, while the specific elements and measures included in performance plans should be tailored to program needs. The level of governance should be determined based on specific program requirements.

For programs that require more structure, designation of a governance body, such as a workgroup or team, can add structure and process that may be helpful to empower individuals and organizations to participate more effectively. The governance structures and process can be formalized as they are in the Data Stewardship Program, which includes a Data Stewardship Council, a Chief Data Steward, designated divisional and regional data stewards, business data stewards, and subject matter experts. Alternatively, a council may not be necessary as is the case with the Safety and Incident Investigations Program that has been able to define roles and responsibilities for individuals and offices, SOPs, training, and other program requirements that ensure BSEE will be able to fulfill its mission. Training could be offered broadly in areas that can help to promote needed skills including program management, collaboration, teamwork, and developing shared values. In addition, program focused training should address the particular needs to build required competencies. For example, SIID developed a training program to improve the investigatory competencies of BSEE staff.

BSEE's selection of an individual or entity to facilitate and champion these actions should consider an individual with expertise in program management as recommended by a recent National Academy of Public Administration study. This study found that program management capabilities are helpful to integrate and align diverse groups whose normal incentives often militate against effective participation.[118]

The study team suggests that the national program management model transformation effort be the focus of a more comprehensive BSEE change management strategy that is

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[118] National Academy of Public Administration***, Improving Program Management in the Federal Government,*** A White Paper by a Panel of the National Academy of Public Administration Sponsored by the Project Management Institute, July 2015. The study examined how to strengthen capabilities to undertake large, complex initiatives. The Panel determined that successful management of change depends on effective program management, a discipline that has evolved over the past few decades to address the challenges of managing such change initiatives.

focused on melding diverse cultures, improving collaboration, and building trust. Chapter 8 discusses the cultural change management proposal.

Recommendation 4.1

BSEE should complete implementation of the national program management model following best practices for organizational transformation tailored to the needs of individual programs and initiatives; the effort should be coordinated by a single individual or entity reporting to the Director or Deputy Director. The effort should be informed by lessons learned from the Safety and Incident Investigations and Data Stewardship Programs, in particular the high levels of collaboration, effective governance structures and processes, and training.

Investigations and Review Unit

BSEE's 2015 organizational realignment eliminated the Investigations and Review Unit (IRU) that was established in June 29, 2010 by Secretarial Order.[119] The IRU was originally created as a function within BOEMRE and was assigned to BSEE when responsibilities were divided between BOEM and BSEE. The IRU was created to:

- Respond to allegations or evidence of misconduct, unethical behavior, and unlawful activities, by employees and by members of the regulated industry;
- Oversee and coordinate internal auditing, regulatory oversight and enforcement systems and programs; and
- Assure swift response to emerging issues and assess significant incidents, including spills, accidents, and other crises.

The IRU also had a significant role in coordinating with the OIG and DOI's Ethics Office. The November 4, 2015 realignment separated the IRU's investigatory responsibilities into two separate components: (1) the Integrity and Professional Responsibility Advisor (IPRA) focused internally on organizational and employee conduct issues and (2) SIID focused on external investigations of reportable incidents by the regulated industry including coordination with OIG on investigatory matters. BSEE's Ethics Office, located in the Office of Administration is responsible for coordination with DOI's Ethics Office, BSEE's Office of Policy and Analysis is responsible for internal audit and coordination with the OIG related to audits. The balance of the duties of the IRU with respect to regulatory oversight, enforcement systems and programs, and response to emerging issues and incidents are now assigned to the national programs based on the nature of the matter.

The rationale for dividing the investigatory functions was to strengthen BSEE's ability to investigate industry incidents while preserving the independence of its internal review capabilities. The realignment and elimination of the IRU promotes greater consistency in the management of different types of investigations and allows for a focus on each. For the

[119] U.S. Department of the Interior, ***Secretarial Order 3304***, June 29, 2010.

investigation of incidents involving industry, the SIIDs investigation team in headquarters provides oversight of investigative activities supervised by regional and district managers. This arrangement fosters prompt responsiveness by avoiding the challenges of headquarters trying to supervise regional personnel. BSEE has established a tiered process for investigation and reporting of incidents, so that investigations are elevated to SIID under appropriate circumstances. Maintaining the initial investigation function in the field allows inspectors to apply the lessons learned to operations, a goal that was expressed by BSEE's Director early in the realignment process.

In interviews, the Academy study team was told that the separation of internal and external investigative functions removed a significant barrier for employees reluctant to elevate issues fearing that they would become a target for scrutiny. The team was also told that there are high levels of regional engagement with SIID in reporting and investigating operational incidents involving industry. This engagement is consistent with reports the study team heard about the extensive collaboration by SIID to develop roles and responsibilities, processes, and procedures for this program.

IPRA conducts investigations of employee misconduct, such as equipment misuse, inappropriate use of email, violations of the ethics code, travel violations, false statements, and hostile work environment allegations. IPRA also responds to employees about other matters referring them to other offices and individuals as necessary. IPRA is building increased understanding with employees about prohibited practices and resources available for employees and is undertaking a series of visits to the regions to inform and educate employees. In addition to advising BSEE employees and investigating incidents, IPRA also assists BOEM employees, through an interagency agreement.

The study team does not have a recommendation in this area, but encourages BSEE to continue development and maturation of the safety and incident investigations program as addressed by Recommendation 4.1 and to ensure high levels of coordination with IPRA.

Environmental Compliance Program

The BSEE realignment changed the name of the Division of Environmental Enforcement to the Division of Environmental Compliance. It also changed the reporting relationship for the regional staffs, which now report to the regional directors instead of the national program director in headquarters. These changes were not part of the initial realignment process that began in 2014, but were incorporated early in 2015 and subsequently included in implementation planning, communications, and briefings required to proceed through to approval and implementation.

Inclusion of the environmental program in the realignment brings a standard approach to all of the BSEE programs concerned with OCSLA oversight, regulatory compliance, and enforcement. That is, each program (OORP, SIID, ECD, and SED) includes a national policy function in headquarters and an operational component in the regions. The Oil Spill Preparedness Division, the Office of Administration (OA), and the Office of Public Affairs (OPA) do not fit this model because they have staff as direct reports to headquarters physically located in the regions. The study team was informed that these anomalies relative to regional reporting are appropriate because OSPD, OA, and OPA operate under different legislative authorities and are not as tightly linked as the others.[120]

The original concepts for the organization of environmental functions were developed in working sessions held in 2010 and 2011, and much of the discussion focused on how the function would be parsed between BOEM and BSEE. The working papers from these sessions evidences a broad discussion about the need to structure the environmental functions in a manner responsive to criticisms of MMS that environmental programs had insufficient voice from the lease sale through the post-plan approval process. The discussions advocated for separation of environment and leasing at the regional level, and adding an environmental compliance and inspection capability to follow through on mitigation. In subsequent materials produced by an interagency implementation team, options were developed for the division of environmental responsibilities between BOEM and BSEE and an organization structure for BSEE was developed with regional environmental enforcement organizations and staff reporting directly to the headquarters Environmental Enforcement Division.

In FY 2016, BSEE undertook an effort to better integrate and communicate environmental protection and compliance activities with development of the Environmental Stewardship Collaboration Group. The Director requested participation by BOEM and BSEE employees in a core group and participation by inter-agency advisory members representing cooperating federal agencies. They were directed to clarify and describe an environmental stewardship vision and mission in alignment with the BSEE strategic plan operational excellence goal for environmental stewardship. They were also asked to identify new ways to enhance environmental stewardship throughout BSEE by inculcating it into all mission areas including permit reviews, inspections, enforcement, research, regulation and standards development, and oil spill response planning.

The core group and inter-agency advisors were directed to complete a report with consensus recommendations and actions regarding:

- BSEE's environmental stewardship responsibilities;
- Coordination efforts with agency partners on environmental stewardship; and
- Tracking and communicating BSEE's environmental stewardship successes.

In July of 2016 the Environmental Stewardship Collaboration Core Group Final Report was completed. The Director announced that actions would be initiated based on the report's recommendations. He also issued a definition that: Environmental Stewardship is the responsibility of all BSEE employees to carry out to the highest standards all duties that contribute, directly or indirectly, to the management, protection and care of the coastal, marine and human environment. The report identifies constructive methods to improve environmental stewardship such as strengthening the BOEM-BSSE relationship with regard

[120] OSPD operates under authority of the Oil Pollution Act of 1990, 33 U.S.C. § 2701 et*et seq*.

to environmental compliance, integrating BSEE's environmental experts into program decision making processes, and establishing an internal working group to strengthen collaboration agreements and MOA and MOU. The report includes appendices that provide specific recommendations for integration of environmental stewardship into all bureau programs and specific direction to modify MOA and MOU.

The Academy study team was told that the report received a mixed reception within BSEE and there was resistance at both the headquarters and the regional levels to implementation of the recommendations. As a result, the effort stalled and BSEE has not implemented a systemic approach to environmental stewardship that could optimize agency expertise and outcomes and improve compliance and enforcement.

The Academy study team considered this historical information, the February 2016 GAO review of BSEE's restructuring,[121] and interviews with BSEE employees. The study team was told that the current organization for regional environmental compliance staff reporting to the regional director could function effectively if lines of communication stay open to ensure issues are appropriately elevated within the regions and with headquarters, collaborative relationships are operating so that effective exchanges of information take place between headquarters and the regions, and there is sufficient input by regional subject matter experts in policy development and ongoing program direction. The study team believes that BSEE should conduct an examination of the BSEE environmental compliance function relative to the original division of responsibilities between BOEM and BSEE, alignment of the program with strategic goals, the recommendations of the Environmental Stewardship Collaboration Core Group, and consideration of alternative courses of action and risk assessment. This process should include a full vetting of proposals to combine environmental inspections with safety inspections, ensuring effective communication among the regions and with headquarters, and full involvement of environmental compliance staff in permit reviews. These actions require the engagement of headquarters and regional participants in an effectively coordinated process leading up to the completion of a formally documented decision about how the environmental compliance program will operate with defined activities, work streams, outputs, roles and responsibilities, and staffing plans for headquarters and the regions.

Once this process is completed, BSEE will be able to make staffing decisions. This process will also be the basis for effective implementation of the national program management model, which should include high levels of collaboration and communication between the regional environmental compliance functions and the headquarters function, clearly understood roles and responsibilities, and engagement of regional experts in the development of nationally applicable policies and procedures. An effort that engages headquarters and the regions and clearly communicates and documents rationales for

[121] Government Accountability Office, ***Oil and Gas Management: Interior's Bureau of Safety and Environmental Enforcement Restructuring Has Not Addressed Long-Standing Oversight Deficiencies***, GAO-16-245, February 2016.

decisions would allow for a more unified effort across BSEE and a transparent process for stakeholders.

Recommendation 4.2

BSEE should produce a program management design for the Environmental Compliance Program that considers the history of the program's organization and functions as well as the work of the Environmental Stewardship Core Group. The design should detail the activities, work streams, outputs, and outcomes. The design should include workforce plans for headquarters and the regions that can be the basis for staffing decisions, addressing gaps in competencies, and effective implementation of the national program. The process should include an assessment of risk related to reporting relationships as well as appropriate internal controls and risk mitigation measures to ensure the function can effectively achieve mission goals.

Regional Realignments

In order to support the national program management model and facilitate alignment with headquarters, the regional offices completed restructuring. The Academy study team did not have an opportunity to conduct a sufficiently detailed review of these changes in order to provide findings or recommendations.

Engineering Technology Assessment Center

In 2015, BSEE established the Engineering Technology Assessment Center (ETAC) to facilitate its ability to keep pace with industry innovation and technology advances. The planning and strategic visioning for this action began in 2013. The goal was to develop a center of expertise to provide knowledge about emerging technology to BSEE's regions and collaborate with academic institutions, the Offshore Energy Safety Institute (OESI), API, and other standard setting bodies. Creation of ETAC was based on an evaluation of industry practices and an assessment of other federal agencies' actions to improve technological expertise by drawing on individuals and organizations in the public and private sector. In creating ETAC, BSEE responded to multiple OIG and OCS Safety Oversight Board recommendations to secure technical expertise needed to review and vet standards, evaluate equipment and operations in the context of the operating environment, and conduct comprehensive reviews of plans.[122]

ETAC is located in Houston, near oil and gas operators, regulators, and manufacturers. It is in its start-up phase, but when fully operational will be a focal point for evaluating emerging technology intended for use in offshore environments, increasing safety, and

[122] Department of the Interior, Office of Inspector General, ***A New Horizon: Looking to the Future of the Bureau of Ocean Energy Management, Regulation and Enforcement,*** December 2010 and U.S. Department of the Interior, Outer Continental Shelf Safety Oversight Board, ***Report to Secretary of the Interior Ken Salazar***, September 1, 2010.

decreasing risk from offshore oil and gas activities. It will provide an additional proficiency for BSEE to augment current technology assessment functions and assist headquarters and regions in developing new offshore oil and gas regulations and evaluating proposed industry standards. Finally, ETAC's engineering staff will be evaluating and using real-time monitoring information being developed by industry. With a small staff, ETAC will manage a flexible base of engineering contracts to support up-to-date expertise in offshore oil and gas technology, equipment development, failure analysis, and testing protocols. ETAC is also establishing professional relationships with equipment manufacturers in the Houston area to keep abreast of the latest developments in offshore oil and gas equipment technology. When the study team was conducting its assessment, ETAC was being staffed and had not yet become the resource it can be for programs and regions. In order to optimize use of the Center by BSEE's operational programs in the regions, there needs to be a greater effort to communicate why ETAC was created, the value it can add to BSEE's mission, and to establish relationships and communication channels between ETAC and the regions. A formal governance structure to create a mechanism for two-way communication between the regions and OORP (who operates ETAC) would be optimal.

Regional staff could be better informed about BSEE's relationship with OESI as well. OESI facilitates knowledgeable transfer in order to promote safety and environmental stewardship in offshore operations. In November of 2013, BSEE entered into an agreement with the Texas A&M Engineering Experiment Station's Mary Kay O'Connor Process Safety Center to manage the OESI as a forum for cooperative research among academia, government, industry, and other non-government organizations in offshore-related technologies.[123] OESI provides a venue for BSEE to draw from experts to improve understanding of scientific and technological developments in the offshore industry and continue to develop the competencies of BSEE's employees.

Recommendation 4.3

BSEE should improve the linkage between ETAC and the regions by expanding outreach and engagement and developing a formal governance body and process to ensure high levels of two-way communication between the regions and Office of Offshore Regulatory Program (OORP).

<u>Data Stewardship and Knowledge Management</u>

Information and knowledge are critically important for BSEE to achieve its mission. BSEE's strategic plan includes an organizational goal: "Information: We consistently collect, analyze, and use quality information to drive decision making." The goal is supported with

[123] Bureau of Safety and Environmental Enforcement, ***BSEE and Texas A&M Engineering Experiment Station Announce Agreement,*** November 7, 201, available at https://www.bsee.gov/newsroom/latest-news/statements-and-releases/press-releases/bsee-and-texas-am-engineering-experiment.

a strategy: "Enhance BSEE's decision-making through the collection, management, and analysis of high quality information."[124]

The Data Stewardship Program gives focus to BSEE's information-based efforts and treats data as an asset that should be effectively managed with consistent policies and procedures. The Program has established a common base of understanding in BSEE about the importance of quality data and has as its goals to ensure that (1) bureau staff all use the same data, (2) data is accurate, and (3) data is consistently captured, defined, and stored. BSEE's data stewardship philosophy includes consistency in definitions, shared responsibility by all employees for stewardship of the data, and ownership at the point of entry. The program's benefits extend beyond data management and include improved collaboration using common data sets, improved program oversight and management using data-driven approaches, and improved automation of processes to facilitate internal processes and both internal and external communications.

BSEE has the foundational elements in place for this program with a full-time Data Steward, clearly defined roles and responsibilities, and a Data Stewardship Council. BSEE developed common metadata standards, a data dictionary and taxonomy, SOPs for consistent data collection, a process for insuring data quality, data stewardship training, and a governance structure in which data needs are identified by the national program managers, largely based on data in past reports that have been found useful. In addition, BSEE has developed a detailed business and information technology (IT) architecture that maps business components, data ownership, data exchange, and subsystems.

While the Data Stewardship Program is increasing the quality and consistency of information, BSEE has also invested in upgrading its IT environment and applications and is developing a business intelligence tool to improve the assimilation of and access to information. Much progress appears to have been made toward goals for data quality and consistency and improved access through IT infrastructure. There are additional opportunities for BSEE to promote information sharing. A consistent theme heard in interviews conducted by the study team in this assessment was that there is reluctance, or even an inability, to share information across organizational units.

Many, if not most, of BSEE's activities require knowledge and information sharing, internally among BSEE offices, and externally with BOEM, industry, other agencies, and the public. Ultimately, information sharing should enable a feedback loop among programs that leads to continuous performance improvement. For example, inspections and SEMS audits may uncover incidents of non-compliance and evidence needed to inform investigation decisions. The outcome generates knowledge that may justify enforcement actions and strengthen oversight.

BSEE also collects and analyzes information provided by industry. For example, industry reports near-miss data through a third party that provides this information to BSEE in an aggregate form to protect confidentiality. BSEE then uses it as the basis for issuing safety

[124] Bureau of Safety and Environmental Enforcement, ***Strategic Plan FY 2016-2019,*** December 21, 2015.

alerts that help prevent recurrence of particular types of incidents and improve safety. BSEE relies on BOEM for information from NEPA assessments to carry out its environmental compliance mission. Permitting and regulatory decisions need to be informed by understanding of emerging technologies used by industry, and require the ability to evaluate their use in deep water and Arctic environments.

The effective use of information therefore depends on the bureau's capacity to share it. To advance knowledge sharing, BSEE could benefit from the development and piloting of a more proactive and structured knowledge management strategy that would complement the existing data stewardship and IT initiatives, with additional elements that enable or strengthen knowledge sharing and collaboration.

A fundamental best practice for knowledge management (KM) is to develop it in a staged process, beginning with pilots for selected critical areas of knowledge. The pilots should be guided by a framework tailored to organizational needs. The framework should identify components associated with four pillars: people, processes, technology, and governance. It is important to consider tools and processes that enable capture and sharing of tacit and context-specific knowledge, for example, through the establishment of communities of practice for critical areas of knowledge that develop KM plans specific to their knowledge areas.

For BSEE, the suggested initial scope and priority focus for KM is on internal knowledge sharing, which would also support organizational knowledge retention and learning. BSEE already has several elements of a KM framework, including the Data Stewardship Program and IT architecture, for which people, processes, technology, and governance are in place. The employee engagement survey (discussed in Chapter 8) documents challenges associated with knowledge sharing and the need for interaction across programs. It also suggests several supporting tools. Building on these, a more complete knowledge assessment should review the knowledge cycle to identify remaining gaps and tools that can be used to address them. Key questions for assessment are: What prevents the flow of information? What is needed to enable it? This information would be used to close important feedback loops in the flow of knowledge between programs, as well as between decisions and outcomes. It should also identify critical knowledge areas, which are suggested by the strategic risks identified as part of ERM.

A KM pilot would evaluate practices for capturing as well as sharing implicit and tacit forms of knowledge through face-to-face or online interactions, such as mentoring, "peer assists," wikis, blogs, after-action-reviews and various types of learning events or training. A more recent development in KM is the use of additional tools for leveraging collective knowledge to address complex challenges. These include joint sense-making exercises, which convene and engage appropriate people who can bring different perspectives to a complex challenge, along with online crowdsourcing tools such as social media, wikis, and blogs, all of which enable leaders to draw on a wider base of thinking.[125]

Pilots are ideally selected for their ability to demonstrate the organizational benefits of KM and provide lessons that can be used for course correction. Full-scale implementation should be supported by a change management plan and an individual who serves as a facilitator for the program, with the support of a designated team that reports to a cross-organizational steering group or advisory council as discussed in Chapter 8.

BSEE may want to consider participating in the Federal Knowledge Management Community, which shares best practices and lessons learned across federal agencies. Among the recognized federal KM initiatives are those of the National Aeronautics and Space Administration (NASA), U.S. Agency for International Development, and U.S. Army.[126] The oil and gas industry is also a source of some important KM case studies.[127]

These cases provide a wealth of lessons from experience that may be relevant in developing a KM approach that is appropriate for BSEE. NASA's Knowledge Services Program may be of particular interest. NASA shares many challenges similar to those of BSEE in that it has a highly technical mission focused on managing risk and has been shaped by high profile defining events, beginning with the Challenger disaster in 1986. An important lesson from the Challenger and Columbia disasters was that, beneath the technical root causes, there was poor team communications and a lack of organizational learning. NASA's formal KM program was established in 2011, in response to a recommendation of the Aerospace Safety and Advisory Panel that found a need for a more systematic approach to capturing implicit and explicit knowledge. [128]

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[125] Dixon, Nancy M., ***The Three Eras of Knowledge Management–Summary***, *Common Knowledge Associates,* 2010, available at http://www.nancydixonblog.com/2010/08/the-three-eras-of-knowledge-management-summary.html.

[126] Hoffman, E. and Boyle, J., ***R.E.A.L Knowledge at NASA: A Knowledge Services Model for the Modern Project Environment***, *Project Management Institute,* 2015, available at: http://www.pmi.org/-/media/pmi/documents/public/pdf/white-papers/real-knowledge-nasa.pdf; Hoffman, E. and Boyle, J. 2014. ***Managing Mission Knowledge at NASA***, at https://www.td.org/Publications/Magazines/TD/TD-Archive/2014/07/Managing-Mission-Knowledge-at-NASA; Rogers, E.W. (CKO Goddard Space Flight Center), ***Building the Goddard Learning Organization: A knowledge management architecture of Learning Practices to help Goddard function more like a Learning Organization***, 2011; United States Agency for International Development, Learning Lab, ***Collaborating, Learning and Adapting Framework and Maturity Model***, October 27, 2016, available at <https://usaidlearninglab.org/library/collaborating%2C-learning%2C-and-adapting-cla-framework-and-maturity-matrix-overview; U.S. Army, ***Knowledge Management Principles***, available at http://usacac.army.mil/cac2/AOKM/AOKM2008/A4%20Doc%201%20AKM%20Principles%2025%20JUN%2020081.pdf.

[127] Gorelick, C., Milton N. and April K., ***Performance through learning: Knowledge Management in Practice***, New York: Routledge, 2004; Elsevier Butterworth-Heinemann, Oxford UK Chapter 7: British Petroleum's Knowledge Management Journey A Decade of Change. By Nick Milton and Carol Gorelick in conversation with Kent Greenes.

[128] Hoffman, E. and Boyle, J., ***R.E.A.L Knowledge at NASA: A Knowledge Services Model for the Modern Project Environment,*** *Project Management Institute*, 2015, available at http://www.pmi.org/-/media/pmi/documents/public/pdf/white-papers/real-knowledge-nasa.pdf.

The environmental compliance program might serve as a useful pilot program for BSEE to consider, given that it needs to better define information needed to support the mission both from BOEM and internally, from subject matter experts. Establishment of a community of practice would strengthen the capacity to share data and expertise across regions. A knowledge assessment and management strategy would also support the clarification of roles and responsibilities in this program.

Panel Recommendation 4.4

BSEE should develop a knowledge management (KM) strategy that complements the existing Data Stewardship Program and IT program with tools that enable knowledge sharing and close gaps in the knowledge cycle. As part of this strategy, BSEE should consider establishing communities of practice for critical areas of knowledge to facilitate organizational knowledge retention, knowledge sharing, and learning. A KM pilot for a critical area of knowledge can be used to demonstrate the benefits of KM and inform the strategy prior to full-scale implementation.

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CHAPTER 5: OPERATIONAL AND ORGANIZATIONAL EXCELLENCE

The Government Performance and Results Act of 1993 (GRPA) and GPRA Modernization Act of 2010, in combination with direction issued by OMB, establish requirements for the 24 federal departments and major agencies to publish strategic plans, annual performance plans, and annual performance reports and to operate a strategic review process as part of an effective performance program.[129][130] DOI complies with these requirements and issues a department-wide strategic plan and annual performance plans and reports. DOI also conducts a strategic review process as part of its performance program. DOI's FY 2014-2018 Strategic Plan is comprised of six mission areas. BSEE's mission is incorporated within the area focused on the responsible use of the nation's resources and BSEE's operational goals are subsumed within DOI Mission Area 3, Powering Our Future and Responsible Use of the Nation's Resources. BSEE's goals for organizational excellence align with a set of departmental principles and management goals.[131]

There is no statutory or other requirement for BSEE to issue a stand-alone strategic plan. In the five years since it began operations, BSEE has issued two strategic plans. BSEE's second strategic plan, issued in December of 2015, is significantly matured from the first plan issued in October of 2012. The current plan was developed through a collaborative process involving a broad representation of internal stakeholders and significantly engaged the senior leadership team. As OMB recommends in its direction regarding strategic planning for departments and agencies, BSEE considered risk in the planning process and is incorporating strategic foresight to inform planning and prepare for the future.

Also consistent with practices recommended by OMB, BSEE's performance management program includes a regular cycle of organizational performance reviews conducted with leadership to evaluate a consistent set of information and metrics. BSEE is continuing to refine and develop new performance measures to inform program management and uses the strategic plan long-term initiatives to guide prioritization of annual actions. BSEE also uses enterprise risk management to identify and manage risks to performance.

As OMB describes in Circular A-11, strategic planning serves a number of important management functions related to achieving an agency's mission, including:

- Communicating to agency managers, employees, delivery partners, suppliers, Congress, and the public a vision for the agency and its future;

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[129] P.L. 103-62, 107 Stat 285, August 3, 1993 and P.L 111-352, 124 Stat. 3866, January 4, 2011.
[130] Office of Management and Budget, ***Circular No. A-11***, 2016, available at https://obamawhitehouse.archives.gov/omb/circulars_a11_current_year_a11_toc.
[131] U.S. Department of the Interior, Strategic Plan for Fiscal Years 2014-2018, available at https://www.doi.gov/sites/doi.gov/files/migrated/bpp/upload/DOI-Strategic-Plan-for-FY-2014-2018-POSTED-ON-WEBSITE.pdf.

- Aligning resources and guiding decision-making to accomplish priorities to improve outcomes;
- Informing agency decision-making about the need for major new acquisitions, information technology, strategic human capital planning, evaluations, and other evidence-building and evidence-capacity building investments; and
- Helping agencies invite ideas and stimulate innovation to advance agency goals.[132]

The actions that BSEE has taken thus far to use strategic planning to help drive organizational performance, maturity, and transformation are notable. The Academy study team identified areas where additional effort can advance these efforts.

FY 2016-2019 Strategic Plan

BSEE's current strategic plan, released in December 2015, establishes a vision for the bureau's future state and sets operational and organizational goals used by the bureau and its partners to guide collective efforts working toward this future state.[133] A summary presentation of the FY 2016-2019 Strategic Plan is shown in Figure 5-1 below.

The plan's operational excellence and organizational excellence goals cascade down to a set of strategies and initiatives. The three operational excellence goals for safety, environment, and conservation are supported by four strategies and 14 initiatives that focus on multi-year reforms in how BSEE does its work. The bureau uses these to guide the prioritization of annual actions with milestones to achieve interim results. BSEE's three strategic goals for organizational excellence focused on people, information, and transparency are supported by 6 strategies and 22 initiatives that also help the bureau set priorities for annual action plans. The strategies in the current plan are crosscutting to promote the integration of programs in areas including detecting noncompliance, risk-based decision making, and improving employee engagement. The initiatives in the plan that identify specific steps to support the strategies are intended to be dynamic and are reviewed regularly by BSEE leadership as they prioritize and sequence annual action plans.

BSEE's FY 2016-2019 Strategic Plan reflects maturation from the original (FY 2012-2015) plan, including more specific goals with greater definition of desired outcomes, and information about the goals that will be achieved. The current plan reflects the bureau's refinement of strategy, moving beyond the earlier plan's more output-focused operational goal to regulate, enforce, and respond to OCS development to three operational goals that focus on outcomes in safety, environmental stewardship, and conservation. Likewise the organizational goal in the original plan focused on establishing the bureau, including "building and sustaining" the organization, whereas the current plan includes three goals

[132] Office of Management and Budget, ***Circular No. A-11***, 2016, available at https://obamawhitehouse.archives.gov/omb/circulars_a11_current_year_a11_toc.
[133] Bureau of Safety and Environmental Enforcement, ***Strategic Plan FY 2016-2019***, December 21, 2015, available at https://www.bsee.gov/agendas/public-engagement/2016-2019-bsee-strategic-plan .

that envision a world-class organization and is an employer of choice, uses quality information, and promotes transparency.

<table>
<tr><td colspan="2" align="center">Mission
To promote safety, protect the environment and conserve resources through vigorous regulatory oversight and enforcement

Vision
Fostering an agile, trusted, and collaborative organization dedicated to reducing risk offshore

Principles
Clarity, consistency, predictability, accountability</td></tr>
<tr><td>Operational Excellence Goals
• Safety: We reduce risk to those working offshore by advancing a culture of safety that encourages industry to go beyond baseline regulatory compliance.
• Environment: We promote environmental stewardship through integrated prevention, compliance, and preparedness activities.
• Conservation: We actively identify and pursue opportunities to improve oil and gas recovery and ensure accurate production measurement.</td><td>Organizational Excellence Goals
• People: We are an employer of choice: we value, engage, and support our people so they can excel.
• Information: We consistently collect, analyze, and use quality information to drive decision making.
• Transparency: We promote transparency through processes that ensure consistency, efficiency, accountability, and collaboration.</td></tr>
</table>

Figure5-1 BSEE FY 2016-2019 Strategic Plan

In the fall of 2013, BSEE leadership began to define its vision that evolved into the principles in the FY 2016-2019 Strategic Plan: clarity, consistency, predictability, and accountability.[134] Development of the plan began in December of 2014 and a project team was established in 2015 to develop a future state for BSEE that could advance these principles.

BSEE's plan development generally mirrors best practices, with planning across organizational operating units[135] including staff from all levels of the organization. Senior leadership, representing all of the organizational components, engaged in several phases of plan development including examination of the bureau's current state and visionary future state. Through an iterative process, BSEE developed goals and strategies to align bureau efforts to attain the visionary future state, vetted the draft strategic plan with programs, and informed employees about the plan through a sustained process of engagement.

[134] Bureau of Safety and Environmental Enforcement, ***Strategic Plan FY 2016-2019***, at https://www.bsee.gov/agendas/public-engagement/2016-2019-bsee-strategic-plan.
[135] Office of Management and Budget, ***Circular A-11/Section 230***, July 1, 2016.

Although there was significant input by internal stakeholders, the study team did not find evidence of outreach with external stakeholders, a practice that is recommended by OMB.

BSEE's plan development process included consideration of risks to ensure that the strategic direction and messaging embedded in the plan effectively support the bureau's priorities for safety, environmental protection, and conservation. These efforts to align goals, strategies, and initiatives based on risk, advanced BSEE's risk management competencies and the use of enterprise risk management (ERM). BSEE's deployment of an ERM program is responsive to OMB direction to identify and manage risks to performance and achievement of strategic objectives.[136]

With the advent of a new Administration, DOI will begin to develop a new strategic plan, as required by the GPRA Improvement Act.[137] OMB's timeline indicates that draft agency plans are due to OMB by June 2, 2017.[138] BSEE's strategic planning program will be well positioned to participate in this process, although a working group could help inform and communicate the results of this effort.

<u>Performance Management</u>

BSEE's Office of Policy and Analysis (OPAA) manages the strategic planning process and the ERM program. OPAA coordinates and leads BSEE's quarterly performance review process that involves BSEE's senior leadership and incorporates and integrates consideration of program performance metrics, funding and staffing resources, status of work plans and annual action plans, and the status of implementation of OIG and GAO audit recommendations. BSEE's organized approach to conducting regular, routine evaluations of performance and use of a set of organizational metrics is a best practice based on OMB[139] and GAO guidance.[140]

BSEE has actions planned and underway to mature the bureau's performance management framework, including the following:

- OPAA is working with program managers throughout the bureau to identify, pilot, and evaluate measures that support implementation of the FY 2016-2019 Strategic Plan. Once developed, the measures will expand on performance information and

[136] Office of Management and Budget, ***Circular A-11, Section 270,*** Performance and Strategic Reviews, July 1, 2016.
[137] ***Government Performance and Accountability Act of 2010***. Public Law 111-352, 124 Statute. 3866, January 4, 2011.
[138] Office of Management and Budget, ***Circular No. A-11***, 2016, available at https://obamawhitehouse.archives.gov/sites/default/files/omb/assets/a11_current_year/s230.pdf.
[139] Office of Management and Budget, ***Circular A-11, Section 270 Performance and Strategic Reviews***, July 1, 2016.
[140] Government Accountability Office, ***Managing for Results: Practices for Effective Agency Strategic Reviews***, GAO-15-602, July 29, 2015.

strengthen the ability of national program managers to conduct data-driven performance and progress reviews.

- BSEE is developing a leadership dashboard to include a set of information that will keep leadership informed about performance outcomes, including information used in organizational performance reviews held with BSEE leadership.
- BSEE has developed a Foresight Initiative to inform its ability to prepare for the future. The Initiative considers energy development and operations in the coming decade with input from energy experts to identify trends and consider future threats and opportunities, assess risks, and inform strategic planning and the development of capacities and competencies.

BSEE's leadership demonstrates its commitment to use of the strategic plan and communication through the Director's messaging and distribution of the plan in the BSEE annual report. These efforts to improve employees' understanding of the plan and its relevance to their work has the potential to advance bureau efforts to improve collaboration and build consensus around the bureau's priorities. According to an employee engagement survey conducted in 2016, an overwhelming majority of employees (88 percent) stated that they are able to relate to BSEE's mission. However, only 45 percent of the employees surveyed said they have seen the strategic plan, and just 24 percent of employees outside of headquarters indicated that they had seen it. This is a lost opportunity since the plan communicates the bureau's vision, principles, and priorities and is a tool to increase employee engagement, align work efforts, and gain input to inform future planning. Reactivation of the working group that participated in developing the plan, comprised of cross-program and cross-regional representatives, could promote communication of the plan and improved understanding of bureau priorities and initiatives. Selection of the members of the group should consider the ability of the members to be advocates and change agents within their organizations.

BSEE is taking important steps to assess the needed future state beyond the scope of the current strategic plan and evaluating trends that will impact bureau programs. The study team recommends ongoing support for the Foresight Initiative, as this process can help BSEE to anticipate and guide the development of infrastructure and processes and put in perspective the current pace of development of oil and gas in the OCS, how that may change in the future, and the impact on BSEE's programs and workload. OMB recommends that agencies integrate strategic foresight in the planning process as BSEE has done.[141] This ability to look ahead and inform operational and organizational alignment is among GAO's seven practices that federal agencies can use to facilitate effective strategic reviews, including evaluation of what would constitute success in ten years for each strategic objective to better plan for and understand near-term progress toward long-term outcomes.[142] The study team also encourages BSEE to continue its careful and deliberate efforts to develop new performance measures that can help to inform managers and senior

[141] Office of Management and Budget, ***Circular A-11/Section 230***, July 1, 2016.
[142] Government Accountability Office, ***Managing for Results: Practices for Effective Agency Strategic Reviews***, GAO-15-602, July 29, 2015.

leadership and assist the national program managers to access data that can be used in performing their oversight roles.

Recommendation 5.1

Establish a working group comprised of program and regional representatives, in order to promote improved awareness of and engagement in strategic planning, inform the process for annual priority setting, and expand the use of risk management. Selection of the members of the group should consider the ability of the members to be advocates and change agents within their organizations and the team should be operational in time to assist with BSEE's participation in the development of a new DOI strategic plan.

Recommendation 5.2

BSEE should institutionalize its Foresight Initiative to provide input to strategic planning and risk assessment and to help anticipate and guide BSEE's programs and operations.

<u>Annual Action Plans</u>

BSEE's annual action plans guide completion of short-term operational and organizational initiatives and support interim progress in longer-term transformation, including the development of policies and procedures, regulatory updates, and program pilots. The identification and prioritization of these projects is dynamic, reflecting ongoing discussion by BSEE's Management Council and external and internal influences. In producing its 2016 Action Plan, BSEE's developed plans and timelines for 43 projects. The development of project work plans to lay out details and milestones for these projects demonstrates BSEE's commitment to improvement and reform and maintaining high levels of performance. The bureau realized that it was not feasible to expect that all of these projects could be completed within the specified timeframes given the competing demands on the individuals assigned these tasks, and subsequently the initiatives were prioritized and reduced in number – a positive step for focusing effort on a smaller set of achievable outcomes.

The study team suggests that a more rigorous process to prioritize and sequence BSEE annual actions over a multi-year period could help to ensure that results meet expectations and that commitments align with the capacity of managers and programs. Centralized development of annual plans and coordination of the multi-year planning process by OPAA should include prioritization and sequencing of tasks, taking risk assessment into account, assignment of roles and responsibilities for leadership and participation, progress tracking and reporting, and follow-up.

Recommendation 5.3

BSEE should enhance its annual and multi-year planning to include prioritization and sequencing of tasks, taking risk assessment into account, assignment of roles and responsibilities for leadership and participation, tracking progress, and following up.

Enterprise Risk Management

Risk management is at the core of BSEE's mission. BSEE recognizes the importance of risk with a strategic plan goal to "reduce risk to those working offshore" and a strategy to "incorporate risk-based decision making into our core safety functions." In support of this mission, BSEE is implementing an ERM Program.

The ERM Program is a bureau-wide initiative that is required by OMB in all federal agencies.[143] It offers a promising and innovative approach that is intended to proactively manage risk across programs, inform risk-based decision-making, drive continuous improvement in performance, and inform the strategic planning process. Ultimately, it should provide a feedback loop between management decisions and risk outcomes, as well as between leadership and field operations.

BSEE has been using risk assessments for internal control purposes, and is integrating ERM into the bureau's priority setting process. BSEE's ERM approach generally follows the ERM model as outlined in guidance developed by an interagency ERM working group[144] and includes key elements identified in guidance on good practices for managing risk:[145]

- **Align ERM to goals and objectives** – Ensure the ERM process maximizes the achievement of agency mission and results;
- **Identify risks** – Assemble a comprehensive list of risks including both threats and opportunities that could affect the agency in achieving its goals and objectives;
- **Assess risks** – Examine risks considering both the likelihood of the risk and the impact of the risk on the agency mission;
- **Select risk response** – Select the response (based on risk appetite) such as acceptance, avoidance, reduction, share/transfer, or maximize opportunity;
- **Monitor risks** – Monitor how risks are changing and if responses are successful; and
- **Communicate and report on risks** – Communicate risks to stakeholders and report on the status of addressing the risk.

BSEE's self-assessment indicates that the ERM Program is at Maturity Level 3, with all of the framework elements in place including a program charter, roles and responsibilities, risk maturity model, policy, methodology, process, and a handbook. Transition to the ERM software platform will facilitate progress to a higher level of maturity and ease further

[143] Enterprise Risk Management became a requirement for federal agencies in July 2016, Office of Management and Budget, Circular A123, available at https://www.whitehouse.gov/sites/default/files/omb/memoranda/2016/m-16-17.pdf.
[144] United States Chief Financial Officers Council and the Performance Improvement Council. (US CFOC and PIC), ***Playbook: Enterprise Risk Management for the U.S. Federal Government***, 2016, available at https://cfo.gov/wp-content/uploads/2016/07/FINAL-ERM-Playbook.pdf.
[145] Government Accountability Office, ***Enterprise Risk Management: Selected Agencies' Experiences Illustrate Good Practices in Managing Risk***, GAO-17-63, December 1, 2016.

integration of data into the strategic planning process. BSEE has identified 84 current risk treatments and proposals for another 177 are being considered.

Enterprise risk includes all risks, both operational (external) and those related to internal controls within the organization, that could affect the ability of BSEE to achieve its mission.[146] BSEE's framework identifies 12 strategic risks:

- Jurisdiction – failure to interpret and apply
- High Technology and Unknowns – failure to understand leaves gaps in regulation
- Establish Regulations and Guidance – failure to address identified risks
- Production and Conservation – facilitate adequate and accurate production volumes and conservation
- Permitting – failure to adequately vet and approve permits
- Inspection/Audit Guidelines –failure to establish sufficient guidelines
- Inspection/Audit Deficiencies – failure to identify
- Response – failure to facilitate adequate response capabilities
- Investigations – failure to adequately identify causal event information to prevent recurrence
- Enforcement – failure to motivate industry to high level of compliance
- Decommissioning – failure to appropriately oversee/inform lease liability
- BSEE Internal – failure to maintain internal control

Top risks identified in BSEE's first full ERM cycle were permitting, high technology and unknowns, and decommissioning. Failure to maintain internal control was also high on the list. As BSEE undertakes its next cycle of ERM, these risks may shift. Based on a 2014 discussion by a panel of experts at the National Academy of Public Administration[147] some, but not all, aspects of BSEE's ERM align with best practices:

- Sets a tone at the top indicating that leadership understands the value of integrating risk into strategy setting;
- Communicates the value and raised awareness of ERM's importance;
- Integrates risk into performance management;
- Demonstrates the value of risk by using it to improve performance; and
- Broadly uses ERM as the basis for open dialogue between risk leaders and senior leadership.

The ERM Program is understood by some components within the agency, primarily headquarters, and is generally accepted among the leadership, but there is disagreement about the approach, the categorization of risks, and the degree of emphasis on organizational versus operational risk. Some BSEE units have trepidation about the

[146] Bureau of Safety and Environmental Enforcement, ***Enterprise Risk Management (ERM) Handbook,*** April 2016.

[147] National Academy of Public Administration/Ernst & Young, LLP***, From Enterprise Risk Management to Risk-Enabled Performance – a Conversation with Leaders***, May 7, 2014.

implications of being labeled a high risk and the additional requirements that are imposed for risk reduction and reporting. BSEE's ERM exists in parallel with program-based risk management initiatives that use different conceptual approaches, and there is disagreement regarding the classification of various types of risks. Part of the reason for this is the lack of a common lexicon or vocabulary for risk dialogue and communication.

Establishment of communities of practice for managing critical areas of knowledge associated with strategic risks (as suggested in Chapter 4 in support of a KM strategy) could promote dialogue about risk as well as shared understanding and development of a common lexicon. It would also enable those engaged in program-based risk management initiatives to provide input on the ERM approach and vice-versa.

The risk-based inspection initiative that BSEE is piloting is an example of a program-based risk management initiative that is intended to reduce risk associated with inspections, which was also identified as one of the strategic risks. Development of the initiative was initially based on a statistical analysis to target high-risk facilities. With input from regional staff, it evolved to include additional factors. Within BSEE there are differing views about conceptual approaches to risk assessment, specifically with regard to the acceptance of more subjective and qualitative approaches used for less quantifiable types of uncertainties. The use of subject matter expertise along with quantitative data should be viewed as complementary, recognizing the unavoidable role of informed even if subjective professional judgments in the context of limited information.

Among the insights drawn from the 2014 National Academy of Public Administration Panel discussion was that a dialogue about uncertainties might help to overcome resistance to dialogue about risk and ultimately lead to better articulation of risk. The Panel also suggested that pilot projects that use ERM to assess risks could be used to facilitate discussion of both risks and opportunities, which could be expected to improve understanding and acceptance of ERM. The Panel also suggested including the risk of maintaining the status quo in risk assessments. This would help to make the case for the change in organizational culture that is needed to adopt ERM, which should also be supported by a change management plan.

BSEE's risk-based inspection pilot could advance understanding of different and complementary approaches to risk assessment. It could also help demonstrate the value of risk assessment and risk-based decision making and ultimately facilitate institutionalization of ERM. It could also be a tool used in the development of a multi-year plan to guide prioritization and sequencing of BSEE efforts that compete for a limited amount of capacity.

Recommendation 5.4

BSEE should establish communities of practice for management of strategic risks and develop a common lexicon that can be used for risk communication. To this end, the ERM program should incorporate learning from the results of the inspection pilot underway and other areas where risk management pilots can expand its use and improve capability. BSEE should also incorporate ERM into its multi-year planning (see recommendation 5-3).

CHAPTER 6: OVERCOMING HUMAN RESOURCE CHALLENGES

A 2010 implementation plan that was prepared to respond to the Report of the Outer Continental Shelf Safety Oversight Board described the actions that DOI would take to improve and strengthen management, regulation, and oversight of OCS operations. The plan described the efforts that would be necessary with the reorganization of these functions and the need to recruit scores of new professionals, develop training programs and curricula, and develop management structures and systems appropriate to the scale and mission of the new organizations.[148] When BSEE was established, it faced daunting human capital challenges, including significant staffing shortfalls, urgent training and employee development needs, competition for mission-critical skills, and inadequate systems and management structures. In addition to building core capacity for BSEE's mission execution, BSEE also needed to quickly expand its human resources capacity, deploy systems and processes, and provide human resource services to BOEM, ONRR and itself.

BSEE has made significant progress in these areas including completing a Human Capital Management Strategic Plan to guide the bureau's human capital programs and alignment with mission and strategic goals. BSSE established a Human Capital Council that promotes strategic alignment of human capital programs and priorities with operational needs. In addition, BSEE has improved hiring and retention; expanded training programs focused on technical and leadership development and specific skills gaps; modernized human capital systems; conducted workforce planning and data-driven reporting; and improved the organization's access to information that can be used to enhance workforce planning including demographic trends, competencies, and skills. BSEE's efforts in these areas have generated the following positive results:

- An increase in staffing of 679 employees or 28 percent, comparing employment as of October 2012 with September 17, 2016;
- An increase of 34 percent in the number of technical training courses delivered in FY 2015 as compared to FY 2014;
- Increased salaries for mission-critical technical positions in the Gulf of Mexico Region including petroleum engineers, civil engineers, geophysicists, geologists, and inspectors that allow up to 35 percent more than basic pay rates.

BSEE's human capital efforts evidence ongoing maturation based on a model of strategic human capital management developed by GAO that identifies eight critical success factors to gauge an organization's progress in addressing four challenges that create risk in federal agencies. Agencies are encouraged to use the model to promote human capital management that is fact-based, focuses on strategic results, and incorporates merit

[148] U.S. Department of the Interior, ***Implementation Plan In Response to the Outer Continental Shelf Safety Oversight Board's September 1, 2010 Report to the Secretary of the Interior,*** September 4, 2010.

principles.[149] BSEE's efforts to date and actions planned for the future indicate progression from a more prescriptive approach to a more innovative and flexible approach in most of these areas.

- Leadership – BSEE's leadership recognizes the importance of human capital to mission accomplishment and promotes the partnership of human capital professionals with agency leaders and program managers through the Human Capital Council.
- Strategic human capital planning – BSEE's strategic plan and Human Capital Management Strategic Plan support alignment of human capital approaches with bureau mission, vision, and strategic goals. BSEE uses data gathered on the workforce to drive decision making in acquiring, developing, and retaining talent.
- Acquiring, developing, and retaining talent – BSEE's investments in human capital including hiring and training are aligned with mission needs and BSEE has implemented flexible and innovative approaches to meet training needs.
- Results-oriented organizational cultures – BSEE promotes diversity and is working to improve the linkage of organizational performance with individual performance.

Continued maturation of human capital strategies and progression based on these critical success factors will facilitate achievement of BSEE's operational and organizational excellence strategic goals.

Leadership Commitment to Human Capital Management

BSEE has strong leadership commitment to human capital, both in the Director's external and internal communications, and the ongoing deliberative effort by BSEE's senior leadership to support human resource programs and investments. In his first communication with BSEE on October 31, 2013, the Director identified human capital issues as a priority for the bureau and outlined a set of goals including leveraging existing bureau expertise with continued training; creating opportunities for employee advancement and fair compensation; and enhancing efforts to attract talent in a competitive job market. He shared his vision for a BSEE work environment that embraces diversity and in which employees have the tools to do their jobs, the opportunity to contribute and grow, and the confidence that they will be recognized for their work and accomplishments. This information was shared in an all-employee email along with a commitment that the BSEE 2013-2018 Human Capital Management Strategic Plan would be used as a roadmap to guide bureau efforts to attain these goals.

In subsequent communications, the Director continued to emphasize the importance of keeping a focus on the development of and support for human capital, which demonstrates a leadership commitment to ongoing improvement and engagement in the particulars of BSEE's efforts. This is evidenced in the Director's communications and in BSEE's leadership

[149] Government Accountability Office, ***A Model of Strategic Human Capital Management,*** GAO-02-373SP, March 2002.

team discussions about the imperative for succession planning; decisions to create the BSEE Human Capital Council to serve as a governance body that could oversee and provide ongoing support for human capital programs; creation of a leadership development program; increased technical training; and expanded workforce planning.

Strategic Human Capital Planning

BSEE's commitment to alignment of its human capital strategies in order to acquire, develop, and retain people to meet mission needs is evident in the strategic plan that includes an organizational excellence goal that is focused on people, specifically stating "We are an employer of choice, we value, engage, and support our people so they can excel." This goal is supported by two strategies that promote the creation of a high-performing and collaborative environment:

- Improve engagement with employees to foster a culture of collaboration within BSEE; and
- Develop and sustain a well-trained, high-performing and diverse workforce.

These strategies are supported by initiatives that seek to foster team building, collaboration and trust; implement an internal communications approach that encourages dialogue; assess and ensure training is provided; utilize recruitment and retention incentives and alternate appointment authorities; use processes that recruit, motivate, train, and reward the workforce in accordance with merit systems principles and federal regulations; and implement programs that promote a diverse and inclusive workplace.

The Human Capital Management Strategic Plan 2013-2018, issued in September 2013, depicts the environment within which BSEE operated in 2013 and identifies the challenges that the bureau faced at that time. A set of human capital goals and strategies present the actions that BSEE planned to take to overcome challenges and achieve recruitment, hiring, diversity, retention, and performance management goals for the workforce.

The plan includes data-driven analyses of hiring needs and describes external factors, like competition, that the bureau expected would challenge its ability to achieve hiring goals. The plan includes strategies for marketing, branding, and recruiting including filling vacancies in twelve mission-critical occupations; performance management to establish expectations and recognize good performance; succession planning to prepare for retirements over a five year period; retaining talent; and increasing diversity. The plan prescribes actions necessary to increase staffing by 28 percent overall (with October 2012 as the baseline for comparison), including hiring to address staffing shortages of up to 62 percent in some mission-critical occupations. At the time the plan was developed the bureau was facing a very competitive market for mission-critical occupations, challenging BSEE's ability to address priority hiring of inspectors, engineers, geophysicists, geologists, and environmental specialists.[150] The plan also describes the challenges due to looming retirements, threats to knowledge retention, and the unique problems associated with performance of job functions that require specialized technical and local knowledge that can take years to acquire.

BSEE is in the process of updating the Human Capital Management Strategic Plan in recognition of the changing circumstances since it was prepared. The Academy study team was told that the updated plan will shift its focus from recruiting and hiring, which were urgent efforts in 2013, to focus on needed strategies to retain, motivate, and manage the workforce. BSEE is aware of potential external threats to its human capital management, including increased competition in the event that industry demand increases, as well the potential for reduced funding that could threaten its ability to maintain an adequate workforce and competencies.

Recruitment, Hiring, and Retention

Using the Human Capital Management Strategic Plan as a guide, BSEE has been successful in recruiting and hiring, nearly reaching its hiring goals as of the end of FY 2016. There were 679 employees on board as of October 2012 and 871 on board as of September 17, 2016, an increase of 28 percent. BSEE had planned additional hiring in 2017 that would allow them to reach full staffing by the end of Fiscal Year (FY) 2017.[151] However, a recently imposed federal hiring freeze will likely impact achievement of this goal.

To address hiring and retention goals, BSEE overcame significant pay and benefit disparities between federal compensation and industry pay rates. BSEE developed detailed analyses supporting the salary amounts that would be needed to effectively compete with industry for technical job series and shared them with DOI, OMB, and the Office of Personnel Management (OPM). Congress authorized special pay rate authority on an interim basis beginning in 2012. Authority for special pay rates was included in appropriations legislation on an annual basis for geophysicists, geologists, and petroleum engineers that allowed increases of up to 25 percent over basic pay.[152] In August 2015, OPM administratively authorized permanent special pay rates for technical positions in the Gulf of Mexico Region including petroleum engineers, civil engineers, geophysicists, geologists, and inspectors that allowed increases of up to 35 percent more than basic pay.[153] BSEE also sought and received OPM approval for similar salary rates for mission-critical positions in the Alaska and Pacific Regions. BSSE continues to closely monitor hiring, collect data, and report results in order to maintain support for the special pay rate

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[150] Bureau of Safety and Environmental Enforcement, ***Human Capital Management Strategic Plan 2013-2018***, September 2013.
[151] Bureau of Safety and Environmental Enforcement, ***Annual Report 2015***, available at https://www.bsee.gov/annual-report/safety/bsee-2015-annual-report.
[152] Government Accountability Office, ***Oil and Gas Oversight: Interior Has Taken Steps to Address Staff Hiring, Retention, and Training But Needs a More Evaluative and Collaborative Approach***, September 2016.
[153] Ibid

authority. BSEE recently created an Office for Workforce Analysis and Planning within the Human Resources Division to focus on these matters.

BSEE's actions to address pay disparities with industry in order to achieve hiring goals and retain employees in very competitive occupations were recognized by GAO in 2014.[154] In testimony before the House Committee on Natural Resources, GAO recognized BSEE's use of special salary rates provided by Congress to retain geologists, geophysicists, and petroleum engineers; efforts to document the need for special salary rates with OPM; use of hiring incentives (albeit on a limited basis); reduced timeframes for hiring; and marketing to facilitate recruitment. In February 2015 when GAO evaluated these areas again, they found that progress had been made but that BSEE needed to do more.[155] In September 2016, GAO reviewed hiring, retention, and training for DOI oil and gas programs and found that BSEE had improved its use of hiring and retention incentives by substantially increasing the number of staff receiving retention incentive payments and student loan repayments. GAO also found that BSEE had taken steps to reduce the time to hire including adopting new human resources software to facilitate tracking the hiring process, issuing new hiring process guidance, and conducting training on the new guidance.[156]

The OIG also recognized BSEE's accomplishments, while suggesting that more could be done, in a November 2015 report that addressed BSEE's implementation of strategies to tackle human capital challenges. The OIG provided positive feedback about BSEE's efforts to work with DOI, OPM, and OMB to identify special salary enhancements to narrow the gap between the federal government and industry salaries and the use of existing authorities to offer recruitment, retention, and relocation incentives, and student loan repayments. The OIG also highlighted BSEE's use of recruitment teams to visit and build professional contacts at universities and engineering departments as well as at professional events and conferences, and to target engineers and scientists at entry level and mid-level grades. In addition, the OIG noted the use of DOI's cooperative agreement with the Partnership for Public Service to fund student ambassadors who provide peer-to-peer outreach on college campuses to increase knowledge about federal career opportunities. The OIG also reported on BSEE's use of position trackers for collecting data relevant to the overall hiring process, revised processes and tools to help track hiring timeframes, reduced applicant processing times, and decreased long-term operating costs.[157]

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[154] Government Accountability Office, Testimony Before the Subcommittee on Energy and Mineral Resources, Committee on Natural Resources, House of Representatives, Oil and Gas Management: Continued Attention to Interior's Human Capital Challenges is Needed, February 27, 2014.
[155] Government Accountability Office, ***High-Risk Series, An Update***, GAO-15-290, February 2015.
[156] Government Accountability Office, ***Oil and Gas Oversight: Interior Has Taken Steps to Address Staff Hiring, Retention, and Training But Needs a More Evaluative and Collaborative Approach***, September 2016.
[157] Department of Interior, Office of Inspector General, ***Inspector General's Statement Summarizing the Major Management and Performance Challenges Facing the U.S. Department of the Interior***, November 2015.

BSEE closely monitors its workforce and workforce trends with a dashboard that is issued at the end of each pay period and shared with BSEE leadership. The tool has been useful for BSEE to identify where delays happen and facilitate individual actions, educate managers in the process to increase their awareness and facilitate the steps for which they are responsible. However, according to GAO BSEE has not conducted systematic analyses of the data to improve processes such as reducing hiring times.[158] The need to accelerate hiring times is a consistent theme in GAO's recommendations to BSEE along with the need to conduct data-driven analyses to improve ongoing processes, and explore expanded use of recruitment, relocation, retention and other incentives. The Academy study team was told that BSEE's human resources program is focused on these efforts. BSEE has developed an 80-day hiring model consistent with OPM's goal for federal hiring. BSEE is also benchmarking hiring timeframes and conducting training for managers and others involved in the hiring process to achieve reforms and reduce the time it takes to hire. BSEE's 80-day model for hiring would reduce the time it takes to hire (as reported by GAO)[159] from the 197 days it took to hire a petroleum engineer in 2012. BSEE's Human Resources Division recently completed a supervisory guide on compensation flexibilities to assist managers and clarify regulations relating to the use of compensation flexibilities available including relocation payments, superior qualifications compensation, special hiring needs appointments, student loan repayment, and creditable non-federal/non-military service for leave accrual.

Succession Planning

Among the areas of focus in BSEE's Human Capital Management Strategic Plan is succession planning, including strategies to recruit, hire, and train employees to become future leaders and capturing corporate knowledge from experienced employees. BSEE recognized the need to build leadership competencies and has taken significant steps to develop managers with the creation of its three-track Leadership Development Program. Each of the three tracks is focused on a different stage in leadership. For example, BSEE's launch of an initial track, the Emerging Leaders Program, includes opportunities for rotations, coaching/mentoring, and experiential practical learning for BSEE employees who hold GS-11, GS-12, and GS-13 positions.

The plan also identified strategies for a formal mentoring program with a knowledge transfer component; selected management, leadership, and information courses to meet the needs of individual offices; and utilizing flexible position management to assist with

[158] Government Accountability Office, Testimony Before the Subcommittee on Energy and Mineral Resources, Committee on Natural Resources, House of Representatives, ***Oil and Gas Management: Continued Attention to Interior's Human Capital Challenges is Needed,*** February 27, 2014; Government Accountability Office, ***High-Risk Series, An Update,*** GAO-15-290, February 2015; Government Accountability Office, ***Oil and Gas Oversight: Interior Has Taken Steps to Address Staff Hiring, Retention, and Training But Needs a More Evaluative and Collaborative Approach***, September 2016.

[159] Government Accountability Office, Testimony Before the Subcommittee on Energy and Mineral Resources, Committee on Natural Resources, House of Representatives, ***Oil and Gas Management: Continued Attention to Interior's Human Capital Challenges is Needed***, February 27, 2014.

succession planning. The study team encourages BSEE to fulfill its commitment to launch the next two Leadership Development Program tracks while also considering immediate focused efforts, consistent with the strategies identified in the Plan, to prepare for retirements and potential gaps in bureau senior leadership.

BSEE has a modest cadre of senior leaders, many of whom are or will soon be eligible for retirement. These are crucially important positions that require technical knowledge, leadership skills, and management expertise. Consistent with its Human Capital Management Strategic Plan, BSEE should consider initiating targeted actions to prepare employees for future advancement and create opportunities for rotations, details, and temporary assignments for qualified individuals who have leadership potential and are interested in advancing their career. BSEE could also consider a flexible position management approach that has been used by other bureaus and the DOI Office of the Secretary. A co-director or co-chief is appointed and works side-by-side with the individual planning to retire for a six to twelve month period, which allows the newly appointed co-chief to learn from the incumbent and assume leadership responsibilities while being mentored and coached by the individual that will soon retire.

Recommendation 6.1

BSEE should continue to develop opportunities for GS-14 and GS-15 employees who can gain experience in order to be prepared to assume leadership positions and ensure continuity.

<u>Employee Survey Results</u>

BSEE's ability to attract and retain employees is highly dependent on the quality of the work experience and environment. Employees are able to communicate their views and attitudes through the annual Federal Employee Viewpoint Survey (FEVS). Through this not-for-attribution survey conducted by OPM, employees can voice their views about factors that impact their ability to do their jobs, their perceptions about treatment and respect, the degree to which their opinions are taken into consideration, and other factors. Many federal agencies actively encourage their employees to take part in order to gain feedback about employees' attitudes. Survey results provide valuable insight into the challenges agency leaders face in ensuring that their agencies have an effective workforce. BSEE evaluates the annual data, but could do more to use the results to help drive improved employee engagement and understand human resource challenges. For BSEE, a relatively new organization that is continuing to work on melding diverse cultures, FEVS is a good source of data about the attitudes and views of the workforce and individual organizations. This information can be used to improve the work environment, identify areas where employees are frustrated or feel they lack support, and areas where the bureau may experience employee retention problems in the future.

The most recent Federal Employee Viewpoint Survey (FEVS) was conducted in the spring of 2016.[160] About 49.1 percent of BSEE's employees participated in the FEVS, about the same rate as DOI employees overall (50.1 percent) and above the government response rate of 45.8 percent. In general, the scores are in line with those for the government, with notable exceptions. As compared to other federal agencies, BSEE employees report higher scores relating to resource sufficiency, reasonable workload, physical working conditions, assessment of training needs, recruiting people with the right skills, promotions based on merit, policies and programs promoting diversity, protections from health and safety hazards, and work/life programs. Scores for BSEE are below the overall government in areas including communicating the goals and priorities of the organization, communication from management, and collaboration across work units. See Figure 6-1 below.

	BSEE	DOI	Government
Areas where BSEE's scores are above the government scores (DOI shown for comparison):			
9. Sufficient resources	60.7%	41.5%	46.6%
10. Reasonable workload	65.7%	48.1%	57.5%
14. Physical working conditions allow employees to do their jobs well	76.2%	67.9%	65.7%
18. My training needs are assessed	62.6%	52.4%	52.9%
21. My work unit is able to recruit people with the right skills	47.2%	41.1%	42.6%
22. Promotions are based on merit	45.0%	37.9%	34.5%
34. Policies and programs promote diversity	66.9%	55.4%	57.8%
35. Employees are protected from health and safety hazards	80.2%	78.2%	76.0%
Areas where BSEE's scores are below the government scores (DOI shown for comparison):			
56. Managers communicate the goals and priorities of the organization	54.3%	52.9%	60.3%
58. Managers promote communication among different work units	48.1%	47.5%	52.0%
59. Managers support collaboration across work units	50.4%	53.0%	55.7%
64. Satisfaction with information received from management about what is going on	41.0%	45.6%	48.0%

Figure 6-1. 2016 FEVS -Comparison of BSEE, DOI and Government Results[161]

BSEE's 2016 scores in general improved over previous years, using 2014[162] scores for comparison.[163] The scores for years 2014 – 2016 reflect upward trends in considering

[160] U.S. Office of Personnel Management, ***Federal Employee Viewpoint Survey, Government wide Management Report; Bureau of Safety and Environmental Enforcement 2nd Level Subagency Comparison Report***, 2016.
[161] U.S. Office of Personnel Management, ***Federal Employee Viewpoint Survey Results, Bureau of Safety and Environmental Enforcement, 2016*** (Positive Results Reported)).
[162] U.S. Office of Personnel Management, ***Federal Employee Viewpoint Survey, Government wide Management Report***, 2014.
[163] Note: 2013 FEVS results were not sufficiently complete to use as a basis for comparison.

BSEE a good place to work, job satisfaction, and satisfaction with pay. There are areas where the scores declined including understanding how work relates to BSEE's goals and priorities, individual accountability, respect, and information. Figures 6-2 below presents these results. BSEE scores for how work relates to the agencies' goals and priorities are consistent with the results of an employee engagement survey conducted by BSEE that is discussed in Chapter 8.

	2014	2015	2016
Scores Increased:			
3. Encouraged to come up with new and better ways to do things	54.5%	57.7%	61.1%
40. Good place to work	61.4%	64.7%	64.7%
69. Job satisfaction	60.5%	68.9%	66.9%
70. Satisfaction with pay	51.0%	54.5%	61.8%
71. Satisfaction with organization	54.2%	58.8%	58.4%
Scores Decreased:			
12. I know how my work relates to the agency's goals and priorities	86.1%	84.0%	80.8%
16. I am held accountable for achieving results	85.6%	84.6%	80.4%
49. My supervisor treats me with respect	79.5%	81.8%	75.4%
64. Satisfaction with information received from management about what's going on	46.1%	43.7%	41.0%

Figure 6-2. 2016 BSEE FEVS Results- Comparison Across Years[164]

Notoriety surrounded the 2010-2011 reorganization of MMS because ethical lapses and misconduct of a small contingent of employees gained traction in the press and led to extreme, ongoing scrutiny of BSEE's employees.[165] BSEE's efforts to maintain employee awareness through training, internal controls, and improved transparency help sustain a positive environment and discourage ethical conflicts and misconduct. FEVS data can also help inform the bureau about the confidence that employees have that they can report concerns and/or suspected issues without reprisal. BSEE's scores in this area continue to be in an acceptable range as compared to the rest of government as shown below in Figure 6-3.

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[164] U.S. Office of Personnel Management, ***Federal Employee Viewpoint Survey Results, Bureau of Safety and Environmental Enforcement, 2014, 2015, 2016*** (Positive Results Reported)).

[165] Department of Interior, Office of Inspector General, ***Investigative Report***, August 7, 2008.

	2014	2015	2016
17. I can disclose a suspected violation of law, rule or regulation without fear of reprisal Note: The 2016 DOI score is 59.4% and the government score is 62.1%	62.1%	63.0%	62.7%
37. Arbitrary action, personal favoritism and coercion are not tolerated Note: The 2016 DOI score is 54.6% and the government score is 53.1%	52.5%	55.3%	54.2%
38. Prohibited personnel practices are not tolerated Note: The 2016 DOI score is 67.7% and the government score is 66.7%	66.4%	66.9%	66.2%
54. Senior leaders maintain high standards of honesty and integrity Note: The 2016 DOI score is 47.1% and the government score is 51.8%	50.3%	55.0%	48.4%

Figure 6- 3. 2016 BSEE FEVS Results- Comparison Across Years[166]

Training Programs

The importance of training is evident in BSEE's strategic plan, which includes a strategy to "Develop and sustain a well-trained, high performing and diverse workforce" embedded within the goal for Organizational Excellence. The strategy is linked to two initiatives:

- Continuously assess critical training needs and ensure appropriate technical and leadership training is provided; and
- Ensure that processes are in place to recruit, motivate, train, and reward the BSEE workforce in accordance with merit system protection principles and federal regulations.

BSEE has developed and implemented multiple new training programs to promote leadership development, improved technical proficiency, familiarity with investigation techniques, oil spill preparedness, and new employee orientation. BSEE's Human Capital Council is responsible for aligning human capital programs with the bureau's mission, vision, goals, and priorities and oversees the full breadth of human resources activities including training.

In their 2010 reviews of DOI's OCS management, the OIG and the Outer Continental Shelf Safety Oversight Board recommended improvements in training and professional development for inspectors including:

- Develop a bureau-wide certification or accreditation program for inspectors;
- Consider partnering with the Bureau of Land Management and its National Training Center.

[166] U.S. Office of Personnel Management, ***Federal Employee Viewpoint Survey Results, Bureau of Safety and Environmental Enforcement, 2014, 2015, 2016*** (Positive Results Reported)).

- Develop a standardized training program to ensure inspectors are knowledgeable in all pertinent regulations, policies, and procedures.
- Ensure that annual training keeps inspectors up-to-date on new technology, policies, and procedures.
- Develop Individual Development Plans for inspectors designed to achieve career advancement strategies, promoting sound succession planning and fostering employee development and satisfaction.

BSEE's National Offshore Training Program (NOTP), which is operated by the Offshore Training Branch in OORP, provides comprehensive, multi-tiered, professional development for inspectors, engineers, and scientists focusing on deep water drilling, subsea operations, and training for other specialty areas. With classes on-site in the Gulf of Mexico Region, NOTP has established curricula and requirements tailored to develop and refresh skills for professions including inspectors and engineers. In addition to classes that address tailored requirements for inspectors and engineers, NOTP offers classes in aviation safety, general awareness security, and accident review that are required for all frequent offshore travelers. NOTP tracks and reports on the completion of training and shares this information to help managers ensure that their staff members complete required training. In FY 2015, BSEE held 106 training courses for 979 participants resulting in 23,980 training hours, a 34 percent increase in the number of courses, a 2.5 percent increase in participants, and 2.5 percent increase in hours over FY 2014.

Although BSEE does not currently require accreditation or certification of inspectors, BSEE requires that they meet established training requirements, which are tracked by their supervisors. BSEE has established training and competency requirements for inspectors to progress to higher skill levels. Course work and on-the-job training is required and approval to operate at Levels II and III is only given after evaluation and approval by a Supervisory Inspector who confirms that the inspector has the necessary knowledge and sufficiently demonstrated capability in the field.

With regard to partnering with BLM, BSEE staff attend BLM classes when this meets their training needs; GAO reported that 15 BSEE employees did so during the years 2012 to 2015. Under the terms of a recently executed BLM-BSEE interagency agreement, staff from either bureau can attend classes if the curriculum meets the other agency's training needs. In addition, BLM and BSEE cooperated in the development of a simulation course entitled *BSEET 3D Drilling Rig Tour*, and have agreed to continue collaboration. BSEE has also committed to higher levels of coordination with BLM and BOEM with regard to their training needs, evaluating training effectiveness, and pursuing potential opportunities for sharing training resources and developing technical competencies for all key oil and gas staff.[167]

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[167] Government Accountability Office, ***Oil and Gas Oversight: Interior Has Taken Steps to Address Staff Hiring, Retention, and Training But Needs a More Evaluative and Collaborative Approach,*** GAO-16-742, September 2016.

BSEE is planning to review NTOP effectiveness and the need for improvements, including the possible addition of a certification component. This is responsive to GAO recommendations,[168] statutory requirements,[169] and OPM and DOI requirements for review of training programs to identify training needs and assess how well training efforts contribute to accomplishing the agency mission.

BSEE developed training programs responsive to OIG and Outer Continental Shelf Safety Board recommendations for improved expertise in investigations. Both entities recommended appropriate training in incident investigation. The Safety and Incident Investigations Division Chief implemented a new training program for personnel with investigatory responsibilities through the Federal Law Enforcement Training Center (a component of the Department of Homeland Security) in Charleston, South Carolina. Classroom and scenario based training is provided to personnel that may be involved with any phase of an investigation. This standardized training helps ensure that data collection is done in a consistent and repeatable manner. Coursework provides a practical understanding of how to plan, conduct, and conclude an incident investigation; it includes the methods and techniques used for data gathering, interviewing, and reporting investigative findings. The participants are provided classroom instruction, workshops, and case studies.

The National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling identified inadequate training as a key deficiency contributing to insufficient oversight by MMS. Among the Commission's recommendations was improved technical expertise within the staff responsible for reviewing and approving oil spill response plans. BSEE's Oil Spill Preparedness Division (OSPD) has created a Preparedness Analyst Qualification System that establishes the requirements whereby preparedness analysts satisfy training and qualification requirements, including standardized training, experience, and demonstrated performance. OSPD's program incorporates in-house classroom and on-line training.

One of the outcomes of BSEE's human capital planning was the identification of a critically important need to undertake succession planning and leadership training. BSEE's Human Capital Management Strategic Plan identified BSEE's age cohorts, which revealed a large number of employees over 50, a high percentage of BSEE's employees that were or would be imminently eligible for retirement, and a large cohort of young employees that would not be ready to assume leadership positions. Thus, preparing employees to assume leadership positions became a compelling need and BSEE developed a training program to address this need.

BSEE's Leadership Development Program achieves Strategic Plan goals for skills development for managers who can lead the bureau in the future. This program develops supervisory and managerial competencies and leadership skills to prepare employees to assume leadership positions; it also develops individual leadership skills to enhance overall

[168] Ibid.
[169] 5 U.S.C. § 4121, added by the Federal Workforce Flexibility Act of 2004.

effectiveness. There are three tracks within the program, each focused on different stages of leadership and organized around OPM's Leadership Framework, which consists of five executive core qualifications and 28 leadership competencies. Training of the first cohort of BSEE employees has begun in one track, Emerging Leaders, which is an 18-month program consisting of classroom training, coaching and mentoring, and experiential/practical learning. Two other tracks are being developed: the Excellence in Leadership Program and Leadership Fundamentals. BSEE has created an Office for Leadership Development and Engagement to support the development of leadership and mentoring programs.

Organization of BSEE's Training Programs: Federal agencies are encouraged to use the most appropriate mix of centralized and decentralized approaches for training and development programs. Centralized training programs can enhance consistency of training content and offer potential cost savings, standardize record keeping, and improve the accuracy of reporting. Alternatively, a decentralized approach can facilitate efforts to tailor training to meet specific needs. A combination of both centralized and decentralized approaches can be implemented with central management of reporting and record keeping.

Regardless of the approach selected, strategic training and development guidance recommends that agencies deploy mechanisms to effectively limit unnecessary overlap and duplication of effort and ensure delivery of integrated and consistent messages. It is important to ensure that training and development efforts are cost effective relative to the anticipated benefits and to incorporate performance measures that can be used to demonstrate contributions that these programs make to improve results. By incorporating valid measures of effectiveness into their training and development programs they offer, agencies can better ensure that they adequately address training objectives and thereby increase the likelihood that desired changes will occur in the target population's skills, knowledge, abilities, attitudes, or behaviors. [170]

Training programs in BSEE currently operate under the leadership and guidance of four programs: the Office of Administration, SIID, OORP, and OSPD. Consideration could be given to consolidating aspects of these programs in order to achieve efficiencies, standardize curriculum development, and simplify tracking and reporting. Such consolidation may facilitate BSEE's efforts to evaluate training needs of staff, develop technical competencies, and annually evaluate training, as required by OPM and directed in the DOI Departmental Manual.[171]

BSEE's Training Governance Board should engage all of these offices and divisions as an initial step to share expertise and lessons learned, establish comprehensive standard training requirements for employees, and become a BSEE resource for the identification of

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[170] Government Accountability Office, ***Human Capital: A Guide for Assessing Strategic Training and Development Efforts in the Federal Government***, GAO-04-546G.
[171] GAO, ***Oil and Gas Oversight: Interior Has Taken Steps to Address Staff Hiring, Retention, and Training But Needs a More Evaluative and Collaborative Approach***, GAO-16-742, September 2016.

training and development improvements. This would help ensure that BSEE is achieving high levels of integration of its training programs.

Recommendation 6.2

BSEE should create a training governance structure that encompasses oversight of all of its training programs, not just technical training, and should assess the benefits of consolidating or leveraging aspects of its training programs to ensure the highest levels of integration and efficiency across the bureau.

<u>Fostering An Inclusive Workplace</u>

Strategic human capital management guidance depicts high performing agencies as those that are inclusive and foster an environment that empowers and involves employees. An inclusive workplace is at a competitive advantage for achieving results. One component of an inclusive workplace is striving to reduce the causes of workplace conflicts and ensuring that conflicts are addressed fairly and efficiently.

Maintaining an inclusive workplace is a challenge that all federal agencies confront. GAO examined this issue and found that federal agencies have been increasingly using alternative dispute resolution programs (ADR) to resolve workplace disputes. ADR can be a way to avoid the more formal dispute resolution process or as a supplement to traditional ways of handling disputes. Another factor in the increasing adoption of ADR practices has been a recognition that traditional methods of dispute resolution do not always get at the real or underlying issues involved between disputants and that methods that focus on the disputants' interests may have advantages. Options available to federal agencies include ADR, ombudsmen, mediation, dispute resolution boards, and peer panels. All appeared to be useful in resolving workplace disputes, thereby avoiding more formal avenues for resolution.[172] To complement ADR, organizations also invested in training efforts aimed at preventing disputes and equipping employees and managers with skills to resolve disputes.

