BSEE Proposed Well Control Revisions Rule
Cost and Economic Analysis

Prepared For:

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BLADE ENERGY PARTNERS

Executive Summary

Introduction

The U.S. Department of the Interior's Bureau of Safety and Environmental Enforcement (BSEE) recently published new proposed revisions related to the "Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control" rule (hereafter, 2016 rule or 2016 Well Control Rule) which was adopted in 2016. BSEE's stated goal was to "to propose revisions that could reduce unnecessary regulatory burdens while ensuring that any such activity is safe and environmentally responsible." Calash and Blade Energy Partners (hereafter Blade Energy or Blade) undertook a study to evaluate the potential cost savings and economic impact effects of the proposed revisions (and associated sections and subsections) on oil and gas drilling operations in the US Gulf of Mexico (GOM), and the influence that these effects would have on the broader economy. The report also examines the continuing cost burden of the 2016 Well Control Rule as currently written and if the proposed changes were to be adopted. Although both the original 2016 rule and the proposed rule revisions would apply to all US offshore oil and natural gas development, only the impacts to the Gulf of Mexico were considered for this study. Additionally, the report develops a scenario based on the potential impact of certain sub sections of the original 2016 rule which are not proposed to be change materially, under a more restrictive regulatory environment.

Cost of the 2016 Well Control Rule

To better understand the potential cost savings associated with proposed 2018 changes to the 2016 Well Control Rule a review of the current cost burden of the adopted rule was completed. This review was based on the previously published report, "BSEE Proposed Well Control Rule Cost and Economic Analysis[1]", an analysis of the differences between the proposed and adopted Well Control Rule, and the actual impact of the rules as enforced by BSEE. This review included a detailed analysis for each individual section/requirement of the adopted 2016 rule. A significant number of the sections of the adopted well control increased expenses for industry participants, however changes between the proposed rule and the adopted rule as well as BSEE's enforcement of the rule led to lower costs than originally predicted. It is important to note that if in the future a more restrictive regulatory regime from BSEE develops and portions rule are enforced with less flexibility, the potential costs (and the potential for lost activity) associated with the well control rule would likely be much higher.

The increased costs associated with the 2016 rule are felt throughout the offshore oil and gas supply chain. Certain operators and contractors, especially those more active in deepwater,

[1] "BSEE Proposed Well Control Rule Cost and Economic Analysis", Quest Offshore and Blade Energy, Released July 2015

have been more impacted more than others. Cumulative direct costs due to the adoption of the rule are estimated at nearly $3.7 billion for the ten years from 2018 to 2027. The impact of the rule is expected to lead to continued increased costs for industry participants. (Table 1)

Table 1: Estimated Cost Burden of the 2016 Well Control Rule Before Proposed Revisions (Base Development Scenario) $Millions

Category	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Ten Year Total
BOP Replacement or I	$27.2	$28.6	$30.1	$780.4	$61.5	$29.9	$31.1	$31.0	$47.2	$32.5	$1,099.5
Compliance and Docu	$6.9	$7.5	$8.7	$8.9	$9.1	$8.7	$9.1	$8.9	$8.9	$9.3	$86.1
Containment	$56.5	$63.0	$64.9	$64.3	$68.5	$59.9	$64.6	$64.3	$70.5	$70.0	$646.6
Rig Requirements	$4.5	$5.2	$5.8	$5.7	$6.0	$5.6	$6.0	$5.7	$5.7	$6.0	$56.2
Real Time Monitoring (	$17.6	$19.6	$20.2	$20.0	$21.3	$18.6	$20.1	$20.0	$22.0	$21.8	$201.2
Tubing and Wellhead E	$0.3	$0.3	$0.3	$0.3	$0.4	$0.3	$0.4	$0.3	$0.3	$0.4	$3.3
Well Design	$166.6	$193.6	$209.3	$209.9	$225.9	$202.8	$219.0	$218.3	$235.9	$239.5	$2,120.9
BSEE	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$2.1
Total	**$279.8**	**$317.9**	**$339.7**	**$1,089.8**	**$392.9**	**$326.2**	**$350.3**	**$348.9**	**$390.7**	**$379.8**	**$4,215.9**

Source: Calash, Blade

Cost Savings of the Proposed Well Control Rule Revisions

A detailed analysis for each individual section/requirement of the proposed 2018 rule revisions was undertaken by Calash and Blade Energy. The adoption of the proposed 2018 revisions are expected to provide moderate costs savings to industry participants throughout the study period. The cost savings estimates presented in the study are also compared to BSEE's estimates of cost savings as presented in the BSEE's Initial Regulatory Impact Analysis.

The expected cost savings associated with the proposed 2018 revisions are significant but are estimated at only around 37 percent of the average annual cost of the 2016 Well Control Rule across the ten year (2018 to 2027) period. Cumulative direct cost savings due to the adoption of the proposed 2018 revisions as currently written are estimated at nearly $1.4 billion for the ten years from 2018 to 2027. The expected impact of the proposed revisions will fluctuate year to year due to different projected activity levels as well as implementation timing in the original 2016 Well Control Rule. (Table 2)

Table 2: Estimated Cost Saving of the Proposed 2018 Well Control Rule Revisions (Base Development Scenario) $Millions

Category	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Ten Year Total
BOP Replacement or I	-$15.7	-$16.1	-$766.3	-$46.4	-$16.1	-$16.3	-$16.3	-$31.6	-$16.6	-$31.6	-$973.2
Compliance and Docu	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Containment	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Rig Requirements	-$0.2	-$0.2	-$0.2	-$0.3	-$0.2	-$0.2	-$0.2	-$0.2	-$0.2	-$0.2	-$2.4
Real Time Monitoring (	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Tubing and Wellhead E	-$27.7	-$30.1	-$31.6	-$32.3	-$33.0	-$31.3	-$29.9	-$28.4	-$27.0	-$27.0	-$298.4
Well Design	-$10.1	-$11.1	-$11.1	-$11.9	-$10.8	-$11.6	-$11.5	-$12.3	-$12.6	-$12.5	-$115.5
BSEE	-$0.2	-$0.2	-$0.2	-$0.2	-$0.2	-$0.2	-$0.2	-$0.2	-$0.2	-$0.2	-$2.2
Total	**-$54.0**	**-$57.8**	**-$809.5**	**-$91.1**	**-$60.4**	**-$59.8**	**-$58.2**	**-$72.7**	**-$56.6**	**-$71.5**	**-$1,391.6**

Source: Calash, Blade

Potential Impact of Well Control Rule with Restrictive Enforcement – Gulf of Mexico Oil and Gas Development

Prior to the adoption of 2016 Well Control Rule certain provisions of the 2016 rule, especially the section §250.414, “Planned safe drilling margins” which prescribe drilling margins at .5 pound per gallon were identified by the prior report as likely to prevent a large number of Gulf of Mexico wells from being drilled. There were minor differences between the originally proposed and adopted rule, as well as minor changes to the rule in the proposed 2018 revisions. However, even if the proposed revisions were adopted a large number of wells could likely not be drilled under these prescriptive drilling margins in a more restrictive regulatory environment.

Since the adoption of the 2016 Well Control Rule, BSEE has approved drilling margins that deviate from this prescriptive requirement, minimizing the potential impact of this section. According to BSEE[2], “BSEE has approved operators’ use of drilling margins that are less than 0.5 pounds per gallon (ppg) for 32 wells, 31 of which were in deep water.” BSEE is also seeking comments as to whether it should further refine or change this section of the rule or its approach to implementing it. If this section of the rule (even after the proposed changes) were to be implemented as written, without the case by case approval of differing margins, it would likely reduce the total amount of Gulf of Mexico oil and natural gas activity, including the number of wells drilled and projects developed. The rule would likely negatively influence deepwater development the most, especially high pressure, high temperature, and ultra-deepwater wells which may no longer be drillable, and the resources that these wells might have developed may be lost. A significant number of both shallow and deepwater wells drilled into depleted reservoirs may also become undrillable, and those resources would also remain undeveloped. These lost reserves would primarily result from the effects of §250.414, “Planned safe drilling margins”, though other regulations could also have a significant effect on the ability to produce from these reserves depending on BSEE’s enforcement. A strict implementation of the Well Control Rule even if the proposed revisions are adopted, could lead to a decrease of an average of around 16 wells drilled per year in the Gulf of Mexico.

This study projects that oil and natural gas production in the Gulf of Mexico will be 3.4 million barrels of oil equivalent (BOE) per day in 2018 and will decline to 2.7 million BOE per day by 2037. If the 2016 rule were restrictively enforced even with the proposed 2018 revisions, Gulf of Mexico production is forecasted to potentially be nearly 15% or 0.4 million BOE per day lower by 2037.

[2] Federal Register, Vol. 83, No. 92, Friday, May 11, 2018, Department of the Interior, Bureau of Safety and Environmental Enforcement, 30 CFR Part 250 Oil and Gas and Sulfur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control Revisions, Page 6

Total cumulative spending on offshore oil and natural gas development in the Gulf of Mexico OCS is projected at nearly $871 billion between 2018 and 2037 or roughly $42 billion per year. In a more restrictive regulatory environment with more restrictive enforcement, cumulative spending is projected at $751 billion; an average reduction of about $4.7 billion or over 11 percent per year. As currently written the 2016 Well Control Rule with proposed 2018 revisions puts a significant amount of offshore activity at risk both through regulatory uncertainty and the potential for significant activity reductions if in the future BSEE's is more restrictive in its enforcement of the rule. Although the proposed 2018 revisions are generally positive for the oil and natural industry due to reduced cost burdens, the potential negatives of less flexible enforcement of the rule even with the adoption of the 2018 revisions under a more restrictive regulatory environment where BSEE was less flexible greatly outweigh the cost savings associated with the proposed revisions.

Economic Impact of Well Control Rule

The study projects total employment supported from the Gulf of Mexico offshore oil and natural gas industry to rise from approximately 350 thousand in 2018 to over 515 thousand by 2037 under the base development scenario. The potential employment impacts of the potentially more restrictive enforcement of the 2016 Well Control Rule even with the 2018 revisions adopted could lead to a reduction in industry supported employment levels by over 60 thousand by as early as 2027 due to reduced oil and natural gas development. (Table 3)

Table 3: Estimated Total Supported Employment Levels from GoM Oil and Gas Development by Scenario – 2018 to 2037

Case	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Base Case	349	376	435	420	436	449	443	470	534	546
Restrictive Enforcement Case	341	337	398	385	385	417	399	426	471	487
Difference	8	39	37	35	50	32	43	44	63	59

Case	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Base Case	594	566	572	575	593	599	534	561	547	515
Restrictive Enforcement Case	531	478	506	494	495	496	458	479	481	426
Difference	63	88	66	80	98	102	75	82	66	89

Source: Calash

The Gulf of Mexico offshore oil and natural gas industry will contribute an estimated $29.5 billion annually to US GDP in 2018 and is projected to grow to over $43.5 billion by 2037. The Well Control Rule, if enforced with less flexibility, and despite the proposed revisions, could lead to a projected reduction of GDP supported Gulf of Mexico oil and natural gas activities of $7.6 billion annually by 2037. The 10-year cumulative GDP cost burden of the rule in a more restrictive regulatory environment from 2018 to 2027 is estimated at over $34 billion. (Table 4)

Table 4: Estimated Supported GDP from GoM Oil and Gas Development by Scenario – 2010 to 2037 $Millions

Case	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Ten Year Total
Base Case	$29,440	$32,249	$36,206	$35,505	$36,082	$37,584	$37,393	$40,208	$44,094	$45,393	$374,153
Restrictive Enforcement Case	$28,717	$28,813	$33,095	$32,677	$32,110	$34,844	$33,798	$36,432	$38,930	$40,538	$339,955
Difference	$723	$3,436	$3,111	$2,828	$3,972	$2,739	$3,595	$3,776	$5,163	$4,854	$34,198

Case	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	20 Year Total
Base Case	$48,642	$46,564	$47,517	$46,886	$48,513	$48,501	$43,777	$45,346	$44,813	$43,450	$838,161
Restrictive Enforcement Case	$43,250	$39,679	$41,890	$40,496	$40,583	$40,541	$37,645	$38,975	$39,292	$35,803	$738,109
Difference	$5,392	$6,885	$5,627	$6,389	$7,929	$7,960	$6,132	$6,370	$5,521	$7,647	$100,051

Source: Calash

Annual government revenues from Gulf of Mexico lease sales, rents, and royalties is expected to rise from about $6.5 billion in 2018 to $10 billion by 2027 under the base development scenario. Reduced oil and natural gas development anticipated under the Restrictive Enforcement scenario is projected to lead to lower overall government revenues, primarily as a result of lower production royalties being collected due to lower production volumes. Reduced government revenues could be as high as $615 million per year as early as 2027, and $1.3 billion by 2037. The 10-year cumulative lost government revenue burden of the rule from 2018 to 2027 is estimated at over $3.9 billion. (Table 5)

Table 5: State and Federal Government Revenues from GoM Oil and Natural Gas by Scenario - 2018 to 2037 $Millions

Case	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Ten Year Total
Base Case	$6,498	$6,784	$8,667	$9,232	$9,375	$9,527	$9,770	$10,177	$10,121	$10,050	$90,200
Restrictive Enforcement Case	$6,464	$6,718	$8,525	$9,014	$9,080	$9,140	$9,328	$9,660	$9,551	$9,433	$86,914
Difference	$34	$66	$141	$217	$295	$386	$442	$517	$570	$616	$3,286

Case	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	20 Year Total
Base Case	$10,805	$11,350	$11,376	$10,254	$9,937	$9,718	$9,208	$8,740	$8,602	$8,975	$189,165
Restrictive Enforcement Case	$10,145	$10,637	$10,527	$9,481	$9,119	$8,824	$8,199	$7,702	$7,442	$7,655	$176,645
Difference	$660	$713	$849	$773	$818	$894	$1,009	$1,038	$1,160	$1,320	$12,520

Source: Calash

The proposed 2018 revisions to the “Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control” rule are expected to lead to cost savings for operators, contractors, and other participants in the Gulf of Mexico offshore oil and natural gas industry. However, even if the proposed 2018 revisions are adopted certain sections of the rule could potentially lead to reduced activity levels depending on BSEE’s enforcement of these sections. This would likely lead to reduced activity and spending, which is projected to lower production, employment levels, and the growth in GDP and government revenues.

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Section 1 – Introduction

The Gulf of Mexico oil and gas industry has a large positive influence on the local economies of the Gulf coast and the broader U.S. economy by providing desirable and well-paying employment for hundreds of thousands of Americans, creating revenues for many levels of the U.S. government, and by contributing to the country's energy supply. The Gulf of Mexico offshore oil and gas industry has grown into the world leader in safety and technology, consistently setting records by safely developing some of the deepest and most complex offshore projects in the world.

Recently, despite historically low oil prices from 2014 to 2018, efforts to revitalize mature fields and a shift towards deepwater areas have been renewing the strength of the offshore industry. This has led to a reversal of long-standing trend of decline in offshore production. With oil prices now returning to levels well above the investment threshold for most offshore projects, the Gulf of Mexico offshore oil and gas industry is poised for significant growth. Due to the technological advances made in the deepwater Gulf of Mexico, the industry's global influence has grown steadily. The Gulf has steadily grown into one of the world's most prominent and important oil and natural gas production areas, both in terms of economic value and importance to the global oil and gas industry.

Through an expanded and rigorous set of industry standards put in place over the last ten years, the Gulf of Mexico has come to be seen throughout the world as the standard of safety in deepwater and high pressure/high temperature production. Companies operating in the region have not only developed technologies capable of safely and reliably operating in previously impossible-to-reach areas and depths but have built the region into a center for research and innovation, and a global leader in safety, reliability and technology. While the industry has both supported and led efforts to ensure a safe operating environment through the adoption of new technical standards, certain changes to the regulatory environment, especially certain sections of the "Blowout Preventer Systems and Well Control Rule" or Well Control Rule adopted by BSEE in 2016 after initially being proposed in 2015, have increased cost for industry participants without substantially increasing safety. Additionally, certain sections of the rule which have had relatively little impact due to less restrictive enforcement by BSEE could, if in the future a more restrictive regulatory regime from BSEE develops and portions of the rule are enforced with less flexibility, significantly limit potential future Gulf of Mexico activity. While the 2018 revisions proposed to the Well Control Rule by BSEE are generally projected to lower the compliance burden on the industry without compromising safety, without further changes (which BSEE is considering) future activity could remain at risk based on restrictive enforcement.

1.1 Purpose of the Report

Calash was commissioned, in collaboration with Blade Energy Partners, to review the proposed revisions to the rule, "Oil and Gas and Sulphur Operations in the Outer Continental Shelf – Blowout Preventer Systems and Well Control Revisions". The report seeks to provide an independent evaluation of the costs associated with the current 2016 Well Control Rule, the potential cost savings associated with the 2018 revisions, and the potential impacts of the rule in the future in a more restrictive regulatory environment. In addition, potential impacts on Gulf of Mexico oil and natural gas development, supported employment, GDP, and government revenue are also projected.

The report seeks to identify the costs due to the 2016 rule associated with additional engineering, regulatory oversight, constrained drilling margins, additional BOP construction and maintenance requirements, changes to the regulations surrounding casings and decommissionings, real time monitoring and well containment regulations, amongst others. Once these costs are established, the report will project the effect that the proposed 2018 revisions to the 2016 Well Control Rule may have, impacts of the rule on project viability, as well as the potential impacts on the economy as a whole.

1.2 Report Structure

The report is structured as follows: First the report outlines the study methodology in Section 2, followed by a summary of the direct costs associated with the original well control 2016 rule in Section 3. In Section 4 the potential cost savings of the proposed 2018 revisions to the Well Control Rule are discussed, including a comparison to BSEE's cost savings estimates. Following that summary, the study will present forecasts of US offshore oil and gas activity in both the current regulatory environment and in a scenario where certain provisions of the Well Control Rule are more restrictively enforced in Section 5. Based on the findings from the activities forecasts, the study them outlines the macroeconomic effects of the scenarios on total employment, gross domestic product (GDP) and government revenues in Section 6. Following the findings and conclusions in Section 7, the appendices section contains detailed information on the analysis of the proposed revisions as well as a more detailed explanation of the methodology of the report.

