A Cost-Benefit Analysis of Increased OCS Bonding

July 13, 2023

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I. EXECUTIVE SUMMARY

The offshore oil and gas industry remains conflicted between investors looking for a return on capital, a push by certain groups to eliminate oil and gas drilling, and a global need for sustained affordable energy prices. A decrease in oil and gas investments and related drilling over recent years has resulted in an unprecedented rise in commodity prices and inflation not seen in 40 years. Recent and potential bankruptcies by independent operators in the Outer Continental Shelf ("OCS") of the Gulf of Mexico ("GOM") have sparked potential action by the Bureau of Ocean Energy Management ("BOEM") and the current Presidential Administration (the "Administration") to revisit previously proposed regulations to increase surety bonding requirements - all in an effort to protect the U.S. taxpayer. Regardless of the genuine intent of all interested parties, further constraints on oil and gas capital are the greatest threat to the U.S. taxpayer.

A. BACKGROUND

Opportune LLP ("Opportune"), a leading global business advisory firm, previously released a July 2016 independent study (the "2016 Study") assessing the economic effect that BOEM NTL 2016-N01 (the "2016 NTL")[1] would have had on the offshore oil and gas industry (the "Industry"), Gulf Coast and United States.

Federal regulations have always required previous owners to remain responsible for the decommissioning costs of wells, pipelines, and other facilities (commonly referred to as plugging and abandonment, or "P&A") that existed at the time of the sale of such properties.[2] As a result, there had never been a single instance in which the U.S. taxpayer was required to bear the cost to P&A an OCS property. Regardless of those facts, the 2016 NTL would have changed the way many independent oil and gas operators fund P&A costs in the GOM's OCS by requiring them to post supplemental surety bonds or other collateral to guarantee coverage for 100% of the future P&A costs attributable to the oil and gas properties in which they own a working interest.

The stated purpose of the 2016 NTL was to protect the U.S. taxpayer from ever having to pay offshore decommissioning costs for an oil and gas company that falls into bankruptcy; however, <u>Opportune's 2016 Study concluded that the proposed changes were wholly disproportionate to any potential risk.</u>

After publication of the 2016 Study, liquidity across the Industry deteriorated under the weight of bloated balance sheets resulting from the combination of overheated commodity prices from 2011 to 2015 and capital markets that fueled excessive acquisition and development spending during the shale boom. The result was a volumetric supply overhang from late 2014 to 2016 that prevented commodity prices from recovering enough to offset the Industry's constrained capital. Commodity prices stabilized through 2019 as global demand eroded excess supply and the Industry began to recover; however, the COVID-19 pandemic shut down the global economy and "threw the supply chain and demand completely out of whack"[3]. Within the first three months of 2020, U.S. production dropped approximately 20% as private and public companies shut-in wells and slashed drilling budgets. The front-month May 2020 WTI crude contract settled at an unprecedented low of negative $37.73 per barrel in April 2020.

[1] Notice to Lessees ("NTL") No. 2016-N01 issued July 14, 2016
[2] 30 CFR §556.62(d)
[3] President Biden, White House Press Briefing, May 10, 2022

Since July 2016, a total of 12 U.S. independent offshore oil and gas companies filed bankruptcy with respect to approximately $18.8 billion in total capital, including approximately $4.0 billion in future P&A liabilities[4]. All related P&A liabilities were either assumed by the reorganized Debtor, subsequent buyers of the underlying assets, co-lessees and/or predecessors in title, or funded through a liquidation trust – at a miniscule cost to the American taxpayer.

B. 2023 UPDATE

BOEM published a new proposed rule on June 29, 2023[5] (the "Proposed Rule") to increase financial assurance requirements on the Industry. BOEM states[6] that the proposed changes "advance the Biden-Harris Administration's federal oil and gas reform agenda, which was outlined in a report from the Department of the Interior developed in response to Executive Order 14008[7]."

The Proposed Rule requires OCS companies to provide additional financial assurance (bonds) if i) their S&P/Moody's credit ratings and that of their current co-owners are lower than BBB-/Baa3; and ii) the current value of their proved oil and gas reserves is less than three times than the associated undiscounted P&A liability. As such, Opportune is updating the 2016 Study to independently review the following:

- Current BOEM estimated P&A liabilities for OCS leases and the underlying historical data aggregated by The Bureau of Safety and Environmental Enforcement ("BSEE") (the "BOEM Database")[8]
- Actual historical costs of OCS P&A liabilities borne by U.S. taxpayers
- Current distribution of OCS P&A liabilities by major integrated ("Majors"), large independent ("Large Independents") and small independent ("Small Independents") lessees[9]
- Estimated effect to U.S. taxpayers and the Gulf Coast as a result of implementing the Proposed Rule