Ombudsman positions provide significant benefits by helping employees to resolve issues that could impact their performance. Although federal employees are afforded opportunities for redress of workplace disputes, these traditional processes can become adversarial and impact the underlying relationships and harm the long-term productivity of the office and morale of employees. Ombudsmen provide an informal option to deal pragmatically with conflicts and other organizational climate issues.

In an evaluation of ten federal agencies, GAO found that ombudsmen deal with a wide range of workplace issues, helping employees get answers, listen to employee concerns, counsel them on alternative courses of action, and coach them in managing situations. At the same time, the ombudsmen can add value by bringing systemic issues to management's

[172] Government Accountability Office, ***A Model of Strategic Human Capital Management***, GAO-02-373SP, March 2002.

attention and thereby help correct organizational situations and develop strategies to prevent and manage conflict. Vital to this role is confidentiality, neutrality, and independence. Key aspects of the function include direct access to agency leadership and neutrality in dealings by not taking sides in disputes, but rather advocating for results through informal resolution.[173]

Within DOI, the Office of Collaborative Action and Dispute Resolution Office is the responsible office that can provide assistance in evaluating expanded use of ADR and/or establishing an ombudsman function or securing comparable services. The study team did not include a recommendation in this area because the team did not assess the degree to which BSEE already utilizes alternative dispute resolution and mediation. Rather, the study team suggests that BSEE could, if needed, expand its use of ADR and/or establish an ombudsman or procure ombudsman services.

[173] Government Accountability Office, ***Human Capital, The Role of Ombudsmen in Dispute Resolution***, GAO-01-466, April 2001.

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Chapter 7: Adequate Resources for Safety, Environmental Protection, and Conservation Offshore

The National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling conducted an exhaustive analysis of the causes of the DWH disaster and recommended reforms to make offshore energy production safer. One of three core issues identified by the Commission was the need for adequate funding. The Commission recommended that Congress make it a priority to fund BOEM and BSEE to regulate offshore oil and gas development "in order to ensure a safer and more environmentally responsible industry in the future." Recognizing that a portion of the funding for these bureaus comes from offsetting collections, the Commission suggested that the oil and gas industry should provide more funding, including possibly through increased inspection fees or imposition of an annual regulatory fee or fees on new and existing leases.[174]

BSEE's FY 2016 budget of $204.7 million consisted of $88.5 million in appropriated funds and $116.2 million in offsetting collections ($59 million in inspection fees, $49.4 million in rental receipts and $7.8 million in cost recovery fees). This is also BSEE's approximate 2017 operating level under the continuing resolution that is currently in place.[175]

Between FY 2012 and 2016, BSEE's budget increased by a total of $7.3 million (3.7 percent). This includes increases of $12.2 million or 16 percent in appropriations, which were offset by reductions in offsetting collections of $4.9 million or 4 percent. These increases were added to a funding base for DOI's OCS programs that had been increased by Congress. Congress appropriated $29 million in 2010 for the restructuring of DOI's OCS programs. In 2010 Congress also provided new authority to charge annual inspection fees and continued authority to fund a portion of the budget from rental income collected on existing oil and gas leases. Together, inspection fees, rental income and other cost recovery fees comprised about 57 percent of BSEE's FY 2016 budget.

Originally intended to provide stability for BSEE's programs by leveraging appropriations, these funds from industry are now declining and in addition inspection fee authority does not provide the flexibility that BSEE needs to charge for follow-up and more complex inspections. BSEE and DOI, with support from OMB, proposed in the recent FY 2017 President's budget to address the challenge of declining collections and changes to the inspection fee program, however, Congress did not act on these proposals and BSEE continues to face a potential shortfall in funding.

In addition, expanding responsibilities for oversight of OCS renewable energy development and additional workload and other issues related to decommissioning are likely going to

[174] Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, ***Deep Water: The Gulf Disaster and the Future of Offshore Drilling,*** January 2011, available at https://www.gpo.gov/fdsys/pkg/GPO-OILCOMMISSION/pdf/GPO-OILCOMMISSION.pdf.

[175] Further Continuing and Security Assistance Appropriations Act, 2017, P.L. 114-254, December 1010, 2016.

impact BSEE's budget and should be considered in BSEE's budget planning and identified, as appropriate, in future budget requests.

Budget Outlook

BSEE faces budgetary challenges because of a potential shortfall in funding resulting from a decline in collections that fund a significant portion of the budget. The 2017 budget included proposals to address the shortfall, but Congress did not enact 2017 appropriations. BSEE and most other federal agencies are funded through a continuing resolution that supports operations through April 28, 2017. The continuing resolution essentially continues the 2016 funding levels and authorities. In FY 2016, collections comprised 57 percent of BSEE's total budget; thus, a shortfall could significantly impact BSEE's ability to maintain its current capabilities.

The single largest source of collections to offset BSEE's budget comes from inspection fees. The annual appropriations act includes authority to charge inspection fees using a fee structure with variable fee amounts for inspections of drilling rigs and production facilities. The current legislation allows BSEE to charge a drilling rig inspection fee each time a drilling rig inspection is conducted. However, BSEE can only charge operators of production facilities for one annual inspection of such facilities regardless of whether or not follow up inspections are required in the same year.

To remedy this situation, the FY 2017 budget proposed to modify the inspection fee legislative authority to allow charges for additional facility inspections and thereby align the fee collections more closely with the actual requirements for inspection. Inspection of deep water facilities imposes additional costs. Because oil and gas operations in the Gulf of Mexico have increasingly shifted further offshore, deep water facilities account for a greater share of OCS production. As of January 2016, 80 percent of the total OCS production occurred in deep water. In addition, the bureau has placed greater emphasis on witnessing high-risk activities, which, again because of their complexity, consume more resources to inspect. Finally, new inspection initiatives require inspectors to spend more time conducting follow-up inspections on higher risk facilities, performing in-depth incident investigations, and preparing enforcement actions such as civil penalties. Currently, an inspection fee is not charged for any of these activities. There were approximately 1,000 follow up inspections conducted in FY 2015 and 1,600 in FY 2016 that BSEE was unable to charge a fee for under the current inspection fee language.

In addition, inspection fee collections are declining. In recent years, the amount authorized in the appropriations act for inspection fees has been constant at $65 million, but the bureau collected $58 million in FY 2014, $55.5 million FY 2015, and $50.1 million in FY 2016. The inspection fee language change request, as discussed earlier, is intended to align fee collections with the manner in which inspections are being performed and to ensure adequate funding for the inspection program. In action on the FY 2017 appropriation bills, the House and Senate provided $12 million in appropriated funding in lieu of approving the proposed inspection fee structure change. This is not a sustainable approach, particularly since the House stated that this would be the last time appropriated funds would be provided to offset collection shortfalls and directed BSEE to prioritize program activities accordingly. This is an indication that BSEE may have to reduce its budget in the future in order to absorb the shortfall in funding caused by constrained fee authority.

An additional significant source of funds that offsets BSEE's budget comes from rental receipts. Rental receipts are collected from active leases before they begin production. Collections from rental income have declined and are expected to continue to decline. This is because fewer leases are being sold in the Gulf of Mexico; fewer tracts will likely be leased; and the number of leases subject to rentals will likely decrease. The FY 2017 budget request proposed to change the allocation of offsetting rental receipt revenue between BOEM and BSEE moving from a 65/35 percent division respectively, to a 70/30 percent division. In anticipation of lower offshore rental receipts and fee collections, the request included an increase of $7.5 million in direct appropriations to address the projected shortfall. The shortfall for both bureaus in FY 2017 is estimated at $15.94 million when using FY 2016 estimates as a baseline and is expected to grow to $82.3 million by FY 2025.[176]

Although offsetting collections are anticipated to decline, overall OCS activity and programmatic requirements are not decreasing. Despite reduced oil and gas prices, production in the Gulf of Mexico has steadily increased as new long-term projects came on line in 2015 including five deep water projects that began production during 2015. Given the increasingly complex operations offshore, it is important for BSEE to maintain capacity to support expected levels of program activity and protect the important gains in safety and environmental protection that have been achieved in the last five years.

When collections are less than the amount programmed in the budget, the difference is funded by the General Treasury, ensuring that BSEE receives the amounts programmed in the budget. These amounts to fund the shortfall come from within the overall allocations for appropriations, causing a scoring problem for the Congress and OMB that has to be addressed within constrained budgetary amounts allowed for appropriations. This is an area of risk for BSEE because without increased appropriations to make up the shortfall, the budget for the bureau will have to be reduced and the gap between the amounts needed and anticipated collections is widening.

BSEE has, in recent years, been able to fund a portion of its non-recurring expenses with funds available from unobligated balances in prior years. However, these funds cannot serve to address this long-term problem of declining collections and potentially inadequate resources. Thus, a long-term strategy to avoid reductions to BSEE's budget is needed.

BSEE has assessed the potential impacts of a reduced budget, which include slowing or, in some cases, halting the progress made in improving safety, environmental compliance, and enforcement activities. Reduced levels of staffing could impact inspections, investigations,

[176] U.S. Department of the Interior, ***Budget Justifications and Performance Information, Fiscal Year 2017: Bureau of Safety and Environmental Enforcement***, pp. 44-46.

permitting, technology assessment and standards development, compliance and enforcement, and oil spill response planning and preparedness. Reduced staff could have an impact on the ability of the bureau to respond to industry requests and potentially impact timeframes to respond to industry with permit reviews and approvals for exploration and development. Budgetary reductions could impact research and capacity for independent assessment of technology to identity design defects. Reductions could also impact BSEE's efforts to develop initiatives such as data stewardship and support for modernization of information technology that will streamline the exchange of information with industry and improve transparency.

Alternative Funding Scenarios

In its 2011 recommendation that the oil and gas industry provide more funding, including possibly raising the inspection fee or imposing annual regulatory fees on new and existing leases, the President's Commission compared this fee proposal to the mechanism used by the Federal Communications Commission (FCC). In FY 2016 the FCC received $384 million[177] from regulatory fees imposed on interstate and international radio, television, wire, satellite and cable operators in all 50 states, the District of Columbia, and U.S. territories. An independent U.S. government agency overseen by Congress, the Commission is the United States' primary authority for communications law, regulation, and technological innovation. The FCC is authorized to obligate funds up to the amount approved in the annual appropriations act. Amounts appropriated are offset by fees collected from industry. Fee amounts collected in excess of the budget are not available to the FCC.

This is a similar arrangement to BSEE, whereby BSEE's annual budget is funded through appropriations and these are offset by the amounts collected into the General Treasury from inspection fees, rental income, and other fees. This arrangement ensures ongoing congressional oversight of the fees collected as well as the amounts made available to operate federal programs. An alternative arrangement whereby a new source of revenue is made available directly to BSEE with authorization to obligate in total, such as is available to some federal programs, would require congressional enactment of legislation to authorize the new source of funding and the use of funds by BSSE. Executive Branch and congressional approval would be required, but because it allows for reduced oversight it is unlikely that this arrangement would be acceptable to the Executive Branch or Congress.

The Commission suggested that an industry-based source of funds for BSEE would be an advantage in terms of long-term stability. They suggested that if regulation were funded by the industry instead of the taxpayers, Congress would have less incentive to reduce funding.[178] The Commission offered that Congress could instruct DOI to include lease

[177] U.S. Federal Communications Commission, ***FY 2017 Budget in Brief***, February 2016.
[178] National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, ***Deep Water: The Gulf Disaster and the Future of Offshore Drilling***, January 2011, available at https://www.gpo.gov/fdsys/pkg/GPO-OILCOMMISSION/pdf/GPO-OILCOMMISSION.pdf.

provisions that require the imposition of regulatory fees, which is permissible based on broad authority in OCSLA to include in leases “such rental and other provisions as the Secretary may prescribe at the time of offering the area for lease.”[179]

DOI could impose a new fee or new fees through the leasing process through rulemaking. However, because of the comity between the Executive Branch and Congress it would be important to notify and solicit input from Congress before doing so. Imposing a new fee on industry would be preferable, because a proposal to seek funding for BSEE from current OCS funding streams, i.e. existing fees, rentals, royalties, or bonus bids would impact the amounts deposited into the General Treasury and already accounted for thereby creating a scoring problem and adding to the deficit.

In FY 2016, in addition to inspections fees and rental receipts, BSEE collected $7.8 million through cost recovery fees. Cost recovery is authorized by the Independent Offices Appropriations Act of 1952, which provides authority to federal agencies to recover the costs of providing services to the non-federal sector. There are 31 different services and activities conducted by BSEE for which there are charges including for example review of plans and applications by oil and gas operators.

BSEE recently conducted an in-depth review of these 31 services and pre-production site visits along with the associated cost recovery fees to determine whether the costs of providing each of the services supports the existing fee structure in the existing regulations. This review and associated proposal to align fees with costs complies with OMB requirements in Circular A-25, which requires that federal agencies assess charges to identifiable recipients of special benefits derived from federal activities beyond those received by the general public.[180] A Federal Register notice issued on November 17, 2016 is a result of this review and provides the basis to revise the fee schedule in order to:

- Increase 17 fees;
- Reduce 8 fees;
- Subdivide 6 fees into two tiers by complexity, with six of the subdivided fees increasing above the existing undivided fee, and six decreasing;
- Decrease certain fees for two of the facility production safety system applications for visits offshore and increase them for visits to facilities while in a shipyard; and
- Implement a new pre-production site visit fee for four facility production safety system applications that did not previously include site visit fees.[181]

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[179] 43 U.S.C. § 1337(b)(6)).
[180] OMB Circular A-25 requires federal agency review of user charges to determine whether adjustments are necessary and to review other agency programs to determine whether new fees should be established for any services it provides, at: https://obamawhitehouse.archives.gov/omb/circulars_a025//.
[181] Federal Register, ***Proposed Rule - Adjustments to Cost Recovery Fees Relating to the Regulation of Oil, Gas, and Sulfur Activities on the Outer Continental Shelf***, November 17, 2016, pp. 81033-81049.

As stated in the Federal Register Notice, the results of BSEE's analysis of the costs of these services reflects the changes in offshore operations in the last ten years: offshore operations have moved into deeper, more complex, and more hostile environments. This evolution of offshore operations has resulted in increasingly technical and more complex requests submitted by operators. Reviewing and approving these requests requires extensive communication and collaboration among offshore operators, BSEE engineers, and BSEE subject matter experts. It also requires additional time and more experienced, senior-level staff. The costs of these services also reflect higher personnel costs than were included in the existing regulation due to the special pay rates for BSEE's geoscientists and engineers conducting this work.

Originally scheduled to close on January 17, 2017, BSEE extended the comment period on the proposal through February 16, 2017.[182] Once finalized the new regulation would adjust BSEE's estimated cost recovery to align with the costs of providing these services. The timing on the processing of public comments and finalization of the regulation is not known.

Stability in BSEE's funding would support continuity for the organization and retention of its highly skilled workforce. The Commission was not alone in recognizing the impact of inadequate resources on the ability of MMS to effectively regulate an industry with some of the most complex technology available in the energy field.[183]

Recommendation 7.1

BSEE, in cooperation with DOI and OMB, should finalize the cost recovery regulation and continue to seek proposed changes in inspection fees to align them with current program requirements. BSEE, in cooperation with BOEM, should formulate proposals to submit to DOI and OMB that fund the shortfall in collections. Timely action is needed so these additional regulatory fees can be included in future OCS leases and avoid impacts to BSEE's budget.

<u>Renewable Energy:</u> Assuming full responsibility for the regulatory aspects of the renewable energy program will result in increased workload and costs for BSEE. In particular, there are very likely unique skills and competencies needed that BSEE may not currently possess. In preparation for projects coming on line in FY 2019, resources should be included in BSEE's budget for this new set of responsibilities.

[182] Federal Register, ***Proposed Rule - Oil, Gas, and Sulfur Activities on the Outer Continental Shelf – Adjustments to Cost Recovery Fees***, January 5, 2017, pp 1284-1285.
[183] Stuart Theriot, ***Changing Direction: How Regulatory Agencies Have Responded to the Deepwater Horizon Oil Spill (Part I of II)***, *LSU J. Energy L. & Res. Currents,* November 19, 2014.

Recommendation 7.2

BSEE should consider funding requirements for the renewable program as part of FY 2018 budget formulation and in future budgets.

Decommissioning: Responsibilities for decommissioning are also an expanding area of responsibility for BSEE. Aging infrastructure in the OCS and a sustained period of low prices for oil and natural gas are driving a significantly increased workload. BSEE is responsible for working with operators and determining if existing structures will be left in place or removed, reviewing and approving permits, and conducting compliance reviews of the work done by operators. More than 40 percent of the platforms on the OCS are over 25 years old. Over the past decade industry has averaged 130 platform removals annually, however, the number of permits issued for platform removal in 2012 was three times this number.[184] There is also a significant workload for BSEE related to evaluating the liability and financial assurance associated with performance of decommissioning, including bankruptcy petitions and restructuring agreements. BSEE is working closely with BOEM, the Office of the Solicitor and others in DOI to identify liabilities and ensure that these costs do not revert to the government.

Recommendation 7.3

BSEE should consider funding requirements for the decommissioning program as part of FY 2018 budget formulation and in future budgets.

[184] BSEE Decommissioning Liability Workshop, New Orleans, LA, August 25, 2016 and Michael Saucier, BSEE Decommissioning Abandonment Summit, no date.

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Chapter 8: Facilitating Organizational and Cultural Change

BSEE has achieved substantial development since its establishment in 2011. BSEE was created for the explicit purpose of implementing reforms in management of the OCS, for which the need had long been recognized and the Deepwater Horizon event created a sense of urgency. The establishment of BSEE as a separate entity represents a change in DOI's national program focus towards balancing production with safety and environmental compliance and conservation. In support of this balanced program, BSEE has adopted a risk-based approach, giving greater attention to low probability, high consequence events and being more prepared to respond to new and emerging types of operational and organizational risks, which could impact the OCS and expose taxpayers to liability.

As detailed throughout this report, this shift in focus has led to the modification of BSEE's organizational structure and new capabilities, processes, and procedures necessary to support it. It has also led to the implementation of new and more effective, performance-based regulatory approaches. While BSEE faces a number of risks, continued progress toward attaining strategic goals and ongoing activities planned to keep pace with industry developments could help to reduce risk. Risk could also be reduced with a change management strategy that facilitates cultural change, communication and collaboration, and encourages alignment with BSEE's strategic vision.

A change management strategy can build on work that has already been done and be the mechanism to facilitate initiatives that are being implemented– the national program management model, environmental stewardship, and the communication and employee engagement strategy (discussed later in this chapter). The change management strategy can also integrate desired and/or planned changes to assume additional responsibilities for renewable energy regulation and enforcement. The results of internal reviews and evaluations can also inform a change management strategy as can actions recommended and directed by others including GAO and Congress.

Change management is an important component of implementing organizational realignments, as well as in establishing and strengthening governance and accountability procedures. It is also an essential element of ERM (discussed in Chapter 5), which relies on collaboration and knowledge sharing to support risk-based decision making, learn from risk-based pilot efforts, and adjust those efforts based on experience. As a cross-cutting initiative, ERM, can drive change by creating opportunities to integrate and connect program elements. Knowledge management, discussed in Chapter 4, shares a number of tools with change management that can be used to build a culture of collaboration.

<u>Change Management</u>

Change Management can be defined as a "deliberate set of activities that facilitate and support the success of individual and organizational change and the realization of its intended business results."[185] Key elements of change management, as adapted by the Academy are:[186]

- Ensure top leadership drives the transformation
- Establish a clear vision and integrated strategic transformation goals
- Design the organizational structure that will enable the vision
- Create a sense of urgency, implement a timeline, and show progress from day one
- Communicate frequently through multiple channels to multiple stakeholders
- Dedicate a powerful implementation guidance team to manage the transformation process
- Engage employees to seek their improvement ideas, build momentum, and gain their ownership for the transformation
- Sustain the effort by nurturing a new culture, rewarding risk, and assessing progress

Appendix H includes a summary of widely accepted best practices for change management that could supplement the BSEE-tailored change management strategy described here.[187]

The study team's concept of a change management strategy is a structured group of activities designed to achieve and sustain desired outcomes and drive toward BSEE's desired future state. The change management strategy defines the transformation process that BSEE would use to achieve better integration across the organization, complete efforts that bring consistency and cohesiveness to operations, improve collaboration and communication, and better align multiple efforts to bring about more effective outcomes sooner and more efficiently.

As an organization in transition that is committed to strategic goals for operational and organizational excellence, BSEE is in an ideal position to implement change that is not only necessary but also unavoidable in a the rapidly shifting environment in which BSEE operates. Some of the core elements described above are in place: top leadership is driving transformation with a clear vision and strategic goals defined in the strategic plan. BSEE's principles for clarity, consistency, predictability, and accountability that are embedded in the strategic plan can help drive cultural and employee behaviors. Although it faces implementation challenges, the national program management model provides an organizational structure that is designed to enable the vision and promote maturity in program areas that GAO has criticized including investigations and enforcement. Implementation of the model is inextricably linked with and dependent on cultural change.

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[185] Association of Change Management Professionals, ***What is Change Management***?, available at http://www.acmpglobal.org/?page=WhatisCMhttp://www.acmpglobal.org/?page=WhatisCM.
[186] Adapted from Kotter 2002, in National Academy of Public Administration , **U.S. Coast Guard Modernization Study**, Washington D.C., April 2009.
[187] Cohen, Dan and John Kotter, ***The Heart of Change,*** Boston: Harvard Business School Press, 2002; Government Accountability Office, ***Results-Oriented Cultures: Implementation Steps to Assist Mergers and Organizational Transformations***, GAO-03-669, July 2003; Marc A. Abrahamson and Paul R. Lawrence, ***Transforming Organizations***, Lanham, MD: Rowman and Littlefield Publishers, 2001.

A key challenge for BSEE in implementing planned change, including model implementation, is getting buy-in and ownership at all levels and in all units of the organization, particularly the larger units that have a substantial influence on the organization. This will require employee engagement and input as to the way to achieve the desired future state, as early in the process as possible. The strategic planning process can provide a basis for expanded engagement and getting buy-in for needed changes. Use of the Foresight process can engage the leadership in exploring more uncertain longer-term alternative scenarios that could affect the mission, and potential consequences of decisions in a changing environment.

An important aspect of getting buy-in will be to acknowledge and reconcile conflicting visions of the organization's immediate and long-term future, which might also be explored using Foresight tools. Particular differences that came to the attention of the study team pertain to the environmental compliance program, for which roles and responsibilities remain to be definitively decided, and between the conceptual approaches to risk management found in program-based initiatives and in ERM.

Another important aspect of buy-in is to make the case for specific changes that demonstrates their urgency and their benefits, for individual employees and programs as well as for the organization and its principal stakeholders - the regulated industry and the public. The strategic plan, combined with results of the Foresight process, and examples from the areas of success in collaboration and national program management model implementation – in SIID and data stewardship – should all be used to make the case for change and to engage all levels of the organization.

Implementation of the change management strategy will require the articulation of activities needed to achieve these benefits including an integrated timeline with milestones, guidance of a dedicated team (governance), and performance agreements linked to the roles that individuals have in the process. The entire process will need to be supported by leadership and a strategy for communication and ongoing employee engagement.

Design and Implementation of a BSEE Change Management Strategy

As discussed in Chapter 4, BSEE considered a change management plan in 2015 as a potential tool to support implementation of the national program management model. That initial change management plan suggests a number of useful initiatives including strategic communications, leadership engagement, employee engagement, and training to support BSEE's people through the transition. The initial change management plan was intended to support implementation of the program management model and so is likely not appropriate for BSEE's ongoing organizational and cultural transformation, but may provide a point of departure for the development of a more comprehensive strategy.

BSEE's change management strategy should build on its earlier efforts and on the best practices already discussed, incorporating specific guidance in the following areas:

- Leadership;
- Culture;
- Governance;
- Communication; and
- Collaboration.

The Leadership Component: BSEE has two large and highly influential entities that dominate its operations, culture, and norms. The Office of Offshore Regulatory Programs (OORP), located in headquarters, is significantly larger in size and scope than the Oil Spill Preparedness, Environmental Compliance, Safety and Incident Investigations, and Safety Enforcement Divisions. The Gulf of Mexico Region (GOMR) controls a field program that eclipses the Pacific and Alaska regional programs in size and scope of activity. Given their size and influence, OORP, GOMR and their leaders should have a significant role in leading change management efforts along with the other senior management team members.

All of BSEE's leaders and managers should be ensuring engagement in change efforts throughout all levels of their organization, making sure there are high levels of communication and collaboration, creating opportunities for teamwork and making training, coaching, mentoring and other tools available to facilitate this process. BSEE's 2015 change impact assessment underscored the need for strong collaboration between members of headquarters management functions and among the members of the Management Council. The assessment also recommended the use of strategies, tools, and resources to encourage teamwork and open communication in order to overcome a tendency of individual members to make decisions independent of other activities taking place across the bureau.

The Cultural Component: The Academy study team was told in interviews that cultural differences are impeding the ability of some organizations and individuals to work together as well as they should. The team was also told there is insufficient appreciation, understanding, and respect between headquarters and the regions and that collaboration is not practiced uniformly throughout the organization. Despite cultural differences and less than desirable engagement levels, however, BSEE's employees are committed to the organization and its mission. This is a positive force for change and a good foundation for integrating the efforts of BSEE's employees and organizations to work more effectively toward a common culture and BSEE's strategic goals.

The organizational culture is shaped by the underlying assumptions, beliefs, values, attitudes, and expectations shared by an organization's members. Culture change or perpetuation of a desired culture is a long- term effort that takes 5-10 years to complete and requires a combination of techniques. Of greatest importance is leadership, the commitment from management in words and actions, and training to promote and develop skills.[188]

The following techniques were found to be useful by private sector companies in changing a culture and perpetuating a desired culture. Strong top management and a display of commitment and support for core values and beliefs are crucial.

- Display top management commitment and support for values and beliefs;
- Train employees to convey and develop skills related to values and beliefs;
- Develop a statement of values and beliefs;
- Communicate values and beliefs to employees;
- Use a management style compatible with values and beliefs;
- Offer rewards, incentives, and promotions to encourage behavior compatible with values and beliefs;
- Convey and support values and beliefs at organizational gatherings;
- Make the organization's structure compatible with values and beliefs;
- Set up systems, procedures, and processes compatible with values and beliefs;
- Replace or change responsibilities of employees who do not support desired values and beliefs;
- Use stories, legends, or myths to convey values and beliefs;
- Make heroes or heroines of exemplars of values and beliefs;
- Recruit employees who possess or will readily accept values and beliefs;
- Use slogans to symbolize values and beliefs;
- Assign a manager or group primary responsibility for efforts to change or perpetuate culture.[189]

BSEE's mission for safety, protecting the environment, and conserving resources through vigorous regulatory oversight and enforcement has been in place since 2011 and captures the bureau's core values. BSEE's efforts to bring about a melding of diverse cultures that exist within the bureau could be informed with the use of data-driven analyses of workforce composition and employee feedback both through the FEVS results (discussed in Chapter 6) and the employee engagement process discussed later in this chapter. This is an area that requires special attention in that BSEE's workforce includes a mix of employees who have many years of service and relatively new federal employees, more mature employees who are nearing retirement and millennials. About one-half of BSEE's employees have ten or fewer years of federal service and about one-quarter have more than 25 years of federal service. The single biggest cohort of employees is comprised of individuals with 5-9 years of service. Nearly one-half of the employees are in mission-critical series including engineers, geographers, geologists, geophysicists, and inspectors.

[188] Government Accountability Office, ***Organizational Culture: Techniques Companies Use to Perpetuate or Change Beliefs and Values***, GAO/NSIAD-92-105, February 1992.
[189] Government Accountability Office, ***Organizational Culture: Techniques Companies Use to Perpetuate or Change Beliefs and Values***, GAO/NSIAD-92-105, February 1992.

The spread of employees geographically is also not uniform, with the majority of employees in headquarters and GOMR.

The Governance Component: Governance is defined as the structures and processes that enable the organization.[190] Governance structures can improve the organizational and operational effectiveness of federal agencies and programs. Governance provides a structure for collaboration, information sharing, and decision making; promotes alignment and common understanding of the organization's vision, goals, and priorities; improves the deployment of resources; is a venue to resolve conflicts; provides representation for majority and minority views; and maintains a sense of urgency and focus.[191]

Governance structures and processes, in the form of councils, committees, boards and management teams should be a component of BSEE's change management strategy. In developing the strategy, BSEE should balance the value of additional governance structures and processes with the additional resources needed to support these structures and processes. BSEE's has formal governance structures and processes in place at the leadership level and for information technology (IT), data stewardship, human resources, and training.

The Management Council: Serving as BSEE's executive steering committee, the BSEE Management Council (MC) includes the senior managers in headquarters and the regions. It is a forum for interaction among the office, division, and regional directors and with the Director and Deputy Director. Meetings of the MC are regularly scheduled and consistently held. The MC has been a consistent source of direction, leadership, and strategic alignment for the bureau.

Although no longer in existence, the Management of Operations and Policy or MOP operated at the middle management level and as a forum for OORP and the regions to work through programmatic and operational issues. Although the Director and Deputy Director encourage senior managers to meet, this is not happening (at least not consistently) and does not substitute for a formalized, instituted governance structure. There continues to be an interest on the part of BSEE's senior managers to create a middle management body as a venue to share information and collaborate on programmatic and operational issues. There is no effort underway to establish a group and there is a lack of consensus about the scope and purpose because of concerns about convening a group that is too large to be functional and the need for focused discussion about individual program areas that does not require attendance by all members of the leadership team.

More informal governance structures in the form of communities of practice could help to address these needs. The study team recommends that BSEE establish communities of practice for critical areas of knowledge associated with strategic risks as part of a

[190] IBM Corporation, ***Defining Program Governance and Structure,*** 2005.
[191] State of Illinois Interoperability Project, ***Best Practices in Project Governance Research Summary***, February 2013.

knowledge management strategy, and in support of enterprise risk management as discussed in Chapters 4 and 5. The study team also recommends convening a strategic plan working group (recommended in Chapter 5) and governance bodies organized around national program managers (discussed in Chapter 4).

IT Governance: There is a governance framework for information technology (IT) including shared governance with BOEM to align and prioritize IT-enabled solutions and resources based on the goals, directives, and missions of the bureaus and with DOI plans. The BOEM/BSEE IT Technology Leadership Board includes representation from both bureaus and ONRR. It is the highest-level body that oversees and approves the shared IT portfolio, IT strategic plan, IT policies and budget, and makes determinations about identified risks. BOEM and BSEE each have a Requirements Priority Board that is the second level body that governs the bureaus' IT portfolio, the budget, and investments. The BSEE Requirements Priority Board is chaired by the Chief of the Office of Budget and includes other national program managers and regional directors. An Integrated Project Priority Team works on behalf of BOEM and BSEE, with representation from both bureaus, to manage individual projects and investments and integrate the efforts of separate BOEM and BSEE Project Priority Teams. For all of these entities, the Boards have been established and are operational, charters are in place, and roles and responsibilities are defined.

Human Capital Governance: Governance for human capital matters is also in place. The BSEE Human Capital Council is responsible for aligning Human Capital programs with the strategic plan; encouraging continuous improvement and management accountability; and ensuring that the bureau has the technical and managerial knowledge and skills needed to accomplish its goals. The Council is responsible for developing strategies for current and future needs, monitoring metrics to achieve goals, and benchmarking human capital programs. Membership includes a full complement of human resources, training and equal employment representatives as well as programs and regions, but not on a permanent basis. The consistent presence of a representative from a region and a program office (potentially this membership could rotate among the regions and programs) would add program perspective.

Data Stewardship Governance: The Data Stewardship Council was established to facilitate implementation of the Data Stewardship Program, provide management guidance on matters related to data and information assets, and other matters that relate to data and IT efforts that impact data stewardship. The Council promotes managing data as an asset to ensure that data are discoverable, accessible, and usable for BSEE's mission areas and that BSEE's efforts align with Departmental policy and implementation guidance.

Training Governance: The Training Governance Board is charged with oversight of the technical training program operated by OORP, including planning and evaluation to gauge effectiveness of the program. Expanded governance to provide oversight and program engagement in all training programs could help improve sharing of expertise and support, inform the development of curriculum and training requirements, evaluation, and ensure ongoing alignment with BSEE priorities. The study team recommends expansion of training governance in Chapter 6.

Additional BSEE governance could add opportunities for alignment of national policy development and oversight, program management and execution, and alignment with strategic goals, business process, budgetary resources, and acquisition plans, and identify impediments and risks to the ongoing program. Governance, in the context of this discussion about team-oriented, decision-making bodies, is also an opportunity to expand collaboration, communication, information dissemination, and education.[192]

The Communication Component: BSEE has deployed multiple types of communication to promote internal and external understanding and engagement. Employees can get information from the internet and intranet sites, the Director's corner, blog or Pipeline (a BSEE internal communication). External stakeholders have access to the internet site and informative annual reports for 2014, 2015, and 2016.[193] There are additional avenues for communication with BSEE for operators that are not addressed here. BSEE's strategic plan advocates for fostering a culture of collaboration and "intra-bureau interaction and team building through details among headquarters, regional, and district offices to enhance collaboration and trust and minimize barriers to productivity."[194]

In 2016 BSEE conducted a two-month, in-depth process to gain insights into effective communication and employee engagement. Employees were asked about the forms of communication that they would like to see. As part of the initiative, BSEE's Office of Public Affairs conducted over 100 employee interviews and more than 50 focus groups, making sure to include an adequate representation of BSEE organizations. A common theme emerged – employees have limited interaction with other programs and minimal knowledge of activities and people outside of their immediate office. The isolation of employees and limited flow of information contributes to low levels of engagement and collaboration.

As part of the employee engagement initiative, BSEE employees provided input on their use and the value of existing communication tools. Employees were very positive about the BSEE annual report. Based on the results of interviews and focus groups, the Public Affairs Office developed a set of recommendations to improve employee interaction and communication as well as promote team building, use of a trust model to deepen relationships, and executive and team coaching. In addition, a number of specific recommendations were made to develop tools that could increase collaboration including:

- An automated internal bureau-wide employee directory with current email addresses, telephone numbers, and profiles to reflect current roles.
- Organization charts with names and contact information to allow employees to see where other employees are located within the organization and understand the chain of command.

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[192] IBM Corporation, ***Defining Program Governance and Structure,*** 2005.
[193] Bureau of Safety and Environmental Enforcement, ***Annual Report 2014, 2015, and 2016,*** at: https://www.bsee.gov/newsroom/library/annual-report.
[194] Bureau of Safety and Environmental Enforcement, ***Strategic Plan FY 2016-2019***, December 21, 2015.

- A formalized rotation program across the districts in the Gulf of Mexico Region and between headquarters and the regions to promote improved understanding of the bureau and its programs, develop professional relationships among employees, and for employees to be able to get developmental experience.
- A mentorship program to facilitate knowledge transfer and reduce knowledge loss and promote the development of individual development plans and a broader understanding of programs and activities.
- Brown bag sessions for senior staff to share knowledge on their area of expertise and to facilitate knowledge transfer.
- Cross-disciplinary teams that foster collaboration including in-person contact when possible or video teleconferencing to build professional relationships, foster improved understanding and information flow.
- Redesign of the BSEE Pipeline to improve ease of use.
- A newsletter or news brief to inform employees about current activities.

Additional recommendations were made to conduct employee orientation more frequently, develop a BSEE handbook for employees, and standardize the process for archiving work. Lastly, the initiative generated recommendations for improved communication by managers including regular staff meetings and open door policies, as well as consideration for staggered hours of operation because BSEE operates in multiple time zones and training for professional development.

BSEE has incorporated a number of the strategies in its Leadership Development Program, which will provide long-term benefits; however, some of these strategies could be deployed on a broader basis as part of the change management strategy. These strategies have the potential to build professional relationships and respect, advance knowledge management, and foster collaboration. Other agencies including the Transportation Security Administration and U.S. Secret Service have implemented employee engagement tools that allow employees to identify ideas and new ways of doing business using a web-based crowd-sourcing platform. The Secret Service's Spark! program encourages employees to submit ideas, suggestions, or recommendations for improved security, efficiency, costs savings, and morale. Employees indicate their support for posted suggestions, and depending on the ratings and potential impact, they are forwarded to managers for a response. Managers have 30 days to respond to the proposals and are responsible to vet and implement them.[195] Implementation of a tool like this and other KM tools described in Chapter 4 could help advance communication and collaboration as could implementation of recommendations made in the employee engagement process.

<u>The Collaboration Component:</u> BSEE advanced a vision for itself that involves high levels of collaboration and included it in the 2016-2019 Strategic Plan as follows: "Fostering an

[195] National Academy of Public Administration, ***United States Secret Service: Review of Organizational Change Efforts***, October 2016 at: http://www.napawash.org/2016/1825-united-states-secret-service-review-of-organizational-change-efforts.html.

agile, trusted, and collaborative organization dedicated to risk offshore."[196] The national program management model advances collaboration. BSEE has the tone-at-the-top for collaboration, but additional effort is needed to make it an ongoing practice that is embedded in how the bureau's employees work together on a day-to-day basis.

BSEE does not have mechanisms to monitor, evaluate, report, and reinforce accountability for collaboration. Thus, BSEE should be building goals for collaboration into performance plans and reviews. Effective performance management can help individuals to see the connection between their daily activities and organizational goals. Successful organizations use their performance management systems to support their strategic and performance goals, their core values, and transformational objectives.[197] A review of lessons learned for engaging millennials and other age groups identifies key drivers to enable employee engagement, which include constructive performance conversations, career development and training, work-life balance, inclusive work environment, employee involvement, and communication from management.[198]

BSEE's can increase efforts to foster collaboration by expanding employee engagement and communication, creating opportunities for teams to work together under the umbrella of a change management strategy. The national program management model has as one of its key values high levels of collaboration and BSEE's continued efforts to improve understanding and support for the model will also contribute to positive cultural change. BSEE's training programs will also foster cultural change, particularly leadership training, which includes rotations of employees. The knowledge management strategy recommended in Chapter 4 is explicitly designed to foster collaboration through knowledge sharing, and should be supported by a change management plan. BSEE's ability to create a culture of collaboration, face ongoing changes in its environment, and implement the recommendations in this report can be facilitated with a structured approach to organizational change management. A change management program and strategy should be the organizing framework to unify BSEE's efforts.

Recommendation 8.1

BSEE should develop and utilize a more comprehensive change management strategy to support the development of a more unified, collaborative and proactive organizational culture, using tools that can strengthen capabilities for engagement, knowledge sharing, collaboration and communication. The strategy should consider best practices and specific guidance provided by the study team, and address special challenges with respect to leadership, culture, governance, collaboration, and communication. The study team suggests that a full-time change management advocate should lead this effort.

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[196] Bureau of Safety and Environmental Enforcement, ***Strategic Plan 2016-2019,*** December 21, 2015.
[197] Government Accountability Office, ***Results Oriented Cultures: Creating a Clear Linkage Between Individual Performance and Organizational Success,*** GAO-03-488, March 2003.
[198] Government Accountability Office, ***Federal Workforce: Lessons Learned for Engaging Millennials and Other Age Groups***, GAO-16-880T, September 29, 2016.

APPENDIX A: EXPERT ADVISORY GROUP AND STUDY TEAM

EXPERT ADVISORY GROUP

Dan Blair,* — Mr. Blair is the former President and Chief Executive Officer of the National Academy of Public Administration. He has more than 26 years of federal public service and is a recognized expert and prominent leader in public service management, having served in top leadership positions in the Executive and Legislative branches as well as the regulatory sector. He received successive Presidential appointments to the Office of Personnel Management and the Postal Regulatory Commission and was unanimously confirmed by the Senate. Prior to joining OPM, he served on Capitol Hill, working for nearly 17 years on the staffs of both House and Senate committees charged with postal and civil service oversight. He received a Bachelor of Journalism degree from the School of Journalism at the University of Missouri-Columbia and his J.D. from the School of Law at the University of Missouri-Columbia.

Barry Rabe,* — Dr. Rabe currently serves as the J. Ira and Nicki Harris Family Professor of Public Policy, at the Gerald Ford School of Public Policy, at the University of Michigan. He is a former Visiting Professor at the University of Virginia's Miller Center of Public Affairs. He was a non-resident Senior Fellow in the Governance Studies Program of the Brookings Institution and President of the Federalism Section of the American Political Science Association. He held positions with the University of Michigan as the Director, Program in the Environment; Interim Dean, School of Natural Resources and Environment; President, Public Policy Section, American Political Science Association; Book Series Editor, American Governance and Public Policy, Georgetown University Press. Much of his recent research examines state and regional development of policies to reduce greenhouse gases, which has been conducted in collaboration with the Brookings Institution, the Miller Center of Public Affairs at the University of Virginia, and the Pew Center on Global Climate Change. In 2006, he became the first social scientist to receive a Climate Protection Award from the U.S. Environmental Protection Agency in recognition of his contribution to both scholarship and policy making. His 2004 Brookings book, *Statehouse and Greenhouse: The Evolving Politics of American Climate Change Policy*, received the 2005 Lynton Keith Caldwell Award from the American Political Science Association in recognition of the best book published on environmental politics and policy in the past three years. In 2007, he received the Daniel Elazar Award for Career Contribution to the Study of Federalism from the American Political Science Association.

*Academy Fellow

ACADEMY STUDY TEAM

Joseph P. Mitchell, Ph.D., *Director of Academy Programs* — Dr. Mitchell leads and manages the Academy's studies program and serves as a senior advisor to the Academy's President and Chief Executive Officer. He has served as Project Director for past Academy studies for the Government Printing Office, the U.S. Senate Sergeant at Arms, U.S. Agency for International Development/Management Systems International, the National Park Service's Natural Resource Stewardship and Science Directorate, and the USDA Natural Resources Conservation Service. During his 16 years at the Academy, Dr. Mitchell has worked with a wide range of federal cabinet departments and agencies to identify changes to improve public policy and program management, as well as to develop practical tools that strengthen organizational performance and assessment capabilities. As the Academy's studies director, he has provided executive-level leadership, project oversight, and subject matter expertise to over 60 highly regarded organizational assessments and studies, consulting engagements, and thought leader engagements. He holds a Ph.D. from the Virginia Polytechnic Institute and State University, a Master of International Public Policy from the Johns Hopkins University School of Advanced International Studies, a Master of Public Administration from the University of North Carolina at Charlotte, and a B.A. in History from the University of North Carolina at Wilmington.

Pamela Haze, *Project Director* — Ms. Haze has been a Fellow of the National Academy of Public Administration since 2012. She served as Project Director for the Academy's strategic plan development for the Urban Indian Health Program, a component of the Indian Health Service in the Department of Health and Human Services, and as a Senior Advisor on the Academy's evaluation of organizational reform efforts within the U.S. Secret Service and an assessment for the Farm Services Agency in the U.S. Department of Agriculture. Before joining the Academy staff, she served as the Deputy Assistant Secretary for Budget, Finance, Performance and Acquisition at the U.S. Department of the Interior (DOI). In addition, she served as the Director of DOI's Office of Budget. She spent the majority of her 34-year federal career with DOI and worked for the Fish and Wildlife Service, the U.S. Geological Survey, the Bureau of Land Management, and the Bureau of Outdoor Recreation. She is a recipient of the Elmer Staats Award for Personal and Professional Standards and the Meritorious and Distinguished Presidential Rank Awards. Ms. Haze received a Bachelor of Science in Biology and Masters of Science in Environmental Science from George Mason University.

Thorsen, Kim, *Senior Advisor* — Ms. Thorsen is a Senior Advisor at the Academy who previously served as Deputy Assistant Secretary for Public Safety, Resource Protection, and Emergency Services at DOI and before that as the Department's Director of Law Enforcement and Security. In those roles, she served as advisor to departmental leadership on law enforcement, intelligence, security, emergency management, aviation, wildland fire, and border activities. She has an extensive career in law enforcement having started her career as a criminal investigator at the Forest Service in the Department of Agriculture. She holds a Bachelor of Science degree from Humboldt State University and attended the senior Executive Fellows Program at Harvard University's John F. Kennedy School of Government.

Larry Novey, *Senior Advisor* — Mr. Novey joined the Academy as a Senior Advisor in May 2016 and, in addition to this project, is working on an assessment of governance and management reform at the National Nuclear Security Administration and on an update of EPA's framework for assessing community financial capability in clean-water compliance. Mr. Novey brings extensive experience as counsel to federal agencies, in private legal practice, and on Senate committee staff. Most recently, he served as Chief Counsel for Governmental Affairs for the U.S. Senate Committee on Homeland Security and Governmental Affairs, where he was responsible for legislative and policy development in cross-agency areas such as agency organization, regulatory policy and process, and human capital management. Previously, Mr. Novey was Washington Counsel at an international law firm, where he advised and assisted companies and coalitions regarding regulatory compliance and the resolution of mass claims from toxic-substance exposure. He has also worked as an attorney at government agencies on matters involving environmental protection and on processes for streamlined approval of energy projects. Mr. Novey received a J.D. from Columbia University and an A.B. from Harvard College.

Sylvia Tognetti, *Senior Advisor* — Ms. Tognetti is a Senior Advisor at the Academy working on environmental projects, including current work for the Environmental Protection Agency. She previously worked with the Academy as a Research Associate in 2000 on a study of innovation in environmental protection at the EPA. She also teaches World Physical and Cultural geography courses as an adjunct professor at the University of the District of Columbia Community College. She has held positions at the National Academy of Sciences and the former Congressional Office of Technology Assessment. She has consulted with a variety of non-profit and multi-lateral organizations as well as a private firm on matters of science and policy associated with land and water and climate change. Her work resulted in several reports and publications, including a chapter in the Millennium Ecosystem Assessment, for which she served as a lead author. She also held a position with the World Resources Institute's Food, Forests and Water program, Natural Infrastructure for Water initiative, helping to build the case and develop strategies for increased public and private investment in conservation and restoration of forests, wetlands and other ecosystems for their natural infrastructure values. She holds a Masters in Geography from the University of Maryland.

Emily Fay, *Research Associate* — Ms. Fay joined the Academy in August 2016. In addition to this project, she is working on Academy reviews for the National Nuclear Regulatory Commission and the Transportation Security Administration. She previously worked with the Peace Corps as a volunteer in Botswana and for the George Mason School of Policy, Government, and International Affairs. She received her Master's in Public Administration degree from George Mason University in December 2016 and holds a B.A. in International Affairs from James Madison University.

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Appendix B: Participating Individuals and Organizations

(Titles and positions listed are accurate as of the time of the Academy's contact.)

United States Department of the Interior

Schneider, Janice – Assistant Secretary – Land and Minerals Management

Office of Inspector General

Carlson, Jeff – Director, Energy Audit Unit
Kendall, Mary – Deputy Inspector General

Bureau of Safety and Environmental Enforcement

Headquarters

Buffington, Sharon – Chief, Offshore Training Branch, Office of Offshore Regulatory Programs (OORP)
Dwarnick, Sue – Director, Offshore Safety Improvement Branch, OORP
Fish, David – Chief, Environmental Compliance Division
Fisher, Robert – Chief, Safety and Enforcement Division (Acting)
Keith, John – Senior Advisor
Mabry, Scott – Chief, Office of Administration (OA)
Madden, Molly – Chief, Office of Policy and Analysis
Middleton, Bob – Deputy Chief, OORP
Modrow, Eric – Chief, Office of Budget
Moore, David – Chief, Oil Spill Preparedness Division
Morris, Doug – Chief, OORP
Noem, Stacey – Chief, Safety and Incident Investigations Division
Pardi, Nicholas – Chief, Office of Public Affairs
Pittman, Michael – Chief, Risk Assessment and Permit Policy Division, OORP
Powers, Tim – Chief Data Steward, OA
Salerno, Brian – Director
Schneider, Margaret – Deputy Director

Alaska Region

Fesmire, Mark – Regional Director

Gulf of Mexico Region

Broussard, T.J. – Chief, Office of Environmental Compliance
Green, Susan – Senior Staff, Petroleum
Herbst, Lars – Regional Director
Karl, Kevin – Deputy Director for Production
Kovacs, Stephen – Chief, Office of Enforcement
Prendergast, Michael – Deputy Regional Director for District Operations, Investigations, Enforcement, and Environmental Compliance
Sanders, Ramona – Chief, Environmental Monitoring Unit

Trosclair, Troy – Deputy Regional Supervisor for District Operations

Pacific Region
Fesmire, Mark – Regional Director (Acting)

Bureau of Ocean Energy Management

Cruikshank, Walter – Deputy Director
Orr, Renee – Chief, Office of Strategic Resources

Stakeholders

Government Accountability Office
Rusco, Frank – Director, Natural Resources and Environmental Issues
Talbert, Matthew – Senior Analyst, Natural Resources and Environmental Issues

Van Ness Feldman LLP
Michael Farber

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APPENDIX D: MATRIX OF RECOMMENDATIONS OF THE NATIONAL ACADEMY STUDY TEAM

Topic	Background	Objective	Recommendation
A Mission for Safety, Environmental Protection, and Conservation			
3.1 Maintain a Deconflicted Mission	DOI instituted reforms to its OCS energy program in 2010-2011 to address long-standing weaknesses and shortcoming and in consideration of extensive expert advice, including Presidentially appointed commissions and review boards. Key among the reforms was the separation of DOI's OCSLA responsibilities, to avoid critical responsibilities being compromised by being combined in an entity with contradictory roles. Three entities – BOEM, BSEE, and ONNR – were created to effectively deliver on DOI's responsibilities for (1) managing the mineral resources on the OCS, (2) oversight and enforcement of safety and environmental regulations, and (3) collecting, accounting for, and verifying natural resources and energy revenues. Restructuring to combine these entities would risk reversing the gains made while also causing disruption, uncertainty, and delay.	To ensure that safety, the environment, and conservation of OCS resources are effectively promoted by an entity that can focus on vigorous regulatory oversight and enforcement.	BSEE should remain a separate entity with high levels of coordination with BOEM and ONRR.

Topic	Background	Objective	Recommendation
A Mission for Safety, Environmental Protection, and Conservation (cont.)			
3.2 Complete the Inventory and Updating of Bureau Guidance	BSEE has been conducting an extensive inventory of policies, procedures, and guidance (including handbooks, directives, and Notices to Lessees), much of which was created before BSEE existed and dates back to the 1980s, in order to have a complete record. It is also been updating and creating new policies, procedures, and guidance and automating to facilitate their use internally and externally (by industry and others). BSEE created a system of interim policies, procedures, and guidance for organization of current materials while it continues these efforts.	To maintain an internal focus on completing the inventory; moving to a permanent set of policies, procedures, and guidance; and ensuring priority materials are updated and or created promptly.	BSEE should continue its efforts to inventory, organize, and update policies, procedures, and guidance. It should assign realistic and enforceable timeframes to managers for updating these materials.

Topic	Background	Objective	Recommendation
A Mission for Safety, Environmental Protection, and Conservation (cont.)			
3.3 Support the Environmental Compliance Mission	BOEM is responsible for environmental review under the National Environmental Policy Act (NEPA), including completion of environmental impact statements and environmental assessments. BSEE uses these materials to inform permit reviews and compliance and enforcement efforts.	To ensure that BSEE has adequate environmental information on which to base permit reviews, development of mitigating actions, and conduct inspections and compliance reviews and enforcement actions.	In instances when BSEE does not have adequate information needed to support environmental decisions associated with permitting and enforcement, this situation should be communicated to BOEM. The Memoranda of Agreement (MOA) and Standard Operating Procedures (SOPs) that BOEM and BSEE operate under should be revised or supplemented by the establishment of processes with timelines to ensure that expectations are clearly understood. These processes established by revision or supplementation of the MOAs and SOPs should also include robust procedures for the elevation of matters for resolution, when necessary, and for the periodic review of the process by which BSEE obtains needed information from BOEM to identify systemic issues and needed improvements.

Topic	Background	Objective	Recommendation
A Mission for Safety, Environmental Protection, and Conservation (cont.)			
3.4 Transfer Renewable Energy Compliance and Enforcement Responsibilities	When BOEM and BSEE were created, BOEM was given the responsibility for management of the OCS renewable energy program. BSEE is working with BOEM to assume responsibility for safety and environmental oversight and regulation of OCS renewable energy.	To ensure that BSEE has the capacity and capability in place for an OCS renewable energy compliance and enforcement program, has the ability to fulfill responsibilities based on scheduled projects coming on line, and is planning and preparing for projected future program growth.	BSEE should work with BOEM to accelerate the transfer of environmental oversight, facility inspection, and regulatory enforcement responsibilities for the OCS renewable energy program and develop a schedule to be monitored by ASLM. BSEE should consider these new responsibilities in the development of workforce plans and should ensure that resources are available for these efforts and, as necessary, requested in future budgets.

Topic	Background	Objective	Recommendation
A Mission for Safety, Environmental Protection, and Conservation (cont.)			
3.5 Maintain Alignment with BOEM	BOEM and BSEE were created to separate conflicting OCSLA responsibilities and allow BSEE to develop and operate an effective safety and environmental compliance program. The two bureaus remain closely interconnected, by design, to ensure that each adequately supports the other, primarily in environmental compliance.	To establish sustainable mechanisms that enable BSEE and BOEM to more effectively provide mutual support in interdependent areas and to resolve issues timely and in a manner that best supports DOI goals.	ASLM should establish formal, regularly scheduled reviews of ongoing BOEM and BSEE alignment, processes, and linkages. Among the most important issues to address immediately are updates to the Environmental Compliance MOA and SOPs, and transfer of environmental oversight, facility inspection, and regulatory enforcement responsibilities for the OCS renewable program from BOEM to BSEE. ASLM should seek assistance from ASPMB, as needed, to provide support in matters that require a DOI-wide policy or economic review and in convening working groups to address specific matters.

Topic	Background	Objective	Recommendation
A Mission for Safety, Environmental Protection, and Conservation (cont.)			
3.6 Elevate Decommissioning Issues	Operators in the OCS are required to plug wells, remove structures and pipelines, and take other actions to decommission once production has ended. When they enter into a lease, operators are required to demonstrate their financial ability to conduct these activities to ensure the OCS is returned to its original condition either through bonding or self-insuring for these costs. Under this complex regulatory program, which is administered in part by BSEE and in part by BOEM, financial-assurance and decommissioning requirements and the enforcement of these requirements are intended to ensure that facilities are decommissioned at no cost to the government. However, depending on the policies applied, certain approaches to regulation and enforcement might have the unintended consequence of undermining some operators' financial stability, thereby increasing the risk that neither a responsible operator nor adequate bonding might be available to cover decommissioning costs in certain instances.	To inform DOI leadership and national policy officials of the potential risks of unfunded decommissioning costs, and to facilitate consideration of options – including choices involving BOEM or BSEE regulatory or enforcement policies, or including possible proposed legislation – that might help mitigate those risks.	BSEE should work with BOEM, ASLM, DOI's Office of the Solicitor, and others to elevate issues and provide supporting analyses related to the risk that financial stress in the oil and gas industry might result in some failure to conduct or fund needed decommissioning – issues include (1) choices in BOEM or BSEE regulatory or enforcement policy that might help mitigate those risks, and (2) the absence of a funding source for decommissioning in the event an operator is unable to pay these costs.

Topic	Background	Objective	Recommendation
Strategic Alignment of the Organization			
4.1 Improve Alignment with the National Program Manager Model	BSEE implemented an organizational realignment based on the national program management model on November 4, 2015 that is intended to bring clarity, consistency, predictability, and accountability to BSEE's operations. Several successful models of national program implementation within BSEE demonstrate high levels of communication, collaboration, and understanding of the roles of headquarters and the regions. Other programs and initiatives have not progressed to a comparable level of national program management performance.	To effectively implement BSEE's realignment and facilitate efforts to bring consistency to processes and practices based on the national program management model.	BSEE should complete implementation of the national program management model incorporating best practices for organizational transformation tailored to the needs of individual programs and initiatives; the effort should be coordinated by a single individual or entity reporting to the Director or Deputy Director. The effort should incorporate lessons learned from the Safety and Incident Investigation and Data Stewardship Programs, in particular the high levels of collaboration, effective governance structures and processes, and training.

Topic	Background	Objective	Recommendation
Strategic Alignment of the Organization (cont.)			
4.2 Complete the Environmental Compliance National Program Design	BSEE's realignment to the national program management model changed the reporting relationship for regional environmental compliance staff that were direct reports to the headquarters Division Director and now report to the regional directors. This deviates from historical documents that were the basis for organization of the BSEE environmental enforcement function (now renamed environmental compliance). BSEE has not implemented a systematic approach to environmental stewardship as was envisioned in the establishment of the Environmental Stewardship Collaboration Group, which could optimize agency expertise and outcomes and improve compliance and enforcement. In addition, there are differing views about the nature of the work and role of inspections in the Environmental Compliance Program.	To (1) formulate an Environmental Compliance Program design that engages headquarters and the regions and considers the original design of the environmental enforcement function and the results of the Environmental Stewardship Collaboration Group's work, (2) make final decisions about the appropriate staffing and workforce composition, and (3) complete implementation of the national program and ensure high levels of collaboration and communication.	BSEE should produce a program management design for the Environmental Compliance Program that considers the history of the program's organization and functions as well as the work of the Environmental Stewardship Core Group. The design should detail the activities, work streams, outputs, and outcomes. The design should include workforce plans for headquarters and the regions that can be the basis for staffing decisions, addressing gaps in competencies, and effective implementation of the national program. The process should include an assessment of risk related to reporting relationships as well as appropriate internal controls and risk mitigation measures to ensure the function can effectively achieve mission goals.

Topic	Background	Objective	Recommendation
Strategic Alignment of the Organization (cont.)			
4.3 Improve Utilization of the Engineering Technology Assessment Center	BSEE established ETAC to assist regions with maintaining up-to-date knowledge about emerging technology and support standards setting.	To effectively utilize ETAC's resources for standards setting and national policy development and ensure high levels of knowledge transfer to and from the regions to inform operations, inspections, and permitting.	BSEE should improve the linkage between ETAC and the regions by expanding outreach and engagement and developing a formal governance body and process to ensure high levels of two-way communication between the regions and Office of Offshore Regulatory Compliance (OORP).
4.4 Strengthen Data Stewardship with Knowledge Management	BSEE's Data Stewardship Program is effectively working toward goals to increase the quality and consistency of data, but information and knowledge is not being effectively shared across all of BSEE's organizational units.	To promote more effective information and knowledge sharing.	BSEE should develop a knowledge management (KM) strategy that complements the existing Data Stewardship Program and IT program with tools that enable knowledge sharing and close gaps in the knowledge cycle. As part of this strategy, BSEE should consider establishing communities of practice for critical areas of knowledge to facilitate organizational knowledge retention, knowledge sharing, and learning. A KM pilot for a critical area of knowledge can be used to demonstrate the benefits of KM and inform the strategy prior to full-scale implementation.

Topic	Background	Objective	Recommendation
Operational and Organizational Excellence			
5.1 Reactivate the Strategic Plan Working Group	BSEE convened a working group comprised of a cross-section of BSEE employees that participated in development of the 2016-2019 Strategic Plan, but disbanded the working group after the plan was completed.	To expand awareness of the plan and its use as the basis for ongoing strategic alignment of the organization, resources, priorities, and actions; to create a conduit for continuing input for strategic planning and management; and to facilitate collaboration.	Establish a working group comprised of program and regional representatives, in order to promote improved awareness of and engagement in strategic planning, inform the process for annual priority setting, and expand the use of risk management. Selection of the members of the group should consider the ability of the members to be advocates and change agents within their organizations and the team should be operational in time to assist with BSEE's participation in the development of a new DOI strategic plan.
5.2 Continue the Foresight Initiative	BSEE established the Foresight Initiative to help understand how changes in the energy landscape, geopolitics, technology shifts, workforce, and other factors may impact future activities and programs.	To inform strategic planning, program and budget development, and workforce planning and to better prepare for changes and challenges in the future.	BSEE should institutionalize its Foresight Initiative to provide input to strategic planning and risk assessment and to help anticipate and guide BSEE's programs and operations.

Topic	Background	Objective	Recommendation
Operational and Organizational Excellence (cont.)			
5.3 Enhance Annual and Multi-year Planning	BSEE conducts annual and multi-year planning to drive continuous improvement, advance operational and organizational strategic goals, and respond to stakeholders.	To effectively manage BSEE's annual and multi-year planning and thereby maintain momentum and focus on priority activities.	BSEE should enhance its annual and multi-year planning to include prioritization and sequencing of tasks taking risk assessment into account, assignment of roles and responsibilities for leadership and participation, tracking of progress, and following up.
5.4 Expand Understanding and Use of Enterprise Risk Management	BSEE developed an Enterprise Risk Management Program (ERM) to inform strategic planning and decision-making, strengthen internal controls, and clarify priorities. However, the program is not uniformly accepted, understood, or utilized because there are different conceptual approaches to management of risk found within existing program based initiatives, and there currently is not a common lexicon for risk communication.	To improve the capacity to systematically address organizational and operational risks.	BSEE should establish communities of practice for management of strategic risks and develop a common lexicon that can be used for risk communication. To this end, the ERM program should incorporate learning from the results of the inspection pilot underway and other areas where risk management pilots can expand its use and improve capability. BSEE should also incorporate ERM into its multi-year planning (see recommendation 5-3).

Topic	Background	Objective	Recommendation
Overcoming Human Resource Challenges			
6.1 Conduct Targeted Succession Planning for Senior Leadership	BSEE's senior management cadre comprised of senior executives and GS-15's is small, with a number of individuals who are now or soon could become retirement eligible. BSEE established its Leadership Development Program to develop future leaders, but more targeted efforts are needed to prepare a cadre of individuals that could potentially assume senior leadership roles.	To ensure effective succession in leadership.	BSEE should continue to develop opportunities for GS-14 and GS-15 employees who can gain experience in order to be prepared to assume leadership positions and ensure continuity.

Topic	Background	Objective	Recommendation
Overcoming Human Resource Challenges (cont.)			
6.2 Increase Integration of Training Programs	Training programs are conducted by four BSEE entities to support mission needs. Improvements in effectiveness and efficiency are possible with consolidation of training programs program components. The Training Governance Board oversees technical training, but does not oversee the other training programs.	To holistically address training needs for BSEE employees, to achieve improved effectiveness and efficiency, to improve tracking and reporting, and to increase integration of these programs.	BSEE should create a training governance structure that encompasses oversight of all of its training programs, not just technical training, and should assess the benefits of consolidating or leveraging aspects of its training programs to ensure the highest levels of integration and efficiency across the bureau.
Adequate Resources for Safety, Environmental Protection, and Conservation Offshore			
7.1 Increase Fees and Offsetting Collections	BSEE's resources are at risk due to declining collections comprising approximately 57 percent of its budget and limitations on inspection fees charged to industry.	To address a potential budget shortfall due to declining collections and inflexibilities in the inspection fee.	BSEE, in cooperation with DOI and OMB, should finalize the cost recovery regulation and continue to seek proposed changes in inspection fees to align them with current program requirements. BSEE, in cooperation with BOEM, should formulate proposals to submit to DOI and OMB that fund the shortfall in collections. Timely action is needed so these additional regulatory fees can be included in future OCS leases and avoid impacts to BSEE's budget.

Topic	Background	Objective	Recommendation
Adequate Resources for Safety, Environmental Protection, and Conservation Offshore (cont.)			
7.2 Budget for Renewable Energy Compliance and Enforcement	BSEE is assuming responsibility for safety and environmental oversight of renewable energy projects that may require additional staff and competencies.	To be prepared to assume renewable energy program safety and environmental oversight responsibilities.	BSEE should consider funding requirements for the renewable program as part of FY 2018 budget formulation and in future budgets.
7.3 Budget for Decommissioning	BSEE's decommissioning workload is increasing.	To address an expanding workload in decommissioning.	BSEE should consider funding requirements for the decommissioning program as part of FY 2018 budget formulation and in future budgets.

Topic	Background	Objective	Recommendation
Facilitating Organizational and Cultural Change			
8.1 Implement a Change Management Strategy	BSEE is actively working on operational and organizational reform aligned with the strategic plan, but lacks an integrated organizational change management program or strategy.	To bring greater cohesiveness to BSEE's organizational and cultural change efforts and foster greater collaboration, employee engagement, and communication.	BSEE should develop and utilize a comprehensive change management strategy to support the development of a more unified, collaborative and proactive organizational culture, using tools that can strengthen capabilities for engagement, knowledge sharing, collaboration, and communication. The strategy should consider best practices and specific guidance provided by the study team, and address special challenges with respect to leadership, culture, governance, collaboration, and communication. The study team suggests that a full-time change management advocate should lead this effort.

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APPENDIX E: BSEE'S COLLABORATIVE RELATIONSHIPS WITH FEDERAL AGENCIES

BSEE's works closely with federal and other partners in a variety of ways to leverage its resources. Roles and responsibilities are defined in memoranda of understanding or agreement and interagency agreements.

U.S. Department of the Interior

Within the Department of the Interior, BSEE works closely with BOEM to promote energy independence, environmental protection and economic development through responsible science-based management of offshore conventional and renewable energy and marine mineral resources. BOEM studies the environment and leases resources on the OCS, while BSEE enforces the terms of the leases. BOEM and BSEE also collaborate on decommissioning and the Rigs to Reefs Program. The Office of Natural Resources Revenue (ONRR) collects and disburses royalty revenues generated by energy production on federal lands, to include the Outer Continental Shelf. BSEE performs meter inspections on behalf of ONRR to ensure companies are accurately reporting production totals. BSEE works closely with the Fish and Wildlife Service and operates the Protected Species Program throughout offshore energy programs on the OCS. BSEE monitors and protects animals identified in the Endangered Species Act.

U.S. Coast Guard

BSEE and the U.S. Coast Guard (USCG) have aligned jurisdictional and regulatory responsibilities related to offshore energy development on the OCS. From offshore inspections to incident response and investigations, the two organizations collaborate extensively to reduce redundancy and ensure consistency and clarity for the regulated community. The two organizations work together under an overarching Memorandum of Understanding and several memoranda of agreement related to specific issues that touch on the organizations' shared operating space.

Department of Energy

BSEE and the Department of Energy (DOE) work together in the areas of spill prevention research, risk modeling, renewable energy initiatives, and technology research. BSEE leverages its resources through interagency agreements with two DOE national labs and pursues other areas of common interest to both organizations through a formal Memorandum of Collaboration.

U.S. Department of Transportation, Pipelines and Hazardous Materials Safety Administration

Oil, natural gas, and related liquids produced on the Outer Continental Shelf are transported to shore primarily through the use of pipelines regulated by the U.S.

Department of Transportation, Pipelines and Hazardous Materials Safety Administration (PHMSA). BSEE collaborates with PHMSA in the areas of pipeline safety, spill prevention and response and pipeline rights of way. BSEE entered into an Interagency Agreement with the Department of Transportation's Bureau of Transportation Statistics to develop and manage a voluntary and confidential "Near Miss" reporting tool for individuals working in the offshore oil and gas industry.

Environmental Protection Agency

BSEE and the Environmental Protection Agency (EPA) work cooperatively to protect the environment using different statutory authorities. BSEE coordinates with the EPA on compliance and enforcement matters related to energy development on the OCS. BSEE and EPA have regional memorandums of agreement in the Pacific and Gulf of Mexico OCS regions to coordinate compliance with EPA National Pollutant Discharge Elimination System permits, including facility inspections and enforcement of permit violations. Under statutory direction, BSEE conducts air monitoring directed by the Clean Air Act in the Alaska and Gulf of Mexico regions.

National Aeronautics and Space Administration

BSEE and the National Aeronautics and Space Administration (NASA) entered into a five-year agreement allowing BSEE to capitalize on the best risk management approaches from the aeronautics industry to inform stakeholders and further strengthen worker and environmental safety protections on the OCS. Probabilistic risk assessment is a technique used by NASA to quantitatively model risk. It was used in the modeling of the Space Shuttle Program and is presently being used for the International Space Station and Orion deep space capsule programs.

U.S. Department of Commerce, National Oceanic and Atmospheric Administration

BSEE works with the National Oceanic and Atmospheric Administration (NOAA) in the operation of the Protected Species Program throughout offshore energy programs on the OCS, monitoring and protecting animals identified in the Endangered Species Act and the Marine Mammals Protection Act. NOAA and BSEE also work together on decommissioning requests under the Rigs To Reef policy.

U.S. Army Corps of Engineers

BSEE and the U.S. Army Corps of Engineers coordinate on projects affecting the OCS and shorelines. Both agencies are involved when operators request permission to decommission facilities under the Rigs to Reefs policy.

Interagency Coordinating Committee on Oil Pollution Research

The Interagency Coordinating Committee on Oil Pollution Research (ICCOPR) serves as a forum for its federal members to coordinate and maintain awareness of ongoing oil pollution research activities. The Interagency Committee is comprised of 14 members representing federal independent agencies, departments, and department components. The Coast Guard chairs the Interagency Committee and NOAA, BSEE, and EPA rotate assignments as the vice-chair every two years. The Oil Pollution Act of 1990 requires the Interagency Committee to prepare an Oil Pollution Research and Technology Plan to define the roles of each Federal agency involved in oil spill research and development and to promote cooperation with industry, universities, research institutions, state governments, and other nations.

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APPENDIX F: NATIONAL PROGRAM MANAGEMENT MODEL ROLES AND RESPONSIBILITIES

During the planning for implementation of the national program management model, BSEE developed a clear and consistent set of descriptions for all of the national program managers that is a useful communication tool for internal and external communications. As discussed in Chapter 4, this study recommends posting these descriptions on BSEE's website along with the current organization chart to help improve understanding of the model.

Safety Enforcement Division (SED)

- Collaboratively develops and maintains national compliance and enforcement policy under the guidelines of the Director's Compliance Enforcement Continuum
    - Establishes and maintains complementary procedures and business rules necessary for full implementation of the SED's national program including, but not limited to:
        - Staff training requirements;
        - Tracking and reporting obligations;
        - Setting and revising enforcement priorities;
        - Liaison roles and responsibilities
    - Monitors the execution and effectiveness of the bureau's safety enforcement role and purpose

Safety and Incident Investigations Division (SIID)

- Responsible for establishing the national policies related to the conduct of investigations by BSEE investigators regarding incidents on the OCS
    - Establishes national policies regarding required training for BSEE investigators
    - Establishes procedures for how investigations are conducted and documented, and how incident information is managed
    - Monitors execution and effectiveness of the investigation program

Environmental Compliance Division (ECD)

- Establishes national strategic goals of the environmental compliance program to increase the accuracy, effectiveness and consistency of its environmental compliance activities
    - Oversees environmental compliance activities in accordance with the National Environmental Policy Act (NEPA), the Endangered Species Act (ESA), the Outer Continental Shelf Lands Act (OCSLA), and other statutory requirements
    - Establishes national data needs for the environmental compliance program, maintains and monitors national performance standards, and sets national

policies regarding environmental compliance activities conducted by BSEE personnel
    - Monitors the execution and effectiveness of environmental compliance activity

Integrity and Professional Responsibility Advisor (IPRA)

- Responsible for promptly and credibly responding to allegation or evidence of misconduct and unethical behavior by BSEE employees
    - Works with the Office of Inspector General on internal matters the IPRA investigates
    - Pursues certain administrative investigations with the OIG's consent and knowledge
    - Advises the OIG of the status and results of IPRA investigations, as requested
    - Consults with the Department's Ethics Office and BSEE's Ethics Office with respect to matters the IPRA investigates regarding the Standards of Ethical Conduct for Employees in the Executive Branch (5 CFR Part 2635)
    - Fulfills the same responsibilities on behalf of BOEM with respect to BOEM employees

Office of Offshore Regulatory Programs (OORP)

- Responsible for regulatory, safety, and conservation compliance related to the development of the Nation's offshore resources
    - Develops and maintains regulations, policies, standards, and guidelines for best available and safest practices that govern industry's offshore operations nationwide
    - Promotes efforts to improve safety and environmental protections in offshore operations through policy development and program oversight, funding research into new technologies, and managing external partnerships with industry safety organizations
    - Provides oversight of bureau aviation management and the bureau's offshore training center
    - Manages information collection in compliance with the Paperwork Reduction Act and fulfills federal regulation liaison functions at BSEE
    - Monitors the implementation and effectiveness of activity areas within the program area

Oil Spill Preparedness Division (OSPD)

- Responsible for regulations, policies, standards, guidance, and oversight of oil spill preparedness and oil spill research

- Reviews and approves oil spill response plans, conducts government-initiated unannounced table top and/or deployment exercises, performs response equipment verifications, and exercises enforcement authority with respect to oil spill preparedness for regulated facilities in both Federal and state offshore waters of the U.S. (30 CFR Part 254)
- Manages Ohmsett, the National Oil Spill Response Research and Renewable Energy Test Facility, which supports both technology innovation and training
- Funds and independently conducts research to advance the understanding and efficiencies of mechanical and alternative oil spill response technologies
- Monitors the execution and effectiveness of the overall oil spill preparedness activity

Office of Administration (OA)

- Responsible for financial management and all administrative activities of BSEE
- Oversees the bureau's administrative functions including but not limited to:
  - Acquisition and federal assistance management
  - Human resource management and employee development
  - Data stewardship and information resources management
  - General office services
  - Delegations of authority

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Appendix G: GAO Guidance on Mergers and Organizational Transformations[199]

GAO reported key practices that federal agencies can follow to transform their cultures in response to governance challenges. Because no two merger, acquisition, or transformation efforts are exactly alike, the "best" approach for any given effort depends upon a variety of factors specific to each context. These key practices are:

1. Ensure top leadership drives the transformation. Leadership must set the direction, pace, and tone and provide a clear, consistent rationale that brings everyone together behind a single mission.

2. Establish a coherent mission and integrated strategic goals to guide the transformation. Together, these define the culture and serve as a vehicle for employees to unite and rally around.

3. Focus on a key set of principles and priorities at the outset of the transformation. A clear set off principles and priorities serves as a framework to help the organization create a new culture and drive employee behaviors.

4. Set implementation goals and a timeline to build momentum and show progress from day one. Goals and a timeline are essential because the transformation could take years to complete.

5. Dedicate an implementation team to manage the transformation process. A strong and stable team is important to ensure that the transformation receives the needed attention to be sustained and successful.

6. Use the performance management system to define responsibility and assure accountability for change. A "line of sight" shows how team, unit, and individual performance can contribute to overall organizational results.

7. Establish a communication strategy to create shared expectations and report related progress. The strategy must reach out to employees, customers, and stakeholders and engage them in a two-way exchange.

8. Involve employees to obtain their ideas and gain their ownership for the transformation. Employee involvement strengthens the process and allows them to share their experiences and shape policies.

9. Build a world-class organization. Building on a vision of improved performance, the organization adopts the most efficient, effective, and economical personnel, system, and process changes and continually seeks to implement best practices.

[199] GAO, Results-Oriented Cultures: Implementation Steps to Assist Mergers and Organizational Transformations, GAO-03-669, July 2003

APPENDIX H: ORGANIZATIONAL CHANGE MANAGEMENT BEST PRACTICES

Heart of Change[200] (Kotter/Cohen)	**Implementation Steps to Assist Mergers and Organizational Transformations** (GAO July 2003)[201]	**Transforming Organizations** (Abramson/Lawrence)[202]
Create a sense of urgency so that people start telling each other, "Let's go; we need to change things!"	Ensure top leadership drives the transformation.	Select the right person.
Pull together a guiding team powerful enough to guide a big change.	Establish a coherent mission and integrated strategic goals to guide the transformation.	Clarify the mission.
Create clear, simple, uplifting visions and sets of strategies.	Focus on a key set of principles and priorities at the outset of the transformation.	Get the structure right.
Communicate the vision through simple, heartfelt messages sent through multiple channels so that people begin to buy into the change.	Set implementation goals and a timeline to build momentum and show progress from day one.	Seize the moment (urgency/right time).
Empower people by removing obstacles to the vision.	Dedicate an implementation team to manage the transformation process.	Communicate, communicate, communicate.
Create short-term wins that provide momentum.	Use the performance management system to define responsibility and assure accountability for change.	Involve key players.
Maintain momentum so that wave after wave of change is possible.	Establish a communication strategy to create shared expectations and report related progress.	Engage employees.
Make change stick by nurturing a new culture.	Involve employees to obtain their ideas and gain their ownership for the transformation.	Persevere.