1.3 About Calash

Since Calash's creation it has evolved from an oil and natural gas commercial and operational due diligence provider into an award-winning energy advisory firm providing strategy, business advisory, economic analysis, and mergers and acquisitions support services. As a function of Calash's core business, the company is engaged daily in the collection and analysis of data as it relates to the oil and natural gas industry. Calash serves the global community of operating oil and natural gas companies, their suppliers, financial firms, and many others by providing detailed analysis on projects, investments, capital investment and operational spending undertaken by the onshore and offshore industries. Calash analyzes market data from a variety of sources at the project level for projects throughout the world.

1.4 About Blade Energy

Blade Energy Partners is an independent consulting company that focuses on resolving the challenges of complex projects in the energy industry. The company provides leading-edge expertise to solve drilling, completion, production, reservoir and pipeline challenges. Blade works with the sole objective of safely and efficiently maximizing returns on reserves and assets. Since its creation over 15 years ago, Blade has collaborated on a wide variety of engineering, research, and development projects in several sectors of the oil and gas and geothermal industries. Blade comprises over 80 engineers, scientists, and project managers. Sixty percent of our staff possess advanced degrees and of those, twenty percent hold doctoral degrees in applied science or engineering. Blade engineers are highly experienced, with, on average, 10+ years in the industry, serving major operating and service companies.

1.5 Excluded from This Study

This paper has been limited in scope to the assessment of the effects of the 2016 rule "Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control", potential cost savings from the 2018 proposed revisions, and potential impacts from restrictive enforcement of the rule on the Gulf of Mexico OCS. The rule including the proposed revisions will affect all U.S. OCS offshore oil and natural gas exploration and production areas both current and future. The study also does not attempt to calculate the effects of the 2016 rule or the proposed 2018 revisions on mid-stream or down-stream oil and natural gas entities. In addition, the calculated government revenue potential does not include personal income taxes, corporate income taxes or local property taxes.

Given the unpredictable nature of advancements in technology and innovation in the oil and gas industry, the scope of this paper was limited to the effects that regulations would have on future activity with the assumption that the methods and equipment mentioned in the regulation would still be in use at the end of the study period. It is entirely possible that new designs, methods and target reservoirs would change over time and no longer fall under the umbrella of these regulations, but if that were the case, the effects would be primarily felt toward the end of the forecast period.

In addition to the possibility of new technologies being used in the region, the study has also excluded the effects of activity in other regions inclusive of Alaska, Pacific, and Atlantic OCS regions.

Section 2 – Data Development

2.1 Data Development

The authors of this report (Blade Energy and Calash) have undertaken a detailed engineering and economic analysis of the Bureau of Safety and Environmental Enforcement (BSEE), rule on “Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control”, as published in the Federal Register Vol. 81 Friday, No. 83 on April 29, 2016 as well as with the proposed revisions to the rule “Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control Revisions”, as published in the Federal Register Vol. 83, No. 92 on Friday, May 11, 2018.

The purpose of this review was to provide a summary of the most impactful areas of the current 2016 Well Control Rule and the proposed 2018 changes to the rule. This study in no way is exhaustive, especially in light of the relatively short period available to develop this analysis and the highly technical nature of these regulations.

This analysis focuses on the likely engineering burdens and operational effects of these regulations and attempts to calculate the costs or cost savings of these burdens (or their removal) wherever possible. As such, this analysis is essentially forward looking and potentially subject to significant changes based on the adoption of the proposed changes, the way in which the Well Control Rule and proposed changes are enforced, and a variety of other factors

A narrower view of the regulations which focuses solely on the narrow cost of implementing individual sections of the rule without considering the engineering and operational burdens imposed by the regulations is likely to underestimate the costs of the rule and the cost savings of the proposed revisions. Due to the limited time available to prepare this report, as well as the continuing significant uncertainties about the way the Well Control Rule has been enforced, the projected costs, engineering requirements and operational burdens for all current regulations and proposed changes are not included in this report. Additionally, the internal costs to BSEE of implementing and administrating the proposed rule are only calculated in this report where BSEE or this report have identified cost savings associated with the proposed revisions.

To better understand the potential cost savings associated with 2018 proposed revisions to the Well Control Rule a review of the current cost burden of the adopted 2016 rule was completed. This review was based on the previously published report, “BSEE Proposed Well Control Rule Cost and Economic Analysis”, an analysis of the differences between the proposed and adopted Well Control Rule, and the actual impact of the rules as enforced by BSEE. This review included a detailed analysis for each individual section/requirement of the adopted. A significant number of the sections of the adopted well control increased expenses for industry participants, however changes between the proposed rule and the adopted rule as well as BSEE's enforcement of the rule led to lower costs than originally predicted. It is important to note that under a more restrictive regulatory regime the potential costs (and the potential for lost activity) associated with the Well Control Rule would likely be much higher.

2.2 Engineering Review

The engineering review of the proposed rule was undertaken by a number of subject matter experts within Blade. The review focused on the engineering and operational effects of the proposed revisions and attempts to calculate the cost savings of the proposed revisions. The engineering review attempted to provide the most reasonable outcome and implications of the proposed revisions, while emphasizing the likely effects of the revisions as written. Blade provides its independent view expressly disclaiming any warranty, liability, or responsibility for completeness, accuracy, use, or fitness to any person for any reason.

2.3 Data Development Limitations of the Report

The report's authors make no representation as to the effects of Well Control Rule or the proposed revisions not addressed specifically in this report and do not discount the possibility that these proposed revisions could impose significant engineering, operational or other burdens on industry or regulators. The report's authors' estimates herein of the effects that BSEE's Proposed revisions will have on current and future engineering, operations and advances in technology are an independent good faith qualitative view arising from considerations by various subject matter experts within Calash (an independent consulting firm focused on oil and gas operations and economics) and Blade Energy (an engineering consulting company in well design, engineering and operations). Both Calash and Blade Energy are providing this independent view expressly disclaiming any warranty, liability, or responsibility for completeness, accuracy, use, or fitness to any person for any reason.

2.4 Cost and Cost Savings Calculations

The cost and cost savings calculations associated with the proposed 2018 revisions were developed by Calash by calculating the projected engineering and operational burdens by reasonable assumptions of the costs associated with them and the length or scale of these burdens. All costs and cost savings associated with the regulations were attempted to be calculated based on the most economic method for overcoming the actual burden imposed by the regulations as enforced by BSEE and any burdens which would overlap with other burdens were discounted to avoid double counting. All costs presented in this study are in constant 2017 dollars.

2.5 Data Development

The report's scenario development focused on constructing a tiered "bottom-up" model that separates the complete life cycle of offshore operations and subsequent effects into three main categories and five sub categories. The three main categories are as follows; an "Activity" model that assesses potential reserve information in the context of estimating the possible number of projects within the Gulf of Mexico OCS and the currently forecasted projects and trends in exploration and project development in the region; a "Spending" model based on the requirements to develop projects within the "Activity Forecast"; and an "Economic" model focused on the economic impact on employment and government revenue from the "Spending" model. These categories include, leasing activity, drilling, infrastructure & project development, and production & operation.

After the creation of the baseline model with the operational, cost, drilling and development impacts of the 2016 rule, "Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control" as adopted and enforced included, a second scenario with the potential impacts of the Well Control Rule (especially those sections related to drilling margins) including the proposed 2018 revisions in a more restrictive regulatory environment was developed. This scenario resulted in the creation of the "Restrictive Enforcement Scenario" which attempts to provide a reasonable projection of oil and natural gas exploration and development activity in the Gulf of Mexico OCS if Well Control Rule was enforced restrictively without case by case approval by BSEE of drilling margins that are less than .5 ppg. After the development of this scenario, the scenario's potential implications for oil and natural gas production, employment, GDP, and government revenues were then calculated.

2.6 Economic Data Development

Development of GDP and job data were calculated using the BEA's RIMs II Model providing an input-output multiplier on spending at the industry and state levels for each defined category. Model outputs considered from spending effects include number of jobs and GDP multiplier effects. Further delineation is presented in the form of direct and indirect and induced job numbers, which encompass the number of jobs relating to the spending in that category versus indirect and induced jobs that are created from pass-through spending.

RIMs Categories used:

- Architectural, Engineering, and Related Services
- Construction
- Drilling Oil and Gas Wells
- Fabricated Metal Product Manufacturing

- Mining and Oil and Gas Field Machinery Manufacturing
- Natural Gas Distribution
- Oil and Gas Extraction
- Steel Product Manufacturing from Purchased Steel
- Support Activities for Oil and Gas Operations

2.7 Governmental Revenue Development

Governmental revenue data is presented in three categories: bonus bids from lease sales, rents from purchased but not yet developed leases, and royalty payments from producing leases. The projected revenue was calculated using the current operating structure of the Gulf of Mexico where applicable due to a lack of existing structures in the Atlantic states. Lease sales and rental rates were calculated through the simulation of lease sales within each individual area, while the number of leases acquired has been modeled on historical rates and based on the estimated amount of reserves in the region. Calash has modeled lease sales for the first five years on the draft proposed program, after this the report assumes yearly area wide sales within each region - thus contrasting the current sales which have included a sale approximately every other year.

The federal / state government revenue split of leases, rents and royalties were modeled assuming a similar percentage split as in GOMESA (Gulf of Mexico Energy Security Act). Under GOMESA 37.5 percent of OCS bonus bid, rent, and royalty income is distributed to the appropriate states. GOMESA has an annual revenue cap for states.

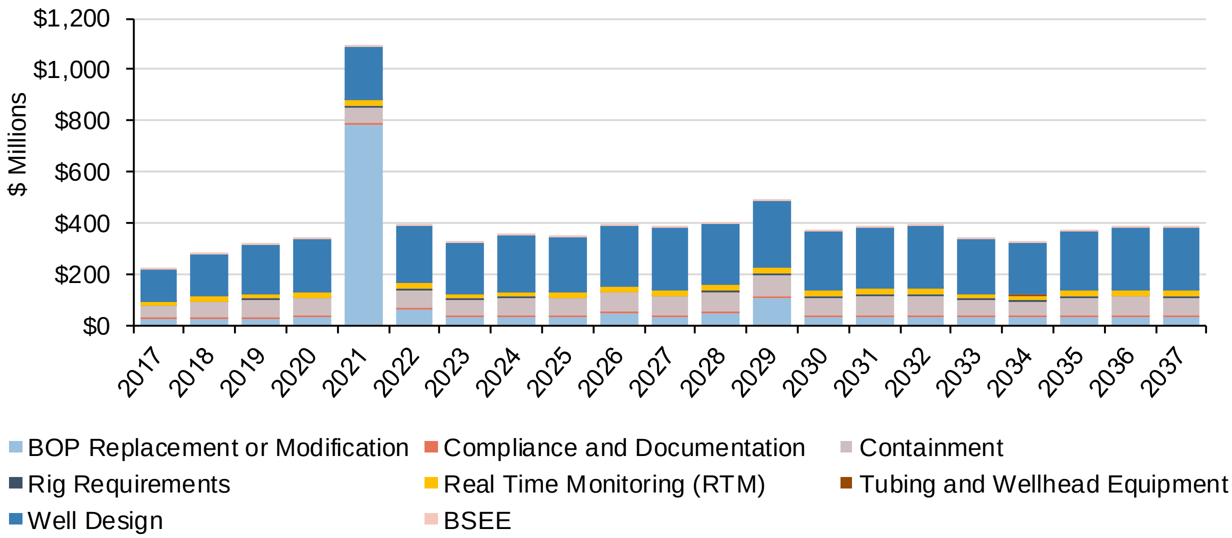
Production pricing was calculated using the EIA estimates for both West Texas Intermediate crude spot and Henry Hub natural gas prices from the 2018 EIA Annual Energy Outlook. Due to the steady recent increase in oil and natural gas prices this forecast should be considered conservative and actual revenues could potentially be higher. Additional governmental revenues such as income and corporate taxes were considered outside of the scope of this study and are likely to provide additional government revenues throughout the studied period.

Section 3 – Cost of the 2016 Well Control Rule

To provide an estimate of the potential cost savings associated with proposed 2018 revisions to the 2016 Well Control Rule a review of the current cost burden of the adopted rule was undertaken. The review was based on the previously published report, "BSEE Proposed Well Control Rule Cost and Economic Analysis", an analysis of the differences between the proposed and adopted Well Control Rule, and the actual impact of the rules as enforced by BSEE. This review included a review of each individual section/requirement of the adopted 2016 rule. A significant number of the sections of the adopted well control cause significant increases in direct costs for industry participants, however changes between the original proposed 2016 rule and the adopted rule as well as BSEE's enforcement of the rule led to lower costs than originally predicted. It is important to note that under a more restrictive regulatory regime the potential costs (and the potential for lost activity) associated with the 2016 Well Control Rule would likely be much higher.

Cumulative direct costs due to the adoption of the 2016 rule are estimated at nearly $3.7 billion for the ten years from 2018 to 2027, an average of nearly $370 million per year. (Figure 1)

Figure 1: Estimated Cost Burden of the 2016 Well Control Rule by Year 2017 to 2037 $Millions



Source: Calash, Blade

For the purposes of this report, cost increases due to the adoption of the 2016 Well Control Rule were divided into seven subsections based on the subsections present in the well control rule as well as a separate category for costs that are borne by BSEE. The BSEE cost category is limited to costs that have been identified in the analysis of the proposed revisions and likely excludes a significant portion of the extra cost to BSEE of administering the Well Control Rule. The analysis of costs of the rule is an attempt to estimate the burden based on the actual enforcement of the 2016 rule by BSEE, however due to differences in enforcement as well as differences in the internal procedures and organizations of operators, contractors and other industry participants these costs are indicative only and would likely vary greatly within organizations. These costs also exclude costs associated with industry standards, such as API 53 (Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells) which BSEE incorporates by reference. The cost of regulations is calculated based on Calash's "Base Development Scenario" for the Gulf of Mexico and is the projected activity levels for various offshore oil and natural gas related activities based on current regulations without the proposed revisions to the rule. Apart from annual activity trends costs also vary annually based on deferred compliance of certain sections of the Well Control Rule.

The largest projected burdens over the 2018 to 2027 period due to the current 2016 Well Control Rule are projected to be due to the Well Design subsection of the rule with a total cost burden of over the ten year period estimated at over $2.1 billion to industry (over $210 million per year on average). Projected costs due to the BOP section of the Well Control Rule stand at over $1.1 billion over the ten year period (over $110 million on average).

The real time monitoring subsection of the Well Control rule is projected to lead to a cost burden of over $200 million over the ten year period, compliance and documentation is projected to lead to an over $85 million burden on industry, and the rig requirements subsection is projected to lead to an over $55 million burden. The tubing and wellhead equipment subsection is projected to add extra costs of over $3 million over the ten year period. The containment subsection is projected to add additional costs of around $650 million over the ten year period; these costs exclude the multi-billion-dollar investment in containment that the industry has made in the last decade.

Section 4 – Cost Savings of the Proposed 2018 Well Control Rule Revisions

4.1 Cost Savings of the Proposed 2018 Well Control Rule Revisions

The proposed 2018 revisions to the Well Control Rule "Oil and Gas and Sulfur Operations on the Outer Continental Shelf Blowout Preventer and Well Control Revisions" are expected to provide moderate relief of some of the direct costs borne by the oil and natural gas industry as a result of the Well Control Rule initially proposed in 2015. The savings from the proposed 2018 revisions are projected to provide savings to industry as a result of reduced reporting, reduced alternate procedure requests, reduced redundant permit resubmissions, reduced lost rig time due to waiting for district manager approvals, reduced redundant inspections, and reduced requirements to upgrade equipment such as BOPs.

Additionally, the proposed 2018 revisions are projected to provide some cost savings to BSEE primarily as a result of decreased administration costs related to resubmissions of permits, and alternate procedures requests, and the administration of the BSSE Approved Verification program. Although this reduced burden is positive for the industry, some sections of the rule will remain materially unchanged despite minor revisions which could in the future impose additional costs to the US economy due to slower or reduced OCS development under a more restrictive regulatory environment.