<u>Opportune shows within its revised study (the "Opportune 2023 Study") how the perceived benefits of additional bonding requirements remain wholly disproportionate to any potential risk. This Opportune 2023 Study reiterates how the current rule has adequately protected U.S. taxpayers for decades. Implementing the Proposed Rule would force independent lessees out of business, achieving the opposite public policy objective than purportedly intended by BOEM.</u>

The Opportune 2023 Study has been conducted to independently calculate the OCS P&A liability, assess the risk such liability poses to the U.S. taxpayer, and perform a cost-benefit analysis of how the Proposed Rule would economically affect the Industry, Gulf Coast and United States. This study was performed by Opportune's valuation, petroleum engineering[10] and financial

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[4] See Exhibit A – Summary of Offshore Operator Bankruptcies: 2016 – 2023. Amounts include two Ch. 11 filings by Fieldwood Energy. $18.8 billion represents the combination of $14.8 billion in Pre-petition Capital plus $4.0 billion in P&A Obligations.

[5] Federal Register, Vol. 88, No. 124, June 29, 2023.

[6] www.boem.gov/newsroom/press-releases/boem-proposes-stronger-financial-assurance-requirements-offshore-oil-and

[7] Exec. Order No. 14008, *Tackling the Climate Crisis at Home and Abroad*. 86 Fed. Reg. 7619, January 27, 2021.

[8] Estimated P&A and Collateral obtained from https://www.boem.gov/oil-gas-energy/risk-management/property-lists-0 as of March 15, 2023

[9] Majors and Large Independents are defined as having a tangible net worth, or market capitalization, of over $10.0 billion as of March 15, 2023. Small Independents are defined as all other OCS lessees who have a tangible net worth that is either less than $10.0 billion or unavailable from public sources. See Appendix C of the Opportune 2022 Study for a listing of lessees considered to be Majors and Large Independents (including subsidiaries and successors); Small Independents represent all other lessees.

[10] Ralph E. Davis Associates is a wholly-owned subsidiary of Opportune LLP.

reporting[11] professionals through a series of interviews with Industry representatives, commercial banks and surety brokers, and includes an analysis of independently obtained P&A cost data and market research.

The results of the Opportune 2023 Study and recommended solutions are presented within the report and appendices.

C. Key Findings

The current system works: U.S. taxpayer funding of decommissioning liabilities is infinitesimal.

Historically, federal regulations have required previous owners (i.e., the "previous chain of title") to remain responsible for the P&A costs of wells and facilities that existed at the time of the sale of such properties to previous owners.[12] Current regulations operate to greatly reduce or maintain the current minimal risk to taxpayers. For example, a current lessee would have to default, file for bankruptcy, unsuccessfully auction the properties due to no interested buyers, and have no solvent co-owner(s) or previous owner in the chain of title for the taxpayer to be liable. In the limited cases where funding for the P&A liabilities of a bankrupt owner is uncertain, a decommissioning trust or cash escrow has been established to fund the future decommissioning. <u>Unlike the $2.1 trillion paid to other industries since 1970[13], the potential Industry P&A cost to the U.S. taxpayer is infinitesimal.</u>

For the first time in Industry history, BSEE announced a Draft for Proposal seeking bids to decommission 15 orphan wells located in the Matagorda Island, High Island, and West Delta areas of the OCS[14]. The decommissioning costs will be funded from the 2021 Infrastructure and Jobs Act appropriations. Based on BOEM's database, the P&A liability associated with the orphan wells and their related infrastructure is approximately $37.7 million[15] – an infinitesimal amount (~0.8%) compared to the $4.5 billion in royalties and revenue the U.S. government (i.e., taxpayer) received in 2021 alone from offshore Gulf of Mexico operations.

BOEM estimated P&L liabilities are overstated and the underlying assumptions remain opaque and flawed.

The ongoing and future decommissioning of oil and gas infrastructure in the OCS is no small task and the process is costly. Opportune believes, however, that BOEM's $84.8 billion[16] [17]estimate of the existing P&A liability is not transparent and remains dramatically overstated.

Since 2016, BSEE has subsequently improved its cost database by collecting actual decommissioning cost data from OCS lessees; however, <u>it is not clear whether the costs captured within the BSEE database agree with the same assumptions underlying each lessee's audited financial statements.</u> Not utilizing audited financial information unnecessarily adds costly government bureaucracy and begs the question of whether a black box is overstating OCS P&A liabilities.

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[11] Opportune LLP is not a CPA firm.

[12] 30 CFR §556.62(d)

[13] See Exhibit B – Summary of Historical U.S. Government Bailouts, by Industry.

[14] "Orphaned Wells on the U.S. Outer Continental Shelf", BSEE Virtual Industry Day Presentation; February 2, 2022.

[15] See Exhibit C.

[16] Note that the collective tangible net worth of the Majors and Large Independents exceeds $1,274 billion and $552 billion, respectively, per Capital IQ as of March 15, 2023.