200 Dan Cohen and John Kotter, *The Heart of Change.* Boston: Harvard Business School Press, 2002.
201 U.S. Government Accountability Office, *Report to Congressional Subcommittees, Results Oriented Cultures: Implementation Steps to Assist Mergers & Organizational Transformations* GAO-03-669. Washington, D.C.: July 2003.
202 Marc A. Abrahamson and Paul R. Lawrence, *Transforming Organizations.* Lanham, MD: Rowman and Littlefield Publishers, 2001.

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ISSUE: Decommissioning Liabilities – Orphaned Infrastructure, Terminated Leases, and Idle Iron

I. KEY POINTS

An important charge in BSEE's authorizing legislation is to ensure that exploration, development, and production activities undertaken pursuant to OCSLA are properly secured and removed (i.e., decommissioned) to ensure the long-term protection of the resource and the surrounding environment. As production and operations mature, the decommissioning of wells and facilities on terminated leases or on active leases that are no longer useful for operations will be a growing portion of BSEE's oversight activities. As it relates to decommissioning liabilities, operator bankruptcies are a growing concern for both the Bureau and taxpayers. When the responsible parties for offshore infrastructure go bankrupt, the obligation for decommissioning may fall to the Federal government.

Decommissioning obligations are addressed in 30 CFR 556.604(d) - "Every current and prior record title owner is jointly and severally liable, along with all other record title owners and all prior and current operating rights owners, for compliance with all non-monetary terms and conditions of the lease and all regulations issued under OCSLA, as well as for the fulfilling all non-monetary obligations, including decommissioning obligations, which accrue while it holds record title interest." BOEM oversees the program for obtaining general bonds and supplemental bonds (i.e., financial assurance) to cover decommissioning obligations to protect the American public in cases such as bankruptcy.

To date, BSEE estimates the orphaned liability (i.e., leases with no viable co-lessee or predecessor) within the Gulf of Mexico Region (GOMR) is approximately $53.4 million. In the Pacific Outer Continental Shelf Region (POCSR), it is currently estimated to be $5 million in orphaned liabilities. Note that the subject operator in the POCSR has not declared bankruptcy but indicated it does not have the wherewithal to properly decommission its infrastructure. The final decommissioning cost estimates in the POCSR for these potential orphaned liabilities will not be made until BSEE, BOEM, and Office of Solicitor finalize negotiations with the current and predecessor lessees. The estimated orphaned liability in the POCSR could escalate to as high as $93.7 million depending on predecessors not being capable of performing.

These orphan liability estimates for the GOMR and POCSR is the liability after taking into account financial assurance obtained by BOEM. BSEE has assessed many options for covering the liability shortage, but thus far has not identified a source of funding to cover the liabilities so that it can contract for the proper decommissioning of these facilities and wells.

II. OPPORTUNITIES AND CHALLENGES

The offshore oil and gas industry working in the OCS has made progress in the amount of infrastructure decommissioned over recent years. For example, in the 1990s and early 2000s, approximately 4,000 platforms existed; currently, there are roughly 1,800 platforms. Similarly, the number of wells peaked in the mid-1990s at approximately 15,000, and now there are about 9600. However, many of these facilities are still on production and are not yet due for decommissioning.

To ensure timely decommissioning, BSEE issues violations (Incidents of Non-Compliance) to operators that have failed to decommission all lease facilities and wells within one year of the lease termination as prescribed by regulation and lease stipulation. Additionally, BSEE issues orders to operators to decommission facilities and wells on active leases that no longer have future utility. BSEE continues to track infrastructure that is required to be decommissioned and enforces such requirements when necessary due to safety and environmental concerns.

Despite the progress in recent years, the decommissioning rate appears to have slowed, likely because of low oil and gas prices and to some degree, COVID-19 pandemic. Generally, operators prefer to commit capital to exploration, development, and production activities instead of decommissioning obligations.

In FY 2020, BSEE anticipating "standing in the shoes" of the liable party on orphaned infrastructure, developed a statement of work, and is seeking procurement of a contract to perform decommissioning of orphaned infrastructure in the GOMR. In order to be successful, BOEM must determine available and appropriate funding sources and BSEE must apply sound risk criteria to ensure that the government can contract for the safe and efficient decommissioning of orphaned OCS infrastructure. Consequently, having sufficient funds for the future to cover the proper decommissioning of wells, platforms and pipelines is essential to avoid passing the burdensome cost to taxpayers.

III. BACKGROUND

Regulations governing the decommissioning of wells, platforms, and pipelines are contained in 30 CFR Subpart Q. Subpart Q also contains language that requires wells and platforms to be decommissioned when no longer useful for operations (e.g., "idle iron"), but since no timeline is provided, BSEE issued NTLs mentioned above. BSEE requires operators to decommission infrastructure in a timely manner consistent with regulations and guidance as follows:

- For non-active leases, all wells, platforms, and pipelines must be decommissioned within one year after lease expiration, termination, or relinquishment.
- For active leases, infrastructure determined to be no longer useful for operations (i.e., "idle iron"), must be decommissioned pursuant to the guidance provided by recently revised Notices to Lessees and Operators No. 2018-G03 and No. 2020-P02.

Implementation of the guidance includes BSEE communicating with operators about their aging infrastructure and issuing decommissioning orders when necessary. After operators complete decommissioning activities, BSEE must verify that all the decommissioning obligations have been met, including clearing the seafloor of debris around wells, platforms, and other facilities. It should be noted that in cases of bankruptcy or failure to perform by current lessees, BSEE pursues predecessor interest owners to demand performance.

In order to protect taxpayers from having to fund decommissioning operations, BSEE is responsible for estimating a distribution of decommissioning costs for all wells, facilities, pipelines, and site clearance, which is then used by BOEM to ensure sufficient financial assurance is collected.

In April 2016, BSEE began collecting actual decommissioning expenditure data from the oil and gas operators. Starting in August 2020, BSEE adjusted its algorithms and estimates for GOMR and POCSR and provided updated cost data to BOEM. Further, BOEM takes into account that the financial assurance should not be based on the lowest cost for which an oil and gas company can do the work, but rather the cost that the U.S. taxpayer would potentially incur in cases such as bankruptcy.

Without proper financial assurance, Congress would have to provide funding in cases where the Federal Government must assume the responsibility to decommission (e.g., operator bankruptcies).

IV. **PREPARED BY:** Lars Herbst, BSEE GOMR, Regional Director, (504) 736-2589, and Mark Fesmire, BSEE POCSR, Acting Regional Director, (907) 334-5303
DATE: September 4, 2020

UNITED STATES DEPARTMENT OF THE INTERIOR
BUREAU OF SAFETY AND ENVIRONMENTAL ENFORCEMENT
PACIFIC OUTER CONTINENTAL SHELF REGION

NTL No. 2020-P02 Effective Date: August 21, 2020

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES
IN THE PACIFIC OUTER CONTINENTAL SHELF REGION

Decommissioning of Pacific Outer Continental Shelf Region (POCSR) Facilities

This Notice to Lessees and Operators (NTL) supersedes NTL No. 2009 P04. The new NTL adds provisions resulting from amendments to the Decommissioning regulations during 2011 to 2016[1] and clarifies how lessees/operators should communicate their decommissioning plans to BSEE's Pacific region office and conduct decommissioning operations. This NTL offers guidelines regarding the permitting process for decommissioning platforms, pipelines, and other related oil and gas facilities on the Pacific Outer Continental Shelf Region (POCSR). It provides advice and guidance on procedures for you to use in coordinating with the Bureau of Safety and Environmental Enforcement (BSEE) and other affected parties.

In accordance with 30 CFR 250.107(a), you must protect health, safety, property, and the environment by: (1) performing all operations in a safe and workmanlike manner; and (2) maintaining all equipment and work areas in a safe condition. These requirements remain in effect during decommissioning operations, from the cessation of production through the actual removal activities. During the time the platform is stacked, you must maintain equipment in a safe condition. You should direct any questions regarding the platform equipment safety requirements to the Regional Supervisor, Office of Field Operations.

Decommissioning Requirements

As your OCS platforms approach the end of their projected economic life, you should initiate the early stages of developing applications for decommissioning and plans to remove such facilities. In developing these applications, you should refer to your Lease Agreements and 30 CFR Part 250, Subpart Q – Decommissioning Activities for specific requirements pertaining to:

- Permanently Plugging Wells (30 CFR 250.1710 through 250.1716),
- Temporary Abandoned Wells (30 CFR 250.1721 through 250.1723),

[1] 76 Fed.Reg. 64462 (Oct. 18, 2011), as amended at 77 FR 50896 (Aug. 22, 2012); 80 FR 75810, (Dec. 4, 2015); 81 FR 26037), Apr. 29, 2016; 81 FR 80591 (Nov. 16, 2016).

● Removing Platforms and Other Facilities (30 CFR 250.1725 through 250.1730),
● Decommissioning of OCS Facilities subject to an Alternate Use right-of-use and easement (30 CFR 250.1731),
● Site Clearance for Wells, Platforms, and Other Facilities (30 CFR 250.1740 through 250.1743), and
● Pipeline Decommissioning (30 CFR 250.1750 through 250.1754).

You should review lease stipulations and conditions of approval s for your Development and Production Plan (DPP) and any modifications, including those placed on former lessees/operators for which the current lessee/operator is now responsible pursuant to an assignment of that lease. You should provide detailed technical and environmental plans for conducting decommissioning operations in a safe and environmentally sound manner to the Regional Supervisor. BSEE will review your decommissioning plans in consultation with Federal, State, and local agencies, as well as other affected parties. Your plans should focus on engineering and safety considerations and address how you will ensure compliance with applicable regulations and requirements in Subpart Q.

BSEE will conduct the environmental review according to CEQ regulations (40 CFR 1500 through 1508) and Departmental procedures that implement the National Environmental Policy Act (NEPA) per DOI Manual Part 516, Chapter 15. [2] NEPA procedures ensure that environmental information is made available to public officials and citizens before decisions are reached and actions are taken. BSEE employs the NEPA process to identify and assess reasonable alternatives to proposed actions, in order to avoid or minimize adverse effects of these actions upon the quality of the human and physical environment.

Early Notification and Coordination

We urge you to meet with POCSR staff at the earliest practicable time to discuss your plans for decommissioning your OCS oil and gas facilities. These meetings should take place during the early conceptual design stages of the decommissioning project, before you submit the initial platform removal application. Your application is due to POCSR at least two years before production is projected to cease. See 30 CFR 250.1704(a).

We encourage you to schedule early coordination meetings with Federal, State, and local regulatory agencies, and other affected parties to review preliminary information outlining the conceptual framework and general timetable for decommissioning facilities. The goal of these

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[2] Our environmental review will also involve consultation with the National Marine Fisheries Service and U.S. Fish and Wildlife Service pursuant to the requirements of the Endangered Species Act, Marine Mammal Protection Act, and the Magnuson-Stevens Fishery Conservation and Management Act. Additionally, we will conduct a review under Section 106 of the National Historic Preservation Act with consultations, as appropriate, and government-to-government consultation with affected Indian Tribes in accordance with DOI Policy on Consultation with Indian Tribes, as appropriate.

meetings is to share information and promote open communication among all parties. This approach will help to identify permitting requirements and timetables, information needs,

environmental concerns, and other issues that could impact how you conduct decommissioning operations. This approach will also provide an opportunity for regulatory agencies to develop a more coordinated and streamlined process for reviewing and approving projects.

<u>Decommissioning Applications and Timing</u>

According to 30 CFR 250.1704, you must submit your initial platform removal application to the Regional Supervisor at least 2 years before production is projected to cease. Under 30 CFR 141, you may propose, in writing, an alternate procedure for the Regional Supervisor's consideration, on a case-by-case basis.

Submit these platform applications and the pipeline decommissioning/removal application referenced below to:

Regional Director
Office of Regional Director
760 Paseo Camarillo, Suite 102
Camarillo, CA 93010

According to 30 CFR 250.1725(a) through (c), you must: remove all platforms and other facilities within one year after the lease or pipeline right-of-way terminates, unless you receive approval from BSEE to maintain the structure to conduct other activities; submit a final removal application to the BSEE for approval; and remove a platform or other facility according to the approved application. See 30 CFR 250.1725.

The information that you must include in the initial and final platform removal applications is specified at 30 CFR 250.1726 and 250.1727 and listed here for easy reference:

<u>Initial Platform Removal Application</u>

a. Platform/facility removal procedures, including the types of vessels and equipment you will use;
b. Facilities (including pipelines) you plan to remove or leave in place;
c. Platform/facility transportation and disposal plans;
d. Plans to protect marine life and the environment during decommissioning operations, including a brief assessment of the environmental impacts of the decommissioning operations and procedures and mitigation measures that will be taken to minimize the impacts; and
e. Projected decommissioning schedule.

Final Platform Removal Application

a. Identification of the applicant, as specified in the regulation at 30 CFR 250.1727;
b. Identification of the structure, as specified in the regulation;
c. Description of the structure, as specified in the regulation;

d. Description, including anchor pattern, of the vessel(s) you will use to remove the structure;
e. Identification of the purpose of the removal, as specified in the regulation;
f. Description of the removal method, as specified in the regulation;
g. Your plans for transportation and disposal (including as an artificial reef) or salvage of the removed platform;
h. If available, the results of any recent biological surveys conducted in the vicinity of the structure and recent observations of turtles or marine mammals at the structure site;
i. Plans to protect archaeological and sensitive biological features during removal operations including a brief assessment of the environmental impacts of the removal operations and procedures and mitigation measures you will take to minimize such impacts; and
j. A statement whether or not you will use divers to survey the area after removal to determine any effects on marine life.

Pipeline Decommissioning/Removal Application

You must comply with regulations in Subpart Q governing pipeline decommissioning/removal requirements at 30 CFR 250.1750 through 250.1754, whether by decommissioning-in-place or by removal. These regulations specify that pipeline decommissioning or removal applications must identify the information to be included and that will be submitted to BSEE for approval before the proposed activity is performed.

Environmental Considerations and Information Sources

As specified above, you must include the required environmental information in the initial and final platform removal applications, as well as for pipeline removal applications. Although decommissioning of oil and gas facilities may have long-term environmental benefits, the process of removing the facilities has the potential to cause adverse impacts to water quality, air quality, sensitive species, habitats, commercial and recreational fishing, and other resources.

You should consider these impacts when formulating decommissioning applications and develop effective measures to minimize and mitigate such impacts. At a minimum, your analysis should address the methods for plugging wells and removing platform topsides and jackets, as well as any subsea infrastructure, as set forth in § 250.1703. Environmental documents that you prepared for DPPs may supply useful information on equipment that poses environmental concerns and mitigation measures. POCSR urges you to update your environmental documents to identify any new or additional equipment including, but not limited to, valves, pumps, flanges, production safety systems, and oil/water separation units that were installed after the last DPP was provided to BOEM or BSEE.

We look forward to working closely with you on decommissioning and removing OCS oil and gas facilities as the need arises. We encourage you to contact BSEE POCSR at the earliest practicable time to discuss plans for decommissioning facilities.

Guidance Document Statement

In accordance with 30 CFR 250.103, BSEE may issue Notices to Lessees and Operators (NTLs) that clarify or provide more detail about certain requirements. NTLs may also outline what you must provide as required information in your various submissions to BSEE.

Paperwork Reduction Act of 1995 Statement

The Office of Management and Budget (OMB) approved the information collection requirements in these regulations and assigned OMB control numbers 1014-0024 and 1014-0010, respectively. This notice does not impose any additional information collection requirements subject to the Paperwork Reduction of 1995.

Contact

If you have any questions or need clarification regarding this NTL, please contact the POCSR OSO at bseepacoso@bsee.gov.

S /by/ Mark Fesmire

Mark E. Fesmire, PE JD
Pacific OCS Region
Regional Director

UNITED STATES DEPARTMENT OF THE INTERIOR
BUREAU OF SAFETY AND ENVIRONMENTAL ENFORCEMENT
GULF OF MEXICO OCS REGION

NTL No. NTL 2019-G05 Effective Date: May 10, 2019

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES
AND PIPELINE RIGHT-OF-WAY HOLDERS,OUTER CONTINENTAL SHELF, GULF OF MEXICO OCS REGION

Site Clearance and Verification for Decommissioned Wells, Platforms, and Other Facilities

This Notice to Lessees and Operators and Pipeline Right-of-way Holders (NTL) supersedes NTL No. 98-26, *Minimum Interim Requirements for Site Clearance (and Verification) of Abandoned Oil and Gas Structures in the Gulf of Mexico*, effective November 30, 1998. It updates the guidance on this topic.

Guidance

The following guidance regarding site clearance and verification of decommissioned wells, platforms, and other facilities is listed by regulatory reference:

1. 30 CFR 250.1703(a)

30 CFR 250.1703(a) requires you to get approval from the appropriate District Manager before decommissioning wells and from the Regional Supervisor before decommissioning platforms and pipelines or other facilities. To do so, you must submit an application for approval in accordance with 30 CFR 250.1712 and 30 CFR 250.1727. As part of your final application for approval to remove a platform or other facility, you must develop a procedural plan for site clearance and verification activities and submit it to the Regional Supervisor, Office of Structural and Technical Support (OSTS) for approval (30 CFR 250.1727). For wells, you must develop and submit a similar plan to the appropriate District Manager for approval with the Application for Permit to Modify (APM, Form BSEE-124) for the associated well (30 CFR 250.1712). At a minimum (and as applicable for the proposed methodology), your plan should include the proposed:

- Verification method and details (30 CFR 250.1740); and
- Verification grid, noting all applicable features (30 CFR 250.1741(a), (f), (g), and 250.1742.).

To allow for appropriate oversight, you should notify the appropriate District Manager for well sites or the Regional Supervisor for platform or other facility sites at least 48 hours before you begin the site clearance and verification work.

2. 30 CFR 250.1703(e) and 30 CFR 250.1703(f)

Under the general requirements for decommissioning set forth in 30 CFR 250.1703(e), you must clear the seafloor of all obstructions created by your lease and/or right-of-way (ROW). The purpose of site clearance is to remove all obstructions, including debris created, used, deposited, accumulated, or abandoned on the seabed during lease and pipeline ROW operations so that they do not interfere with other uses of the Outer Continental Shelf (OCS). You must remove all obstructions, including obstructions identified or located outside of the minimum clearance areas identified under 30 CFR 250.1741(a). You may remove obstructions from the seabed using heavy-duty trawls, diver assistance, remotely-operated vehicles (ROV), or other methods approved by the appropriate District Manager or Regional Supervisor. The regulations address subsequent verification methodologies to determine if the site is clear of obstructions at 30 CFR 250.1740 – 250.1742.

You should immediately report any obstructions temporarily left outside of the minimum clearance areas, including any debris dragged and dropped or trawling gear lost during site clearance, to BSEE at Decomm-Environmental@bsee.gov to allow the bureau to notify other OCS users in the vicinity of the obstructions. You should provide a description of the material (if the material was observed prior to being dropped) or the gear, the area and block, the approximate coordinates, and the permit number under which the work is being conducted. In accordance with 30 CFR 250.1741(c), you must mark the area to be cleared as a hazard to navigation according to USCG requirements until you complete site clearance

3. 30 CFR 250.1740

Under 30 CFR 250.1740, you must complete all obstruction removal and subsequent verification work within 60 days of permanently plugging a well or removing a platform/facility. You are also required to verify that the site is clear of obstructions by one of several methods, including dragging a trawl over a well site. If obstructions exist, the use of a trawl may or may not actually remove these obstructions. If the trawl or other verification method used indicates that an obstruction exists that is not removed, a method or means must be identified to remove the obstruction. You should not deposit any objects outside the minimum grid area for any reason and, if you do, you must verify that such objects have been removed under 30 CFR 250.1740. If you determine that obstruction removal and/or verification efforts will require additional time to complete, BSEE GOMR recommends that you request a departure under 30 CFR 250.142 from the District Manager or Regional Supervisor prior to the regulatory deadline. Your extension request should include a summary of all site clearance work completed to date at the location and the reason for the additional time (e.g., significant amount of debris, obstruction/snag investigation(s) and recovery, complexity of the verification operations).

4. 30 CFR 250.1741

If you use a trawl, you must follow the survey requirements that pertain to the specific type of well or facility removed as set forth in 30 CFR § 250.1741. The minimum distance requirements are designed to protect pipelines, shipwrecks, and sensitive biological features as well as to ensure that there are no obstructions remaining on the seabed, including but not limited to those that may impact future fishing operations. However, BSEE may include conditions to an approval under 30 CFR § 250.1703(a) that require greater avoidance distances to ensure adequate protection of identified, protected resources within or near the trawl area.

5. 30 CFR 250.1741(a)

The circular trawl areas where the trawl is dragged in a grid-like pattern as required under 30 CFR 250.1741(a) are based on the potential drift of debris inadvertently lost during normal operations. In situations where the areas identified in the regulation do not include all of the debris (*e.g.*, such as that lost during storms or lost from damaged or toppled facilities), BSEE GOMR may require additional areas to be included in the area to be trawled during its review and approval of the procedural plan to ensure that the site is clear of obstructions, as required under 30 CFR 250.1740.

BSEE considers a "well protector jacket" (listed in 30 CFR 250.1741(a)(4)) to include any temporary structure (*e.g.*, well protector, well jacket) protecting a well during exploration activities, which is most often maintained without quarters, processing units, and other equipment associated with production and development operations.

6. 30 CFR 250.1741(b)

Under 30 CFR 250.1741(b), you must trawl 100 percent of the limits described in 250.1741(a) in two directions. To ensure the 100 percent required trawl coverage of the clearance grids/trawling area, you should use the appropriate grid pattern as follows:

A. A 40-ft grid pattern for vessels equipped with two 50- to 65-ft nets or four 30-ft nets;
B. A 60-ft grid pattern for vessels equipped with two 66- to 80-ft nets or four 31- to 40-ft nets; or
C. An 80-ft grid pattern for vessels equipped with two 81-ft or larger nets or four 41-ft or larger nets.

If trawling operations are interrupted for any reason and then resumed, changes to the grid pattern may be necessary to ensure that 100 percent coverage of the area is maintained. If you encounter a snag that the trawl could not recover on any grid line, you should retrawl the grid line. In order to verify that the site is clear of obstructions, you should record the location of all lost or snagged site clearance trawling equipment (heavy-duty and verification nets, lines, doors, chains, etc.). If you are not able to recover lost gear or snag after successive trawling, then you must: 1) mark the location as a hazard to navigation according to U.S. Coast Guard (USCG) requirements; 2) investigate the obstruction (using sonar, ROV, diver, etc.); 3) remove the gear and OCS-related obstructions and debris (if applicable) from the seabed using an alternative method; and 4) retrawl the grid line to ensure 100 percent coverage.

7. 30 CFR 250.1741(c)

Unmarked obstructions pose a hazard to other OCS users which can lead to vessel or equipment damage and has the potential to cause harm or injury to the personnel. To prevent other OCS users, primarily commercial shrimpers/trawlers, from snagging their gear on unremoved obstructions and debris at well abandonment and platform removal sites, you are required under 30 CFR 250.1741(c) to mark the location as a hazard to navigation according to USCG requirements until you complete the site clearance and verification work. Information on buoy specifications and associated permitting is available from the USCG Eighth District Office, Waterways Branch – Private Aids to Navigation Section (PATON), 500 Poydras St. Suite 1230, New Orleans, LA 70130; Phone: (504) 671-2330 or 671-2328; or via email at d8OANpaton@USCG.mil.

Pursuant to 30 CFR 250.142, you may request a departure from the obligation to mark the site from the District Manager or Regional Supervisor when existing platforms or facilities are within close proximity or when other conditions exist that would prevent commercial trawlers from potentially being impacted by unremoved obstructions, including debris. If the situation(s) exist before you submit your procedural plan, you should include the departure request and justifying circumstances in the plan for bureau consideration and approval.

8. 30 CFR 250.1741(d)

Under 30 CFR 250.1741(d) you must use a trawling vessel equipped with a calibrated navigational positioning system capable of providing position accuracy of ±30 feet. The calibrated navigation system on the trawling vessel should be capable of producing either (1) a real-time paper track plot of the vessel position or (2) a hard copy post-plot of all or any specific lines so that you can verify that the area has been satisfactorily covered before the vessel departs. The plot should use a scale no smaller than 1 inch = 400 ft and show the vessel track as a continuous line.

9. 30 CFR 250.1741(e) and Endangered Species Act Compliance Conditions

For debris removal, you may use heavy-duty nets of any size or net strength. 30 CFR 250.1741(d) requires that for final verification work, the trawling net be representative of those used in the commercial fishing industry (one that has a net strength equal or greater than that provided by No. 18 twine). The Endangered Species Act Section 7 Consultation Biological Opinion issued by the National Marine Fisheries Service, dated August 28, 2006 (available at https://www.boem.gov/Environmental-Stewardship/Environmental-Studies/Gulf-of-Mexico-Region/ESA_Biological_Opinion-pdf.aspx), identifies a number of additional terms and conditions designed to control incidental take. The nets used for both debris removal and verification must not be equipped with turtle excluder devices (TEDs) so that objects picked up by the trawl do not escape. Trawl nets must have a minimum stretched mesh size of 4 inches at the cod end and 2 inches elsewhere, and a maximum stretched mesh size of 6 inches. You should notify the USCG, Eighth District, Enforcement Branch at least 48 hours before you conduct trawling operations with a net not equipped with a TED. You must release any shrimp caught in the net. You must also limit trawl times to no more than 30 minutes to allow for the removal and release of any captured sea turtles. If a sea turtle is captured in the trawl, you must:

- Contact BSEE's Office of Environmental Compliance (OEC) by phone and at protectedspecies@bsee.gov and National Marine Fisheries Service (NMFS) Southeast Regional Office (SERO) at takereport.nmfsser@noaa.gov immediately;
- Resuscitate and release any captured sea turtles as per NMFS' guidelines found online at https://www.sefsc.noaa.gov/turtles/TM_NMFS_SEFSC_580_2010.pdf (see page 3-6; Plate 3-1).
- Photograph the turtle, and complete a Sea Turtle Stranding Form for each turtle caught in your nets (https://www.sefsc.noaa.gov/species/turtles/strandings.htm) and submit the form to NMFS and BSEE (to the email addresses noted above).

10. 30 CFR 250.1741(f)

Under 30 CFR 250.1741(f), you must ensure that you trawl no closer than 300 feet from a shipwreck, and 500 feet from a sensitive biological feature. If known archaeological resources, shipwrecks, or sensitive biological features are in the vicinity of the site clearance and verification location, the environmental analyses prepared for the Application for Permit to Modify (APM) or the structure removal application will identify sufficient mitigation, minimization, or avoidance measures to protect the resources, which BSEE may implement through conditions of approval. You must adhere to any conditions of approval during the trawling activities, and satisfy the associated reporting requirements.

If trawling activities indicate the presence of a previously-unidentified biologic or archaeologic resource (*e.g.*, recovery in the nets of corals, rocks, or any object of potential archaeological significance), you must cease trawling work and contact OEC immediately for additional guidance. If trawling activities recover any object of potential biological or archaeological significance, you must immediately halt operations in compliance with 30 CFR 250.1741(f) and 250.194(c) and immediately report this discovery and its location coordinates to the OEC via email at Env-Compliance-Arc@bsee.gov and by phone at (504) 736-2796. BSEE will provide you additional guidance for the protection of any potential biological or archaeological resources and how to continue with the site clearance and verification work.

11. 30 CFR 250.1741(g)

If you trawl near an active pipeline, you must meet the requirements in the table set forth in 30 CFR 250.1741(g). BSEE may require you to conduct debris detection, recovery, and verification using other methods (in place of or in addition to trawling), which may require revision and resubmittal of the procedural plan associated with your application pursuant to 30 CFR 250.1712 and 30 CFR 250.1727. In areas where trawling is prohibited by 250.1741(g), you must conduct obstruction detection, recovery, and site clearance verification by the other methods listed in 30 CFR 250.1742, or as approved by BSEE.

Additionally, BSEE recommends that you conduct a seabed survey of the area using remote sensing tools (e.g., side-scan/sector-scanning sonar, magnetometers, ROV video) to obtain information about the current condition of any pipelines in the area before you begin trawling to avoid unnecessary snags-to and unearthing-of decommissioned pipelines and/or damage to active pipelines and the risk of potential pollution events.

12. 30 CFR 250.1742(a)

For site clearance verification with sonar equipment, your procedural plan should provide for:

- identifying targets of potential debris;
- stating the size and shape of debris that can be detected;
- achieving 100 percent coverage of the appropriate grid area at required resolution;
- the investigation and identification of targets detected in the sonar survey;
- the recovery of targets identified as debris/obstructions in the investigation; and
- documentation and verification that targets identified as debris/obstructions have been removed.

In addition, BSEE typically prefers that the sonar equipment and deployment:

- Operates at a nominal 500 kHz frequency (or equivalent);
- Provides overlapping coverage for the verification area;
- Provides scanning along and across track for towed side scan sonar equipment sufficient to identify targets as potential debris; and
- Provides sector scanning sonar deployment sufficient to identify targets as potential debris.

In most cases, where the initial sonar survey identifies obstructions and you conduct subsequent debris recovery work to remove the items from the seabed (generally with diver assistance and support vessel(s)), BSEE may require a second sonar survey to capture the post-retrieval seabed conditions and to provide the "verification" that the site is "cleared." If the initial sonar survey does not detect any obstructions, including debris, you may rely on the sonar records and associated report to verify that the site is cleared.

13. 30 CFR 250.1742(c)

For site clearance verification with an ROV, your procedural plan should provide for:

- identifying targets of potential debris;
- ROV camera(s) capable of recording 100 percent of the appropriate grid area;
- a survey pattern of concentric circles or parallel lines no more than 10 feet apart;
- the recovery of targets identified as debris/obstructions in the investigation; and
- documentation and verification that targets identified as debris/obstructions have been removed.

Similar to 30 CFR 250.1742(a), if an initial ROV video survey detects obstructions, including debris, and subsequent removal work is required, BSEE may require you to perform a second ROV video to capture the post-retrieval seabed conditions and to provide verification that the site is cleared.

14. **30 CFR 250.1743(a)(5) and 30 CFR 250.1743(b)(6)**

As part of your Application for Permit to Modify (APM) (30 CFR 250.1743(a)) or site clearance verification report (30 CFR 250.1743(b)), you should include:

- Verification method and details (30 CFR 250.1740);
- Verification grid, noting all applicable features (30 CFR 250.1741(a), (f), and (g));
- Vessel navigational positioning system documentation (30 CFR 250.1741(d));
- Net information (30 CFR 250.1741(e));
- Corporate and financial tie statement (30 CFR 250.1741(h)(1)); and
- Copies of the commercial trawling licenses (30 CFR 250.1741(h)(2)).

Under 30 CFR 250.1743, you must certify that the site is clear of obstructions. Your APM or site clearance verification report must include a list of all debris you collected as a result of any of the retrieval methods, including material collected in both the heavy-duty and verification nets, items recovered by divers during snag investigations and retrievals, and any lost or recovered trawling gear. You also should provide digital images depicting the debris removed by your trawling and snag recovery contractors.

15. **30 CFR 250.1743(a)(6) and 30 CFR 250.1743(b)(7)**

Your APM or site clearance report post-trawling job plots or maps for both heavy-duty and verification nets should be set at a minimum scale of 1inch = 200 ft. Both heavy-duty and verification trawl plots or maps should include: proper grid line numbering (including multiple grid passes for retrawls, if any); the center location of the platform, facility, or well; the marked location of all mitigated avoidance areas; and the marked location of any snags, dropped gear, or debris.

Guidance Document Statement

The BSEE issues NTLs as guidance documents in accordance with 30 CFR 250.103 to clarify and provide more detail about certain BSEE regulatory requirements and to outline the information you provide in your various submittals. Under that authority, this NTL sets forth guidance regarding regulatory requirements that provides a clear and consistent approach to complying with those requirements. However, if you wish to use an alternate approach, you may do so, after you receive approval from the appropriate BSEE office.

Paperwork Reduction Act of 1995 Statement

The Office of Management and Budget (OMB) has approved the information collection requirements and assigned OMB Control Numbers 1014-0022 for the subpart A regulations, 1014-0010 for the subpart Q regulations, and 1014-0026 for the APM submissions. This NTL does not impose any additional information collection requirements subject to the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 et seq.).

Contacts

Please address any questions regarding this NTL to:

1. The Workover/Completion Engineer in the appropriate BSEE GOMR District office regarding site clearance and verification for wells;

2. The BSEE GOMR Office of Structural and Technical Support (OSTS) by telephone at (504) 736-2634 regarding site clearance and verification for platforms or other facilities; or

3. The BSEE GOMR Office of Environmental Compliance (OEC) by telephone at (504) 736-3245 or via email at Decomm-Environmental@bsee.gov regarding environmental concerns (e.g., archaeological resources, protected species, biological features) encountered during either well or platform/facility site clearance and verification work.

/S/ Lars Herbst
Lars Herbst
Regional Director
Gulf of Mexico Region

UNITED STATES DEPARTMENT OF THE INTERIOR
BUREAU OF SAFETY AND ENVIRONMENTAL ENFORCEMENT
GULF OF MEXICO OCS REGION

NTL No. 2018-G03 Effective Date: December 11, 2018

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES AND PIPELINE RIGHT-OF-WAY HOLDERS IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO OCS REGION

Idle Iron Decommissioning Guidance for Wells and Platforms

This Notice to Lessees and Operators and Pipeline Right-of-way Holders (NTL) supersedes NTL No. 2010-G05, Decommissioning Guidance for Wells and Platforms, and is being issued to update and streamline guidance on this topic. This NTL provides clarification and guidance to help ensure that idle infrastructure on active leases is decommissioned in a timely manner in accordance with regulation. This NTL reaffirms the decommissioning guidance contained in NTL No. 2010-G05 (issued on September 15, 2010), carries forward the substance of the definitions provided therein, and adds language that describes BSEE's authority to work with operators to accomplish such work (i.e., the Bureau of Safety and Environmental Enforcement (BSEE) possesses discretion in implementing schedules for decommissioning idle iron).

Background

Idle infrastructure poses a potential threat to the Outer Continental Shelf (OCS) environment and potential financial liabilities if destroyed or damaged in a future event, such as a hurricane. The cost and time to permanently plug wells and remove storm-damaged infrastructure is significantly higher than decommissioning assets that have not been damaged as of the time of decommissioning. These increased costs have potential ramifications on financial security requirements and may even impact the future viability of your company.

Regulatory Authority for Decommissioning Idle Wells and Platforms

Pursuant to 30 CFR 250.1703, you must permanently plug all wells and remove all platforms and other facilities when no longer useful for operations. Further, 30 CFR 250.1711 states that BSEE will order you to permanently plug a well if it poses a hazard to safety or the environment, or is not useful for lease operations and is not capable of oil, gas, or sulphur production in paying quantities.

To clarify the phrases "no longer useful for operations" and "not capable of oil, gas, or sulphur production in paying quantities," "toppled platform," and "downhole zonal isolation," BSEE provides the following guidance:

In determining whether a well is "*capable of production in paying quantities,*" BSEE will include wells that can produce enough oil, gas, or sulphur to yield a positive stream of income after subtracting normal expenses. These expenses may include actual royalty payments based on the well's production and the direct lease operating costs allocated to the well.

BSEE will consider the following timeframes, when determining whether a well or platform is "*no longer useful for operations*":

(1) For a ***well***,
  (a) the well has not been used in the past 5 years (i) for operations associated with the exploration for or the development and production of oil, gas, sulphur, or other mineral resource or (ii) as infrastructure to support such operations; and
  (b) you have no plans to use the well (i) for operations associated with the exploration for or the development and production of oil, gas, sulphur, or other mineral resource, or (ii) as infrastructure to support such operations.

(2) For a ***platform***, the platform has
  (a) been toppled or otherwise destroyed; or
  (b) not been used in the past 5 years (i) for operations associated with the exploration for or the development and production of oil, gas, sulphur, or other mineral resource, (ii) as infrastructure to support such operations, or (iii) for other energy- or marine - related purposes as authorized by BSEE or the Bureau of Ocean Energy Management.

BSEE will consider "*toppled platforms*" to include platforms or other structures that have collapsed or fallen or been displaced by a storm or other external forces and, as a result of such an event, are partially or completely destroyed.

BSEE views "*downhole zonal isolation*" to mean isolating all hydrocarbon and sulphur zones by adhering to the plugging and testing requirements of 30 CFR 250.1712 (approval); 30 CFR 250.1713 (notification); 30 CFR 250.1714 (plugs); 30 CFR 250.1715(a)(1), (a)(2), or (a)(3) (plugging); and 30 CFR 250.1715(b)(1) or (b)(2) (plug test). Downhole zonal isolation includes meeting the casing pressure management requirements of API RP 90 (as incorporated by reference in 30 CFR 20.198) and 30 CFR 250.519 – 250.530.

Guidance

Because the regulations do not expressly prescribe the time frame for decommissioning idle wells and platforms when no longer useful for operations, the following guidance is provided:

1. Decommissioning Idle Wells on Active Leases

A. Pursuant to 30 CFR 250.1703 and 250.1711(b), if any well is no longer useful for operations (as defined above) ***and*** is no longer capable of producing oil, gas, or sulphur in paying quantities, you must perform one of the following and should do so as soon as possible, but no later than 3 years after the well is no longer useful for operations:

i. Permanently plug and abandon the well in accordance with 30 CFR 250.1712 through 250.1716; or
ii Plug the well in accordance with 30 CFR 250.1712 through 250.1715 (i.e., only wellhead and casing removal requirement remains); or
iii. Provide the well with downhole zonal isolation (see definition above). Within 2 years after you provide a well with downhole zonal isolation, BSEE expects

you to comply with either (i) or (ii) above.

B. In performing the work set forth in paragraph A above, we recommend that you prioritize the well work based on risk conditions, such as:

i. Wells on structures with the highest risk of toppling (e.g., those structures that have not passed required assessments or are structurally damaged (including leaners)).
ii. Wells that were producing oil.
iii. Wells that are capable of natural flow. In order for a well to be deemed incapable of natural flow, the appropriate BSEE Gulf of Mexico (GOM) Region District Manager must approve your application for such a determination as required by 30 CFR 250.810 or 250.825 for dry and subsea trees, respectively.
iv. Wells that have casing pressure.
v. Wells that are located close to the shoreline, environmentally sensitive areas, or other infrastructure.

C. Future Use Determination: For any well that meets element (1)(a) of the definition of "no longer useful for operations," but which you believe to be useful for operations or capable of production in paying quantities, you should provide supporting documentation to the BSEE GOM Regional Supervisor, Regional Field Operations, for review and concurrence. Note that if BSEE determines such well is useful for lease operations or is capable of producing oil, gas, or sulphur in paying quantities, you may still be required to perform a downhole zonal isolation in order to ensure compliance with 30 CFR 250.106(c), depending on the length of time needed before you can return to the well to resume useful operations. If BSEE requires downhole zonal isolation, BSEE will require you to specify a timeframe for completion of such work at the time of the aforementioned BSEE determination. Note that No. 1.A.iii above will not be applicable whether the zonal isolation is completed as required by BSEE or voluntarily by the operator and that BSEE may continue to monitor the well until operations are resumed.

The supporting documentation should include, but may not be limited to, the following:

1. Detailed discussion of your plans for the well.
2. Log section identifying the zone(s) to be produced.
3. Recoverable reserve estimate.
4. Reservoir parameters (e.g., porosity, acre-feet, water saturation, formation volume factor, etc.) including recovery factor.
5. List of all wells penetrating the reservoir.
6. Structure map showing penetration points and depths for each well penetrating the reservoir, fluid contacts, and reservoir boundaries.
7. Isopach map showing the net feet of pay for each well, identified at the penetration point.
8. Any well test information acquired.
9. Detailed economic analysis.
10. A schedule of the well work.

11. An estimated date of resuming production.

2. Decommissioning Idle Platforms or Other Facilities on Active Leases

A. Pursuant to 30 CFR 250.1703(c), you must remove a platform (including a toppled platform) or other facility when it is no longer useful for operations. Because the regulations do not expressly prescribe the time frame for completing these operations, BSEE clarifies that you are required to do so as soon as possible, but no later than 5 years after the platform is no longer useful for operations.

B. Future Use Determination: For any platform or other facility that has not been used in the past 5 years and which you believe to be useful for future operations, you should submit to the BSEE GOM Regional Supervisor, Regional Field Operations, supporting documentation demonstrating the usefulness for review and concurrence. The supporting documentation should include but may not be limited to the following:
   i. Detailed discussion of the facility's future utility.
   ii. Detailed schedule for operations to resume on the facility.

3. Idle Iron Reporting

Although you are expected to monitor your idle wells and platforms and to undertake decommissioning on your own initiative, in accordance with the regulations, as clarified by this NTL, BSEE plans to continue to provide you with a list of idle wells and platforms annually to help expedite the process. Companies may conduct idle iron abandonment operations consistent with the regulations and timelines provided in this NTL while taking into consideration their individual workload or risk matrix. However, BSEE retains the discretion to be flexible on the timelines listed above when justified on a case-by-case basis to the satisfaction of the Regional Supervisor. In making such a decision to extend such timelines, BSEE will consider all wells, platforms, and other facilities that are no longer useful for operations and not capable of production in paying quantities, as well as your decommissioning schedule (anticipated permit submittal, work start, and work complete date) for each well and platform. Failure to comply with the timelines outlined in this NTL without a BSEE extension of time may result in the issuance of decommissioning orders from BSEE.

Other Decommissioning-Related Issues:

BSEE reminds you of your regulatory obligation to decommission infrastructure on terminated/expired/relinquished leases and rights-of-way within 1 year after the lease or right-of-way expiration/termination/relinquished date in accordance with 30 CFR 250.1710, 30 CFR 250.1725(a), 30 CFR 250.1010(h), and the lease or right-of-way instrument. Failure to do so within this 1-year period, absent BSEE's approval, will typically result in the issuance of an Incident of Noncompliance. Further, BSEE expects that operators will ordinarily prioritize decommissioning of expired or terminated lease structures, wells, and pipelines over Idle Iron infrastructure, absent countervailing safety or environmental considerations. In addition:

- Pursuant to 30 CFR 250.1711(a), the BSEE GOM Region will order you to permanently plug any well that poses a hazard to safety or the environment.

- You must submit decommissioning applications, receive approval of those applications, and submit subsequent reports according to the requirements and deadlines in 30 CFR 250.1704 (and regulations referenced therein) to the appropriate BSEE District and/or Regional Offices.

- Pursuant to 30 CFR 250.1704(i), you must submit a certified summary of expenditures for permanently plugging any well, removal of any platform or other facility, clearance of any site after wells have been plugged or platforms or facilities removed, and decommissioning of pipelines.

Guidance Document Statement

BSEE issues NTLs as guidance documents in accordance with 30 CFR 250.103 to clarify or provide more detail about certain BSEE regulatory requirements and to outline the information you provide in your various submittals. Under that authority, this NTL sets forth guidance and clarification regarding certain regulatory requirements and provides a clear and consistent approach to complying with those requirements.

Paperwork Reduction Act of 1995 Statement

The information referred to in this NTL is intended to provide clarification or guidance regarding compliance with requirements contained in 30 CFR Part 250, Subparts A, H, J, and Q, and with Applications for Permit to Modify (APMs). The Office of Management and Budget (OMB) has approved the information collection requirements in these regulations under OMB Control Numbers 1014-0022, 1014-0003, 1014-0016, 1014-0010, and 1014-0026, respectively. This NTL does not impose any additional information collection requirements subject to the Paperwork Reduction Act of 1995.

Contacts

Please address any questions on the content of this NTL to BSEE GOM Regional Field Operations, Decommissioning Support Section by e-mail at BSEEIdleIron@bsee.gov.

/S/ Lars Herbst
Lars Herbst
Regional Director

UNITED STATES DEPARTMENT OF THE INTERIOR
BUREAU OF SAFETY & ENVIRONMENTAL ENFORCEMENT

NTL No. 2017-N02 Effective Date: March 02, 2017

NATIONAL NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS AND SULPHUR LEASES, OUTER CONTINENTAL SHELF (OCS)

Reporting Requirements for Decommissioning Expenditures on the OCS

Purpose

On April 27, 2016, the Bureau of Safety and Environmental Enforcement (BSEE) issued Notice to Lessees and Operators (NTL) No. 2016-N03, *Reporting Requirements for Decommissioning Expenditures on the OCS*, to provide guidance and clarification regarding regulatory requirements pertaining to the submission of certified decommissioning expenditure summaries following the permanent plugging of any well, removal of any platform or other facility, and clearance and verification of any site. BSEE amended its regulations addressing decommissioning expenditure reporting, effective December 16, 2016, by including requirements for the submittal of certified summaries of decommissioning expenditures for right-of-way (ROW) and lease term pipelines. The additional requirements concerning the submission of certified decommissioning expenditures summaries are found at 30 CFR 250.1704(i).[1] As a practical matter, BSEE recognizes, and prefers, that the operator submit the required summary of decommissioning costs on behalf of the lessees, the owners of operating rights, or the pipeline ROW holders. The summaries must be submitted within 120 days after completion of each decommissioning activity.

This NTL supersedes NTL No. 2016-N03, provides guidance and clarification regarding submission of certified decommissioning cost expenditure summaries following permanent plugging of any well, removal of any platform or other facility, clearance and verification of any site, and decommissioning of any pipeline segment as required by 30 CFR 250.1704(i). To minimize the reporting burden while ensuring that BSEE receives accurate, complete, and consistent data, BSEE recommends that, except as noted below, you use methods, procedures, and expenditure classifications set out in Model Forms, Model Form Interpretations, Accounting Guidelines and other documents published by The Council of Petroleum Accountants Societies, Inc. (COPAS). Specifically, BSEE requests that you rely on the COPAS guidelines (*e.g.* Classifications for Summary Form Billing© (MFI-26) and Joint Audit Data Exchange© (AG-26)) for reporting by cost classifications and/or examination of joint interest transactions as the primary framework upon which to submit the required information.

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[1] In addition, amended 30 CFR 250.1704(j) authorizes the BSEE Regional Supervisor to request additional information in support of any decommissioning activity included in a summary of decommissioning expenditures under 30 CFR 250.1704(i).

Authority

BSEE's regulations at 30 CFR 250.103 authorize BSEE to issue NTLs that clarify or provide more detail about certain requirements. According to 30 CFR 250.103, NTLs may also outline what regulated entities must provide as required information in their various submissions to BSEE. In addition, 30 CFR 250.1704(i) and (j) authorize the BSEE Regional Supervisor to provide specific instructions or guidance regarding the submission of certified summaries of decommissioning expenditures and additional information (such as invoices and contracts) concerning decommissioning activities.

Background

BSEE will use this information, as well as other information and analyses, to improve estimates of future decommissioning costs. BSEE will share its prepared cost estimates with the Bureau of Ocean Energy Management (BOEM) for use in setting necessary financial assurance levels to minimize both the possibility that the government will incur decommissioning costs and the possibility that BOEM will require more financial assurance than necessary to cover future decommissioning liabilities from lessees, ROW holders, and operating rights owners. BSEE recommends participation by both the operations and joint interest accounting functional groups within an organization in undertaking the requisite data compilations and submissions.

Reporting Basis and Characterization of Costs

Allocation of Expenditures - BSEE estimates decommissioning liabilities on well-by-well, structure-by-structure, pipeline-by-pipeline, and site clearance-by-site clearance bases. Correspondingly, 30 CFR 250.1704(i) requires separate submittal of summaries of actual expenditures for each decommissioned asset. However, operators generally decommission wells, pipelines, and/or facilities in batches or "campaigns" with expenditures generally authorized and tracked based on an Authorization for Expenditure (AFE) or equivalent document/process. As a result, you will most likely make some form of cost allocation to satisfy BSEE's regulatory requirements. To ensure that BSEE receives accurate reporting on a consistent basis, you should prepare and submit summaries using invoice-level allocations among decommissioned assets (wells, platforms, facilities, and pipeline segments) and cost categories (*see* next section). Note that invoice-level allocations also will be necessary for turnkey service invoices. Unless requested under 30 CFR 250.1704(j), BSEE typically will not require that you submit invoice-level allocations, although you should use them to develop the required summaries.

BSEE expects you to make a good faith determination of the most appropriate allocation bases (e.g., task/activity duration, length of tubulars, effort in person-hours) for purposes of allocating costs. Accurate and consistent cost allocations will maximize the utility of reported expenditures to BSEE for its use in preparing future decommissioning liability estimates. A clear, complete, and accurate summary is required for each permanently plugged well, platform or facility removed, site cleared, and pipeline segment decommissioned.

Classification and Restatement of Expenditures – You should report all costs on a gross (100% working interest) basis. The COPAS Retirement and Abandonment (R&A) Expenses should be further sub-classified/restated using the four cost categories listed below (along with bulleted examples), as applicable to a specific decommissioning activity:

1. *Transportation and Staging*
    - Transportation – crew boats, work boats, supply vessels, current monitoring vessels, cargo barges, helicopter and aviation support, motor freight and hauling
    - Communications, shore base logistics, and dock services
    - Catering, groceries, and other subsistence
    - Fuel, water, and lubricants
    - Turnkey services related to this cost category, including allocated amounts;

2. *Location*
    - Rig/vessel mobilization/demobilization
    - Surveying and location preparation
    - Debris removal/clean up, site/seabed survey, trawling and nets
    - Mooring systems/components, standby and back-down systems
    - Turnkey services related to this cost category, including allocated amounts;

3. *Contract Services, Lifting, Diving and Service Units*
    - Daywork drilling/workover rigs, lift boats, derrick/crane barges, heavy lift vessels
    - Cutting, diving, flushing and filling, and ROV (remotely operated vehicle) services
    - Coil tubing, snubbing/hydraulic workover
    - Rental tools for surface and subsurface operations
    - Mud and brines, cementing, pipe handling and related services, and bits
    - Wireline services, slickline and electric, logging and perforating
    - Maintenance, cleaning, testing, disposal, and inspection services
    - Turnkey services related to this cost category, including allocated amounts;

4. *Other Decommissioning Related Costs*
    - Site supervision, engineering, and consulting
    - Disposal of material flushed from decommissioned pipelines
    - Health, Safety & Environment and regulatory compliance
    - Lost equipment, damaged equipment repair
    - Miscellaneous supplies and materials
    - Insurance
    - Overhead
    - Turnkey services related to this cost category, including allocated amounts
    - Costs not elsewhere classified.

Costs Chargeable to Joint Account and Overhead – All costs chargeable to a joint account should be included. In the case where no joint account exists, you should classify and report the decommissioning costs as if the recommended COPAS framework were applicable. BSEE wants to ensure that all relevant costs are reported in the summary, including those that an individual, such as an operator's project manager who typically signs/routes vendor invoices, might not see. Specifically, you should report charges to the joint account for operator-provided direct goods and services, consistent with COPAS guidelines and the venture Joint Operating Agreement. Operator receipts from joint interest owners for overhead, if any, should be included and allocated as appropriate.

Treatment of Conductor Casing Removal Costs – In situations where lessees cut and pull conductor casing during the final stage of well plugging and abandonment, as part of the structure removal activity, BSEE recommends that the operator report these costs, along with the number of conductors removed, separately on an aggregate basis. This will allow BSEE to better distinguish structure removal from well abandonment expenditures in these situations.

Permanently Plugged Wells – Casing Not Cut – Where lessees install all of the required plugs in a well for permanent abandonment (PA), but defer the cutting and pulling of the casing to a later date, costs are to be reported 120-days after completion of the plugging operation. In addition, lessees should separately report costs associated with cutting and pulling the casing within 120 days after completion of the cutting and pulling operation.

Submittal Certification – Section 250.1704(i) requires you to certify each summary of expenditures that you submit. A single certification statement will suffice if you submit multiple expenditure summaries at the same time. The certifying individual must be a representative of your company authorized to attest to the truth, accuracy and completeness of the summary. BSEE leaves the precise certification verbiage to your discretion but suggests that the certification statement on corporate letterhead include the following elements:

1. Name(s) and title(s) of individual(s) certifying the decommissioning expenditure summary;
2. Statement regarding authorization of certifying individual(s) to submit decommissioning summary;
3. Statement attesting to the "truth, accuracy and completeness" of the decommissioning expenditure report; and
4. A table showing which wells (12-digit API number), removed platforms/facilities (Complex ID/Structure Number combination), decommissioned pipeline segments (Pipeline Segment Number), and/or sites cleared/verified (Complex ID/Structure Number combination or API Number if not structurally associated with a platform) the certified summaries cover for batch submission of decommissioning cost summaries.

Reporting Period – BSEE appreciates that there could be situations where it may take longer than the 120-day reporting period allowed by regulation for you to receive and process all decommissioning related invoices. In such cases, BSEE will consider granting an extension when timely requested and sufficiently justified. BSEE would rather receive a single complete submission with a reporting period extension than a preliminary summary followed by some number of revisions/supplements. However, failure to submit decommissioning cost summaries in the timeframe required by the regulation, or as extended by BSEE, may result in BSEE's issuance of an Incident of Noncompliance.

Requests for Additional Information – If, pursuant to 30 CFR 250.1704(j), the Regional Supervisor requests additional information in support of any decommissioning activity expenditures included in a summary submitted pursuant to 30 CFR 250.1704(i), BSEE recommends that the response be consistent in all material respects with that outlined in COPAS Accounting Guideline Joint Audit Data Exchange© (AG-26). BSEE also recommends that you keep sufficiently detailed cost allocation records (among assets and cost categories) should an additional information request be made by the Regional Supervisor pursuant to 30 CFR 250.1704(j).

Structure of Submitted Data

In order to comply with 30 CFR 250.1704(i), you must submit a complete summary of expenditures actually incurred for each decommissioned asset by the relevant decommissioning activity type: well abandonment (by API Number); structure removal (by Complex ID and Structure Number pair); pipeline segment decommissioning (by Pipeline Segment Number); and site clearance and verification (by Complex ID and Structure Number pair or API Number if not structurally associated with a platform). In addition, each decommissioning cost summary should include the following information whenever relevant:

1. **Date of Submission** – The date that the data is submitted to BSEE;

2. **Initial or Revised? (I/R#)** –"I" for initial submission, and "R1", "R2", etc., for subsequent revisions as appropriate. BSEE expects revision submittals to be exceptional events that result from reporting errors, untimely invoice receipts, and the like. Revision submittals should reflect updated activity totals rather than incremental changes from prior submission(s);

3. **Submitter Company Name;**

4. **Submitter Company Number** – The Company Number corresponding to item 3, above;

5. **Decommissioning Activity Type (PR/PA/SCV/PL)** - The type of reported cost, *i.e.*,
    a. "PR" for platform and facility removal (including PLETS (pipeline end terminations), PLEMS (pipeline end manifolds), subsea templates, etc., per 30 CFR 250.1700(c)),
    b. "PA" for well abandonment,
    c. "SCV" for site clearance and verification, and
    d. "PL" for pipeline segment decommissioning;

6. **Multi-Asset Activity Flag (Y/N)** – Whether the decommissioning activity is part of a multiple asset decommissioning project. For example, decommissioning costs for an asset included as part of a two (or more) well decommissioning project would be indicated with a "Y" because each activity was of the same type. "N" would indicate the costs of a project involving a single well or a project with a single structure. In the case of a project involving a single structure and two or more wells, this field would be marked as "N" for the structure removal and "Y" for each of the wells;

7. **Turnkey Contracting Flag (Y/N)** – Whether a majority of the decommissioning expenditures for the reported asset decommissioning were incurred under a "turnkey"-type contract(s), otherwise this would be marked as "N;"

8. **Permanently Plugged Well – Casing Not Cut (Y/N)** – For a well with all of the required plugs in place for PA, but for which casing cutting and removal remains to be performed, this would be marked with a "Y," otherwise "N." No response is required for a platform or facility removal (PR) activity, a site clearance and verification (SCV) activity, or a pipeline segment decommissioning (PL) activity. (Note: A well in this condition is technically defined as "temporarily abandoned" and is labeled as such within BSEE official records until casing is cut);

9. **Partially Decommissioned Assets (Y/N)** – For an asset that has been partially decommissioned (*e.g.*, deck removed from platform, installation of some but not all required plugs in well, or pipeline flushed but not decommissioned) prior to completion of the activity being reported, this would be marked with a "Y," otherwise "N;"

10. **Rigs to Reefs Flag (Y/N)** –Whether the structure removal operations were conducted as part of a Rigs to Reefs program. No response is required for well plugging (PA), site clearance and verification (SCV), or pipeline segment decommissioning (PL) activities;

11. **Pipeline Segment Removal Flag (Y/N)** – Whether the pipeline segment was removed as opposed to being decommissioned in place. No response is required for well plugging (PA), structure removal (PR), or site clearance and verification (SCV).

12. **Onshore Disposal of Material Flushed from Pipeline Flag (Y/N**) – Whether material flushed from a pipeline segment was disposed onshore or not. No response is required for well plugging (PA), structure removal (PR), or site clearance and verification (SCV).

13. **Activity Duration (number of days)** – The approximate duration of the decommissioning activity. When decommissioning activities on one asset are interrupted for efforts on another asset, the original activity duration no longer directly corresponds to a single elapsed calendar time period;

14. **API Number or Complex ID-Structure Number** – For well decommissioning expenditures, the well's 12-digit API number; for decommissioned pipeline segments, the Pipeline Segment Number; for platform/facility removal, the Complex ID and its Structure Number; and for site clearance, the Complex ID and its Structure Number or API Number, if not structurally associated with a platform;

15. **Transportation and Staging Costs** – See examples in text above;

16. **Location Costs** – See examples in text above;

17. **Contract Services, Diving and Service Unit Costs** – See examples in text above;

18. **Other Decommissioning Related Costs** – See examples in text above;

19. **Decommissioning Cost Total** – The sum of the four cost categories above;

20. **Conductor Removal Cost Activity Association** – Whether conductor cutting and removal costs are included as part of a PA activity or a PR activity as described in No. 5 above;

21. **Number of Conductors Removed** – The number of conductors removed as part of a broader structure removal activity. No response is required if conductor removal was accounted for as part of a well PA, site clearance (SCV), or pipeline segment decommissioning (PL) activity;

22. **Conductor Removal Cost** – The estimated cost to remove well conductors when performed as part of a structure removal activity. No response is required if conductor removal was accounted for as part of a well PA, site clearance (SCV), or pipeline segment decommissioning (PL) activity. <u>This cost should not be reported as an amount incremental to the costs above (items 13 through 16)</u>;

23. **Name of Individual Certifying Reported Costs;**

24. **Title of Individual Certifying Reported Costs;**

25. **Phone Number of Individual Certifying Reported Costs;**

26. **Email Address of Individual Certifying Reported Costs;**

27. **Comments** – An optional field intended to accommodate any supplemental information that the submitter deems appropriate or potentially useful to BSEE.

Format for Submission

BSEE will accept both electronic (preferred) and paper-based submissions. BSEE requests that you submit the required information in either Microsoft Excel© xls or xlsx formats or delimited text files. Paper submissions should use a simple columns and rows layout.

Protection of Information

You should identify any commercial or proprietary information to BSEE when submitting your summaries. BSEE will protect proprietary information according to the Freedom of Information Act (5 U.S.C. 552) and DOI's implementing regulations (43 CFR part 2); 30 CFR 250.197, *Data and information to be made available to the public or for limited inspection;* and 30 CFR part 252, *OCS Oil and Gas Information Program.*

Submittal of Information

For the electronic submission of information, you should submit the report files as attachments to:

- For the Gulf of Mexico Region, gomrdecommcost@bsee.gov;
- For the Pacific Region, pocsrdecommcost@bsee.gov; and
- For the Alaska Region, akocsrdecommcost@bsee.gov

For the non-electronic submission of information, you should use the following mailing addresses for the Gulf of Mexico, Pacific and Alaska Regions:

- Regional Supervisor, Regional Field Operations
  Decommissioning Support Group (GE 1078A)
  Bureau of Safety & Environmental Enforcement
  1201 Elmwood Park Boulevard
  New Orleans, Louisiana 70123-2394;

- Regional Supervisor, Office of Strategic Operations
  Bureau of Safety & Environmental Enforcement
  760 Paseo Camarillo, Suite 102
  Camarillo, CA 93010-6002; and

- Regional Supervisor, Regional Field Operations
  Bureau of Safety & Environmental Enforcement
  3801 Centerpoint Drive, Suite 500
  Anchorage, AK 99503-5823

Paperwork Reduction Act of 1995 Statement

The Office of Management and Budget (OMB) has approved the information collection requirements for Decommissioning under OMB Control Numbers 1014-0011 and 1014-0030. This NTL does not impose any additional information collection requirements subject to the Paperwork Reduction Act of 1995.

Contact

For information or questions regarding this NTL, lessees or others may contact the appropriate Regional office as follows:

Gulf of Mexico Region: Decommissioning Support Section
Phone: (504) 736-7569;

Pacific Region: Regional Supervisor for Office of Strategic Operations
Phone: (805) 384-6325;

Alaska Region: Regional Supervisor for Regional Field Operations
Phone: (907) 334-5300

Douglas Morris /S/
Douglas Morris
Chief, Office of Offshore Regulatory Programs

UNITED STATES DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE
PACIFIC OCS REGION

NTL No. 2010-P05

Effective Date: February 19, 2010
Expiration Date: February 18, 2015

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE PACIFIC OUTER CONTINENTAL SHELF REGION

Decommissioning Cost Report Update

This Notice to Lessees and Operators (NTL) supersedes NTL No. 2004-P03, Offshore Facility Decommissioning Costs Report.

This NTL serves to notify you of the availability of a new report entitled, "Decommissioning Cost Update for Removing Pacific OCS Region Offshore Oil and Gas Facilities, January 2010."

The new report contains updated cost estimates for decommissioning Outer Continental Shelf (OCS) oil and gas facilities in the Pacific OCS Region (POCSR). This cost report was prepared for the Minerals Management Service (MMS) by Proserv Offshore, which developed cost estimates in accordance with Federal regulations (30 CFR 250) governing oil and gas operations conducted on the OCS. The regulations specify requirements for plugging wells, decommissioning platforms and pipelines, and clearing a lease site. This report is one of the inputs used by MMS to determine if a lessee is required to post a supplemental bond to ensure OCS lease decommissioning obligations are met. Title 30 CFR 256 and MMS Notice to Lessees No. 2008-N07, Supplemental Bond Procedures (http://www.mms.gov/ntls/Attachments/2008-N07.htm), specify the requirements for supplemental bonds. The MMS POCSR customarily prepares a decommissioning cost report every 5 years to determine estimated cumulative lease liabilities and support decisions regarding supplemental bonding requirements; this new report is the third in the series and supersedes the 2004 report.

The MMS Technology Assessment & Research Program website, at http://www.mms.gov/tarprojects/646.htm, provides a link to Volume 1 of the report and includes additional information on the project and directions for obtaining Volume 2 (detailed appendices). Volume 1 may also be downloaded directly, at http://www.mms.gov/tarprojects/646/AA.pdf.

Guidance Document Statement

The MMS issues NTL's as guidance documents in accordance with 30 CFR 250.103. This NTL is informational and provides details about the availability of a new report for public review. The report helps to ensure that operators plan appropriately to follow through on meeting decommissioning liabilities by providing an up-to-date assessment of those liabilities.

Paperwork Reduction Act of 1995 Statement

This NTL does not impose information collection requirements subject to the Paperwork Reduction Act of 1995.

If you have any questions or need clarification regarding this NTL, please contact Mr. John Smith at john.smith@mms.gov or (805) 389-7833 or Mr. Jaron E. Ming at jaron.ming@mms.gov or (805) 389-7502.

Ellen G. Aronson
Regional Director
Pacific OCS Region

Feb. 19, 2010
Date

UNITED STATES DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE
GULF OF MEXICO OCS REGION

NTL No. 2009-G25

Effective Date: August 26, 2009
Expiration Date: August 25, 2014

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES AND PIPELINE RIGHT-OF-WAY HOLDERS ON THE OUTER CONTINENTAL SHELF, GULF OF MEXICO OCS REGION

Shutting In Producible Wells During Rig Moves

This Notice to Lessees and Operators (NTL) supersedes NTL No. 2004-G09, effective May 17, 2004. It specifies that the guidance regarding when you must shut in producible wells during rig moves applies to rigs and related equipment used during well-completion, well-workover, and well decommissioning operations, as well as drilling operations; makes amendments to Appendices B, C, and D; and provides a guidance document statement.

Authority

The regulation at 30 CFR 250.406(b) requires you to shut in all producible wells located in the affected wellbay below the surface and at the wellhead when you: (1) move a drilling rig or related equipment on or off a platform, (2) move or skid a drilling unit between wells on a platform, or (3) move a mobile offshore drilling unit (MODU) within 500 feet of a platform.

The regulations at 30 CFR 250.502 and 250.602 requires all wells in the same well-bay, which are capable of producing hydrocarbons, to be shut in below the surface with a pump-through-type tubing plug, and at the surface with a closed master valve prior to moving well-completion and well-workover rigs and related equipment, unless otherwise approved by the District Manager.

The regulation at 250.1703(f) requires that all decommissioning activities must be conducted in a manner that is safe, does not unreasonably interfere with other uses of the OCS, and does not cause undue or serious harm or damage to the human, marine, or coastal environment.

Procedures

The four appendices to this NTL provide guidance on how you may comply with 30 CFR 250.406(b), 250.502, 250.602, and 250.1703(f). They describe the various types of rigs and phases of rig movement, specify when wells must be shut in (wells need not be shut in if the rig is stacked on location), and delineate the documentation you submit to the appropriate MMS

Gulf of Mexico OCS Region (GOMR) District Office if you request approval of a departure under 30 CFR 250.142.

Guidance Document Statement

The MMS issues NTL's as guidance documents in accordance with 30 CFR 250.103 to clarify, supplement, and provide more detail about certain MMS regulatory requirements and to outline the information you provide in your various submittals. Under that authority, this NTL sets forth a policy on and an interpretation of a regulatory requirement that provides a clear and consistent approach to complying with that requirement. However, if you wish to use an alternative approach for compliance, you may do so, after you receive approval from the appropriate MMS office under 30 CFR 250.141.

Paperwork Reduction Act of 1995 (PRA) Statement

The information collection referred to in this NTL is intended to provide clarification, description, or interpretation of requirements contained in 30 CFR 250, Subparts A, D, E, F, and Q. The Office of Management and Budget (OMB) has approved the information collection requirements for Subparts A, D, E, F, and Q under OMB Control Numbers 1010-0114, 1010-0141, 1010-0067, 1010-0043, and 1010-0142, respectively. This NTL does not impose any additional information collection subject to the PRA.

Contact

If you have any questions regarding this NTL, please contact the appropriate MMS GOMR District Office

[original signed]

Lars T. Herbst
Regional Director

Appendices

Appendix A (Mat-supported Jack-up Rigs)
Appendix B (Independent Leg Jack-up Rigs)
Appendix C (Platform Rig Move On/Off; Requires Use of Barge/Heavy Lifting Vessel)
Appendix D (Platform Rig Move On/Off; Requires Use of Rig Crane and Workboats)

APPENDIX A
MAT-SUPPORTED JACK-UP RIGS

Moving On Location

ACTIVITY	SHUT IN?		INFORMATION NEEDED FOR A DEPARTURE REQUEST
	YES	NO	
Move Rig Within 500 feet/Pin to Seafloor	X		A.1
Jack-up to Airgap		X	
Skid/Cantilever	X		A.2
Install Lines, Hoses, and Ladders		X	
Hammer/Drive Pipe	X		A.3
Move BOP Stack and Riser (Bell Nipple)	X*		A.4

* Only affected wells (i.e., those wells that could be hit by a falling BOP stack)

Moving Off Location

ACTIVITY	SHUT IN?		INFORMATION NEEDED FOR A DEPARTURE REQUEST
	YES	NO	
Move BOP Stack and Riser (Bell Nipple)	X*		A.4
Cantilever Back	X		A.2
Jack Down		X	
Jack Mat Off Bottom and Bring Mat to Tow Position	X		A.1
Move Rig Off Within 500 feet	X		A.1

* Only affected wells (i.e., those wells that could be hit by a falling BOP stack)

DEPARTURE DOCUMENTATION FOR MAT-SUPPORTED JACK-UP RIGS

A.1 Provide the following in your departure request:

(1) A diagram indicating the horsepower rating of the tow vessels and showing the tow line positioning relative to the rig hull and the well/platform position;

(2) A statement that you will provide tow vessels with horsepower sufficient to exert an immediate pull from location, and that the tow vessels will remain attached with towlines in tension until the jack-up rig is pinned to seafloor;

(3) A diagram that shows all prior spud can/mat locations, bottom obstructions, hull standoff distance to platform at water line, mat position and standoff to platform at seafloor, and location of reflectors/buoys used for rig positioning; and

(4) A statement that all vessels will remain attached and in tension from a time prior to when the mat is pulled off the bottom until the rig is more than 500 feet from the platform.

<u>A.2</u> Provide the following in your departure request:

(1) A diagram or photograph showing the storage position and restraint system for the diverter and blowout preventer (BOP) stack; and

(2) A statement that this equipment will remain properly secured in this storage position during all skid/cantilever operations.

<u>A.3</u> Provide the following in your departure request:

(1) Documentation of how the equipment will be moved and properly secured in reference to existing producing wells;

(2) A description of the well bay area including its height and the distance from the rig floor to the platform deck;

(3) A description of the method you will use to protect the surrounding producing wells;

(4) The type of material construction of the platform deck (grating vs. solid decking or steel plate);

(5) The point load calculations; and

(6) A diagram from an overhead view indicating the potential fall path radius for a single joint of dropped drive pipe.

<u>A.4</u> Provide the following in your departure request:

(1) A diagram indicating the position of the BOP stack, the stack height, and the height of well bay;

(2) A plat showing the well bay and the path the rig will follow to or from the affected well;

(3) If there is a deck between the BOP stack and the well bay, a description of the deck protection type and the point load calculations; and

(4) If the BOP stack is located within the well bay, a statement that affected wells will remain shut in until the BOP stack is secured.

APPENDIX B
<u>INDEPENDENT LEG JACK-UP RIGS</u>

<u>Moving On Location</u>

ACTIVITY	SHUT IN? YES	SHUT IN? NO	INFORMATION NEEDED FOR A DEPARTURE REQUEST
Move Rig Within 500 feet/Pin to Seafloor	X		B.1
Preload	X		B.2
Jack-up to Airgap		X	
Skid/Cantilever	X		B.3
Install Lines, Hoses, and Ladders		X	
Hammer/Drive Pipe	X		B.4
Move BOP Stack and Riser (Bell Nipple)	X*		B.5

* Only affected wells (i.e., those wells that could be hit by a falling BOP stack)

<u>Moving Off Location</u>

ACTIVITY	SHUT IN? YES	SHUT IN? NO	INFORMATION NEEDED FOR A DEPARTURE REQUEST
Move BOP Stack and Riser (Bell Nipple)	X*		B.5
Cantilever Back	X		B.3
Jack Down		X	
Jet Legs Free (Legs to MPD) **		X	
Jet Legs Free (Legs from MPD to Free from Seafloor and Rig Within 100 feet)	X		B.6
Rig More than 100 feet and Moving Off Within 500 feet	X		B.6

* Only affected wells (i.e., those wells that could be hit by a falling BOP stack)
** Minimum Penetration Depth (MPD) means the rig hull's buoyant draft during jetting operation in feet, plus twenty (20) feet of mudline penetration on all legs. Example: For a rig with a hull draft of 18 feet during jetting operation, MPD is the point where all legs have a minimum of 38 feet of penetration below the mud line.

<u>DEPARTURE DOCUMENTATION FOR INDEPENDENT LEG JACK-UP RIGS</u>

<u>**B.1**</u> Provide the following in your departure request:

(1) A diagram indicating the horsepower rating of the tow vessels and showing the tow line positioning relative to the rig hull and the well/platform position;

(2) A statement that you will provide tow vessels with horsepower sufficient to exert an immediate pull from location, and that the tow vessels will remain attached with towlines in tension until the jack-up rig is pinned to seafloor; and

(3) A diagram that shows all prior spud can/mat locations, bottom obstructions, hull standoff distance to platform at water line, spud can position and standoff to platform at seafloor, and location of reflectors/buoys used for rig positioning.

B.2 Provide the following in your departure request:

(1) If this is the first independent leg rig at this location, a site-specific soil boring and leg penetration analysis provided by a Geotechnical Engineer having experience in the area to ensure there is no risk of punch through at the specific location or encountering shallow hazards; or

(2) If this is not the first independent leg rig at this location

(a) If you will use existing can holes,

(i) The method you intend to use to align the can holes;

(ii) Previous preload weight and resulting leg penetration, and the proposed preload weight for this operation. If the planned preload is larger or the spud can size is smaller than historical rig moves, a site-specific soil boring and spud can penetration analysis provided by a Geotechnical Engineer having experience in the area to ensure there is no risk of punch through at the specific location or encountering shallow hazards. If the planned preload is less than or equal to the historical preload(s) and the spud can size is the same or larger than previous spud cans, no additional information is necessary; and

(iii)Data on the number of preload cycles and load weights.

(b) If you will develop new spud can holes,

(i) A diagram showing existing can hole/mat locations and their position relative to the planned can hole locations;

(ii) The intended method to establish new can holes and the effect that existing soil disturbances may have on spud can penetration analysis specified in Item iii below;

(iii)A site-specific soil boring and spud can penetration analysis provided by a Geotechnical Engineer having experience in the area to ensure there is no risk of punch through at the specific location or encountering shallow hazards; and

(iv)Data on the number of preload cycles and load weights.

B.3 Provide the following in your departure request:

(1) A diagram or photograph showing the storage position and restraint system for the diverter and blowout preventer (BOP) stack; and

(2) A statement that this equipment will remain properly secured in this storage position during all skid/cantilever operations.

B.4 Provide the following in your departure request:

(1) Documentation of how the equipment will be moved and properly secured in reference to existing producing wells;

(2) A description of the well bay area including its height, and the distance from the rig floor to the platform deck;

(3) A description of the method you will use to protect the surrounding producing wells;

(4) The type of material construction of the platform deck (grating vs. solid decking or steel plate);

(5) The point load calculations; and

(6) A diagram from an overhead view indicating the potential fall path radius for a single joint of dropped drive pipe.

B.5 Provide the following in your departure request:

(1) A diagram indicating the position of the BOP stack, the stack height, and the height of well bay;

(2) A plat showing the well bay and the path the rig will follow to or from the affected well;

(3) If there is a deck between the BOP stack and the well bay, a description of the deck protection type and the point load calculations; and

(4) If the BOP stack is located within the well bay, a statement that affected wells will remain shut in until the BOP stack is secured.