The authors of this report (Blade Energy and Calash) have undertaken a detailed engineering and economic analysis of the proposed revisions with the purpose of projecting the total cost savings of the proposed revisions if implemented as currently written. This analysis is in no way is exhaustive, especially in light of the relatively short period available to develop this analysis, and the highly technical nature of these regulations. This analysis focuses on the likely engineering and operational savings of these regulations and wherever possible attempts to calculate it based on the measures being taken to overcome the burdens based on the actual enforcement of the Well Control Rule by BSEE. The following table, prepared by Calash, presents a summary of the estimated direct costs savings of the proposed revisions (Table 6). Estimated cost savings are identified by rule section, subsection, or, when necessary, individual line item where multiple regulations cumulatively contributed to cost savings. For more specific explanations and analysis of the regulations cited in this table please see Appendix 1, BSEE Proposed Revisions Appendix. The projected savings of the 2018 revisions are calculated based on Calash's "Base Development Scenario" for the Gulf of Mexico and the projected activity levels for various offshore oil and natural gas related activities based on current regulations without the proposed revisions. The potential impact on development of certain sections of the 2016 rule which would remain materially unchanged if the 2018 revisions are adopted as currently proposed in a more restrictive regulatory environment are discussed in Section 5, Potential Impact of the Well Control Rule – Gulf of Mexico Oil and Gas Development. The average annual cost savings to industry participants of the proposed revisions are projected at around $137 million per year from 2018 to 2027. Cumulative 10-year cost savings are estimated at nearly $1.4 billion. (Table 6)

Table 6: Estimated Annual Cost Savings from the 2018 Rule Revisions by Subsection–2018 to 2027 $Thousands

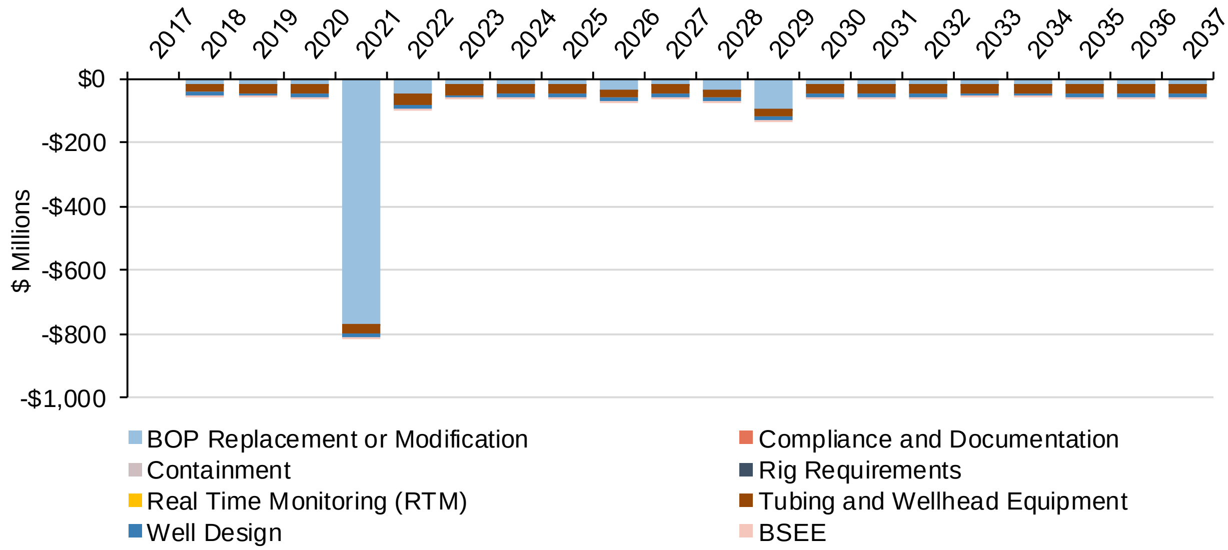
CFR	Category	10 Year Cumulative	Annual Average
§250.292	Compliance and Documentation	$1.0	$0.1
§ 250.423	Well Design	$9.1	$0.9
§ 250.428 (c)	Well Design	$70.4	$7.0
§ 250.428 (d)	Well Design	$100,066.6	$10,006.7
§ 250.461	Well Design	$3,287.4	$328.7
§ 250.712	Rig Requirements	$2,342.1	$234.2
§ 250.722	Well Design	$0.0	$0.0
§ 250.722	Well Design	$8,338.9	$833.9
§ 250.731	BOP	$234.8	$23.5
§ 250.731 (c)	BOP	$1,794.5	$179.4
§ 250.732	BOP	$9,750.0	$975.0
§ 250.734	BOP	$795,000.0	$79,500.0
§ 250.736 (d)	BOP	$234.8	$23.5
§ 250.737 (d)(2) and (3)	BOP	$69.9	$7.0
§ 250.737 (d)(4)	BOP	$145.3	$14.5
§ 250.737 (d)(5)	BOP	$125,009.9	$12,501.0
§ 250.737 (d)(13)	BOP	$145.3	$14.5
§250.738 (f)	BOP	$145.3	$14.5
§ 250.739	BOP	$26,928.0	$2,692.8
1716	Well Design	$296,338.5	$29,633.9
Total		**$1,369,911.8**	**$136,991.2**

Source: Calash, Blade

Costs savings are projected to vary year to year based on activity levels, with the largest cost savings projected in 2021 ($927 million), when a deferred provision of the original Well Control Rule (§250.734) would likely have required significant upgrades or replacement of existing BOPs. In other years savings are typically driven by wells drilled (especially deepwater wells) and project activity with cost savings varying from as low as around $280 million in 2019 to over $340 million in 2026.

Cost savings associated with well design regulations are projected at an average of over $11 billion per year from 2018 to 2027 (a total of over $112 million over the same period), while costs associated with changes to BOP regulations are projected at just under $96 million a year from 2018 to 2027 on average for a total of around $960 million over the same period.

Figure 2: Estimated Annual Cost Savings from the 2018 Rule Revisions by Category – 2018 to 2027



Source: Calash, Blade

These cost savings are projected to account for around 37 percent of the total identified costs associated with the 2016 Well Control Rule from 2018 to 2027.

4.2 Ten Year Cost Comparison – Study Estimates vs. BSEE

Although the potential cost saving associated with the proposed revisions “Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control Revisions” developed by this study were developed independently, for some sections where BSEE likely had access to better data analyzing the proposed revisions, and where this analysis found BSEE’s analysis reasonable similar assumptions were used. In some case this study and BSEE’s economic impact analysis projected similar impacts but with for example differing time and cost savings for preparing permit resubmissions. The following table provides a ten year cost savings comparison to BSEE’s own economic analysis impact study for reference. It’s important to note that due to differing activity forecasts between this study and BSEE’s analysis even when relatively similar cost savings metrics where used for a subsection, the total presumed cost savings may differ (for example if more wells were predicted to be drilled in each year in this analysis). It is also important to note that both the BSEE’s cost analysis and that provided by this study take into account the varied implementation timelines of the Well Control Rule. The following numbers for BSEE’s analysis also vary slightly from the totals in that report due to some minor nonmaterial calculation inconsistencies within their report. (Table 7)

Table 7: BSEE Ten Year Cost Savings from the 2018 Rule Revisions Comparison Table

Year	BSEE	Study Estimates
Year 1	$24	$50
Year 2	$24	$54
Year 3	$25	$58
Year 4	$640	$809
Year 5	$25	$91
Year 6	$56	$60
Year 7	$26	$60
Year 8	$42	$58
Year 9	$57	$73
Year 10	$27	$57
Ten Year Total	**$946**	**$1,370**

Source: Calash, Blade, BSEE

The overall industry-incurred cost savings due to the proposed 2018 revisions over ten years show relatively similar cost savings, under which this study has projected an average of around $136 million per year while BSEE foresees savings of $94.5 million per year. Over a ten year period, this study projects cost savings of nearly $1.4 billion, compared to BSEE estimate of just over $945 billion, with this study projecting cost savings 45 percent higher across this period.

Section 5 – Potential Impact of the Well Control Rule with Restrictive Enforcement – Gulf of Mexico Oil and Gas Development

While the cost savings associated with the proposed 2018 revisions to the Well Control rule could potentially spur some increased activity in the Gulf of Mexico OCS, the largest potential impact activity remains if in the future a more restrictive regulatory regime from BSEE develops and portions of the original 2016 Well Control Rule are enforced with less flexibility in a restrictive regulatory environment. These provisions, specifically § 250.414, will not be materially changed by the proposed 2018 revisions. Currently, BSEE is on a case by case basis approving drilling margins less than the .5 pound per gallon required by the original Well Control Rule. BSEE has consistently approved these margins, indicating that wells that deviate from these margins can be safely drilled. Although under BSEE's current enforcement standards the only impact is the potential for deferred investment due to regulatory uncertainty (which is difficult to quantify), the potential impacts if BSEE were to restrictively enforce this section would likely be large. BSEE specifically cites 32 wells (of which 31 were deepwater wells) as having been approved to be drilled with margins less than .5 PPG which accounts for around 10% of all wells or 15% of deepwater wells since the adoption of the 2016 Well Control Rule. BSEE itself has recognized the potential impact of these sections and states in the proposed revisions, "the number is significant enough for BSEE to consider whether it should further refine the approach it is taking in the current regulations". The potential impact of these provisions is only heightened due to its outsize potential impact on deep water wells which require large investments and typically produce equally large volumes of oil and natural gas. To quantify the effects of the potential restrictive enforcement of these sections of the rule if BSEE were to cease approving margins that deviate from the prescriptive .5 PPG, the study forecasted how activity levels for Gulf of Mexico OCS oil and gas activity could be impacted compared to the base case. The forecasted activity levels include the number of wells drilled, projects executed, total production, and spending. These activity forecast drive the spending projections from which GDP, employment and government revenue effects are estimated.

5.1 Wells Drilled

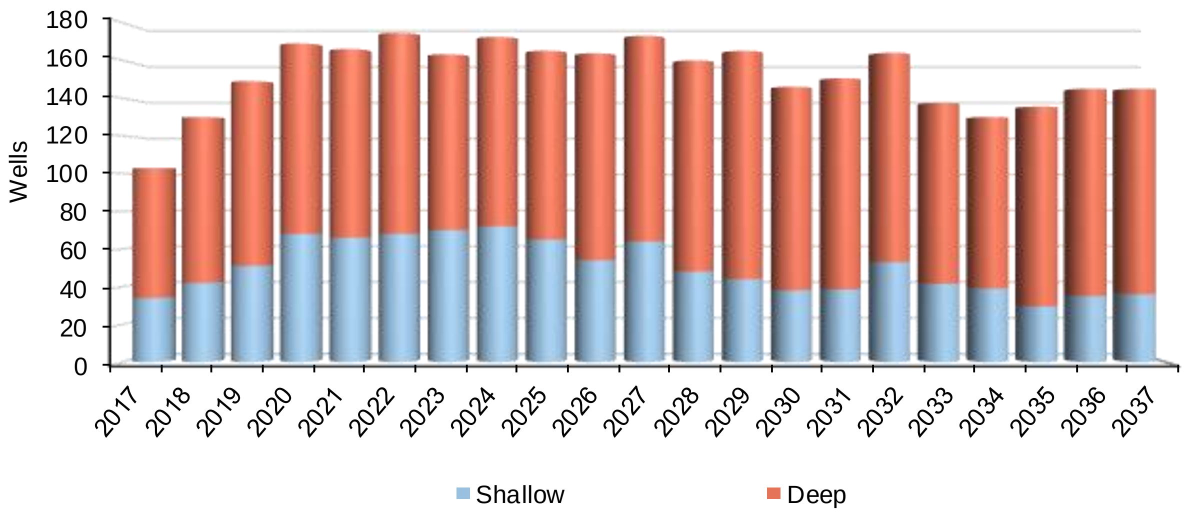
Exploration, appraisal and development drilling is used to identify, confirm, delineate, and produce oil and natural gas, making it one of the most important offshore oil and natural gas activities. Drilling is a very capital-intensive process employing drilling rigs that require large crews as well as significant quantities of consumables ranging from food and fuel to drill pipe and fluids. Drilling rigs (mobile offshore drilling units – MODU's) and platform rigs must constantly be resupplied and crewed, and thus lead to high levels of activity in the areas and ports that support offshore drilling activity.

Drilling activity in the US Gulf of Mexico is projected to grow steadily with year to year fluctuations throughout the forecast period due to rising oil prices and as exploration of new geologic areas continues and development of known production areas progresses.

This potential decrease in drilling under this scenario, is primarily due to the potential effects of less flexible enforcement of §250.414, "Planned safe drilling margins" in a more restrictive regulatory environment. Since many of the wells that are projected to be drilled in the Gulf of Mexico are in particularly deep water, and located in high pressure, high temperature reservoirs, or are being drilled in depleted reservoirs, some of these wells would be no longer technically possible to drill or complete under if §250.414 was restrictively enforced, and others, particularly development wells, may become economically non-viable.

Drilling activity has shifted from primarily shallow water areas into progressively deeper and higher-pressure areas, as the reservoirs in shallower areas mature and new fields are discovered. Deepwater wells, which typically have a relatively high level of spending associated with them are much more likely to be impacted. Under the base development scenario, a total of around 3,100 wells are projected to be drilled from 2018 to 2037, with 67 percent of the wells projected in deep water and 33 percent projected in shallow water. (Figure 3)

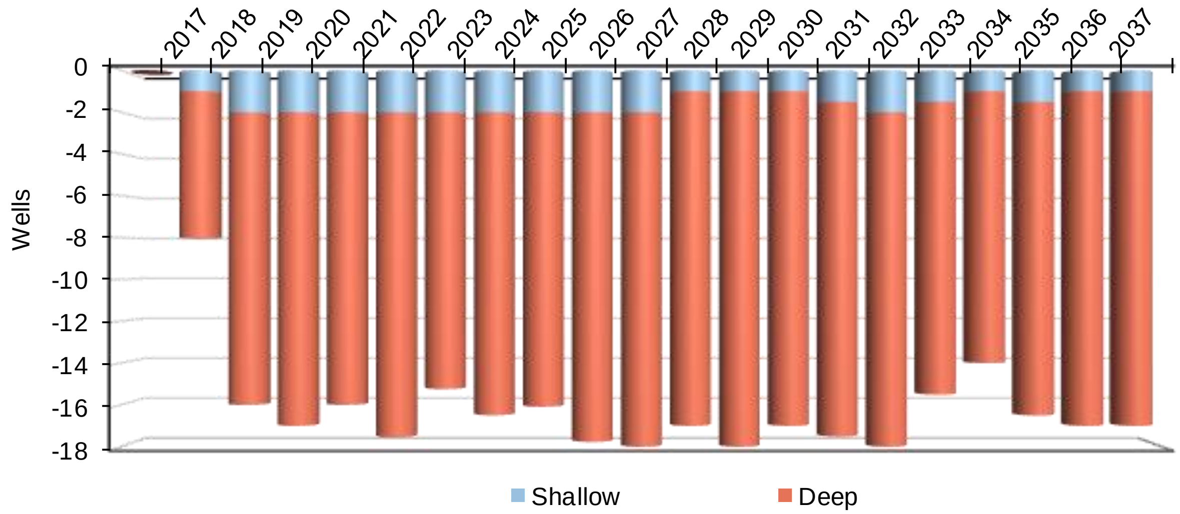
Figure 3: Number of GoM Wells Drilled by Water Depth Base Development Scenario



Source: Calash

Under the Restrictive Enforcement Scenario, approximately around 325 fewer wells are projected to be drilled from 2018 to 2027, an average of over 32 wells per year. These potential lost wells are primarily in deepwater, with an estimated 295 deepwater wells potentially not drilled (an around 14 percent decline) over the forecast period. Under this scenario, 991 shallow water wells are projected to be drilled, a three percent decline compared to the base development case.

Figure 4: Reduction in GoM Wells Drilled by Water Depth Restrictive Enforcement Scenario



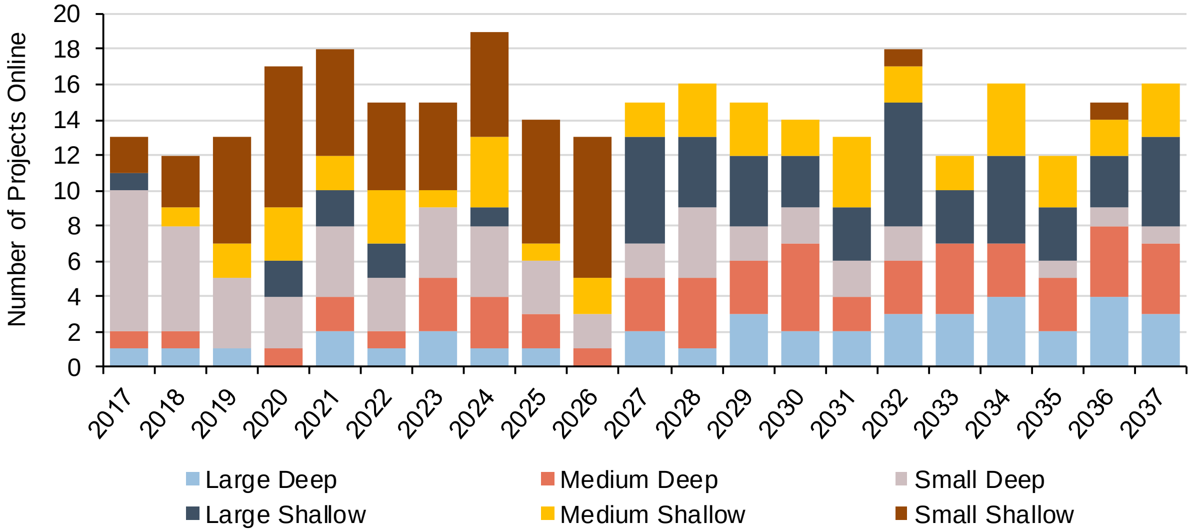
Source: Calash

5.2 Projects Executed

Developing an offshore project is a complex process that requires a significant amount of time, planning and high levels of capital investment. Project executions and their respective timelines are the best indicator of overall market health, as they can be viewed as representative of total trends in production, employment and revenue for the broad market.