[17] Note the $84.8 billion represents the sum of the undiscounted P70 and the deterministic costs of all leases in the OCS, excluding ROW and RUE properties, per the BOEM Database.

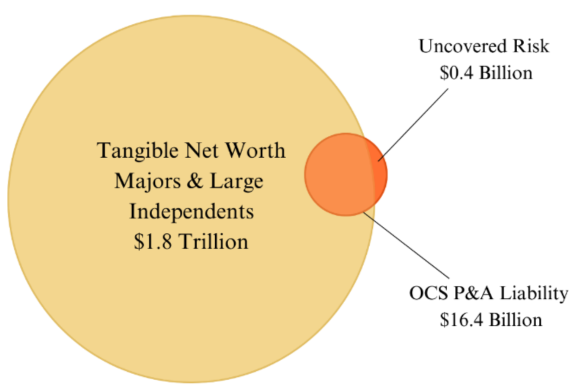
BSEE has also begun applying a combination of a probability-weighting[18] of historical cost data and a deterministic value approach ("Deterministic") to better assess the underlying risk of related properties when calculating individual lease P&A liabilities. According to the law firm Vinson & Elkins LLP, "The deterministic value approach is calculated by BSEE based on its evaluation of decommissioning cost data but the model does not include elements of randomness; given a particular input, the same output will be produced every time."[19] BOEM proposes to use a "P70" probability-weighting, plus Deterministic, value to set the amount of any required supplemental financial assurance; however, <u>Opportune believes a P50 probability-weighting is more representative of a log-normal distribution's statistical average.</u>

Finally, the Proposed Rule places bonding requirements on lessees that are based on the unrealistic undiscounted assumption that all active OCS leases might be decommissioned at once (tomorrow). <u>Opportune estimates that the net present value of the P50 (plus Deterministic) liability to P&A all OCS leases is approximately $16.4 billion ("OCS P&A Liability").</u>

The underlying risk to the U.S. Taxpayer is overstated.

The implied risk to the U.S. taxpayer underpinning the Administration's desire for the Proposed Rule is overstated. BOEM holds each lessee responsible for 100% of the lease P&A liability, regardless of the amount of working interest actually owned by the individual lessee. Surety brokers state that the BOEM database cites the full P&A amount for each lease in order to maximize coverage, particularly when one or more of the lease's owners are exempt; however, the individual lessee's pro rata obligation is cited by BOEM when requesting additional bonding via a demand letter. BOEM's intent is unclear as the public information available on its website overstates the total OCS P&A Liability and the underlying risk to the U.S. taxpayer.

The OCS P&A Liability associated with properties in which the Majors and Large Independents are not part of the current ownership or previous chain-of-title (the "Uncovered Properties") is only $1.2 billion, which is ~7% of the total OCS P&A Liability calculated by Opportune. Approximately $761 million in bonding has already been posted (to the benefit of BOEM) with respect to the Uncovered Properties, leaving an estimated uncovered risk to the taxpayer of $391 million (the "Uncovered Risk"), or ~2% of the total OCS P&A Liability calculated by Opportune.



[18] BSEE applies P50, P70 or P90 cases to a log-normal distribution of historical cost data to estimate a 50%, 70% or 90% probability that the actual abandonment costs will be less than the underlying BSEE costs

[19] "BSEE Considerations in Establishing Decommissioning Liability Estimates for Offshore Facilities", Vinson & Elkins LLP, June 2021.

Small Independents will be unable to obtain the required bonding; the Proposed Rule will become a catalyst to spur the bankruptcy risk from which it was intended to protect the U.S. taxpayer

The Proposed Rule cites an estimated $9.2 billion[20] in supplemental bonding to effectively insure the $391 million in Uncovered Risk noted above.

Beyond the cost[21] of such additional supplemental bonds, the lack of capacity in the surety bond market guarantees that the additional bonding requirements are untenable, as most Small Independents will simply not be able to obtain the supplemental bonding required for their existing properties, let alone the supplemental bonding required to drill the future wells necessary to support their capital structure. Under increasing pressure by ESG activists, surety markets have threatened to exit the offshore sector since publication of the 2016 NTL, thereby drastically reducing available bonding capacity.

To secure any available bonding, Small Independents would have to provide cash collateral that their balance sheets cannot currently support due to recent asset impairments that permanently reduced their net worth, as U.S. GAAP[22] prevents asset values from being written back up as commodity prices recover in the future. <u>The overall opportunity cost of tying up this amount of the Small Independents' liquidity is enormous, resulting in a dollar-for-dollar reduction in their ability to develop properties and pay down debt, inevitably increasing the risk of additional bankruptcies.</u>

The Proposed Rule will result in dramatically reduced future production, economic activity, and U.S. royalty revenue