B.6 Provide the following in your departure request:

(1) A diagram indicating the horsepower rating of the tow vessels and showing the tow line positioning relative to the rig hull and the well/platform position;

(2) A statement that all vessels will remain attached and in tension from a time prior to when the spud cans are pulled above the MPD until the rig is more than 500 feet from the platform; and

(3) A statement that you will provide tow vessels with horsepower sufficient to exert an immediate pull from location, and that the tow vessels will remain attached with towlines in tension until the jack-up rig is more than 500 feet from platform.

APPENDIX C
PLATFORM RIG MOVE ON/OFF
Requires Use of Barge/Heavy Lifting Vessel

ACTIVITY	SHUT IN?		INFORMATION NEEDED FOR A DEPARTURE REQUEST
	YES	NO	
Move Barge Within 500 feet of Platform	X*		C.1 and C.3
Perform Lifts During Rig Up	X		C.2
Move BOP Stack/BOP Riser	X**		C.3
Install Lines, Hoses, and Ladders		X	
Hammer/Drive Pipe	X		C.4
Skidding Between Wells	X		C.5
Perform Lifts During Rig Down	X		C.2 and C.3
Move Barge Off Within 500 feet of Platform	X		C.1 and C.3

* Shut-in required only when moving barge into location and securing same. Once secured, production may resume until heavy lifting begins.
** Only affected wells (i.e., those wells that could be hit by a falling BOP stack)

DEPARTURE DOCUMENTATION FOR PLATFORM RIG MOVE

C.1 Provide the following in your departure request:

(1) A diagram indicating the horsepower rating of the tow/transport vessels and the means of positioning relative to platform;

(2) A statement that you will provide tow vessels with horsepower sufficient to exert an immediate pull from location, and that the tow vessels will remain attached with towlines in tension until the barge is properly secured while adjacent to facility; and

(3) If you will use dynamically positioned vessels, the downstream position of the vessel between major lifts.

C.2 Provide the following in your departure request:

(1) If you will be lifting to/from platform area(s) where wells and process equipment are not located,

(a) Information that shows that the crane load capacity is sufficient for the lift (boom angle, dynamic vs. static); and

(b) Information that shows the crane location, lift path, and set down area for each lift. Make sure that set down areas confirm there are no hydrocarbon process lines or wells affected by the lifting path.

(2) If you will be lifting to/from area(s) affected by wells and/or process equipment,

(a) Information that shows that the crane load capacity is sufficient for the lift (boom angle, dynamic vs. static);

(b) Platform structural data and point load calculations showing that the facility, including production process systems, can withstand a dropped object;

(c) A lift sequence plan describing the order of lifts and lift positioning on platform deck relative to well bay area and production process equipment; and

(d) A statement that you will resume production of the affected wells only after the rig substructure is in place and the well bay is protected from impacts.

C.3 Provide the following in your departure request:

(1) A diagram indicating the position of the BOP stack, the stack height, the height of well bay, and the path the rig/barge will use to make the move;

(2) If there is a deck between the BOP stack and the well bay, a description of the deck protection type and the point load calculations (thickness of deck and beam spacing); and

(3) If the BOP stack is located within the well bay, a statement that affected wells will remain shut in until the BOP stack is secured.

C.4 Provide the following in your departure request:

(1) Documentation of how the equipment will be moved and properly secured in reference to existing producing wells;

(2) A description of the well bay area including its height and the distance from the rig floor to the platform deck;

(3) A description of the method you will use to protect the surrounding producing wells;

(4) The type of material construction of the platform deck (grating vs. solid decking or steel plate);

(5) The point load calculations; and

(6) A diagram from an overhead view indicating the potential fall path radius for a single joint of dropped drive pipe.

C.5 Provide the following in your departure request:

(1) A diagram or photograph showing the storage position and restraint system for the diverter and blowout preventer (BOP) stack; and

(2) A statement that this equipment will remain properly secured in this storage position during all skidding operations.

APPENDIX D
<u>PLATFORM RIG MOVE ON/OFF</u>
Requires Use of Rig Crane and Workboats

ACTIVITY	SHUT IN?		INFORMATION NEEDED FOR A DEPARTURE REQUEST
	YES	NO	
Move Boat(s) & Secure or DP at Platform		X	
Perform Lifts during Rig Up	X		D.1
Move BOP Stack/BOP Riser	X*		D.2
Install Lines, Hoses, and Ladders		X	
Hammer/Drive Pipe	X		D.3
Skidding Between Wells	X		D.4
Perform Lifts During Rig Down	X		D.1 and D.2
Move Boat(s) & Secure or DP at Platform		X	

* Only affected wells (i.e., those wells that could be hit by a falling BOP stack)

<u>DEPARTURE DOCUMENTATION FOR PLATFORM RIG MOVE</u>

<u>D.1</u> Provide the following in your departure request:

(1) If you will be lifting to/from platform area(s) where wells and process equipment are not located,

(a) Information that shows that the crane load capacity is sufficient for the lift (boom angle, dynamic vs. static); and

(b) Information that shows the crane location, lift path, and set down area for each lift. Make sure that set down areas confirm there are no hydrocarbon process lines or wells affected by the lifting path.

(2) If you will be lifting to/from area(s) affected by wells and/or process equipment,

(a) Information that shows that the crane load capacity is sufficient for the lift (boom angle, dynamic vs. static);

(b) Platform structural data and point load calculations showing that the facility, including production process systems, can withstand a dropped object;

(c) A lift sequence plan describing the order of lifts and lift positioning on platform deck relative to well bay area and production process equipment; and

(d) A statement that you will resume production of the affected wells only after the rig substructure is in place and the well bay is protected from impacts.

<u>D.2</u> Provide the following in your departure request:

(1) A diagram indicating the position of the BOP stack, the stack height, the height of well bay, and the path the rig/platform crane will use to make the move;

(2) If there is a deck between the BOP stack and the well bay, a description of the deck protection type and the point load calculations (thickness of deck and beam spacing); and

(3) If the BOP stack is located within the well bay, a statement that affected wells will remain shut in until the BOP stack is secured.

D.3 Provide the following in your departure request:

(1) Documentation of how the equipment will be moved and properly secured in reference to existing producing wells;

(2) A description of the well bay area including its height and the distance from the rig floor to the platform deck;

(3) A description of the method you will use to protect the surrounding producing wells;

(4) The type of material construction of the platform deck (grating vs. solid decking or steel plate);

(5) The point load calculations; and

(6) A diagram from an overhead view indicating the potential fall path radius for a single joint of dropped drive pipe.

D.4 Provide the following in your departure request:

(1) A diagram or photograph showing the storage position and restraint system for the diverter and blowout preventer (BOP) stack; and

(2) A statement that this equipment will remain properly secured in this storage position during all skidding operations.

United States General Accounting Office

GAO

Report to the Chairman, Committee on Governmental Affairs, U.S. Senate

May 1994

OFFSHORE OIL AND GAS RESOURCES

Interior Can Improve Its Management of Lease Abandonment

RESTRICTED--Not to be released outside the General Accounting Office unless specifically approved by the Office of Congressional Relations.

RELEASED

GAO

United States
General Accounting Office
Washington, D.C. 20548

Resources, Community, and
Economic Development Division

B-255788

May 11, 1994

The Honorable John Glenn
Chairman, Committee on Governmental Affairs
United States Senate

Dear Mr. Chairman:

In response to your request, this report discusses (1) actions taken by the Department of the Interior's Minerals Management Service to minimize the environmental impact of the abandonment of federal oil and gas leases on the Outer Continental Shelf and (2) the estimated costs of lease abandonment and the Minerals Management Service's approach for ensuring that the government is not burdened with these costs. We focused our review on the Gulf of Mexico because almost all offshore oil and gas structures on federal leases are located there.

As agreed with your office, unless you publicly announce its contents earlier, we plan no further distribution of this report until 30 days from the date of this letter. At that time, we will send copies to the Secretary of the Interior and other interested parties. We will make copies available to others on request.

This work was performed under the direction of James Duffus III, Director, Natural Resources Management Issues, who can be reached at (202) 512-7756 if you or your staff have any questions. Major contributors to this report are listed in appendix III.

Sincerely yours,

Keith O. Fultz

Keith O. Fultz
Assistant Comptroller General

Executive Summary

Purpose

When oil and gas production from a federal lease on the Outer Continental Shelf (OCS) ends, the Department of the Interior's Minerals Management Service (MMS) is responsible for ensuring that the parties responsible for the lease bear the costs of abandoning the leased area. Lease abandonment includes plugging and abandoning wells, removing structures, and clearing lease sites, all of which must be done in a manner that prevents unreasonable harm to marine life and the environment. In response to a request from the Chairman, Senate Committee on Governmental Affairs, this report discusses (1) MMS' actions to minimize the environmental impact of lease abandonment and (2) the estimated costs of lease abandonment and MMS' approach for ensuring that the government is not burdened with these costs. The report focuses on MMS' actions in the Gulf of Mexico because almost all OCS oil and gas structures are located there.

Background

As of December 1993, there were about 3,800 OCS oil and gas structures, virtually all of which were located in the Gulf of Mexico. These structures vary in size and complexity, and costs for lease abandonment range from about $50,000 to $100 million per structure, depending on the size of the structure and the depth of the water in which the structure is located. If the responsible parties do not properly abandon leases, the federal government may have to incur these costs. For many years, more structures were installed each year than removed. However, in 1992 and 1993, a total of 343 structures were removed and 195 installed, all in the Gulf of Mexico.

OCS oil and gas structures are removed most often by using underwater explosives to shear the portions of the structures that extend to the ocean's floor. Explosives kill nearby fish and can kill marine mammals and endangered sea turtles if they are in the vicinity of the structure being removed.

Among the purposes of the Outer Continental Shelf Lands Act are (1) balancing resource development with protection of the environment and (2) encouraging the development of new and improved technology that will eliminate or minimize the risk of damage to the environment. Under other laws, including the Endangered Species Act, the Department of the Interior and the Department of Commerce's National Marine Fisheries Service are responsible for protecting the environment and marine life.

As part of MMS' approach for protecting the environment and ensuring that the government is not burdened with lease abandonment costs, it is important that the agency ensure that wells are properly plugged and abandoned and lease sites cleared. If these tasks are done properly in the first place, it is less likely that future problems will occur that may damage the environment and cause the government to incur costs.

Results in Brief

MMS has acted to protect the environment by (1) limiting the use of explosives in order to protect endangered sea turtles and (2) requiring that wells be plugged and lease sites cleared. However, MMS has not encouraged the development of nonexplosive structure removal technologies that would eliminate or minimize environmental damage. In addition, MMS does not have an overall inspection strategy that targets its limited resources to adequately ensure that wells are properly plugged and abandoned and that lease sites are properly cleared.

At the time of GAO's review, MMS was not required to pay any lease abandonment costs if responsible parties had failed to do so. MMS has a workable approach for protecting the government from incurring lease abandonment costs, consisting of requiring a general bond for all leases and supplemental bonds in the amount of the total estimated costs of lease abandonment for leases without at least one party deemed financially capable. However, prior to November 1993, the criteria that MMS had been using to assess the financial capability of the parties responsible for OCS leases may not have adequately measured a company's ability to pay for the potentially significant costs of lease abandonment. As of March 1993, Gulf of Mexico leases having $4.4 billion worth of estimated lease abandonment costs were covered by only $68 million in bonds. In August 1993, MMS promulgated new regulations that changed those criteria and increased the amounts of the general bonds that the parties responsible for OCS leases are required to provide.[1] However, both of these changes are to be phased in without a deadline for completion. For example, the new general bond amounts will only be required when a change occurs in lease activity or ownership. Therefore, implementing the new coverage may take some time, and some leases may never have the new coverage. In the meantime, the federal government may be at risk for lease abandonment costs that exceed bond coverage.

[1]These regulations became effective November 26, 1993.

Principal Findings

MMS Could Do More to Protect the Environment From the Effects of OCS Oil and Gas Lease Abandonment

To protect the environment, MMS and the National Marine Fisheries Service, which is responsible for protecting marine endangered species, formally agreed on measures for protecting endangered sea turtles when underwater explosives are used to remove OCS structures. These measures limit the amount of explosives that may be used without specific approval. Furthermore, MMS requires that lease sites be verified as having been cleared.

However, MMS has not adequately studied the costs and benefits of using nonexplosive technology that would eliminate or minimize the risk of environmental damage from removing OCS structures. Certain actions by MMS may actually encourage the use of explosives. For example, in 1993, MMS proposed relaxing the limits on the use of explosives without having adequately documented the need for larger explosive charges or the probability of harmful effects on marine life. Several oil and gas company representatives told us that if MMS encouraged or required the use of nonexplosive removal methods, companies would further develop this technology.

In addition, MMS does not have an overall inspection strategy for targeting its limited resources to ensuring that wells are properly plugged and abandoned. If wells are not properly plugged and abandoned, leaks can occur after a lease site has been abandoned, causing serious damage to the environment and marine life. MMS has only about 50 technicians in the Gulf of Mexico Region to inspect about 3,800 OCS facilities, and they generally inspect well plugging only when it happens to coincide with other inspections.

Furthermore, MMS' inspection strategy does not adequately ensure that OCS oil and gas lease sites are cleared. For leases in water less than 300 feet deep, MMS requires the responsible parties to hire trawlers to verify that the sites have been properly cleared. However, MMS does not control the hiring of trawlers or independently verify that sites have been properly cleared.

MMS Is Improving How It Protects the Government From Incurring OCS Oil and Gas Lease Abandonment Costs, but More Could Be Done

To guarantee that parties responsible for lease abandonment costs bear those costs, MMS requires that OCS leases be covered by surety bonds.[2] At a minimum, every lease must be covered by a general bond in a fixed amount. Since May 1992, MMS has required that any lease that does not have at least one party that is financially capable of fulfilling lease abandonment obligations be covered by a supplemental bond in the full amount of the estimated lease abandonment costs. Lease abandonment costs range from about $50,000 to $100 million for a structure. For the 1,811 active OCS leases in the Gulf of Mexico with structures or wells, GAO estimated the total cost of lease abandonment, as of March 1993, at about $4.4 billion in current dollars. However, these leases were covered by only $68 million in bonds. MMS determined that of these leases, 1,702, with estimated lease abandonment costs of about $4.2 billion, were held by at least one financially capable party. These leases were covered by a total of $45 million in general bonds.

MMS' August 1993 regulations increased the required amounts of general bonds, which should eventually increase the total amount of bond coverage on OCS leases. However, the increases are to be phased in over time, only when a change occurs in lease activity or ownership, with no deadline for completion. Also, at the same time, MMS changed the evidence required for evaluating the financial capability of parties responsible for OCS leases. Before, MMS used criteria that were developed for purposes unrelated to assessing a party's ability to pay for lease abandonment costs. The revised criteria, if properly implemented, could provide greater assurance that the leases have either at least one financially capable party or supplemental bonds in the full amount of the estimated lease abandonment costs. However, there is no specified time frame for implementing the new criteria, and they could be phased in over time. Thus, it may be some time until a significant number of leases have the new general and supplemental bonds, and some leases may never have them before the leases are abandoned. In commenting on a draft of this report, MMS said that it plans to initiate a rulemaking to set deadlines for completing new bond requirements.

Recommendations to the Secretary of the Interior

GAO recommends that the Secretary of the Interior direct the Director of MMS to

[2]A surety bond is a guarantee that the bond writer will pay a stipulated amount if the purchaser of the bond defaults on paying for obligations covered by the bond.

- encourage the use of nonexplosive technologies for removing offshore structures, whenever possible, that will eliminate or minimize the risk of harm to the environment and marine life;
- study the feasibility, benefits, and costs of mandating the use of nonexplosive methods of removing offshore structures, whenever possible, because of the harm that explosives do to marine life;
- require MMS to develop an inspection strategy for targeting its limited resources to ensure the proper plugging and abandonment of OCS wells and the clearance of lease sites; and
- complete a rulemaking to place time limits on the phase-in of both the increased general bond amounts and supplemental bonding under the new criteria.

Agency Comments

In written comments on a draft of this report, the Departments of the Interior and Commerce generally agreed with GAO's recommendations. Interior agreed that OCS lease abandonment technology needs further review, taking into account factors including safety, cost, and environmental effects. Interior stated that it was reevaluating its inspection strategy and considering various options for witnessing more abandonment activities. In addition, Interior stated that it recognized the need for a deadline for all lessees to have increased bond coverage and is developing regulations to accomplish this. Commerce noted that the report is well written and will be understood by an audience with a broad range of expertise on the impacts that removing structures has on marine environments. The departments' comments have been incorporated in the report where appropriate.

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Abbreviations

GAO	General Accounting Office
MMS	Minerals Management Service
NEPA	National Environmental Policy Act
NMFS	National Marine Fisheries Service
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act
SBA	Small Business Administration

Introduction

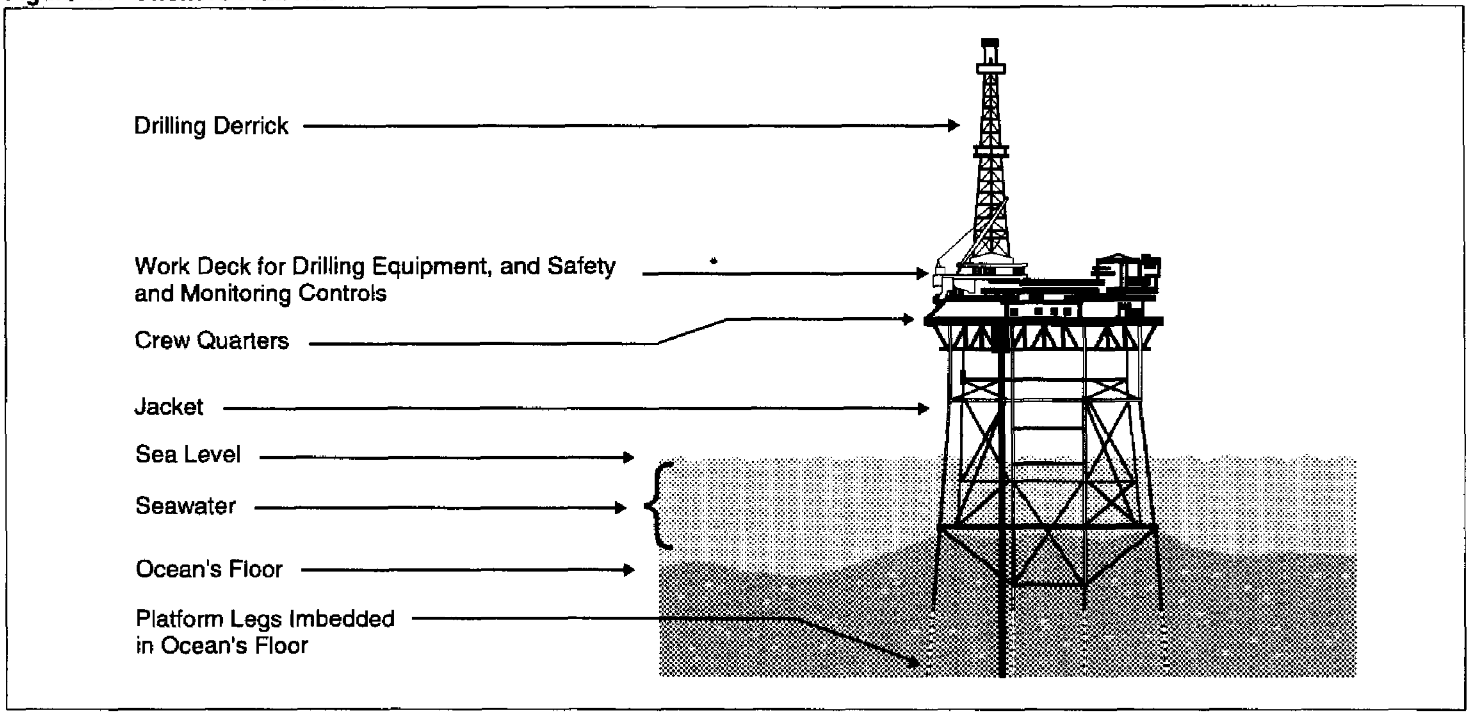
Since 1953, the Department of the Interior has managed the development of oil and gas resources of the Outer Continental Shelf (OCS).[1] Interior's Minerals Management Service (MMS) issues and manages OCS oil and gas leases; among other things, MMS is responsible for ensuring that when production ends, the leases are abandoned in a manner that prevents unreasonable harm to marine life and the environment. MMS is also responsible for ensuring that the parties responsible for the OCS leases bear the costs of the lease abandonment activities. These activities include plugging and abandoning wells to prevent leaks, removing structures, and clearing lease sites of obstructions to prevent hazards to commercial fishing and shrimping as well as navigation.

OCS oil and gas structures vary in size and complexity. Simple structures include such things as single pipes and single well protectors. Modern structures are made of steel, or sometimes, steel and concrete. Most of the large platforms have living quarters for the crew, a helicopter pad, and room for drilling and production equipment. A typical platform is designed so that 12 to 48 or more wells may be drilled from it by directional drilling. Wells from a single platform may extend over an area of several thousand acres (as measured at the bottom of the holes).

Platforms consist of three main components—the superstructure, or deck; the jacket; and the pilings. The deck is the surface where work is performed. The jacket rests on the ocean's floor and has columns, or legs, that extend above the water's surface. Pilings to hold the structures in place are driven through the legs into the ocean's floor. The jacket guides the installation of pilings and is a structural unit to support the deck. Furthermore, it resists waves, currents, wind, and earthquakes. Figure 1.1 shows a steel-jacket offshore platform.

[1]The OCS is the area approximately from 3 to 200 miles off the coast of the United States that is under federal jurisdiction. It may extend even further off the coast if oil or gas can be economically developed. The first 3 miles offshore (9 miles offshore in the cases of Texas and the Gulf coast of Florida) are under the jurisdiction of the adjacent states.

Figure 1.1: Offshore Platform



Oil and gas structures are removed most often by using underwater explosives to shear the portions that extend to the ocean's floor. This kills nearby fish and can kill marine mammals and endangered sea turtles if they are near the structure being removed. To fulfill its responsibility for protecting the environment, MMS regulates OCS lease abandonment; this includes limiting the use of underwater explosives to remove structures in the Gulf of Mexico.

MMS is also responsible for ensuring that parties responsible for OCS lease abandonment costs pay those costs. These costs range from about $50,000 to $100 million per structure, depending on the structure's size and the water's depth in which it is located. The federal government may have to incur these costs if the responsible parties fail to pay them.

As of December 1993, there were about 3,800 OCS oil and gas structures, virtually all of which were located in the Gulf of Mexico.[2] For many years,

[2]MMS has four OCS regions: Alaska, Atlantic, Gulf of Mexico, and Pacific. Because most OCS leases are in the Gulf of Mexico, this report only addresses MMS' management of lease abandonment in its Gulf of Mexico Region.

more structures were installed each year than removed. However, in 1992 and 1993, a total of 343 structures were removed and 195 installed, all in the Gulf of Mexico.

Laws Pertaining to the Abandonment of OCS Leases

The Outer Continental Shelf Lands Act (OCSLA), as amended (43 U.S.C. 1331 et seq.), requires the Secretary of the Interior to administer mineral leasing, exploration, and development on the OCS. Among OCSLA's purposes are balancing resource development with protection of the environment and encouraging the development of new and improved technology for the production of resources that will eliminate or minimize the risk of damage to the environment. OCSLA also mandates that the Secretary require the use of the best available and safest technologies feasible. To enforce the requirements, including those affecting the environment, OCSLA requires the Secretary to inspect every OCS facility at least once annually as well as to conduct periodic on-site inspections without advance notice.

In addition, under the National Environmental Policy Act of 1969 (NEPA), as amended (42 U.S.C. 4321 et seq.), it is national policy that all federal agencies, including MMS, promote efforts that will prevent or eliminate damage to the environment. Under NEPA, agencies must study alternative courses of action concerning uses of available resources when a recommended action might significantly affect the quality of the environment.

Two other acts are also relevant to protecting marine life from the effects of OCS oil and gas lease abandonment. One, the Endangered Species Act of 1973, as amended (16 U.S.C. 1531 et seq.), requires, among other things, that federal agencies consult with the Secretary of Commerce in order to ensure that any action will not likely jeopardize the continued existence of any marine endangered or threatened species. Endangered sea turtles and other marine life were found dead on the Texas and Louisiana coasts in 1986. Evidence suggested that this was caused by explosives used to remove OCS oil platforms in adjacent waters. As a result, the National Marine Fisheries Service (NMFS), within the Department of Commerce, and MMS formally agreed on measures for protecting endangered sea turtles in the Gulf of Mexico when oil and gas structures are removed using explosives.

The second act is the Marine Mammal Protection Act of 1972, as amended (16 U.S.C. 1371 et seq.), which places a moratorium on the "taking" of marine mammals, including a complete cessation of harassing, hunting, capturing, or killing, except as approved under the act. This act does not require federal agencies to consult with the Secretary of Commerce to ensure that actions will not jeopardize marine mammals. However, approval must be obtained from the Secretary for exceptions to the moratorium on taking. MMS also addresses the effects of OCS lease abandonment on marine mammals in its environmental impact statements and environmental studies.

Objectives, Scope, and Methodology

The Chairman, Senate Committee on Governmental Affairs, asked us to evaluate the Department of the Interior's management of OCS oil and gas lease abandonment. We were asked to evaluate (1) MMS' actions to minimize the environmental impact of lease abandonment and (2) the estimated costs of lease abandonment and MMS' approach for ensuring that the government is not burdened with these costs.

To evaluate Interior's actions to minimize the environmental effects of lease abandonment, we reviewed applicable federal laws and regulations. We interviewed MMS officials at the Gulf of Mexico OCS Region regarding the removal of structures and site clearance requirements. We interviewed academicians in the scientific community. We interviewed NMFS officials at the Southeast Regional Office and the Galveston Laboratory about the use of explosives for the removal of OCS structures. We interviewed representatives from oil and gas companies working offshore, OCS oil and gas service contractors, and the Offshore Operators Committee (an industry association of oil and gas operators in the Gulf of Mexico) about methods for removing offshore structures. We interviewed representatives from the Gulf of Mexico Fishery Management Council to obtain information on the effect of explosives on fish.[3] We interviewed officials and reviewed documents of the U.S. Army Corps of Engineers' New Orleans District Office regarding methods of removing offshore structures in Louisiana state waters. Finally, we contacted several environmental groups to obtain their views on the environmental effects of removing structures in the Gulf of Mexico. The groups we contacted included the World Wildlife Fund, the National Wildlife Federation, the Natural Resources Defense Council, the National Fish and Wildlife Foundation, the National Coalition for Marine Conservation, the Sierra Club, Greenpeace, the Environmental Defense Fund, the National Audubon Society, Friends of the Earth, and the Center for Marine Conservation.

[3]The Gulf of Mexico Fishery Management Council is one of eight regional Fishery Management Councils established by the Fishery Conservation and Management Act of 1976, as amended (16 U.S.C. 1852). The Council manages fishery resources in the Gulf of Mexico.

In order to determine if MMS' procedures ensure that oil and gas companies adequately clear the ocean's floor after removing their structures, we interviewed several members of MMS' site clearance committee. This committee included (1) MMS and state and local officials and (2) representatives from the oil and gas and commercial fishing and shrimping industries. We also interviewed five commercial fishermen/shrimpers to obtain their views on the adequacy of MMS' site clearance procedures. Two of the commercial fishermen/shrimpers were members of the site clearance committee, another was president of the Louisiana Shrimp Association, and one was a member of the Organization of Louisiana Fishermen. In addition, we interviewed the executive director of the Texas Shrimp Association.

To determine estimated total OCS lease abandonment costs to remove structures, plug wells, and clear sites in the Gulf of Mexico, we obtained and analyzed an MMS database containing estimated lease abandonment costs for active leases with structures or wells. We verified that formulas used by MMS to calculate lease abandonment costs were accurately derived from actual cost data developed by MMS for 37 structures. We verified that MMS' estimated lease abandonment costs were accurately calculated using the formulas. Finally, we calculated lease abandonment costs for all active leases with structures and/or wells using MMS' formulas.

To evaluate Interior's approach to ensure that the government is not burdened with lease abandonment costs, we reviewed MMS' OCS bonding requirements as they relate to lease abandonment. We also reviewed federal laws and regulations. Furthermore, we interviewed MMS officials at headquarters in Washington, D.C., and at the Gulf of Mexico OCS Region. And we interviewed industry representatives from four major oil and gas trade associations—the American Petroleum Institute, the Independent Petroleum Association of America, the Offshore Operators Committee, and the National Ocean Industries Association. In addition, we interviewed officials of the Surety Association of America and the Department of the Treasury regarding the evaluation of financial risk as well as the reliability of surety companies providing OCS bonds. Finally, we gathered information on state laws and regulations concerning lease abandonment and bonding requirements from state regulatory officials with the Louisiana Department of Natural Resources, the California State Lands Commission, and the Texas General Land Office.

The Departments of the Interior and Commerce provided written comments on a draft of this report. These comments are presented in appendixes I and II, are evaluated in chapter 4, and have been incorporated in the report where appropriate. We conducted our review from October 1992 through November 1993 in accordance with generally accepted government auditing standards.

MMS Could Do More to Protect the Environment From the Effects of OCS Oil and Gas Lease Abandonment

Although MMS has acted to ensure that OCS oil and gas lease abandonment does not adversely affect the environment in the Gulf of Mexico, it could do more. Specifically, MMS has not done all it can to encourage the development of nonexplosive structure-removal technologies that would eliminate or minimize damage to the environment. In addition, MMS does not have an inspection strategy for ensuring that wells are properly plugged and abandoned and lease sites cleared to protect the environment.

MMS Has Taken Actions to Limit Lease Abandonment Effects on Marine Life and the Environment

MMS requires lessees to remove all oil and gas structures from the OCS within 1 year after a lease is terminated. In addition, lessees must plug and abandon wells and clear the site. MMS regulates these lease abandonment activities to protect the environment; this includes providing for the suspension or prohibition of any activity that poses a threat to aquatic life or to the marine, coastal, or human environment.

MMS Requires Well Plugging and Abandonment

MMS regulations require that OCS oil and gas wells that are no longer useful be plugged and abandoned in accordance with specified technical provisions. A producing well is no longer useful when it lacks the capacity for further profitable oil and gas production. Wells can be abandoned throughout the life of a lease. Operators must submit a notice of intent to abandon a well, which must show the reason for abandonment, supporting data, and a description of the proposed work. According to MMS, its engineers review this documentation for compliance with regulations.

Well plugging and abandonment generally involves setting a series of cement plugs inside a well. The operator must test the plugs under pressure to protect against the possibility of a leak. Lessees are required to submit a well abandonment report to MMS describing the manner in which the work was accomplished.

Structure Removal Is Done in Stages

Generally, portions of structures above the water are removed first. Then the portions of structures that extend to the ocean's floor are removed. It is this underwater aspect of structure removal that poses the greatest risk to the environment. These portions are removed by using either explosives or nonexplosive means such as cutters.[1] To prevent obstructions from oil and gas activities from remaining after removal, MMS regulations require that all OCS oil and gas platforms and other structures be removed to a

[1]Examples of cutters include arc cutters, which use a torch to cut, and mechanical cutters, which use rotating blades or a high-pressure jet of sand to cut.

depth of at least 15 feet below the ocean's floor unless an exception is approved by MMS.

In accordance with the agreement reached between NMFS and MMS to protect endangered sea turtles in the Gulf of Mexico, companies cannot use more than 50 pounds of explosives per detonation unless an exception is granted for each use of more than 50 pounds. Companies must also (1) have observers, approved by NMFS, to look for turtles around the removal site prior to, during, and after the detonation; (2) conduct an aerial survey before and after each detonation; (3) delay a detonation to allow observed turtles to be removed to at least 1,000 yards away from the blast site; (4) detonate only during daylight hours; (5) look for turtles and marine mammals before and after detonations and remove dead or injured ones; (6) stagger detonations to minimize the cumulative effects of the blasts; (7) not use explosive charges to scare turtles away; and (8) report the results to MMS and NMFS. If a company seeks an exception to the restriction on using more than 50 pounds of explosives per detonation or to remove a structure less than 15 feet below the ocean's floor, MMS and NMFS consult to determine if additional measures—for example, a larger area observed or increased time of observations—should be required.

Besides protecting turtles, the above actions help protect marine mammals. For example, no exception has been granted to the OCS oil and gas industry under the Marine Mammal Protection Act for the incidental killing of marine mammals through the removal of structures. However, in 1990, the American Petroleum Institute requested that NMFS provide such an exception. In June 1993, NMFS published a proposed rule providing for such an exception.

MMS Requires Site Clearance

MMS regulations require that every OCS lease site be cleared so that structures, equipment, and other obstructions do not conflict with other uses of the OCS. In addition, MMS regulations and a related notice require a lessee to verify and certify that the ocean's floor at a lease site has been cleared. Since 1990 MMS has required that, in the Gulf of Mexico, parties responsible for OCS leases must contract with trawlers to verify that sites are clear for all sites located in water less than 300 feet deep. These sites must be trawled entirely in two directions by a trawling boat outfitted with nets that are representative of the accepted shrimping industry standard. All oil- and gas-related debris encountered during the trawl must be removed from the ocean's floor. In addition, a verification letter from the trawler, including details and results of the trawl, must be submitted by the lessee or operator to MMS.

MMS began requiring trawlers to verify site clearance in the Gulf of Mexico after receiving complaints from the commercial shrimping industry that some sites were not being properly cleared of debris and obstructions. To respond to those complaints, MMS formed a committee to study the site clearance problem and make recommendations on how MMS could best revise its regulatory requirements. The site clearance committee, comprising shrimping industry and oil and gas industry representatives as well as state and local government and MMS officials, recommended MMS' current requirements.

For structures located in water over 300 feet deep, lessees must verify a site's clearance by means that are approved by MMS. MMS requires that operators verify that these sites are cleared by using sonar.

MMS Conducts Other Activities to Protect the OCS Environment

To comply with NEPA, MMS prepares environmental impact statements and environmental assessments. These documents are prepared every 5 years for the oil- and gas-leasing program, for each lease sale, and for specific activities under the leasing program. The program and sale documents address lease abandonment activities.

MMS also has an Environmental Studies Program that develops information needed for an assessment of the impacts that the oil-and gas-leasing program has on the OCS. This program has produced several studies on specific aspects of the OCS environment, including the use of explosives to remove oil and gas structures. In addition, its staff members are generally cognizant of other environmental studies.

MMS also has Environmental Operations staff members who are responsible for ensuring that lease activities are environmentally acceptable. For example, they evaluate environmental studies in order to make recommendations on how lease activities should be conducted, and they conduct endangered species consultations with NMFS.

MMS Is Not Encouraging Nonexplosive OCS Structure Removal Technology

Although one of the purposes of OCSLA is to encourage technology that will eliminate or minimize the risk of environmental damage, MMS has not adequately studied the costs and benefits of using nonexplosive technologies nor taken actions to encourage their use. The majority of OCS oil and gas structures have been removed using explosives, which kill fish and can harm any other nearby marine life. However, technologies for the removal of structures exist that do not use explosives and do not adversely affect the environment by killing fish and threatening endangered sea turtles and protected marine mammals.

Explosives Kill Marine Life

The fact that the explosives used to remove OCS oil and gas structures kill nearby marine life has been well documented. Following the kills of endangered turtles, protected dolphins, and fish that evidence suggested resulted from the use of explosives to remove platforms in the Gulf of Mexico in 1986, MMS began formal consultation with NMFS under the Endangered Species Act to limit the use of explosives in order to protect endangered turtles. In addition, a 1987 MMS environmental assessment of potential impacts associated with the removal of OCS structures noted that, unlike explosives, nonexplosive removal methods minimize or eliminate harm to marine life. The potential for explosive removal methods to harm marine life was also pointed out in MMS' 5-year oil and gas Environmental Impact Statement for 1992-97, which states that "platform removal could result in harm to sea turtles and marine mammals when explosive structure-removal operations are conducted."

In May 1991, the Gulf of Mexico Fishery Management Council, which represents recreational fishing, commercial fishing, seafood processing, and environmental, scientific, consumer, and state conservation interests expressed concern to MMS that the use of explosives to remove OCS oil and gas structures was killing large numbers of fish. The Council urged MMS to suspend the use of explosives to remove large offshore structures until MMS determined the effects on fish. MMS responded that the available evidence on the effects on fish of using explosives to remove OCS structures did not justify a moratorium on the use of explosives. Nevertheless, in 1991, MMS initiated a study to be done by NMFS to determine the extent of fish kill caused by explosive removals of OCS oil and gas structures. This study is now scheduled to be completed around the end of 1994.

Nonexplosive Methods of OCS Structure Removal Are Used to Some Extent

Nonexplosive methods of removing OCS oil and gas structures are available and would minimize or eliminate adverse effects on the environment. From 1987 through 1992, 570 OCS oil and gas structures were removed in the Gulf of Mexico. Of these, 378 (66 percent) were removed using explosives, and the remaining 192 (34 percent) were removed using nonexplosive methods.

A 1987 environmental assessment by MMS on the removal of OCS structures stated that both arc cutters and mechanical cutters are feasible, and that with both methods, "damage to marine life is minimal or non-existent."[2] The assessment also stated that several nonexplosive technologies, such as cutters that use abrasive sand, were emerging. A 1987 U.S. Army Corps of Engineers paper on the removal of structures in Louisiana state waters commented on alternative methods of removing structures.[3] It stated that the industry most often uses explosives because it believes them to be cheaper and simpler. However, the paper also stated that nonexplosive techniques can be equally effective. The paper noted that the Corps had received 15 requests to remove structures using explosives, but further noted that when the Corps sent back a standard request for information, including a request for information on why explosives were needed, 11 of the requests were withdrawn and nonexplosive means used instead.

Officials of some oil and gas companies that use nonexplosive methods such as cutters told us that these methods have already proved to be cost-effective in successfully removing structures. However, even some of these officials told us that it is cheaper and/or more efficient to use explosives for some removals. And representatives from some other companies believe that explosives are generally cheaper and/or more efficient for removing structures.

Officials of two companies that manufacture cutters for the removal of offshore structures told us that although they have successfully demonstrated their technologies to OCS oil and gas operators, some operators resist using these technologies. One official cited companies' long-term use of explosives as one reason for this resistance. The other official cited companies' bad experiences with previous nonexplosive methods as another reason. The latter official said that oil and gas companies have not taken into consideration the improvements in

[2]Gulf of Mexico OCS Region, Proceedings: Eighth Annual Gulf of Mexico Information Transfer Meeting, OCS Study MMS 88-0035 (Dec. 1987), pp. 304-306.

[3]Robert Bosenberg,"Perspective on Oil and Gas Production Structure Removals and the Permit Process," U.S. Army Corps of Engineers, New Orleans District.

mechanical cutter technology that have made it as cost-effective as explosives.

We were unable, however, to determine for ourselves which method was more efficient and/or economical. Neither MMS nor the oil companies that we contacted had documented the relative costs and benefits of the different technologies. Such cost-benefit studies of using alternative technologies should, among other things, consider the effects of water depth, structure size and configuration, environmental effects, and human safety. Anecdotal evidence provided by oil companies and MMS and the results of our analysis of how structures have been removed were both inconclusive and contradictory.

MMS Actions Encourage Use of Explosives

Although one of OCSLA's purposes is to encourage the development of new and improved technology to eliminate or minimize the risk of damage to the environment, MMS has not weighed the costs and benefits of nonexplosive removal methods nor encouraged their use. In fact, certain MMS actions may actually encourage the use of explosives.

For example, in 1993, MMS' Gulf of Mexico Region proposed to NMFS relaxing the limits on the use of explosives. The proposal would allow companies, without getting a specific exception from NMFS, to increase the maximum amount of explosives used from 50 to 150 pounds per detonation, and the proposal would eliminate the use of observers in certain areas of the Gulf that are designated as unlikely to have turtles present. The MMS Gulf of Mexico Regional Supervisor for Field Operations told us that MMS proposed the change because companies sometimes had to use repeated explosive charges to accomplish the removal of a structure, which was inefficient. However, another MMS regional official told us that oil and gas companies have rarely requested exceptions to use larger explosive charges. In fact, since the NMFS limit of 50 pounds per detonation was imposed in 1988, only 9 of 335 removals of structures, through 1992, used more than 50 pounds of explosives per detonation, by approval from NMFS.

MMS initiated the proposal to relax the limits on the use of explosives without adequate study. For example, MMS did not analyze the extent to which larger explosive charges have been required to remove certain structures. In addition, MMS' justification for designating certain areas of the Gulf, where endangered sea turtles need less protection from explosives, is not relevant. MMS cited an NMFS study that concluded that one area of the Gulf needed additional protective measures but the remainder of the Gulf would be adequately protected under existing requirements. The study did not address increasing the allowed amount of explosive charges from 50 to 150 pounds per detonation. Furthermore, MMS' study, being conducted by NMFS, of the effects of explosives on fish is not yet complete.

Some oil and gas company representatives told us that if MMS encouraged or required the use of nonexplosive removal methods, companies would have an incentive to develop this technology and that this technology should be given an opportunity to prove and improve itself. This reflects a 1985 National Research Council report that stated that as the number of removals of OCS structures increases, technical removal proficiency will improve. And one company official told us that MMS' proposal to allow the increased amount of explosives without having to seek an exception from NMFS actually encourages the use of explosives and serves as a disincentive to using nonexplosive methods.

While OCSLA requires that MMS encourage the use of technologies that eliminate or minimize the risk of damage to the environment, MMS Gulf of Mexico regional officials told us at the time of our review that MMS is not, and does not have plans for, doing anything to encourage nonexplosive removal methods. One official said that such action is not MMS' responsibility and that MMS is not concerned with what method is used, even though relaxing the limit on the use of explosives might encourage the use of explosives. However, in commenting on a draft of our report, MMS noted that it was reevaluating the potential safety and environmental impacts of various structure-removal technologies.

MMS Does Not Have an Inspection Strategy for Ensuring That Wells Are Properly Plugged

MMS does not have an overall inspection strategy for ensuring that wells are properly plugged and abandoned to protect against future leaks. If oil leaks from an improperly plugged well, there is a risk that the environment and marine life will be adversely affected. Mammals, birds, fish, shellfish, and plants can be killed by oil. An MMS official told us that although no abandoned OCS oil leases are known to have had leaking plugged wells, leaks have been known to occur from plugged wells on leases that have not yet been abandoned. However, if a well were found to be leaking after the lease was abandoned and its structures removed, correcting the problem would be more difficult. Boats, equipment, and personnel would have to be mobilized to replug the well. During this period of time, oil would continue to escape from the well.

The OCSLA requires that MMS inspect all OCS facilities subject to environmental regulation at least once a year and that MMS conduct periodic unannounced inspections. MMS' approximately 50 technicians in the Gulf of Mexico Region are responsible for inspecting about 3,800 OCS facilities. According to MMS, in 1992, 516 wells were plugged and abandoned in the Gulf of Mexico, and MMS technicians inspected 46, or about 9 percent of them. However, technicians inspect well plugging and abandonment only when that coincides with either a scheduled annual inspection or an unannounced inspection. MMS does not have an overall strategy that targets its limited inspection resources to ensure that wells are properly plugged and abandoned. For example, MMS does not target leases near the end of their productive lives for inspection to ensure that wells have been properly plugged and abandoned and may never inspect the plugging and abandonment of wells on some leases. As a result, we believe MMS has little assurance that wells will not leak after a lease site has been abandoned.

MMS Lacks Adequate Assurance That Lease Sites Are Properly Cleared

MMS lacks adequate assurance that OCS oil and gas lease sites are properly cleared. MMS relies on lessees and operators to conduct and verify site clearance but does not independently verify that it is done properly.

For leases in water less than 300 feet deep, MMS requires lessees and operators to hire trawlers to conduct site clearance, then to submit to MMS a letter from the trawlers verifying that sites were cleared plus a letter from the lessees and operators that the verification was witnessed by them. MMS allows lessees and operators to hire the trawlers, as long as the trawlers have a valid commercial trawling license and prior experience in trawling operations. When this procedure began in 1990, MMS and the fishing and shrimping industry believed the trawlers would have a vested interest in ensuring that lease sites were properly cleared. However, MMS does not require that trawlers hired for site clearance verification derive their livelihood from fishing or shrimping. MMS approves the trawlers that lessees and operators plan to hire on the basis of their satisfying MMS' equipment and experience requirements. However, MMS does not verify that site clearance verification has been properly performed. For example, MMS does not observe trawlers, hire trawlers to spot-check sites, or use alternate means to verify site clearance when possible. An MMS Gulf of Mexico regional official told us that such additional measures could be considered but that they have not been used to date because existing procedures are thought to be adequate.

Several commercial fishermen and shrimpers told us they were pleased with MMS' current use of trawlers for site clearance, and they believed the Gulf of Mexico is cleaner now than it used to be. Nevertheless, the president of the Louisiana Shrimp Association, representing commercial shrimpers in that state, expressed concern to us about the need for better independent site clearance verification. Specifically, he told us about an instance when he was hired by a salvage company to clear a site but was dismissed before verifying that the site was cleared because his nets continued to snag on an obstruction. The salvage company nevertheless submitted a site clearance verification letter to MMS. Subsequently, he informed MMS that the site was not clear, and MMS required the responsible company to send divers to determine if the snag was caused by debris from the lease site. The divers retrieved an object, but it was not determined whether the object was due to oil and gas activities.

MMS Is Improving How It Protects the Government From Incurring OCS Oil and Gas Lease Abandonment Costs, but More Could Be Done

MMS has developed a workable approach for protecting the government from incurring OCS oil and gas lease abandonment costs in the Gulf of Mexico. However, prior to an August 1993 change in MMS' bonding requirements, MMS' implementation of this approach had been putting the government at financial risk. As of March 1993, Gulf of Mexico leases with $4.4 billion in estimated lease abandonment costs were covered by only $68 million in bonds.

MMS' approach consists of two parts: (1) requiring a general bond for all leases and (2) requiring supplemental bonds in the amount of the total estimated costs of lease abandonment for leases without at least one party deemed financially capable. However, the criteria that MMS had been using to assess financial capability may not have adequately measured a company's ability to pay for the potentially significant costs of lease abandonment.

In August 1993, MMS promulgated new regulations that changed the criteria for financial capability and increased the general bond amounts.[1] However, both of these changes are to be phased in over an open-ended period of time. This could result in a lengthy period before the new coverage is in place, and some leases may never have the new coverage. In commenting on a draft of this report, MMS said that it recognizes the need for a deadline for all leases to comply with the increased levels of bond coverage and is developing a rulemaking to accomplish that result.

In addition, proper well plugging and abandonment and structure removal are needed to minimize the opportunity for problems to surface after a lease has been abandoned. If such problems were to occur and MMS were unable to locate responsible parties to correct the problems and/or to obtain sufficient remuneration from bonds, the government would have to incur the costs.

MMS Has Taken Actions to Hold Parties Responsible for Lease Abandonment Costs

MMS regulations require OCS leases to be covered by surety bonds to guarantee compliance with all lease terms, including lease abandonment.[2] If a lease has more than one lessee, MMS requires co-lessees to designate a single operator to fulfill the lessees' obligations, including posting the bond. However, the co-lessees remain liable if the operator defaults on obligations.

[1]These regulations became effective November 26, 1993.

[2]MMS also accepts U.S. Treasury securities in lieu of surety bonds and, as of November 1993, accepts other means of financial security—for example, a nonrevocable letter of credit.

Ownership of a lease, in whole or part, may be assigned from one party to another, with MMS' approval. An assignee obtains the benefits and liabilities of its lease that occur from the assignment date forward. The assignor remains responsible for obligations that accrued prior to assignment, including lease abandonment.

General Bonds

MMS regulations specify that, at a minimum, every OCS oil and gas lease must be covered by a general bond. Previously, this bond was in the amount of $50,000 for a bond covering a single lease or $300,000 for an areawide bond covering all leases bonded by one party in one OCS area.[3] However, MMS, concerned that those general bond amounts might be inadequate because of the high costs of lease abandonment, changed its regulations in August 1993 to increase general bond amounts to as much as $3 million for an areawide bond. In order not to overwhelm the oil and surety industries by requiring simultaneous conversion to the higher amounts, MMS regulations provide that the new amounts will be phased in when there is a change in lease activity or ownership.

Supplemental Bonds

In May 1992, MMS decided to require a supplemental bond for any lease that does not have at least one responsible party that is financially capable of fulfilling lease abandonment obligations. A supplemental bond is required for the full amount of estimated lease abandonment costs, less the amount of general bond coverage. If MMS determines that estimated lease revenues and oil and gas reserves are sufficient to enable the responsible parties to pay for lease abandonment costs, the supplemental bond amount may be phased in over time.

Protecting Against the High Costs of OCS Oil and Gas Lease Abandonment

OCS oil and gas lease abandonment costs can range from $50,000 to $100 million dollars for a structure. Lease abandonment costs vary depending on water depth as well as the size and complexity of structures. For the 1,811 active leases with structures or wells in the Gulf of Mexico, we estimated the total cost of lease abandonment at about $4.4 billion as of March 1993.[4] These leases were covered by $68 million in bonds. Prior to the mid-1980s, most OCS oil and gas leases were obtained by large oil and gas companies. MMS considered the financial resources of these

[3]An OCS area is the same as one of MMS' four regions.

[4]MMS has not attempted to estimate when each lease would be abandoned. Therefore, this estimate, in current dollars, is based on the assumption that all structures were removed, wells plugged and abandoned, and sites cleared at the time this estimate was made.

companies sufficient to ensure performance of lease obligations, including payment of lease abandonment costs, and only required general bonds to protect the government from incurring these costs. However, according to MMS, leases are increasingly being held by smaller oil and gas companies. This is happening for two reasons. First, as production declines from older leases, large companies no longer regard them as economical to operate. Smaller companies, with less expenses, believe they can operate some of those leases profitably, so the large companies assign those leases to the smaller ones. Second, smaller companies are increasingly bidding on and obtaining new leases. Because smaller companies generally have less financial resources, the risk that a company might not be able to pay its lease abandonment costs could increase.

MMS' August 1993 regulations, which increased general bond amounts, should eventually increase the total amount of bond coverage on OCS leases in the Gulf of Mexico. However, increased bond amounts are to be phased in over time, with no deadline for when the phase-in shall be completed. That is, new general bond amounts will only be required when a lease comes up for review because of certain actions that may occur during the life of a lease, such as the filing of an exploration plan or a development and production plan. Thus, it may be some time before many leases have the new bond amounts. Furthermore, leases that are in production in the Gulf of Mexico may not experience an action that would trigger an increase in the general bond amount.

At the time of our review, MMS had not paid any lease abandonment costs because responsible parties had failed to do so. However, there have been a few cases in which bonded parties defaulted on lease abandonment obligations. For the cases that have been resolved, MMS has been able to get co-lessees or new parties taking over those leases to accept responsibility for paying the costs. Because MMS holds assignors responsible for lease abandonment costs, large oil and gas companies that assign leases to smaller companies continue to provide assurance that lease abandonment costs will be covered for those leases. However, because assignors could also default, supplemental bonds serve a valuable purpose for protecting the government's financial interest.

Furthermore, to protect the government from incurring lease abandonment costs if responsible parties cannot be found and/or lease bonds are insufficient to cover the costs, it is important that MMS have measures in place to ensure that wells are properly plugged and abandoned and lease sites are properly cleared. Properly abandoning leases in the first place would reduce the opportunity for problems to arise later that may result in the incurring of costs by the government.

MMS Is Improving Its Criteria for Determining Financial Capacity

The criteria that MMS had been using to determine the financial capacity of parties responsible for OCS leases may not have adequately measured their ability to pay for the potentially significant costs of lease abandonment. As a result, MMS may not have been obtaining sufficient bond coverage through supplemental bonds. As of March 1993, Gulf of Mexico leases with \$4.4 billion in estimated lease abandonment costs were covered by only \$68 million in bonds. However, MMS' August 1993 regulations that change the criteria could improve this situation.

From May 1992 until November 1993, MMS allowed a company to submit various evidence to demonstrate its financial capacity. However, in lieu of other evidence, MMS adopted certain criteria for deeming a company financially capable of meeting its lease abandonment responsibilities. These criteria included (1) a Small Business Administration (SBA) criterion for distinguishing between large and small oil and gas companies, (2) two financial criteria developed by MMS on the basis of SBA's criterion, and (3) MMS' criterion for determining large oil and gas companies for the purpose of regulating bidding on OCS leases. Thus, to be deemed financially capable of fulfilling lease abandonment obligations without a supplemental bond, a company must have met one of the following criteria:

- Total employment of 500 or more.
- Minimum net worth of \$35 million.
- Minimum gross annual sales of \$45 million.
- Worldwide production of oil, gas, and petroleum products that exceeds 1.6 million barrels in 6 months.

The criteria used by MMS between May 1992, when it began requiring supplemental bonds, and November 1993 were developed for purposes unrelated to assessing a company's ability to pay lease abandonment costs. For example, a company with 500 employees but with less than \$35 million in net worth would have been considered financially capable, without regard to the estimated abandonment costs of its leases.

As of May 4, 1993, MMS' financial capacity criteria resulted in the exemption of 153 parties from the requirement for supplemental bonding. These 153 parties were responsible for 1,702 (94 percent) of the 1,811 leases with structures and/or wells in the Gulf of Mexico. Because MMS determined that these 1,702 leases were held by at least one financially capable party, only general bonds were required. The estimated lease abandonment costs for these leases was about $4.2 billion and was covered by $45 million in general bonds.

Being determined financially capable may have little to do with a company's financial capability, according to the criteria used by MMS until November 1993. For example, as of January 29, 1993, MMS had identified four bankrupt companies responsible for OCS oil and gas leases that were on the exempt list. That is, they met one of MMS' criteria—for example, number of employees—but were in bankruptcy.

In August 1993, MMS revised its regulations for supplemental bonds to change the evidence required for evaluating financial capability. As a result of the revised regulations, MMS will use audited financial statements, projected production, longevity of OCS operations, credit ratings, and past compliance with legal requirements. However, the regulations do not specify what criteria will be used to determine that a company is financially capable. At the time of our review, MMS was developing these criteria. An MMS Gulf of Mexico Region official told us that MMS is attempting to develop criteria that relate to a company's total liability for offshore operations. The revised regulations, if properly implemented, could provide greater assurance that leases have either at least one financially capable party or supplemental bonds in the full amount of estimated lease abandonment costs.

However, MMS' May 1992 supplemental bond criteria specified that such bond coverage would be phased in over time. That is, leases would only be subject to supplemental bonds when certain activities occurred, such as the filing of exploration plans. MMS' August 1993 regulations do not specify a time frame for implementation. If the new requirements for supplemental bonds are phased in over time, it may take some time until a significant number of leases that should have supplemental bonds have them. Furthermore, some leases may never have an activity that triggers review of the need for supplemental bonds. In commenting on a draft of this report, MMS said that it recognizes the need for a deadline for all leases to comply with the increased levels of bond coverage and is developing a rulemaking to accomplish that result.

MMS Has Not Obtained Supplemental Bonds for All OCS Leases That Need Such Bonds

As of March 1993, 109 of the 1,811 leases in the Gulf of Mexico with structures and/or wells did not have at least one responsible party that met MMS' pre-November 1993 criteria for financial capacity. Although MMS' procedures required supplemental bonds in the full amount of estimated lease abandonment costs for these leases, 68 leases did not have supplemental bonds. The estimated lease abandonment costs for these 68 leases are about $114 million, but they are covered by only about $4 million in bonds.

Although MMS requires supplemental bonds on all leases without at least one financially capable responsible party, since supplemental bonding began in 1992, MMS has been obtaining supplemental bonds only on leases as they were assigned. A Gulf of Mexico Region official told us that MMS is planning to obtain supplemental bonds on other leases where needed, in accordance with the supplemental bonding criteria that became effective November 1993.

We found that 61 of the 68 leases that should be but are not covered by supplemental bonds were leased by or assigned to current lessees before MMS implemented its supplemental bond procedures and may not have had changes in lease activity that would trigger the requirement of supplemental bonds. These leases have estimated abandonment costs of $108 million but are covered by only about $3 million in total bonds. The remaining seven leases that should have supplemental bonds but do not were leased by or assigned to current lessees after MMS implemented its supplemental bond procedures. Specifically, we found the following:

- Four leases have new structures or wells since their most recent assignments. When MMS reviewed the assignments, supplemental bonds were not required because there were no structures or wells on the leases. MMS should have obtained supplemental bonds to cover the new estimated abandonment costs for these leases of $1.4 million. However, these leases are covered by only about $100,000 in bonds.
- Two leases are covered by one areawide bond. However, their total estimated lease abandonment costs exceed the amount of the areawide bond, so the leases are inadequately covered and should have supplemental bonds. These leases have estimated abandonment costs of $700,000 but are covered by $300,000 in bonds.
- One lease was transferred as part of a bankruptcy resolution to a company that is not exempt. MMS is working on obtaining a supplemental bond on this lease. This lease has estimated abandonment costs of $3.4 million.

Because these leases do not have appropriate bond coverage, the government is at risk for their costs of lease abandonment.

Conclusions and Recommendations

To protect the environment from the effects of OCS oil and gas lease abandonment and to protect the federal government from incurring costs, it is important that OCS oil and gas lease abandonment be done properly. For example, if wells are not properly plugged and abandoned, the environment could be damaged before personnel, boats, and equipment could be mobilized to replug the well. Furthermore, if MMS were unable to locate responsible parties to correct problems caused by improper site clearance and/or to obtain sufficient remuneration from bonds, the government would have to incur the costs.

We believe that MMS could do more to ensure that OCS oil and gas lease abandonment does not adversely affect the environment in the Gulf of Mexico. MMS has not encouraged the nonexplosive removal of OCS structures. In addition, MMS does not have an overall inspection strategy for ensuring that wells are properly plugged and abandoned nor does it independently verify that lease sites are properly cleared. As a result, MMS has little assurance that wells will not leak after a lease has been abandoned and that sites are properly cleared.

While we believe that MMS has developed a workable approach for reducing the likelihood that the government will be burdened with lease abandonment costs, it could do more. Its implementation of this approach has not ensured that all parties have been adequately bonded, and it may be some time before a significant number of leases have the coverage required.

MMS Could Do More to Protect the Environment From the Effects of OCS Oil and Gas Lease Abandonment

MMS has taken actions to protect the environment in the Gulf of Mexico from adverse effects of lease abandonment. However, MMS could do more to protect the environment. Specifically, MMS has not done all it can to meet OCSLA's purpose of encouraging the development of technologies that minimize or eliminate harm to the environment. Using explosives to remove OCS structures kills marine life, and alternative technologies that do not adversely affect the environment are available and can be further developed. While MMS has not studied the costs and benefits of using such technologies nor encouraged their use, in commenting on this report, MMS noted that it is reevaluating the potential safety and environmental impacts of various structure removal technologies.

In addition, MMS does not have an overall strategy that targets its limited inspection resources to ensuring that wells are properly plugged and abandoned and lease sites cleared. As a result, MMS has little assurance that wells will not leak after a lease site has been abandoned and that sites are properly cleared. MMS' inspection strategy for ensuring that wells are properly plugged and abandoned could include targeting some of its inspections to a sample of plugging and abandonment operations. MMS could take any number of actions to assure that lease sites are properly cleared, such as having

- on-board MMS observers during selected trawling operations;
- independent verification, using trawlers hired by MMS or other means, to sample sites that have been verified as clear by lessees and operators;
- MMS certification of trawlers that may be hired for site clearance verification; and/or
- direct contracting of trawlers by MMS, to be reimbursed by the oil and gas companies.

MMS Is Improving How It Protects the Government From Incurring OCS Oil and Gas Lease Abandonment Costs, but More Could Be Done

MMS' approach, which requires (1) general bonds for OCS oil and gas leases with responsible parties that are financially capable and (2) supplemental bonds in the full amount of estimated lease abandonment costs for leases without at least one financially capable party, is workable for providing reasonable assurance that the taxpayer is not burdened with lease abandonment costs. However, until recently, MMS' implementation of this approach put the government at risk because MMS' criteria for determining parties' financial capacity may not have been appropriate to ensure sufficient financial coverage.

In addition, under pre-August 1993 criteria, MMS did not obtain supplemental bonds for 68 leases that should have had them. Instead of financial coverage in the full amount of estimated lease abandonment costs, these leases have bonds that would cover only about 4 percent of their estimated abandonment costs.

MMS' August 1993 regulations established new financial capability criteria for determining the need for supplemental bonds and increased general bond amounts. If properly implemented, the new criteria could help ensure that the government is adequately protected from incurring lease abandonment costs. However, because the time frames for implementation of these requirements are open-ended, it is possible that it will be some time before a significant number of leases have the new coverage required under the regulations. And leases that do not have the necessary administrative change to trigger a review of the need for supplemental bonds may never have supplemental bond coverage. In commenting on a draft of this report, MMS recognized the need for a deadline for all leases to comply with the increased levels of bond coverage and said that it is developing a rulemaking to impose such a deadline.

Recommendations to the Secretary of the Interior

In order to better protect the environment from the effects of OCS oil and gas lease abandonment and the federal government from incurring the costs of such abandonment, we recommend that the Secretary of the Interior direct the Director of MMS to do the following:

- Encourage the use of nonexplosive technologies for removing offshore structures, whenever possible, that will eliminate or minimize the risk of harm to the environment, in accordance with OCSLA's purpose.
- Study the feasibility, benefits, and costs (including the potential effects on the environment and the safety of humans) of mandating the use of nonexplosive methods of removing offshore structures, whenever possible, because of the harm that explosives do to marine life.
- Require MMS to develop an inspection strategy for targeting its limited resources to ensure the proper plugging and abandonment of OCS wells and the clearance of lease sites.
- Complete a rulemaking to place time limits on the phase-in of both the increased general bond amounts and supplemental bonding under the new criteria. Establishing such limits would help ensure that the government is adequately protected from incurring costs associated with OCS lease abandonment that should be paid by the companies responsible for the leases.

Agency Comments

In commenting on a draft of this report, the Department of the Interior generally agreed with our recommendations. Specifically, Interior agreed that OCS lease abandonment technology needs further review, taking into account factors including safety, cost, and environmental effects. Interior noted that it considered safety a prime concern when evaluating the technologies proposed for the removal of OCS structures. Interior also indicated that while it has had few problems with improper lease abandonments, it was reevaluating its inspection strategy and considering options for witnessing more abandonment activities. In addition, Interior stated that it recognized the need for a deadline for all lessees to comply with the increased levels of bond coverage and is developing a rulemaking to accomplish this.

The Department of Commerce concurred with our recommendations to Interior and noted that the report is well written and will be understood by an audience with a broad range of expertise on the impacts of the removals of OCS structures on marine environments. Commerce suggested that it would be helpful if the report explained the characteristics of structures that can be more cheaply or efficiently removed with the use of explosives. We cannot provide the characteristics of structures that can be more cheaply or efficiently removed with the use of explosives because neither MMS nor the oil companies that we contacted had documented the relative costs and benefits of using such technologies. Accordingly, we have recommended that MMS study the feasibility, benefits, and costs of mandating the use of nonexplosive methods of removing offshore structures. Such a study should consider, among other things, the effect of water depth, structure size and configuration, environmental effects, and human safety. Commerce also noted that it would be useful if the report provided specific guidance on how MMS should encourage alternative removal technologies for removing offshore structures and suggested that MMS might use incentives or penalties. We believe that until a cost-benefit study of alternative methods of removing OCS structures is completed, it would be premature to use incentives or penalties. Rather, MMS should issue a directive encouraging the use of nonexplosive technologies, whenever possible, that will eliminate or minimize the risk of harm to the environment.

Both departments' comments have been incorporated in the report where appropriate.

Comments From the Department of the Interior

United States Department of the Interior

MINERALS MANAGEMENT SERVICE
Washington, DC 20240

APR 0 5 1994

Mr. James Duffus III
Director, Natural Resources Management Issues
U.S. General Accounting Office
441 G Street, NW.
Washington D.C. 20548

Dear Mr. Duffus:

The Department of the Interior appreciates the opportunity to review the General Accounting Office (GAO) draft report GAO/RCED 94-82, "OFFSHORE OIL AND GAS RESOURCES: Interior Can Improve Its Management of Lease Abandonment." General and specific comments prepared by the Minerals Management Service (MMS) on the draft report findings and recommendations are enclosed for your incorporation into the final GAO report (Appendix A). The general comments included in Appendix A are intended to inform the GAO about the complexities found in the audit subject matter as they relate to the findings and recommendations. Specific comments pertaining to individual recommedations follow the general comments.

We appreciate the time and effort your auditors spent in meeting with members of the MMS on March 10, 1994, to clarify the issues and to ensure a mutual understanding of the report contents. My staff informs me that the meeting was positive and beneficial to all involved.

Sincerely,

Bob Armstrong
Assistant Secretary, Land and
Minerals Mangement

Enclosure

Comments from the Minerals Management Service (MMS) Concerning the Draft General Accounting Office (GAO) Report - "OFFSHORE OIL AND GAS RESOURCES: Interior Can Improve Its Management of Lease Abandonment" (GAO/RCED-94-82)

The MMS appreciates the efforts made by GAO in evaluating its lease abandonment program. We feel that the meeting that we had with your office on March 10 was particularly helpful in clarifying both of our views. We also appreciate the extension until March 18 to submit our response.

As we said at the meeting, abandonments in the Outer Continental Shelf (OCS) are becoming more numerous; therefore, MMS is studying several aspects of its abandonment program to see if improvements or updates are necessary. The MMS will consider GAO's report, conclusions, and recommendations as it carries out its mission of ensuring safe and effective well and lease abandonments.

The GAO recommends that MMS study the feasibility of using nonexplosive methods for removing OCS oil and gas structures and, wherever possible, encourage their use. The MMS agrees that abandonment technology needs further review and assessment. To this end, we are reevaluating the potential safety and environmental impacts of various structure removal technologies.

The MMS considers safety a prime concern when evaluating the technologies proposed in structure removal applications. Unfortunately, some nonexplosive removal techniques entail great risk to human life. Commonly used nonexplosive techniques were instrumental in the deaths of at least three divers and the injury of two others in separate OCS incidents in recent years.

The MMS also is reviewing its abandonment requirements, including the relationship of the structure depth removal requirement to the application of nonexplosive techniques. In some cases, MMS's standard requirement to remove a structure to 15 feet below the mud line makes nonexplosive technology unfeasible. We also must ensure that the site is completely cleared and that any portion of a structure left in place remains buried over time. Otherwise, it could present a hazard to vessels, fishing activities, and other uses of the OCS.

Many factors determine the feasibility of nonexplosive techniques. The MMS will continue to take factors such as safety, cost, water depth, the age and condition of the structure, as well as the presence of grouting in structure members into account when evaluating structure removal applications.

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To ensure that any adverse effects on the marine environment are minimized, MMS consults with the National Marine Fisheries Service (NMFS). All structure removals using explosives (generic and nongeneric) are conducted in a manner that is consistent with our agreement with NMFS. The NMFS experts witness the structure removals. The MMS marine scientists and inspectors often witness these removals also.

The MMS has commissioned studies and uses all available information concerning explosive and nonexplosive techniques for oil and gas facility removals. The MMS currently is funding a study, conducted by NMFS, to determine the risk that nonprotected fish may be killed during explosive removals of various types of structures.

The MMS also conducts workshops and meetings concerning oil and gas structure removals. In March 1994, at the University of Santa Barbara, MMS is sponsoring a public workshop concerning the removal of offshore oil and gas facilities. A noteworthy meeting in 1991 with the Offshore Operators Committee (OOC) provided an update on platform removal techniques. In the opinion of recognized experts in the field, except for simple structures in shallow water, nonexplosive removal methods are neither cost effective, safe, nor reliable. The OOC presented a study which concluded that the potential impact of explosive removal of structures on red snapper populations is insignificant when compared to the impact of bycatch from shrimp trawling activities.

The GAO also recommended that MMS target abandonments in an inspection strategy. Although we have had few problems with improper abandonments in the OCS, we are evaluating our inspection strategy and considering options for witnessing more abandonment activities.

Well pluggings are very successful in the OCS. The MMS regulations require the testing of cement or mechanical plugs in abandoned wells to prevent leaks. The MMS engineers assess plugging plans and procedures for all well abandonments to ensure compliance with the regulations. The MMS inspectors then verify that the wells and leases are abandoned in accordance with the approved plans and procedures.

With regard to clearing lease sites, MMS requires specific verification procedures. This strategy has proven to be extremely successful, and complaints from shrimpers snagging equipment on debris have been greatly reduced. The MMS requires that trawlers possess a valid commercial trawling license for both the vessel and its captain. Also, the captain must have prior experience in trawling operations. It is our experience that the captains and crews take great pride in their work because they have a vested interest to verify that sites are

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properly cleared since they may also have a shrimping operation. Also, if the sites are not cleared properly, the lessee is still responsible for cleanup activities.

The GAO also recommends that MMS amend regulations regarding end-of-lease surety bonding to place time limits on the phase-in of both the increased general bond amounts and supplemental bonding. The MMS recognizes the need for a deadline for all lessees to comply with the increased levels of bond coverage and is developing a rulemaking to accomplish that result.

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GAO Response to Interior's Comments

See the end of chapter 4 for a discussion of these comments.

Comments From the Department of Commerce

THE SECRETARY OF COMMERCE
Washington, D.C. 20230

MAR 23 1994

The Honorable James Duffus III
Director, Natural Resources Management Issues
General Accounting Office
Resources, Community, and
Economic Development Division
Washington, D.C. 20548

Dear Mr. Duffus:

Enclosed is a copy of the Department of Commerce's reply to the General Accounting Office draft report entitled "Offshore Oil and Gas Resources: Interior Can Improve Its Management of Lease Abandonment."

These comments are prepared in accordance with the Office of Management and Budget Circular A-50.

Sincerely,

Ronald H. Brown

Enclosure

COMMENTS: The draft report is well written and will, therefore, be understood by an audience with a broad range of expertise on the impacts of rig removals on marine environments. The report addresses the significant issues regarding the removal of structures related to the production of oil and gas resources in the Gulf of Mexico: (1) safeguarding the environment and (2) ensuring that the government, thus the American taxpayer, is not burdened with the costs of mitigating environmental impacts.

There are, however, a few areas in which the report could be strengthened. First, there are a number of places where interpretations or quotes of specific documents or publications are included. Readers would benefit from a "Literature Cited" section in the report with appropriate citations noted in the body of the report.

Now on p. 20.

The word "some" appears several places in the text. For example, on page 22 the author states "...it is cheaper and/or more efficient to use explosives for some removals." Readers would benefit from more detailed information in these instances. In the above example, the authors could explain the characteristics of structures for which explosives are cheaper or more efficient, as well as the proportion of structures for which explosives would be the preferred method of removal.

The report repeatedly states that the Minerals Management Service (MMS) is improving its protection of the environment, but could do more. Specific suggestions for actions that the MMS could initiate are generally lacking. The MMS would benefit from additional guidance or suggestions in specific actions it could initiate to encourage alternative methods and to alter its inspection strategy.

Several specific comments follow:

Now on p. 2.

- page 3, line 39-42. The report states that the Department of Interior is responsible for the environment, and the Department of Commerce, through the National Marine Fisheries Service, is responsible for marine life. Such a division understates the management responsibility of the Department of Commerce. The Department of Commerce is responsible for conserving marine and estuarine ecosystems, which include living resources and their habitats.

Now on p. 13.

- page 12, second paragraph. The report states "However, approval must be obtained from the Secretary for exceptions to the moratorium on taking." That approval is a rule-making process and includes public notice and comment.

Now on p. 17.

- page 17, third paragraph. The "agreement" noted in the first line of the paragraph is a formal consultation under Section 7 of the Endangered Species Act (ESA). It included an Environmental Assessment and biological opinion.

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Now on p. 17.

- pages 17-18, carry-over paragraph. The consultation required to use more than 50 pounds of explosive is a separate consultation under Section 7 of the ESA for each instance in which more than 50 pounds of explosive is requested.

RECOMMENDATION: Encourage the use of non-explosive technologies for removing offshore structures, whenever possible, that will eliminate or minimize the risk of harm to the environment and marine life.

RESPONSE: The Department concurs with this recommendation. The report does not describe specific actions to implement this recommendation. We note that encouraging alternatives to explosives may take either of two broad approaches: offering incentives for using other technologies, such as cutters, and imposing penalties for using explosives. The former approach is preferred.

RECOMMENDATION: Study the feasibility, benefits, and costs of mandating the use of nonexplosive methods of removing offshore structures, whenever possible, because of the harm that explosives do to marine life.

RESPONSE: The Department concurs with this recommendation. Our support of such a study does not mean that the Department believes that use of explosive removal methods necessarily results in significant harm to environments. The potential for such harm exists, but experience so far (results of monitoring removals under the ESA, Section 7, Consultations) indicates that the potential harm is not necessarily realized. We add, however, that bulk explosives and shaped charges should be distinguished from one another. Using shaped charges may result in smaller explosions (approximately 12 pounds versus 50 pounds for bulk explosives). The benefits of nonexplosive, rather than explosive, methods should be evaluated on their impact on affected populations. Clearly, explosive structure removals kill fish and other marine life; however, the number of organisms killed is only a portion of the impact evaluation.

The report states that MMS is currently studying the impact of explosive structure removals on fish populations in the Gulf of Mexico. The recommended study on the feasibility, benefits, and costs of mandatory use of nonexplosives would benefit from the results of this study, which is due for completion in late 1994. A major consideration in evaluating the impact of explosive removals is to separate the impact of the explosion from the removal of the structure, which is mandated by law. Did the addition of the structures increase the carrying capacity of affected fish populations within the Gulf by creating habitat that would otherwise have been unavailable? Hopefully, the study

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MMS is conducting on fish populations will answer this and other related questions.

RECOMMENDATION: Require MMS to develop an inspection strategy for targeting its limited resources to ensure the proper plugging and abandonment of Outer Continental Shelf wells and the clearance of lease sites.

RESPONSE: The Department concurs with the intent of this recommendation. Presumably MMS' lack of an inspection strategy results from the detection of no problems in those cases where inspections coincided with other efforts. Such a finding would support focusing limited resources on other responsibilities. If, however, there are problems noted in the inspections that have been conducted, a more thorough inspection strategy is warranted.

RECOMMENDATION: Amend regulations regarding bonding to place time limits on the phase-in of both the increased general bond amounts and supplemental bonding under the new criteria.

RESPONSE: The Department concurs with this recommendation. This recommendation is supported by the most specific advice in the report. It is not clear, however, if amending regulations would help alleviate problems with inadequate bond coverage in existing leases.

GAO Response to Commerce's Comments

See the end of chapter 4 for a discussion of these comments.

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United States Government Accountability Office
Washington, DC 20548

June 5, 2008

Congressional Requesters

Subject: *Oil and Gas Royalties: Litigation over Royalty Relief Could Cost the Federal Government Billions of Dollars*

Oil and gas production from federal lands and waters is critical to meeting the nation's energy needs. This production provided about 31 percent of all oil and 29 percent of all natural gas produced in the United States in fiscal year 2007. Every five years, the federal government decides the areas in the offshore waters of the United States it will offer for leasing and establishes a schedule for individual lease sales. The Department of the Interior's Minerals Management Service (MMS) has conducted these sales at least once per year for at least the past 30 years. During the sales, oil and gas companies bid for the rights to explore and develop the oil and gas resources on these leases and also agree to pay the federal government royalties on the resources produced.