Over the forecasted period of this study (2018-2037), 140 deepwater projects and 158 fixed platform-based oil and natural gas projects are projected to begin production under the base development scenario. (Figure 5)

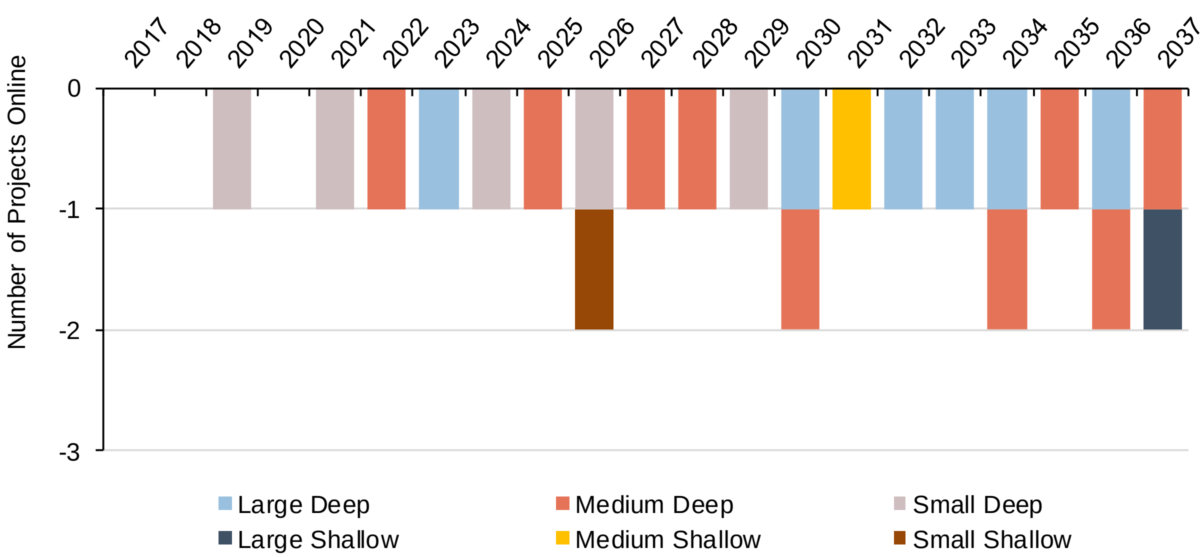
Figure 5: Number of GoM Projects Online by Water Depth and Size Base Development Scenario



Source: Calash

As a result of potential lost drilling activity due to more restrictive enforcement of subsections of the Well Control Rule related to drilling margins under the Restrictive Enforcement Scenario, the total number deepwater projects developed is projected to decrease by 14 percent and shallow water projects are projected to decrease by nearly four percent under the new regulations. (Figure 6)

Figure 6: Number of GoM Projects Online Reduction by Water Depth and Size Restrictive Enforcement Scenario



Source: Calash

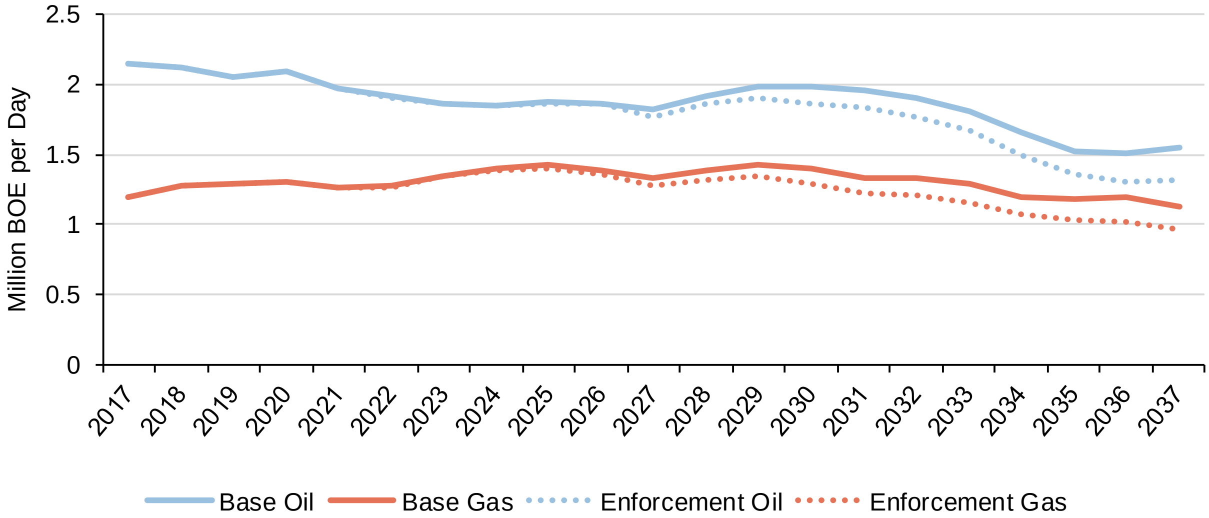
Total project spending is primarily driven by overall activity levels, and partially driven by the project design and size of the projects executed. Reduced drilling directly impacts project development by reducing discovery of new oil and gas reserves as well as through an inability to develop discovered reserves by drilling development wells. Restrictive enforcement of § 250.414 would lead to both a reduction in new discoveries, and by causing oil and gas reserves that have been discovered but have not been developed remaining undeveloped. Additionally, new wells on existing or partially developed projected may not be drilled, further reducing investment. As this section if restrictively enforced would primarily reduce drilling of deepwater wells would further reduce potential investment due to the higher levels of spending typically associated with deepwater projects.

5.3 Production

The number of projects developed, coupled with reservoir size and reservoir productivity, is the main determinant of oil and natural gas production levels. Most oil and natural gas reservoirs contain a combination of oil, natural gas, water, and other native substances such as sand, sulphur, CO2, and salt, though some reservoirs may contain nearly all oil or all natural gas. In order to forecast aggregate production, each project was modeled based on production curves for similar developments, taking into account the start-up, ramp-up, peak, and decline timing, as well as the expected hydrocarbon mix.

This study projects that production in the Gulf of Mexico will decline slightly throughout the forecast period with year to year fluctuations. Production is projected to decline to 2.67 million BOE per day by 2037, with approximately 58 percent of production oil (1.54 million BOE per day), and 42 percent of the production natural gas (1.13 million BOE per day). (Figure 7)

Figure 7: **GoM Oil and Natural Gas Production by Type Base Development vs. Restrictive Enforcement Scenario – MMBOED 2017 to 2037**



Source: Calash

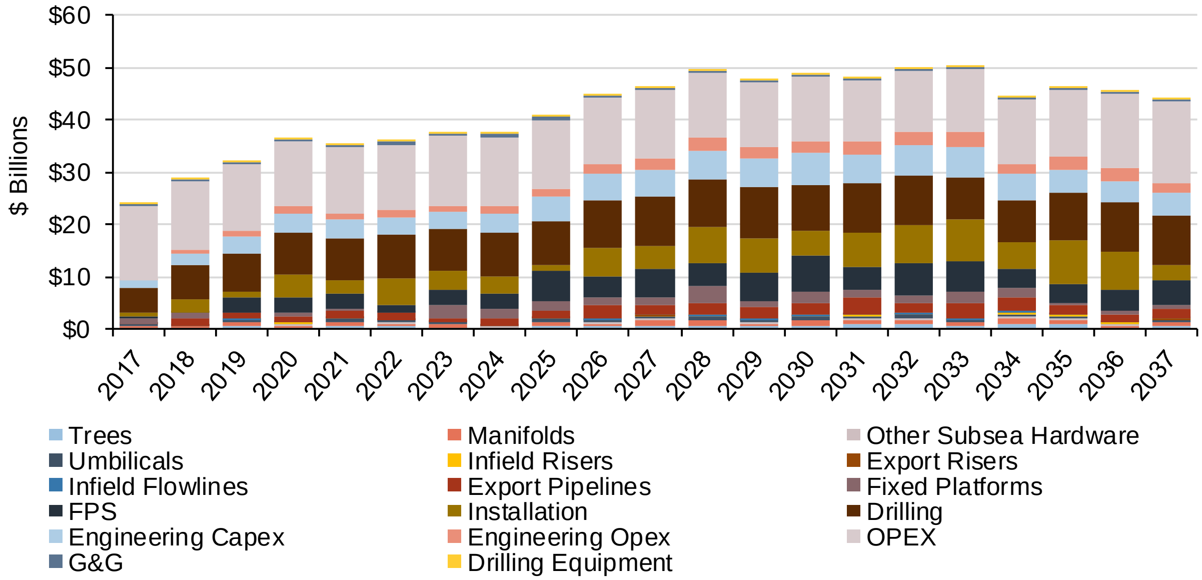
Under the Restrictive Enforcement Scenario, Gulf of Mexico production is forecasted to be reduced by nearly 15% or 0.4 million BOEPD by 2037.

5.4 Total Spending

Offshore oil and natural gas exploration and development is a capital-intensive process. Offshore projects require exploratory seismic surveys, drilling, production equipment, engineering, operational expenditures including the ongoing supply of consumables, and maintenance as well as other spending to be found and developed. The total cumulative spending from offshore oil and natural gas development is projected to be over $847 billion between 2018 and 2037 under the base case scenario and $751 billion under the Restrictive Enforcement Scenario, a yearly average of $42 and $37.5 billion respectively, which equals an average decline of nearly $4.8 billion per year. This represents an around 12 percent decrease in total spending as a result of potential restrictive enforcement of sections of the Well Control Rule related to drilling margins.

For the purposes of this report, spending is divided into seven main categories: Drilling, Engineering, G&G, Installation, OPEX, Platforms, and Subsea Umbilicals, Risers and Flowlines (SURF). Each category encompasses a major type of exploration and production activity and has a significant influence on overall spending. (Figure 8)

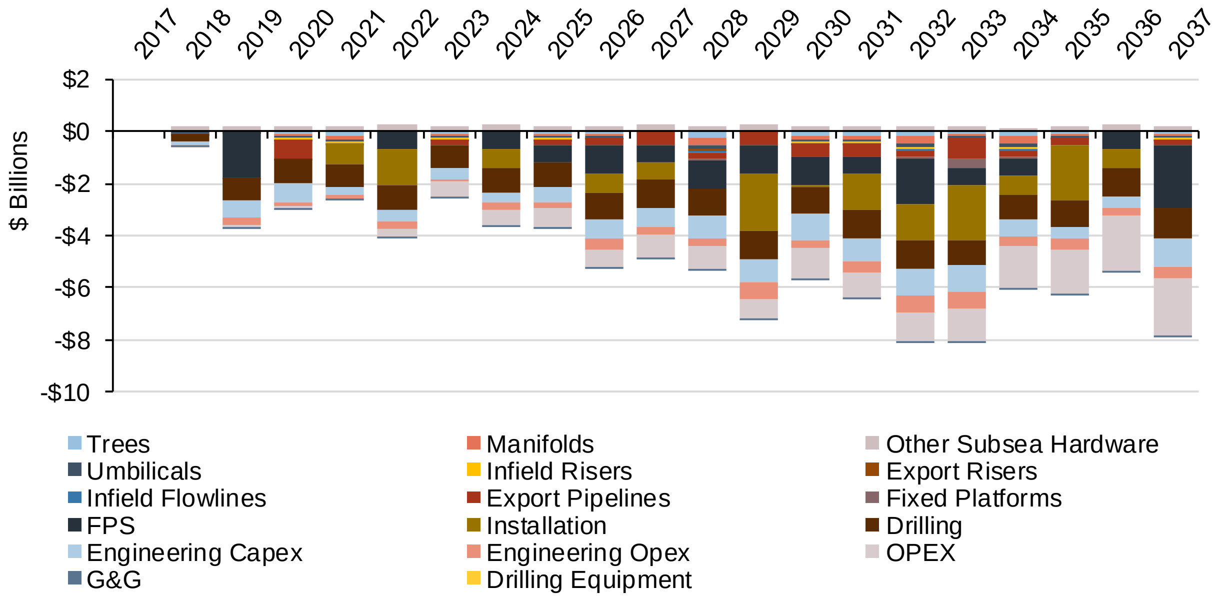
Figure 8: **Total Spending on GoM Oil and Natural Gas Development Base Scenario – 2018 to 2037**



Source: Calash

While spending is projected to decrease slightly in both scenarios due to reduced compliance costs associated with the proposed revisions to the Well Control Rule, this reduction in spending is minimal compared to the potential impact from fewer wells drilled and projects developed in a more restrictive regulatory environment due to restrictive enforcement of subsections of the rule related to drilling margins. (Figure 9)

Figure 9: Restrictive Enforcement Scenario Spending on GoM Oil and Natural Gas Development Reductions 2018 to 2037 ($Billions)



Source: Calash

Section 6 – Economic Impact of Potential Restrictive Enforcement of the Well Control Rule

In order to further quantify the potential impacts of less flexible enforcement of certain provisions of the original 2016 Well Control Rule after the potential adoption of the proposed 2018 revisions in a restrictive regulatory environment (specifically § 250.414 which will not be materially changed by the proposed revisions), Calash constructed an economic analysis model to estimate changes in jobs, GDP, and governmental revenue. The estimates created throughout this section closely parallel spending and activity trends. Employment and GDP effects are calculated using the most recent Bureau of Economic Analysis' (BEA) RIMS models in order to quantify the effects of domestic spending.

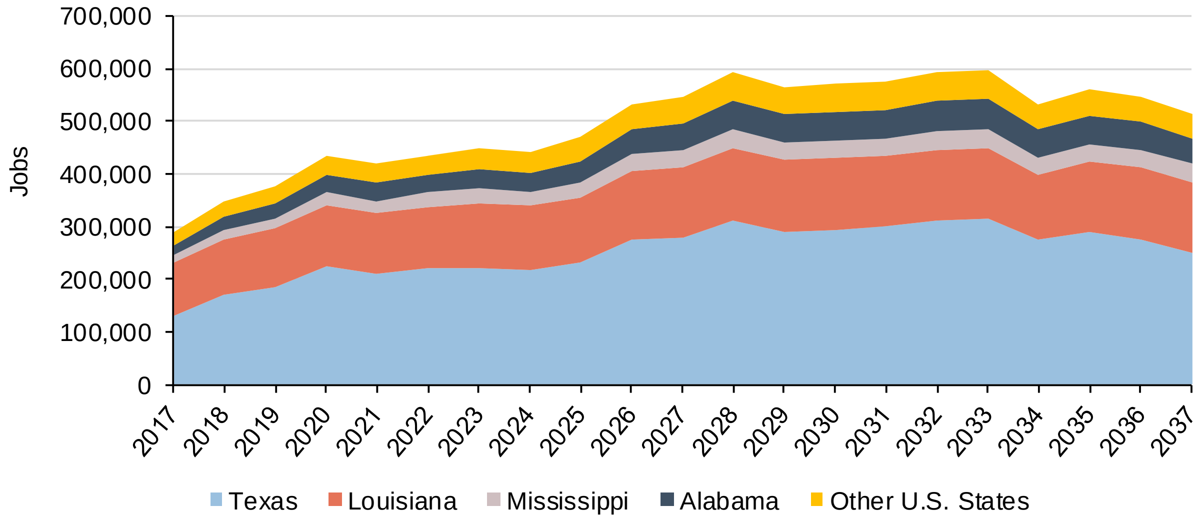
This analysis further underscores that the economic impact of decreased spending due to the potential restrictive enforcement of certain sections of the Well Control Rule. The projected net economic impact of this scenario is significant declines in employment, GDP, and federal revenue from 2018 forward.

6.1 Employment

The offshore oil and gas industry has a long history of significant employment throughout the nation and in particular the Gulf Coast states. Continued investment in offshore infrastructure has built a buoyant and diverse supply chain that has historically provided high wages to significant numbers of white and blue-collar laborers. Despite reductions due to reduced activity associated as a result of lower oil prices in recent years, total employment supported by industry spending is still estimated at approximately 349 thousand in 2018 with nearly 121 thousand direct industry jobs and an additional over 225 thousand jobs provided from indirect and induced industry spending.

Employment is expected to grow throughout the forecast with year to year fluctuations, as continued project investment, particularly in deep and ultra-deep waters is projected to lead to employment growth throughout the region. Gulf of Mexico OCS activity-driven employment within the U.S. is likely to grow from 349 thousand jobs in 2018 to more than 515 thousand by 2037, which is below the peak projected levels of around 600 thousand in 2033. No major shifts are expected within the state employment distribution, as Texas and Louisiana are expected to continue to be the most significant beneficiaries of offshore oil and gas with 170 thousand and 108 thousand jobs in 2018 respectively, and 275 thousand and 140 thousand jobs projected by 2037. (Figure 10)

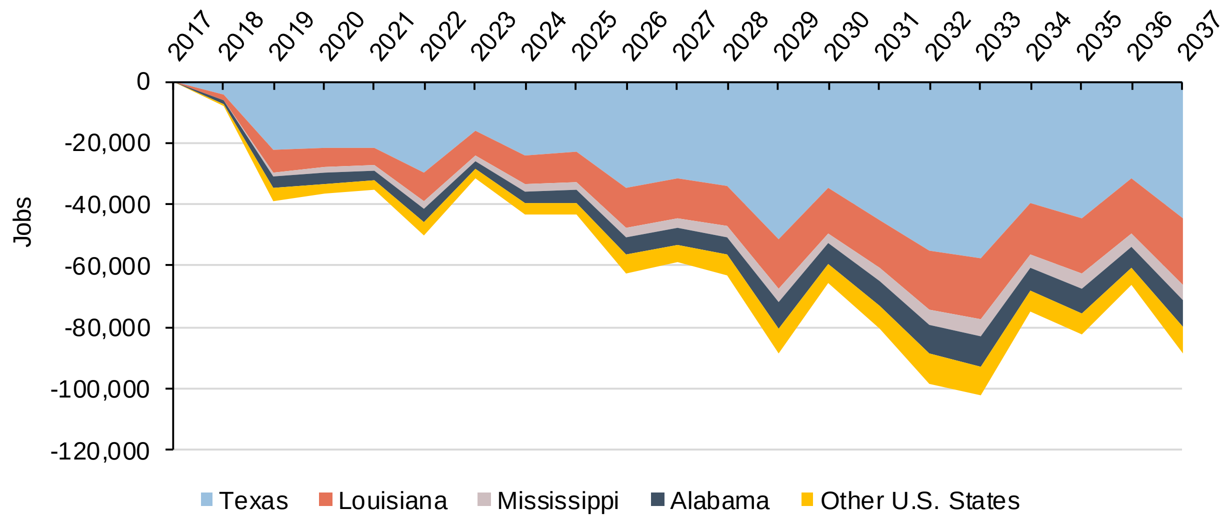
Figure 10: Jobs Supported by GoM Oil and Natural Gas Development by State - Base Development Scenario



Source: Calash

In the Restrictive Enforcement Scenario yearly employment supported is projected to decline relative to the base forecast, continuing to widen throughout the forecast period years with around 90 thousand yearly jobs displaced through lost offshore activity by 2037. Gulf of Mexico oil and natural gas development is projected to support fewer jobs due to fewer wells being drilled and lower overall spending. (Figure 11)

Figure 11: Jobs Supported by GoM Oil and Natural Gas Development by State Reductions – Restrictive Enforcement Scenario



Source: Calash

This lower employment level is likely to primarily affect the Gulf Coast, with Texas and Louisiana expected to see employment levels of around 45 thousand and 22 thousand jobs lower by 2037.