In our updated analysis, Opportune relies on BOEM's contention that their Proposed Rule will result in increased bonding premiums for "small" companies of approximately $257 million per year. Using our development model, we estimate that these higher costs will lead to less offshore development activity, lower economic growth, reduced hydrocarbon production, and lower federal royalties. In our model we assume a received price of $61 per barrel of oil equivalent ("boe", using a 6:1 gas:oil ratio and other assumptions), an assumed finding and development cost of $25/boe, along with other economic and operational assumptions, and find that the increased bonding requirements could result in a production decrease of approximately 55 million barrels of oil equivalent (boe) and approximately 36,000 fewer jobs over a 10-year time horizon. Additionally, the Opportune 2023 Study indicates that the US economy (particularly in the Gulf Coast states) will experience a decline in Gross Domestic Product (GDP) of as much as $9.9 billion over the same period. Beyond the opportunity cost of wells not drilled and the resulting overall impact to the Gulf Coast, the reduction in development may result in estimated lost royalties to the U.S. Department of the Interior of approximately $573 million over the 10-year period. All told, total direct and indirect costs of Additional Bonding Requirements to the taxpayer may total over $10.5 billion.

Cost-Benefit Analysis - U.S. Taxpayer

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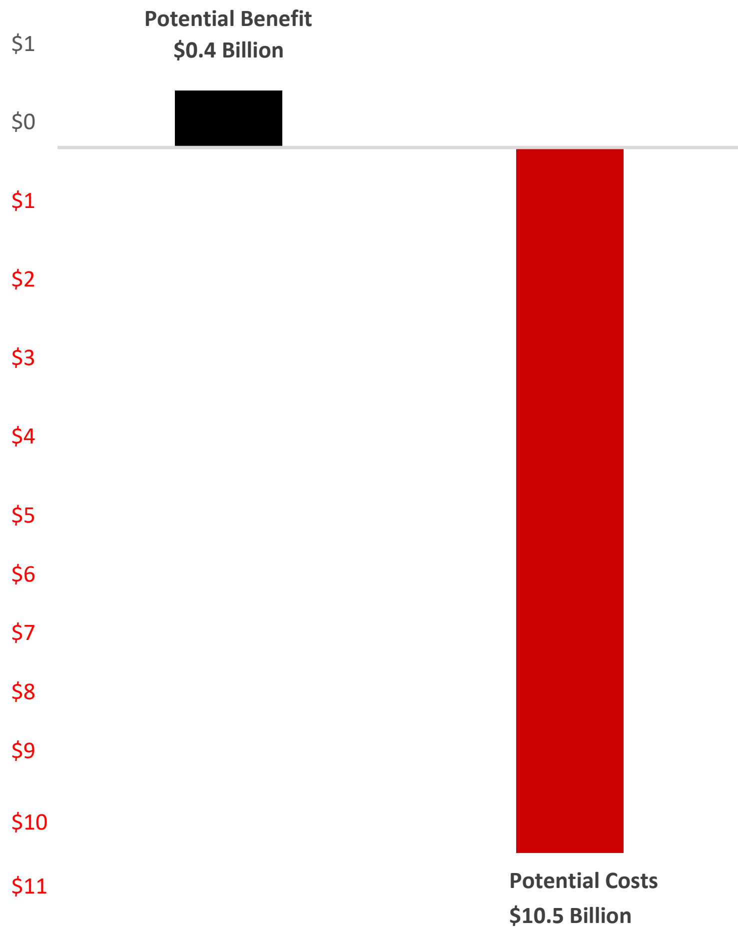
[20] Federal Register, Vol. 88, No. 124, June 29, 2023.
[21] Approximately 1-4% of the total surety bond's face amount.
[22] Generally Accepted Accounting Principles



There is a better way than the Proposed Rule: increased communication with operators and a focus on Sole-Liability Properties

The Opportune 2023 Study concludes that the estimated costs to U.S. taxpayers and the Industry will drastically exceed the benefits generated by the Proposed Rule. The Opportune 2023 Study shows the current system adequately addresses BOEM's concerns about the potential risk to taxpayers.

BOEM began improving the process during the prior Administration by collecting actual decommissioning data and considering feedback from stakeholders about the potential impact of Sole-Liability Properties. Under the current Administration, BOEM should abandon the Proposed Rule in favor of continued active discussions with OCS lessees to avoid any perception of a politicized process aimed to diminish drilling and development of the OCS.

The Opportune 2023 Study proposes additional solutions to support OCS lessees and protect taxpayers.