In 1995, a time when oil and natural gas prices were significantly lower than they are today, Congress passed the Outer Continental Shelf Deep Water Royalty Relief Act (DWRRA), which authorized MMS to provide "royalty relief" on oil and gas produced in the deep waters of the Gulf of Mexico from certain leases issued from 1996 through 2000.[1] This "royalty relief" waived or reduced the amount of royalties that companies would otherwise be obligated to pay on the initial volumes of production from leases, which are referred to as "royalty suspension volumes."[2] The DWRRA also authorized the Secretary of the Interior to provide royalty relief to promote oil and gas development or to increase production from leases in the Gulf of Mexico.

In implementing the DWRRA for leases sold in 1996, 1997, and 2000, MMS specified that royalty relief would be applicable only if oil and gas prices were below certain levels, known as "price thresholds," with the intention of protecting the government's royalty interests if oil and gas prices increased significantly. MMS did not include these same price thresholds for leases it issued in 1998 and 1999, and this action raised Congressional concerns that the federal government would lose billions of

[1]These leases are covered under Section 304 of the act, which applies to leases issued between November 28, 1995 and November 28, 2000. However, since no leases were issued in 1995, we refer to these leases as DWRRA leases issued from 1996 through 2000.

[2]Royalty suspension volumes establish cumulative production volumes above which royalty relief no longer applies. Royalty suspension volumes vary according to depth, ranging from a minimum of 17.5 million barrels of oil equivalent in water depths of 200 to 400 meters to a minimum of 87.5 million barrels of oil equivalent in water depths greater than 800 meters.

dollars in forgone revenues.[3] In addition, the Kerr-McGee Corporation—which was active in the Gulf of Mexico and is now owned by Anadarko Petroleum Corporation—filed suit challenging the Department of the Interior's authority to include price thresholds in DWRRA leases issued from 1996 through 2000. Recently, the U.S. District Court for the Western District of Louisiana granted summary judgment in favor of Kerr-McGee concerning the application of price thresholds to those leases.[4] The court held that the DWRRA did not provide MMS with the authority to impose price thresholds on production below the royalty suspension volumes for leases issued under the DWRRA from 1996 through 2000. Interior officials disagree with the court's decision, and in December 2007 the Department of Justice filed notice to appeal this decision. In response to the possible loss of future royalty revenues on these leases, Congress has been considering legislative action.

We reported in April 2007 that MMS's failure to include price thresholds on leases issued in 1998 and 1999 under the DWRRA would likely cost the federal government billions of dollars in forgone royalties, but precise costs were impossible to determine because of uncertain future prices and production levels.[5] However, we developed a number of scenarios to illustrate how different prices and production levels will influence these costs. We determined that, in addition to the $1 billion that had already been forgone, future costs could range between $4.3 billion and $10.5 billion over about 25 years, depending on the future prices of gas and oil and the volumes produced on these leases. MMS also estimated that the Department of the Interior faced losing an additional $60 billion in forgone royalties if it lost legal challenges to its application of price thresholds in all the DWRRA leases issued in 1996, 1997, and 2000. We noted, however, that MMS made this estimate in October 2004 and that this estimate may have included overly optimistic assumptions about the amount of oil and gas production that could occur over the lifetime of the leases. In light of the recent rise of oil prices to more than $100 per barrel and natural gas to $8 per thousand cubic feet and the recent judgment against MMS-imposed price thresholds, you asked us to: (1) update our scenario that illustrates the potential loss of royalties because of the absence of price thresholds in leases issued in 1998 and 1999 and (2) provide an update of the possible consequences of Kerr-McGee's legal challenge on royalties already collected and evaluate the potential for additional forgone royalties if price thresholds no longer apply to future production from the 1996, 1997, and 2000 DWRRA leases.

To update our scenario illustrating the potential loss of royalties from leases issued in 1998 and 1999, we increased the upper bounds of oil and gas prices to $100 per barrel

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[3]By forgone royalties, we mean royalties that would be payable if Congress had not authorized royalty relief under the DWRRA.

[4]*Kerr-McGee Oil and Gas Corp. v. Allred*, No. 2: 06-CV-0439, 2007 U.S. Dist., Lexis 83424 (W.D. La. Oct. 18, 2007).

[5]GAO, *Oil and Gas Royalties: Royalty Relief Will Cost the Government Billions of Dollars but Uncertainty Over Future Energy Prices and Production Levels Make Precise Estimates Impossible at this Time*, GAO-07-590R (Washington, D.C.: Apr. 12, 2007).

and $8 per thousand cubic feet, respectively, well above the levels of our high-price scenario in the April 2007 report. We did not, however, revise our lower bounds for prices. To update the consequence of the Kerr-McGee challenge to royalties already collected, we interviewed MMS officials, reviewed legal documents, and reviewed MMS's estimate on royalties paid to date. To evaluate the potential for forgone royalties on future production from the 1996, 1997, and 2000 leases, we reviewed estimates made by MMS in October 2004 and its more recent estimates released in February 2008. Specifically, we reviewed the methodology and assumptions MMS used to estimate the amount of future oil and natural gas production from DWRRA leases. To assess the likelihood of future oil and gas discoveries on DWRRA leases, we reviewed statistical data on field sizes, discovery success rates, and the availability of drilling rigs in the deep waters of the Gulf of Mexico. We determined that the data were sufficiently reliable for the purposes of this report. We also developed a series of scenarios to illustrate the uncertainty of prices and future production and their effect on the amount of future forgone royalties. A more detailed description of our scope and methodology is provided in enclosure 1. We conducted our review primarily from November 2007 through April 2008 in accordance with generally accepted government auditing standards. These 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 the evidence we obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

Summary

Regarding the 1998 and 1999 leases, which included no price thresholds, the cost to the federal government could be significantly more than the upper bound we reported in April 2007 if higher oil and natural gas prices are sustained over the lives of these leases. In April 2007, we developed scenarios that illustrated the federal government could sustain losses of between $4.3 billion and $10.5 billion, depending on production levels and oil and gas prices over about the next 25 years. Assuming similar oil production levels but higher oil and natural gas prices of $100 per barrel and $8 per thousand cubic feet, respectively—prices that are closer to current prices than the maximum prices used in our 2007 scenarios—the upper bound of these scenarios could climb to as high as $14.7 billion, a 40 percent increase. There are no guarantees, however, about what future prices will be. For example, oil prices have topped $130 per barrel since we did the analysis for this report, but it is also possible that prices could fall below our lower price assumptions. Thus, these scenarios should not be viewed as probabilistic estimates of what actual forgone royalties will be, or even firm boundaries within which forgone royalties will fall. Rather, the scenarios reflect reasonable possibilities based on recent experience and possible future prices.

With regard to the 1996, 1997, and 2000 leases, because the U.S. District Court for the Western District of Louisiana ruled in October 2007 that price thresholds do not apply to DWRRA leases, the federal government may have to refund over $1.13 billion in royalties that have already been collected from DWRRA leases issued in 1996, 1997,

and 2000, if the government loses on appeal. The government also faces forgoing additional royalty revenues, which will likely be in the billions of dollars, on future production from these leases. We developed a number of scenarios that illustrate the magnitude of possible forgone royalties at different price levels. For example, our scenarios ranged from $15.1 billion of lost revenue for a low production scenario with $70 per barrel of oil and $6.50 per thousand cubic feet of gas to as high as $38.3 billion for high production levels and prices of $100 per barrel of oil and $8 per thousand cubic feet of natural gas over about the next 25 years. The same caveats apply to interpreting these scenarios as those for the 1998 and 1999 leases.

Overall, our work illustrates that the value of future forgone royalties is highly dependent upon oil and gas prices, production levels, and the ultimate outcome of litigation over price thresholds. Assuming that the District Court's ruling in the Kerr-McGee case is upheld, future forgone royalties from all the DWRRA leases issued from 1996 through 2000 could range widely--from a low of about $21 billion to a high of $53 billion. The $21 billion figure assumes low production levels and oil and gas prices that average $70 per barrel and $6.50 per thousand cubic feet over the lives of the leases. The $53 billion figure assumes high production levels and oil and gas prices that average $100 per barrel and $8 per thousand cubic feet over the lives of the leases.

Not Including Price Thresholds in 1998 and 1999 Leases Could Cost the Government More in Forgone Royalty Payments Should Recent Increases in Oil and Natural Gas Prices Be Sustained

In February 2007, MMS estimated that in addition to the $1 billion in revenues already forgone the range of future forgone revenues is between $6.4 billion and $9.8 billion from not including price thresholds in leases issued in 1998 and 1999. MMS calculated these estimates under a range of assumptions about oil and natural gas prices and future production levels. MMS used two price assumptions—one employing a constant price of $45 per barrel of oil equivalent and the other using the Office of Management and Budget's (OMB) projected oil and gas prices, which escalate through time.[6] For future production volumes from the 1998 and 1999 leases, MMS made low and high estimates. The low estimate did not allow for expected growth in oil and natural gas reserves, while the high estimate included expected growth in reserves based on past experience with oil and natural gas leases in the Gulf of Mexico.[7] Reserves are the amount of oil and natural gas that is believed to be economically recoverable with current technology and prices. Reserve growth is the tendency of the initial reserve estimates to increase in the future as more becomes known about the oil and gas field. We reviewed MMS's assumptions and methodology for estimating the potential forgone revenue from 1998 and 1999 leases and found them to be reasonable.

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[6]One barrel of oil equivalent equals one barrel of oil or 5.62 thousand cubic feet of natural gas.

[7]As oil and gas reserves are developed and more knowledge of the field is obtained, proven reserves generally experience some growth.

In order to provide further perspective on just how much these future costs may vary, we developed and analyzed different scenarios in April 2007 that illustrate how the cost to the federal government is sensitive to changes in both oil and natural gas prices and future production volumes.[8] Accordingly, our scenarios used a range of values for oil and natural gas prices and future production volumes to illustrate the uncertainty surrounding future forgone federal royalty revenues.[9] Because oil and natural gas prices have historically been volatile, at the time we made our initial estimates we selected a variety of prices, including $50 and $70 per barrel of oil and $6.50 per thousand cubic feet of natural gas. In our analyses, we assumed that price thresholds would rise 2.1 percent per year, based on their average annual increase over the past 12 years. Similarly, our scenarios included low and high volume estimates for future oil and natural gas production from these leases. In these scenarios, the estimated forgone royalty revenues vary significantly. For example, an oil price of $50 per barrel and a natural gas price of $6.50 per thousand cubic feet and low production volumes resulted in $4.3 billion in forgone royalties.[10] Alternatively, with $70 per barrel of oil and $6.50 per thousand cubic feet of natural gas, the high production volume assumption yielded $10.5 billion.

In June 2007, MMS also provided an update on the loss of potential royalties from not including price thresholds on the leases issued in 1998 and 1999. MMS used oil and natural gas prices cited within OMB's *Economic Assumptions for the 2008 Budget*. Based on an average oil price of $60.78 per barrel and an average natural gas price of $7.52 per thousand cubic feet, MMS estimated that between $5.3 billion and $7.8 billion may be lost in future royalties. The low estimate assumes that reserves do not grow, and the high estimate assumes that reserves do grow over time.

Because oil and natural gas prices increased substantially since the study we completed in 2007, we developed an additional scenario with higher oil and natural gas prices. We used the same methodology as that in our April 2007 study, updating only the oil and natural gas prices.[11] At an oil price of $100 per barrel and a natural gas price of $8 per thousand cubic feet, a low production level yields potential losses of $8.7 billion. With the same prices and a high production level, potential losses climb to $14.7 billion. It is important to note, however, that there is no assurance

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[8]These scenarios are not probabilistic estimates of what may actually happen with royalty revenue. Rather, they are illustrative examples using estimates of future oil and natural gas production that we believe are reasonable based on the history of leases in the Gulf of Mexico and using oil and gas prices that are within the range of prices that have existed in the past 3 years. As such, we believe the scenarios are reflective of plausible possibilities, but we do not assign any probabilities to any of the scenarios.

[9]The royalty rate for DWRRA leases in less than 400 meters of water is 16.67 percent, and the royalty rate for leases in waters greater than 400 meters is 12.5 percent.

[10]It should be noted that if prices were to fall and remain at or below $36.40 per barrel for oil and $4.68 per thousand cubic feet for natural gas in real 2007 dollars, no royalties would be due even if the price thresholds that were imposed on the 1996, 1997, and 2000 leases were applied to the 1998 and 1999 leases.

[11]See enclosure II in GAO-07-590R.

these recent high oil and natural gas prices will be sustained over the lives of the leases, about 25 more years. For more information on this scenario, see enclosure II.

Kerr-McGee's Challenge of Interior's Authority to Include Price Thresholds in DWRRA Leases Could Result in Refunding Royalty Payments

As of September 30, 2007**,** leases issued under the DWRRA in 1996, 1997, and 2000 have generated $1.13 billion in royalties for the U.S. government, according to MMS. If the Kerr-McGee decision is upheld on appeal and is applied to all 1996, 1997, and 2000 DWRRA leases, the federal government may be required to refund these royalties. As of November 2007, 57 of the leases issued in 1996, 1997, and 2000 under the DWRRA have produced oil and natural gas upon which royalties have been paid. Only eight of the leases issued in 1996, 1997, and 2000 are expected to produce oil and gas in excess of their royalty suspension volumes. The amount of this excess production is expected to be about 14 percent of the total production from all the leases issued in 1996, 1997, and 2000 that are producing or expected to produce.

In early 2006, Kerr-McGee filed the suit challenging the Department of the Interior's authority to include price thresholds in its DWRRA leases. In effect, this suit sought to remove price thresholds from leases issued in 1996, 1997, and 2000 because Interior did not include price thresholds on leases issued in 1998 and 1999. In June 2006, Kerr-McGee agreed to enter into mediation with Interior in an attempt to resolve the issue; however, the mediation was unsuccessful and litigation resumed. In October 2007, the U.S. District Court for the Western District of Louisiana ruled in favor of Kerr-McGee.

The court held that price thresholds in leases issued under the DWRRA from 1996 through 2000 to Kerr-McGee for oil and gas production below a threshold volume were unlawful. According to the court, "The Interior has no discretion to enact a price threshold requirement that applies to volumes below the minimum volume of royalty-free production." The DWRRA specifies that royalties are not due on certain amounts of production, referred to in the ruling as "the minimum volume of royalty-free production" and referred to by others as royalty suspension volumes. The court agreed with Kerr-McGee's interpretation that the section of the DWRRA that requires mandatory royalty relief prevents Interior from enacting price thresholds for volumes below the royalty suspension volumes.

Senior Interior officials and many congressional leaders disagree with the decision. They believe that Congress intended for royalty relief to apply only during times of low oil and natural gas prices and that the DWRRA grants Interior the authority to set price thresholds for new leases. In December 2007, the Department of Justice filed a notice to appeal the decision.

Congressional leaders are seeking legislative remedies for the absence of price thresholds in DWRRA leases issued in 1998 and 1999. Sections 7502 and 7504 of H.R. 3220, the New Direction for Energy Independence, National Security and Consumer Protection Act, would provide legislative avenues for addressing the absence of price thresholds. Section 7502 proposes that holders of leases issued in 1998 and 1999 under the DWRRA can request the Secretary of the Interior to amend these leases to include price thresholds. This would formally allow Interior and the lessees to renegotiate these leases. Interior and some companies began negotiations in late 2006 to apply price thresholds to future production from 1998 and 1999 leases. To date, 6 companies have formally agreed to terms, but 44 have not agreed to terms. Section 7504 would exclude parties that hold an interest in DWRRA leases issued from 1996 through 2000 from acquiring new oil and gas leases in the Gulf of Mexico unless the party renegotiates the leases to include price thresholds. This section would also impose a fee on oil and gas production from the Outer Continental Shelf lands in the Gulf of Mexico if these leases are not subject to price thresholds. Section 223 of S. 701, the Strategic Energy Fund Act of 2007, contains an identical provision, as do H.R. 2809 and several other bills.

Kerr-McGee's Challenge Could Also Cost the Government Billions in Future Forgone Royalty Payments

If the Kerr-McGee ruling is upheld on appeal and applied to all DWRRA leases issued in 1996, 1997, and 2000, the potential loss of royalties from future production is likely to be in the billions of dollars, but the exact amount will depend on future energy prices and production levels. MMS estimated in October 2004 that forgone royalties on the 1996, 1997, and 2000 leases could be as high as $60 billion. In 2006, we reviewed MMS's assumptions and methodology for estimating the potential forgone revenue and found them to be reasonable. However, because much has been learned about the productivity of the leases since that initial estimate and because oil and natural gas price expectations have changed, we believe that this estimate needed to be updated. In particular, we found that estimates for reserve growth were overly optimistic in light of a more recent MMS study on reserve growth in the Gulf of Mexico. MMS's 2004 estimates on the size and number of future discoveries also appeared overly optimistic, given historical statistics on field size, a 2006 assessment of the availability of drilling rigs in the Gulf of Mexico, and a smaller number of leases available to drill in 2008 than were available in 2004. MMS concurred with our observations.

In February 2008, MMS released an update on its October 2004 estimate of potential losses from the 1996, 1997, and 2000 leases. MMS estimated a range of potential future forgone revenue between $15.7 billion and $21.2 billion, based on assumptions about oil and natural gas prices and future production levels. MMS used OMB's prices of $80.92 per barrel of oil and $8.70 per thousand cubic feet of natural gas, as cited in OMB's *Economic Assumptions for the 2009 Budget*. For future production levels, MMS made low and high estimates. The low estimate did not allow for expected growth in oil and natural gas reserves, while the high estimate included expected growth in reserves. We reviewed these assumptions and the methodology and found them to be reasonable.

Nonetheless, in order to provide further perspective on just how much these future costs may vary, we developed and analyzed different scenarios that illustrate how the cost to the federal government is sensitive to changes in both oil and natural gas prices and future production volumes. These scenarios are similar to those we used to illustrate forgone royalty revenue from the 1998 and 1999 leases. To illustrate the uncertainty surrounding potential forgone federal royalty revenues, our scenarios use a range of values for oil and natural gas prices and future production volumes. Because oil and natural gas prices have been volatile and high during 2007 and 2008, we selected oil prices of $70 and $100 per barrel of oil and $6.50 and $8 per thousand cubic feet of natural gas. In our analyses, we assumed that price thresholds would rise 2.1 percent per year, based on their average annual increase over the past 12 years. Similarly, our scenarios included low and high volume estimates for future oil and natural gas production from these leases. In these scenarios, as might be expected, the estimated forgone royalty revenues vary significantly. For example, an oil price of $70 per barrel and a natural gas price of $6.50 per thousand cubic feet and low production volumes result in $15.1 billion in forgone royalties. With the same prices but higher production volumes, this estimate increases to $27.2 billion. Alternatively, with $100 per barrel of oil and $8 per thousand cubic feet of natural gas, the low production volume assumption yields forgone royalties of $21.2 billion and the high production volume assumption yields $38.3 billion. For more detailed information on each of the scenarios and the estimated potential forgone royalty revenue, see enclosure III.

Of the 84 leases issued in 1996, 1997, and 2000 that are currently producing or are capable of producing in the future, 76 do not appear capable of producing amounts of oil and gas that will exceed the royalty suspension volumes. The total amount of oil and gas for these 76 leases below the royalty suspension volumes represents about 86 percent of the estimated amounts that the1996, 1997, and 2000 leases will collectively produce over their productive lives. Thus, only about 14 percent of the production from leases issued in 1996, 1997, and 2000 would be royalty bearing should Interior lose on appeal and the ruling in the Kerr-McGee suit is applied to DWRRA leases issued from 1996 through 2000. In addition to the impact on receiving fewer royalties in the future from the 1996, 1997, and 2000 leases, losing the appeal could also adversely affect the government's negotiation of price thresholds for the 1998 and 1999 leases. Some companies have suspended or delayed negotiations, pending outcome of the Kerr-McGee suit.

Agency Comments

We provided a draft of this report to the Department of the Interior and the Minerals Management Service (MMS) for review and oral comments. In commenting on the report, they generally agreed with GAO's methodology and conclusions. In response to their comments, we added clarification as to why the potential for future forgone royalties from the 1996, 1997, and 2000 leases with grown reserves appeared higher than they anticipated. We also incorporated their technical comments as appropriate.

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We are sending copies of this report to appropriate congressional committees, the Secretary of the Interior, the Director of the Minerals Management Service, the Director of the Office of Management and Budget, and other interested parties. We will also make copies available to others upon request. In addition, the report will be available at no charge on GAO's Web site at http://www.gao.gov.

If you or your staffs have any questions about this report, please contact me at (202) 512-3841 or ruscof@gao.gov. GAO staff who made contributions to this report include Ron Belak, Glenn C. Fischer, Mark Gaffigan, Dan Haas, and Barbara Timmerman.

Frank Rusco

Frank Rusco
Acting Director, Natural Resources and Environment

Enclosures

List of Requesters

The Honorable Jeff Bingaman
Chairman
Committee on Energy and Natural Resources
United States Senate

The Honorable Carl Levin
Chairman
The Honorable Norm Coleman
Ranking Member
Permanent Subcommittee on Investigations
Committee on Homeland Security and Governmental Affairs
United States Senate

The Honorable Ron Wyden
Chairman
Subcommittee on Public Lands and Forests
Committee on Energy and Natural Resources
United States Senate

The Honorable Nick J. Rahall
Chairman
Committee on Natural Resources
House of Representatives

The Honorable Darrell E. Issa
Ranking Member
Subcommittee on Domestic Policy
Committee on Oversight and Government Reform
House of Representatives

The Honorable Daniel K. Akaka
United States Senate

The Honorable Maria Cantwell
United States Senate

The Honorable Thomas R. Carper
United States Senate

The Honorable Byron L. Dorgan
United States Senate

The Honorable Richard J. Durbin
United States Senate

The Honorable Russell D. Feingold
United States Senate

The Honorable Dianne Feinstein
United States Senate

The Honorable Tim Johnson
United States Senate

The Honorable John F. Kerry
United States Senate

The Honorable Jon Kyl
United States Senate

The Honorable Frank R. Lautenberg
United States Senate

The Honorable Robert Menendez
United States Senate

The Honorable Barbara A. Mikulski
United States Senate

The Honorable Patty Murray
United States Senate

The Honorable Barack Obama
United States Senate

The Honorable Jack Reed
United States Senate

The Honorable Ken Salazar
United States Senate

The Honorable Charles E. Schumer
United States Senate

The Honorable Carolyn B. Maloney
House of Representatives

Enclosure I: Scope and Methodology

To update our scenario that illustrates the potential loss of royalties from leases issued in 1998 and 1999, we revised oil and gas prices upward to $100 per barrel and $8 per thousand cubic feet. The methodology is similar to that described below for leases issued in 1996, 1997, and 2000 under the Outer Continental Shelf Deep Water Royalty Relief Act of 1995 (DWRRA).[12]

To determine the fiscal impacts of price thresholds that may no longer apply to oil and gas leases issued in 1996, 1997, and 2000 under the DWRRA, we first met with Minerals Management Service (MMS) personnel in the Economics Division in Herndon, Virginia. We reviewed their October 2004 estimate of royalties that could be forgone if price thresholds did not apply to 1996, 1997, and 2000 DWRRA leases. We concluded that they followed standard engineering and financial practices and that they had generated the estimate in good faith. Since this estimate, however, additional information became available, and we believed their estimate needed to be updated. MMS concurred. Differences between our current estimates and MMS's 2004 estimate are due to changes in oil and gas prices, updated information on the size of deep water oil and gas fields that have been discovered but are not yet producing, the growth of oil and gas reserves over time, and the availability of drilling rigs in the Gulf of Mexico. MMS updated its 2004 estimate to address these issues and released this updated estimate in February 2008. We also reviewed this estimate and similarly found that it followed standard engineering and financial practices and was done in good faith. During the course of our work, we visited MMS's Gulf of Mexico regional office in New Orleans and interviewed engineers and geologists about technical aspects of oil and gas production in the deep waters of the Gulf of Mexico. In addition, we contacted industry representatives for their opinions on oil and gas exploration and development in the deep waters of the Gulf of Mexico.

Within MMS's Technical Information Management System (TIMS), we identified all 3,401 leases issued under the DWRRA, 2,369 of which were issued in 1996, 1997, and 2000. From this database, we were able to identify the status of these leases, the extent to which they had been explored and developed, and the production that had occurred on some of them. As of April 2008, a total of 94 of the leases issued in 1996, 1997, and 1999 have produced, are currently producing, or are expected to produce oil and gas in the future under DWRRA provisions. Ten of the 94 leases have either stopped producing or appear to be no longer capable of producing significant amounts, 47 are still producing, and 37 are expected to commence production at some future time. As of January 1, 2008, we estimate that about 135 of the additional 1996, 1997, and 2000 leases were still active but had not yet been tested for oil and gas. We also collected pertinent information from TIMS, current through September 2006, on the estimated reserves of leases that are currently producing and leases capable of producing but not yet connected to infrastructure (producible leases). We interviewed MMS personnel in New Orleans to better understand how these reserve estimates were made. For producing and producible leases, we corroborated lease

[12]See GAO-07-590R, enclosure 1, page 8.

information in TIMS with MMS's final bid results. We also obtained recent information on reserve growth for each producing or producible lease and obtained monthly oil and gas production volumes through July 2006 from MMS's Oil and Gas Operations Reports (OGOR). We updated these production data with additional production amounts through December 2007 when these data became available. We reviewed production data for characteristic decline patterns, questioned MMS personnel on how they verified these data and on reasons for periods of time with zero production (predominantly the result of hurricane activity), and compared each lease's cumulative production with reserve estimates in TIMS. We found the data in TIMS and in OGOR to be sufficiently reliable for the purposes of our analysis.

We considered the timing of future production to identify and exclude from our analysis the possible production volumes that will be royalty free when sales prices drop below anticipated price thresholds in the future. However, because only the sales price of $6.50 for natural gas is expected to fall below price thresholds during the time frame of our scenarios, this time is projected to be January 2024, and royalty revenue from gas production after January 2004 is anticipated to be less than 1 percent of total gas royalty revenue, we did not adjust production volumes.

To project production from future discoveries on 1996, 1997, and 2000 leases, we examined MMS projections for future drilling activity, historic discovery rates, average field sizes, and anticipated lease expiration dates for DWRRA leases in waters deeper than 800 meters, where MMS anticipates all the future DWRRA discoveries will occur. First, we assumed that the range for the number of possible untested leases drilled in all of the deep waters of the Gulf of Mexico would be between 30 and 60. This assumption was based on the availability of rigs to drill exploratory wells in waters deeper than 800 meters and MMS projections in the 2006 deep water report. Second, we assumed the success rate of future deep water lease discoveries would be the same for such deep water leases drilled from 1974 through 1995, which was 28 percent. Third, we scheduled the expiration dates of the 1996, 1997, and 2000 leases for each year through 2010 and calculated for each of these years the percentage of all untested deep water leases below 800 meters that would be 1996, 1997, and 2000 leases. We assumed that there would be 3,700 total active deep water leases each year. Fourth, we assumed that each new field discovery would consist of two leases because 97 percent of the existing 198 fields in Gulf of Mexico waters deeper than 800 meters are composed of from one to four leases, with two leases being the average field size. Finally, for 2008 through 2010, we assumed the number of field discoveries on 1996, 1997, and 2000 leases would be between zero and five. This assumption was derived by multiplying the estimated range of untested leases that could be drilled in all Gulf of Mexico deep waters (30 to 60 per year) by an estimated percentage of all deep water leases that will be active untested 1996, 1997, and 2000 leases, and by also multiplying by the assumed historical success rate of 28 percent. We doubled this number in order to account for the average field consisting of two leases and rounded the resulting high number to five. For these new discoveries, we converted these numbers into oil and gas production volumes by multiplying them by the average of the reserves for all producing and producible DWRRA leases.

With these assumptions, we developed several scenarios that illustrate that the potential for forgone royalties is highly dependent upon prices and production volumes. We chose prices of $70 for oil and $6.50 for gas because these were in the range of common prices during late 2007. We also chose prices of $100 for oil and $8 for gas because these prices are close to prices common in early 2008. We did not escalate oil and gas prices over the time period of our scenario. To illustrate the impact of changing production volumes on forgone royalties from producing and producible leases, we assumed low and high production levels. Our low production assumption is equal to MMS's estimated reserves, which we corrected in several instances when cumulative production through December 2007 exceeded estimated reserves projected in July 2006. Our high production assumption is equal to the sum of the estimated reserves for each lease multiplied by its corresponding growth factor. To illustrate the impact of changing production volumes on forgone royalties from future discoveries, we also selected low and high assumptions. Our low production assumption is zero discoveries, and our high assumption is five discoveries. We did not multiply production assumptions from future discoveries by growth factors, but such growth is possible.

Enclosure II: Scenario Illustrating the Sensitivity of Forgone Royalties to Changes in Future Production Volumes from 1998 and 1999 DWRRA Leases at High Oil and Natural Gas Prices

Scenario 1 illustrates possible forgone federal royalty payments resulting from MMS's omission of price thresholds in leases issued in 1998 and 1999 when oil and natural gas prices exceed price thresholds. This scenario updates the upper limit of prices chosen for our previous scenarios that we published in April 2007. In those scenarios, we used oil prices of $36, $50, and $70 per barrel and natural gas prices of $4.50 and $6.50 per thousand cubic feet.

Scenario 1 uses an oil price of $100 per barrel and a natural gas price of $8 per thousand cubic feet and retains these prices over the lives of the leases (see table 1). We illustrate the forgone royalties with both low and high volume estimates of future oil and gas production. In this scenario, the productive time frame is from August 2006 through the lives of the leases, which are about 25 years. In the low production volume estimate, we use MMS's "ungrown reserve" estimates and assume five additional leases are discovered to be productive in the future. Our scenario results in $8.7 billion in forgone royalties. This estimate increases to $14.7 billion in the high production volume case, which uses MMS's "grown reserves" and 10 future discoveries.

Table 1: Scenario 1 Assumes That from 1998 and 1999 Leases, Oil Would Be Sold for $100 per Barrel and Natural Gas Would Be Sold for $8 per Thousand Cubic Feet.

	Ungrown reserves and five future discoveries	**Grown reserves and 10 future discoveries**
Forgone royalties on future production from producing and producible leases	$7.3 billion	$11.3 billion
Additional forgone royalties on future production from leases with new discoveries	$1.4 billion	$3.4 billion
Total forgone royalties	**$8.7 billion**	**$14.7 billion**

Source: GAO.

Enclosure III: Scenarios Illustrating the Sensitivity of Forgone Royalties to Changes in Oil and Natural Gas Prices and Future Production Volumes from DWRRA Leases Issued in 1996, 1997, and 2000

The following two scenarios illustrate the range of possible forgone royalties that could result if price thresholds are no longer applicable to leases issued in 1996, 1997, and 2000.

Scenario 2 illustrates possible future forgone federal royalty payments if price thresholds are no longer applicable to these leases during times when oil and natural gas prices exceed the price thresholds (see table 2).[13] Specifically, we selected an oil price of $70 per barrel and a natural gas price of $6.50 per thousand cubic feet to illustrate the forgone royalties with both low and high volume estimates of future oil and gas production. In this scenario, the production time frame is from January 2008 through the lives of the leases, which is about 25 years. In the low production volume estimate, we use MMS's "ungrown reserve" estimates and assume that no additional leases are discovered in the future. This scenario results in $15.1 billion in forgone royalties. The estimate increases to $27.2 billion in the high production volume case, which uses MMS's "grown reserves" and five future discoveries.

Table 2: Scenario 2 Assumes That from 1996, 1997, and 2000 Leases, Oil Would Be Sold for $70 per Barrel and Natural Gas Would Be Sold for $6.50 per Thousand Cubic Feet.

	Ungrown reserves and no future discoveries	**Grown reserves and five future discoveries**
Forgone royalties on future production from producing and producible leases	$15.1 billion	$26.2 billion
Additional forgone royalties on future production from leases with new discoveries	$0	$1.0 billion
Total forgone royalties	**$15.1 billion**	**$27.2 billion**

Source: GAO.

Scenario 3 illustrates possible forgone royalties with higher oil and natural gas prices. Using similar assumptions on production volumes as in Scenario 2, $100 per barrel of oil and $8 per thousand cubic feet of natural gas yield $21.2 billion in forgone future royalties for the low production estimate and $38.3 billion in forgone future royalties for the high production estimate (see table 3).

[13]In scenario 2, gas prices drop below price thresholds in the latter years of the producing lives of the leases, but this revenue is anticipated to be less than 1 percent of total gas royalty revenue.

Table 3: Scenario 3 Assumes That from 1996, 1997, and 2000 Leases, Oil Would Be Sold for $100 per Barrel and Natural Gas Would Be Sold for $8 per Thousand Cubic Feet.

	Ungrown reserves and no future discoveries	**Grown reserves and five future discoveries**
Forgone royalties on future production from producing and producible leases	$21.2 billion	$36.9 billion
Additional forgone royalties on future production from leases with new discoveries	$0	$1.4 billion
Total forgone royalties	**$21.2 billion**	**$38.3 billion**

Source: GAO.

The $36.9 billion in forgone royalties on future production in table 3 is $15.7 billion greater than MMS's highest estimate of $21.2 billion released in February 2008. About half of this difference is attributed to the higher oil and gas prices we used in table 3. The other half of the difference is because we anticipate greater reserve growth than MMS.

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OIL AND GAS ROYALTIES

Royalty Relief Will Likely Cost the Government Billions, but the Final Costs Have Yet to Be Determined

Statement of Mark E. Gaffigan, Acting Director
Natural Resources and Environment

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Highlights

Highlights of GAO-07-369T, a testimony before the Committee on Energy and Natural Resources, United States Senate

OIL AND GAS ROYALTIES

Royalty Relief Will Likely Cost the Government Billions, but the Final Costs Have Yet to Be Determined

Why GAO Did This Study

Oil and gas production from federal lands and waters is vital to meeting the nation's energy needs. As such, oil and gas companies lease federal lands and waters and pay royalties to the federal government based on a percentage of the oil and gas that they produce. The Minerals Management Service (MMS), an agency in the Department of the Interior, is responsible for collecting royalties from these leases. In order to promote oil and gas production, the federal government at times and in specific cases has provided "royalty relief," waiving or reducing the royalties that companies must pay. However, as production from these leases grows and oil and gas prices have risen since a major 1995 royalty relief act, questions have emerged about the financial impacts of royalty relief.

Based on our work to date, GAO's statement addresses (1) the likely fiscal impacts of royalty relief on leases issued under the Outer Continental Shelf Deep Water Royalty Relief Act of 1995 and (2) other authority for granting royalty relief that could further impact future royalty revenue.

To address these issues our ongoing work has included, among other things, analyses of key production data maintained by MMS; and reviews of appropriate portions of the Outer Continental Shelf Deep Water Royalty Relief Act of 1995, the Energy Policy Act of 2005, and Interior's regulations on royalty relief.

www.gao.gov/cgi-bin/getrpt?GAO-07-369T.

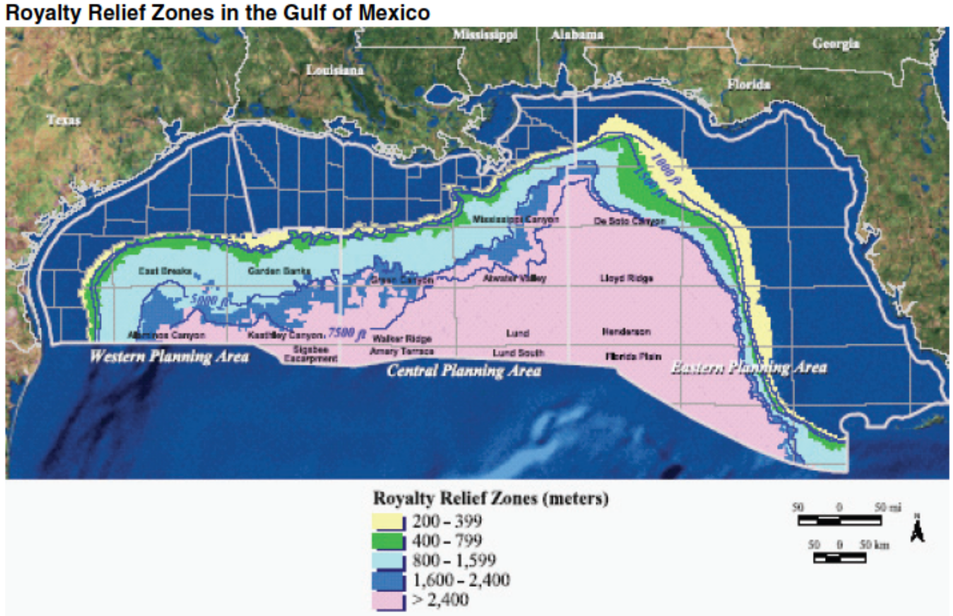
To view the full product, including the scope and methodology, click on the link above. For more information, contact Mark Gaffigan at 202-512-3841 or gaffiganm@gao.gov.

What GAO Found

While precise estimates remain elusive at this time, our work to date shows that royalty relief under the Outer Continental Shelf Deep Water Royalty Relief Act of 1995 will likely cost billions of dollars in forgone royalty revenue—at least $1 billion of which has already been lost. In October 2004, MMS estimated that forgone royalties on deep water leases issued under the act from 1996 through 2000 could be as high as $80 billion. However, there is much uncertainty in these estimates. This uncertainty stems from ongoing legal challenges and other factors that make it unclear how many leases will ultimately receive royalty relief and the inherent complexity in forecasting future royalties. We are currently assessing MMS's estimate in light of changing oil and gas prices, revised estimates of future oil and gas production, and other factors.

Additional royalty relief that can further impact future royalty revenues is currently provided under the Secretary of the Interior's discretionary authority and the Energy Policy Act of 2005. Discretionary programs include royalty relief for certain deep water leases issued after 2000, certain deep gas wells drilled in shallow waters, and wells nearing the end of their productive lives. The Energy Policy Act of 2005 mandates relief for leases issued in the Gulf of Mexico during the five years following the act's passage, provides relief for some gas wells that would not have previously qualified for royalty relief, and addresses relief in certain areas of Alaska.

Royalty Relief Zones in the Gulf of Mexico



Source: Minerals Management Service, the Department of the Interior.

Mr. Chairman and Members of the Committee:

We appreciate the opportunity to participate in the Committee's hearing on federal royalties obtained from the sale of oil and natural gas produced from federal lands and waters. Oil and gas production from federal lands and waters is vital to meeting the nation's energy needs, supplying about 35 percent of all the oil and about 25 percent of all the natural gas produced in the United States in fiscal year 2005. Oil and gas companies that lease federal lands and waters agree to pay the federal government royalties on the resources extracted and produced from the lease. In fiscal year 2006, oil and gas companies received over $77 billion from the sale of oil and gas produced from federal lands and waters, and the Minerals Management Service (MMS), the Department of the Interior's (Interior) agency responsible for collecting royalties, reported that these companies paid the federal government about $10 billion in oil and gas royalties. Clearly, such large and financially significant resources must be carefully developed and managed so that our nation's rising energy needs are met while at the same time the American people are ensured of receiving a fair rate of return on publicly owned resources, especially in light of the nation's current and long-range fiscal challenges.

In order to promote oil and gas production, the federal government has at times and in specific cases provided "royalty relief"—the waiver or reduction of royalties that companies would otherwise be obligated to pay. When the government grants royalty relief, it typically specifies the amounts of oil and gas production that will be exempt from royalties and may also specify that royalty relief is applicable only if oil and gas prices remain below certain levels, known as "price thresholds." For example, the Outer Continental Shelf Deep Water Royalty Relief Act of 1995, also known as the Deep Water Royalty Relief Act (DWRRA), mandated royalty relief for oil and gas leases issued in the deep waters of the Gulf of Mexico from 1996 to 2000. These deep water regions are particularly costly to explore and develop. However, as production from these leases has grown, and as oil and gas prices have risen far above 1995 levels, serious questions have been raised about the extent to which taxpayer interests have been protected. These concerns were brought into stark relief when it was learned that MMS issued leases in 1998 and 1999 that failed to include in the lease contracts the price thresholds above which royalty relief would no longer be applicable, making large volumes of oil and natural gas exempt from royalties and significantly affecting the amount of royalty revenues collected by the federal government. Although leases are no longer issued under DWRRA, further royalty relief is currently available under other legislation and programs, raising the prospect that the federal government may be forgoing additional royalty revenues.

Recently, congressional committees, the Department of the Interior's Office of the Inspector General,[1] public interest groups, and the press have questioned whether our nation's oil and gas royalties are being properly managed. Many of these entities have also amplified questions about whether the oil and gas industry is paying its fair share of royalties, especially in light of rapidly rising oil and gas prices, record industry profits, and a highly constrained federal budgetary environment. GAO has expressed similar concerns, and the U.S. Comptroller General has highlighted royalty relief as an area needing additional oversight by the 110th Congress.[2]

You asked us today to address royalty relief issues based on our ongoing work for this Committee. Specifically, my testimony (1) discusses the likely fiscal impacts of royalty relief for leases issued under the Deep Water Royalty Relief Act of 1995 and (2) describes other authorities for granting royalty relief that could further impact future royalty collections. To address these issues, our ongoing work has included interviews of MMS personnel in the Economics Division in Herndon, Virginia and the Gulf of Mexico OCS Region in New Orleans, Louisiana. We have collected and are analyzing key production data maintained by MMS and are examining numerous documents and studies. We are also reviewing appropriate portions of the Deep Water Royalty Relief Act of 1995, the Energy Policy Act of 2005, and Interior's royalty relief regulations. Our work follows the issuance of our report last year explaining why oil and gas royalties have not risen at the same pace as rising oil and gas prices.[3] In addition, we are conducting other work for your Committee on federal oil and gas royalty rates and the diligent development of federal oil and gas resources. Our work is being done in accordance with generally accepted government auditing standards.

[1] *Minerals Management Service's Compliance Review Process,* Department of the Interior Office of the Inspector General, Report No. C-IN-MMS-0006-2006 (Washington, D.C.: December, 2006).

[2] *Suggested Areas for Oversight for the 110th Congress,* GAO-07-235R (Washington, D.C.: November 17, 2006).

[3] *Royalty Revenues: Total Revenues Have Not Increased at the Same Pace as Rising Natural Gas Prices due to Decreasing Production Sold,* GAO-06-786BR (Washington, D.C.: June 21, 2006).

In summary, we have found the following:

- Our work to date shows that the likely fiscal impact of leases issued under the Deep Water Royalty Relief Act of 1995 is in the billions of dollars in lost royalty revenues, but precise estimates of the costs are not possible at this time for several reasons. First, MMS's failure to include price thresholds for leases issued in 1998 and 1999 along with current attempts to renegotiate these leases have created uncertainty about which leases will ultimately receive relief. MMS estimates that the failure to include these price thresholds during a period of higher oil and gas prices could cost up to $10 billion in forgone royalty revenue. To date, about $1 billion has already been lost. In addition, a recent lawsuit questions whether MMS has the authority to set price thresholds for the leases issued from 1996 through 2000. Depending on the outcome of this litigation, MMS preliminary estimates indicate that this could result in up to $60 billion in additional forgone royalty revenue. Beyond the problematic implementation of the royalty relief provisions, assessing the ultimate fiscal impact of royalty relief is a complex task, involving inherent uncertainty about future production and prices. We are currently assessing MMS's estimates of royalty relief costs in light of two years worth of additional production data and several other variables, including changing oil and gas prices, revised estimates of the amount of oil and gas that these leases are expected to produce, the availability of deep water rigs to drill untested leases, and the present value of these royalty payments. In addition, any loss in royalty revenues may be partially mitigated by the potential benefits of royalty relief, such as increased production or increased fees that companies are willing to pay the federal government to acquire these leases.

- Additional royalty relief, potentially affecting future federal royalty collection, is offered under other programs and legislation. More specifically, royalty relief can be provided under two existing authorities: (1) the Secretary of the Interior's discretionary authority and (2) the Energy Policy Act of 2005. MMS currently administers several royalty relief programs in the Gulf of Mexico under discretionary authority provided by the 1978 amendments to the Outer Continental Shelf Lands Act of 1953. These programs largely address royalty relief for certain leases issued in deep waters after 2000, certain deep gas wells drilled in shallow waters, and wells nearing the end of their productive lives. In addition, the Congress authorized additional royalty relief under provisions of the Energy Policy Act of 2005. Certain provisions in the Energy Policy Act of 2005 are similar to those in DWRRA in that they mandate royalty relief for leases issued in the Gulf of Mexico during the five years following the act's passage. The Energy Policy Act of 2005 also extends royalty relief to gas produced in the Gulf of Mexico from certain new wells that previously would not have qualified for royalty relief. Other provisions in the act address royalty relief in areas of Alaska where there currently is little or no production.

Background

The Department of the Interior (Interior), created by the Congress in 1849, oversees and manages the nation's publicly owned natural resources, including parks, wildlife habitat, and crude oil and natural gas resources on over 500 million acres onshore and in the waters of the Outer Continental Shelf. In this capacity, Interior is authorized to lease federal oil and gas resources and to collect the royalties associated with their production. Onshore, Interior's Bureau of Land Management is responsible for leasing federal oil and natural gas resources, whereas offshore, MMS has leasing authority. To lease lands or waters for oil and gas exploration, companies generally must first pay the federal government a sum of money that is determined through a competitive auction. This money is called a bonus bid. After the lease is awarded and production begins, the companies must also pay royalties to MMS based on a percentage of the cash value of the oil and natural gas produced and sold.[4] Royalty rates for onshore leases are generally 12 and a half percent whereas offshore, they range from 12 and a half percent for water depths greater than 400 meters to 16 and two-thirds percent for water depths less than 400 meters. However, the Secretary of the Interior recently announced plans to raise the royalty rate to 16 and two-thirds percent for most future leases issued in waters deeper than 400 meters. MMS also has the option of taking a percentage of the actual oil and natural gas produced, referred to as "taking royalties in kind," and selling it themselves or using it for other purposes, such as filling the nation's Strategic Petroleum Reserve.

[4]Specifically, royalties are computed as a percentage of the monies received from the sale of oil and gas, with the total federal royalty revenue equal to the volume sold multiplied by the sales price multiplied by the royalty rate.

The Deep Water Royalty Relief Act Will Likely Cost the Federal Government Billions of Dollars in Forgone Royalty Revenues, but Precise Estimates Remain Elusive

Based on our work to date, the Deep Water Royalty Relief Act (DWRRA) will likely cost the federal government billions of dollars in forgone royalties, but precise estimates of the costs are not possible at this time for several reasons. First, the failure of MMS to include price thresholds in the 1998 and 1999 leases and current attempts to renegotiate these leases has created uncertainty about which leases will ultimately receive relief. Second, a recent lawsuit is questioning whether MMS has the authority to set price thresholds for the leases issue from 1996 through 2000. The outcome of this litigation could dramatically affect the amount of forgone revenues. Finally, assessing the ultimate fiscal impact of royalty relief is an inherently complex task, involving uncertainty about future production and prices. In October 2004, MMS preliminarily estimated that the total costs of royalty relief for deep water leases issued under the act could be as high as $80 billion, depending on which leases ultimately received relief. MMS made assumptions about several conditions when generating this estimate and these assumptions need to be updated in 2007 to more accurately portray potential losses. In addition, the costs of forgone royalties need to be measured against any potential benefits of royalty relief, including accelerated drilling and production of oil and gas resources, increased oil and gas production, and increased fees that companies are willing to pay through bonus bids for these leases.

Implementing Royalty Relief Has Been Problematic and Resulted In Unanticipated Costs

The Congress passed DWRRA in 1995, when oil and gas prices were low and production was declining both onshore and in the shallow waters of the Gulf of Mexico. The act contains provisions to encourage the exploration and development of oil and gas resources in waters deeper than 200 meters lying largely in the western and central planning areas of the Gulf of Mexico. The act mandates that royalty relief apply to leases issued in these waters during the five years following the act's passage—from November 28, 1995 through November 28, 2000.

As a safeguard against giving away all royalties, two mechanisms are commonly used to ensure that royalty relief is limited and available only under certain conditions. The first mechanism limits royalty relief to specified volumes of oil and gas production called "royalty suspension volumes," which are dependent upon water depth. Royalty suspension volumes establish production thresholds above which royalty relief no longer applies. That is, once total production for a lease reaches the suspension volume, the lessee must begin paying royalties. Royalty suspension volumes are expressed in barrels of oil equivalent, which is a term that allows oil and gas companies to combine oil and gas volumes into a single measure, based on the relative amounts of energy they contain.[5] The royalty suspension volumes applicable under DWRRA are as follows: (1) not less than 17.5 million barrels of oil equivalent for leases in waters of 200 to 400 meters, (2) not less than 52.5 million barrels of oil equivalent for leases in waters of 400 to 800 meters, and (3) not less than 87.5 million barrels of oil equivalent for leases in waters greater than 800 meters. Hence, there are incentives to drill in increasingly deeper waters. Before 1994, companies drilled few wells in waters deeper than 500 meters. MMS attributes additional leasing and drilling in deep waters to the passage of these incentives but also cites other factors for increased activity, including improved three-dimensional seismic surveys, some key deep water discoveries, high deep water production rates, and the evolution of deep water development technology.

After the passage of DWRRA, uncertainty existed as to how royalty suspension volumes would apply. Interior officials employed with the department when DWRRA was passed said that they recommended to the Congress that the act should state that royalty suspension volumes apply to the production volume from an entire field. However, oil and gas companies paying royalties under the act interpreted the royalty suspension volumes as applying to individual leases within a field. This is important because an oil and gas field commonly consists of more than one lease, meaning that if royalty suspension volumes are set for each lease within a field rather than for the entire field, companies are likely to owe fewer royalties. For example, if a royalty suspension volume is based on an entire field composed of three leases, a company producing oil and gas from a 210 million barrel-oil field—where the royalty suspension volume is set at 100 million—would be obligated to pay royalties on 110 million barrels (210 minus 100). However, if the same 210-million barrel field had the same suspension volume of 100 million barrels applied to each of the three leases, and 70 million barrels were produced from each of the three leases, no royalties would be due because no lease would have exceeded its royalty suspension volume. After passage of the act, MMS implemented royalty relief on a field-basis and was sued by the industry. Interior lost the case in the Fifth Circuit Court of Appeals.[6] In October 2004, MMS estimated that this decision will cost the federal government up to $10 billion in forgone future royalty revenues.

[5]One barrel of oil equals one barrel of oil equivalent. One thousand cubic feet of gas (mcf) is converted to barrels of oil equivalent by dividing it by 5.62.

[6]Santa Fe Snyder Corp. v. Norton, 385 F.3d 884 (5th Cir. 2004).

A second mechanism that can be used to limit royalty relief and safeguard against giving away all royalties is the price threshold. A price threshold is the price of oil or gas above which royalty relief no longer applies. Hence, royalty relief is allowed only so long as oil and gas prices remain below a certain specified price. At the time of the passage of DWRRA, oil and gas prices were low—West Texas Intermediate, a key benchmark for domestic oil, was about $18 per barrel, and the average U.S. wellhead price for natural gas was about $1.60 per million British thermal units. In an attempt to balance the desire to encourage production and ensure a fair return to the American people, MMS relied on a provision in the act which states that royalties may be suspended based on the price of production from the lease. MMS then established price thresholds of $28 per barrel for oil and $3.50 per million British thermal units for gas, with adjustments each year since 1994 for inflation, that were to be applied to leases issued under DWRRA.

As with the application of royalty suspension volumes, problems arose with the application of these price thresholds. From 1996 through 2000—the five years after passage of DWRRA—MMS issued 3,401 leases under authority of the act. MMS included price thresholds in 2,370 leases issued in 1996, 1997, and 2000 but did not include price thresholds in 1,031 leases issued in 1998 and 1999. This failure to include price thresholds has been the subject of congressional hearings and investigations by Interior's Office of the Inspector General. In October 2004, MMS estimated that the cost of not including price thresholds on the 1998 and 1999 leases could be as high as $10 billion. MMS also estimated that through 2006, about $1 billion had already been lost. To stem further losses, MMS is currently attempting to renegotiate the leases issued in 1998 and 1999 with the oil and gas companies that hold them. To date, MMS has announced successful negotiations with five of the companies holding these leases and has either not negotiated or not successfully negotiated with 50 other companies.

In addition to forgone royalty revenues from leases issued in 1998 and 1999, leases issued under DWRRA in the other three years—1996, 1997, and 2000—are subject to losing royalty revenues due to legal challenges regarding price thresholds. In 2006, Kerr McGee Corporation sued MMS over the application of price thresholds to leases issued between November 28, 1995 and November 28, 2000, claiming that the act did not authorize Interior to apply price thresholds to those leases. [7] MMS

[7] Kerr-McGee (Andarko) suit 3/17/06, W.Dist. LA, CV06-0439LC

estimated in October 2004 that if price thresholds are disallowed for the leases it issued in 1996, 1997, and 2000, an additional $60 billion in royalty revenue could be lost.

Assessing the Fiscal Impact of Royalty Relief Is Inherently Complex

Trying to predict the fiscal impacts of royalty relief is a complex and time-consuming task involving considerable uncertainty. We reviewed MMS's 2004 estimates and concluded that they had followed standard engineering and financial practices and had generated the estimates in good faith. However, any analysis of forgone royalties involves estimating how much oil and gas will be produced in the future, when it will be produced, and at what prices. While there are standard engineering techniques for predicting oil and gas volumes that will eventually be recovered from a lease that is already producing, there is always some level of uncertainty involved. Predicting how much oil and gas will be recovered from leases that are capable of producing but not yet connected to production infrastructure is more challenging but certainly possible. Predicting production from leases not yet drilled is the most challenging aspect of such an analysis, but there are standard geological, engineering, and statistical methods that can shed light on what reasonably could be expected from the inventory of 1996 through 2000 leases. Overall, the volume of oil and gas that will ultimately be produced is highly dependent upon price and technology, with higher prices and better technology inducing greater exploration, and ultimately production, from the remaining leases. Future oil prices, however, are highly uncertain, as witnessed by the rapidly increasing oil and gas prices over the past several years. It is therefore prudent to assess anticipated royalty losses using a range of oil and gas prices rather than a single assumed price, as was used in the MMS estimate.

Given the degree of uncertainty in predicting future royalty revenues from deepwater oil and gas leases, we are using current data to carefully examine MMS's 2004 estimate that up to $80 billion in future royalty revenues could be lost. There are now two additional years of production data for these leases, which will greatly improve the accuracy of estimating future production and its timing. We are also examining the impact of several variables, including changing oil and gas prices, revised estimates of the amount of oil and gas that these leases were originally expected to produce, the availability of deep water rigs to drill untested leases, and the present value of royalty payments.

To fully evaluate the impacts of royalty relief, one must consider the potential benefits in addition to the costs of lost royalty revenue. For example, a potential benefit of royalty relief is that it may encourage oil and gas exploration that might not otherwise occur. Successful exploration could result in the production of additional oil and gas, which would benefit the country by increasing domestic supplies and creating employment. While GAO has not assessed the potential benefits of royalty relief, others have, including the Congressional Budget Office (CBO) in 1994, and consultants under contract with MMS in 2004.[8] The CBO analysis was theoretical and forward-looking and concluded that the likely impact of royalty relief on new production would be very small and that the overall impact on federal royalty revenues was also likely to be small. However, CBO cautioned that the government could experience significant net losses if royalty relief was granted on leases that would have produced without the relief. The consultant's 2004 study stated that potential benefits could include increases in the number of leases sold, increases in the number of wells drilled and fields discovered, and increases in bonus bids—the amount of money that companies are willing to pay the federal government for acquiring leases. However, questions remain about the extent to which such benefits would offset the cost of lost royalty revenues.

Additional Programs and Legislation Authorize Royalty Relief, Potentially Affecting Future Federal Royalty Collection

Although leases are no longer issued under the Deep Water Royalty Relief Act of 1995, royalty relief can be provided under two existing authorities: (1) the Secretary of the Interior's discretionary authority and (2) the Energy Policy Act of 2005. The Outer Continental Shelf Lands Act of 1953, as amended, granted the Secretary of the Interior the discretionary authority to reduce or eliminate royalties for leases issued in the Gulf of Mexico in order to promote increased production. The Secretary's exercising of this authority can effectively relieve the oil and gas producer from paying royalties. MMS administers several royalty relief programs in the Gulf of Mexico under this discretionary authority. MMS intends for these discretionary programs to provide royalty relief for leases in deep waters that were issued after 2000, deep gas wells located in shallow waters, wells nearing the end of their productive lives, and special cases not covered by other programs. The Congress also authorized additional royalty relief under the Energy Policy Act of 2005, which mandates relief

[8] *Waiving Royalties for Producers of Oil and Gas from Deep Waters,* Congressional Budget Office, May 1994. *Effects of Royalty Incentives for Gulf of Mexico Oil and Gas Leases*, P.K. Ashton, L.O. Upton III, and M.H. Rothkopf, under Contract No. 0103CT71722, U.S. Department of the Interior, Minerals Management Service, Economics Division, Herndon, VA, OCS Study 2004-077.

for leases issued in the Gulf of Mexico during the five years following the act's passage, provides relief for some wells that would not have previously qualified for royalty relief, and addresses relief in certain areas of Alaska.

MMS Currently Administers Royalty Relief Using Discretionary Authority

Under discretionary authority, MMS administers a deep-water royalty relief program for leases that it issued after 2000. This program is similar to the program that DWRRA mandated for leases issued during the five years following its passage (1996 through 2000) in that royalty relief is dependent upon water depth and applicable royalty suspension volumes. However, this current program is implemented solely under the discretion of MMS on a sale-by-sale basis. Unlike under DWRRA, the price thresholds and the water depths to which royalty relief applies vary somewhat by lease sale. For example, price thresholds for leases issued in 2001 were $28 per barrel for oil and $3.50 per million British thermal units for natural gas, with adjustments for inflation since 2000. As of March 2006, MMS reported that it issued 1,897 leases with royalty relief under this discretionary authority, but only 9 of these leases were producing.

To encourage the drilling of deep gas wells in the shallow waters of the Gulf of Mexico, MMS implements another program, the "deep gas in shallow water" program, under final regulations it promulgated in January 2004. MMS initiated this program to encourage additional production after noting that gas production had been steadily declining since 1997. To qualify for royalty relief, wells must be drilled in less than 200 meters of water and must produce gas from intervals below 15,000 feet. The program exempts from royalties from 15 to 25 billion cubic feet of gas per well. According to MMS's analysis, these gas volumes approximate the smallest reservoirs that could be economically developed without the benefit of an existing platform and under full royalty rates. In 2001, MMS reported that the average size of 95 percent of the gas reservoirs below 15,000 feet was 15.7 billion cubic feet, effectively making nearly all of this production exempt from royalties had it been eligible for royalty relief at that time.[9] This program also specifies a price threshold for natural gas of $9.91 per million British thermal units in 2006, substantially exceeding the average NYMEX futures price of $6.98 for 2006, and ensuring that all gas production is exempt from royalties in 2006.

[9]The average of the other 5 percent was 105 billion cubic feet, and these reservoirs are within the highly productive Norphlet Trend.

Finally, MMS administers two additional royalty relief programs in the Gulf of Mexico under its discretionary authority. One program applies to leases nearing the end of their productive lives. MMS intends that its provisions will encourage the production of low volumes of oil and gas that would not be economical without royalty relief. Lessees must apply for this program under existing regulations. MMS administers another program for special situations not covered by the other programs. Lessees who believe that other more formal programs do not provide adequate encouragement to increase production or development can request royalty relief by making their case and submitting the appropriate data. As of March 2006, no leases were receiving royalty relief under the "end of productive life," and only three leases were receiving royalty relief under the "special situations" programs.

The Energy Policy Act of 2005 Authorizes Additional Royalty Relief

The Congress authorized additional royalty relief under the Energy Policy Act of 2005. Royalty relief provisions are contained in three specific sections of the act, which in effect: (1) mandate royalty relief for deep water leases sold in the Gulf of Mexico during the five years following passage of the act, (2) extend royalty relief in the Gulf of Mexico to deep gas produced in waters of more than 200 meters and less than 400 meters, and (3) specify that royalty relief also applies to certain areas off the shore of Alaska. In the first two situations, the act specifies the amount of oil and/or gas production that would qualify for royalty relief and provides that the Secretary may make royalty relief dependent upon market prices.

Section 345 of the Energy Policy Act of 2005 mandates royalty relief for leases located in deep waters in the central and western Gulf of Mexico sold during the five years after the act's passage. Similar to provisions in DWRRA, specific amounts of oil and gas are exempt from royalties due to royalty suspension volumes corresponding to the depth of water in which the leases are located. However, production volumes are smaller than those authorized under DWRRA, and this specific section of the Energy Policy Act clearly states that the Secretary may place limitations on royalty relief based on market prices. For the three sales that MMS conducted since the passage of the act, MMS included prices thresholds establishing the prices above which royalty relief would no longer apply. These price thresholds were $39 per barrel for oil and $6.50 per million British thermal units for gas, adjusted upward for inflation that has occurred since 2004. The royalty-free amounts, referred to as royalty suspension volumes, are as follows: 5 million barrels of oil equivalent per lease between 400 and 800 meters; 9 million barrels of oil equivalent per lease between 800 and 1,600 meters; 12 million barrels of oil equivalent per lease between 1,600 and 2,000 meters; and 16 million barrels of oil equivalent per lease in water greater than 2,000 meters. MMS has already issued 1,105 leases under this section of the act.

Section 344 of the Energy Policy Act of 2005 contains provisions that authorize royalty relief for deep gas wells in additional waters of the Gulf of Mexico that effectively expands the existing royalty-relief program for "deep gas in shallow water" that MMS administers under pre-existing regulations. The existing program has now expanded from waters less than 200 meters to waters less than 400 meters. A provision within the act exempts from royalties gas that is produced from intervals in a well below 15,000 feet so long as the well is located in waters of the specified depth. Although the act does not specifically cite the amount of gas to be exempt from royalties, it provides that this amount should not be less than the existing program, which currently ranges from 15 to 25 billion cubic feet. The act also contains an additional incentive that could encourage deeper drilling—royalty relief is authorized on not less than 35 billion cubic feet of gas produced from intervals in wells greater than 20,000 feet deep. The act also states that the Secretary may place limitations on royalty relief based on market prices.

Finally, the Energy Policy Act of 2005 contains provisions addressing royalty relief in Alaska that MMS is already providing. Section 346 of the act amends the Outer Continental Shelf Lands Act of 1953 by authorizing royalty relief for oil and gas produced off the shore of Alaska. MMS has previously included royalty relief provisions within notices for sales in the Beaufort Sea of Alaska in 2003 and 2005. All of these sales offered royalty relief for anywhere from 10 million to 45 million barrels of oil, depending on the size of the lease and the depth of water. Whether leases will be eligible for royalty relief and the amount of this royalty relief is also dependent on the price of oil. There currently is no production in the Beaufort Sea. Although there have been no sales to date under this provision of the act, MMS is proposing royalty relief for a sale in the Beaufort Sea in 2007. Section 347 of the Energy Policy Act also states that the Secretary may reduce the royalty on leases within the Naval Petroleum Reserve of Alaska in order to encourage the greatest ultimate recovery of oil or gas or in the interest of conservation. Although this authority already exists under the Naval Petroleum Reserves Production Act of 1976, as amended, the Secretary must now consult with the State of Alaska, the North Slope Borough, and any Regional Corporation whose lands may be affected.

Conclusions

In order to meet U.S. energy demands, environmentally responsible development of our nation's oil and gas resources should be part of any national energy plan. Development, however, should not mean that the American people forgo a reasonable rate of return for the extraction and sale of these resources, especially in light of the current and long-range fiscal challenges facing our nation, high oil and gas prices, and record industry profits. Striking a balance between encouraging domestic production in order to meet the nation's increasing energy needs and ensuring a fair rate of return for the American people will be challenging. Given the record of legal challenges and mistakes made in implementing royalty relief to date, we believe this balance must be struck in careful consideration of both the costs and benefits of all royalty relief. As the Congress continues its oversight of these important issues, GAO looks forward to supporting its efforts with additional information and analysis on royalty relief and related issues.

Mr. Chairman, this concludes my prepared statement. I would be pleased to respond to any questions that you or other Members of the Committee may have at this time.

GAO Contact and Staff Acknowledgments

For further information about this testimony, please contact me, Mark Gaffigan, at 202-512-3841 or gaffiganm@gao.gov. Contact points for our Offices of Congressional Relations and Public Affairs may be found on the last page of this statement. Contributors to this testimony include Dan Haas, Assistant Director; Ron Belak; John Delicath; Glenn Fischer; Frank Rusco; and Barbara Timmerman.

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United States Government Accountability Office
Washington, DC 20548

April 12, 2007

Congressional Requesters:

Subject: *Oil and Gas Royalties: Royalty Relief Will Cost the Government Billions of Dollars but Uncertainty Over Future Energy Prices and Production Levels Make Precise Estimates Impossible at this Time*

Oil and gas from federal lands and waters is critical to meeting the nation's energy needs, providing about 35 percent of all oil and 25 percent of all the natural gas produced in the United States in fiscal year 2005. Oil and gas companies that lease federal lands and waters agree to pay the federal government royalties on the resources extracted and produced from these leases. In 1995—a time when oil and natural gas prices were significantly lower than they are today—Congress passed the Outer Continental Shelf Deep Water Royalty Relief Act of 1995 (DWRRA), which authorized the Department of the Interior's (Interior) Minerals Management Service (MMS) to provide "royalty relief" on oil and gas produced in the deep waters of the Gulf of Mexico from leases issued from 1996 through 2000. This "royalty relief" waived or reduced the amount of royalties that companies would otherwise be obligated to pay. In implementing the DWRRA for leases sold in 1996, 1997, and 2000, MMS specified that royalty relief would only be applicable if oil and gas prices were below certain levels, known as "price thresholds," thereby protecting the government's royalty interests should oil and gas prices increase significantly. MMS did not include price thresholds for leases it issued in 1998 and 1999. Because oil and natural gas prices have risen significantly in recent years, the omission of price thresholds on the leases issued in 1998 and 1999 has resulted in significant foregone royalties to the federal government. In an effort to recoup some of these royalties, Interior is currently negotiating with some of the oil and gas companies that own these leases. Congress has also been considering legislative actions to recoup foregone royalty revenues on these leases or to encourage companies to negotiate with MMS. In addition to the foregone royalties on the 1998 and 1999 leases, one company, Kerr-McGee, is currently pursuing a legal challenge to the Interior's authority to place price thresholds on any deep water leases issued between 1996 and 2000 under the DWRRA.[1] If successful, this legal challenge would lead to additional foregone royalties on leases issued in 1996, 1997, and 2000.

We reported to the Senate Committee on Energy and Natural Resources in January 2007 that the royalty relief for leases issued under the DWRRA will likely cost the federal government billions of dollars, but that the final costs have yet to be

[1] Kerr-McGee Oil and Gas Corp. v. Burton, No. CV06-0439LC (W.D. La. March 17, 2006).

determined.[2] At that time, MMS' most recent estimates of forgone royalties were made in October 2004. In light of these findings, you asked us to evaluate the potential for foregone royalties resulting from the omission of price thresholds on the leases issued in 1998 and 1999. We are also reporting on the status of Kerr-McGee's legal challenge to the Interior's authority to set price thresholds for the leases issued in 1996, 1997, and 2000 under the DWRRA, and the potential implications this challenge could have on federal royalty revenues.

To evaluate the potential for foregone royalties on the 1998 and 1999 leases, we reviewed estimates made by MMS in October 2004 as well as its updated estimates from February 2007. Specifically, we reviewed MMS' methodology and assumptions that were used to estimate the amount of future oil and natural gas production from DWRRA leases, and we examined the timing of this future production using decline curve analysis--an engineering tool that projects future production based on the decline in past production. We also reviewed statistical data on field sizes, discovery success rates, and drilling rig availability in the deep waters of the Gulf of Mexico to assess the likelihood of future oil and gas discoveries on DWRRA leases. In addition to reviewing MMS' estimates, we developed and analyzed a series of scenarios to study the uncertainty surrounding estimates of future foregone royalties. These scenarios used a range of assumptions about oil and natural gas prices and future production levels. Since MMS has not yet updated its estimate of the forgone royalties from leases issued in 1996, 1997, and 2000 should thresholds no longer apply, we did not have all of the available data to fully report on expected future foregone royalties on these leases. However, we did evaluate MMS' methodology and assumptions used to make its 2004 estimate of foregone revenue during the three year period and provide our comments on this. We also collected information from MMS on the amount of royalties that have already been collected on the 1996, 1997, and 2000 leases, which may need to be refunded if the federal government loses the ongoing legal challenge related to these leases. Finally, we worked with MMS and reviewed legal documents to provide an update on the status of the legal challenge. A more detailed description of our scope and methodology is provided in enclosure 1. We conducted our review from September 2006 through March 2007 in accordance with generally accepted government auditing standards.

In summary:

The absence of price thresholds in leases issued in 1998 and 1999 has already cost the government about $1 billion and MMS' most recent estimate in February 2007 indicates a range of future foregone royalties of between $6.4 billion and $9.8 billion over the lives of the leases. We believe the methodology and assumptions used by MMS to make these estimates are reasonable. However, because there is considerable uncertainty about future oil and natural gas prices and production levels, actual foregone royalties could end up being higher or lower than MMS's estimates. Our analysis shows that future foregone royalties are quite sensitive to changes in prices or in the amount of oil and natural gas produced. For example, one

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[2] *Oil and Gas Royalties: Royalty Relief Will Likely Cost the Government Billions, but the Final Costs Have Yet to Be Determined*, GAO-07-369T (Washington, D.C.: January 18, 2007).

scenario that assumed high production levels and a price of $70 per barrel for oil and $6.50 per thousand cubic feet for natural gas—prices that are higher than those used by MMS but within the range of recent market prices—indicated that the future foregone royalties could be as high as $10.5 billion. Alternatively, a scenario that assumed low production levels and $50 per barrel for oil and $6.50 per thousand cubic feet for natural gas indicated that future forgone royalties could be as low as $4.3 billion. MMS is currently negotiating with oil and gas companies to apply price thresholds to future production from the 1998 and 1999 leases. To date, the results of these negotiations have been mixed -- 6 of the 45 companies involved have agreed to terms; others have agreed to negotiate but have not yet come to terms; and some companies have yet to agree to negotiate.

With regard to the legal challenge to the Interior's authority to include price thresholds on leases issued under the DWRRA, Kerr-McGee filed suit in early 2006, but agreed to enter mediation with Interior in an attempt to resolve the issue. The mediation was unsuccessful and litigation has resumed. If the government loses this litigation it will lead to additional foregone royalty revenues from the 1996, 1997, and 2000 leases that included price thresholds. The additional foregone royalty revenues could include royalties on these leases totaling approximately $1 billion that have already been collected and which may have to be refunded as well as royalties on future production. MMS estimated in October 2004 that potential foregone royalties on future production could be up to $60 billion over the life of the leases, should the federal government lose the legal challenge. In our review of the methodology and assumptions used in MMS' estimate, we found that MMS may have over-estimated the amount of oil and natural gas that would be produced from these leases over the course of their lifetime. MMS officials agreed with this assessment and said that an updated estimate of foregone revenue from these leases might be considerably lower than the $60 billion figure but that they are not currently working to develop a revised estimate.

The Congress needs accurate and timely information to consider legislative action to recoup forgone royalties. Because the amount of royalties potentially recouped from such action may be dependent upon fluctuating oil and gas prices and changing production volumes, we are recommending that MMS provide to the Congress (1) the status of the leases and the annual amount of royalties that have been foregone on the 1998 and 1999 DWRRA leases until the issue is resolved, (2) the status of the leases and the annual amount of royalties collected to date from the 1996, 1997, and 2000 DWRRA leases until the Kerr-McGee suit is resolved, and (3) periodic estimates of future foregone royalties from 1998 and 1999 DWRRA leases and future royalties that may be at risk from 1996, 1997, and 2000 DWRRA leases until these issues are resolved.

Failure to Include Price Thresholds in 1998 and 1999 Leases Will Cost the Government Billions in Foregone Royalty Payments

As Assistant Secretary Allred of the Department of the Interior recently testified before the Congress, the absence of price thresholds in leases issued in 1998 and 1999 has already cost the government almost $1 billion. In February 2007, MMS estimated a range of potential future foregone revenue for these leases of between $6.4 billion and $9.8 billion. MMS calculated these estimates under a range of assumptions about oil and natural gas prices and future production levels. MMS used two price assumptions–one employing a constant price of $45 per barrel of oil equivalent and the other using the Office of Management and Budget's projected oil and gas prices, which escalate through time.[3] For future production volumes from the 1998 and 1999 leases, MMS made low and high estimates—the low estimate did not allow for expected growth in oil and natural gas reserves, while the high estimate included expected growth in reserves based on past experience with oil and natural gas leases in the Gulf of Mexico.[4] Reserves are the amount of oil (or natural gas) that is believed to be economically recoverable at current technology and prices. Reserve growth is the tendency of the initial reserve estimates to increase or "grow" in the future as more becomes known about the oil and gas field. We reviewed MMS' assumptions and methodology for estimating the potential foregone revenue from 1998 and 1999 leases and found them to be reasonable.

In order to provide further perspective on just how much these future costs may vary, we developed and analyzed different scenarios that illustrate how the cost to the federal government is sensitive to changes in both oil and natural gas prices and future production volumes.[5] In developing these scenarios, it is important to understand that the three key variables that determine total federal royalty revenues are production volume, sales price, and royalty rate. Royalties paid to the federal government are then calculated using the following equation: *Royalty Revenue = volume sold x sales price less deductions x royalty rate.*

Accordingly, our scenarios employ a range of values for oil and natural gas prices and future production volumes to illustrate the uncertainty surrounding potential foregone federal royalty revenues.[6] Since oil and natural gas prices have historically been volatile, we selected a variety of prices, ranging from a low of $36 per barrel of oil to a high of $70 per barrel and a low of $4.50 per thousand cubic feet of natural gas to a high of $6.50 per thousand cubic feet. In our analyses, we assumed that price thresholds would rise 2.1 percent per year, based on their average annual increase over the past 10 years. Similarly, our scenarios included low and high volume estimates for future oil and natural gas production from these leases. In these scenarios, the estimated foregone royalty revenues vary significantly. For example, an oil price of $50 per barrel and a natural gas price of $6.50 per thousand cubic feet

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[3] One barrel of oil equivalent (BOE) equals one barrel of oil or 5.62 thousand cubic feet of natural gas.

[4] As oil and gas reserves are developed and more knowledge of the field is obtained, proven reserves generally experience some growth.

[5] These scenarios are not probabilistic estimates of what may actually happen with royalty revenue. Rather, they are illustrative examples using estimates of future oil and natural gas production that we believe are reasonable based on the history of leases in the Gulf of Mexico and using oil and gas prices that are within the range of prices that have existed in the past three years. As such, we believe the scenarios are reflective of plausible possibilities, but we do not assign any probabilities to any of the scenarios.

[6] The royalty rate for DWRRA leases in less than 400 meters of water is 16.67 percent, and the royalty rate for leases in waters greater than 400 meters is 12.5 percent.

and low production volumes results in $4.3 billion in foregone royalties.[7] With the same prices but higher production volumes, this estimate increases to $7.4 billion. Alternatively, with $70 per barrel of oil and $6.50 per thousand cubic feet of natural gas, the low production volume assumption yields foregone royalties of $6.2 billion and the high production volume assumption yields $10.5 billion. For more detailed information on each of the scenarios and the estimated potential foregone royalty revenue, see enclosure 2.

To recoup some of the potential foregone revenue on the 1998 and 1999 leases, MMS is currently negotiating with oil and gas companies in an attempt to apply price thresholds to future production from these leases. If successful, this approach would partially undo the omission of price thresholds for future production, thereby implementing the royalty relief as though price thresholds had been included in the leases. However, the results of these negotiations have been mixed—as of late February, 2007, only 6 of 45 companies had agreed to terms, while others were either negotiating or had not yet agreed to negotiate. Moreover, uncertainty about the current legal challenge to Interior's authority to set price thresholds on any DWRRA leases may further deter or complicate negotiated settlements.