The BEA's RIMS model allows the calculation of employment estimates for both direct jobs (employment for those that work within the industry) and indirect and induced jobs (those created through the network of oil and gas operations as well as ancillary spending from the industry and its employees). In the Base Case direct job numbers are projected to grow from 121 thousand to 185 thousand between 2018 and 2037, representing 53 percent growth, while indirect jobs are expected to grow from 227 thousand to 329 thousand, a 45 percent growth. (Table 8)

Table 8: Direct vs. Indirect/Induced, and Total Employment Supported by GoM Oil and Natural Gas Development – Base Development Scenario vs. Restrictive Enforcement Scenario

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Base Direct	94,769	121,163	130,540	158,121	148,813	156,634	162,551	158,463	169,115	200,833	203,953
Base Indirect	195,273	227,479	245,231	276,623	271,139	279,013	286,388	284,158	300,471	333,170	341,997
Base Total	*290,042*	*348,641*	*375,771*	*434,744*	*419,952*	*435,647*	*448,939*	*442,621*	*469,586*	*534,003*	*545,950*
Restrictive Enforcement Direct	94,769	118,577	115,009	143,573	134,701	135,971	151,235	141,600	152,852	175,842	180,772
Restrictive Enforcement Indirect	195,273	222,244	221,822	254,439	249,905	249,410	266,173	257,544	273,147	295,509	306,328
Restrictive Enforcement Total	*290,042*	*340,821*	*336,832*	*398,012*	*384,606*	*385,381*	*417,408*	*399,144*	*425,999*	*471,351*	*487,100*
Total Difference	**0**	**-7,820**	**-38,939**	**-36,732**	**-35,346**	**-50,266**	**-31,531**	**-43,477**	**-43,587**	**-62,652**	**-58,850**

	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Base Direct	228,165	214,903	217,848	220,967	228,512	233,781	202,638	213,342	203,323	185,350
Base Indirect	365,695	351,127	354,216	353,538	364,665	364,769	330,977	347,995	343,340	329,850
Base Total	*593,859*	*566,030*	*572,064*	*574,505*	*593,177*	*598,550*	*533,615*	*561,337*	*546,663*	*515,200*
Restrictive Enforcement Direct	203,893	177,753	192,594	188,557	188,772	191,516	173,886	180,894	179,873	152,171
Restrictive Enforcement Indirect	326,808	299,874	313,540	305,531	305,938	304,758	284,585	298,120	300,773	274,148
Restrictive Enforcement Total	*530,701*	*477,628*	*506,134*	*494,087*	*494,710*	*496,274*	*458,470*	*479,014*	*480,646*	*426,319*
Total Difference	**-63,158**	**-88,403**	**-65,930**	**-80,418**	**-98,467**	**-102,276**	**-75,145**	**-82,323**	**-66,017**	**-88,880**

Source: Calash

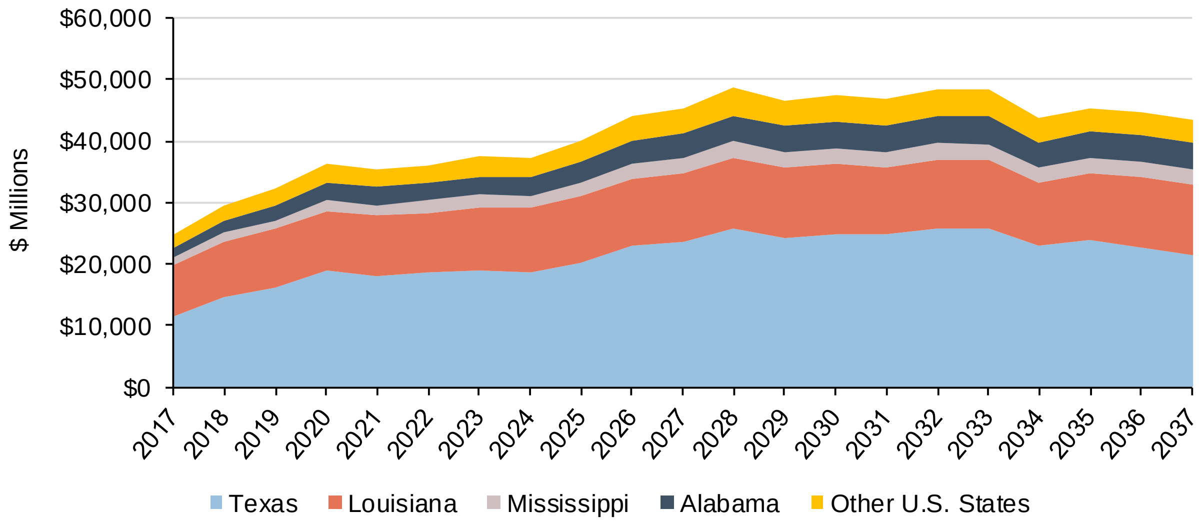
The potential impacts of the sections of the Well Control Rule related to drilling margins in a more restrictive regulatory environment are projected to have a large impact on indirect jobs, with an expected net loss of 55 thousand jobs or a 17 percent reduction compared to the base case, while direct jobs are expected to see a smaller net loss of 33 thousand jobs or 18 percent of projected employment in 2037.

6.2 GDP (Gross Domestic Product)

The gross domestic product (GDP) effects of the offshore oil and natural gas industry were calculated as a multiplier on spending within the U.S., further utilizing the BEA's RIMs model. The estimated potential impacts of potential less flexible enforcement of certain sections of the Well Control Rule in a more restrictive regulatory environment are therefore likely to be strongly correlated to any shifts within spending, with international spending (mainly on platform fabrication) excluded and should mirror the shifts throughout employment.

The current GDP impact of the Gulf of Mexico offshore oil and natural gas industry in the U.S. is estimated at over $29 billion annually in 2018 and is projected to continue to grow to around $43 billion by 2037 – representing around 48 percent growth. (Figure 12)

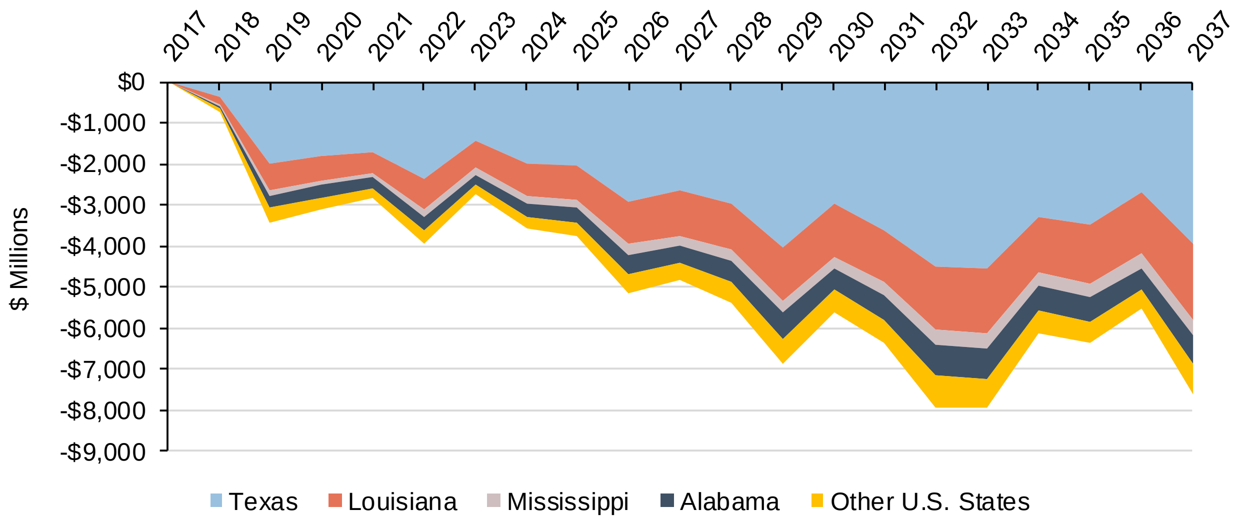
Figure 12: Estimated GDP Supported by GoM Oil and Natural Gas Development by State Base Scenario– 2017 to 2037 ($Millions)



Source: Calash

In the Restrictive Enforcement scenario, the GDP impact from Gulf of Mexico oil and natural gas activities is projected to be $7.6 billion lower in 2037. The cumulative 20-year loss of GDP from 2018 to 2037 is estimated at $100 billion. (Figure 13)

Figure 13: Estimated GDP Supported by GoM Oil and Natural Gas Development by State Restrictive Enforcement Scenario– 2017 to 2037 ($Millions)

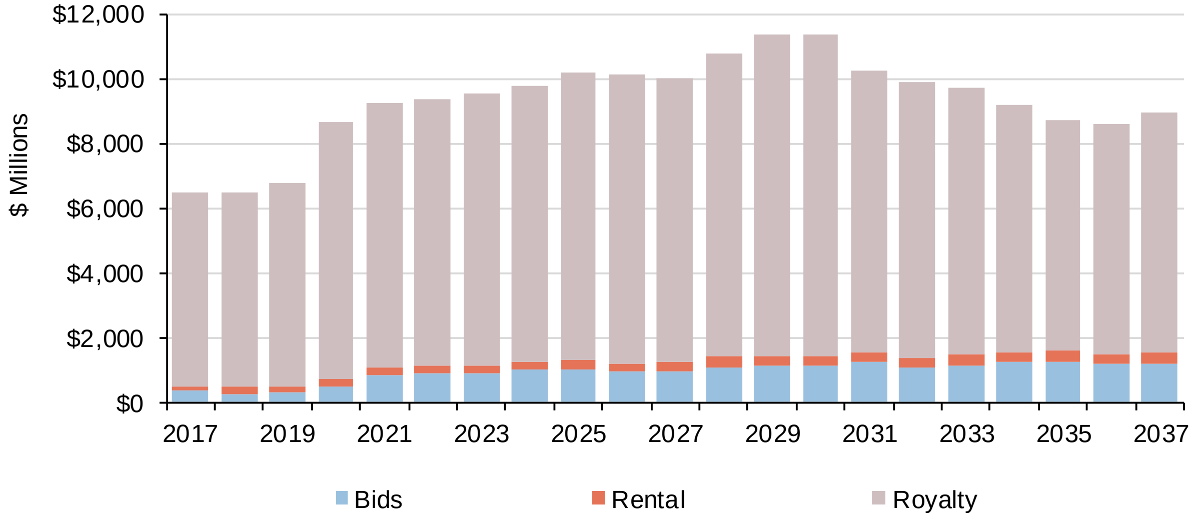


Source: Calash

6.3 Government Revenue

Government revenues due to Gulf of Mexico offshore oil and gas operations are currently collected through three main revenue streams; revenue from lease sales, lease rental rates, and production royalties. The distribution of these revenues streams is heavily skewed towards production royalties, which account for around 80 percent of revenues from offshore oil and natural gas activities. Total government revenues from Gulf of Mexico offshore oil and gas royalties are estimated at between $7.7 and $6.5 billion in recent years. (Figure 14)

Figure 14: Projected Governmental Revenues from GoM Oil and Natural Gas Development – Base Development Scenario ($Millions)



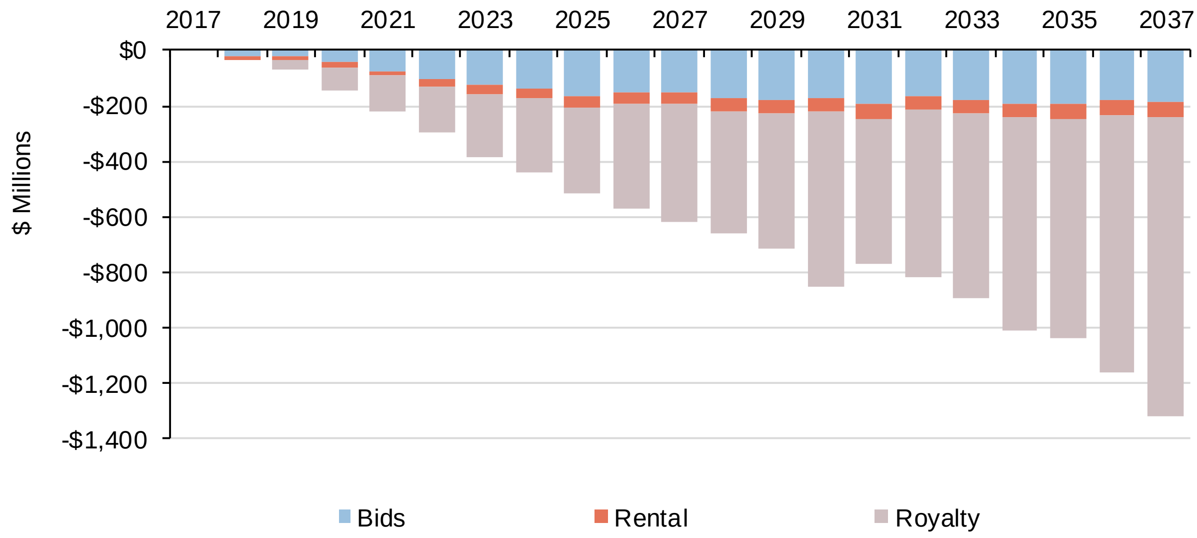
Source: Calash

Under the base development scenario, future lease sale levels are expected to return to levels more in line with levels prior to the large drop in oil prices from 2014 to 2018. Lease sale revenue are projected to grow from $245 million to $1.2 billion over the forecast period. Block rentals account for the smallest portion of government revenue and are projected to fluctuate between $221 and $350 million per year over the forecast. Production royalties, calculated using the EIA long term oil and gas price forecast from February 2018, fluctuate due to production levels and oil prices, ranging from a low of from a $7.1 billion to a high of $9.9 billion.

State and Federal governments share in the revenue from the GOM oil and natural gas development. Under GOMESA and regulations applicable to revenues beginning in 2007, offshore revenues are shared between state and federal governments. The second phase of GOMESA revenue-sharing took effect in 2017, which led to an approximately a 62.5% to 37.5% split between state and federal governments with revenue capping provisions at $500 million for states.

The effects of potential less flexible enforcement of the Well Control Rule in a more restrictive regulatory environment with less flexibility would be projected to lead to lower government revenues of around $13.9 billion from 2018 to 2037, and average of around $695 million per year. As production impact from reduced activity are delayed, the long-term impact of this scenario would likely be greater. (Figure 15).

Figure 15: Projected Governmental Revenues from GoM Oil and Natural Gas Development Reductions – Restrictive Enforcement Scenario ($Millions)



Source: Calash

The revenue effects at the state level are expected to be minimal as GOMESA limits of $500 million per year are reached under both revenue scenarios in most years under Calash's interpretation of the law.

Section 7 – Conclusions

The oil and gas industry in the Gulf of Mexico has a significant positive impact on the local economies of the Gulf coast and the broader U.S. economy. The industry supports well-paying employment for hundreds of thousands of Americans and provides revenues to many levels of the U.S. government. The industry has also grown into the world leader in offshore safety, technology, and scientific research. Despite low oil prices which led to reduced activity, Gulf production areas have been longstanding sources of employment and production, with activity expected to increase due to rising commodity prices. Due to the work being done in the deepwater Gulf of Mexico, the industry's global influence has grown steadily, along with the economic benefits which it brings.

The proposed 2018 revisions to the 2016 rule, "Oil and Gas and Sulphur Operations in the Outer Continental Shelf – Blowout Preventer Systems and Well Control", are expected to have a positive impact on the industry due to reduced compliance cost without impacting safety. However, certain sections of the Well Control Rule (especially § 250.414 which prescribes drilling margins) if in the future a more restrictive regulatory regime from BSEE develops, and portions of the rule are enforced with less flexibility, seriously limit the ability of operators, drilling contractors, and service providers to safely, effectively, and economically operate in U.S. offshore areas. These provisions could lead to a material reduction in offshore activity, especially in deepwater areas.

After analyzing the operational and economic impacts of the proposed revisions, as well as the actual and potential impact of the Well Control Rule this study has projected that the following potential effects.

- A significant number of the sections of the previously adopted 2016 Well Control Rule increased expenses for industry participants, however changes between the originally proposed rule and the adopted rule as well as BSEE's enforcement of the rule led to lower costs than originally predicted. It is important to note that under a more restrictive regulatory regime the potential costs (and the potential for lost activity) associated with the well control rule either as written or if the proposed revisions are adopted would likely be much higher.
- The adoption of the proposed 2018 revisions is expected to provide material costs savings to industry participants throughout the study period. The cost savings associated with the proposed revisions are significant and are estimated at approximately 37% of the average annual cost of the Well control rule across the ten year (2018 to 2027) period. Cumulative direct cost savings due to the adoption of the proposed revisions as currently written are estimated at nearly $1.4 billion for the ten years from 2018 to 2027.

- Prior to the adoption of 2016 Well Control Rule, certain provisions of the Rule, especially the section §250.414, "Planned safe drilling margins" which prescribe drilling margins at .5 pound per gallon were identified as likely to prevent a large number of Gulf of Mexico wells from being drilled. There were minor differences between the originally proposed and adopted rule, as well as minor changes to the rule in the proposed 2018 revisions. However, even if the proposed 2018 revisions were adopted a large number of wells could likely not be drilled under these prescriptive drilling margins.
- Since the adoption of the 2016 Well Control Rule, BSEE has approved drilling margins that deviate from this prescriptive requirement, minimizing the potential impact of this section. According to BSEE, "BSEE has approved operators' use of drilling margins that are less than 0.5 ppg for 32 wells, 31 of which were in deep water." BSEE is also seeking comments as to whether it should further refine or change this section of the rule or its approach to implementing it.
- If this section of the rule (even with the proposed changes) were to be implemented as written, without the case by case approval of differing margins it would likely reduce the total amount of Gulf of Mexico oil and natural gas activity, including the number of wells drilled and projects developed. The rule would likely negatively influence deepwater development the most, especially high pressure, high temperature, and ultra-deepwater wells which may no longer be drillable.
- The total cumulative spending from offshore oil and natural gas development in the Gulf of Mexico is projected to be over $847 billion between 2018 and 2037 under the base case scenario and $751 billion under the Restrictive Enforcement Scenario, a yearly average of $42 and $37.5 billion respectively, which equals an average decline of nearly $4.8 billion per year. This represents an around 12 percent decrease in total spending as a result of potential restrictive enforcement of sections of the well control rule related to drilling margins.
- Gulf of Mexico OCS activity-driven employment within the U.S. is projected to grow from 349 thousand jobs in 2018 to more than 515 thousand by 2037, which is below the peak projected levels of around 600 thousand in 2033. In the Restrictive Enforcement Scenario yearly employment supported is projected to decline relative to the base forecast, continuing to widen throughout the forecast period years with around 90 thousand yearly jobs displaced through lost offshore activity by 2037.
- The current GDP impact of the Gulf of Mexico offshore oil and natural gas industry in the U.S. is estimated at over $29 billion annually in 2018 and is projected to continue to grow to around $43 billion by 2037 – representing around 48 percent growth.

- In the Restrictive Enforcement scenario, the GDP impact from Gulf of Mexico oil and natural gas activities is projected to be $7.6 billion lower in 2037. The cumulative 20-year loss of GDP from 2018 to 2037 is estimated at $100 billion.
- The effects of potential less flexible enforcement of the Well Control Rule in a more restrictive regulatory environment would be projected to lead to lower government revenues of around $13.9 billion from 2018 to 2037, an average of around $695 million per year.
- While the proposed 2018 revisions to the Well Control Rule are generally positive and would likely reduce the regulatory cost burden on the industry, it is clear that the potential negative impact of sections of the rule related to drilling margins in a more restrictive regulatory environment greatly outweighs any cost savings which would be derived from the proposed revisions.

Appendix 1 – BSEE Proposed Revisions Appendix

This Report provides an independent high-level review and evaluation of the United States Department of the Interior Bureau of Safety and Environmental Enforcement ("BSEE"), proposed 2018 revisions to the rule on "Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control". The purpose of this report was to provide a summary of the most impactful sections and subsections of the proposed revisions. This study is in no way exhaustive - especially in light of the short period available to review the proposed revisions, the highly technical nature of these regulations, and time to develop this analysis with comments.