The Opportune 2023 Study also puts forward proposals, which include using basic and widely accepted valuation techniques to estimate the P&A liability and financial health of OCS lessees; improving the process by which BOEM gathers P&A cost and collateral information; and introducing a new cash reserve to be funded by current OCS lessees to supplement current co-owners or previous owners in the chain of title and further protect the U.S. taxpayer. The following table provides a high-level summary of the solutions proposed, the details of which are further described within the Opportune 2023 Study:

Opportune Study – Recommended Solutions for BOEM Consideration

Valuation	Data Gathering	Financial Assurance
• Value P&A liabilities using the discounted ARO[23] balance audited and included in the financial statements of every lessee • When assessing lessees' financial strength and credit rating: o Use forward strip pricing to reflect the current market value of proved reserves. o Exclude the audited ARO liability from the value of proved reserves to avoid a double jeopardy effect when comparing to the related P&A liability	• Avoid duplication of costs and efforts by requiring both private and public OCS lessees to report the future P&A costs and dates, by property, underlying the ARO amount included in their audited financial statements. • Upload amounts noted above to a national BSEE database, similar to Federal requirements for U.S. refineries[24].	• Replace any additional bonding requirements with a cash reserve self-funded by 1% of each OCS lessee's pro rata share of future production until such reserve equals the Uncovered Risk ($0.4B). • Absent capacity in the bond market, create a federal agency to issue bonds on Sole-Liability Properties. If the U.S. government believes the taxpayer is really at risk, allow taxpayers to inherently participate in the upside of the premium float.

[23] Asset Retirement Obligation, which is the term used for P&A in Accounting Standards Codification 410-20.
[24] 40 CFR § 80.75, 80.125 and 80.150

II. Background Information

The purpose of the Opportune 2023 Study is to perform a cost-benefit analysis of proposed financial assurance rules developed by BOEM for the plugging and abandonment of the energy infrastructure in the Gulf of Mexico's outer continental shelf. The Opportune 2023 Study independently calculates the OCS P&A liability, assesses the risk such liabilities pose to the U.S. taxpayer, and perform a cost-benefit analysis of the Proposed Rule's economic effect on the Industry, Gulf Coast and United States.

Opportune LLP, a leading global business advisory firm, performed this study using its valuation, petroleum engineering and financial reporting[25] professionals through conducting interviews with Industry representatives, commercial banks and surety brokers, along with analyzing independently-obtained P&A cost data and market research.

This section provides information on the i) offshore drilling and infrastructure, ii) decommissioning requirements, iii) decommissioning cost estimates, and iv) historical financial assurance requirements. Note that certain background information previously included in the 2016 Study has been excluded from this update, or otherwise summarized, to limit duplication and remove details that may no longer be relevant.

A. Offshore Drilling and Decommissioning Requirements

In 1938, a predecessor to ExxonMobil completed the first producing offshore well in a water depth of 14 feet off the Louisiana coast. The first offshore well out of the sight of dry land was drilled in 1947 by a predecessor to Anadarko, as operator for predecessors of ConocoPhillips and BP. As the U.S. population grew post-World War II and became more dependent on oil and gas production, offshore drilling moved further offshore and in to depths exceeding 1,000 feet of water by 1970. As development of the shallower water (depths of 500 feet or less; the "Shelf") increased, the Majors moved further offshore in search of discoveries large enough in size to meet their internal reserve replacement and potential profit requirements.

Title 30, Section 250 of the Code of Federal Regulations ("CFR") requires that all wells be plugged, and platforms removed within one year after a lease terminates. In addition, all other lease structures, decommissioned pipelines and obstructions should be removed and cleared from the seafloor within five years of such infrastructure no longer useful for operations.

Section 250.1701 further states that (***emphasis added***):

> "Lessees and owners of operating rights are ***jointly and severally responsible*** for meeting decommissioning obligations for facilities on leases, including the obligations related to lease-term pipelines, ***as the obligations accrue***[26] and until each obligation is met."

Although estimates vary, the latest published independent research[27] notes that approximately 6,900 oil and gas structures have been installed approximately 5,300 structures have been removed in the Gulf of Mexico since offshore drilling first began, leaving approximately 1,600 active structures as of August 2022. Additionally, over 46,000 wells have been drilled, of

[25] Opportune LLP is not a CPA firm.

[26] Meriam-Webster defines accrue as follows: "to increase in value or amount gradually as time passes: to grow or build up slowly".

[27] Mark J. Kaiser, Shallow-water Gulf of Mexico Decommissioning Market Valued at $6.3 Billion, www.offshore-mag.com, August 2022.

which over 38,000 wells have been plugged, leaving an active inventory of approximately 8,000 wells.

B. Decommissioning Cost Estimates

BSEE is responsible for approving all decommissioning activities, as well as aggregating and estimating the amount of historical P&A cost and future liabilities. BSEE monitors potential idle wells and infrastructure based on information from the Technical Information Management System ("TIMS"), which is the main data system used by the Department of the Interior ("Interior"). BSEE notifies lessees of their related decommissioning liabilities and requests a plan and schedule for decommissioning the lessee's applicable assets.

Lessees must report the outcome of all activities to plug wells, remove platforms or other facilities, decommission pipelines, and clear sites around such infrastructure. BSEE estimates the costs of decommissioning activities based on well depth and the number and types of wells, pipeline segments, and structures on a lease.