A Successful Challenge to Interior's Authority to Include Price Thresholds On Leases Issued Under the DWRRA Could Cost the Government Billions In Additional Revenues

Kerr-McGee filed suit against the Department of the Interior in early 2006, challenging its authority to place price thresholds on any of the leases issued under the DWRRA. In particular, this suit seeks to in effect, remove price thresholds from leases issued in 1996, 1997, and 2000. In June 2006, Kerr-McGee agreed to enter into mediation with Interior in an attempt to resolve the issue; however, the mediation was unsuccessful and litigation has resumed. As of July 2006, the 1996, 1997, and 2000 leases have generated approximately $1 billion in royalties. If the government loses this legal challenge, it may be required to refund these royalties and to forego future royalties on these leases.[8] As a result, the government could stand to lose billions of additional dollars. In addition to the impact on royalties on the 1996, 1997, and 2000 leases, losing the suit brought by Kerr-McGee would also impact the government's negotiation of price thresholds for the 1998 and 1999 leases.

MMS estimated in October 2004 that foregone royalties on the 1996, 1997, and 2000 leases could be as high as $60 billion. Because much has been learned about the productivity of the leases since that initial estimate and because price expectations have changed, an updated estimate may differ significantly from the 2004 estimate.

For example, of the 2,369 leases issued in 1996, 1997, and 2000, 1,294 have expired without ever producing oil or gas. Of the remaining leases, 12 have produced and

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[7] It should be noted that if oil prices were to fall and remain at $36 per barrel or below and natural gas prices at $4.50 per thousand cubic feet or below, no royalties would be due even if the price thresholds that were imposed on the 1996, 1997, and 2000 leases were applied to the 1998 and 1999 leases.

[8] Future foregone royalties are dependent on the "royalty suspension volume." Royalty suspension volumes are cumulative production amounts above which royalty relief no longer applies.

have either reached the end of their productive lives or appear incapable of further production; 38 were still producing as of July 2006; 26 appear capable of producing in the future after being connected to infrastructure; and 999 are still active but untested for oil and gas. On the other hand, oil and natural gas prices have increased since the estimate of foregone royalties in 2004. In our review of the methodology and assumptions used in MMS' 2004 estimate, we found that MMS may have made overly optimistic assumptions about the amount of oil and natural gas production that would occur over the lifetime of these leases. MMS officials agreed with this assessment and also agreed that a new estimate of potential foregone royalties might be considerably lower than their earlier $60 billion figure. However, MMS officials told us that they are not currently working to update these figures.

Conclusions

It is impossible to precisely estimate how much royalty revenue the federal government could lose as the result of the 1998 and 1999 leases that did not include price thresholds or if Interior loses the legal challenge to its authority to include price thresholds for the leases issued in 1996, 1997, and 2000, because of the inherent uncertainty of future oil and natural gas prices and production volumes. Nonetheless, MMS estimates of foregone royalty revenues from 1998 and 1999 leases seem reasonable, in light of our analysis. There is considerably more uncertainty, however, regarding potential foregone royalty revenue for leases issued in 1996, 1997, and 2000. Although MMS has not yet updated its 2004 estimate of the future potential royalty losses on the leases at issue in the Kerr-McGee suit, it is clear that such an update could differ significantly from its earlier estimate because of likely changes to production and price assumptions. As Congress considers ways to address foregone royalties, it will need the best available information on a year-to-year basis about royalties that have been foregone to-date, those that have been paid but that are at risk in the suit, and estimates of how much is at stake going forward. Because new information will become available every year that these leases are in effect, we expect these figures and estimates to change significantly over time.

Recommendations for Executive Action

To assist the Congress in its efforts to find appropriate remedies for foregone royalty revenues or those that may be at risk, we recommend that MMS report to the Congress (1) the status of the leases and the annual amount of royalties that have been foregone on the 1998 and 1999 DWRRA leases until the issue is resolved, (2) the status of the leases and the annual amount of royalties collected to date from the 1996, 1997, and 2000 DWRRA leases until the Kerr-McGee suit is resolved, and (3) periodic estimates, as MMS resources allow, of future foregone royalties from 1998 and 1999 DWRRA leases and future royalties that may be at risk from 1996, 1997, and 2000 DWRRA leases until both of these situations are resolved.

Agency Comments

We provided a draft of this report to the Department of the Interior and the Minerals Management Service (MMS) for review and comment. They provided oral comments, which we have incorporated as appropriate. In general, MMS officials said they agreed with our findings and recommendations. Specifically, MMS officials said that providing the Congress with both the retrospective annual amounts of foregone royalties from 1998 and 1999 DWRRA leases and royalties collected from 1996, 1997, and 2000 leases would be manageable. However, agency officials stated that providing the Congress annual prospective estimates of both of these values would require significant work and cost. Accordingly, we revised our recommendations to provide MMS with the flexibility to develop these estimates as MMS resources allow or as needed by the Congress.

We are sending copies of this report to appropriate Congressional committees, the Secretary of the Interior, the Director of MMS, the Director of the Office of Management and Budget, and other interested parties. We will also make copies available to others upon request. In addition, the report will be available at no charge on GAO's Web site at http://www.gao.gov.

If you or your staff have any questions or comments about this report, please contact me at (202) 512-3841 or gaffiganm@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 contributions to this report include Ron Belak, Glenn C. Fischer, Dan Haas, Frank Rusco, and Barbara Timmerman.

Mark C. Gaffigan

Mark Gaffigan
Acting Director, Natural Resources
and Environment

Enclosures

Scope and Methodology

To determine the fiscal impacts of not including price thresholds on deep water oil and gas leases issued under the Outer Continental Shelf Deep Water Royalty Relief Act of 1995 (DWRRA), we met with MMS personnel in the Economics Division in Herndon, Virginia. We reviewed their October 2004 estimate of forgone royalties due to not including price thresholds in 1998 and 1999 deep water leases and their estimate of royalties that could be forgone if price thresholds did not apply to 1996, 1997 and 2000 DWRRA leases. We concluded that they followed standard engineering and financial practices and had generated the estimates in good faith. However, more than two years had passed since their estimates, and we believed that the estimates needed to be updated. MMS concurred and gave us their preliminary results in March 2007. We recently reviewed these preliminary results and generally concurred with their methodology and assumptions as well as with the magnitude of their estimates. During the course of our work in 2006, we visited MMS's Gulf of Mexico Regional Office in New Orleans and interviewed engineers and geologists on technical aspects of oil and gas production in the deep waters of the Gulf of Mexico. In addition, we contacted industry representatives for opinions on oil and gas exploration and development in the deep waters of the Gulf of Mexico.

To perform our scenario analysis, we identified within MMS's Technical Information Management System (TIMS) all 3,401 leases issued under the DWRRA, 1,032 of which were issued in 1998 and 1999. From this database, we were able to identify the status of these leases and the extent to which they had been explored and developed and the production that had occurred on some of them. As of July 2006, a total of 33 of the leases issued in 1998 and 1999 have produced, are currently producing, or are expected to produce oil and gas in the future. Four of the 33 leases have either stopped producing or appear to be no longer capable of producing significant amounts; 14 are still producing; and 15 are expected to commence production at some future time. As of January 1, 2007, 563 additional 1998 and 1999 leases were still active but had not yet been tested for oil and gas. As of March 28, 2007, 486 of the leases issued in 1998 and 1999 have expired, been relinquished, or been terminated.[9] We also collected from TIMS pertinent information current through July 2006 on the status of each lease and the estimated reserves of producing leases and leases capable of producing but not yet connected to infrastructure (producible leases). We interviewed MMS personnel in New Orleans to better understand how these reserve estimates were made. For producing and producible leases, we corroborated lease information in TIMS with MMS's final bid results. We also obtained recent information on reserve growth for each producing or producible lease and obtained monthly oil and gas production volumes through July 2006 from MMS's Oil and Gas Operations Reports (OGOR). We reviewed production data for characteristic decline patterns, questioned MMS personnel on how they verified these data and on reasons for periods of time with zero production (predominantly the result of hurricane activity), and compared each lease's cumulative production with reserve estimates in TIMS. We found the data in TIMS and in OGOR to be sufficiently reliable for the purposes of our analysis.

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[9] Total lease numbers for 1998 and 1999 leases do not add to 1,032 due to overlapping time periods.

In consultation with MMS experts, we estimated the timing of future production to identify and exclude from our analysis the possible production volumes that will be royalty free when sales prices drop below anticipated price thresholds in the future. To determine the timing of future production from currently producing leases, we used standard decline curve analysis, which projects future production based on the declining pattern of past production. For 1998 and 1999 producing leases, we segregated leases into three zones based on water depth, which determines how much production is royalty free. Zone A contains leases in waters from 200 to 400 meters deep (17.5 million BOE exempt from royalties); zone B contains leases in waters from 400 to 800 meters deep (52.5 million BOE exempt from royalties); and zone C contains leases in waters deeper than 800 meters (87.5 million BOE exempt from royalties). We constructed separate decline curves for the oil and gas fraction for leases in zone C, but did not do so for leases in the A and the B zones because these leases were either not producing or were producing insignificant volumes. When constructing decline curves, we adjusted for time periods of zero production due to major hurricanes. We also ensured that the total production predicted by the decline curves was equal to the total reserves estimated by MMS. For larger leases, we tracked projected cumulative production to predict whether a lease would exceed its royalty suspension volume so as not to include the amounts over the suspension volumes in our estimate of forgone royalties.

We also used decline curve analysis to predict the timing of future production from producible leases, all of which are in the C zone. In consultation with MMS experts, we constructed a composite gas decline curve and a composite oil decline curve using production data from all producing DWRRA leases in the C zone, adjusted for missing data. Based on advice from MMS and industry representatives, we assumed that producible leases would produce for 15 years. Based on the 7 year average time from discovery to first production of 144 producing fields in Gulf of Mexico waters deeper than 800 meters, we assumed that each of the producible C zone leases would first start producing seven years after its discovery.

To project production from future discoveries on 1998 and 1999 leases, we examined MMS projections for future drilling activity, historic discovery rates, average field sizes, and anticipated lease expiration dates for DWRRA leases in waters deeper than 800 meters, where MMS anticipates all the future DWRRA discoveries to occur. First, we assumed that the range for the number of possible untested leases drilled in all of the deep waters of the Gulf of Mexico would be between 30 and 60. This assumption was based on the availability of rigs to drill exploratory wells in waters deeper than 800 meters and MMS projections in the 2006 deep water report. Second, we assumed the success rate of future deep water lease discoveries would be the same as for such deep water leases issued from 1974 through 1995—this success rate was 28 percent. Third, we scheduled the expiration dates of the 1998 and 1999 leases for each year through 2009 and calculated for each of these years the percentage of all untested deep water leases below 800 meters that would be 1998 and 1999 leases, assuming that there would be 3,700 total active deep water leases each year. Fourth, we assumed that each new field discovery would consist of two leases because 97 percent of the existing 198 fields in Gulf of Mexico waters deeper than 800 meters are composed of from one to four leases, with two leases being the average field size.

Finally, for 2007 through 2009, we assumed the number of field discoveries on 1998 and 1999 leases would be between 5 and 10. This assumption was derived by multiplying the estimated range of untested leases that could be drilled in all Gulf of Mexico deep waters (30 to 60 per year) by the percentage of all deep water leases that are active untested 1998 and 1999 leases and by the assumed success rate of 28 percent. We doubled this number in order to account for the average field consisting of two leases. For these new discoveries, we converted these numbers into oil and gas production volumes by multiplying them by the average of the reserves for all producing and producible DWRRA leases, adjusting for the possibility that some leases would have reserves greater than the royalty suspension volume of 87.5 million BOE.

With these assumptions, we developed several scenarios that illustrate that the potential for forgone royalties is highly dependent upon prices and production volumes. We selected the price scenario of $36 for oil and $4.50 for gas to illustrate that there would be no forgone royalties at these prices because they should remain below predicted price thresholds for the lives of the DWRRA leases. We chose prices of $50 and $70 for oil and $6.50 for gas because these were in the range of common prices during 2006. We did not escalate oil and gas prices over the time period of our scenario. However, we increased 2006 price thresholds by 2.1 percent per year, based on the average increase over the past 10 years. To illustrate the impact of changing production volumes on forgone royalties from producing and producible leases, we assumed low and high production levels. Our low production assumption is equal to MMS's estimated reserves. Our high production assumption is equal to MMS's estimated reserves multiplied by the average weighted growth factor. To illustrate the impact of changing production volumes on forgone royalties from future discoveries, we also selected low and high assumptions. Our low production assumption is 5 discoveries, and our high assumption is 10 discoveries. We did not multiply production assumptions from future discoveries by growth factors but such growth is possible.

Scenarios Illustrating the Sensitivity of the Cost to the Federal Government to Changes in Oil and Natural Gas Prices and Future Production Volumes

We present two scenarios below to illustrate the range of potential future costs to the federal government that could result from the omission of price thresholds in leases issued in 1998 and 1999.

Scenario 1 illustrates possible foregone federal royalty payments resulting from MMS's omission of price thresholds in leases issued in 1998 and 1999 when oil and natural gas prices exceed price thresholds (see table 1).[10] Specifically, we selected an oil price of $50 per barrel and a natural gas price of $6.50 per thousand cubic feet to illustrate the forgone royalties with both low and high volume estimates of future oil and gas production. In this scenario, the productive timeframe is from August 2006 through the lives of the leases—about 25 years. In the low production volume estimate, we use MMS's "ungrown reserve" estimates and assume 5 additional leases are discovered in the future. Our scenario results in $4.3 billion in foregone royalties. This estimate increases to $7.4 billion in the high production volume case, which uses MMS' "grown reserves" and 10 future discoveries.

Table 1: Scenario 1 assumes that from 1998 and 1999 leases, oil would be sold for $50 per barrel and natural gas would be sold for $6.50 per thousand cubic feet.

	Ungrown Reserves and 5 Future Discoveries	**Grown Reserves and 10 Future Discoveries**
Foregone royalties on Future Production from Producing and Producible Leases	$3.8 Billion	$6.0 Billion
Additional Foregone Royalties on Future Production from Leases with New Discoveries	$0.5 Billion	$1.4 Billion
TOTAL FOREGONE ROYALTIES	$4.3 Billion	$7.4 Billion

Source: GAO

Scenario 2 illustrates possible forgone royalties with a higher oil price, but the price is within the range of prices we have seen in recent years (see table 2). Using similar assumptions on production volumes as in Scenario 1, $70 per barrel of oil and $6.50 per thousand cubic feet of natural gas yields $6.2 billion in forgone future royalties for the low estimate and $10.5 billion in forgone future royalties for the high estimate.

[10] In some of our scenarios, oil and gas prices drop below price thresholds in the latter years of the producing lives of the leases. In these cases, this royalty revenue is not considered forgone royalties.

Table 2: Scenario 2 assumes that from 1998 and 1999 leases, oil would be sold for $70 per barrel and natural gas would be sold for $6.50 per thousand cubic feet.

	Ungrown Reserves and 5 Future Discoveries	**Grown Reserves and 10 Future Discoveries**
Foregone royalties on Future Production from Producing and Producible Leases	$5.2 Billion	$8.1 Billion
Additional Foregone Royalties on Future Production from Leases with New Discoveries	$1.0 Billion	$2.4 Billion
TOTAL FOREGONE ROYALTIES	$6.2 Billion	$10.5 Billion

Source: GAO

List of Addressees

The Honorable Jeff Bingaman
Chairman, Committee on Energy and Natural Resources
United States Senate

The Honorable Carl Levin
Chairman, Permanent Subcommittee on Investigations
Committee on Homeland Security and Governmental Affairs
United States Senate

The Honorable Norm Coleman
Ranking Member, Permanent Subcommittee on Investigations
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U.S. Department of the Interior
Office of Inspector General

EVALUATION REPORT

OPPORTUNITY TO INCREASE OFFSHORE OIL AND GAS RENTAL REVENUES, MINERALS MANAGEMENT SERVICE

REPORT NO. 99-I-387
MARCH 1999

United States Department of the Interior

OFFICE OF INSPECTOR GENERAL
Washington. D.C. 20240

MAR 31 1993

EVALUATION REPORT

Memorandum

To: Assistant Secretary for Land and Minerals Management

From: Robert J. Williams' Robert J. Williams
Assistant Inspector General for Audits

Subject: Evaluation Report on Opportunity To Increase Offshore Oil and Gas Rental Revenues, Minerals Management Service (No. 99-I-387)

INTRODUCTION

This report presents the results of our evaluation of potential increases in revenues for certain leases subject to the Deep Water Royalty Relief Act of 1995 (Public Law 104-58). During the followup evaluation of our December 1993 audit report "Offshore Minerals Leasing Activities, Minerals Management Service" (No. 94-I-l 79), we noted that the Minerals Management Service has an opportunity to significantly increase rental revenues from certain offshore oil and gas leases. The objective of this evaluation was to provide information to Service management on laws, regulations, policies, and procedures relating to the opportunity to increase revenues and an estimate of the amount of revenues that may be realized by this opportunity.

BACKGROUND

The Minerals Management Service's mission includes managing the Offshore Minerals Leasing Program under the provisions of the Outer Continental Shelf Lands Act, as amended. To accomplish this part of its mission, the Service prepares oil and gas leasing schedules, holds lease sales on offshore tracts (up to 5,760 acres), and awards leases on offshore Federal lands to the highest qualified bidder. For each lease awarded, the Service receives revenues in the form of bonus bids, rental fees, and royalties if a lessee begins production of oil and gas on the leased tracts. Bonus bids are a one-time cash amount paid per acre to the Service by the highest qualified bidders on leases they obtain. Rental fees are annual payments based on a fixed dollar amount per acre established at the time a lease is issued. Lessees make royalty payments equal to a stated share or percentage of the value of the oil or gas produced on a tract. During calendar years 1997 and 1998, rent and royalty revenues from the Outer Continental Shelf oil and gas leases totaled about $6.9 billion, which consisted of royalties of about $6.4 billion and rents of $467 million.

SCOPE OF EVALUATION

The evaluation was conducted at the Service's Economics Division in Herndon, Virginia. As part of the evaluation, we reviewed laws, regulations, and records pertaining to the Service's offshore oil and gas leasing program and interviewed Service personnel responsible for administering the program. We also reviewed the Secretary's Annual Statement and Report to the President and the Congress for fiscal year 1995, which was required by the Federal Managers' Financial Integrity Act; the Departmental Reports on Accountability for fiscal years 1996 and 1997, which include information required by the Act; and the Service'sannual assurance statement on management controls for fiscal year 1997. Based on our review, we determined that no material weaknesses were included in these documents that directly related to the objective and scope of our evaluation. Furthermore, we evaluated the system of internal controls to the extent that they related to the objective and scope of the evaluation. We did not identify any internal control weaknesses. Instead, we identified an opportunity for the Minerals Management Service to increase oil and gas lease rental fee revenues. The evaluation was conducted in accordance with the "Quality Standards for Inspections," issued by the President's Council on Integrity and Efficiency. Accordingly, we included such tests of records and other evaluation procedures that were considered necessary to accomplish our stated objective.

PRIOR AUDIT COVERAGE

In our December 1993 audit report "Offshore Minerals Leasing Activities, Minerals Management Service" (No.94-I-179), we found that the Service charged rates for bonus bids of $25 per acre and for rental fees of $3 per acre, which were less than the $32.50 and the $5 per acre rates, respectively, recommended in its internal studies, even though the Outer Continental Shelf Lands Act, as amended, requires that the Government receive fair market value for leases.

Our prior report included a recommendation that the Service should establish a procedure which would require both the minimum bonus bid and the rental fee rates to be evaluated before each offshore oil and gas lease sale and require the rates to be increased, as appropriate, based on the evaluation. The Service concurred with the recommendation, stating that it believed that "periodic evaluation of the effects of minimum bids and rental rates on Government receipts as well as other leasing objectives is clearly in the public interest."

In our March 1998 evaluation report "Follow up of Offshore Minerals Leasing Activities, Minerals Management Service" (No. 98-I-385) we found that the Service had taken action to implement the recommendation made in our December 1993 audit report. As a result, we determined that the increased rental fees for offshore oil and gas leases issued from September 1993 to August 1997 had generated an estimated $141 million in additional Federal revenues between calendar years 1993 and 1997 and were expected to generate an additional $194 million for these same leases during the 4-year period of 1998 to 2001.

RESULTS OF EVALUATION

We found that the Minerals Management Service has an opportunity to increase rental fee revenues. Specifically, the Deep Water Royalty Relief Act allows for royalty payments to be suspended for up to 87.5 million barrels of oil equivalent' produced under offshore leases in deep water (considered by the Royalty Relief Act to be water depths of 200 meters or more) primarily in the central and western portions of the Gulf of Mexico. During the period when royalty payments are suspended, the Service's offshore oil and gas lease terminates rental fees. Thus, the Department of the Interior does not receive any revenues during the period when royalties are suspended for offshore leases, This is in contrast to the terms of onshore leases, which require payments to be equal to the higher of rental fees or royalties throughout the time period of the lease. Based on our review, we estimated that the Government has lost the potential to earn rental revenues of as much as $3.7 million associated with deep water leases issued prior to the Royalty Relief Act and has lost the potential to earn rental revenues ranging from $6.9 million to $75.9 million on oil and gas leases issued in 1996 and 1997, subsequent to the Royalty Relief Act. However, the Service has an opportunity to increase rental revenues by an estimated $2.4 million to $26 million for leases that will be issued between April 1, 1999, and December 3 1, 2000, by changing the terms of these leases before they are sold to require rental payments during periods of royalty relief.

The Deep Water Royalty Relief Act

In November 1995, the Outer Continental Shelf Lands Act was amended by Public Law 104-58, Title III (the Deep Water Royalty Relief Act). The amendment requires that new deep water leases in the central, western, and a small portion of the eastern Gulf of Mexico issued within 5 years of the date of the amendment be offered with a provision suspending royalties on a specified number of barrels of production, depending on water depth. In accordance with the Deep Water Royalty Relief Act, the minimum royalty suspension volumes are as follows:

- 17.5 million barrels of oil equivalent for leases in water depths of 200 to 400 meters.

- 52.5 million barrels of oil equivalent for leases in water depths of 400 to 800 meters.

'The Minerals Management Service defines "barrel of oil equivalent" as follows: "The amount of energy resource (m this document, natural gas) that is equal to one barrel of oil on an energy basis. The conversion is based on the assumption that a barrel of oil produces the same amount of energy when burned as 5,620 m^3 of natural gas."

- 87.5 million barrels of oil equivalent for leases in water depths of more than 800 meters.

The purposes of the Deep Water Royalty Relief Act were to (1) promote development or increase production on the Gulf of Mexico's Outer Continental Shelf or (2) encourage production ofmarginal resources on producing or nonproducing leases in deep water. While deep water leases issued before November 1995 are not automatically covered by the Act, royalty relief for production under these leases would be available if the lessee requested and the Secretary of the Interior determined that new production under these leases might not be economical in the absence of relief.

Current Lease Terms

The Code of Federal Regulations (43 CFR 3 103.2-2) states that rental payments for onshore oil and gas leases "shall not be due on acreage for which royalty or minimum royalty is being paid." (The Code defines "minimum royalty" as the equivalent of the yearly rental charges.) Thus, annual rental fees are required to be paid on onshore leases until royalties are paid in an amount that exceeds the annual rental fees. In contrast, the Service's offshore oil and gas lease form in use since at least 1986 states, with regard to rent, that "the Lessee shall pay the Lessor, on or before the first day of each lease year which commences prior to a discovery in paying quantities[2] of oil or gas on the leased area, a rental as shown on the face hereof." Consequently, rental fees are not paid once a leased tract begins to produce oil or gas. In addition, the offshore leases issued since the Royalty Relief Act automatically provide royalty relief for leases issued in oil fields previously approved by the Service as being eligible for royalty relief. Thus, eligible leases automatically provide relief from rental and royalty payments for up to 87.5 million barrels of oil, whereas onshore leases require the payment of rent until annual royalties exceed the annual rental due on a lease. A senior-level Service official stated that the Service was aware that the offshore lease prepared in response to the Royalty Relief Act would eliminate rent fees during periods of royalty relief.

Estimate of Impact on Rental Revenues

We estimated that the Government has lost the potential to earn rental revenues of as much as $3.7 million on deep water leases issued prior to the Royalty Relief Act and has lost the potential to earn revenues ranging from $6.9 million to $75.9 million for oil and gas leases issued in 1996 and 1997, which was subsequent to the Royalty Relief Act. However, the Service has an opportunity to increase rental revenues by an estimated $2.4 million to $26 million for leases that will be issued between April 1, 1999, and December 3 1, 2000, by changing the terms of these leases before they are sold to require rental payments during periods of royalty relief. The details regarding our approach to estimating these impacts are as follows:

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[2]"Paying quantities" is defined in the Code of Federal Regulations (30 CFR 250.111) as the "production of oil, gas, or both in quantities sufficient to yield a return in excess of the costs, after completion of the well, of producing the hydrocarbons at the wellhead."

Pre-Royalty Relief Act Leases. The Service told us that it expects 23 nonproducing deep water oil and gas leases issued prior to the Royalty Relief Act to be producing by 2002 and that royalties for these leases could be suspended under the Act if the lessees request and the Secretary approves the requests. If all 23 lessees were approved for royalty relief, we estimated that the Service has lost the potential to earn as much as $3.7 million in rental fee revenues because the Department's offshore leases do not require rental fees during periods of royalty relief. The revenues of $3.7 million were calculated as follows: 23 leases multiplied by 5,380 acres (average lease size) multiplied by $7.50 per acre rental fee multiplied by 4 **years.**[3] However, we recognize that it is possible that none of these leases will be approved for royalty relief and, in that case, no rental revenues would be lost.

Post-Royalty Relief Act Leases. Because of the large number of leases covered by the Deep Water Royalty Relief Act and the increase in the per acre rental charge from $3.00 to **$7.50,** the loss of rental fees paid to the Department could be significant for leases issued after the Royalty Relief Act. We estimated that the Service has lost the potential to earn revenues ranging from $6.9 million to $75.9 million. To derive this estimate, we requested that the Service determine the number and percentage of existing deep water leases issued after the Royalty Relief Act which were producing and the number and percentage of nonproducing leases it expected to produce in the future. We also requested an estimate of the average time expected for an oil and gas well to attain production that exceeded the suspension volumes included in **the** Act.

In its response to our requests, the Service stated that as of June 1998, 2 to 5 percent of the leases in deep water were producing. It further stated that there were no leases producing in water depths exceeding 400 meters. In addition, we found that the most current issue of the Minerals Management Service's publication "Offshore Stats" for the third and fourth quarters of 1997 stated that about 22 percent of existing offshore leases were producing. Although most of these producing leases were in water depths of 200 meters or less, we noted that the oil and gas industry experts were reporting that improvements in offshore exploration and drilling technologies had greatly lowered the costs to produce oil and gas in water depths of more than 200 meters and that the prospect of increased production for leases in this area was higher than in the past. Also, the Department of Energy, which maintains statistics on energy production and consumption, reported that because of the lower costs, oil and gas production in deep water was increasing.

During our evaluation, Service officials said that they recognized that their experience with production in water exceeding 200 meters was limited and that deep water oil and gas production costs were declining. They suggested that a reasonable estimate of the potential increased rental revenues be based on a production rate ranging from 2 to 22 percent of the 2,138 leases entered into since the effective date of the Act. Service officials estimated that it would take almost 4 years for a tract to produce oil or gas above the royalty suspension volumes. The estimate of lost revenues of $6.9 million was calculated by multiplying 43

[3]This is the average period of time that the Service estimated it would take for a lessee to reach the royalty suspension volume and to begin paying royalties.

leases (2 percent of 2,138 leases) by 5,380 acres (average lease size) multiplied by the $7.50 per acre rental fee multiplied by the 4-year average period of suspended royalties. The estimate of lost revenues of $75.9 million was calculated by multiplying 470 leases (22 percent of 2,138 leases) by 5,380 acres (average lease size) multiplied by the $7.50 per acre rental fee multiplied by the 4-year average period of suspended royalties.

In addition to these leases, the Service advised us that it anticipates deep water lease sales of 3.9 million acres between April 1, 1999, and December 3 1, 2000, when the Royalty Relief Act is due to expire. By revising the lease terms to require annual rental fee payments during periods of royalty suspension, we believe that the Service has the potential to earn revenues estimated at between $2.4 million and $26 million from these leases. This estimate was calculated by multiplying .08 million acres (2 percent of 3.9 million acres) and .86 million acres (22 percent of 3.9 million acres) by the $7.50 per acre rental fee multiplied by the 4-year average period of suspended royalties.

We believe that the Service, to realize those potential rental revenues, should revise its oil and gas leases before the sales are executed to continue annual rental fee payments during periods of royalty suspension. In that regard, our General Counsel, in a November 20, 1998, memorandum, noted that the United States Code (43 U.S.C. 1337(b)(6)) states that oil and gas leases "shall contain such rental and other provisions as the Secretary may prescribe at the time of offering the area for lease." Also, the General Counsel stated that the Service should determine whether it has the authority to revise existing leases to require such payments before the lessees are granted royalty relief to preclude new lessees from paying rental fees while existing lessees are not required to pay royalties or rental fees.

Recommendations

We recommend that the Director, Minerals Management Service:

1. Ensure that offshore oil and gas leases which will be issued in the future under the provisions of the Deep Water Royalty Relief Act of 1995 require that annual rental fee payments continue during royalty suspension periods until royalty payments meet or exceed the annual rental fees for leased tracts covered by the Act.

2. Request a Solicitor's opinion as to whether the Service has authority to modify terms of existing leases to require rental payments of lessees during royalty suspension periods. If this authority does not exist, the Service should request a Solicitor's opinion as to whether legislation can be sought to remedy this situation.

Minerals Management Service Response and Office of Inspector General Reply

In the October 7, 1999, response (Appendix 2) to our draft report from the Director, Minerals Management Service, the Service nonconcurred with both recommendations but stated that it would consider the report's recommendations as it begins discussions of whether the financial terms for deep water leases should be changed for future lease sales. Based on the response, we have revised the recommendations to clarify our intent. However, we consider the Service's comments to be partially responsive to both recommendations (see Appendix 3).

Recommendation 1. Nonconcurrence

In commenting on the report, the Service said that Recommendation 1 applied to future leases issued under the provisions of the Royalty Relief Act; however, it questioned whether the recommendation applied to leases which existed prior to the Act. We revised the recommendation to clarify that it applied only to future leases. The Service also stated that the Assistant Secretary for Land and Minerals Management had issued a notice in the *Federal Register* and hosted a workshop in June 1998 to begin discussions of whether the financial terms for deep water leases should be changed for future lease sales and that it would consider the report's recommendations during its review.

Recommendation 2. Nonconcurrence

The Service said that Recommendation 2 applied to leases which were issued prior to and after the Royalty Relief Act, stating that it could not "unilaterally change" leases already issued, that a number of leases were already producing and were not eligible for royalty relief, and that lessees who hold leases issued after the Royalty Relief Act do not require that the Service approve royalty relief. The Service said that it therefore had "no leverage on which to rely in negotiating changes to lease terms."

Based on these comments, we have revised Recommendation 2 to clarify that the Service should seek a Solicitor's opinion regarding whether there is authority for the Service to modify lease terms to require rental payments of lessees during royalty suspension periods and, if such authority is lacking, whether legislation can be sought to remedy this situation.

Additional Comments on Report

The Service also made other comments regarding our recommendations and our estimates ofpotential increased revenues. The Service's comments and our replies to these comments are in the paragraphs that follow.

The Service commented that the statement in our August 1997 draft report that Service officials "generally concurred" with the report's recommendations during our June 2, 1998, exit conference is "incorrect." We included this statement based on the Service's comments at the exit conference that it agreed with the report's conclusions that under the terms of the Service's offshore oil and gas leases, the Department would not receive rental revenues during periods of royalty relief and that it would pursue implementing our recommendations. However, the Service advised us that implementation may be difficult since the July 8, 1998, Department of the Interior appropriations bill for fiscal year 1999 (H.R. 105609) included a statement that restricted it from making changes to the financial terms of the oil and gas leases. Specifically, the appropriations bill stated the following:

> It has come to the attention of the Committee [on Appropriations] that MMS [Minerals Management Service] is proposing a public workshop to look at whether modifications to deep water leases are warranted. The Committee expects that existing financial terms for these lease sales will be maintained until this workshop is completed, public comments fully analyzed, and a report provided to the House and Senate Committees on Appropriations.

While this language restricts the Service from making changes to the financial terms of the leases until certain actions are completed, it does not prohibit the Service from making such changes. Also, the Service stated that it would pursue implementation of the report's recommendations, which we interpreted to mean that the Service "generally concurred" with the intent of the recommendations.

The Service stated that increasing rental fees could reduce offshore oil and gas lease sales and revenues from bonus bids on these leases. In response to a recommendation in our December 1993 audit report "Offshore Minerals Leasing Activities, Minerals Management Service," the Service also commented that lease sales and revenues from bonus bids would decline. However, our March 1998 evaluation report "Followup of Offshore Minerals Leasing Activities, Minerals Management Service" noted that the Service increased the rental rates on offshore oil and gas leases from $3 per acre to $7.50 per acre and realized increased rental revenues of $141 million between September 1993 and August 1997, with expected additional rental revenues of $194 million between fiscal years 1998 and 2001. Also, the minimum bid rates did not decline after the rental rate was increased to $7.50 per acre but remained at $25 per acre, which is the same rate that had been in effect for more than 50 years.

The Service stated that our report had "overestimate[d]" the $6.9 million to $75.9 million on deep water leases because it could not "unilaterally change" leases which it had issued and that companies had bid on leases with the understanding that they would not have to pay rent during a period of royalty relief. The estimated range was suggested by a senior-level Service official after our exit conference on a preliminary draft of this report. However, based on the Service's comments to the draft report, we have revised the final report to recognize the range of $6.9 million to $75.9 million as an estimate of rental revenues that the Service has lost the potential to earn because of its offshore lease provisions instead of classifying these amounts as potential additional revenues.

The Service commented that only 23 of 112 deep water leases existing prior to the Royalty Relief Act were eligible to request royalty relief and that the remaining 89 leases were producing in paying quantities and thus ineligible for royalty relief. However, the Code of Federal Regulations (30 CFR 203.1) states that the Service is authorized to grant royalty relief in three situations, including granting relief for a producing lease proposing to "significantly expand production under a Development Operations Coordination Document

. . . or a supplementary ... [Document], that Minerals Management Service approved after November 28, 1995." Thus, under these circumstances, the 89 producing leases could request and be eligible for royalty relief. Notwithstanding this provision, we have revised the estimate for theses leases fi-om $18 million to an estimate of as much as $3.7 million.

In accordance with the Departmental Manual (360 DM 5.3), we are requesting a written response to this report by April 30, 1999. The response should provide the information requested in Appendix 3.

The legislation, as amended, creating the Office of Inspector General requires semiannual reporting to the Congress on all audit reports issued, the monetary impact of audit findings (Appendix 1), actions taken to implement audit recommendations, and identification of each significant recommendation on which corrective action has not been taken.

We appreciate the assistance of Office of the Secretary and Bureau personnel in the conduct of our evaluation.

APPENDIX 1

CLASSIFICATION OF MONETARY AMOUNTS

Finding Area	Potential Additional Revenues
Opportunity to increase rental revenues for leases to be issued between April 1, 1999, and December 31, 2000	$2.4 million to $26 million

United States Department of the Interior

MINERALS MANAGEMENT SERVICE
Washington, DC 20240

OCT -7 1998

Memorandum

To: Assistant Inspector General for Audits

Through: For Bob Armstrong Piet deWitt OCT - 9 1998
Assistant Secretary, Land and Minerals Management

From: Cynthia Quarter-man C Quarterman
Director, Minerals Management Service

Subject: Evaluation Report on Opportunity to Increase Offshore Oil and Gas Rental Revenues, Minerals Management Service (Assignment No. I-IN-MMS-002-98A(D))

We appreciate the opportunity to comment on the Office of Inspector General draft evaluation report. Before commenting directly on its recommendations, we would like to note two factual errors contained in the report.

First, the report's statement that Minerals Management Service officials generally concurred with the report's recommendations at a June 2, 1998, exit conference is incorrect. MMS officials did not concur in the recommendations. Rather, they indicated that language in the Conference Report for the Department of the Interior's Fiscal Year 1998 supplemental appropriations restricted MMS from making regulatory changes to the terms of the current Deep Water Royalty Relief Program. MMS officials said they would *consider* implementation of the OIG recommendations when appropriate and if permitted by congressional direction.

Second, the report overestimates the revenues associated with the recommendations. The report estimates additional rental revenues of $6.9 to $75.9 million on deep water leases issued in 1996 and 1997. However, the Government has no legal authority to unilaterally change lease terms on existing leases, so no additional revenues are possible on these-leases. The report also projects that rental fees of $18 million will be lost if the Department of the Interior approves relief for 112 deep water leases issued prior to the Deep Water Royalty Relief Act and does not continue rental payments during the relief period. Currently, 89 of those leases are producing and, consequently, are not eligible for royalty relief. Also, it is possible that none of the remaining 23 leases will apply for or be granted royalty relief. Therefore, the report should indicate that potential rental fees from these leases could range from zero to $3.7 million.

Comments on Recommendations

- Ensure that offshore oil and gas lease terms require that annual rental payments continue during royalty suspension periods until royalty payments meet or exceed the annual rental fee for leased tracts covered by the Deep Water Royalty Relief Act.

DISAGREE -- There are two types of leases to which this recommendation applies:

- leases issued since November 1995 subject to the royalty suspension provisions of the DWRRA, and

- leases that will be issued in the future under the provisions of the DWRRA.

With respect to the former, we have no legal authority to unilaterally change lease terms on existing leases. Therefore, this recommendation cannot be implemented for this category of leases. Further discussion of existing leases appears in our response to the second recommendation below.

With respect to the latter category, the implementation of the DWRRA was developed through comprehensive public and internal processes that considered legislative intent and input from constituents and many parts of the Administration. We believe that the financial terms for deep water leases should not be changed for future lease sales held under the DWRRA without a similar, careful review. MMS has already started such a review. The Assistant Secretary, Land and Minerals Management, issued a *Federal Register* Notice and hosted a workshop in June 1998 to begin discussions of whether the financial terms for deep water leases should be changed for future lease sales. We will consider the report's recommendations concerning rentals as we proceed with this process.

- Revise existing offshore oil and gas leases prior to granting the lessees royalty relief to require the payment of rental fees during periods of royalty suspension. Legislation should be sought to implement this recommendation if necessary.

DISAGREE - The type of leases to which this recommendation is intended to apply is unclear. However, there are two categories of deep water leases that it may seek to address:

- leases issued after November 1995 that have not yet gone into production, and

- non-producing leases issued prior to 1995 that apply for royalty relief on the basis that the proposed production project would be uneconomic at the lease stipulated royalty rate.

With respect to the first category of leases, it should be noted that MMS does not "grant" royalty relief to them. In accordance with the DWRRA provisions, the royalty suspension volume is incorporated into the lease terms. Lessees do not apply for nor does MMS approve the royalty relief; therefore, it has no leverage on which to rely in negotiating changes to lease terms.

In any case, MMS opposes this recommendation because its implementation would violate the integrity of the bonus bid auction system. That is, MMS sold these leases under specific terms known to all bidders and received cash bonuses in return based on the bidders' evaluation of the tracts offered with those terms. Had bidders known that rents would be charged during the suspension period, they would have submitted lower bids and fewer tracts would have been sold.

Attempts by MMS or Congress to revise existing lease terms would raise serious potential breach of contract issues and the possibility of extensive litigation. Furthermore, if we were to seek retroactively to change the terms of existing leases, we believe that potential bidders would be more likely to bid less and on fewer leases at future sales, more than offsetting any additional rental revenues that might be collected.

Consequently, we believe that retroactive changes in terms of existing leases are counter-productive if not illegal, but as stated under the first recommendation, we will continue to evaluate prospective changes to lease terms for future lease sales.

In the case of the second category of leases, Congress intended to provide economic incentives to encourage owners of marginal properties to undertake development and production activities that would not be profitable at lease royalty rates. MMS has written guidelines in accord with Congress' purpose, which permit it to determine financial terms on any non-producing lease granted royalty relief. That determination is made as appropriate on a case-by-case basis.

The provisions of the current program mandated by the DWRRA will sunset in November 2000. MMS already has begun an effort to design a follow-on program. In this process, we will carefully consider the rental issues raised in this report. We believe that these issues can best be dealt with in a comprehensive fashion rather than trying to impose new rental terms on existing contractual and financial arrangements.

Again, thank you for the opportunity to provide comments on the report.

STATUS OF EVALUATION REPORT RECOMMENDATIONS

Finding/ Recommendation Reference	Status	Action Required
1 and 2	Unresolved.	Provide responses to the revised recommendations stating concurrence or nonconcurrence. If concurrence is indicated, provide action plans that include target dates and titles of the officials responsible for implementation. If nonconcurrence is indicated, provide reasons for the nonconcurrence.

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BY THE COMPTROLLER GENERAL

Report To The Chairman, Committee On Energy And Natural Resources United States Senate

OF THE UNITED STATES

Selectively Reducing Offshore Royalty Rates In The Gulf Of Mexico Could Increase Oil Production And Federal Government Revenue

The U.S. government leases large areas in the Outer Continental Shelf in the Gulf of Mexico for the development of oil resources and receives royalties on the oil produced. Conventional methods of oil recovery have recovered or are expected to recover about half of the 16 billion barrels of oil discovered in this area. Other oil recovery methods, collectively known as enhanced oil recovery (EOR), could potentially increase production by about 1 billion barrels of oil.

EOR in the Gulf is expensive and does not appear to be economically justified in most cases. Under existing economic conditions and federal policies, GAO's review indicates that utilizing EOR methods will probably produce only about 10 percent of the additional recoverable oil. However, financial incentives in the form of royalty reductions could increase both oil production and federal government revenue if applied on a project-by-project basis. Universal applications of royalty reduction for EOR, however, while achieving increased oil production, would not increase federal government revenue.

GAO recommends that the Department of the Interior's Minerals Management Service initiate action that would allow for selective royalty reductions for EOR projects in the Gulf in instances where both total oil production and federal government revenue will increase.

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WASHINGTON D.C. 20548

B-214429

The Honorable James A. McClure
Chairman, Committee on Energy
and Natural Resources
United States Senate

Dear Mr. Chairman:

As requested by Senator Lowell P. Weicker, Jr., former Chairman, Subcommittee on Energy Conservation and Supply, Senate Committee on Energy and Natural Resources, we examined steps the federal government could take to encourage environmentally sound enhanced oil recovery (EOR) in the Outer Continental Shelf in the Gulf of Mexico. However, because of recent changes to Subcommittee and Committee jurisdictions, and as arranged with the legal counsel for your Committee, we are addressing our report to you. This report responds to Senator Weicker's request and analyzes how royalty reductions could be used to encourage industry to initiate EOR in the Gulf. By initiating action to reduce royalties in certain instances, both domestic production and federal government revenue could be increased.

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As arranged with your office, the distribution of the report will be restricted for a period of 7 days, unless released by the Committee. After this time, we will send copies to appropriate House and Senate committees; the Departments of the Interior, Energy, and Treasury; and other interested parties. We will also make copies available to others upon request.

Sincerely yours,

Charles A. Bowsher

Comptroller General
of the United States

COMPTROLLER GENERAL'S REPORT TO THE COMMITTEE ON ENERGY AND NATURAL RESOURCES UNITED STATES SENATE

SELECTIVELY REDUCING OFFSHORE ROYALTY RATES IN THE GULF OF MEXICO COULD INCREASE OIL PRODUCTION AND FEDERAL GOVERNMENT REVENUE

D I G E S T

The U.S. government leases large areas in the Outer Continental Shelf (OCS) in the Gulf of Mexico for the development of oil resources. As part of the lease agreements, the federal government receives royalties on each barrel of oil produced.

According to the Department of the Interior's Mineral Management Service (MMS), conventional methods of oil recovery (using natural reservoir[1] pressure and/or injected water to displace oil trapped underground) have recovered or will recover about half of the estimated 16 billion barrels of oil discovered in the OCS.

Other oil recovery methods, collectively known as enhanced oil recovery (EOR), could produce approximately an additional 1 billion barrels. (This additional recoverable oil is shown in the figure on page ii.) EOR uses heat, chemicals, or gases to help displace the oil underground and make it flow more easily.

EOR methods in the OCS are expensive, however, and undertaking EOR production does not now appear to be economically justified in most cases. Unless the economic feasibility of these methods changes, many oil fields in the OCS may not produce this additional recoverable oil.

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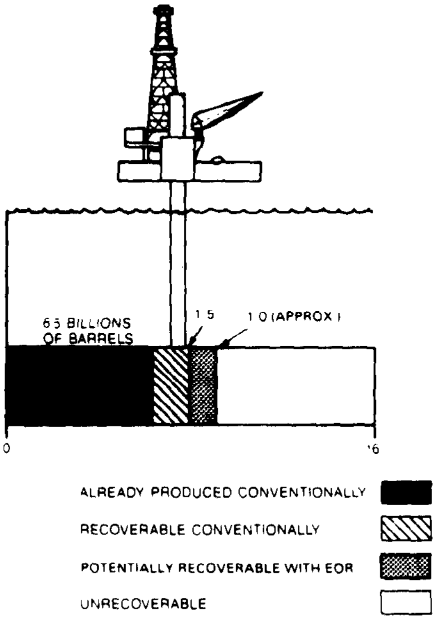
[1]A reservoir is an underground formation consisting of porous rock containing oil and is sealed by other layers of surrounding rock. In this report it refers to an individual, sealed formation containing oil.

FIGURE 1
OIL PRODUCTION IN THE GULF OF MEXICO

(BILLION BARRELS)



Many reservoirs amenable to EOR methods lie in areas that have been producing since the late 1950's, and conventional production may soon cease. Federal regulations require that oil production platforms be removed within 1 year after production stops. If this occurs before EOR production is started, Minerals Management Service and industry officials agree that it would not be economically feasible to replace the platform for the recovery of EOR oil. In addition, physical reservoir conditions may make EOR projects less attractive later if conventional production has ceased and oil is no longer moving freely.

WHY THE REVIEW WAS MADE

The former Chairman of the Subcommittee on Energy Conservation and Supply, Senate Committee on Energy and Natural Resources, requested that GAO examine steps the federal government could take to encourage environmentally sound EOR in the OCS in the Gulf of Mexico. In accordance with this request, and as further agreed with the Committee's office, GAO addressed the following issues:

--The likelihood that oil production platforms on sites suitable for potential EOR on federally leased areas[2] in the OCS in the Gulf of Mexico will be abandoned by the year 2000.

--The impact of platform abandonment on potential EOR production until the year 2000.

--Whether the federal government could provide financial incentives for EOR that would improve production.

--The associated impact of incentives on federal government revenue.

--The environmental implications of increased offshore EOR.

SCOPE AND METHODOLOGY

To analyze these issues, GAO obtained data from a study entitled Enhanced Oil Recovery in the Gulf of Mexico (Jan. 1983), prepared for the Department of Energy (DOE) by the consulting firm Lewin and Associates, Inc. According to government and industry officials, these data are the most up-to-date, detailed information available on both platform abandonment and EOR production in the OCS of the Gulf of Mexico. The Lewin study, using various assumptions on oil prices and technology, analyzed reservoirs containing about 20 percent of the oil discovered in the OCS.

GAO adjusted the crude oil price assumptions used in the Lewin study downward to reflect more recent projections, used three technology assumptions, and derived new platform abandonment and EOR production estimates. GAO then (1) extrapolated these results to the entire OCS in the Gulf, (2) evaluated the influence of federal incentives, and (3) estimated the potential federal government revenue from EOR production with and without incentives. GAO also reviewed current government and industry practices with regard to EOR, and assessed information pertaining to the environmental implications of EOR.

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[2]A lease authorizes the exploration, development, and production of minerals within a given area (up to 5,760 acres). Usually, several oil production projects are ongoing under a given lease.

WHAT GAO FOUND

Platform abandonment by the year 2000 and its impact on production and federal revenue

According to GAO's analysis, about 60 to 75 percent of existing platforms on sites suitable for EOR are likely to be abandoned and removed by 2000, depending on future oil prices and the development of EOR technology. If this occurs, GAO estimates that only about 100 million barrels (MMB), or about 10 percent of the recoverable EOR oil, is likely to be produced. This would leave at least 870 MMB of technically recoverable oil in the ground and associated federal royalties uncollected.

Across-the-board incentives could increase production, but reduce federal revenue

GAO evaluated how financial incentives ranging from \$1 to \$5 per barrel, applied to all EOR projects, would affect EOR production and federal government revenue. Incentives ranging from \$1 to \$4 per barrel increased cumulative production most when considered for both moderate and high oil price assumptions. Production with these incentives ranged from about 55 MMB to 725 MMB of oil depending on oil prices and technology development. A \$5 incentive increased production only slightly above a \$4 incentive and was, therefore, less effective per dollar. Across-the-board incentives to all EOR projects did not, however, appear to be cost-effective. Although these incentives could increase oil production, some EOR projects will be profitable and are likely to be initiated without an incentive. As a result, the federal government would forego revenue for each barrel produced by these projects. (See pp. 11 to 16.)

Incentives on a project-by-project basis could increase both EOR production and federal government revenue

On the other hand, project-by-project royalty reductions by the Minerals Management Service could increase both production and federal government revenue. In this type of program, royalty reductions would be granted only for those projects where it would otherwise not be profitable to produce EOR oil. Allowing a reduction only on additional oil gives the federal government a financial share in the increased production that otherwise would not have occurred. The amount of additional EOR oil and the associated government revenue from such a program cannot be predicted with certainty because negotiations between industry and the federal government would be necessary in order to agree on the projects that qualify and the size of the royalty reduction needed. (See pp. 19 to 24.)

According to both the Minerals Management Service and industry representatives, agreement can generally be reached on the amount of oil remaining to be produced by conventional methods in Gulf reservoirs because a long history of oil production is available to both parties. They therefore believe that it is possible to estimate the amount of EOR oil that could be produced and the incentive needed to offset additional EOR production costs. Although GAO did not perform an analysis of the resources needed to carry out such a program, according to Minerals Management Service officials, the administration of project-by-project royalty reductions could probably be handled through its ongoing operations. (See pp. 19 to 24.)

The principle of reducing government revenue to encourage increased production when project economics dictate is not new. Louisiana recently authorized severance tax reductions on incremental EOR oil[3] on a project-by-project basis. Officials involved in that process are confident that their state agencies can administratively apply severance tax reductions on a project-by-project basis. (See p. 22.)

In addition, GAO has previously recommended the selective use of different royalty rates to maximize oil production and/or government revenue.[4] (See p. 22.)

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[3]Incremental oil is the amount above what would have been produced with conventional production had it continued until the economic limit of the reservoir was reached.

[4]Interior Should Continue Use of Higher Rates for Offshore Oil and Gas Leases (RCED-83-30, Dec. 20, 1982).

Authority to reduce royalties exists but has not been used

Royalty reductions are authorized by federal law and regulation. Minerals Management Service officials told GAO that companies can apply for reduced royalties when they undertake new methods or add to existing ones. However, GAO's review of the royalty reduction regulations revealed no specific guidance describing how or when companies could apply for reduced royalties to offset increased EOR cost. (See pp. 19 and 23 to 24.)

GAO questioned oil industry representatives on why there had been no applications for reduced royalties in the Gulf. Although responses varied, most centered on how industry officials perceived that the Minerals Management Service would evaluate a royalty reduction request. Oil industry representatives believed that reduced royalties would have to be evaluated on a project-by-project basis to be practical. But, since the Minerals Management Service generally establishes royalties based on an entire lease area, oil representatives were doubtful that the Service would reduce royalties on an individual EOR project basis, particularly if other oil production on the lease is still profitable. (See pp. 23 to 24.)

Potential environmental implications appear to be minimal

EOR tends to extend and expand environmental impacts associated with conventional oil recovery. On the basis of limited offshore and more extensive onshore experience to date, expanded EOR production is not expected to introduce major environmental impacts.

Industry consensus indicates that carbon dioxide has the greatest growth potential for EOR in the OCS in the Gulf. Carbon dioxide is a relatively benign substance, and the environmental experts GAO spoke with agreed that it is not expected to affect the Gulf environment adversely.

Existing environmental laws apply to EOR in the OCS. Minerals Management Service and Environmental Protection Agency officials believe these laws are adequate to deal with environmental problems that might occur on any specific project. These agencies have jurisdiction over the OCS in the Gulf and review exploration/development plans and inspect oil production platforms annually. (See pp. 25 to 27.)

RECOMMENDATION TO THE SECRETARY OF THE INTERIOR

GAO recommends that the Secretary of the Interior have the Director of the Minerals Management Service initiate action that would allow for royalty reductions on EOR projects in the OCS in the Gulf of Mexico where it would result in both increased production and increased federal government revenue. In doing this, the Director should establish guidelines that

--facilitate industry preparation of royalty reduction proposals and government evaluation of these applications;

--permit timely evaluation of royalty reduction proposals (i.e., early enough in the productive life of a well or reservoir to permit industry to implement EOR effectively, but late enough for the federal government to have sufficient data to evaluate the need for royalty reduction, usually during the last few years of conventional production); and

--allow royalty reductions on a project-by-project basis while maintaining the existing royalty for the remainder of the lease area.

AGENCY COMMENTS

The Departments of Energy and the Interior commented on a draft of this report; their comments are included in appendix I. DOE pointed out that GAO had taken a conservative approach in estimating the recoverable oil using EOR methods. The potential, according to DOE, may well be greater than that calculated by GAO if reservoirs that are known, but currently undeveloped, are included in the area from which GAO's estimates are derived. However, DOE agreed, in general, with the report and noted that maximum recovery of this country's petroleum resources is in the national interest--a goal that can be furthered by GAO's recommendation.

Unlike DOE, Interior noted that GAO's estimates of EOR potential may be optimistic. However, Interior, although noting a number of concerns, commented that GAO's recommendation is of sufficient importance to merit consideration. Furthermore, Interior agreed that its regulations now in effect may need refinement and clarifying guidelines and that these are now under study. Although both Departments expressed concerns about the administrative process involved with a royalty reduction program, they agreed that such a program could provide an opportunity to produce oil that might otherwise remain in the ground. (See pp. 29 to 34.)

Contents

ILLUSTRATIONS

ABBREVIATIONS

B/D	barrels per day
CFR	Code of Federal Regulations
DOE	Department of Energy
EIS	environmental impact statement
EOR	enhanced oil recovery
EPA	Environmental Protection Agency
ERA	Economic Regulatory Administration
MMB	million barrels
MMS	Minerals Management Service
OCS	Outer Continental Shelf

GLOSSARY

Advanced technology	Assumes that an injectant moves through a reservoir at the rate of a unit of carbon dioxide followed by a less costly, less dense gas.
Base technology	Assumes that an injectant moves through a reservoir at the rate at which carbon dioxide displaces a mixture of carbon dioxide and crude oil.
Conservative technology	Assumes that an injectant moves through a reservoir at (1) either the rate at which carbon dioxide displaces water or (2) the rate at which carbon dioxide displaces crude oil, whichever is slower. This technology recovers as much oil as base technology but at a slower pace and at greater cost.
Conventional oil recovery	Oil production using natural reservoir pressure (primary recovery) and/or injected water (secondary recovery).
Economically recoverable	The amount of oil that will be produced with current oil prices and production costs.
Economic limit	The end point of profitable oil production from a given reservoir.
Enhanced Oil Recovery	Enhanced oil recovery, sometimes called "tertiary recovery," involves the use of heat, chemicals, or gases to thin oil, increase oil volume, decrease the pressure holding the oil in reservoir rock, and/or help it flow more easily. This generally increases the amount of oil recovered.
Severance tax	A tax on the recovery and use of potential resources imposed at the time the resource is extracted from the earth.
Technically recoverable	The amount of oil that is recoverable from a given reservoir when cost is not a factor.

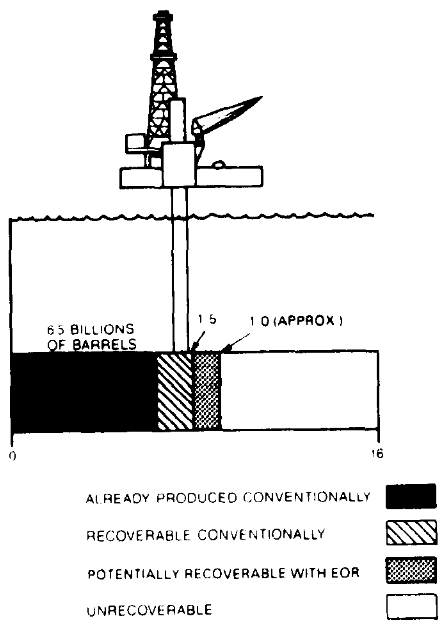
CHAPTER 1

INTRODUCTION

The U.S. government has leased large areas in the Outer Continental Shelf (OCS) in the Gulf of Mexico for the development of oil resources. As part of the lease agreements, the federal government receives royalties on oil production. The federal government is also concerned with this production as an important domestic energy resource. To date about 16 billion barrels of oil have been discovered. About half of this oil has been or can be produced by conventional oil recovery methods--those using natural reservoir[1] pressure and injected water. Of these 8 billion barrels, about 6.5 billion have already been produced.

About 8 billion barrels will be left after conventional production. Other methods, collectively called enhanced oil recovery (EOR), work by injecting heat, chemicals or gases into an oil reservoir to help the oil flow more easily. These methods using known technology or technology under development could recover an additional estimated 970 million barrels (MMB) to 1.2 billion barrels of the remaining oil. Figure 1 shows the oil that can be produced with conventional methods and the estimated contribution from EOR.

FIGURE 1
OIL PRODUCTION IN THE GULF OF MEXICO
(BILLION BARRELS)



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[1]A reservoir is an underground formation consisting of porous rock containing oil and is sealed by other layers of surrounding rock. In this report, it refers to an individual, sealed formation containing oil.

Conditions in the OCS in the Gulf of Mexico are such that many of the reservoirs amenable to EOR methods lie in areas that have been producing since the late 1950's and may soon be abandoned. EOR methods are expensive, and undertaking EOR production does not now appear to be economically justified in most cases.

OBJECTIVES AND METHODOLOGY

The former Chairman, Subcommittee on Energy Conservation and Supply, Senate Committee on Energy and Natural Resources, requested that we examine steps the federal government could take to encourage environmentally sound EOR in the OCS in the Gulf of Mexico. However, because of recent changes to subcommittee jurisdiction, we have addressed the report to the Chairman, Senate Committee on Energy and Natural Resources. Pursuant to the request, and as further agreed with the Subcommittee's office, we addressed five specific issues:

--The likelihood that production platforms on sites suitable for potential EOR on federal leases in the OCS of the Gulf of Mexico would be abandoned by the year 2000.

--The impact of platform abandonment on potential production until the year 2000.

--Whether the federal government could provide financial incentives for EOR that would improve production.

--The associated impact of incentives on government revenue.

--The environmental implications of increased offshore EOR.

To analyze these issues, we obtained data from a study entitled Enhanced Oil Recovery in the Gulf of Mexico (DOE/ET/14010-1, Jan. 1983) prepared for the Department of Energy (DOE) by the consulting firm Lewin and Associates, Inc. We used these data because government and industry officials said that they were the most up-to-date, detailed information available on both platform abandonment and EOR production in the Gulf of Mexico. We adjusted crude oil price data downward to reflect more recent projections and derive new platform abandonment and EOR production estimates, extrapolated these results to the entire OCS in the Gulf, evaluated the influence of federal incentives on production, and estimated the potential federal government revenue from EOR production with and without incentives.

The Lewin study focused on reservoirs on federal OCS leases in the Gulf and contained detailed data on a sample of 176 reservoirs. The sample reservoirs originally contained 3.28 billion barrels, or about 20 percent of the oil discovered in the federally owned portion of the Gulf. About 51 percent of the oil in sampled reservoirs was projected by Lewin to be recovered by conventional methods, leaving 1.6 billion barrels as a potential target for EOR.

The study estimated oil production and reservoir conditions using conventional recovery for the 176 reservoirs. Conventional oil recovery continued until it was projected to be no longer profitable, at which point these individual reservoirs would either be abandoned or become targets for EOR. When all reservoirs being produced by a platform were abandoned, the platform was also projected to be abandoned.

Technical analysis for each reservoir was then made under conservative, base, and advanced technology assumptions to determine the amount of oil recoverable with EOR. Base technology represents the Lewin study's "best guess" because it most closely reflects current EOR technology expectations. The other two cases represent either more conservative or optimistic assumptions about technology and for the availability of more effective and less expensive means. This analysis found that between 240 million and 300 million barrels (15 to 19 percent of the 1.6 billion barrels) remaining after conventional recovery in sample reservoirs could be produced depending on EOR technology. Carbon dioxide flooding[2] is considered by industry to be the most likely technology choice for offshore EOR. This is because the economic feasibility and technical application of EOR methods favor carbon dioxide as having the greatest growth potential for offshore EOR in the Gulf of Mexico.

DOE noted in its comments that the state of knowledge about EOR and offshore recovery costs may have changed since the Lewin study. However, only a limited number of new EOR projects have been initiated in the Gulf of Mexico over the last few years. Given this limited experience to date offshore, it is too early to determine if the state of knowledge has changed sufficiently to improve the economic feasibility of EOR. Several large-scale carbon dioxide projects are underway onshore, however, and the experienced gained should improve the understanding of this EOR method.

Offshore recovery cost has declined over the past couple of years as lower prices reduced the demand for production-related equipment and drilling services. While declining production costs tend to improve the economic feasibility of EOR projects, declining oil prices reduced revenue to more than offset this cost reduction. Therefore, EOR methods in the Gulf may be somewhat less economically feasible due to declining oil prices.

An economic analysis was made in the study using a discounted cash-flow model to estimate the required oil price needed to initiate a given EOR project. This price was compared with the estimated imported crude oil price in the year the platform was

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[2]Carbon dioxide is an incombustible gas which, under the right conditions, mixes with oil and facilitates its displacement from a reservoir.

projected to be abandoned to determine which EOR projects would be economically feasible. In cases where the oil price was too low for profitable production, the study projected that the platform would be abandoned. The Lewin study found that because many EOR projects were not economically feasible many platforms could be abandoned by the year 2000. This would reduce the potential for EOR production because the cost of replacing the platforms would be prohibitive.

The data generated in the Lewin study from the sample of reservoirs was reviewed by the Department of the Interior, which did its own technical analysis of selected reservoirs. Interior's review analyzed a subset of the data and confirmed the overall study results. Further, industry officials believed that the basis for the Lewin analysis was sound.

Adjustments to the Lewin study

We adjusted the Lewin study's assumption of imported crude oil prices downward to reflect changed market conditions and more recent estimates made by Data Resources Incorporated.[3] Reducing this price projection led to new results for projected platform abandonment and production. We then used the revised production projections to estimate government revenue collected through royalties.[4] Because offshore royalty rates generally constitute 16 2/3 percent of each barrel of oil produced, we used about $5 (per $30 barrel of oil) as the revenue collected by the federal government. These calculations establish a reasonable projection of platform abandonment, oil production, and federal government revenue over the next 10 to 15 years, given no changes in federal government policy.

In agency comments, both DOE and Interior noted that recently declining oil prices may further influence the economic feasibility of EOR methods. Overall, if oil prices continue downward or remain low, fewer EOR projects will be initiated. In effect, this will also make incentives such as royalty reductions less

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[3]Data Resources Incorporated is an econometric modelling firm with up-to-date energy data and projections.

[4]Although oil companies pay windfall profit and corporate income taxes, we calculated only royalty revenue. No windfall profit tax on oil from enhanced methods is expected to be collected after about mid-1986. In effect, inflation adjustments to the base price of enhanced oil, stipulated by legislation, are projected to increase its price to the current selling price of oil. Consequently there will be no "windfall profit" to tax (i.e., the difference between the selling price of oil and the adjusted base price). In the case of corporate income taxes, if companies did not undertake EOR projects, they could make alternative investments with comparable tax implications for the federal government.

effective because fewer projects would become economically feasible with the same royalty reduction. Regardless of oil prices, however, royalty reductions on a project-by-project basis can still be used to improve the economic feasibility of potential EOR projects.

These results for EOR production and federal government revenue were extrapolated from the sample reservoirs to the entire OCS in the Gulf to provide an overall view of potential EOR in this area. This extrapolation is inherently less certain than results derived from analysis of sample reservoirs and provides an upper-bound estimate of EOR potential. We based this extrapolation on a ratio between projected production in the sample reservoirs and the Minerals Management Service's (MMS) production estimates of actual oil-in-place in these reservoirs. This ratio was then applied to other known reservoirs in the OCS in the Gulf that were not studied in detail to estimate the total production potential for EOR.

Evaluating the impact of federal incentives on platform abandonment and production

After evaluating platform abandonment and its impact on production and associated federal revenue under current conditions in the Gulf, we considered the effect that federal financial incentives of $1 to $5 per barrel would have on platform abandonment, production, and associated federal government revenues. Platform abandonment and production were estimated in the same way as earlier estimates. Federal government revenue was re-estimated differently; net revenue for each incentive considered the cost of the incentive.

How an incentive could be provided

We examined ways the federal government might make financial incentives available. We decided to focus on royalty reductions after considering programs and laws currently in effect. MMS already has authority to reduce royalties. We considered whether royalty reductions on a project-by-project basis could provide sufficient incentive to increase EOR production and federal government revenue and whether it was administratively feasible. However, because there was no way to determine how many EOR projects would be initiated on a project-by-project basis, we do not estimate the revenue associated with this program.

Industry and government views

In addition to performing quantitative analysis and a review of royalty reductions, we discussed our results with senior industry and government officials and with technical experts. We sought their views on platform abandonment, EOR production, and asked about their plans to develop reservoirs with these methods. These discussions helped us verify estimates of platform abandonment and ensure that we did not overlook practical factors which could change our results.

Environmental issue evaluation

We evaluated possible environmental implications of increased EOR. To do this, we reviewed environmental studies of the Gulf by the Office of Technology Assessment, the Department of Energy, and the National Petroleum Council. We also interviewed knowledgeable officials at the Environmental Protection Agency (EPA), oil companies, and the Louisiana Department of Natural Resources and held discussions with a consulting environmentalist known for his expertise in EOR and with various environmental groups.

We conducted our review in accordance with generally accepted government auditing standards. Our review took place between September 1983 and February 1984.

CHAPTER 2

EOR IN THE GULF OF MEXICO: PLATFORM ABANDONMENT, PRODUCTION, AND FEDERAL GOVERNMENT REVENUE

About 8 billion barrels of oil under the Gulf of Mexico will remain unrecovered by conventional techniques unless technology and current oil prices change. EOR could recover about 970 MMB to 1.2 billion barrels of this oil, but it is expensive to implement. At issue is the amount of oil that might be recovered with EOR as a result of changes in royalty policies. To place the resource in perspective, potential EOR oil in the Gulf of Mexico is equivalent to about 10 percent of the recoverable oil from Prudhoe Bay, Alaska.

The amount of oil that is estimated to be economically recoverable by EOR methods ranges from about 55 MMB to 455 MMB, depending on technology and oil price assumptions. These estimates would still leave about 745 MMB to 915 MMB of technically recoverable oil unrecovered.[1]

Initiating EOR in a timely fashion, as a means of producing as much of the technically recoverable oil as possible, is becoming critical because postponing offshore EOR until it becomes economically feasible is usually not possible. Federal regulation requires that oil production platforms be removed within 1 year after production ceases. High platform replacement costs, combined with high operating costs, practically ensures that the amount of remaining oil recoverable by EOR will not justify a replacement platform and the redrilling of wells. As a result, timing is important because for offshore EOR to be used, the original platform must be in place.

The objective of this chapter is to analyze the likely rate of platform abandonment in the OCS in the Gulf and its impact on EOR production and related federal government revenue. On the basis of our analysis, if current leasing practices in the OCS in the Gulf and oil prices remain within the expected range, a substantial percentage of the platforms on possible EOR sites could be abandoned by the year 2000.

NO CHANGE IN POLICY RESULTS IN HIGH PLATFORM ABANDONMENT, REDUCED OIL PRODUCTION, AND POSSIBLY LOST FEDERAL REVENUE

Platform abandonment, EOR production, and federal government revenue are discussed below. These projections represent what could occur in the OCS in the Gulf of Mexico if no incentives are given to influence the economic feasibility of EOR. Our results

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[1]These figures are derived as follows: 1.2 billion barrels less 455 MMB equals 745 MMB, and 970 MMB less 55 MMB equals 915 MMB.

are derived from the analysis of two oil price paths (moderate and high)[2] as well as for conservative, base, and advanced EOR technology.

Platform abandonment

Under base technology and moderate oil price assumptions --our best estimate--about 52 percent of the platforms on the sample reservoirs would be abandoned by 1991. This rate of abandonment did not change when we considered higher oil price assumptions or improved technology. By the year 2000, platform abandonment, under moderate oil prices, could range from 70 to 75 percent, depending on the recovery technologies used.

Table 1 summarizes and compares our findings under various technology cases, for the sample reservoirs, using the two oil price assumptions.

Table 1

Platform Abandonment for Sample Reservoirs in the Federal Gulf of Mexico by Technology Case

	Abandonment under moderate oil prices			Abandonment under high oil prices		
	Conservative[a] technology	Base[b] technology	Advanced[c] technology	Conservative technology	Base technology	Advanced technology
	(percent)			(percent)		
1981-1991	52	52	52	52	52	52
1992-2000	23	21	18	19	18	7
Total	75	73	70	71	70	59

[a]Assumes injectants used for EOR will move more slowly than under base technology.

[b]Assumes current industry thinking from ongoing field tests and production.

[c]Assumes an optimistic view of current technology and that the injectants will move faster than under base technology while costing less.

Source: GAO

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[2]"Moderate" oil prices (in 1981 dollars) start with $37.05 in 1981, decline to $24.88 by 1985, then rise to $38.56 by 2000.

"High" oil prices (in 1981 dollars) start with $37.05 in 1981, decline to $26.66 by 1984, then rise to $47.67 by 2000.

With higher oil prices, platform abandonment is estimated to be somewhat lower by 2000. Increasing oil prices raise companies' revenues, making the use of EOR techniques economically more feasible and prolonging production. As a result, fewer platforms are abandoned by the year 2000. Advanced technology and high oil prices together reduce platform abandonment considerably when compared to the conservative technology combined with moderate oil prices.

Extrapolating our results on platform abandonment to other potential EOR targets in the Gulf is difficult because of limited data on these platforms. No study has been made evaluating the economic life of all platforms in the OCS in the Gulf because individual company data would be necessary. However, on the basis of the best available information, we assumed that the abandonment rates for the sample reservoirs are representative of those in the Gulf as a whole.

EOR production

Between now and 2000, our analysis shows that the estimated amount of technically recoverable EOR oil from the sample reservoirs, regardless of economics, ranges from about 240 to 300 cumulative MMB. When extrapolated to the OCS in the Gulf, the estimate increases to between 970 MMB and 1.2 billion barrels of cumulative oil production.

Under our moderate oil price estimates, we found that cumulative EOR production could range from about 15 MMB to 35 MMB. With higher oil price assumptions, cumulative production could increase significantly from 35 MMB to 110 MMB. However, in order for EOR production to reach 110 MMB, advanced EOR technology would have to be developed.

Table 2 shows the influence of higher prices and technology on EOR production. We found that cumulative production increases from 15 MMB for moderate-priced oil with conservative technology to 110 MMB for high-priced oil with advanced technology. When extrapolating these results to all Gulf reservoirs, the estimates increase from 55 MMB to 455 MMB. Overall, advanced technology and/or high oil prices yield substantially more oil.

Table 2

Estimated Production From Reservoirs in the Gulf of Mexico by Technology Case
(all numbers rounded)

	Moderate-priced oil			High-priced oil		
	Conservative technology	Base technology	Advanced technology	Conservative technology	Base technology	Advanced technology
	(MMB)			(MMB)		
Oil estimated technically recoverable						
Sample reservoirs	240	240	300	240	240	300
Entire Gulf reservoirs	970	970	1,220	970	970	1,220
Oil estimated economically recoverable						
Sample reservoirs	15	25	35	35	40	110
Entire Gulf reservoirs	55	100	145	145	165	455

Base technology and moderate oil prices, or our best estimate, most closely represent current conditions. Under these assumptions, about 100 MMB of the 970 MMB of technically recoverable oil will likely be produced in the OCS in the Gulf. In other words, if the economic feasibility of EOR in the Gulf continues unchanged, approximately 870 MMB of potential cumulative oil production will remain unrecovered.

Federal revenue

The federal government collects revenue from oil production in the OCS through royalties and taxes. If offshore oil platforms that could be used to produce oil using EOR are abandoned, the government stands to give up future revenue on this unrecovered oil.

Without a change in policy, our analysis shows that the potential federal government revenues from the sample reservoirs could range from about $70 million to $180 million under our moderate oil price assumptions, depending on technology. Under base technology, or our best estimate, revenue will be about $120 million. When these results are extrapolated to other known reservoirs in the OCS in the Gulf, estimated federal revenue could range from about $285 million to $735 million ($490 million under base technology assumptions). However, if oil prices rise to meet our high price and advanced technology assumptions, total federal government revenue could increase to as much as $2.3 billion.

In summary if conditions in the OCS in the Gulf remain unchanged, only about 100 MMB or about 10 percent of the technically recoverable oil by EOR will be produced, leaving almost 870 MMB of potential production behind. The main reason for this loss is EOR project economics. That is, few EOR projects can produce oil for less than the current selling price. Therefore, if EOR project costs and oil prices remain unchanged, it appears that a substantial number of platforms will be abandoned and large amounts of potential production and associated federal government revenues would be lost.

ACROSS-THE-BOARD INCENTIVES WOULD SUBSTANTIALLY INCREASE PRODUCTION BUT WOULD REDUCE FEDERAL REVENUE IN ALL BUT A FEW INSTANCES

Federal incentives could be used to encourage EOR production in the sample reservoirs and in the OCS in the Gulf as a whole. We evaluated the effect of incentives ranging from $1 to $5 per barrel to determine if they would increase oil recovery without reducing federal government revenue. By providing incentives, the federal government could stimulate some companies to initiate EOR that would not otherwise have done so. On the basis of our analysis, incentives ranging from $1 to $4 per barrel increased cumulative production most--from about 55 MMB to 725 MMB of oil. However, by providing an incentive for all EOR projects, the federal government stands to lose revenue in all but a few, relatively unlikely cases. This is due primarily because the government would lose royalty revenue on that oil (55 MMB to 455 MMB as shown in table 2) which could be economically recoverable using EOR.

Platform abandonment

According to our analysis, incentives combined with high oil prices and/or advanced technology are likely to reduce platform abandonment the most. Using high oil price assumptions, we found that all incentives of $1 or more reduce platform abandonment; a $4 incentive for instance could reduce platform abandonment from 13 to 44 percent, depending on the technology. With this incentive, and assuming the most realistic or base technology, we estimate that about 54 to 64 percent of the platforms will be abandoned by the year 2000. This estimate compares with our earlier platform abandonment estimate of 70 to 73 percent by 2000, if EOR project economics remain unchanged.