This Report reviewed key technical effects expected by the proposed revisions on industry operations and included those key technical impacts within a larger evaluated economic analysis of the Well Control Rule. The larger economic analysis viewed impacts across stakeholders, including the industry operators, industry support providers (i.e. engineers, designers, manufacturers, service, and equipment suppliers), government revenue losses, and resultant employment effects. The key technical effects were reviewed by Blade Energy Partners, and the economic analyses and evaluation was provided by Calash.

The analysis in this Report focuses on the likely engineering and operational effects of these regulations, and wherever possible attempts to calculate the cost of overcoming these burdens. As such, this analysis is essentially forward looking, and therefore subject to significant changes based on the final revisions as implemented by BSEE, the way in which the Well Control Rule and revisions to it are implemented, and a variety of other factors. Due to the limited time available to prepare this report, as well as significant uncertainties about the way the Well Control Rule and any revisions to it have and would be implemented, the projected costs and engineering and operational burdens for all proposed regulations are not included in this Report. Additionally, the internal costs to BSEE of implementing and administrating all provisions of the original 2016 rule are not included in this report.

The report's authors make no representation as to the effects of revisions or current regulations not addressed specifically in this report, and do not discount the possibility that these proposed revisions could impose additional significant engineering, operational or other burdens on industry, regulators or others. The report's authors' estimates herein of the effects that the Well Control Rule and any proposed revisions of the rule will have on current and future engineering and operations and technology advances are an independent good faith qualitative view arising from unfortunately short considerations by various subject matter persons within Calash (an independent consulting firm focused on oil and gas operations and economics) and Blade Energy (a consulting company in well design, engineering and operations).

As this was an independent review, industry and others (operators, original equipment manufacturers, support and service providers) may, and surely will have differences of opinion with all or part of this analysis. This analysis was not in any way prepared to contradict or supersede any other view. Both Calash and Blade Energy are providing this independent view expressly disclaiming any warranty, liability, or responsibility for completeness, accuracy, use, or fitness to any person for any reason.

§250.413 (g)

Proposed Change: This rulemaking would add in paragraph (g) a parenthetical clarification of ‘‘surface and downhole’’ after ‘‘proposed drilling fluid weights’’, to ensure the operator includes the weight of the drilling fluid in both places. This clarifies the information the operator has previously been required to provide, without adding a new burden, and improves the safety of the drilling operation by ensuring the drilling fluid weight is fully evaluated and appropriate for the estimated bottom hole pressures.

General Impact: BSEE is already requiring surface and downhole mud weights before they approve an APD or APM. This proposed change would simply codify the existing BSEE practice and help to clarify the requirement. Therefore, there would be no additional impact.

Industry Cost Savings: None

BSEE Cost Savings: None

§250.414 (c)

Proposed Change: This proposed rule would revise paragraph (c)(3) of this section to add the words ‘‘and analogous’’ before ‘‘well behavior observations’’ and ‘‘, if available’’ at the end of paragraph (c)(3) of this section. This minor wording change would ensure that operators use available data from wells with similar conditions as the well being drilled when determining the pore pressure and fracture gradient to ensure accuracy and safety when establishing the drilling margin. BSEE is specifically soliciting comments about the effectiveness of the use of related analogous data and how the pore pressure and fracture gradient are determined without related analogous data. Please provide reasons for your position. In the proposed rule text, the drilling margin requirements are mostly unchanged. The current regulations allow for a deviation from the default 0.5 pound per gallon (ppg) drilling margin. The deviation does not have to be submitted as an alternate procedure or departure request; rather, it may be submitted with the Application for Permit to Drill (APD) along with the supporting justifications. BSEE is currently approving margins other than 0.5 ppg based on specific well conditions. BSEE is working to provide consistent approval throughout the regions and districts, and, as described more fully below, BSEE is specifically soliciting comments about the process to deviate from the 0.5 ppg drilling margin. The purpose of the drilling margin is to ensure that the drilling fluid weight used allows for some variability in the pore pressure and fracture gradient, ensuring the safety of drilling operations. In 2011, the National Academy of Engineering and National Research Council of the National Academies recommended that ''[d]uring drilling, rig personnel should maintain a reasonable margin of safety between the equivalent circulating density and the density that will cause wellbore fracturing.'' Macondo Well Deepwater Horizon Blowout—Lessons for Improving Offshore Drilling Safety (NAE Report), Recommendation 2.2 (p. 43). The NAE Report stated further that ''until a reasonable standard is established, industry should design the ECD [equivalent circulating density] so that the difference between the ECD and the fracture mud weight is a minimum of 0.5 ppg . . . Additional evaluations and analyses should be performed to establish an appropriate standard for this margin of safety.'' Id. The Department's 2011 joint investigation team report (DOI JIT Report) regarding the causes of the April 20, 2010, Macondo Well blowout recommended that BSEE define the term ''safe drilling margin(s)'' and that such a definition should ''encompass pore pressure, fracture gradient and mud weight.'' The Bureau of Ocean Energy Management, Regulation and Enforcement Report Regarding the Causes of the April 20, 2010, Macondo Well Blowout (DOI JIT Report), Recommendation 3 (p. 202). Thus, the NAE Report and the DOI JIT Report recommended additional evaluations, analyses, and definition of what a safe drilling margin is. In the 2016 final well control rule preamble, BSEE cited this JIT Report recommendation and the bureau's prior typical reliance on a minimum of 0.5 ppg below the lower casing shoe pressure integrity test or the lowest estimated fracture gradient as an appropriate safe drilling margin and as the basis for including this as the default requirement in the current section 250.414(c). 81 FR 25888, 25894 (April 29, 2016). Section 250.414(c) also allows for using an equivalent downhole mud weight, provided that the operator submitted adequate documentation justifying the use of an alternative equivalent downhole mud weight. Since the WCR became effective, BSEE's records show that there have been 305 wells drilled. Of those wells, BSEE has approved operators' use of drilling margins that are less than 0.5 ppg for 32 wells, 31 of which were in deep water. Even though these 32 wells represent only 10 percent of the total wells drilled in that time frame, the number is significant enough for BSEE to consider whether it should further refine the approach it is taking in the current regulations or whether it should adhere to its practice of identifying a specific drilling margin with an avenue for allowing operators to submit adequate documentation justifying the use of a different drilling margin, such as risk modeling data, off-set well data, analog data, and seismic data. The Explanatory Statement for the 2017 Consolidated Appropriations Act, Public Law 115–31 (May 5, 2017), also recommended that BSEE consider revising the 2016 WCR. It stated: Blowout Preventer Systems and Well Control Rule. —The Committees encourage the Bureau to evaluate information learned from additional stakeholder input and ongoing technical conversations to inform implementation of this rule. To the extent additional information warrants revisions to the rule that require public notice and comment, the Bureau is encouraged to follow that process to ensure that offshore operations promote safety and protect the environment in a technically feasible manner. 163 Cong. Rec. H3881 (daily ed. May 3, 2017). For these reasons, BSEE is requesting comment and further statistical analysis from stakeholders about whether the 0.5 ppg drilling margin in this proposed rule should be revised or removed. BSEE solicits comments on alternatives to the current set 0.5 ppg drilling margin. Specifically, BSEE requests comment on replacing it with a more performance-based standard under which the approved safe drilling margin is established on a case-by-case basis for each well, based on data and analysis particular to that well, through the permitting process. BSEE also requests comment on potentially providing for a different drilling margin or multiple drilling margins that are specific to the conditions in which the wells are drilled, such as if the well is drilled in deep water or shallow water. BSEE further requests comment on whether removal of a specific reference to a 0.5 ppg standard from the regulation may be appropriate. For example, the standard establishes a prescriptive margin without an in-depth analysis of appropriate margins for potential hole sections, which must take into account factors, such as cutting loads, equivalent downhole mud weight, and fluid temperatures and pressures. Further, enforcing a prescriptive minimum margin can force operators to encroach on pore pressure, which might result in unintended kicks. These types of considerations may suggest that a more case-by-case approach toward the establishment of appropriate safe drilling margins for particular wells through the permitting process would be preferable. Consequently, BSEE specifically solicits comments regarding the potential removal of the specific reference to a 0.5 ppg drilling margin from § 250.414(c) and its replacement with a more performance based, case by- case standard for the establishment of appropriate safe drilling margins through the well permitting process. BSEE also requests comment on the criteria that BSEE could use to apply alternative approaches, such as an operator demonstrating that a well is a development well as opposed to an exploratory well. To utilize this alternative option, the rulemaking could specify what documentation operators would need to submit with the APD in order to provide adequate justification. BSEE requests comment on what supplemental data would provide an adequate level of justification for deviating from the 0.5 ppg drilling margin under identified circumstances, such as requiring the submission of offset well data, analog data, seismic data, and decision modeling. BSEE also requests comment on whether there are situations where drilling can continue prior to receiving alternative safe drilling margin approval from BSEE. BSEE requests comment on (1) whether there are situations where, despite not being able to maintain the approved safe drilling margin, an operator's continued drilling with an alternative drilling margin creates little risk; (2) the criteria that BSEE should use to define those situations and the available alternative drilling margins; and (3) what level of follow-up reporting (e.g. submitting a follow-up notice to BSEE within a specified time frame) would be appropriate. Such an approach could provide assurance that an operator, with the appropriate level of justification, could continue to drill as real time data is evaluated, and would largely be designed to add more clarity to the existing option(s) provided by § 250.414(c)(2). This would provide a proactive approach to managing risk and ensuring safe operations, while also providing increased investment certainty for the regulated community. In addition, BSEE could add the words ‘‘and analogous’’ before ‘‘well behavior observations’’ and ‘‘, if available’’ at the end of paragraph (c)(3) of this section. This minor wording change could ensure that operators use available data from wells with similar conditions as the well being drilled when determining the pore pressure and fracture gradient to ensure accuracy and safety when establishing the drilling margin. BSEE is specifically soliciting comments about the effectiveness of the use of related analogous data and how the pore pressure and fracture gradient are determined without related analogous data. Please provide reasons for your position.

General Impact: The proposed rule does not remove the word "safe". Industry is tasked with "considering" these offset data. This proposed change is superfluous in that it narrows the data that must be "considered". In reality, the operator must still screen all the data and used only the analogous data which is what would already be considered good industry practice. In this light, there is no new impact, beneficial or otherwise.

This paragraph, in conjunction with §250.414 (h), in the WCR leaves the door open for MPD in that the term "equivalent ECD" can be taken to mean the combination of hydrostatic and applied surface pressure. Per BSEE 32 wells (31 deepwater) of 305 wells drilled since the adoption of the WCR required BSEE to approve operators’ use of drilling margins that are less than 0.5 ppg for 32 wells, which represent 10 percent of the total wells drilled in that time frame. BSEE is considering whether it should further refine the approach it is taking in the current regulations or whether it should adhere to its practice of identifying a specific drilling margin with an avenue for allowing operators to submit adequate documentation justifying the use of a different drilling margin, such as risk modeling data, off-set well data, analog data, and seismic data. Despite these revisions the potential exists that in a more restrictive regulatory environment BSEE could not approve of drilling margins less than .5 PPG which would likely not allow operators to drill these wells.

Industry Cost Savings: None

BSEE Cost Savings: None

§250.292 (g)

Proposed Change: This rulemaking would revise paragraph (p) by clarifying the free standing hybrid riser (FSHR) requirements and removing the requirement for certification of the tether system and connection accessories by an approved classification society or equivalent. Based on BSEE experience during the implementation of the original WCR, these revisions to paragraph (p) would clarify the focus of the requirements for FSHR systems that involve a buoyancy air can suspended from the top of the riser, regardless of the manner of connection, to avoid confusion over whether a specific component type would be considered ‘critical’ or not. The requirements in § 250.292(p)(2) and § 250.292(p)(3) would be removed because the detailed information specified on the FSHR design, fabrication, installation, and load cases is already required by the relevant portions of the platform verification program (PVP) in § 250.910(b), and in §§ 250.1002(b)(5) and 250.1007(a)(4)(ii). This would reduce the burden on operators by eliminating the requirement to submit the same or very similar information on an FSHR system through more than one regulatory permitting process. Section 250.292 paragraphs (p)(4) and (p)(5) would be redesignated as § 250.292 paragraphs (p)(2) and (p)(3), and their language would be revised to align with the clarification in paragraph (p). The requirements in § 250.292(p)(6) would be removed altogether, because they are duplicative of the certification that any permanent pipeline riser installation and its tensioning systems will undergo via the Certified Verification Agent (CVA) requirements of § 250.911, in connection with the PVP.

General Impact: The additional impact will save operators time and expense of preparing a redundant permit applications.

BSEE will save time by not having to review the redundant submissions.

Industry Cost Savings: One man hour for each redundant permit assumed to be one redundant permit per floating production unit utilizing a free standing hybrid riser system.

BSEE Cost Savings: A quarter man hour for each redundant permit assumed to be one redundant permit per floating production unit utilizing a free standing hybrid riser system.

§250.423

Proposed Change: This rulemaking would revise paragraphs (a) and (b) by removing the words “and cementing” after “upon successfully installing”. Revisions to this section are necessary because there are many situations in the design of the casing or liner string running tool where the latching or lock down mechanism is automatically engaged upon installing the string. BSEE has received many alternate procedure requests to accommodate these situations since publication of the original WCR. BSEE is still requiring these mechanisms to be engaged upon successful installation of the casing or liner. The proposed change would allow more flexibility on an operational case-by-case basis in determining the appropriate time to engage these mechanisms and would also reduce the number of alternate procedure requests submitted to BSEE for approval.

General Impact: This proposed change should result in a positive impact on the industry in that alternate procedure requests would be eliminated for the affected equipment.

Industry Cost Savings: Reduction in section 250.141 alternate procedure submissions for deep-water wells. An hour of an industry engineers time assuming ~6.25% of deepwater wells require alternate procedure submissions.

BSEE Cost Savings: Reduction in section 250.141 alternate procedure submissions for deep-water wells. A quarter hour of a BSEE engineers time assuming ~6.25% of deepwater wells require alternate procedure submissions.

§250.428 (c)

Proposed Change: BSEE is proposing to revise paragraph (c) to include the term “unplanned” when describing the lost returns that provide indications of an inadequate cement job. This revision would minimize the number of unnecessary revised permits submitted to BSEE for approval. Current cementing practices utilize improved well modelling to identify and account for zones that may have anticipated losses. It is unnecessary to submit a revised APD to address lost returns for a well cementing program that has been designed for those occurrences. Any unexpected losses would require locating top of cement and determining whether the cement job is adequate. A new paragraph (c)(iii) would be added to allow the use of tracers in the cement, and logging the tracers’ location prior to drill out, as an alternative approach for locating the top of cement. The original WCR did not address this approach, however based upon BSEE experience this addition would provide more viable options and flexibility for locating top of cement to help minimize rig down time running in and out of the hole multiple times, without compromising safety. Existing paragraph (c)(iii) would be redesignated as paragraph (c)(iv).

General Impact: The proposed change would have a positive impact on the industry in that only "unplanned" losses would require further work on the part of the operator and BSEE. Reduction in Application for Permit to Drill (APD) resubmissions due to planned mud losses on all wells drilled.

Industry Cost Savings: 1 hour of an industry engineer’s time. Assuming ~30% of all wells require APD resubmissions.

BSEE Cost Savings: .25 of an hour of a BSEE engineer’s time. Assuming ~30% of all wells require APD resubmissions.

§250.428 (d)

Proposed Change: Paragraph (d) would be revised to clarify that, if there is an inadequate cement job, operators are required to comply with § 250.428(c)(1). The original WCR did not address this provision, however based upon BSEE experience this revision would help assess the overall cement job to allow for improved planning of remedial actions.

This rulemaking would also revise paragraph (d) to allow the preapproval of remedial cementing actions through a contingency plan within the original approved permit; however, if the remedial actions have not already been approved by BSEE, clarification was added directing submittal of the remedial actions in a revised permit for BSEE review and approval. The original WCR did not address this provision, however based upon BSEE experience, BSEE is proposing to allow the remedial actions to be included as contingency plans in the original permit to minimize the time necessary for operators to commence approved remedial cementing actions, and to reduce burdens on operators and BSEE from multiple submissions. If BSEE has already approved the remedial cementing actions in the original permit, additional BSEE approval is not required unless they deviate from the approved actions.

Based upon BSEE experience with the implementation of the original WCR, BSEE has determined that allowing the professional engineer (PE) to certify the remedial cementing actions in the contingency plan within the original permit would help streamline the permitting process and reduce delays to remedial actions without compromising safety. The proposed revision to this paragraph would eliminate the requirement for a PE certification for any changes to the well program so long as the changes were already approved in the permit. This would result in less rig down time waiting for PE certifications before beginning initial remedial actions. In conjunction with the approval of the remedial actions BSEE requires a PE certification for any changes to the well program. These proposed revisions would minimize the number of revised permits submitted to BSEE for approval, reducing burdens on operators and BSEE.

General Impact: The proposed change would have a positive impact on the industry in that only "unplanned" losses would require further work on the part of the operator and BSEE. This would remove lost rig time waiting on approvals of an APD resubmission associated with planned cement loss.

Industry Cost Savings: Reduction in lost rig time waiting for APD resubmissions for pre-approved remedial cementing to be approved. Three hours of rig time assuming all wells (on average) require an APD resubmission.

BSEE Cost Savings: None

§250.433 (b)

Proposed Change: This rulemaking would revise paragraph (b) to modify requirements for subsequent diverter testing by allowing partial activation of the diverter element and not requiring a flow test. The original WCR did not address this provision, however based upon BSEE experience these changes would codify longstanding BSEE policy and minimize the number of alternate procedure requests submitted to BSEE. Full actuation of the diverter element and flow tests are unnecessary with subsequent testing because partial actuation of the element sufficiently demonstrates functionality of the element, and a full flow test would be originally verified on the initial test. These changes would also help minimize the possibility of accidental discharge of mud overboard.

General Impact: The proposed change would have a positive impact on the industry in that only a function test would be required on subsequent diverter actuations.