BSEE may also review and periodically update its costs estimates based on the occurrence of certain events, which may include, but are not limited to, determining a lease may be sold or the lessee is under financial distress, or upon a request by the lessee to review lease obligations and estimates. BSEE is required to input all cost estimates and activities into TIMS.

C. Historical Financial Assurance Rules and Proposals

Title 30 CFR Section 556 requires that all operators provide a non-cancellable bond, payable upon demand to BOEM Regional Director, in the amount of $50,000 per lease or $300,000 for an area-wide bond when there is no operation or activity on the lease. Lease-specific bonds ramp up to $200,000 or $500,000 per lease, depending on whether there is existing exploration or development, respectively. Area-wide bonds increase for the same reasons up to $500,000 or $3 million, respectively.

The Regional Director of BOEM may require operators to provide supplemental bonds based on BOEM's assessment of an operator's ability to meet current or future decommissioning obligations. The Regional Director's assessment may be based on the operator's financial capacity in excess of existing and anticipated lease and other obligations, in addition to the operator's historical operating record, current production and estimated proven reserves of future production. Historically, most companies have been exempt from supplemental bonding, provided: i) net worth exceeds $65 million and is at least two-times the amount of their estimated P&A liabilities; and ii) total company liabilities of no more than 2 to 3 times the value of the adjusted net worth.

GAO Report to Congressional Requesters– December 2015

Due to the bankruptcy of ATP Oil & Gas ("ATP") in 2012 and the subsequent financial distress of a number of offshore oil and gas producers in subsequent years, certain members of the U.S. Congress requested GAO to review Interior's management of liabilities from offshore oil and gas production. In its December 2015 *Report to Congressional Requesters*, GAO issued a report (the "GAO Report") that: (1) examined the Interior's (a) procedures for overseeing decommissioning and estimating its costs, (b) procedures for obtaining financial assurances for these liabilities; and (2) challenges Interior's managing of these liabilities.

To better ensure that the government obtains sufficient financial assurances to cover decommissioning liabilities in the event of lessee default, the GAO Report called for the following actions to be taken by the Interior:

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

SUMMARY OF BOEM NOTICE TO LESSEES– JULY 2016

In a November 2015 letter to GAO, Interior stated that it generally agreed with GAO's draft findings and committed to implementing GAO's recommendations to document procedures, improve the data system, and revise financial assurance procedures and regulations. In its letter, Interior referred to a proposed Notice to Lessees to be issued by BOEM that would provide updated criteria for determining a lessee's ability to meet future decommissioning and other liabilities and the potential need for additional security.

On July 14, 2016, BOEM issued NTL No. 2016-N01, Requiring Additional Security (the "2016 NTL"), which clarifies the procedures and criteria that BOEM Regional Directors are to use in determining if and when additional security may be required for OCS leases, rights-of-way ("ROW"), and rights-of-use and easement ("RUE"). NTL No. 2016-N01 was scheduled to be effective September 12, 2016, and contained the following provisions.

Evaluation of Financial Ability to Carry Out Obligations

The Regional Director would evaluate the ability of lessees to carry out present and future obligations annually to determine whether additional security must be provided. Periodic reviews to evaluate financial ability could be done at any time at the discretion of the Regional Director, but would likely be done when BOEM became aware of any:

- Material or adverse change in a lessee's financial strength or OCS obligations;
- Performance deficiencies, such as incidents of noncompliance, civil penalties or failure to adhere to any term or condition of, or obligation imposed by, a lease, exploration or development and production plan, development operations coordination document, or permit;
- Change in operator or ownership; or
- Violation of Interior or other applicable regulations.

Factors Considered in Evaluation of Financial Ability and Determination of Self-Insurance

The Regional Director's evaluation of financial ability would be based on information submitted by lessees and other information in BOEM's possession demonstrating financial capacity, financial strength, stability, reliability, and record of compliance. The result of such evaluation would determine whether, and how much, additional security would be required. In making this determination, the Regional Director would consider 100 percent of decommissioning and other liability for every lease, ROW, and RUE in which in which a lessee holds an ownership interest, or provides a guarantee.

Financial Capacity as evidenced by recent (not more than 12 months old) audited financial statements, would be demonstrated in part by the following financial criteria:

- Cash Flow from Operations/Total Debt
- Current Ratio
- Earnings Before Interest and Taxes (EBIT)/Interest Expense
- Quick Ratio
- Return on Assets
- Return on Equity
- Total Debt/Capital
- Total Debt/Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA)
- Total Debt/Equity

BOEM established minimum thresholds for each of the nine ratios above, as well as the number of such thresholds that BOEM would require lessees to exceed, to determine that the lessee had adequate Financial Capacity.