Under moderate oil price assumptions, we found that incentives of less than $4 have only a small effect on platform abandonment. A $4 incentive, however, could improve platform availability by 9 to 37 percent, depending on technology. Under high or moderate oil price assumptions, increasing the incentive to $5 per barrel added little to platform availability. In fact, even under high oil prices and advanced technology assumptions, we found that total platform abandonment was only reduced slightly when increasing the incentive from $4 to $5. Table 3 shows the affect of various incentives on platform abandonment, under moderate and high oil prices, and compares them to our best guess, or current project economics.

Table 3

Percentage of Platforms Abandoned on Sample Reservoirs

(Base technology with moderate and high oil prices)

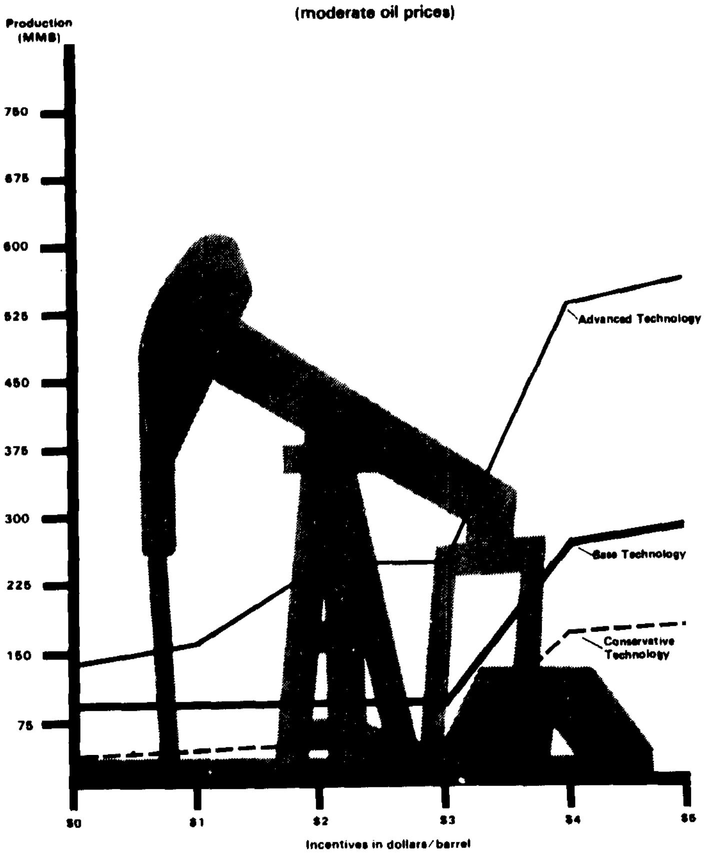
	Estimated abandonment with current project economics	GAO established incentives									
		$1		$2		$3		$4		$5	
	(percent)	High-priced oil	Low-priced oil	High-priced oil	Low-priced oil	High-priced oil	Low-priced oil	High-priced oil	Low-priced oil	High-priced oil	Low-priced oil
		(percent)									
Year 2000	70-73	66	73	63	73	58	73	54	64	54	63

SOURCE: GAO

EOR production

Using moderate oil price assumptions, we found no significant changes in production as a result of a $1-per-barrel incentive. Incentives of $2 to $3 per barrel had varying affects on production estimates, depending on the technology. However, the largest production response across all technology assumptions (per dollar of incentive) occurred at $4 per barrel. This incentive increased our base technology production estimate from the sample reservoirs from about 25 MMB to more than 65 MMB under moderate oil prices. When these base technology results are extrapolated to the entire Gulf, a $4 incentive increased production from about 100 MMB to 275 MMB as shown in figure 2. A larger incentive of $5 leads to a modest increase in production, but reduces the effectiveness of the incentive on a dollar-per-barrel basis.

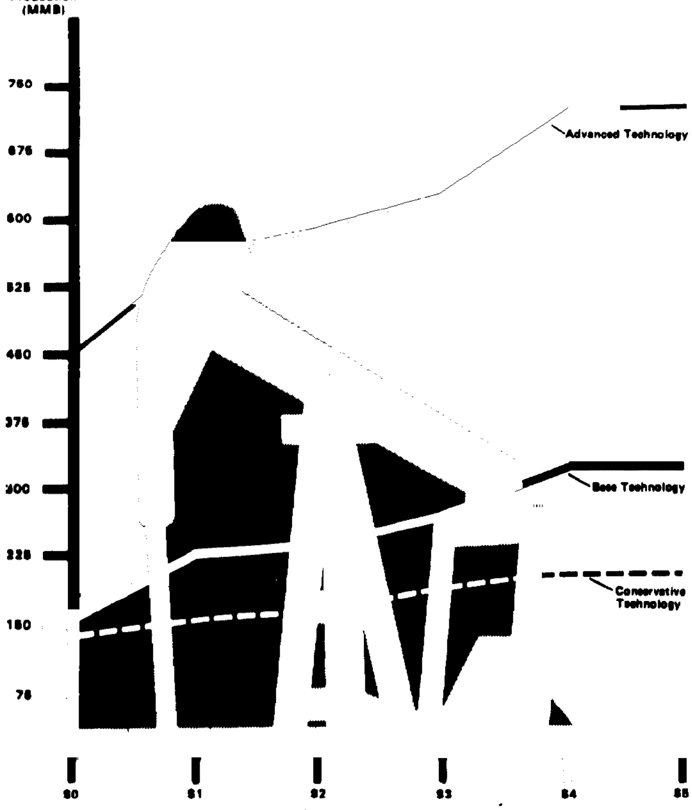
Figure 2
Production Response Per Dollar
of
Incentive
(moderate oil prices)



Source: GAO

Using high oil price assumptions, our analysis showed that in all but one case, each additional dollar of incentive increased production regardless of technology. No single incentive increased EOR production most, per dollar of incentive, for all technologies. Nonetheless, a $4 incentive increased production in our sample reservoirs (under base technology assumptions) from 40 MMB with no incentives to almost 85 MMB. Extrapolating these results to the entire OCS in the Gulf increased the cumulative EOR production estimates with no incentives from around 165 MMB to 340 MMB. A $5 incentive gave almost an identical production estimate as a $4 incentive and therefore was less effective on a per-dollar basis. Incentives under high oil prices increased production as shown in figure 3.

Figure 3
Production Response Per Dollar
of
Incentive
(high oil prices)



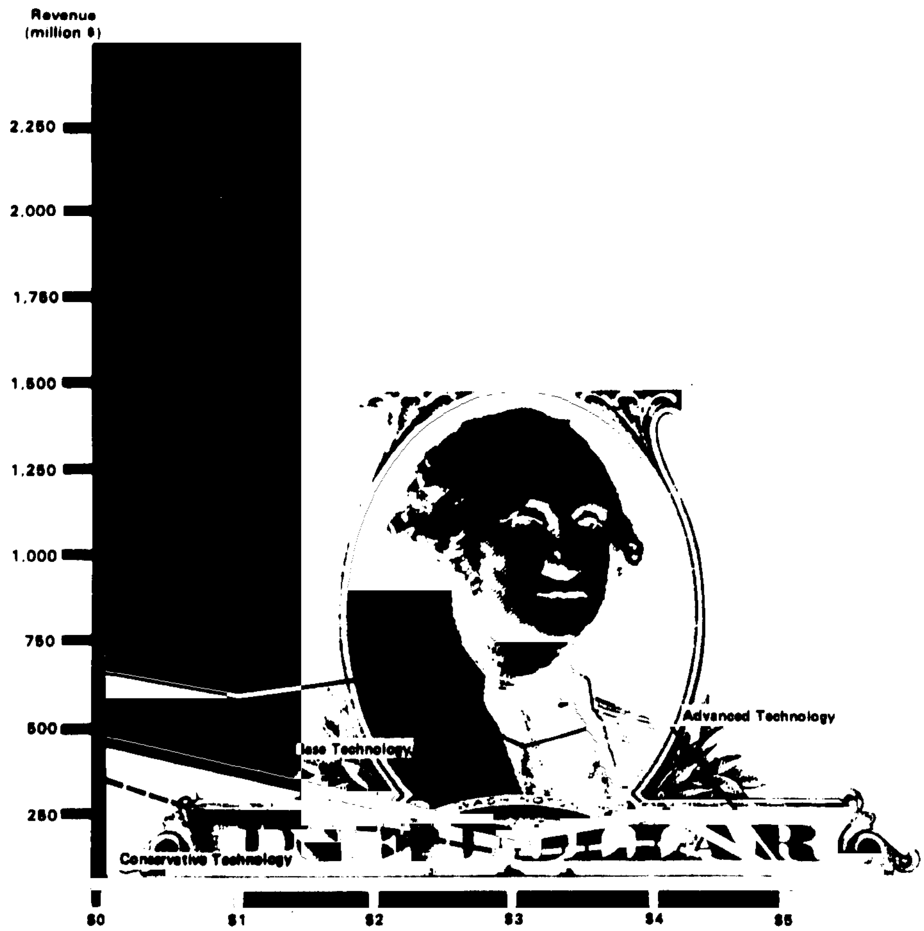
Source: GAO

<u>Federal revenue</u>

In estimating the revenue collected with an incentive, we subtracted the incentive's cost. In cases where additional revenue exceeds the estimated federal government revenue with no incentive, a net positive revenue is generated. Our analysis indicated that in only a few relatively unlikely cases did an across-the-board incentive for EOR make financial sense to the federal government. This occurred because some oil companies would have initiated EOR with or without an incentive; the federal government would therefore stand to lose $1 to $5 for each barrel produced by these projects. Consequently, some companies that would have started EOR anyway would pay less in royalties than otherwise.

In only three instances involving incentives is government revenue maintained or improved. With moderate oil price/advanced technology assumptions, for example, we found that a $2-per-barrel incentive produced federal revenue effects comparable to the $735 million estimated with no incentive. (See fig. 4.) Generally, however, our analysis shows that the federal government could lose more by the incentive than it gains in royalties on the increased production.

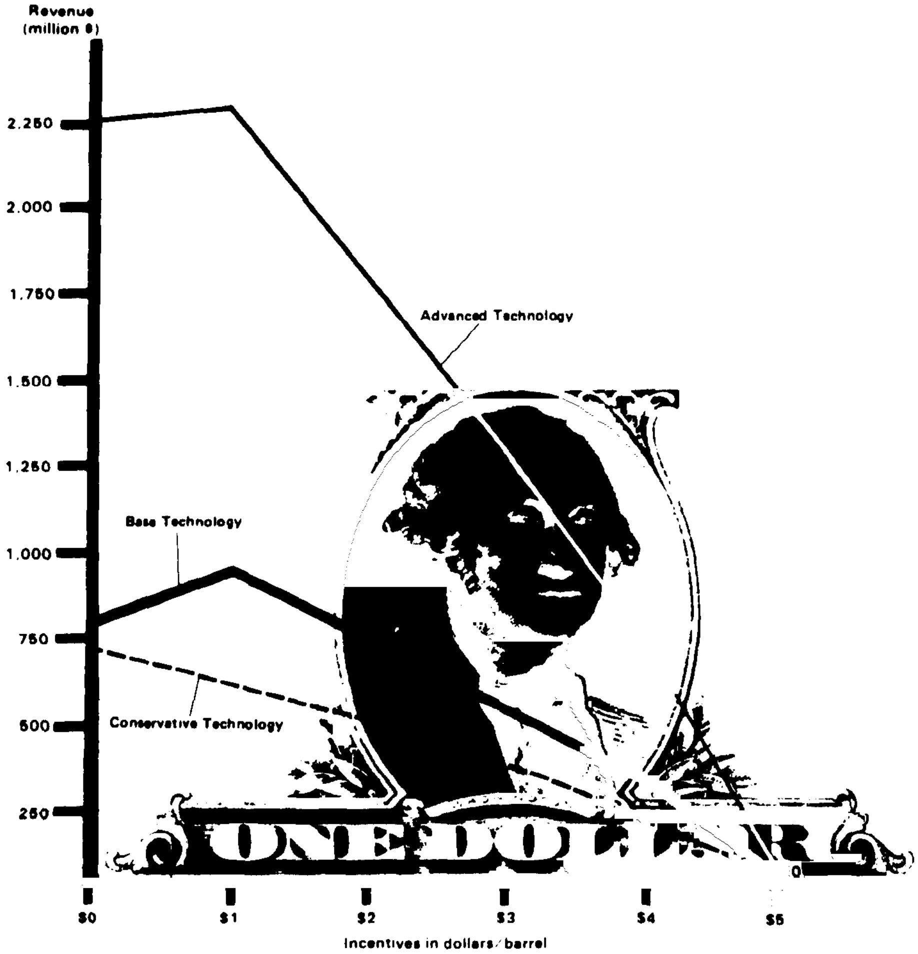
Figure 4
Affect Of Incentives On Government
Revenue
(moderate oil prices)



Source: GAO

We found two other instances, both using high oil price assumptions, in which a $1-per-barrel incentive increased government revenues. Using the base technology assumption, a $1 price incentive increased estimated federal government revenue by $95 million--from $820 million to over $915 million--when extrapolated to the entire OCS in the Gulf. Likewise, a $1 price incentive/ advanced technology assumption increased estimated federal government revenue, but the change was small. As shown in figure 5, incentives of $2 or more per barrel reduce government revenue.

Figure 5
Affect Of Incentives On Government Revenue
(high oil prices)



Source: GAO

CHAPTER 3

APPLYING FINANCIAL INCENTIVES TO EOR

This chapter discusses previous government attempts to encourage EOR and examines royalty reduction as a potential means to provide incentives. We analyzed royalty reductions only because they (1) have the potential to provide a sufficient incentive to increase production, (2) appear to be administratively feasible for implementation on a project-by-project basis, and (3) are currently authorized.

Other means do not appear to have these characteristics. For example, providing incentives through federal income tax deductions or credits would require changes to existing tax laws. Furthermore, focusing income tax on EOR in a way that could be effectively managed might be difficult. Similarly, reducing or eliminating windfall profit taxes[1] might be considered as an incentive because these taxes are currently in place and are applied on a project-by-project basis. However, because of the design of the law and projected stable oil prices, it appears that little or no windfall profit tax will be paid on EOR production after about mid-1986. Therefore, further reductions provide no additional incentive for companies to undertake offshore projects. However, if oil prices increase substantially over the next several years, thereby increasing the profit on which this tax is imposed, adjustments might make this a more viable option.

PREVIOUS EOR INCENTIVES HAVE MET WITH MIXED SUCCESS

After the oil embargo of 1973, the federal government started a program to develop technology to improve EOR after conventional production. This program attempted to promote more rapid technical and commercial advances in EOR techniques through, among other things, federal/industry cost-shared pilot tests. These tests, through field demonstrations, were designed to verify laboratory findings regarding the use of EOR methods. About 25 field demonstrations were initiated at a total cost of about $250 million; the government paid one-third of this amount. Because of budgetary constraints the cost-sharing incentives approach was terminated before a program evaluation was made.

The Energy Conservation and Production Act (Public Law 94-385), passed in 1976, authorized price incentives for EOR and specific high-cost technologies that would be uneconomic without

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[1]The Crude Oil Windfall Profit Tax Act of 1980 established a temporary excise tax (windfall profit tax) on domestically produced crude oil in conjunction with the decontrol of crude oil prices.

these incentives. Furthermore, the act provided for the adjustment of crude oil prices to encourage increased domestic production through EOR.

To meet the act's requirements, DOE's Economic Regulatory Administration (ERA) established the Tertiary Incremental Program on September 1, 1978. In this program, producers were required to prove that an EOR project would be uneconomic under oil price regulation. The most problematic aspect of this program, however, was that producers had to specify how much EOR production they expected to recover before the initiation of the project. Furthermore, producers were bound by their estimates of production and the likely date this production would begin. According to industry representatives, these inflexible and restrictive program requirements generated little interest. Between September 1, 1978, and August 21, 1979, ERA approved only six projects under the incremental plan.

Because of the limited response to the incremental program, and as a result of further public comment, DOE added the incentive or "front end" program on August 21, 1979. This program encouraged producers to undertake high-cost, high-risk technologies such as those used in EOR by allowing them to recoup, "up front," 75 percent of certain allowed expenses, up to $20 million per property. Producers could recoup their investments by selling certain oil at the market-level price instead of the controlled price. The goal was to increase domestic crude oil production and reserves.

To qualify a project for the tertiary incentive program, a producer submitted a "self-certification" report to DOE which contained detailed information demonstrating that the project satisfied the program's regulatory requirement. DOE regulations listed 10 EOR processes that were eligible for the program. "Allowed costs" for each type of EOR process were described and designed to permit recoupment of cost for EOR processes involving a high degree of risk. The greater the risk, the more costs a company could recoup.

The program was successful in initiating new projects: from August 21, 1979, through termination of the program in March 1981, DOE certified 423 projects. These pilot projects ranged from small tests costing a few hundred thousand dollars to large pilots on fieldwide projects with total investment obligations of several hundred million dollars.

Industry officials said that many of these projects, almost exclusively onshore, would have been delayed several years or never attempted without the tertiary incentives program. Although the DOE incentive program initiated many new projects, in our 1981 report, The Tertiary Incentive Program Was Poorly Designed and Administered, (EMD-81-147), we found that DOE had no way to tell if the $846 million in allowable expenses could be recovered. The program was terminated on March 31, 1981, after oil prices were decontrolled.

Overall, previous federal government incentives for encouraging EOR have met with mixed success. Some incentives were overly restrictive, requiring that industry be bound by estimates of uncertain EOR production. Other programs, such as the DOE Tertiary Incentive Program, were too broadly defined. Restrictive incentives stimulated little industry activity; more broadly defined ones increased the number of projects started but provided no way to determine if government costs were recovered.

TIMELY REDUCTION OF OCS ROYALTIES ON A PROJECT-BY-PROJECT BASIS COULD INCREASE EOR PRODUCTION AND FEDERAL GOVERNMENT REVENUE

Royalty reduction on a project-by-project basis could be attractive because it is already authorized by federal law and regulation and could provide increased federal government revenue while increasing EOR production. This procedure would be administratively possible if MMS clarified how and when royalty regulations could be applied to EOR offshore.

The Secretary of the Interior, acting through the Director, MMS, is authorized by 43 U.S.C. 1337 to adjust royalties to promote increased production. MMS has issued regulations to implement this provision. The regulation states:

> "In order to promote increased production in the lease area through direct, secondary, or tertiary recovery means, the Director may reduce or eliminate any royalty or net profit share on the entire leasehold, or on any deposit, tract, or portion thereof that is segregated for royalty purposes." (30 C.F.R. 203.150.)

An incentive program using royalty reductions on a project-by-project basis is practical

Although we found that the government stands to lose revenue if it provides incentives for all companies across-the-board, royalty reductions used as an incentive might be structured to increase, not decrease, federal government revenue. For example, MMS could use its existing authority to allow royalty reductions on the incremental oil[2] produced from EOR projects that would not have been economically feasible without this incentive. Although royalties are reduced, revenues are actually increased because the incremental oil would not have been produced otherwise. The amount and timing of the reduction can be determined for individual EOR projects.

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[2]Incremental oil is that amount above what would have been produced with conventional production had it continued until the economic limit of the field was reached.

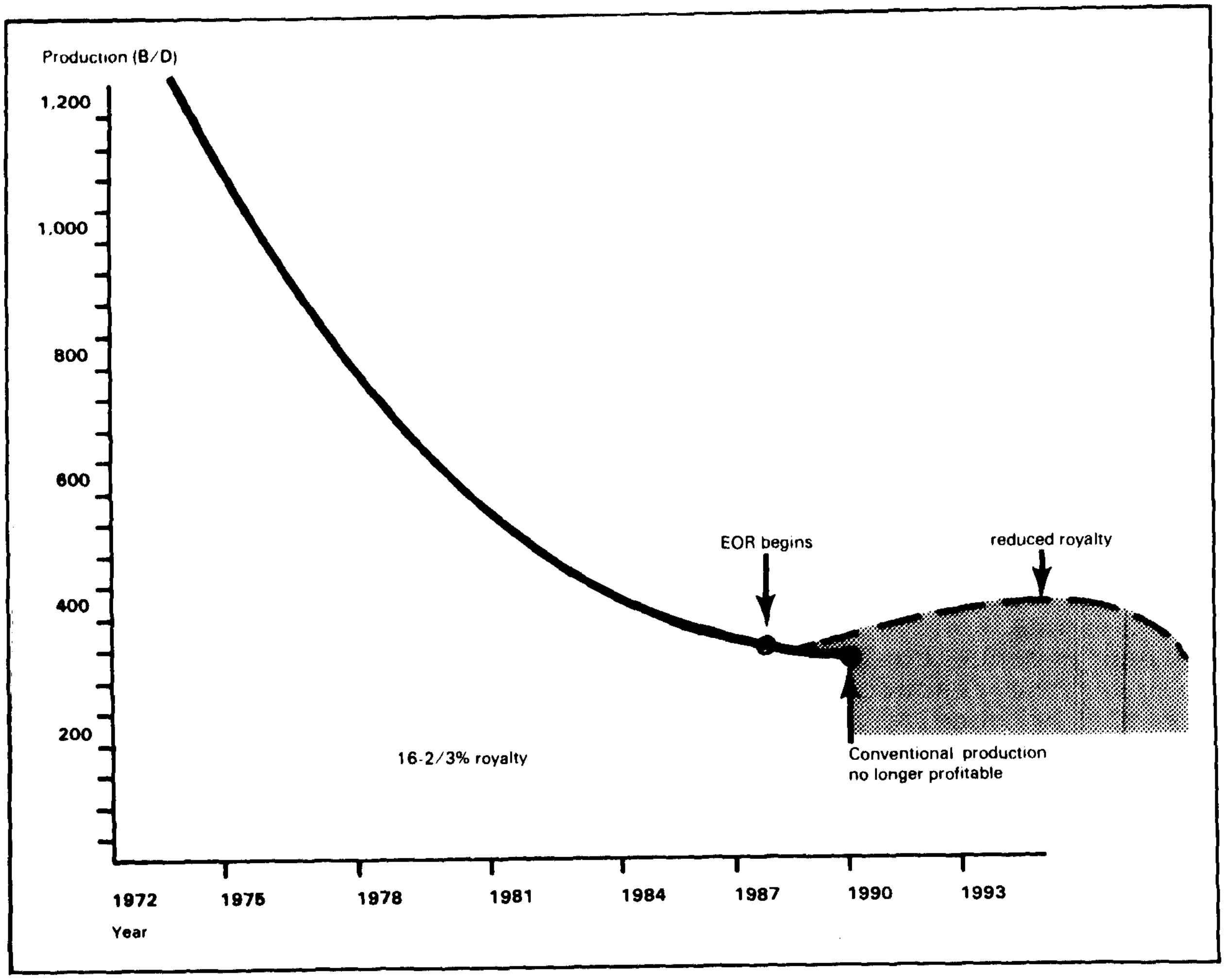
We solicited views from senior MMS executives and oil industry representatives to determine if such a proposal is administratively feasible. According to these officials, agreement would have to be reached between MMS and the industry on the amount of anticipated EOR production and the appropriate size of the royalty reduction. They said that the oil remaining in a reservoir which is expected to be produced by conventional methods can be identified within the last few years of the reservoir's useful life. This expected production can be agreed upon because reservoirs in the OCS in the Gulf have a long, well-documented production history known to both industry and the federal government. Therefore, any oil production above this would be attributed to EOR and eligible for a royalty reduction.

In addition, these officials believe enough information is available that agreement could also be reached on the economic feasibility of EOR projects, including profit, because EOR costs can be estimated and agreed upon. Since both the remaining conventional production and project cost are known or can be accurately estimated, the size of the royalty reduction can be agreed upon. On the basis of this information, we believe that reduced royalties could be applied only to the incremental oil from EOR and limited to projects for which it is economically necessary.

This concept is shown in figure 6. The figure represents the production from a typical oil reservoir, with the curve showing the normal decline in barrels of oil produced over time. At the indicated point on the curve, oil production would stop since it would no longer be profitable. The area under this curve, representing expected cumulative conventional production, can be realistically estimated. When EOR begins, the increased production is shown in the shaded area under the new dotted curve. Reduced royalties, applied to this incremental production that would not otherwise have occurred, would increase federal government revenue.

Figure 6

Reduced Royalties on Incremental Oil



Source: GAO

Consideration might be given to eliminating or significantly reducing royalty payments on this additional oil for the first year or so (subject to a preset maximum limit or project cost) to help EOR projects offset high start-up costs. In this situation royalties on conventional production would continue to be collected at the rate set in the lease until the reservoir reaches its projected economic limit through conventional means.

Agreeing on royalty reductions during the last few years before the economic limit of the reservoir is reached would help industry minimize financial and technical problems. Further, by allowing royalty reduction proposals at this time, MMS would have sufficient data to make an evaluation, while providing industry with enough lead-time to effectively implement EOR.

Louisiana has authorized an EOR incentive program

The principle of reducing government revenue on incremental EOR oil to improve production only when project economics dictate has recently been authorized by the state of Louisiana. In Louisiana, severance tax reductions are allowed on a project-by-project basis. Before this is done, however, the amount of EOR oil that can be produced and the project's economics are agreed upon during a process involving state agencies and a public hearing. We spoke with individuals involved in this process to determine if technical and economic issues could be realistically agreed upon and if severance tax reductions could be administratively applied. Although the idea is novel, those involved in the process were confident that agreement can be reached and that their state agencies can administratively apply severance tax reductions on a project-by-project basis.

From an administrative standpoint, reviewing project applications and granting reductions are not anticipated to create significant problems because the initial number of applications is expected to be small. By using a project-by-project approach, similar to that of Louisiana, MMS could provide an effective economic incentive to producers to invest in EOR projects and increase OCS domestic production. At the same time, federal government revenue could also be increased. Although we have not analyzed the resources needed to carryout such a program, it could probably be handled through ongoing MMS operations.

OUR PREVIOUS VIEWS ON SELECTIVE ADJUSTMENTS TO ROYALTIES

The idea of selectively using different royalty rates to maximize oil production and/or government revenue is an area that we have previously addressed. In our 1982 report, Interior Should Continue Use of Higher Rates for Offshore Oil and Gas Leases (RCED-83-30), we found that the Interior has selectively used higher royalty rates for areas estimated to have high resource levels and low development costs. The report concluded that:

> "An across-the-board increase in the offshore royalty rate may not be appropriate at this time, but continued use of higher royalty rates, in selective instances, based on resource potential estimates and experience with industry responses, would seem desirable."

The principle of selectively using different royalty rates, depending on the amount of oil and its development costs, is consistent with the views in this report, that is, reducing royalties where the amount of remaining oil is small and development costs are high.

CURRENT USE AND PERCEPTIONS OF ROYALTY REDUCTIONS THROUGH MMS

Although MMS is authorized to reduce royalties, this procedure has not been used. To date no offshore royalty reductions have been granted. In fact, only one formal application to reduce royalties has been submitted, and that petition was denied. We therefore examined reasons why the oil industry has not sought royalty reductions as a means to improve EOR project economics.

Why royalty reductions have not been used for EOR

MMS' Gulf of Mexico Regional Manager told us that oil companies can apply for reduced royalties when they undertake new processes or add to existing ones. However, our review of the royalty reduction regulation revealed no specific guidance describing how or when MMS will reduce royalties for oil companies to offset increased costs from expensive offshore production methods such as EOR. MMS' Deputy Associate Director for Operations and the Gulf of Mexico Deputy Regional Manager confirmed that no written guidelines are available for oil companies to determine whether they might qualify for such a reduction offshore.

Oil industry's response to royalty reductions

We asked oil industry representatives why there had been no applications for reduced royalties in the Gulf. Although responses varied, most centered on how industry officials perceived MMS would apply the royalty reduction regulation to an EOR project.[3] Oil representatives were doubtful that MMS would reduce royalties on the basis of an individual EOR project if other oil production on the lease was still profitable. Oil companies view MMS determinations of reduced royalties as being based on the economic need of the entire lease at the end of conventional recovery.

If the company waits until the entire lease is no longer profitable, however, individual EOR project economics could change considerably, and physical constraints could reduce the amount of recoverable EOR oil. An oil reservoir being considered for EOR when nearing the end of its profitable conventional production, for example, may not necessarily coincide with the economics of the entire lease area. Thus, it is important that the economic feasibility of an EOR project be evaluated individually (on a project-by-project basis) rather than against the entire lease. Physical reservoir conditions may also make EOR projects less attractive if production has ceased and oil is no longer moving freely. Overall, oil company officials believed that consideration of royalty reductions based on an entire lease is unlikely to lead to significantly increased activity.

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[3]An EOR project is usually one or more platforms producing oil on an individual reservoir or a small group of reservoirs with similar characteristics.

Additional clarification of the MMS position seems warranted, given the uncertainty surrounding the use of royalty reductions. Although the regulation appears to be aimed at improving resource recovery, it has not proved useful in practice. We believe that royalty reduction, if clarified so as to be applied by MMS on a project-by-project basis, could provide a means for the federal government to stimulate EOR in the OCS in the Gulf prior to the end of conventional production and platform removal. Used in this way, royalty reductions would improve domestic oil recovery and federal government revenue.

CHAPTER 4

EOR: POSSIBLE ENVIRONMENTAL CONCERNS

A large number of petroleum production platforms are in use in the OCS in the Gulf, and a considerable infrastructure is in place to support petroleum production. Extending the use of this infrastructure for EOR or adding additional equipment may raise questions of environmental concerns over and above those now associated with conventional oil production.

Industry consensus indicates that carbon dioxide has the greatest growth potential for EOR in the OCS in the Gulf of Mexico. This is primarily because of the economic and technical feasibility of this method compared to other methods involving heat or chemicals. While carbon dioxide has yet to be widely used offshore, onshore experience indicates that the environmental risk associated with carbon dioxide EOR should be low. Carbon dioxide is a relatively benign substance, and the consensus of environmental experts and groups indicates that it is not expected to damage the Gulf environment. The prudent use of technology and safety-minded industry operating practices, along with current federal environmental laws and regulations (if they are fully enforced), are expected to be adequate to safeguard against possible adverse environmental impacts.

The amount of EOR is likely to be quite small compared with conventional oil recovery operations already in the Gulf. For example, about 6.5 billion barrels of oil have been produced to date by conventional methods from the Gulf of Mexico. Current conventional production is over 300 MMB per year. In comparison, cumulative EOR production up to the year 2000, on the basis of our analysis, could be about 55 MMB to 725 MMB of oil. This is equivalent to, at the most, 11 percent of total conventional production to date. These differences in scale may diminish the significance of environmental concerns regarding EOR.

EFFECTS OF CARBON DIOXIDE

According to environmental groups and experts with whom we spoke, water quality in the OCS in the Gulf is not expected to deteriorate as a result of using carbon dioxide for EOR. EOR could affect water quality in two ways: by discharging water used during production to help recover the oil and by mishandling carbon dioxide.

Water is normally produced along with the oil during all phases of production, both conventional and EOR. Using carbon dioxide for EOR is not expected to change the nature of this water as it is disposed. The quality and composition of the water associated with production is monitored under existing environmental laws. The overall effect of the discharges into the OCS in the Gulf is minimal and the effects of any additional water generated from EOR are also likely to be small.

Accidental discharge of carbon dioxide into the water as a result of spills or leaks is not expected to create an environmental hazard. Carbon dioxide released deep under water will dissolve. Localized changes in the acidity of the water around the release could occur, but will diminish as the carbon dioxide disperses. If released in shallower water, the carbon dioxide will bubble up to the surface and disperse into the atmosphere.

EXISTING ENVIRONMENTAL LAWS APPLY TO EOR

Potential environmental concerns that might be associated with EOR use in the OCS Gulf are expected to be addressed by existing environmental laws including the National Environmental Policy Act, the Clean Air Act, and the Clean Water Act, which now regulate conventional oil recovery. MMS and EPA have jurisdiction over the federal environmental regulatory programs implemented under these acts. States have no jurisdiction on the OCS beyond 3 miles offshore.

MMS requires oil companies to submit plans for exploration and development in the OCS in the Gulf. Before permits are issued, MMS performs an environmental assessment from data submitted by the company requesting the permit. The environmental assessment includes air and water emissions to determine compliance with the acts. MMS' Regional Supervisor told us that under most circumstances EOR would not pose sufficient concern to warrant an additional environmental impact statement (EIS). However, if the potential for environmental impact is significant, MMS is required under the National Environmental Policy Act to prepare an EIS.

EPA has issued a general discharge permit for water discharged from production into federal waters of the Gulf. Oil companies discharging water in this area are required to provide information on the volume and composition of this water. Companies must monitor this water and submit annual compliance reports to EPA. Although EPA does not physically inspect discharge sites, it coordinates this activity with MMS, which inspects oil production platforms at least annually to monitor compliance.

REGIONAL ENVIRONMENTAL STUDIES DO NOT INDICATE SIGNIFICANT CONCERN

No detailed environmental impact studies on the effect of EOR in the OCS in the Gulf have been performed to date. However, MMS conducts regional environmental impact studies that examine the potential effects of proposed or anticipated petroleum production development in the Gulf. The two most recent environmental studies do not indicate particular concern with EOR implementation in the OCS in the Gulf. The most recent study, Final Environmental Impact Statement Gulf of Mexico, Proposed OCS Oil and Gas Lease Offerings (1984), states that increased oil production can be accomplished in the area without a significant impact to the natural and human environment. In preparing this statement, MMS evaluated oil production impacts by estimating the maximum potential production of an area, including EOR production.

Bringing large quantities of carbon dioxide to platforms in the OCS may require the construction of additional pipelines. The other study entitled Regional Environmental Assessment, Gulf of Mexico, Pipeline Activities (Aug. 1983) was prepared as an evaluation of pipeline impacts on the environment of the Gulf. The report indicated that pipeline construction, operation, and maintenance on the OCS caused minimal impacts to onshore air quality. It also stated that, although water quality might be adversely affected during pipeline construction, such effects would be localized and of short duration. Finally, although animal and plant life might be adversely affected during pipeline construction, the nonburied pipelines furnish a substrate for encrusting organisms and promotes increased biological diversity.

CHAPTER 5

CONCLUSIONS AND RECOMMENDATION

After conventional oil recovery methods have been exhausted, about 8 billion barrels of oil will remain in identified oil fields in the OCS in the Gulf of Mexico. As much as 1 billion barrels of the remaining oil could potentially be recovered using enhanced oil recovery methods. Failure to produce this oil will result in lower revenues to the federal government and less domestic energy for the nation.

We found that if nothing changes to affect the economic feasibility of EOR projects in the OCS, the number of existing platforms available to service suitable fields for EOR is likely to be substantially reduced. It appears that about 60 to 75 percent of the platforms currently used for conventional recovery in the sample reservoirs could be abandoned and removed by the year 2000 and would thus be unavailable for EOR. Furthermore, if the sampled reservoir abandonment rates are suggestive of the OCS in the Gulf in general, EOR potential for the whole area may also be jeopardized.

If no steps are taken to change the economic feasibility of EOR in this area and the projected number of platforms are removed, cumulative EOR production could range from about 55 MMB to 455 MMB of oil, depending on technology and oil price assumptions. This represents approximately 6 to 37 percent of the 970 million to 1.2 billion barrels of oil which is estimated to be recoverable by EOR.

Providing across-the-board federal incentives would increase EOR production. Incentives of $1 to $4 per barrel would probably be most effective on a dollar-per-barrel basis. Our extrapolated results for incentives in this range show that cumulative oil production could range from 55 MMB to 725 MMB, depending on oil price and technology assumptions. However, by providing these incentives for all EOR initiated in the OCS, the federal government stands to lose revenue in all but a few instances. These few instances are associated primarily with high oil prices and/or advanced technology, neither of which is considered likely.

This result occurs because providing incentives to all companies initiating EOR allows some companies that would have started projects, regardless of the incentives, to pay less in royalties. Therefore, unless incentives can be given on an EOR project-by-project basis rather than across-the-board, the federal government could lose revenue even though production could increase.

Previous federal government incentives to spur EOR have met with mixed success: some were too restrictive, others too broadly defined. While restrictive incentives stimulated little industry interest, more broadly defined incentives stimulated many projects but provided no way of determining if their cost could be recovered. Project-by-project royalty reduction through MMS, on the other hand, could provide a means to encourage EOR in the OCS in the Gulf without losing federal government revenue. This procedure is currently authorized. It is capable of providing sufficient incentives to improve EOR production and is administratively feasible on a project-by-project basis.

If the use of royalty reductions can be clarified and specific guidelines established, incentives could effectively encourage EOR production. By using incentives selectively on a project-by-project basis for otherwise uneconomic projects, the federal government stands to increase its revenue and improve the domestic recovery of a potentially lost resource. Thus, such an approach could be initiated cost-effectively.

Extending the use of petroleum production platforms in the OCS in the Gulf for EOR may raise questions about its environmental implications. On the basis of limited offshore and more extensive onshore experience to date, expanding EOR production is not expected to introduce major environmental impacts. Existing laws apply to offshore EOR, and their enforcement by MMS and EPA is expected to protect the environment.

RECOMMENDATION

We recommend that the Secretary of the Interior instruct the Director of the Minerals Management Service to initiate action that would allow for royalty reduction on EOR projects in the OCS in the Gulf of Mexico where it would result in both increased production and increased federal government revenue. In doing this, the Director should establish guidelines that

--facilitate industry preparation of royalty reduction proposals and government's evaluation of these applications;

--permit timely evaluation of royalty reduction proposals (that is, early enough in the productive life of a well or reservoir to permit industry to implement EOR effectively, but late enough for the government to have sufficient data to evaluate the need for royalty reduction, usually during the last few years of conventional production); and

--allow royalty reductions on a project-by-project basis while maintaining the existing royalty for the remainder of the lease area.

AGENCY COMMENTS

The Departments of Energy and the Interior commented on a draft of this report; their comments are included in Appendix I. Most of the comments from DOE and Interior addressed the amount of production likely to be associated with EOR and the administrative process involved with royalty reductions. Other clarifying suggestions, which were offered separately, have been incorporated in the report, where appropriate.

DOE pointed out that we had taken a conservative approach in estimating the recoverable oil using EOR methods. The potential, according to DOE, may well be greater than that calculated by GAO if reservoirs that are known, but currently undeveloped, are included in the area from which our estimates are derived. However, DOE agreed, in general, with the report and noted that maximum recovery of this country's petroleum resources is in the national interest--a goal that can be furthered by GAO's recommendation.

Unlike DOE, Interior noted that our estimates of EOR potential may be optimistic. However, Interior, although citing several concerns, commented that our recommendation is sufficiently important to merit consideration. Furthermore, Interior agreed that its current regulations may need refinement and that it may need to establish clarifying guidelines; these are now under study. Nonetheless, both departments agree that royalty reductions could provide an opportunity to produce oil that might otherwise remain in the ground. Moreover, a royalty reduction program will give industry an opportunity to gain valuable experience in using EOR offshore. Both Departments noted that recently declining oil prices may further influence the economic feasibility of EOR methods. We agree that if oil prices continue downward or remain low, few EOR projects will be initiated. (See pp. 4 and 5.)

Both agencies pointed out, to varying degrees, that the administrative process for a project-by-project review of royalty reductions could encounter considerable problems in connection with agreeing on production costs, production estimates, future oil prices, and the remaining reserves in a reservoir. They also pointed out that such a program would require time, skilled personnel, and access to data.

Although the agencies expressed concern about the availability of information to evaluate project applications for royalty reductions, we found in talking with Interior and Minerals Management Service officials and industry representatives that the necessary information was available and could be agreed upon. Production costs in the Gulf are well known and EOR would tend to use pipelines and equipment similar to conventional production. The cost of carbon dioxide or other injectants for EOR could be reasonably estimated because supplies would probably be purchased from known sources. Further, the remaining oil which is expected to be produced by conventional methods can also be identified, particularly within the last few years of a reservoir's useful life. This expected production can be agreed upon because reservoirs in the OCS in the Gulf have a long, well documented production history known to both industry and the federal government. As for production and future oil price estimates, Interior currently makes similar estimates for its lease offerings and sliding scale royalty rates. Nonetheless, if fewer EOR projects are initiated as Interior suggests, the administrative requirements to handle a limited number of applications should be small. If EOR potential is greater than our estimates, as DOE suggests, the administrative requirements could be increased, but so would the benefits to industry and government. We continue to believe that the program can be made available now and that experiences gained over time will shed more light on the administrative requirements.

Other agency comments

DOE and Interior, in addition to commenting on production and the administrative process, offered comments on other aspects of the report. For example, DOE suggested the use of a competitive bidding process, similar to that used in offshore leasing, as perhaps an efficient way to provide a royalty reduction incentive to industry. Under this type of program, industry would be invited to bid for the right to receive royalties from a federal lease in return for a lump sum payment to the federal government. This bidding process would be initiated once a company determined that an EOR project could be economically feasible if royalties were reduced. The company winning the bid would then negotiate a royalty reduction with the platform operator/lease owner. DOE noted in its clarifying suggestions that the cost of organizing and administering an auction could be lower than negotiating project-by-project.

We did not assess the use of a competitive bidding process for royalty reductions because we limited our analysis to programs that are currently authorized. Furthermore, while such a process might be another way a royalty reduction incentive could be provided for EOR, there may be problems associated with the exchange of confidential data between companies and with antitrust laws. Nonetheless, we encourage DOE to assess further the potential for using such a program for royalty reductions.

DOE noted that by restricting our recommendation to actions that would result in both increased production and increased federal government revenue we might ignore a broad range of benefits that would accrue to consumers, taxpayers, and the United States through increased taxes, economic activity and decreased dependence on oil imports. We acknowledge that there may be additional benefits associated with EOR oil other than additional production and royalty revenue. (We assume corporate income taxes will remain roughly the same (see p. 4).) We did not attempt to quantify these potential, additional benefits. Since these projects would not have been undertaken otherwise, if additional benefits such as those suggested by DOE are to be considered in approving royalty reductions that do not meet the criteria in our recommendation, a convincing case should be made that these benefits outweigh the costs.

According to the Interior, our report indicates that

> ". . . approximately 1.0 billion barrels of oil are technically recoverable with EOR techniques. The report also states that a substantial portion of this oil can be recovered through the implementation of the measures recommended by the GAO. These estimates reflect the most optimistic assumptions with regard to technical recoverability and costs."

We do not specifically estimate how much oil will be recovered with the use of royalty reductions because negotiations between industry and government would be necessary. Additionally, Interior's comment does not recognize the fact that our analysis provides a range of possible oil recovery depending on oil prices and technology assumptions. We found that about 55 million barrels (MMB) to 725 MMB of oil could be recovered with EOR methods if royalty rates are reduced between $1 and $4 per barrel. (See figures 2 and 3, pp. 13 and 14.) This range includes about 55 MMB to 455 MMB of EOR oil that could be produced without any change in royalties. Our "best estimate," assuming moderate oil prices and technology, is that about 100 MMB will be produced, if royalty rates are not reduced, and about 100 MMB to 275 MMB with various royalty rate reductions. (See figure 2, p. 13.) This "best estimate" does not reflect the most optimistic assumptions. In addition, these estimates were limited to known reservoirs currently involved in conventional (primary or secondary) recovery. DOE pointed out that this conservative approach may underestimate the actual potential of EOR methods if other known, but currently undeveloped reservoirs are not considered.

Interior does not believe that a $4 reduction in royalty rates, depending on oil price and technology assumptions, could produce up to an additional 725 MMB of oil through EOR. By way of comparison, Interior pointed out that a reduction in Windfall Profit Tax from 70 to 30 percent for EOR projects has produced only one project (with another recently initiated) in the Gulf of Mexico. In addition, Interior noted that

> "the price of crude oil has dropped to a current price of $27 per barrel and is predicted to drop another $2 in the near future. At $25 per barrel, granting a royalty reduction equal to $4.00 would yield producers a revenue per barrel roughly equivalent to that which they received without a royalty reduction when the price was $29. However, since the latter price was not particularly effective in stimulating EOR activity in the Gulf, it is not expected that the $4.00 incentive will result in the incremental recovery suggested in the GAO report under current low price expectation[s]."

Our analysis does not indicate that an <u>additional</u> 725 MMB of oil could be produced with a $4 incentive. In order to produce a total of 725 MMB of oil with a $4 incentive, advance technology and high oil prices must be assumed. (See figure 3, p. 14.) We also note that, even under these optimistic circumstances about 455 MMB of EOR oil would have been produced even without the royalty reduction. We do not support this optimistic estimate as most likely, but use it to show the range of possible production from EOR depending on assumptions. Our "best estimate" assumes moderate oil prices and base technology, or a total of about 275 MMB with a $4 incentive, not 725 MMB of additional EOR oil as Interior indicates. Further, royalty reductions could be a more effective incentive than windfall profit taxes for two reasons. First, royalties are a claim on gross revenue from an EOR project as opposed to Windfall Profit Taxes, which are a claim on income after expenses. Therefore, royalties are paid "off the top" regardless of profitability. Windfall Profit Taxes are paid only to the extent that a profit is made and, furthermore, are subject to a net income limitation. Secondly, according to tax experts we spoke with at the Department of Treasury, the Congressional Budget Office, and industry, no Windfall Profit Tax is expected to be collected on EOR projects after about mid-1986. (See p. 4.) Royalties, however, continue to be a substantial cost to industry. In addition, we recognize that falling oil prices can influence EOR production and have incorporated comments in the report where appropriate. (See pp. 4 and 5).

Interior also noted that additional oil could be produced if royalty rates were reduced for conventional production when production is no longer economically feasible at conventional royalty rates. Further, Interior concludes

> "It is likely that, in a significant number of case, the remaining recovery which can be economically undertaken will be achieved through the use of conventional production techniques and not tertiary techniques."

We have previously advocated the use of a flexible royalty policy to maximize oil production and/or government revenue. In our 1982 report, Interior Should Continue Use of Higher Rates for Offshore Oil and Gas Leases (RCED-83-30), we point out the principle of selectively using different royalty rates for conventional production depending on the amount of oil and its development cost (see p. 22). This previous report addresses royalty rates on conventional production, while the focus of this report is on EOR methods. We advocate the use of royalty reduction on a project-by-project basis only where both increased production and increased federal government revenue result. However, we do not generally agree that royalty reductions on conventional production are likely to result in the same amount of recoverable oil as that associated with using EOR. Conventional methods use natural reservoir pressure or injected water to displace oil. At a point during conventional production, the injected water can no longer physically displace additional oil. EOR methods, such as those using carbon dioxide addressed in this report, can mix with the oil remaining after conventional production and allow a considerable amount of additional oil to be recovered. Nonetheless, if Interior believes it can provide royalty reductions on conventional production following the criteria in our recommendation, the idea merits further consideration. We encourage Interior to follow-up on this suggestion.

Interior did not agree that the abandonment of existing platforms would pose a problem if the oil is to be recovered later by EOR methods. It cites three primary reasons: (1) the vast majority of the large oil fields are in the Miocene trend--a large, deep basin which has not been fully explored--and as deeper production in the Gulf is developed, the new platforms required could be used for future EOR projects, (2) many of the current platforms are old and may not be in the best position for EOR projects, so it is likely that lessees would choose new platforms for many EOR methods, and (3) as industry moves to deeper waters it will dictate the design of mobile platforms that could be used for EOR.

Our analysis of offshore platforms as well as extensive interviews with industry and government experts indicates that if existing platforms, on sites suitable for EOR, are removed, it would not generally be economically feasible to replace a platform for the purpose of an EOR project. Platform replacement and operating costs are extremely high in the Gulf of Mexico. Given the fact that the remaining amount of oil recoverable by EOR methods is relatively low, compared to conventional production, these costs will not be justified in most cases. Companies pointed out that they would retrofit and/or add to their present platforms first, then, if necessary, build additional platforms that could be used in conjunction with their present platforms. In addition to the financial problem of replacing a platform, physical reservoir conditions may make EOR projects less attractive later if conventional production ceases and oil is no longer moving freely. Finally, no oil company we surveyed that was operating in the Gulf was considering the use of a mobile platform for possible future EOR projects. The consensus was that mobile platforms do not lend themselves well to EOR methods because of practical and technical considerations involved with these methods.

Department of Energy
Washington, D.C. 20585

JAN 29 1985

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

Dear Mr. Peach:

The Department of Energy (DOE) appreciates the opportunity to review and comment on the General Accounting Office (GAO) draft report entitled "Selectively Reducing Offshore Royalty Rates Could Increase Oil Production and Federal Government Revenue In the Gulf of Mexico."

DOE generally agrees with the report and is pleased to see the subject of enhanced oil recovery (EOR) in the Gulf of Mexico is receiving your attention. Although DOE does not have direct responsibility for implementing GAO's recommendations, those recommendations involve the development and production of U.S. oil resources and directly affect the national energy objectives to which DOE is committed. Maximum recovery of this country's petroleum resources is in the national interest, and it is a goal that can be furthered by GAO's recommendations. There are, however, four areas in the report that should be expanded on in order to provide the reader with a better understanding of the costs, benefits, and uncertainties involved.

1. The Lewin and Associates study used as the basis of the report reflects 1980-81 data. Oil prices, offshore recovery costs, and the state of knowledge about EOR have all changed since then. These factors are working to shorten platform economic lifetimes and perhaps increase the technical potential of EOR. The report should recognize these changes and comment on how they affect the report's projections.

2. The report should point out the considerable time and resources that will be required for a project-by-project review of royalty incentives. Reaching agreement on costs, production estimates, future oil prices, and what constitutes an economic project will be a difficult, expensive and time-consuming effort and will likely require an expanded bureaucratic structure. To facilitate this process, costs, accounting methods, price projections and, if possible, methods for estimating EOR production should be standardized so that industry understands the rules it is being asked to play by. DOE does not believe that a project-by-project program is the only one that should be considered -- a competitive bidding process

might be more efficient, for example -- but if it does turn out to be the best alternative, policy makers should be made aware of the full extent of the costs and effort involved.

3. In restricting its recommendations to actions that "would result in both increased production and increased federal government revenue" (GAO's emphasis), GAO ignores a broad range of benefits that would accrue to consumers, taxpayers, and the nation from many projects that do not meet the report's strict definition of benefits as arising only from royalty revenues. Reduction of royalties would also produce benefits from increased production of oil that would ultimately reach consumers (oil that otherwise would never be recovered), corporate taxes that would be collected on incremental production, increased economic activity, and decreased dependence on oil imports. An analysis of royalty incentives should include these benefits in order to give decision makers the complete picture.

4. GAO has taken a conservative approach to estimating recoverable EOR. The Lewin and Associates study limited its analysis to previously swept portions of known reservoirs (i.e., areas in which primary and secondary recovery are already taking place). There is also substantial EOR potential from unswept zones of known reservoirs for which additional wells would have to be drilled and from undiscovered reservoirs. The conservative nature of the estimates should be noted in the report. This potential may well be greater than that calculated by GAO for the swept zones.

DOE hopes that these comments will be helpful to GAO in their preparation of the final report.

Sincerely,

M H Dolan

Martha Hesse Dolan
Assistant Secretary
Management and Administration

APPENDIX I

United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

FEB 8 1985

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

Dear Mr. Peach:

We appreciate the opportunity to review your draft report entitled "Selectively Reducing Offshore Royalty Rates Could Increase Oil Production and Federal Government Revenue In the Gulf of Mexico." The Department of the Interior's comments on the draft report are included in the enclosure.

Sincerely,

Deputy Assistant Secretary - Land and
Minerals Management

Enclosure

COMMENTS ON THE GENERAL ACCOUNTING OFFICE DRAFT REPORT ENTITLED "SELECTIVELY REDUCING OFFSHORE ROYALTY RATES COULD INCREASE OIL PRODUCTION AND FEDERAL GOVERNMENT REVENUE IN THE GULF OF MEXICO"

The Department believes that the General Accounting Office (GAO) recommendation may merit further consideration. The GAO recommends that the Minerals Management Service (MMS) "initiate action that would allow for royalty reduction on EOR projects in the OCS in the Gulf of Mexico where it would result in both increased production and increased Federal Government revenue." Further, the GAO recommends that MMS should establish guidelines that:

- "establish specific guidance to facilitate industry preparation of royalty reduction proposals and government's evaluation of these applications;
- permit timely evaluation of royalty reduction proposals (That is, early enough in the productive life of a well or reservoir to permit industry to implement EOR effectively, but late enough for the government to have sufficient data to evaluate the need for royalty reduction, usually during the last few years of conventional production); and
- allow royalty reductions on a project-by-project basis while maintaining the existing royalty for the remainder of the lease area."

The GAO recommendation to review royalty reduction guidelines has merit. However, it must be recognized that EOR is still very much in the pilot stage in Gulf of Mexico-type reservoirs, and that only significant reductions in royalties are likely to induce EOR activity over the next few years. More effective incentives would be provided by major increases in the oil price or sizeable reductions in taxes. Obviously, only royalty rates may be controlled by the Department of the Interior.

The Department agrees that the reduction-in-royalty regulations now in effect may need refinement and clarifying guidelines. This matter is now under study. However, for the reasons presented below, the Department does not agree that GAO recommendations, if applied, would result in the large amounts of incremental oil production suggested.

Recovery

The GAO states that approximately 1.0 billion barrels of oil are technically recoverable with EOR techniques. The report also states that a substantial portion of this oil can be recovered through the implementation of the measures recommended by the GAO. These estimates reflect the most optimistic assumptions with regard to technical recoverability and costs. The geologic complexities of reservoirs in the Gulf of Mexico, the logistics of supplying the necessary fluids and materials to OCS operations, and the availability of injection fluids will restrict the application of most EOR methods in the Gulf for the next several years. Accordingly, the Department believes that the GAO estimates of recoverability represent overstatements of actual EOR potential for the Gulf of Mexico.

Incentives

The GAO's analysis led to the conclusion that the equivalent of a $4.00 reduction in the royalty rate would, depending on oil price and technology assumptions, produce up to an additional 725 million barrels of oil through the initiation of EOR projects. This seems highly unlikely since a reduction in the windfall profits tax from 70 to 30 percent for EOR projects has produced only one project (with another recently initiated) in the Gulf of Mexico. Two others have been proposed but as yet have not been initiated. Thus, a small reduction in the royalty rate is not likely to encourage sufficient EOR activities to produce anywhere near the recovery predicted by GAO. Moreover, the price of crude oil has dropped to a current price of $27 per barrel and is predicted to drop another $2 in the near future. At $25 per barrel, granting a royalty reduction equal to $4.00 would yield producers a revenue per barrel roughly equivalent to that which they received without a royalty reduction when the price was $29. However, since the latter price was not particularly effective in stimulating EOR activity in the Gulf, it is not expected that the $4.00 incentive will result in the incremental recovery suggested in the GAO report under current low price expectation.

Future oil and gas price uncertainty raises another question concerning the incentives proposed by GAO. The oil that could be recovered by EOR methods may be thought of as a newly discovered marginal field. Obviously, investment and production decisions for marginal fields are sensitive to small price changes. There is a problem in designing incentives that encourage long-term investment decisions over a wide range of prices yet assure a given level of royalty revenue to the Federal Government. It is possible that these two objectives cannot be simultaneously attained.

Platforms

The GAO states that 75 percent of the current platforms could be removed by the year 2000, and unless incentives are put in place to encourage widespread EOR activities in the Gulf in the near future, the 725 million barrels of oil will be lost forever. The Department, for the following reasons, does not agree.

1. The vast majority of the large oil fields are in the Miocene trend. The Miocene trend is a large, deep basin, the depths of which have yet to be explored. We have reason to expect deeper production all along this trend which will require new platforms and wells that can be used for future EOR projects.

2. Many of the current platforms in the large fields are old and could not be adapted easily for large EOR projects. Also, many of the wells are not drilled in the best structural position for EOR projects. Additional wells would be needed although, generally, there is little room on the current platforms for new wells. Thus, it is likely that lessees would choose new platforms for many of the EOR methods. A royalty reduction option would, however, allow a lessee to compare the use of an existing platform with a new platform.

3. Industry's move to deeper waters will likely dictate the design of mobile platforms for production systems as operating depths increase. These mobile platforms could also be used for EOR in the older fields in shallower water. Thus, some lessees may decide to abandon existing platforms and delay EOR decisions until mobile platforms are available. However, these decisions will vary among leases and lessees. A lessee's use of an existing platform would reflect an evaluation of the risk and potential returns of an EOR project.

Linking Royalty Reduction to EOR Projects

There is an implicit assumption in the GAO report that oil left unrecovered at the conclusion of primary and secondary recovery must necessarily be recovered through tertiary techniques. It must be understood that oil is left unrecovered not only because of increasing production costs but also because of the existing royalty rate at the time of shut-down. Reducing or eliminating the royalty rate at this point would create an incentive for additional recovery through conventional means. With a royalty rate reduction or elimination, some of the unrecovered oil could be produced using the same techniques of primary and/or secondary recovery that have been used throughout the production history of the reservoir. It is likely that, in a significant number of cases, the remaining recovery which can be economically undertaken will be achieved through the use of conventional production techniques and not tertiary techniques. However, the GAO report does not take this possibility into account.

The objective for royalty reductions should not be creation of an incentive for recovery through tertiary techniques. Rather, the objective should be additional recovery at the least cost by whatever means is available. The effort involved in making the determination that conventional costs per barrel have exceeded price would be similar to the effort involved in granting a royalty reduction on the basis of costs of a tertiary recovery project.

Administrative Problems in Selecting Royalty Reductions

The administrative problems associated with the GAO recommendations have not been adequately addressed in the report. To a major extent, the administrative problems would hinge on the information requirements imposed upon the MMS. Under the GAO proposal, lessees would apply for royalty reductions on a dollars-per-barrel basis. The application for a royalty reduction submitted by the lessee would take into account the remaining reserves, the present value of expected costs, and the present value of expected revenues given an expected time path for future prices. The MMS would then evaluate the application and presumably negotiate the dollar amount of the reduction in royalties if the amount of the reduction requested were to appear excessive. In order to be able to evaluate applications, the MMS would encounter administrative problems in connection with the production cost, especially the costs associated with new or relatively untested EOR techniques; availability and uncertainty associated with estimates of future prices; and reserves remaining in the reservoir. Thus, the evaluations to be conducted by MMS would require time, skilled personnel, and access to data all of which would involve a significant administrative burden on the MMS. The GAO report underestimates the difficulty of performing these functions.

In addition, it must be recognized that most of the regulatory information needed may only be available after lessees have been given the opportunity to test and evaluate pilot EOR projects. This, in turn, creates great regulatory uncertainty on the part of project supporters who will not proceed unless the "ground rules" are clear at the beginning of the EOR project. This point should have been given more attention by GAO, which should have also considered other ways (i.e., elimination of Windfall Profits Tax) to encourage EOR projects.

Despite the concerns raised above, the Department believes that the application of EOR techniques to the OCS is of sufficient importance to warrant further study.

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UNITED STATES DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE

NTL No. 2010-N03

Effective Date: March 25, 2010
Expiration Date: March 25, 2015

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES IN THE OUTER CONTINENTAL SHELF

Guidelines for Royalty Relief Under 30 CFR Part 203

This Notice to Lessees and Operators (NTL) provides guidelines that apply to the revised regulations for pre-production or expansion project royalty relief which we published in the Federal Register on November 18, 2008 (73 FR 69490) and supersedes NTL 2002-N02. Due to the new regulations, Appendix I which pertains to the existing royalty relief application and evaluation procedure used for certain deepwater leases in the Gulf of Mexico, now applies to leases offshore Alaska as well.

Under 30 CFR Part 203, certain lessees may apply to MMS for a suspension of royalty payments or a reduced royalty rate by submitting a complete application. We describe the specific data elements, parameters, reports and computer model or spreadsheets required in a complete application in two separate Appendices to this NTL. They also explain the procedures we will follow for evaluating applications and implementing royalty relief. These appendices are:

> Appendix I: GUIDELINES FOR THE APPLICATION, REVIEW, APPROVAL, AND ADMINISTRATION OF THE ROYALTY RELIEF FOR DEVELOPMENT AND EXPANSION PROJECTS, September 2009 and
>
> Appendix II: GUIDELINES FOR THE APPLICATION, REVIEW, APPROVAL, AND ADMINISTRATION OF ROYALTY RELIEF FOR END-OF-LIFE LEASES, September 2009.

These Appendices originally helped implement the section of the Deep Water Royalty Relief Act that applied to certain leases issued before 1996. Subsequent amendments to the regulations use this original application and evaluation process for other lease groups as well. The basic process described in these original guidelines remains the same, even if they may not always reflect this expanded program focus.

You should carefully review a copy of the appropriate guidelines if you intend to request royalty relief. They will help you structure your application to expedite our evaluation.

You can download the guidelines from the MMS website. They, along with the computer model or spreadsheet that you will need to prepare an application, are available at http://www.mms.gov/econ/econROYDW.htm under the subheadings for Case-by-Case Relief and RSVP for an application for royalty relief in deepwater or offshore Alaska or at http://www.mms.gov/ntls/ for an End-of-Life application.

If you have any questions on this NTL, you may contact Marshall Rose (703) 787-1538.

Paperwork Reduction Act of 1995 Statement: This NTL and its guidelines provide clarification, description, or interpretation of requirements contained in 30 CFR Part 203. The Office of Management and Budget has approved the collection of information required by these regulations and assigned OMB Control Number 1010-0071. This NTL and its guidelines do not impose additional information collection requirements that would be subject to the Paperwork Reduction Act of 1995.

Dated:

MAR 25 2010

Chris Oynes

Chris Oynes
Associate Director for
Offshore Energy and Minerals Management

Attachments:
Appendix I
Appendix II

UNITED STATES DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE

Appendix I to NTL No. 2010-N03

GUIDELINES FOR THE APPLICATION, REVIEW, APPROVAL, AND ADMINSTRATION OF THE ROYALTY RELIEF FOR DEVELOPMENT AND EXPANSION PROJECTS

March 2010

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ATTACHMENTS

Recovery of Costs

According to Federal policy and statute, we charge you a fee for applying for royalty suspension volumes to recover our cost of processing your applications. The Administrative Procedures Act (31 U.S.C. 9701) and Office of Management and Budget Circular A-25 require that we recover our costs when we provide services that confer special benefits or privileges to identifiable non-Federal recipients. Processing of applications for royalty relief clearly falls within this mandate.

Furthermore, our collection of such fees is specifically authorized by the Omnibus Appropriations Bill (PL. 104-134, 110 Stat. 13221, April 26, 1996). The statute provides: "That beginning in fiscal year 1996 and thereafter, fees for the royalty rate relief applications shall be established (and revised as needed) in Notices to Lessees, ...for the costs of administering the royalty rate relief authorized by 43 U.S.C. 1337 (a) (3)."

We may issue a notice to lessees and operators (NTL), updating NTL 98-5N, to provide more detailed information on the royalty relief application fees and when and how you must make payments. We will revise the NTL periodically to reflect our cost experience and to provide other information necessary for the administration of this program.

OVERVIEW OF GUIDELINES
FOR DEEP WATER ROYALTY RELIEF APPLICATIONS UNDER 30 CFR PART 203

We (Minerals Management Service) issued regulations at 30 CFR Part 203 with an update in January 2002 to implement the Outer Continental Shelf Deep Water Royalty Relief Act (Public Law 104-58 (DWRRA)). This Act clarified and expanded the Secretary of the Interior's authority in 43 U.S.C. 1337(a)(3) to reduce royalty rates on existing leases in order to promote development, increase production, and encourage production of marginal resources on producing or non-producing leases. This authority applies to oil and gas leases on the Federal Outer Continental Shelf (OCS) in water at least 200 meters deep in the Gulf of Mexico west of 87 degrees, 30 minutes west longitude that were issued in a lease sale held before November 28, 1995 or after November 28, 2000. Authorized lease(s) qualify for a royalty suspension volume if we determine the field, expansion project, or development project from which it would produce needs royalty relief to be economic.

You (affected lessees) may apply to our Gulf of Mexico Regional office for suspension of royalty payments by submitting the information specified under these regulations. These guidelines detail the format you should use for submitting the necessary information and the procedures and rationale we follow for evaluating applications. This edition of the guidelines reflect decisions made in connection with royalty relief cases over the last 3 years and expanded coverage under the updated regulations we issued in January 2002.

We advise you to review a copy of these guidelines if you intend to request deepwater royalty relief. We also encourage you to gain familiarity with our evaluation process by meeting with our Gulf of Mexico Regional Office prior to submitting an application. These guidelines do not add any requirements to the regulations, but they will help you decide whether to submit an application. Also, they will assist you in structuring your application so as to expedite our evaluation, should you decide to submit one. Be sure to use the most current version, as we will periodically update these guidelines to reflect our experience in processing applications.

Part of your submission requires you to use a computer model that you may obtain from our Regional Supervisor for Production and Development for the Gulf of Mexico OCS Region. The computer model and its documentation as well as these guidelines are also available on the MMS website at http://www.gomr.mms.gov/homepg/offshore/royrelef.html.

Any collection of information that we mention in these guidelines provides clarification, description, or interpretation of requirements contained in 30 CFR part 203. The Office of Management and Budget approved our collection of information required by these regulations and assigned OMB Control Number 1010-0071. These guidelines do not add information collection requirements that would be subject to the Paperwork Reduction Act of 1995.

Dated: 1/24/02

Carolita U Kallaur

Carolita U.Kallaur,
Associate Director
for Offshore Minerals Management

UNITED STATES DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE

Effective Date: February 14, 2002

Guidelines for the Application, Review, Approval and Administration of the Deep Water Royalty Relief Program

A. Introduction

These guidelines interpret regulations (30 CFR Part 203, Subpart B) which establish the terms and conditions for granting royalty suspension volumes under the Deep Water Royalty Relief Act (DWRRA). They apply to Outer Continental Shelf (OCS) oil and gas leases in water depths of 200 meters or more in the Central, Western, and portions of the Eastern Gulf of Mexico (GOM) that were in issued in lease sales held before November 28, 1995 or after November 28, 2000. Other guidelines interpret terms for reducing royalty rates under the OCS Lands Act (OCSLA).

As with the rule, we've written these guidelines in a plain English or conversational style. We (Minerals Management Service) give you (applicants, lessees, operators) directions on what to include in your application and what to do after we process it. Also, we explain how we will process your application and in some cases why we do it that way. Each section of these guidelines refers to the corresponding section in the regulations.

Guidelines are not strict rules like regulations, so we may consider requests for deviation from the guidelines when you provide compelling reasons for deviating from a provision, preferably before submitting a royalty relief application. Terms like "must" or "require" in these guidelines either replicate the regulations or indicate items we will ask you to provide if they do not appear in your application.

This installment of these guidelines incorporates changes we made in the underlying regulations in January 2002. These changes offered the right to apply for supplemental royalty relief to leases issued in sales held after November 2000 if they lie in water 200 meters or deeper in the Gulf of Mexico (GOM) wholly west of 87 degrees, 30 minutes West longitude. Also, the new regulations modified the relief qualification process. Some modifications apply only to leases issued after November 2000 (post-2000 leases) while others apply both to leases issued before the DWRRA (pre-Act leases) and to post-2000 leases. These modifications offer more opportunity, certainty, and flexibility for applicants. The following table summarizes continuing, discontinuing, and new elements in the application process for deepwater royalty relief.

PRINCIPAL ADDITIONS AND MODIFICATIONS IN 2002 TO DWRR APPLICATIONS

Element	*Applies to Pre-Act leases only*	*Applies to Post-2000 leases only*
Eligibility (Central, Western, and western part of Eastern Gulf of Mexico)	**Leases in 200m or more water depth issued before 1996.**	**Leases in 200m or more water depth issued after 2000.**
Unit of Application	**Whole field or Expansion project**	**Development or Expansion project**
Royalty-free production can come from	**Production from the field until the cumulative recovery volume from leases eligible to share in the relief equals the suspension volume.**	**Only production from resources identified in the application until cumulative production equals the suspension volume.**
Minimum suspension volume for non-producing leases	**For fields that did not produce before the Act, matches eligible lease suspension volumes (17.5, 52.5, 87.5 MMBOE) in equivalent water depths.**	**For development projects, matches volumes designated in sale and lease documents plus 10 percent of most likely reserves.**
Credit for sunk costs in application	**For fields with pre-Act leases that did not produce before the application, after-tax costs of and after discovery well used in qualification.**	**For development projects, after-tax cost of the project discovery well on each participating lease.**
Evaluation deadline for non-producing leases	**180 days for first determination, 120 days for a redetermination**	**150 days for first determination, 120 days for a redetermination**
Threshold oil and gas price levels for discontinuing relief	**Statute sets threshold price for light sweet crude oil and natural gas.**	**Original lease terms set threshold price for light sweet crude oil and natural gas.**

Element	*Formerly, but no longer applies to Pre-Act leases*	*Now applies both to Pre-Act and Post-2000 leases*
Discount rate used in evaluation	**Same rate used on viability and profitability tests, applicant chooses between 10% and 15%.**	**Use 10% on viability test, applicant chooses rate between 10% and 15% for profitability test.**
Credit for sunk costs in application for expansion project	**None**	**After-tax cost of the project discovery well on each participating lease.**
Minimum suspension volume for expansion project	**None**	**10 percent of most likely reserves.**
Evaluation deadline for expansion project	**180 days for first determination, 120 days for a redetermination**	**150 days for first determination, 120 days for a redetermination**
Deadline for starting fabrication	**Within 1 year of approval, extendable for up to 1 year.**	**Within 18 months of approval, extendable for up to 6 months.**
Deadline for filing Post-production Development Report	**60 days after the start of production, extendable for up to 60 days**	**120 days after the start of production, extentable for up to 30 days**
Correction for overestimating cost by 20% or more	**Retain only half of suspension volume granted.**	**Retain only half of smaller of suspension volume granted or most likely reserve size.**
Redetermination of field qualification or volume by MMS	**Available for new well or seismic data, 25% lower prices, or 20% higher cost.**	**Available anytime after relief relinquished or withdrawn. Otherwise, for new well or seismic data, 25% lower prices, 20% higher cost, or more efficient development system.**

B. Objectives of Deep Water Royalty Relief (DWRR) (supplements 30 CFR 203.1)

We may grant royalty suspensions in deep water for three purposes -- in order to increase production on leases already in production, to promote development on leases that have not produced (non-producing leases), or to encourage production of marginal resources on producing or non-producing deepwater leases. The program we use to implement this authority has three notable features. One, it applies only to the Western and Central Planning Areas of the GOM and the portion of the Eastern Planning Area of the GOM encompassing whole blocks lying west of 87 degrees, 30 minutes west longitude. Two, this authority only applies to deepwater leases issued in sales held before November 28, 1995 or after November 28, 2000. Three, we suspend royalties only for volumes of production needed to make the field or project economic, subject to minimum suspension volumes.

We implement these royalty relief provisions in conjunction with our stewardship responsibilities for sound management of public lands. This includes conservation of resources, obtaining a fair return to the public on OCS resources and ensuring that all OCS development is safe and consistent with sound environmental standards.

C. Relation of DWRR to Other Types of Royalty Relief (supplements 30 CFR 203.2)

We offer five types of royalty relief as described in the following table. Deep Water Royalty Relief (DWRR) is represented by rows b, c, d and e. Rows a and e represent relief available under the original OCSLA. Royalty suspensions are also available to some deepwater leases under 30 CFR 260 in their lease terms. Attachment A summarizes the main features of the various kinds of royalty relief.

If you have a lease...	And if you...	Then we may grant you...
(a) With earnings that cannot sustain production (End-of-life lease)	Would abandon otherwise potentially recoverable resources but seek to increase production by operating beyond the point at which the lease is economic under the existing royalty rate	A reduced royalty rate on current monthly production and a higher royalty rate (not to exceed the lease stipulated rate) on additional monthly production.[1] (See §§ 203.50 through 203.56.)
(b) Located in a designated GOM deep water area, acquired in a lease sale before November 28, 1995, or after November 28, 2000, and you propose in a DOCD or supplement to expand production significantly	Are producing and seek to increase ultimate resource recovery from one or more reservoirs not previously or currently producing in the field or lease, not simply extend recovery of reservoirs that already produced. (Expansion project)	A royalty suspension for additional production large enough to make the project economic. (See §§ 203.60 through 203.79.)

If you have a lease...	And if you...	Then we may grant you...
(c) Located in a designated GOM deep water area and acquired in a lease sale held before November 28, 1995 (Pre-Act lease)	Are on a field from which no current pre-Act lease produced (other than test production) before November 28, 1995 (Authorized field)	A royalty suspension for a minimum production volume plus any additional volume needed to make the field economic. (See §§ 203.60 through 203.79.)
(d) Located in a designated GOM deep water area and acquired in a lease sale held after November 28, 2000	Have not produced and can demonstrate that the suspension volume in your lease is not enough to make development economic (Development project)	A royalty suspension for a minimum production volume plus any additional volume needed to make your project economic. (See §§ 203.60 through 203.79.)
(e) Where royalty relief would recover significant additional resources or, in certain areas of the GOM, would enable development	Are not eligible to apply for end-of-life or deep water royalty relief, but show us you meet certain eligibility conditions	A royalty modification in size, duration, or form that makes your lease or project economic. (See § 203.80.)

[1] See the separate End-of-Life Lease Guidelines available from your regional MMS office for further explanation.

D. Basis for Granting DWRR (30 CFR 203.60, 63-64, 72)

Section 302(C) of the DWRRA states that an application may be made on the basis of an individual lease or unit. The term, "unit," isn't defined in the Act. The most fundamental issue we faced in implementing the DWRRA for pre-Act leases was should we base royalty relief on single leases or on some geologic or economic unit, such as a field?

Consistency with New Leases: We faced the same issue in the rule for Eligible leases (i.e., issued in sales after November 28, 1995 but before November 28, 2000). As we explain in detail in the preambles for our original rules implementing Sections 302 and 304 of the DWRRA, we believe the field basis for relief is consistent with the intent of Congress.

Under 30 CFR 260.110, an Eligible lease receives a suspension volume automatically, without demonstrating a need for the suspension to assure economic viability. These automatic volumes are established for the fields to which we subsequently assign the Eligible lease. We structured the rule and guidelines to apply royalty suspension provisions for pre-Act leases consistently with royalty suspension provisions for Eligible leases. Accordingly, we follow four principles.

First, we don't grant a royalty suspension volume to a field where any current lease produced before November 28, 1995, except in the case where you undertake a project to significantly expand production on your field. Since those leases which undertook the initial production from the field (and can be said to have taken the most risk) are not eligible for a royalty suspension volume under the DWRRA, neither should the lessees of leases on that producing field that begin production after the DWRRA's enactment. Under these circumstances, Congress certainly recognized that royalty relief isn't necessary to encourage production.

Second, we grant only one royalty suspension volume per Authorized field (i.e., a field not producing before November 28, 1995). We believe the Congress added "or unit" to Section 302 of the DWRRA to allow us to evaluate multi-lease fields. We don't compel unitization of fields applying for royalty relief. But, we expect leases in multi-lease fields that are not unitized to submit a joint application, as discussed in section F and we allocate a suspension volume as explained in section K.

Third, we may grant you a separate royalty suspension volume for each field that includes your lease and qualifies under section H. We may also give you relief for a project that will significantly expand production, even if we already granted a royalty suspension volume to the field that encompasses that project. However, the reserves associated with the project must not have been included in the application for the field-based relief (e.g., excluded as uneconomic, newly recognized on better seismic, etc.).

Fourth, we apply the same price threshold terms (see section N) to pre-Act and certain eligible leases (refer to lease document). Congress prescribed the same royalty suspension volumes for both kinds of leases and we believe intended the same discontinuation of royalty relief at high prices for both kinds of leases.