Industry Cost Savings: None

BSEE Cost Savings: None

§250.461 (b)

Proposed Change: This proposed rule would revise paragraph (b) by extending the maximum permitted survey intervals during angle-changing portions of directional wells from 100 feet to 180 feet. This would account for the majority of the pipe stand lengths and would address developments that BSEE has needed to accommodate through alternative approvals since before the original WCR. Most rigs have upgraded the derrick height to account for the increase in pipe stand lengths to improve drilling efficiency. The pipe stands have routinely become greater than 100 feet, with some pipe stands being as high as 180 feet. Increasing the survey interval to correlate with the now common pipe stand lengths would help improve rig efficiency while drilling. This revision would also minimize the number of alternate procedure requests submitted to BSEE in APDs.

General Impact: Positive impact on industry potentially cutting directional surveying time. In actuality, the surveying time reduction would only apply to the survey of record performed on the last trip out of the hole before running casing.

Industry Cost Savings: Extended survey intervals for directional drilling would lead to 24 man hours of reduced labor for all directional wells assuming around 66% of all offshore wells are directional wells.

BSEE Cost Savings: Extended survey intervals for directional drilling would lead to .25 hours of reduced labor for BSEE per APD for all directional wells assuming around 66% of all offshore wells are directional wells.

§250.518 (e)

Proposed Change: This rulemaking would revise paragraph (e)(1) by clarifying that only permanently installed packers or bridge plugs that are qualified as mechanical barriers are required to comply with API Spec. 11D1. Based upon BSEE experience with the implementation of the original WCR, including questions BSEE received from operators, this revision would codify BSEE's policy to ensure that the required mechanical barriers in a well are held to a higher standard than other common packers or bridge plugs used for various well specific conditions and completions design. Furthermore, BSEE is aware that certain packers and bridge plugs cannot meet the specifications of API Spec. 11D1.

General Impact: This proposed change is positive in nature, but since BSEE admits that the requirement was unobtainable for "certain" devices, the effect is negligible.

Industry Cost Savings: None

BSEE Cost Savings: None

§250.619 (b)

Proposed Change: This rulemaking would revise paragraph (e)(1) by clarifying that only permanently installed packers or bridge plugs that are qualified as mechanical barriers are required to comply with API Spec. 11D1. This revision would codify BSEE's policy developed since the WCR, to ensure that the required mechanical barriers in a well are held to a higher standard than other common packers or bridge plugs used for various well specific conditions and completions design. Furthermore, BSEE is aware that certain packers and bridge plugs cannot meet the specifications of API Spec. 11D1. BSEE would also add that operators must have two independent barriers, one being mechanical, in the exposed center wellbore prior to removing the tree or well control equipment. This addition would codify existing BSEE policy and add into the workover regulations in Subpart F requirements about mechanical barriers similar to those already found in § 250.720(a). This addition would help ensure the well is properly secured before removal of the tree or well control equipment.

General Impact: This proposed change is positive in nature, but since BSEE admits that the requirement was unobtainable for "certain" devices, the effect is negligible.

Industry Cost Savings: None

BSEE Cost Savings: None

§250.712 (g)

Proposed Change: BSEE would add paragraph (g) to clarify that reporting is not necessary for rig movements to and from the safe zone during permitted operations.

General Impact: The impact on operators is positive, due to a reduction in number of rig movement reports for all wells.

Industry Cost Savings: Reduction in number of rig movement reports for all wells. 1 man hour of industry engineer time per report assuming around 11.5 reports per well.

BSEE Cost Savings: None

§250.722

Proposed Change: BSEE is proposing to revise the prolonged operations well casing reporting requirements in paragraph (a)(2) of this section to clarify that District Manager approval is not required to resume operations if a successful pressure test was conducted as already approved in the applicable permit. BSEE would also clarify that the successful pressure test results must be documented in the Well Activity Report (WAR). The original WCR did not address the issue of District Manager approval, however based upon BSEE experience, these revisions would minimize the amount of unnecessary rig operational time waiting for separate BSEE approval of the successful pressure test where BSEE has already approved the relevant testing and streamline BSEE approval of associated operations. These revisions would be applicable only if the actions are appropriately planned for and already approved in the associated permit. The pressure tests are conducted to help verify casing integrity. BSEE would also make a minor revision to this paragraph to provide that the calculations are used to “indicate” not “show” that the well’s integrity is above the minimum safety factors. This change is necessary because the calculations do not guarantee or “show” integrity; they are used as a way to help determine well integrity. Using the word “indicate” removes the definitive statement or assumption that the calculations demonstrate well integrity.

General Impact: The impact on operators is positive for this proposed change, in that wait time for BSEE approval would be eliminated under these circumstances.

Industry Cost Savings: Reduction in number of district manager approvals for resuming operations for all wells, assumes .25 hours of rig time and 1.35 occurrences per well on average.

BSEE Cost Savings: None

§250.723

Proposed Change: This rulemaking would revise this section by removing the phrase "or lift boat." This revision would mostly impact paragraph (c)(3) which requires a shut-in of all producible wells located in the affected wellbay when a lift boat moves within 500 feet of the platform until the lift boat is secured in place and ready to begin operations. Removing the references to lift boats from these requirements would minimize the number of unnecessary well shut-ins and delayed production. Since the original WCR, BSEE reevaluated the lift boat activities, and determined that the vast majority of lift boats used on the OCS are relatively small when compared to the size of a mobile offshore drilling unit (MODU) and would not have the same operational impacts and potential risks as a MODU. BSEE is considering the effects of the size of lift boats for potential future rulemakings, and may gather additional information and provide guidance on a case-by-case basis for any lift boats comparable in size to a MODU.

General Impact: The proposed change would have a positive impact on the industry in that these unnecessary shut-ins would be avoided.

Industry Cost Savings: None

BSEE Cost Savings: None

§250.724

Proposed Change: This rulemaking would revise this section by removing many of the prescriptive real-time monitoring requirements and moving towards a more performance-based approach. BSEE would still require the ability to gather and monitor real-time well data using an independent, automatic, and continuous monitoring system capable of recording, storing, and transmitting data for the BOP control system, the well's fluid handling system on the rig, and the well's downhole conditions with the bottom hole assembly tools (if any tools are installed). Based upon BSEE's evaluation of RTM since the publication of the original WCR, BSEE determined that the prescriptive requirements for how the data is handled may be revised to allow company-specific approaches to handling the data while still receiving the benefits of real-time monitoring. BSEE is specifically soliciting comments if there are alternative ways to meet RTM provisions or if there are alternative means to meet the purposes of real time monitoring. BSEE would completely remove current paragraph (b) with its associated prescriptive requirements, and redesignate paragraph (c) as paragraph (b), with minor revisions to shift certain prescriptive elements toward the more performance-based. BSEE would continue to require the items discussed in current paragraph (c) in a real-time monitoring plan. BSEE expects operators to explain how they would carry out the requirements of the real-time monitoring plan on an individual company basis. BSEE revised this section to outline the real-time monitoring requirements and allow the operators to determine how they would fulfill those requirements.

General Impact: RTM is primarily an operations efficiency tool, although there are aspects that can improve safety; specifically in the area of kick detection. Regarding well integrity as a means to improving safety, the data obtained in the verification of barriers is often in the form of charts and comments placed in the IADC tour book and in the DDR's, not streamed in real-time.

The proposed changes do not give details regarding what is meant my "less prescriptive" and, therefore, the proposed changes remain elusive with respect to calculating an impact.

There will still be considerable effort as the industry begins to prepare and revise their RTM plans to the satisfaction of BSEE; a cost that was already captured following the issue of the original WCR.

As it stands, the proposed changes do not appear to reduce the impact of the original WCR.

Industry Cost Savings: None

BSEE Cost Savings: None

§250.730 (a)(3)

Proposed Change: This rulemaking proposes to revise paragraph (a) by removing “excluding casing shear” and replacing “at all times” with “in the event of flow due to a kick.” Based upon BSEE experience with the implementation of the original WCR, BSEE is removing the phrase “excluding casing shear” because it is not necessary in this context. The requirements of this sentence are applicable to the entire BOP system, including the casing shear. BSEE expects the BOP system as a whole to be capable of closing and sealing the wellbore. BSEE also proposes to clarify that the BOP system must be able to close and seal the wellbore in the event of flow due to a kick. BSEE would make this change to codify BSEE guidance on the original WCR posted on the BSEE website at https://www.bsee.gov/guidance-and-regulations/regulations/well-control-rule. BSEE understands mechanical and operational design limits of equipment and expects operators to ensure ram closure time and sealing integrity before exceeding those operational and mechanical limits.

General Impact: The impact of this proposed change is positive in that it is less prescriptive. BSEE has acknowledged the issues with this regulation and has since issued a clarification on its website. By moving up to the level of the "BOP System" BSEE has given the industry the flexibility needed to meet the spirit of the regulation with equipment already in service. Regardless, the industry, of its own initiative, continues to advance shear-and-seal technology, giving operators, and regulators, even more confidence that these systems will perform as expected and needed to contain a flow due to a kick.

Industry Cost Savings: None

BSEE Cost Savings: None

§250.730 (c)

Proposed Change: This rulemaking would also revise the failure reporting requirements in paragraph (c) to codify BSEE guidance and current practice. The failure reporting references to ANSI/API Specs 6A and 16A would be removed because the failure reporting process outlined in those standards is redundant to API Standard 53 and the remaining requirements of this section. Revisions to this paragraph would include clarification on submitting failure data and reports to BSEE unless BSEE has designated a third party to collect the data and reports, and ensuring that an investigation and failure analysis are started within 120 days. BSEE reevaluated the timeframes set forth in the original WCR regarding performing the investigation and failure analysis and determined that certain operations would not be able to meet the original timeframes. Accordingly, BSEE proposes to require that the investigation and failure analysis be started, but not necessarily completed, within 120 days of the failure. BSEE proposes to add new paragraph (c)(4) explaining that BSEE may designate a third party to collect failure data and reports on behalf of BSEE, and failure data and reports must be sent to the designated third party. The changes regarding submittal of the reports to BSEE or designated third party would codify BSEE guidance on the original WCR posted on the BSEE website at https://www.bsee.gov/guidance-and-regulations/regulations/well-control-rule.

BSEE is currently using www.SafeOCS.gov as the designated third party. Reporting instructions are on the Safe OCS website at: www.SafeOCS.gov. Reports submitted through www.SafeOCS.gov are collected and analyzed by the Bureau of Transportation Statistics (BTS) and protected from release under the Confidential Information Protection and Statistical Efficiency Act (CIPSEA), which permits BTS to confidentially handle and store reported information. Information submitted under this statute also is protected from release to other government agencies, Freedom of Information Act (FOIA) requests, and certain records requests.

General Impact: The effect of this proposed change is positive in that it brings BSEE regulations in line with API Standard 53 and current industry practices regarding failure investigations.

This proposed change is a "new" rule, although it is in line with recent BSEE guidance issued via their website.

Industry Cost Savings: None

BSEE Cost Savings: None

§250.731 (a) & (b)

Proposed Change: This rulemaking would revise the information submitted to BSEE pursuant to paragraph (a)(5) by replacing “to achieve an effective seal of each ram BOP” with “to close each ram BOP.” This revision would affect information submitted to BSEE and, based upon BSEE experience with the implementation of the original WCR, would more accurately reflect the control system and regulator control setting requirements of API Standard 53.

General Impact: This proposed change is essentially a clarification. Since the reporting is still required and only minor changes are to be made to the APD or APM submittal, the impact is minimal.

Industry Cost Savings: Removal of the modification of certification verification requirements for BOP systems would lead to 1 hour of reduced labor for industry per well.

BSEE Cost Savings: Removal of the modification of certification verification requirements for BOP systems would lead to .25 hours of reduced labor for BSEE per well.

§250.731 (c)

Proposed Change: This section would also be revised by removing the BAVO verification requirements in existing paragraphs (d) and (f). The BAVO verifications required by existing paragraphs (d)(1) and (d)(3) were redundant to the verifications required by paragraph (c);however, the verifications required by current paragraph (d)(2) are still necessary and BSEE therefore proposes to add them to revised paragraph (c). BSEE proposes to remove paragraph (f) because the Report that is the subject of that paragraph is proposed for elimination in connection with proposed revisions to § 250.732(d) (see section-by-section discussion of that provision for further explanation). The independent third party verifications under paragraph (c) help ensure that the BOP is fit for service at each specific well. BSEE proposes to revise this section by replacing references to a BAVO with references to an independent third party that meets the requirements of § 250.732(b). For a discussion of the proposed shift from BAVOs to independent third parties, see the section-by-section discussion of §250.732.

General Impact: Removing the BAVO verification requirements would eliminate the need for BSEE to administer the BAVO program. Industry would continue to be required to provide independent third party verifications.

Industry Cost Savings: None

BSEE Cost Savings: Assumes two full time BSEE engineers would be required to administer the BAVO program.

§250.731

Proposed Change: BSEE proposes to completely revise this section by removing all references to a BAVO and, where appropriate, replacing those references with an independent third party. This change would also be made in appropriate locations throughout subpart G where BAVOs are referenced, as noted throughout the applicable section-by-section discussions. Independent third parties have been utilized as a long-standing industry practice to carry out certifications and verifications similar to those which a BAVO would do. BSEE expected most of the companies or individuals currently being used as independent third parties to apply to become a BAVO. Since the publication of the original WCR, BSEE has increased its interaction with the independent third parties to better understand how they operate and carry out certifications and verifications. BSEE has determined that, if as expected the majority of BAVOs would be drawn from the existing independent third parties who would continue to conduct the same verifications, additional BSEE oversight and submittal to become a BAVO would be unnecessary and the BAVO system implemented by the WCR would increase procedural burdens and costs without giving rise to meaningful improvements to safety or environmental protection. If BSEE becomes aware of any performance issues with an independent third party, there are still options for BSEE to address the issues (e.g., through a SEMS audit, or verifications through the permitting process).

General Impact: Modifies testing requirements and reduces duplicative reporting for BOPs requiring mechanical integrity assessments (subsea BOPs and BOPs on floating platforms).

Industry Cost Savings: $15,000 per BOP cost reduction annually for all BOPs requiring Mechanical Integrity Assessments (MIAs).

BSEE Cost Savings: None

§250.732 (b)

Proposed Change: This proposed rule would remove the requirements to verify that testing was performed on the outermost edges of the shearing blades of the shear ram positioning mechanism, found in current paragraph (b)(1)(iv). This would align the verification requirements with BSEE's proposal to remove the centering mechanism required in § 250.734(a)(16) that is the subject of this verification (see section-by-section discussion of § 250.734 for discussion of those changes).

BSEE also proposes to remove from paragraph (b)(1)(i) a vestigial reference to a compliance deadline that has already passed. This is merely an administrative revision.

BSEE would also revise current paragraph (b)(2)(ii) by changing the testing facilities' verification pressure testing hold time demonstration from 30 minutes to 5 minutes. This revision would allow the continued use of the established historical data to help verify the pressure holding time. BSEE is proposing to revise this paragraph after consideration and reevaluation of the original WCR and historical data along with the longstanding successful practical application of that data. BSEE has increased its interaction with testing facilities and is continuing to evaluate any additional testing protocols.

General Impact: The impact of this proposed change is positive for the industry in that it will allow the OEM's to better utilize their limited resources developing technologies that will ensure a shear & seal in the event of a flow due to a kick. The cost differential between the natural course of technology development and attempts to satisfy the original WCR stipulations is left to the OEM's.

The impact of this proposed change is positive for the industry in that it brings the regulations in line with established, and successful, industry practices. The cost benefit is more than the decrease in test hold time would suggest because it allows direct comparison of historical data to current tests. Blade has no way of determining the value of having a direct comparison with testing history so this calculation is left to the OEM's.

Industry Cost Savings: None

BSEE Cost Savings: None

§250.734

Proposed Change: This rulemaking would revise the accumulator requirements in paragraph (a)(3) to better align with API Standard 53. BSEE would remove the reference to the subsea location of the accumulator capacity. BSEE understands that the accumulator system works together with the surface and subsea accumulator capacity to achieve full functionality, and BSEE determined that it was unnecessary to specifically identify only subsea requirements when the entire system is covered within API Standard 53.

Paragraph (a)(3)(i) would be revised by clarifying that the accumulator capacity must be sufficient to close each required shear ram, ram locks, one pipe ram, and disconnect the LMRP. During a well control event, the most critical functions would be to close the BOP components and seal the well. This revision would also align the requirements with the intent of the API Standard 53 request for information finalized after the original WCR.

Paragraph (a)(3)(ii) would be revised to clarify that the accumulator capacity must have the capability to perform the ROV functions within the required times outlined in API Standard 53 with ROVs or flying leads. Based upon BSEE experience with the implementation of the original WCR, BSEE is proposing to revise this paragraph not only to better align with API Standard 53 but also to account for the technological advancements in ROV capabilities and ROV standardization to meet the appropriate BOP closing times via an ROV. Many of these advancements have taken place after publication of the original WCR. BSEE is aware of operators currently using high flow rate ROVs to meet the BOP component closing times of API Standard 53.

Paragraph (a)(3)(iii) would be revised by removing the mention of “dedicated” bottles and allowing bottles to be shared among emergency and secondary control system functions to secure the wellbore. This revision would further align the accumulator capacity requirements with API Standard 53 and account for the appropriate number of accumulator bottles on the subsea BOP stack. This revision would increase operator flexibility to utilize the appropriate accumulator capacity to perform the necessary emergency functions. Through the implementation of the original WCR, BSEE was able to better evaluate the effects of the original WCR accumulator requirements impacting subsea BOP space and weight limitations. This revision would help ensure that the regulatory requirements do not exceed the operational or mechanical design limits of the wellhead and BOP systems, and help minimize risks associated with approaching those design limits.

This rulemaking would also revise paragraph (a)(6)(iv) by clarifying that the autoshear/deadman functions must close at a minimum two shear rams in sequence, not every emergency function. Closing two shear rams in sequence may not be advantageous for certain emergency disconnect system (EDS) functions. Depending upon the rig operations, operators develop different EDS modes that would function different BOP components at appropriate times. The selection of the EDS mode and the specific sequencing of emergency functions should be developed by the operator based on safety considerations and an operational risk assessment. BSEE would make this change to codify BSEE guidance on the original WCR posted on the BSEE website at https://www.bsee.gov/guidance-and-regulations/regulations/well-control-rule.

General Impact: The impact of this proposed change will give operators the flexibility to design their autoshear, deadman and EDS sequencing to meet the needs of their operation and SS BOP capabilities while preserving the requirement that the well bore will be automatically shut-in in the event of an LMRP disconnect. The benefit to industry is the removal of the possibility of one time upgrades being required for subsea BOPs.