- Projected Financial Strength would be based upon the estimated value of existing OCS lease production and proven reserves of future production.
- Business Stability would be based upon five years of continuous operation and production on the OCS or onshore.
- Reliability would be based upon lessee's credit rating from Moody's or Standard and Poor's, or from trade references.
- Record of Compliance would be based upon whether the lessee or any of its affiliates or subsidiaries had been:
  - Assessed civil penalties by either BOEM or BSEE;
  - Found by BOEM and/or BSEE to be non-compliant with any lease, plan, or permit term or condition;
  - Cited by any other agency(ies) with jurisdiction on the OCS, for non- compliance with any regulation; and/or
  - Cited for non-payment or under-payment of rentals, royalties, interest bills, civil penalties, or inspection fees, and such non-payment or under-payment has been referred to the U.S. Treasury for collection within the past five years.

Based on the above criteria, the Regional Director could determine that a lessee had the ability to self-insure some portion of, or all of, any additional security obligations for a lease, ROW, or RUE; however, the Regional Director would not permit the use of self-insurance in an amount in excess of 10 percent (10%) of the lessee's tangible net worth. The Regional Director could determine, based on a lessee's credit rating that it cannot apply self-insurance to sole liability properties. Sole liability properties are leases, ROWs, or RUEs for which a lessee is the only liable party and no prior interest holders who would be liable to BOEM to meet the obligations arising from such properties.

Determination, Notification, and Timing of Additional Security

If the Regional Director determined that a lessee's financial ability along with existing financial assurance was not sufficient to cover its obligations, the Regional Director would notify the lessee in writing. The Regional Director's notification will either: (1) propose an amount of additional security required and give the lessee opportunity to meet with BOEM to discuss this amount; or (2) order that the provide the required additional security or present to BOEM a tailored plan to phase in the additional security requirement.

Tailored Plans to Meet Additional Security Requirements

If a lessee used any type of financial assurance other than surety bonds or Treasury securities to meet its additional security requirement, or if a lessee requested the ability to phase-in its additional security requirement, the lessee would be required to develop a tailored plan to meet that requirement; however, additional security for sole liability properties could not be phased-in. If requested, BOEM would provide guidance in formulating and developing a tailored plan.

If BOEM cannot approve a tailored plan within 180 days of its submission, BOEM could require the lessee to provide the full amount of the required additional security within 30 days of the date on which the 180-day period ends. Once approved, a lessee could request a modification of its approved plan. Pending the decision, the lessee would be required to adhere to the approved plan and timetable for compliance.

If a lessee failed to provide additional security in a timely manner, BOEM could assess penalties under 30 CFR part 550, subpart N; request BSEE to suspend production or other operations in accordance with 30 C.F.R. § 250.173; or initiate action to cancel the lease, pursuant to 30 C.F.R. § 556.1102.

III. POST-2016 REGULATORY AND ECONOMIC ACTIVITY

A. EXECUTIVE ORDERS – 2017 to 2021

In December 2016, BOEM began implementing the 2016 NTL and started issuing orders to lessees and grant holders to provide additional security; however, BOEM subsequently issued a Notice to Stakeholders extending implementation of the 2016 NTL to allow additional time for the BOEM and Trump Administration to review the financial assurance program with all parties.

On March 28, 2017, President Trump issued Executive Order 13783—*Promoting Energy Independence and Economic Growth*, which directed Federal agencies to "review all existing regulations and other agency actions and, ultimately, to suspend, revise, or rescind any such regulations or actions that unnecessarily burden the development of domestic energy resources beyond the degree necessary to protect the public interest or otherwise comply with law."

On April 28, 2017, the Trump Administration issued Executive Order 13795 mandating BOEM to further review the 2016 NTL to determine whether modifications (reductions or additional regulations) to the financial assurance program are necessary, while minimizing unnecessary regulatory burdens.

On June 22, 2017, BOEM issued a third Note to Stakeholders announcing that it was in the final stages of its review of the 2016 NTL and had determined that "more time was necessary to work with industry and other interested parties." As such, BOEM extended the 2016 NTL implementation timeline beyond June 30, 2017, "except in circumstances where there would be a substantial risk of nonperformance of the interest holder's decommissioning liabilities."

In October 2019, the President issued E.O. 13891, *Promoting the Rule of Law Through Improved Agency Guidance Documents* that aimed to prohibit federal administrative agencies from issuing binding rules through guidance documents.

In response to Executive Orders 13783, 13795, and 13891, the Department of the Interior ("Interior") published a new proposed rule in October 2020[28] to: (1) Modify the evaluation process for requiring additional security; (2) streamline the evaluation criteria; and (3) remove restrictive provisions for third-party guarantees and decommissioning accounts. Interior stated that the October 2020 proposal would "provide greater protection as the financial assurance would be focused on the riskiest properties."

On January 20, 2021, President Biden signed E.O. 13990, "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis." This order, among other things, instructed agencies to review the actions taken between January 20, 2017, and January 20, 2021, and consider publishing a notice of proposed rulemaking suspending, revising, or rescinding that action.