Field Designation: Our definition of a field is based on geology and for the purpose of royalty relief is found in 30 CFR 203.0. We directly notify all affected lessees when we establish or redefine a field and issue the OCS Operations Field Names Master List (FNML), which lists all the tracts in each field on the GOM OCS each quarter, with monthly updates. Our Field Naming Handbook explains how we decide what constitutes a field. It identifies six major check-points we use for assigning leases to fields and gives 12 examples of geologic structures in the GOM and the associated field designations. We make this Handbook available via INTERNET on the GOM Region's website.

We assign leases to a field when a well on the lease qualifies as capable of producing in paying quantities under the regulations at 30 CFR 250, Subpart A. If a well doesn't qualify under the rule, we assign the lease to a field when hydrocarbons are first produced from the lease or the lease is allocated production under an approved unit agreement. We will also include other leases/blocks that, in our judgment, ultimately will be part of your field when we evaluate your application. You must submit in the application, data covering any of your leases that you believe will ultimately be part of the field.

Because we continually update field definitions for new leases, data, and qualifying wells, we recommend that you confirm the most current lease make-up of the field before filing an application. That step will preclude delays as described below in processing an application that doesn't conform to our current definition of your field.

We recognize that you may occasionally disagree with the determination that your lease is part of a particular field. To minimize disagreements, we use an informal process to consult with you when establishing and revising field designations. Our regional office will notify you of a preliminary field decision that affects your lease and offer you the opportunity for an informal review and consultation before finalizing your field designation. If you are still dissatisfied, you may appeal the final regional designation to the Director of MMS in accordance with the procedures in section N.

Post-2000 leases: To reduce lessee uncertainty regarding the amount of relief available and to accelerate the application evaluation process, we have changed the basis for relief from field to lease for leases issued after 2000. For applications that do not involve a pre-Act lease, we assign royalty suspension to the project defined by the applicant. Because of the large royalty suspension volumes mandated in the DWRRA, we cannot make this simplification for pre-Act leases. The volumes mandated by the DWRRA were based on estimates of relief appropriate for a typical deepwater field in the early 1990's. Without the large field-based minimums, we can now offer royalty suspension volumes more closely tailored to your project's estimated need. Further, we can offer additional royalty suspension as supplemental relief to post-2000 leases that may already have some royalty suspension in their issuing terms but need more to sanction development.

Application Criteria: The regulations identify five basic conditions for your lease before we will examine your application to suspend royalty payments on new production. Your OCS lease or unit must :

1. Have been issued as a result of a lease sale held before November 28, 1995 or after November 28, 2000;
2. Be in the GOM wholly west of 87 degrees, 30 minutes west longitude;
3. Be in a water depth of at least 200 meters; and
4. Have a discovery (for both pre-Act and post-2000 lease applications)
5. Have been assigned to a field (pre-Act lease applications, only).

The deepest water depth on any lease in a MMS designated field establishes the water depth for that field. However, once we approve an application for relief, the royalty suspension volume for an authorized field will not change based on the addition or subtraction of a lease. We establish the water depth for each lease based on the Lease Terms and Economic Conditions map. We publish these maps before lease sales for areas where the deepwater royalty relief program applies. We base these maps on bathymetric data from the National Oceanic and Atmospheric Administration. For purposes of drawing the map, if the water depth crosses a block, we include that block in the deeper water category for determining the volume suspension. However, the associated royalty rate for some pre-Act leases was based on the median water depth of the lease. We will use the version of the Lease Terms and Economic Conditions map in effect at the time you apply for royalty suspension to determine the water depth of your field.

E. Non-binding Assessments (supplements 30 CFR 203.61)

You may request a non-binding assessment of whether your non-producing, Authorized field or development project would qualify for royalty relief before submitting the first complete application. We offer this option to help those who seek an early indication about the chances for royalty relief on a marginal prospect.

We expect this option to be useful where you are reluctant to spend funds on reducing uncertainties about the commerciality of a field or project without at least an informal indication of its chances for royalty relief. This assessment also could shorten the time we need to evaluate your final application by identifying issues that otherwise would have led us to toll the clock to obtain an explanation or additional information. Finally, it may be useful for fields where you are not willing to risk having to meet the qualification requirements for a redetermination should we reject your complete application for relief.

Our assessment at this preliminary stage isn't binding for two reasons. One, further appraisal and planning can substantially change the approach, data, and assumptions from those we used for the early assessment. In contrast, your complete application for a binding relief determination presents the proposal upon which you agree to be bound as a condition for receiving the royalty relief we determine that you need. Two, we base our non-binding assessment on the premise that the expected values of the data you provide will be confirmed by the additional appraisal and planning you complete before filing a complete application. Should your appraisal and planning indicate that changes in the input assumptions are needed, the original results may change substantially. So, if you wish a binding commitment to royalty relief, you need to submit a complete application as described in section F.

We don't require a complete application for the non-binding assessment. However, we feel we can give you the most reliable indication about your prospect's chances for relief only if you give us virtually equivalent details. A draft application containing preliminary estimates for all the data elements in the Administrative, Geological & Geophysical (G&G), Engineering, Production, Cost, and Economic Viability Reports is essential to ensure that we are assessing the same prospect that you envision. To fully describe expectations for the prospect, you should submit a draft application consisting of all parts of the six reports, discussed in separate sections at the end of these guidelines. For a draft application, you need not include the certifications by an officer in your company and by an independent CPA firm as specified in 30 CFR 203.81 (b), (c), and (d) or in paragraph k of the Cost Report section.

We develop our non-binding assessment of your field's royalty relief prospects presuming that your additional appraisal work would acquire data essential both to making a determination on royalty relief and a decision on development. Therefore, the regulation says your draft application for a non-binding assessment must be accompanied by an appraisal plan that proposes to drill one or more additional wells should we render a favorable non-binding assessment. Further, you need to identify appraisal and delineation well locations and expenses planned before submission of the complete application so we may consider them as sunk costs for purposes of our nonbinding assessment.

We fully expect that uncertainty in your various estimates will be greater than would be the case in a complete application. However, all parts of an application contribute to a common view of the prospect. A fee, prescribed in a separate NTL, must accompany your draft application to cover our cost of developing a full assessment that dependably forecasts whether your prospect can expect to qualify for royalty relief. This fee is less than that for a complete application because we don't do a completeness review as part of our assessment. While any final applications we may be evaluating will take priority, we intend to complete our non-binding assessments as quickly as possible.

Once we provide a non-binding assessment, the regulation specifies that you must wait at least 90 days before submitting a final application on your field or project. This is the case because we feel that 90 days is the minimum time you should need to conduct the additional appraisal and planning required to review and finalize a complete application.

F. Applications (supplements 30 CFR 203.62-63, 71, 81, 83 & 85-89)

To apply for deepwater royalty relief, you need to file a complete application with the MMS Regional Director, Gulf of Mexico Regional Office, 1201 Elmwood Park Blvd., New Orleans, LA. 70123-2394. Applications may be for either:

1. An Authorized field that includes your pre-Act lease and did not produce before November 28, 1995.

2. A development project that involves only post-2000 leases and has not yet produced.

3. An expansion project on either your pre-Act lease your post-2000 lease that will expand production significantly. For a pre-Act lease, you must propose development in a Development Operations Coordination Document (DOCD) or supplemental DOCD approved after November 28, 1995. Because DOCD's don't require an estimate of production, we define significant expansion of production on a pre-Act lease as any project that involves a substantial capital investment (e.g., fixed-leg platform, subsea template and manifold, tension-leg platform, or multiple wells). We define significant expansion of production on a post-2000 lease as any project that adds new resources, not simply extends recovery of reservoirs already in production, with one or more new wells drilled into a reservoir that has not previously produced.

<u>Content:</u> You should finish all well appraisal work before you apply for royalty relief. A complete application includes the original and two copies (one copy for digital information) of:

1) Administrative Information Report;
2) G&G Report;
3) Engineering Report;
4) Production Report;
5) Cost Report; and
6) DWRR Economic Viability and Relief Justification Report

You can find details on the format and content of these reports in the Report Section later in these guidelines. A short form application, as mentioned in section K, case 3, includes only report 1) above. You owe a fee (see our most recent fee NTL, which can found at http://www.gomr.mms.gov/homepg/offshore/royrelef.html) with each application you submit. A complete application for an expansion project also needs to reference an approved DOCD or supplemental DOCD.

Consulting and Certification: We will answer technical questions about your prospective application before we receive it and the processing fee. Such technical questions include: what we expect in the backup reports, how the RSVP model works, what needs to be in a complete application, and what are the currently prescribed economic inputs for the RSVP model. Also, we will describe our evaluation process and answer any question on these guidelines.

The regulation says you or your authorized representative must certify that all information submitted in the application is accurate, complete, and conforms to the format and detail specified in these guidelines. Your application also needs to be accompanied by a report prepared by an independent CPA expressing an opinion on the accuracy of the historical financial information presented and on whether it conforms to the presentation format specified in these guidelines. Attachment D to these guidelines describes what we expect the CPA to review and certify. You should identify an individual with the CPA firm who is knowledgeable about your field or project and is authorized to answer questions on it. Also, to expedite our review, please arrange to make him or her available to respond to questions we may have on the historical information. We still may need to review your records supporting the historical financial information in the application.

Multi-lease Applications: You should submit information about resources on all leases in the field or project. Also, you and other lessees on the field should plan either joint development or a joint application and make sure you meet the performance conditions for retaining approved relief. We've established the following joint application procedures.

1. We will accept only one joint application for all leases that are part of a field, as defined by the Regional Director, on the date of application, except as provided for in subparagraph 3 below. Our Regional Director for the GOM, maintains a list of all leases assigned to each field we've established. Also, we will accept only one application on a development project designed to produce a specific set of reservoirs.

2. You may submit separately to us proprietary G&G data that is a necessary part of the joint application, if you don't want to share that data with other lessees on your field. Your application isn't complete until we receive all the information stipulated in the rule for each lease on the field. In explaining our assumptions and reasoning behind our determinations, we won't disclose proprietary data.

3. We will waive the joint application requirement for a field or project if you show good cause for the waiver. You should fully explain this good cause and demonstrate that you made a good faith effort to obtain the participation of all lessees in the field or project. A

lease that is assigned to the field on the date of application but that isn't included in the application, because its lessee(s) fails or refuses to participate, won't share royalty relief for the field that is the subject of the application. We will include an estimate of the non-participating lease's portion of field or project resources and costs in our economic evaluation of your field or project. Also, we will evaluate the economics without royalties of those resources (up to the size of the royalty suspension volumes in the lease terms) on the field or project that are on eligible or RS leases (those that have royalty suspensions in their lease terms).

4. You or your successors may submit only one complete application for royalty relief during the life of the field or a specific development project, except in the following situations. You may submit another application if:

a) you are eligible to apply for a redetermination under section I,
b) we withdraw or you renounce previously approved royalty relief,
c) you apply for royalty relief for an Expansion project, or
d) you apply for end-of-life royalty relief.

G. Review (supplements 30 CFR 203.65-66)

We may take up to 20 working days after receiving your application to determine whether it's complete. If information is missing, we will attempt to give you an opportunity to submit the needed information during the 20-day period. If we deem the application complete, we will notify you and initiate the evaluation process. If not, we explain to you what the application needs to become complete.

If we propose to revise the make-up of your field after you file an application, we will not delay our completeness review. But, we will advise you that the field we intend to evaluate may differ from the one you described in your application. You may continue to contest this new field definition under the appeal process described in section N.

In situations where we modify your field by adding a lease during our evaluation, we may notify you that we need more information to complete our evaluation. If our regional office does finalize a change in your field make-up, we will ask you to agree to toll the evaluation clock until you can modify your application to include the new lease. We will also ask for an additional 60 days to review the new information. If you own or operate the added lease and decline our request to toll the clock, we will reject your application for inadequate information. If you don't own or operate the added lease and decline our tolling request, that added lease is still entitled to share any relief we approve for you by filing a short form application.

The DWRRA requires that we make a determination within 180 days after we deem your application complete (120 days in the case of a redetermination). The shorter period for the redetermination is based on the notion that we will have the head start of already being familiar with the field. Because they are more narrowly defined, we commit to making a determination on development projects and expansion projects within 150 days.

The 180/150/120-day time period won't begin until we determine and so notify you that your application is complete. Once we deem it complete, you may not initiate a modification (as opposed to a clarification) to your application. Notwithstanding this notification, if during the evaluation period, we find that data in the application are missing, unclear, inconclusive, or otherwise cannot be relied on, we will request new data or information needed to make the application reliable and accurate.

If we request more data, we ask that you agree to our tolling the 180/150/120-day time period from the time we make our request until you provide us the needed information. When you supply the needed information, we will restart the time period with the same number of days remaining for our determination as when the time was tolled. If, within 30 days after our request, you've not agreed to toll the evaluation clock or answered our questions, we will proceed to evaluate what we believe is the most logical development and production configuration for your field or project. Also, we reserve the right to proceed with our own interpretation of your original submission when your application presents inconsistent data. Otherwise, a complete but inconsistent application can be used to withhold data vital to our determination until late in the evaluation process.

We have a "fixed" application policy. During the 180-day evaluation period, you may not update your application based on new information such as actual costs, contracts, or revised design criteria except as described below. We do not believe it would be a fair and equitable process to allow a partial update of information and exclude other items such as oil and gas prices. You always have the option during the evaluation period to withdraw and resubmit the application.

Upon completion of our internal review (prior to a final decision), if our evaluation indicates a potential denial of your application, we may meet with you to identify the data in your application that we revised and to explain the reasons for the revisions. In such cases, we may give you an opportunity to address any misunderstanding which you believe we may have with your application, or to submit additional information to further explain and support the data in question. Also, with regard to the data in question, you may submit new supporting information such as actual costs or contracts. However, we will not revise any cost inputs to RSVP above your original estimates. Further, if you wish to submit additional information, we ask that you agree to a tolling of the evaluation period from the date of our meeting until we receive the information. We may also ask you for an additional tolling period to allow us time to review the new information.

You should notify us immediately if you begin drilling a well during the 180/150/120-day evaluation period. If you expect to complete the drilling operation within this period, we will ask that you agree to toll the clock so the new well information can be incorporated into our evaluation. We would toll the evaluation clock from the beginning of drilling operations at least until we receive the new information. If necessary, we would extend tolling for a specified period to provide time to complete our evaluation of the new information within the legal time limit. If you do not agree to tolling and to any request from us that you modify your application, we may reject your application request because the accelerated drilling program is not consistent with your application or because your application lacks required data.

If we determine that we need to audit sunk costs in order to evaluate your application, we request the 180/150/120-day evaluation period be tolled from the time you receive our notice until you provide and we receive the records necessary to conduct our audit. See section M for the procedures of how this audit determination will be made.

At the end of the 180/150/120-day evaluation period, we may extend for 30 days the time period for making the determination or redetermination without your consent, or for longer than 30 days if you agree. If we don't complete the determination for your field in the prescribed time period, together with any extension thereof, your field gets the minimum royalty suspension volume, as specified in section L below (except when you retract your application). If we don't complete a determination for your development project within its time limit, your project gets a royalty suspension for production during the number of months that a decision is delayed, plus all the royalty suspension volume for which you qualify. For instance, if we take 185 days instead of the maximum of 150 days to determine that your development project needs 35 MMBOE, your project gets a royalty suspension for its first two months of production plus 35 MMBOE. In the case of an Expansion project, the DWRRA specifies that we will collect no royalty on the new production for the first year of production, if we fail to make a determination on time.

H. Economic Evaluation Procedures (supplements 30 CFR 203.67-68)

Economic Measure: Over the years we've studied various measures to forecast whether or not a project might be economic. We've chosen to use net present value (NPV) in these types of assessments because we believe it best meets the characteristics needed to make proper and timely decisions. Specifically, NPV analysis is an appropriate measure of profit, reflects the time value of money, compares and ranks opportunities, indicates directly whether profit exceeds some minimum level, and is a widely used and understood measure of the value of a project. NPV analysis also avoids the analytical problems found with other measures. For instance, rate of return analysis has iteration requirements, can have multiple solutions, and can give ambiguous rankings for projects.

Further, Monte Carlo or probabilistic analysis techniques can be used with NPV calculations to incorporate varying degrees of uncertainty about the many variables that affect the result. This standard decision analysis approach is often used to evaluate projects at the exploration stage. To adapt this tool to evaluation at the development stage, we have added the feature of truncating extremely negative outcomes that may result from some of the simulations. This truncation procedure acts as a proxy for an option value analysis, which would serve to reflect the flexibility an applicant has (but that is not captured in a standard NPV decision analysis) to change a preliminary decision in light of emerging information. When disappointing reserve sizes join low prices or high costs, the prudent operator will in fact cut his losses long before completing full development by abandoning or at least postponing the project. We simulate that outcome by limiting the size of losses to a magnitude compatible with reaching that abort decision.

When the mean or expected NPV is equal to zero, an investment yields a rate of return equal to the chosen discount rate. If the NPV is less than zero, the investment earns a rate of return below the discount rate and is uneconomic. If the NPV is more than zero, the investment earns a larger rate of return and is economic. Therefore, in keeping with standard practice, we chose expected NPV as the decision criteria we use in the determinations discussed below. Our decision criteria is based on the mean NPV of simulations from a large sample of possible outcomes, including the limited losses in those trials where development is quite likely to be aborted.

We considered the use of a lower NPV criterion since a value only slightly less than zero could result in a large volume of relief. However, we dropped this idea due to the difficulty of identifying and justifying any such value.

Economic Tests: We subject applications for DWRR to up to three discounted cash flow (DCF) analyses. All three analyses use the same price assumptions but not necessarily the same discount rate assumptions.

(1) *Viability* (or Dual) *Test*. We determine whether any royalty suspension volume can make your development and attendant new production economic. For this test the DCF is calculated under assumptions most favorable for finding a positive NPV. Proposals that don't predict a positive NPV when no royalties are ever collected from the field and when no costs before the date of the application are counted are either beyond hope economically or exclude vital information. As part of this most favorable perspective, we specify that the lowest discount rate from the range we allow you to choose from will be used for this test. Currently the viability test uses a 10% discount rate.

You initially carry out this DCF analysis as part of the complete application using the Royalty Suspension Viability Program (RSVP v2.14) model that we provide. See Attachment E. In this analysis, we expect you to propose the system you intend to install if we approve royalty relief. Also, we expect you to define scenarios that fairly reflect the range of your uncertainty about the appropriate development scale for your field or project.

Subsequently, we review your analysis to confirm this determination and verify the system you propose is the most economical under the conditions used for this test. Our review also focuses on confirming that you've included appropriate costs and identified adequate resources to predict profits with the proposed system when neither royalties nor sunk costs are included in the DCF, calculated with a 10% discount rate.

We don't allow certain types of costs because they are not directly related to your production from your field. Paragraph h.of the Cost Report section lists costs we consider ineligible. One such item is expenditures for unsuccessful exploration activities, which we distinguish from delineation by the fact that they are not associated with a source of revenue or benefit to the field. RSVP v2.14 includes a feature to adjust for an ineligible element in well costs. When you propose drilling into previously un-penetrated reservoirs, the cost for that completion is included in the analysis only when that reservoir is sampled as not being dry. If the reservoir is to be penetrated by a well that goes through other reservoirs, a proportionate share of the completion costs for non-dry reservoirs are counted. The documentation for RSVP v2.14 more fully explains how this and other features of the model work.

In those instances where no amount of royalty suspension volume would make your field economic, we deny your application for royalty relief.

(2) *Profitability* (or Primary) *Test.* We determine if your proposed development is economic while paying lease royalties. As we are obliged to evaluate the most economical system for developing your field, we invite you to identify alternative systems that you considered and why you believe those are less economical than the one you propose. We evaluate whether the system you propose, or a logical alternative, is most economical should full royalties have to be paid. If we determine that the development of the field would be economic without relief, we deny your application. You choose which discount rate we use for this assessment from a range that we specify. Currently that range is from 10% to 15%. If you do not specify a particular discount rate, we will use 15%.

The following figure illustrate how RSVP develops the essential elements of the viability and profitability determinations. Each test requires 2 passes through the RSVP model. On the first pass, the Resource Module calculates a distribution for the size of the resource for the field or project (in BOEs) and for the oil portion of that resource. It does this by combining samples from up to 8 distributions for each reservoir. Discrete distributions (e.g., binomial) reflect estimates about whether each reservoir contains oil, gas or both, and how much of the reservoir will be oil. Continuous distributions (e.g., triangular) reflect estimates about the size, composition, and producibility of each reservoir.

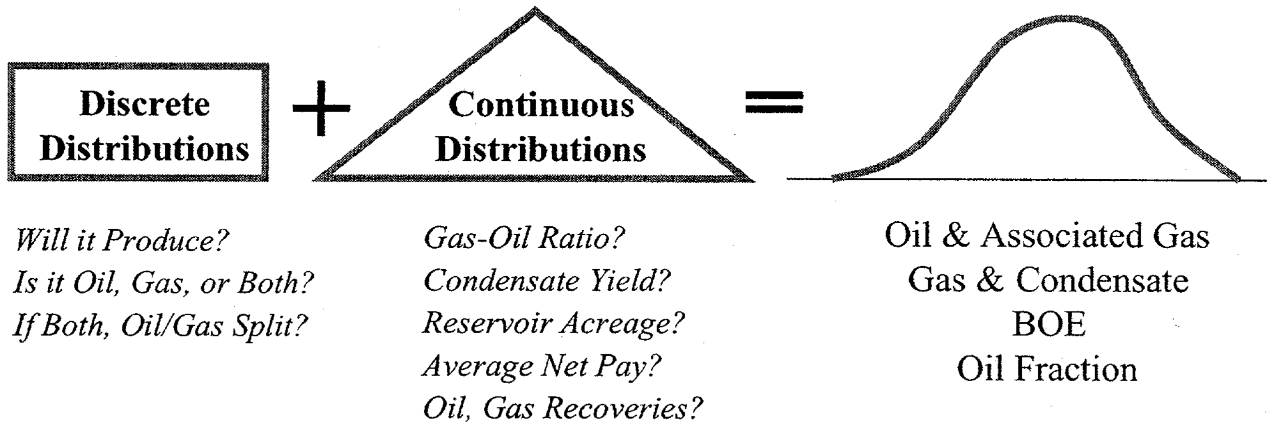
You then enter results from the Resource Module pass, along with up to 3 scenarios for capital costs and production rates, and rerun the model. The Viability Module correlates a narrowed distribution of resources (i.e., reserves) with capital costs and production rates and, using an MMS prescribed price path, calculates a distribution of NPV's. This distribution contains both profitable and unprofitable outcomes. The RSVP truncates "no-go" or loss-limited trials (those with abysmally large losses) to a loss equal to an estimate of expenses incurred up to the abort ("no-go") point. RSVP calculates a mean NPV from the distribution of profitable, unprofitable, and truncated loss trials. To qualify for relief, the mean NPV with neither royalties nor historic (sunk) costs (prospective NPV or PNPV) must be positive, while the mean NPV with full royalties and allowable sunk costs (full NPV or FNPV) must be negative. If your NPV is outside the FNPV to PNPV interval, then royalty relief at any level is not enough to make a difference. Your field or project is either already economic or royalty relief does not provide sufficient additional income to make development economic. (See the attached "RSVP" chart.) Documentation for RSVP provides a detailed explanation of how this spreadsheet model works and can be found at http://www.gomr.mms.gov/homepg/offshore/royrelef.html.

Sunk Cost. Before moving on to the third test, we need to cover how and why we treat sunk cost as we do. Besides royalties, sunk costs are central to the profitability determination. Insofar as the overall goal of royalty relief is to promote the development of marginal fields, economic theory suggests that only costs that are relevant to the development decision of the operator need to be considered. Sunk costs don't affect that decision.

RSVP Resource Module

Input Data by Reservoir

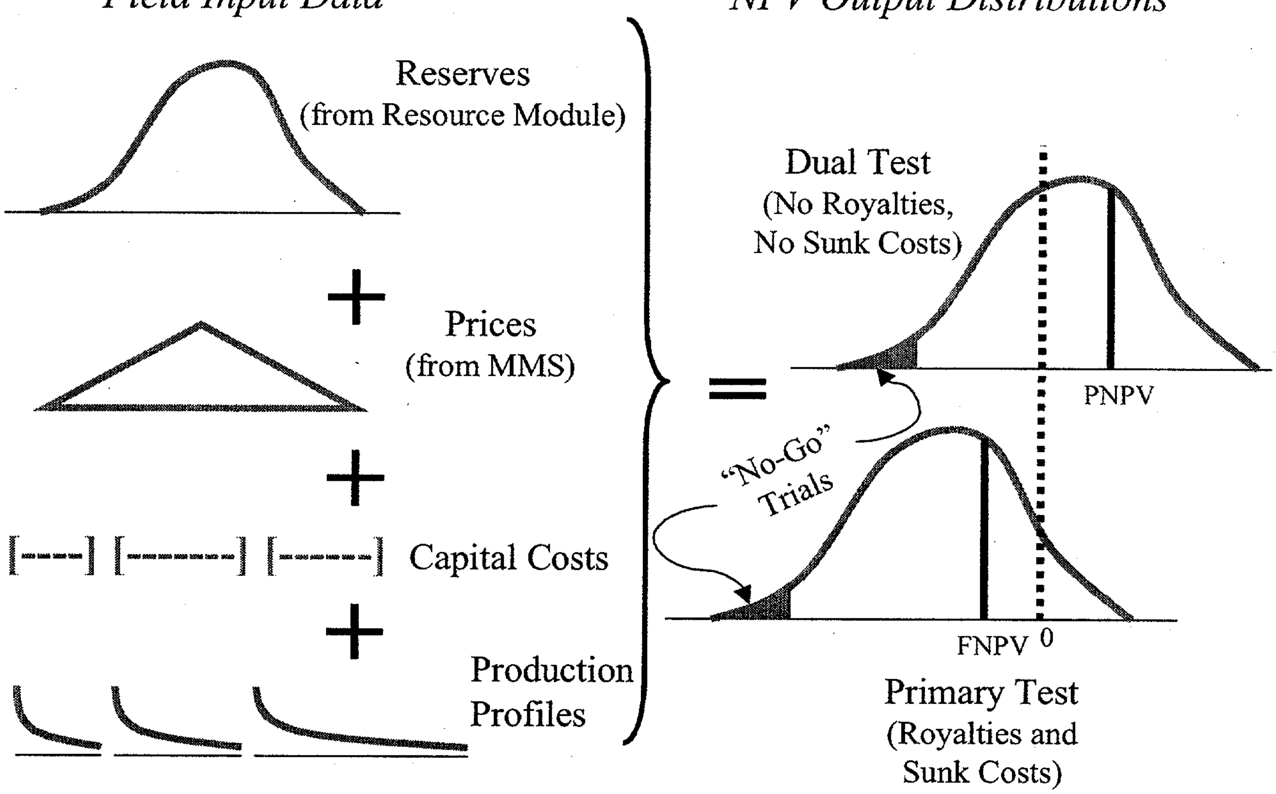
Output Distributions of Field Resources



RSVP Viability Module

Field Input Data

NPV Output Distributions



However, a relief qualification that includes sunk cost may indirectly encourage more development, and perhaps more exploration, than otherwise. Sunk costs in an evaluation make qualification for discretionary royalty relief more likely. The more likely a prospect of a given size is to qualify for relief, the larger is the expected value of a prospect yet to be explored. And, the higher is the payoff from drilling, the more and sooner drilling will take place. Also, the DWRRA directs that we consider all costs associated with exploring, developing, and producing from the lease. Hence, we consider certain eligible types of historical costs (i.e., sunk costs) in making this determination. When your field includes a pre-Act lease and has not produced, other than test production, before you submitted a complete application for royalty relief, we use a broad definition of allowable sunk cost. In this case, we include your eligible expenditures from the date of the first discovery of the field up to the date you submit a complete application, plus the costs of your discovery well if it is qualified as producible under 30 CFR 250, Subpart A in the profitability test.

We use a narrower definition of sunk cost for a development or expansion project application. A narrower definition of sunk cost, in comparison to the definition of sunk cost for pre-Act leases, is consistent with a narrower unit of operation. A specific project, rather than a whole field, is the object of the royalty relief program. In the case of a field, all the resources and development possibilities need to be evaluated. Thus, a field evaluation depends on more complete appraisal, and so provides a basis for the broad definition of allowable sunk costs. But, discerning the relevance of all post-discovery expenditures is more critical when the subject of the application is a specific project rather than an entire field. Such expenditures may benefit existing production as well as future production or may have been incurred on lease resources not included in the application. Therefore, on a development project or expansion project, we limit allowable sunk costs to the cost of the first well on each lease that discovers hydrocarbons in the reservoirs included in the application. Attachment B reproduces the definitions found in the regulations at 30 CFR 203.0, including the 2 forms of allowable sunk costs. Attachment C summarizes categories of allowable costs.

We limit the amount of sunk costs we count to those clearly related to developing your field that have not been recovered in previous transactions. We measure sunk costs on an after-tax expensed basis, using the nominal (current dollar) amounts without any interest or discount rate adjustments. Also, we include only sunk costs incurred by current owners of all leases that are both assigned to the field at the date of the application and included in the application.

We don't count any sunk costs in the profitability test for fields that produced prior to the date you submitted a complete application because they are irrelevant to whether fields continue production or not. We don't count any historical costs incurred by third parties, such as former leaseholders. Such costs are hard to verify and are not relevant to the current owner's decision of whether or not to develop and produce the field. We presume that former owner(s) willingly exchanged the possible future revenues that recover their historic costs for compensation received in transferring their share of the lease(s) to others. In turn, these current owners did not incur these third-party exploration and development costs, but they did or will benefit from their results. Therefore, the costs and benefits of third-party expenses have been fully considered through past market transactions involving the field.

(3) *Volume Test.* We approve your application for royalty relief if the most economical system for the viability test shows a positive NPV and the best system for the profitability test shows a negative NPV. Then, we compute a volume of production on which to suspend royalties that is sufficient to make your field economic. This volume calculation is the third determination.

We won't count sunk costs in computing the royalty suspension volume that will make the field or project economically viable. To do otherwise risks adding relief well beyond that necessary to make development economic. Also, it would direct more relief to just the wrong fields or projects. Those with relatively large sunk costs would qualify for relatively large volume suspension, but they are more likely to continue anyway because they have relatively smaller costs left to incur and that must be covered by future production. However, we ensure that inclusion of sunk cost in the profitability test gives you an unambiguous benefit by guaranteeing successful applications receive at least the minimum royalty suspension volumes specified in section L.

If we determine that it takes more than the minimum volume suspension to make your field or project economic, we will calculate the volume suspension using a similar DCF model. We use the resources, engineering design and prospective costs in the application, as verified and potentially modified by us for the viability test, in this calculation. One major difference in the way we conduct this test arises from your obligation to meet certain performance conditions, per 30 CFR 203.76 of the final rule, in order to realize an approved volume suspension. To incorporate that constraint, we base your volume suspension determination only on the most likely scenario and associated resource range in your approved application.

<u>Special Cases:</u> We apply slight variations to the general evaluation procedure described above in cases where ownership changes, where leases are added to a field, and for evaluating expansion projects.

(1) *Ownership Changes.* When changes in lease ownership occur, they can affect how we consider sunk cost. If there is a break in your ownership tenure, we count only your historical costs since you last obtained a share of the lease. If you've maintained continuous ownership but changed the share of the lease you own, we count your sunk costs on that lease in proportion to the share you owned when you incurred these costs. These principles apply until we make a final determination on your application. Accordingly, a break in ownership on a lease after you submit an application but before we make a final determination could result in a loss of some of the field's otherwise allowable sunk costs. However, after you submit an application, a redistribution of ownership shares on a lease among current or new owners, without a break in ownership, will not affect how we count the allowable costs.

The following table illustrates how we apply these principles to each lease on your field. The table entries represent the percentage ownership of the lease by company and period.

CASE	I	I	II	II	III	III	III
PERIOD	1	2	1	2	1a	1b	2
COMPANY							
A	80	40	80	80	80		40
B	20	20	20		20	60	20
C		40		20		40	40

Period 1 spans the time from when we begin counting sunk costs up to the first change in ownership. Period 2 runs from the end of period 1 until an application is filed. In cases I through III, all period 2 owners are assumed to retain shares during our evaluation process, i.e., during period 3. The results described below would not be affected by a redistribution of ownership shares during period 3 as long as there is no break in ownership in this period. This is the case because there are no sunk costs allowed in period 3, and satisfaction of the continuous ownership requirement would entitle the field to retain all of the sunk costs incurred in period 2.

In case I, we count all of the allowable sunk costs in period 1 since they were all incurred by current owners. Of course, we count all of the allowable sunk costs in period 2 as well since they too, were incurred by the current owners.

In case II, we count only 80 percent of allowable sunk costs spent in period 1. We don't count the remaining 20 percent as it is related to a non-current owner. Again we count all allowable costs in period 2.

Case III represents a situation in which there are two changes in ownership up to the time of application, and stable ownership through a final determination. We count only 20 percent of allowable costs from period 1a owing to continuous ownership by company B but not company A. The subsequent break in ownership for company A precludes our counting its costs from period 1a. For periods 1b and 2, we count all costs because there is continuous ownership from period 2 back to period 1b. That accounts for 100 percent of eligible shares in each period. We apply equivalent rules when ownership changes during the evaluation period.

In case IV, we have two breaks in ownership--one before the application is submitted (period 1b) and the other after submission, but before we make a final determination (period 3). No sunk costs are applicable in period 3. We count all allowable sunk costs in period 2 and in period 1b because all owners in those periods have maintained continuous ownership. We count only B's 20 percent of sunk costs from period 1a because A was compensated for its costs during period 1a in the transfer of all its ownership after that point.

CASE	IV	IV	IV	IV	V	V	V	V
PERIOD	1a	1b	2	3	1a	1b	2	3
COMPANY								
A	80		50	40	80		50	
B	20	100	50	20	20	100	50	20
C				40				80

The final case V is identical to case IV, except that during period 3, when we are evaluating the application, there is a break in ownership. The break in ownership makes companies B and C current owners for purpose of the application. So, we don't count any of A's sunk costs from periods 1a and 2, but we count all of B's sunk costs--50 percent in period 2, 100 percent in period 1b, and 20 percent in period 1a.

To ensure that we include the proper amount of allowable sunk costs in our determination, your application should clearly indicate the historic ownership shares of the current owners for each lease in the application, along with the distribution of allowable sunk costs by lease and time period. Moreover, you should notify us immediately when, during the application review process, there is any change in ownership shares on a lease in your field, with special attention to breaks in ownership. Your failure to indicate the historic and current ownership arrangements in a clear, accurate, and timely manner risks losing any relief that we may grant on the grounds that you provided inaccurate information that is material to our determination.

(2) *Fields Mixing Pre-Act, Eligible and/or post-2000 Leases*. If your pre-Act lease is on a field that already has a royalty suspension volume for new leases under 30 CFR 260.110, you may apply to share the volume suspension under conditions specified in 30 CFR 203.60 and 62-63. Also, your post-2000 lease may apply for development project relief even if it already has a royalty suspension volume. We evaluate your relief application in much the same manner as described above except that we conduct the three DCF determinations taking into consideration the volume suspension to be used by eligible and/or RS leases (those issued after 2000 with a royalty suspension) on the field/project.

Eligible leases (those issued within 5 years after the DWRRA) and RS leases automatically qualify for volume suspensions. Their lessees may or may not choose to join with a pre-Act lease on the same field that wishes to apply for relief. The lessee of the pre-Act lease must show good cause for us to waive the requirement that all leases on the field be part of an application for royalty relief. Upon appropriate application by a pre-Act lease on a mixed field, we will evaluate field economics including the suspension volume we judge the Eligible and/or RS leases will be able to use. This may be the full automatic suspension volume, or it may be less if we decide those leases will be unable to use their full suspension. Case 4, Section L explains how we allocate a volume suspension if we determine that you qualify to share in the field's royalty suspension volume.

An example may help clarify this description. Suppose lease A (the pre-Act lease) and lease B (the Eligible lease) are on the same field and that lease B entitles the field to a royalty suspension volume of 87.5 million barrels of oil equivalent (MMBOE). If we conclude that lease B can produce that much, we reject an application for relief for lease A if the field is economic with royalty free production of 87.5 MMBOE or less. If we decide that lease B can only produce 40 MMBOE, then we reject lease A's application if the field is economic with royalty free production of 40 MMBOE or less. We follow the same procedure when an RS lease is involved in a royalty relief application, either for a field with pre-Act leases or a development project. This approach means we presume any expected profits from lease B offset equivalent losses from lease A, regardless of whether they develop jointly or separately. In the event that we reject your application for lease A, you may be able to file an application for relief under the expansion project provisions explained in item 3 of this section.

Material change conditions on approved relief play a reduced role in this situation. Lease B's status as an Eligible lease, serves to shield its owners from loss or reduction of relief for a material change from the application. Likewise, an RS lease is exposed to loss of only the increment above the royalty suspension with which we originally issued it for violation of a material change condition. Development on lease A still must avoid the material change conditions described in section J. In such cases, we will be more inclined to look at a wider set of possible resource and cost paths before approving a relief application.

(3) *Expansion Projects*. We evaluate your applications for an expansion project with the same three determinations on a project specific basis. We count sunk costs in any of the determinations for an expansion project in the same way we do for a development project. Any royalty suspension volume amounts that we award will apply only to production from reservoirs targeted by your proposed expansion project.

You should note that your receiving a royalty suspension volume on production from a Authorized field doesn't preclude you from obtaining further relief. You may do so under the pre-DWRRA provisions of the OCSLA, the expanded OCSLA royalty relief provisions created by the DWRRA, or under the significant expansion of production portion of the DWRRA. However, your expansion project should recover reserves that were not considered in our original determination (e.g., excluded as uneconomic, or newly recognized based on better seismic, etc.). At least one of the new reservoirs you intend to recover with the expansion project must have a discovery well, as we do not grant relief solely for exploratory activities.

<u>Applicant Inputs:</u> In general, you the applicant provide the resource, productivity and development data, and the costs we use in the determinations. We devote most of the evaluation period to assessing the appropriateness and consistency of these inputs. The following discussion highlights characteristics that we look for in your submission.

(1) *Resource Estimates*. You should give your interpretations of the underlying geology with probability distributions, reflecting the uncertainties about your field's potential size and production. We expect you to use triangular distributions for the parameters used in the resource calculation. You may select other types of distributions from the options available with Crystal Ball in our RSVP v2.14 model, but you must give a detailed explanation of why your choice better represents your geology than the default triangular distribution. We carefully review the raw backup data and may adjust the geological interpretations if we determine others are more appropriate.

We verify your estimates for resources and reserves prior to determining economic viability. Part of our resources and reserves verification involves weighing whether you propose too many or too few reservoirs for development. We may decide to drop reservoirs because they add more cost than revenue to the project. In such cases we will exclude that reservoir's production and drop the associated costs from the analysis. We also drop these costs from the base for your material change performance condition of spending at least 80 percent of the estimated pre-production development costs in your most likely scenario. On the other hand, we may add reservoirs because they would contribute more revenue than cost to your project. In this case we presume that you'll develop the extra reserves in a later phase, so we include the extra costs and revenues after production begins.

(2) *Production and Cost Estimates.* You specify production and capital costs using up to three scenarios (conservative, most likely, optimistic) to reflect the level of uncertainty, if any, in the design scale of your final development system and in the production profile of your reservoirs. We structured the RSVP v2.14 model to simulate adjustments in cost and scale (e.g., number of wells, throughput capacity) based on the potential results of further delineation and project definition. The three scenarios are designed to correlate resource sizes with cost levels. That is, when larger than expected resource sizes are sampled (simulating better than expected delineation results), higher costs (e.g., larger capacity) also tend to be sampled, and vice versa. We will consider an alternative approach to selecting the development scenario for each trial if you convince us that it better reflects the decision variables that will guide your choice among the various scenarios. As in the resource module, you may use probability distributions for productivity and unit cost assumption in the viability module.

You must use care in configuring the development scenarios in RSVP v2.14. We will insist that the mean of the all-trial distribution of capital costs be no more than 7.5 percent above the capital cost estimate you give for the most likely scenario. Also, we insist that the most likely scenario cover at least 1/3 of all trials. These restrictions help ensure that your estimates for the most likely scenario are representative of the uncertainty you face and that your application is not being submitted too early in your decision process.

The 7.5 percent value is derived from one of the conditions under which you may request a redetermination. If your costs rise by more than 20 percent from the most likely estimate in your most recent previous application, you are entitled to a redetermination. That is, 20 percent is the largest capital cost increase that we consider consistent with other elements in your development plan. Conversely, a 5 percent cost decrease represents a conservative estimate of the cost savings you may be able to realize. The midpoint of this interval (7.5 percent) represents the largest average deviation of cost that we will allow. Costs that vary by more than 7.5 percent on average indicate that your application is premature. Greater variance suggests that you are not yet confident enough in your cost estimates to decide whether relief from a 12.5 (or in some cases 16.67) percent royalty is likely to make an unprofitable prospect profitable or not.

The following example clarifies this guidance. Suppose you claim that capital costs (including platform fabrication and installation) and well drilling and completion cost are as shown in the following table.

Scenario Estimate	Conservative	Most Likely	Optimistic	Mean, all trials
Platform cost	$250MM	$250MM	$250MM	
Confidence interval	$245 to $350MM [-2%/+40%]	$225 to $338MM [-10%/+35%]	$210 to $300MM [-16%/+20%]	$300MM
Number of wells	6	5	5	
Average cost/ well	$36 MM	$30 MM	$28 MM	
Well cost	$216MM	$150MM	$140MM	$170MM
Best estimate of capital costs		$400 MM		$470MM

RSVP v2.14 calculates the distribution of capital costs of all trials. Suppose the mean of this distribution is as shown in the right-hand column. The application envisions total capital costs 17.5 percent {[(470/400) - 1] * 100 percent} above the best estimate that your back-up data supports. Looked at another way, your application includes an excessive contingency cost estimate of 17.5 percent. That much uncertainty indicates that it is premature to tell whether royalties are the difference between profit or loss for your field or project.

In this situation, we will reduce by parallel amounts the top end of both your confidence interval on capital costs and the maximum values in your input distributions for average drilling and completion cost by enough so your application does not exceed our 7.5 percent standard. For instance, we may reduce the upper end of the confidence intervals in all three scenarios by 10 percent (to +36, +31.5, and +18 percent from +40, +35, and +20 percent, respectively) and the maximum possible values in the average drilling and completion cost distributions by a like proportion. That would be enough to lower the mean of all trials to what we judge to be more reasonable levels (e.g., platform cost of $265 MM down from $300 MM and well costs of $155 MM down from $170 MM. In this case your implied contingency factor would be lowered to an acceptable 7.5 percent {[((265 + 155)/400) - 1] * 100 percent}.

Where you've significantly reduced uncertainty with substantial delineation and planning, we look for you to more extensively document and explain the rationale if you decide to use fewer than three scenarios. Further, in these instances you may use point estimates in place of ranges or distributions. Your documentation in the various reports should clearly establish the results from such delineation and planning. In cases where you opt to use less than three scenarios, you must identify the most likely scenario.

As explained earlier, RSVP v2.14 includes a loss limit feature, which adjusts illogical trials. For instance, some random samples drawn when you propose large cost and resource uncertainty may pair very small resource sizes with extremely high development costs. This is unrealistic and you would have aborted development rather than lose the large amount of money the model calculates. The adjusted value used on these trials is the present value of non-construction costs you plan to spend in the first year after submitting the application. A few illogical trials are probably unavoidable with the combination of distributions you can chose, especially when you use only one scenario but the full permitted range of uncertainty. However, too many discarded samples distort the model's estimate of the value of your field. Therefore, we insist that the results of your model run must have no more than 20 percent of the trials discarded.

We check your production and development scenarios for consistency with the geologic data and cost data during the review. As with the information you provide on reservoirs, in cases where we find that assumptions other than those you provide are more appropriate, we reserve the right to make all necessary changes in the set of inputs. One assumption that we will carefully evaluate is your choice of what resource sizes are associated with the switch from one production and cost scenario to another. When your application doesn't explain the choices made, we may request tolling and clarification. If you cannot provide adequate justifications for your choices, we will investigate others and use those that maximize NPV for the field.

In other cases, we may find it necessary to adjust your assumptions to insure fair and consistent treatment across relief applications. For instance, some proposals may contain unusual arrangements involving deferred financing of development capital. Such cases may include little pre-production investment in the RSVP v2.1 calculation. In such cases you need to relate your deferred financing payments to the cost incurred by the owner of the equipment. We will use the present value of the deferred payment stream set by your contract with the owner to judge whether you meet the cost-performance conditions at the post-production development review. As we gain experience with applications, we may identify similar issues where we need to make adjustments for fairness and consistency. We will carefully review any such adjustments with you and specify them in the final determination letter.

MMS Inputs: To treat all applicants alike, we provide you with several of the economic assumptions for oil and gas production to be used in the DCF analyses.

(1) *Price and Discount Rate Assumptions:* The Economic Viability and Relief Justification Report section lists price and discount rate assumptions you are to use. We update the price assumptions as dictated by circumstances but at least annually on our web page at www.mms.gov/econ/update. We use the most recent set of economic assumptions that we issued before you filed your application to make all three DCF determinations.

We derive pricing assumptions from long-term projections of oil and gas prices made by major government and possibly private forecasters. We start with oil and gas price assumptions found in information provided by the Energy Information Administration (EIA), Department of Energy. We expect to update price assumptions at least annually in the spring, after the requisite data and forecasts become available from EIA. During periods of rapid change in oil and gas prices we may update our price assumptions more often. You may adjust our prices for the expected API gravity of your reserves, as described in our API gravity adjustment table, if you document these adjustments as discussed in the Economic Viability and Relief Report section. You should request approval for any other price adjustment and get our written approval before making any other adjustments. We consider any other change that we find to our price assumptions as reason for concluding either that the application isn't complete or that it should be rejected.

We also specify a range of discount rates from which you may choose a particular rate. We allow a choice because projects have different characteristics and operators have different risk preferences reflected in their target rates of return. The range we allow for the discount rate is based on historical industry returns and reflects before tax returns appropriate to a field with a discovery, i.e., where the risk of not finding oil or natural gas has been eliminated.

Until now, we insisted that the same discount rate be used for both the viability estimate and the profitability estimate. While ensuring that the application does not give an overly pessimistic portrayal of the field or expansion project, this equivalence of discount rates may be too restrictive. Development without royalty or sunk costs should be less risky than if these costs have to be covered. Thus, the cost of capital under the viability circumstances should be lower than when full royalties and sunk costs must be paid. To acknowledge this potential difference, we now accept applications that demonstrate fields or projects have a positive value for the viability test at a 10-percent real rate of discount. Note this change applies to applications both from pre-Act leases and from post-2000 leases. Applicants retain the right to set the discount rate we use for the profitability test at any value between 10 and 15 percent.

(2) Allowable Costs. The Cost Report section describes what we consider reasonable cost items for use in the DCF analysis. As with the discount rate assumptions, we may update individual items when new information supports a change.

You specify historic costs in the format described in Attachment C. Also, you provide a certification by an independent CPA that these expenditures are accurately reported, relevant to the field or project that is the subject of the application, and follow the proper format. Where sunk costs are important, we may audit your records as part of our verification.

We follow the cost accounting structure prescribed for Net Profit Share Leases (NPSL) in 30 CFR 220.011 - 220.015. We allow you to count all the costs described in Attachment C because they benefit the development and operation of your field. We allow you to include reasonable portions of joint costs that rightfully should be allocated to this field. Joint costs mean any of the cost items listed in Attachment C that benefits this field or project and one or more other operations. Because some joint cost may be difficult to allocate we also allow you to assign a modest overhead amount to certain cost items. We view technical and operations support activities as joint costs to be allocated to the field while finance, administration, and management activities should be covered by the allowed overhead.

We use a stochastic model to handle the uncertainty associated with estimates and allow a potentially generous rate of return on a discovered field. Therefore, you may not claim contingency costs or other cost multipliers specifically intended to characterize uncertainty. Rather, you should use ranges as described above for estimating scenarios for capital costs. We view cost contingencies or multipliers as an ineligible cost as they are an alternative way to consider uncertainty whose use in RSVP, in effect, double-counts uncertainty.

Summary: You provide the necessary information and demonstrate that your field or project can be made economic with royalty relief using standard assumptions and methodology that we provide. We then verify and employ the same information and methodology to evaluate whether your field or project is economic without relief, confirm that royalty relief can make an your otherwise uneconomic field or project economic, and compute the magnitude of relief you need to make the field or project economic. All of these determinations are based on forecasts that estimate the value of your field, except that certain sunk costs are included in the profitability test.

In general, we framed both the qualification tests and relief volume calculation following the principle that the DWRRA aimed to give substantial, but not excessive, incentive to develop marginal fields or projects. Thus, our economic tests are structured so as to minimize the error of rejecting relief for a field that really should qualify, and the volume calculation is structured so as to minimize the error of giving more volume suspension than is necessary to make a field economic. That is, our calculation of volume suspension tends to give the minimum volumes unless there is strong evidence that a larger amount is needed. Our calculation has this tendency because we exclude sunk costs and because we set an upper bound on the discount rate.

I. Redeterminations (supplements 30 CFR 203.74-75)

You may request that we reconsider denial of an application or reconsider the size of the royalty suspension volume granted in an approved application. We offer redetermination unconditionally after we withdraw or you renounce relief. In other circumstances, we make available a redetermination if there is a significant change in the factors upon which we made our original determination, before you start the new production subject to the royalty suspension. You may request a redetermination only in the following cases:

1. There is a change in your resource information (e.g., gross resources, quality of product, flow rates) that is of sufficient magnitude that the results of our initial determination would have been materially different had the previous complete application included the new data. The regulation says the new resource information must result from new G&G activity such as a new well or new 3-D seismic data that did not exist at the time of the previous application. Reinterpretation of existing data doesn't qualify as a significant change in resource information. You may use a change in resource information to qualify for only the first

redetermination on your field. Additional redeterminations are available only for changes 2, 3 and 4 below.

2. You propose a new development system that improves the profitability, *under equivalent market conditions*, of the field or specified set of reservoirs relative to the development system proposed in the prior application. It must be clear that the original application did not consider or deem the new development system feasible. This situation might arise because new technology becomes available or a new owner with a different perspective takes over field development after the initial application. The initial application may have failed because of high prices that have since fallen. In any case, the new application needs to demonstrate that the new approach more efficiently develops the resource than what we originally evaluated. By more efficient, we mean either clearly lower costs or clearly larger recovery, so that estimated profit would increase using the price forecast we used in the previous evaluation.

3. Average annual prices of oil and gas fall by more than 25 percent below their level at the time of your most recent previous application. We determine these averages as follows.

   (a) Calculate the arithmetic average of closing prices for light sweet crude and for natural gas at Henry-Hub on the New York Mercantile Exchange (NYMEX) for the most recent 12 calendar months.

   (b) Weight the average prices for oil and gas calculated in (a) above by specific proportions of oil and gas (in barrels of oil equivalent). The specific proportions you should use are those identified in the most likely development and production scenario you used for the viability test (see Production Report section) in your most recent previous application for royalty relief. For example, if your most likely scenario foresees a development that will produce 80 percent natural gas and 20 percent oil, we weight the average closing prices of natural gas and oil prices for the preceding 12 months by 80 percent and 20 percent, respectively, in calculating the combined price.

   (c) Perform the same calculations in (a) and (b) above, but use the arithmetic average of closing prices for light sweet crude and for natural gas at Henry-Hub on the NYMEX for the 12 calendar-months preceding the date you filed your most recent previous application.

   (d) If the weighted average price calculated under (b) is more than 25 percent less than the weighted average price calculated under (c), you are entitled to a redetermination.

4. Prior to starting construction of the development and production system, you increase your estimate of the eligible development costs for the most likely scenario by at least 20 percent over your corresponding estimate in your most recent previous application. You should fully explain why development costs increased and how you estimated the size of the increase in your application for a redetermination.

Your request for a redetermination needs to include a complete new application in accordance with section F. We will evaluate the request to determine if you're eligible for a redetermination. If you are, we will review the redetermination application in accordance with section G and evaluate it in accordance with section H. Be aware that if you request that we reconsider the size of a royalty suspension volume we granted, you risk losing that volume.

J. Changes in Material Fact (supplements 30 CFR 203.70, 76-77 & 90-91)

We reserve the right to withdraw our approval of or reduce the size of your royalty suspension volume if there is a change in material fact. Withdrawal or reduction of relief serves two relatively modest purposes. One, it replaces more complex "look-back" procedures for correcting errors in our relief assessments that are inevitable in analyses based on forecasts. Two, it fosters applications with reliable information by encouraging you to have done enough delineation and planning so that you are willing to be held to a general approach, schedule, and cost estimate.

We use specific performance conditions to identify whether or not a change in material fact has occurred. We don't expect these performance conditions to be perfect predictors of the entire set of changes that would have reversed results of the original analysis. Many sets of changes could evolve that in combination would alter results or offset each other. However, we believe that the limited, but specific performance conditions that we've selected balance our obligation to protect the public's financial interest with your right to know ahead of time what you must do to keep relief. Our relief approval notice to you will define the specific performance conditions that you must meet in order to retain your royalty relief.

Generally, we will withdraw an approved royalty suspension volume for any one of the following material changes.

1. You change the type of development system from the one you proposed in the approved application. We presume you are sufficiently committed to the proposed system that you are comfortable being bound to it as a condition of relief. A change from that system invalidates the basis on which we determined your need for royalty relief because it indicates that we evaluated the wrong system. It is immaterial whether or not a substituted system, if we evaluated it, would reverse the original approval. The following list of currently distinct systems illustrates possible changes in the type of development system:
   (a) from a dedicated production system to a shared one (e.g., stand-alone platform to tieback);
   (b) from a system with well heads on deck to one with well heads on the seafloor;
   (c) from a fixed platform to a floating production system.

2. You don't start continuous construction of the development and production system described in your application and our approval letter within 18 months of the date we approved your application, notwithstanding any suspensions of operations or production. A longer delay invalidates the basis on which we determined your need for royalty relief because it indicates that the evaluation was done prematurely. Again, it is immaterial whether or not the delay

would reverse the original approval. However, because delays can occur for reasons beyond your control, you may request up to a 6-month extension of this deadline as specified in section N.

Starting of continuous construction means continuous fabrication. Starting and then suspending fabrication of the production facility does not fulfill this performance condition.

To verify that conditions 1 and 2 above have been met, you need to give us evidence of a timely commitment to the approved development and production system in the form of a fabricator's confirmation report.

For a production and development system acquired as a conventional purchase of a newly built facility, this report should include three items:

1) A copy of the contract(s) under which the fabrication yard is building the approved system for you,
2) A letter from the contractor building your system to our Regional Supervisor for Production and Development certifying when continuous construction has started on a specific system, and
3) Evidence that you've paid an appropriate down payment or equivalent manifestation that you've started acquiring the approved development system.

For unconventionally acquired systems (e.g., refitted existing facilities, leased facilities, farmed-in arrangements, etc.) we will specify in the approval letter what equivalent evidence you should give us of timely commitment.

3. (a) You incur actual development costs before commencing production, other than test production, that are less than 80 percent of your estimated pre-production development costs. Your estimate of development costs includes those for the most likely development and production scenario in your approved application as identified in our approval letter. RSVP v2.14 calculates this estimate for you. We use a post-production development report to determine whether your actual capital costs meet this threshold. Pre-production expenditures of less than this share of the costs planned for the most likely scenario invalidates the basis on which we determined your need for royalty relief because it indicates that our evaluation over-weighted a high cost option. You must submit and certify all costs you incur up to start of production, not just enough costs to get above 80 percent of your estimate. That way later adjustments to this cost total, say for disallowed cost items, are least likely to result in a violation of the 80-percent condition. Both estimated and actual figures must cover the period between the application and first production. If your development plans call for a rolling start of production, say as you complete several wells sequentially on the same rig mobilization, we will define start of production as initial production from all wells included in the startup campaign.

   If you inform us of the actual development cost shortfall in the post-production development report, you are entitled to retain part of your royalty relief. Except in cases discussed below where automatic relief (that issued with the lease) is involved, you retain the smaller of one-half of the granted suspension volume or one-half of the most likely production specified in the application. Formerly, the correction for excessively overestimating actual costs was retention of only half of the volume suspension we originally granted. That correction has no real effect when the minimum suspension volume prescribed by the Act more than doubles the field's expected production. Thus, we have changed the way we determine what you retain if you notify us that actual pre-production costs were less than 80 percent of their expected level.

(b) In a redetermination situation, we will withdraw approval of the application if actual development costs turn out to be less than 90 percent of the estimated development costs. You'll not be permitted to retain any of the approved royalty suspension volume. Second chance applications have had the opportunity for additional, more careful delineation and planning, and are therefore expected to incur smaller overestimation cost errors, and are subject to harsher penalties when the violations do occur.

To verify condition 3, you need to give us a post-production development report, including a CPA certification, within 120 days after the start of new production. It certifies the accuracy, completeness and conformity to the detail, as specified at paragraph l. of the Cost Report section, of the information you provide. Our Regional Director for the GOM may extend your due date for up to 30 days. This report should compare actual expenditures, between the date you file your application and the date you start new production, with the comparable estimates from your application's most likely development and production scenario. If your post-production report shows that you violate the cost performance condition in 3. you may keep only part of the relief we gave you.

Our ability to enforce these performance conditions is out of our control in the case of fields that mix leases issued with and without a royalty suspension. No Congressionally mandated automatic relief backstops relief we grant to an expansion project, so we can fully enforce performance conditions in those applications. Eligible lease(s) that participate in a field application keep automatic relief regardless of whether subsequent development violates the application. Unlike eligible leases, RS leases relinquish any automatic relief when they apply successfully for discretionary relief (that approved through application). As explained in the next section, RS leases can reclaim their automatic relief by renouncing discretionary relief. Only the pre-Act lease(s) or post-2000 leases lose all relief for a change of the proposed development system or excess delay in starting fabrication. As for pre-production costs, we require that the pre-Act or post-2000 lease (s) certify all pre-production costs for the field or project. The pre-Act or post-2000 lease(s) keep the right to share relief if this total is at least 80 percent of the application's estimate of these costs. If this total is less than 80 percent of the application estimate, pre-Act or post-2000 leases must pay royalties when field or project production reaches the smaller of one-half the volume suspension we granted to the field or one-half the of the most likely production specified in the application.

If we grant a good cause exception for Eligible lease(s) on the field not to participate in the application, we then hold the pre-Act lease(s) to what it proposed in the application, just as above. The Eligible lease(s) has the automatic suspension volume but is excluded from any relief approved as result of the application, so its performance or lack thereof is immaterial.

We will rescind our approval of your royalty suspension volume and revoke your relief as of the date we approved it if:

(1) You fail to submit the fabricator's confirmation or the post-production development report by the due date,
(2) We discover that you spent less than 80 percent (90 percent in a redetermination) of your estimated development costs and you did not notify us of this fact in your post-production development report, or
(3) We find that you provided false historical information or intentionally inaccurate data that was material to our granting royalty relief.

You owe royalties and late payment interest determined according to 30 U.S.C. 1721 and 30 CFR 218.54 on all production on which you have not paid royalty. You also may be subject to penalties under other provisions of the law.

When we withdraw your previously approved royalty suspension volume for reasons other than that you submitted false information or intentionally inaccurate data, you may initiate a new application for a suspension volume. We review and evaluate the new application in accordance with sections G and H above.

K. Renounce Relief (supplements 30 CFR 203.77)

The option to renounce relief after we have awarded it may seem unnecessary. But, that option provides an escape process should you the applicant find that emerging conditions make you better off had you never applied for royalty relief in the first place. In other words, the renounce provision is a subtle form of insurance associated with supplemental royalty relief. This section identifies some of the circumstances when you may benefit from exercising the option to renounce already approve royalty relief.

Under provisions of section 203.69, the relief we grant to a development project applies only to the project wells covered by the application. Further, it replaces any royalty suspension volume with which we issued the participating leases. This later stipulation prevents lessees from doubling up on royalty suspension by applying discretionary relief to reservoirs identified in their application and automatic relief to other reservoirs on their lease. After a successful application, you may choose to renounce the discretionary relief and reclaim the automatic relief if the reservoirs in the application prove unable to use much royalty suspension. Or you may want to do the same if you subsequently find that reservoirs outside the application are more attractive to develop. For example, say your lease has automatic relief of 7 MMBOE and we approve relief of 12 MMBOE for a development project for reservoir A. Then after further drilling and analysis, your decide reservoir A will only produce 4 MMBOE. You may renounce the relief of 12 MMBOE, produce the 4 from reservoir A and reclaim 3 (7 – 4) MMBOE for use on reservoir B, which was not included in the application. You may not transfer 8 (12 – 4) MMBOE to reservoir

B. Likewise, by renouncing relief you may bring reservoir B into production before reservoir A and claim royalty suspension of up to 7 MMBOE on production from B.

Also, after a successful application you may find or decide you will violate a performance condition we set as a prerequisite for realizing approved royalty relief. While you may normally re-apply even if we withdraw your relief, you may find it advantageous not to wait for the formal withdrawal. This is because we treat already incurred development costs as sunk costs in the subsequent analysis. To minimize the conversion of costs from prospective to sunk, thereby reducing the amount of costs we consider in determining your need for royalty relief, you may renounce relief and accelerate reapplication. Also, you may wish to renounce discretionary relief and reclaim automatic relief if development costs turn out to be well below what you expected, you change from the development system proposed in your successful application, or you do not start fabrication in time on that development system. In the example above, if you spend less than 80 percent of the level anticipated in your application, your discretionary relief would be halved to 6 MMBOE while renouncing that relief would restore your 7 MMBOE automatic relief.

Renouncing relief is essentially equivalent to returning to the state that existed before you filed a royalty relief application. That means, for instance, that only 1 of 2 leases in an approved application cannot renounce relief. Either both or neither may renounce relief. You need to exercise the option to return to automatic relief volumes before those amounts have been produced, to avoid owing back royalties plus interest.

L. Volume Suspensions and Allocations (supplements 30 CFR 203.69 & 71)

This section explains how we apply the royalty suspension volumes in section 302 of the DWRRA to production from your pre-Act lease or to your post-2000 lease. For purposes of this section, any volumes of production that are not royalty bearing under the lease or the regulations in this chapter don't count against royalty suspension volumes. Also, for purposes of this section, production includes volumes allocated to your lease under an approved unit agreement. Test production that is normally royalty bearing does pay royalties but does not count against the suspension volume. The following provisions apply only to those leases that have applied for and received a royalty suspension volume under section 302 of the DWRRA.

Minimum Suspension Volumes: A minimum royalty suspension volume is mandated for all Authorized fields that qualify for royalty relief. We determine the water depth of a field by the water depth delineations in the version of the Lease Terms and Economic Conditions Map and the FNML that are current at the time of your application. If your application for the field includes leases in different water depth categories, we apply the minimum royalty suspension volume associated with the deepest lease. The minimum royalty suspension volumes are:

(a) 17.5 MMBOE for fields in 200 to 400 meters of water;
(b) 52.5 MMBOE for fields in 400 to 800 meters of water; and
(c) 87.5 MMBOE for fields in more than 800 meters of water.

Requirements of the DWRRA, which mandated specific royalty suspensions for eligible leases (those issued between 1996 and 2000 in deep water in the Gulf of Mexico), do not apply to leases issued subsequently. Royalty suspensions offered on RS leases are subject to the regulations in 30 CFR Part 260. Royalty relief provisions on RS leases are now announced in the notice of sale, and are subject to revision with each sale.

We set a variable minimum royalty suspension volume for development projects and for expansion projects as follows. We add an increment of royalty-free production to the base royalty suspension volume with which a qualifying project starts the application process. The base royalty suspension for the project is the sum of the automatic royalty suspension volumes already available to active participating leases. (If we issued your lease with a royalty suspension for a value or period, the base royalty suspension is the volume equivalent based on the data in your approved application for other forms of royalty suspension.) Active participating leases are ones that have or plan to drill into a reservoir identified in the application. If one or more of the active participating leases have used up some or all of their automatic volumes, the minimum suspension volume for a development project is reduced by the amount of the already used royalty relief on that lease. The increment we add to this base is10 percent of the median resource size upon which we based approval of your application. Since the distribution of reserves tends to be skewed, we consider the median or midpoint of the resource distribution, as found by RSVP, to be the most representative measure of the resource size. The RSVP median is based on inputs from your application as we may have adjusted them and explained to you during our evaluation.

For instance, consider a development project that has a median resource size of 60 MMBOE, so there is a 50 percent chance that the actual resource size is above 60 MMBOE and a 50 percent chance that it is below this median level. If the project qualifies for relief and is located on two RS leases each of which we issued with a royalty suspension volume of 9 MMBOE, it will get a royalty suspension increment of 6 MMBOE added to the previous automatic royalty suspension volume of 18 MMBOE. That makes the discretionary royalty suspension volume equal to at least 24 MMBOE. If one of those 2 RS leases neither has nor proposes to drill a well as part of the project, perhaps because they expect to be allocated production from the other lease, then the minimum royalty suspension volume for the project would be (9 + 6 =) 15 MMBOE. Further, if drilling proposed on one of the project's leases ultimately is not undertaken, we will reduce the suspension volume originally awarded to the project. In the approval letter we will note this condition and indicate what the reduced size of the relief will be if it is not met. We will determine what that reduced size is by estimating the volume suspension needed by a project that does not incur the cost of that phantom proposed well, subject to the minimum based on the lease that does have a well. An expansion project targeting a resource size of 60 MMBOE would get at least 6 MMBOE of royalty suspension for a successful application.

<u>*Termination of royalty suspension volumes*</u> - Your royalty suspension will continue until the end of the month in which the cumulative production from the applicable leases in the field or project reaches the approved royalty suspension volume. We intend to provide monthly field or project production data to participating lessees who request it when their field or project has almost produced its suspension volume. However, these data may become available only after field or

project production has exceeded the royalty suspension volume. Nonetheless, you still owe royalties beginning on the first day of the first month following the month in which cumulative production reaches the royalty suspension volume. Any royalties paid late will be subject to interest pursuant to 30 CFR 218.54.

Field Allocation Rules: Fields in deep water may consist of one or more types of lease, including leases issued before November 28, 1995, between November 28, 1995 and November 28, 2000, and after November 28, 2000. Also, fields may consist of leases that are either producing or nonproducing. We follow certain general principles to ensure that royalty relief adheres to the provisions of the DWRRA. These principles are described below.

1. Leases on a field that produced from any current lease before November 28, 1995 are not entitled to a volume suspension based on an eligible lease or an application by an authorized field (field-based royalty suspension). However, any RS lease on that field does get the volume suspension with which we issued it. Also, a pre-Act or post-2000 lease on the field may still apply for expansion project relief.

2. All leases on a field at the time of an application must participate in the application. If a lease chooses not to participate, the others must show good cause for us to evaluate the application covering only part of the field. If we approve field-based relief in this situation, the lease that declined to participate will not share in any of the relief we grant. If the declining lease is an eligible or RS lease, its royalty free production will still count toward the field's royalty suspension volume.

3. A field is entitled to at most one field-based royalty suspension volume. Once we establish that field's royalty suspension volume, the simple addition of pre-Act, eligible, or post-2000 leases to the field won't change the total royalty suspension volume available to that field. This is the case even if the royalty suspension volumes associated with any of the new leases exceed the authorized royalty suspension volume on the field. Such a situation could occur if the field overlaps the 400 or 800 meter contours and an eligible lease is added to the field in the deeper water category after an eligible lease in the shallower water category began production on the field. Also, it could occur if a pre-Act lease added to the field lies in deeper water depth category than the leases included in the field when we approved the royalty suspension volume. RS leases get their full automatic royalty suspension volume, even if we assign them to a field that has finished producing all of its field-based royalty suspension volume. But the RS lease's royalty-free production counts against the field's royalty suspension volume, for as long as any field royalty suspension volume remains.

4. A field with an authorized royalty suspension volume as a result of establishment of relief from an eligible lease may have its relief amount increased. This would happen if we grant a royalty suspension volume to a pre-Act lease on the field that exceeds the established amount of relief on the field. In this case, all pre-Act, eligible, and post-2000 leases approved for royalty relief would then share in the newly determined higher royalty suspension volume for the field.

5. Pre-Act leases never automatically share in the relief established on the field by eligible leases. They need to apply for and be granted relief in order to share in the authorized relief. Post-2000 leases do not share in such field-based royalty suspension volume, but their royalty-free production counts against any remaining royalty suspension volume for the field.

6. Pre-Act or post-2000 leases simply added to a field with an established royalty suspension volume may share in that relief only if the field's authorized relief resulted from an approved application that grants relief on a pre-Act lease. To claim the right to share in relief, the added lease should file the short form application described in sections F.

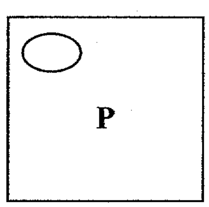
7. All of the pre-Act, eligible, and post-2000 leases on a field with an approved royalty suspension volume may share in any remaining royalty relief authorized for the field. The amounts shared by post-2000 leases will be counted against any royalty suspension volumes issued with these leases. However, such leases may share the field's approved suspension volume in an amount that exceeds the royalty suspension volume with which we issued the RS lease.

8. The addition of a lease to an expansion or development project to which we have granted a royalty suspension volume does not change the project's royalty suspension volume.

9. We may grant a royalty suspension volume only if your entire lease is west of 87 degrees, 30 minutes west longitude. A field that lies on both sides of this meridian receives a royalty suspension volume only for those leases lying entirely west of the meridian.

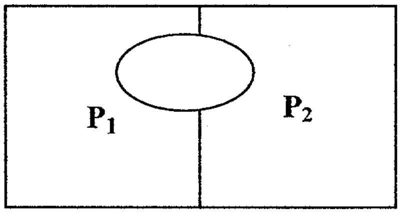
The following cases illustrate how we apply these principles to determine how much royalty suspension volume is available to a field and to distribute, subject to applicable price threshold conditions, this volume among the pre-Act (P), eligible (E), post-2000 RS (R), and post-2000 non-RS (N) leases on the field. Squares represent lease blocks, ovals represent fields, and parallelograms represent projects in the following schematics.

Case 1



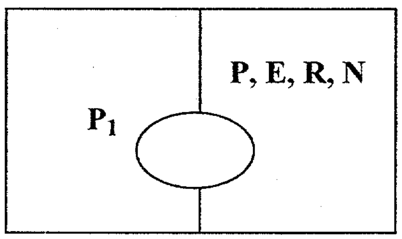
If your field consists of a single pre-Act lease and we approve your application for royalty relief, you owe no royalty payment on production from the lease up to the royalty suspension volume we granted.

Case 2



If your field consists of more than one pre-Act lease and we approve your application for relief, all such pre-Act leases owe no royalty payment until their cumulative production equals the suspension volume we granted. The royalty suspension volume for each lease equals its actual production (or production allocated under an approved unit agreement) until cumulative production equals your field's suspension volume.

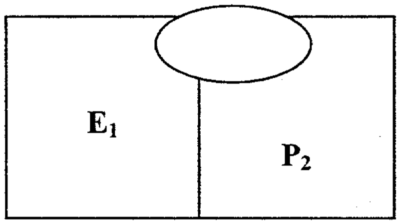
Case 3



If we add your pre-Act lease, eligible lease, or post-2000 to a field that has a royalty suspension volume as a result of an approval of an application from one or more pre-Act leases, the field's royalty suspension volume won't change, even if your added lease is in deeper water. Your added lease may receive a royalty suspension volume only to the extent of its production before the cumulative production from the field equals its approved royalty suspension volume. In this case, a royalty suspension volume for an RS lease is not necessarily limited to the suspension volume in the lease document. Also, an RS lease gets to produce royalty free the full suspension volume with which we issued it even if cumulative production exceeds the approved royalty suspension volume for the field.

The rule doesn't require that your added pre-Act or post-2000 lease submit the full application that the original applicants did. A full application isn't necessary because we've already evaluated the field and see no need to reevaluate that determination. Accordingly, your added pre-Act or post-2000 lease can apply for relief by filing the Administrative Information report (see Section F of these guidelines) with the GOM Regional Office.

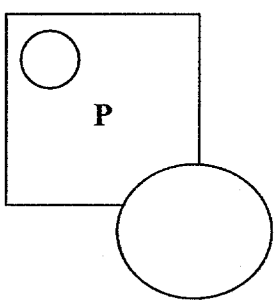
Case 4.



If your pre-Act lease is part of a field that has a royalty suspension volume for eligible leases under 30 CFR 260.110, you cannot share in this relief unless you file and we approve a joint application pursuant to 30 CFR 203.60 and 62-63 and section F.

A post-2000 lease on the field at the time must be part of the application to share the field-based volume suspension in excess of the amount provided in its lease terms. We will waive the joint application requirement if you show good cause for the waiver, but will include the value of the existing relief in our evaluation of your application for the additional relief. If your application meets the economic viability and profitability tests, all of the leases share the single new royalty suspension volume until total cumulative production from the field attains that royalty suspension volume.

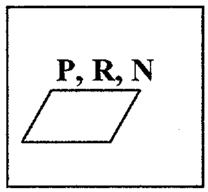
Case 5



Your lease may receive more than one royalty suspension volume. You may get a suspension volume under this rule for each field that includes your pre-Act lease and that meets the evaluation criteria described under section H. Also, you may apply for additional relief for a project to significantly expand production, even if we already granted a royalty suspension volume to the field that encompasses that project. However, your expansion project should anticipate recovering reserves that we didn't consider in making our original determination. Unlike a redetermination for larger relief, applications for relief for significant expansions don't risk loss of any unused part of the earlier relief.

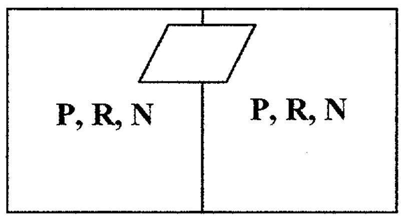
For a development or an expansion project that qualifies for a royalty suspension volume, the rule applies as follows:

Case 6



If your pre-Act or post-2000 lease is the only lease in the project and we approve your application based on significant expansion of production, you owe no royalty payment on the incremental production from the project until that production equals the royalty suspension volume we granted.

Case 7



If your development or expansion project includes more than one lease and your application is approved, no lease owes royalties on incremental production from the project until the cumulative production from the project equals the suspension volume we granted. The royalty suspension volume for each lease equals its actual production (or production allocated under an approved unit agreement) from the project until cumulative production equals the project's suspension volume. Unused suspension volume granted to the project may not be applied to production from the project's leases that were not included in the application for relief.

M. Audits (supplements 30 CFR 203.89 & 91)

We may conclude that an audit is necessary to evaluate an initial application or a redetermination. This conclusion is most likely for applications that have large sunk costs and small estimated losses under the economic determination. If this contingency should occur, we may request that the 180 or 150-day evaluation period be tolled from the time you receive notice until you provide all the records and pay the prescribed fee necessary to conduct the audit. All terms of the relief contract are subject to audit. See 30 CFR 203.81 or the Cost Report, paragraph m. for certification requirements.

Your post-production development report is also subject to audit. We may use such audits to help confirm that a change in material fact (see section J above) has occurred, as well as to determine the applicability of any possible penalties.

N. Appeals (supplements 30 CFR 203.79)

You may appeal three decisions that bear on our relief determinations and redeterminations under 30 CFR 203.79. These decisions are -- our field designations, whether to extend fabrication deadlines that you must meet to keep relief, and our judgments on your eligibility for relief or on the appropriate size of your royalty suspension volume.