Industry Cost Savings: Removal of one time upgrade requirement for all Subsea BOPs $15,000,000 cost savings per BOP arise from lower capital cost expenditures per BOP.

BSEE Cost Savings: None

§250.736 (d)

Proposed Change: This rulemaking would revise paragraph (d)(5) by including equipment requirements for the safety valve when running casing with a subsea BOP. This revision would specify that the safety valve must be available on the rig floor if the length of casing being run exceeds the water depth, which would result in the casing being across the BOP stack and the rig floor prior to crossing over to the drill pipe running string. Based upon BSEE experience with the implementation of the original WCR, the substance of this revision is currently incorporated into every subsea well permit approval as a standard condition. This revision would provide clarity and consistency throughout BSEE permitting and minimize the number of alternate procedure or equipment requests submitted to BSEE.

General Impact: This proposed change should result in a positive impact on the industry in that alternate procedure requests would be eliminated for the affected equipment. This would apply to string lengths that exceed the water depth, assuming that one such string is run per well.

Industry Cost Savings: One man hour per alternative procedure request assuming one string per well.

BSEE Cost Savings: .25 man hours per alternative procedure request assuming one string per well.

§250.737 (b)(1) & (2)

Proposed Change: This rulemaking would revise paragraph (b) to clarify the BOP system pressure testing requirements. These revisions would include clarification that the test rams and non-sealing shear rams do not need to be pressure tested, and this would not impact safety because the non-sealing shear rams are not pressure holding components and the test ram is an inverted ram that is not utilized for well control purposes. Paragraph (b)(2) would be revised to add in the current BSEE policy for conducting the high-pressure test for specific components. For example, some of the revisions would include specific procedures and testing parameters for initial equipment pressure testing and also include the provisions for subsequent pressure testing on the same equipment. Since the publication of the original WCR, BSEE received many questions from operators regarding the operational application of the current pressure testing requirements. This proposed revision would codify BSEE policy and provide clarity and consistency for permitting throughout the Regions and Districts.

General Impact: The clarifications bring the requirements in line with API RP 53 recommendations and current industry practices. Any impact of these proposed changes to the benefit of the operators is negligible because the unreasonable, conflicting and/or hazardous testing practices required were, and will continue to be, likely waived by the District Manager on a case by case basis during the period between adoption of the original WCR and adoption of the proposed rule changes.

Industry Cost Savings: None

BSEE Cost Savings: None

§250.737 (d)(2) & (d)(3)

Proposed Change: In this proposed rule, BSEE would also revise paragraphs (d)(2) and (d)(3) by removing the requirement to submit test results to BSEE where BSEE is unable to witness testing. Based upon BSEE experience with the implementation of the original WCR, these revisions would significantly reduce the number of submittals to BSEE and minimize the associated burden for BSEE to review those submittals. If BSEE is unable to witness the testing, BSEE still has access to the testing documentation upon request in accordance with §§ 250.740, 250.741, and 250.746.

General Impact: The impact of this proposed change is favorable to the operator and BSEE due to the removal of the requirement to submit test results to BSEE where BSEE is unable to witness testing.

Industry Cost Savings: Reduction in report submittals on BOP system tests BSEE assumes 1 hours of industry labor and assumes around 2.35 report submittals per BOP per Year.

BSEE Cost Savings: Reduction in report submittals on BOP system tests BSEE assumes .25 hours of BSEE labor to review per submittal and assumes around 2.35 report submittals per BOP per Year.

§250.737 (d)(4)

Proposed Change: Paragraph (d)(4)(i) would be revised to clarify that the initial subsea BOP test on the sea floor would need to “begin” within 30 days of the stump test. BSEE receives many questions about the timing of the initial subsea test and, as written, the regulation was ambiguous regarding exactly what needed to occur within the 30 days. Based upon its experience with the implementation of the original WCR, BSEE proposes this revision to clarify that the testing has to begin within 30 days. BSEE wants to ensure that the time between the stump testing and the initial subsea test is minimal to help ensure that all of the BOP components can properly function upon installation on the well. Paragraph (d)(4)(iii) would be revised to include annulars in the pressure testing requirements of paragraphs (b) and (c) of this section. This revision would not alter the current testing requirements for annulars, but based upon BSEE experience with the implementation of the original WCR, would provide clarity for where to find them.

Paragraph (d)(4)(v) would be revised to clarify the initial subsea pressure testing requirements to confirm closure of the selected ram through an ROV hot stab. This revision would require the operator to confirm closure through a 1,000 psi pressure test held for 5 minutes. This revision would codify BSEE policy for pressure testing the selected ram through the ROV hot stabs. Based on BSEE experience during the implementation of the original WCR, BSEE has concluded that testing to higher pressures is not necessary for this circumstance because the intended purpose of this test is to verify operability of the ROV hot stab to close the selected ram. Selected rams will be pressure tested according to other regularly required pressure testing intervals. This revision would save rig operational time by reducing the amount of time required to conduct the pressure test, minimize wear of the BOP components, and eliminate associated alternate procedure requests.

Paragraph (d)(4)(vi) would be removed because the testing requirements of the selected ram would now be covered under paragraph (d)(4)(v).

General Impact: Reduction of rig time spent pressure testing is probably negligible since alternative testing is typically sought. The time spent applying for alternative testing would be saved as well as the time BSEE spends reviewing and approving these procedures.

Industry Cost Savings: One man hour per deepwater well preparing alternative procedure request.

BSEE Cost Savings: .25 man hours per deepwater well reviewing alternative procedure request.

§250.737 (d)(5)

Proposed Change: BSEE would revise paragraph (d)(5) by clarifying the alternating testing schedules of control stations and pods. These revisions would ensure that operators develop a testing schedule that allows for alternating testing between the control stations, and also between the pods for subsea BOPs. The intended result of alternating the testing is to ensure that each control station, and each pod for subsea, can properly function all required BOP components. Based on BSEE experience during the implementation of the original WCR, BSEE has concluded that these revisions would help ensure BOP functionality while not inadvertently requiring unnecessarily duplicative testing. This revision would save rig operational time by reducing the number of unnecessary duplicate tests, and minimize the risk associated with wear of the BOP components functioned during testing.

General Impact: Reduction of rig time spent performing duplicate pressure testing. Adoption of the new rule gives flexibility to the operators in that it allows them to develop a plan for alternative pod testing.

Industry Cost Savings: The report defers to BSEE's assumption of cost savings of around $12.5 million per year.

BSEE Cost Savings: .25 Man hours twice per rig month to review alternative procedure requests.

§250.737 (d)(13)

Proposed Change: Paragraph (d)(12)(iv) would be revised by clarifying that, during the deadman test on the seafloor, operators are not required to indicate the discharge pressure of the subsea accumulator throughout the entire test. These revisions would require that the remaining pressure be documented at the end of the test, to help verify the proper accumulator settings required to function the specific critical BOP components.

Paragraph (d)(12)(vi) would be revised to clarify the pressure testing requirements of the original WCR, to confirm closure of the BSR(s) during the autoshear/deadman and EDS testing. This revision would require confirmation of closure through a 1,000 psi pressure test held for 5 minutes. Based upon BSEE experience with the implementation of the original WCR, this revision would codify BSEE policy for autoshear/deadman and EDS pressure testing of the BSR(s). Testing to higher pressures is not necessary for this circumstance because the BSR(s) will be pressure tested according to other regularly required pressure testing intervals. This revision would save rig operational time by reducing the amount of time required to conduct the pressure test, and minimize wear of the BOP components.

General Impact: The savings for this proposed change are due to reduced alternate procedure requests for deepwater wells.

Additional benefits are possible but not quantified by this study due reduction of wear and tear to the BSR components.

Industry Cost Savings: One man hour per alternative procedure request assuming one request per well.

BSEE Cost Savings: .25 man hours reviewing the alternative procedure request assuming one request per well.

§250.738 (f)

Proposed Change: Paragraph (f) would be revised to clarify the testing requirements implemented by the original WCR necessary to verify the integrity of the affected casing ram or casing shear ram and connections. Based upon BSEE experience with the implementation of the original WCR, this revision would codify BSEE policy to allow the pressure testing to the test pressure of the BOP component above this ram as specified in the approved permit.

General Impact: This proposed change is not expected to reduce rig time as the exception is currently handled via an alternate procedure request which would be secured once per well.

Industry Cost Savings: One man hour per alternative procedure request assuming one request per well.

BSEE Cost Savings: .25 man hours reviewing the alternative procedure request assuming one request per well.

§250.739 (b)

Proposed Change: BSEE proposes to revise paragraph (b) by replacing “complete breakdown and detailed physical inspection” with a “major, detailed inspection,” identifying examples of well control system components, replacing references to the BAVO with references to an independent third party, and replacing the requirement to have a BAVO present during each inspection with a requirement for an independent third party to review inspection results.

Replacing “complete breakdown and detailed physical inspection” with a “major, detailed inspection” would correct the industry misconception, prevalent since the promulgation of the original WCR, that each component must be dismantled to its smallest possible part. This was never the intent behind this provision of the WCR, and these revisions would clarify BSEE's positions on the WCR requirement and resolve perceived ambiguities, without substantively altering the inspection requirement. BSEE would make this change to codify BSEE guidance on the original WCR posted on the BSEE website at https://www.bsee.gov/guidance-and-regulations/regulations/well-control-rule. BSEE also proposes to add references to examples of the well control system components requiring inspection to clarify the general reference in the original WCR.

For a discussion of the proposed shift from BAVOs to independent third parties, see the section-by-section discussion of § 250.732.

BSEE would also remove the requirement for the BAVO to be present during each inspection and replace it with a requirement that an independent third party review the inspections results. BSEE expects the independent third party to review the documentation of the inspections to help ensure that the appropriate entities accurately and appropriately complete the activities. These reports would also help facilitate other required verifications that the BOP is fit for service, such as those required by § 250.731. These revisions would ease the original WCR logistical and economic burdens of having the BAVO onsite at all times during all inspections.

General Impact: This proposed change would benefit the industry by reducing the requirement for a third party presence during the "major, detailed inspection" conducted every 5 years.

Industry Cost Savings: Removes requirement of major detailed physical inspections of the WC system components for all BOPS. Report defers to BSEE estimated savings of $153,000 per inspection once every five years per BOP.

BSEE Cost Savings: None

§1703 (b)

Proposed Change: This rulemaking would revise paragraph (b) to clarify that only packers or bridge plugs used as mechanical barriers are required to comply with API Spec. 11D1. Based upon BSEE experience with the implementation of the original WCR, this revision would codify BSEE's policy to ensure that the required mechanical barriers in a well are held to a higher standard than other common packers or bridge plugs used for various well specific conditions and completions design. Furthermore, BSEE is aware that certain packers and bridge plugs cannot meet the specifications of API Spec. 11D1. This revision would minimize the number of alternate equipment requests submitted to BSEE. BSEE would also add that operators must have two independent barriers, one being mechanical, in the exposed center wellbore (e.g., this could be the tubing or casing depending on the well configuration) prior to removing the tree or well control equipment. This addition would codify BSEE policy and align the well decommissioning requirements with similar requirements from §§ 250.720(a) and 250.1712(g). This addition would help ensure the well is properly secured before removal of the tree or well control equipment.

General Impact: This proposed change is positive in nature, but since BSEE admits that the requirement was unobtainable for "certain" devices, the effect is negligible.

Industry Cost Savings: None

BSEE Cost Savings: None

§1716

Proposed Change: This rulemaking would revise paragraph (b)(3) by changing the water depth criteria for when BSEE may approve an alternate depth for removal of the wellhead or casing from 800 meters to 1000 feet. BSEE would include this new regulatory revision in order to codify longstanding BSEE policy established before the original WCR. At depths below 1,000 feet, there is little risk of obstruction to other users of the OCS or its waters or contact with other equipment, and little risk of safety or environmental issues from removal to an alternate depth.

General Impact: This proposed change is positive in that no wellhead removal is required for wells abandoned with SS wellheads in water between 1000 and 2624 ft.

Industry Cost Savings: On a per well basis, the cost can be estimated to be around $270K per well in these water depth ranges when abandoned.

BSEE Cost Savings: None

Appendix 2 – Extended Methodology Appendix

General Methodology

Calash's methodology focused on constructing a tiered "bottom-up" model that separated the complete life cycle of offshore operations and subsequent effects into four main categories – these categories are further developed into cases and presented as the Base Development scenario and Restrictive Enforcement Scenario within the paper. The four main categories are as follows;

A "Restrictive Enforcement" model that independently assesses the individual or combined effects of potential restrictive enforcement of drilling margin related provisions of the Well Control Rule post revisions on the industry.

An "Activity Forecast" model assessing project activity and project modeling information under which the number of expected projects is developed

A "Spending" model based on the requirements of developing projects within the "Activity Forecast"

An "Economic" model focusing on the economic impact on employment and government revenue from the "Spending" model.

Three (Activity Forecast, Spending, and Economic models) of the four individual subsections were further split into five additional criteria that create an individual "Project" model. These categories include; seismic, leasing activity, drilling, infrastructure & project development, and production & operation. (Table 9)

Table 9: Oil and Gas Project Development Model – Aspects of Additional Criteria Included by Model

	Activity Forecast	Spending Model	Economic Model
Reserves	• Total Atlantic Reserves • Reserves by Play • Reserves by Field • Fields into Projects	N/A	N/A
Seismic	• Pre-Lease Seismic • Leased Block Seismic • Shoot Type	• Cost per Acre	• Economic Activity due to Seismic Spending within States
Leasing	• Yearly Lease Sales	• Bonus Bid Prices • Rental Rates	• Federal and State Revenues Created through Lease Sales • Economic Activity due to Increased State/Personal Spending
Exploration Drilling	• Number of Wells Drilled • Water Depth of Wells Drilled • Number of Drilling Rigs Required	• Cost per Well	• Economic Activity due to Exploration Drilling within States
Project Development & Operation	• Project Size • Project Development Timeline	• Spending per Project • Per Project Spending Timeline	• Division of State Spending • Economic Activity due to Project Development within States Vicinity
Production	• Production Type and Amount	• Oil and Gas Price Forecast	• Federal and State Revenues Created through Royalty Sharing • Economic Activity due to Increased State/Personal Spending

Source: Calash

In order to estimate the economic effects and project activity losses through the “Project” model, additional analysis was undertaken to understand which projects would be disrupted through the inability to discover and develop the reserves. This was presented through additional analysis of the Base Development scenario and is provided as the Proposed Rule scenario.

Rule Costing and Cost Saving Methodology

The analysis of spending related to "Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control” and the proposed revisions to this rule was undertaken through the individual analysis of each rule, while also considering the accretive effects of multiple rules placed upon similar equipment, tasks, and future opportunities. The cost of the proposed revisions were analyzed on either the basis of time saved, removed waiting time, the removal of need to replace equipment and other factors. Equipment costs were calculated using actual or estimated replacement costs or by deferring to BSEE’s analysis when the analysis was deemed likely to be accurate depending on the availably of information. All costs are attempted to be calculated on the basis of the actual enforcement of the rule by BSEE. General assumptions used within the modeling are as followed:

Industry Engineering rate (daily): $1,015 a day (based on SPE salary survey averages and a benefits multiplier).

BSEE Engineering rate (daily): $560 a day

Drilling rate (daily) including spread costs[3]: Variable across time, 2018 day rate of $630 thousand for floating rigs and $170 thousand for jack-ups based on industry data.

Project Development Methodology

In order to account for both currently active projects within the Gulf of Mexico and longer-term prospects that will be developed towards the end of the forecast period into the study's project development activity, Calash incorporated two models into the project development forecast. The near-term activity was developed on known projects or prospects currently under consideration for development, while a longer term forecast was developed on top of the near-term forecast through the analysis of oil prices, leasing trends, development trends, historic project sizes and other relevant factors

The forecast of near term projects utilized Gulf of Mexico project data that encompasses all major portions of offshore field development (e.g. exploration, number of wells, length of pipelines, size of FPS unit, installation vessels, etc.). In addition to that information, lead times for project development, sanctioning trends and additional spending information led to the expected timeline and development costs of individual projects. The summation of these costs and timelines over all of the forecasted individual projects provided the total cost of near term projects.

Longer term projects were developed under a less independent methodology for individual projects. In the place of the project-specific spending model, Calash applied historical and current trends within the region to future developments (e.g. a greater focus on deep water oil projects as well as infield drilling and subsea infrastructure) in order to apply the proper costs and timelines to the expected activity. Projects were still delineated by individual timelines and the development scenarios that may be expected of future activity within the region, but were calculated using assumptions on industry trends in production methods instead of on confirmed aspects of the specific projects.

With regards to the Restrictive Enforcement Scenario, projects and wells were examined for potential hurdles that would be encountered under the drilling margins provisions of the Well Control Rule in a more restrictive regulatory environment. These topics were focused on emerging trends such as HPHT reservoirs, ultra-deep wells, projects developing already depleted reservoirs, as well as increased project costs. These identified factors drove the forecasted possibility of delays or lost activity due to project economics, technology-driven hurdles, or regulatory impasses. Furthermore, where necessary, additional costs were administered to

[3] Based on current day rate and spread (additional drilling) costs from Calash data and forecast model.

subsections of projects where increased costs were to be expected for calculations in the economic model.

Project Spending Methodology

This spending analysis accounts for all capital investment and operational spending through the entire "life cycle" of operations. Every offshore oil or natural gas project must go through a series of steps in order to be developed. Initial expenditures necessary to identify targets and estimate the potential recoverable resources in place include seismic surveys (G&G) and the drilling and evaluation of exploration & appraisal (E&A) wells. For projects that are commercially viable, the full range of above-surface and below-water (subsea) equipment must be designed and purchased. Offshore equipment includes production platforms and on-site processing facilities, as well as below-water equipment generally referred to as SURF (Subsea, Umbilicals, Risers and Flowlines). Finally, the equipment must be installed and additional development wells must be drilled. Once under production, further operational expenditures (OPEX) are required to perform ongoing maintenance, production operations and other life extension activities as necessary for continued field production and optimization.

Spending for individual projects was subdivided into sixteen categories covering the complete life cycle of a single offshore project, as well as two additional groups for natural gas processing and operation. Timing and cost for individual categories were assigned based on the previously mentioned project types where prices are scaled according to the complexity and size of the project.

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