B. INTERIOR PROPOSED RULE – June 2023

On June 29, 2023, the Department of the Interior ("Interior") published a new proposed rule (the "Proposed Rule").[29] The Proposed Rule (1) modifies the criteria used for determining whether oil, gas, and sulfur lessees, right-of-use and easement (RUE) grant holders, and pipeline right-of-way (ROW) grant holders may be required to provide bonds or other financial assurance above the current prescribed base bonds; (2) removes existing restrictive provisions for third-party guarantees and decommissioning accounts and adds new criteria under which a bond or third-party guarantee that was provided as supplemental financial assurance may be canceled; and (3) clarifies bonding requirements for RUEs serving Federal leases.

Bonding and Other Security Requirements

The Proposed Rule allows the Regional Director to require additional security when: (1) a lessee or grant holder does not meet the proposed financial strength threshold; or (2) when the lease does not have sufficiently valuable proved oil and gas reserves to be sold to another company that could assume the abandonment obligations.

Leases

BOEM's existing evaluation process for leases is based on the current lessee's ability to carry out current and future obligations. Under the existing regulations, the Regional Director uses five criteria to evaluate the need for additional security: (1) financial capacity; (2) projected financial strength; (3) business stability; (4) reliability in meeting obligations based upon credit rating or trade references; and (5) record of compliance with laws, regulations, and lease terms.

[28] Federal Register, Vol. 85, No. 201, October 16, 2020.
[29] Federal Register, Vol. 88, No. 124, June 29, 2023.

BOEM's Proposed Rule streamlines the evaluation process to use only two criteria to determine if any supplemental financial assurance on a lease may be required: (1) An investment grade issuer credit rating[30], either from an NRSRO, as identified by the United States Securities and Exchange Commission (SEC), or a proxy credit rating determined by BOEM based on the company's audited financial statements; or (2) the 3-to-1 ration of the value of proved oil and gas reserves on a lease to the decommissioning liability associated with these reserves.

BOEM proposes to **eliminate the "business stability" criterion** currently used. The existing regulation bases business stability on five years of continuous operation and production of oil and gas; BOEM has determined that there is little correlation between being in business for five or more years and a company's ability to carry out its present and future obligations. BOEM also conducted a historical analysis of historical offshore company bankruptcies and determined that "whether a company was in business for five or more years had no relationship to its likelihood to declare bankruptcy".

BOEM also proposes to **eliminate the existing "record of compliance" criterion**. BOEM reviewed BSEE's Incidents of Noncompliance ("INCs") and Increased Oversight List and determined that the number of OCS properties owned by a company, not its financial health, is the best predictor of the number of INCs. Companies with a larger number of offshore assets inspected by BSEE accumulated a far greater number of INCs than offshore companies with fewer assets, irrespective of the company's overall financial health. The "record of compliance" criterion was also difficult to fairly apply because not all incidents are considered equal.

Additionally, BOEM proposes to **replace the existing "financial capacity" and "reliability" criteria with issuer credit rating or proxy credit rating**. BOEM has found credit rating to be the most reliable indicator of its overall credit risk or its ability to meet its financial commitments. If a lessee does not have a credit rating, they could submit audited financial statements for BOEM to determine a proxy credit rating. BEOM stated that "audited financial statements, prepared in accordance with Generally Accepted Accounting Principles (GAAP) and accompanied by an auditor's certificate, provide a level of certainty that the financial statements accurately represent the company's economic position and operational performance and would allow BOEM to accurately determine if additional security is needed." If a lessee does not meet the credit rating or proxy rating criteria, the lessee could avoid additional security if BOEM determined that the properties contained proved reserves exceeding three times the decommissioning costs (using the BSEE P70 estimated value) associated with the production of such properties.

Right-of-Use and Easement Grants

BOEM's existing regulations concerning right of-use and easement ("RUE") grants do not prescribe a base bond amount. The Proposed Rule replaces this vague requirement with a **cross-reference to the specific criteria governing bond demands with respect to leases, including the consideration of credit ratings of co-grant holders and lease holders**. The value of proved reserves will not be considered because the grant holder is not entitled to any interest in the reserves.

The Proposed Rule clarifies that any RUE grant holder must provide base financial assurance in a specific amount, regardless of whether the RUE serves a State or Federal OCS lease. **BOEM is proposing to establish a Federal RUE base financial assurance requirement that matches the existing $500,000 base financial assurance requirement for State RUEs.** The Proposed Rule clarifies that a grant holder **may be required to provide supplemental**

[30] Investment grade credit rating is defined as greater than or equal to either BBB- from S&P or Baa3 from Moody's

assurance for the RUU, above the $500,000 base assurance, if the grant holder does not meet the criteria rating or proxy credit rating proposed to be used for lessees.

BOEM also proposes a requirement to **establish a $500,000 area-wide financial assurance**, that would satisfy the base requirement for any RUE holder that owns one or more RUEs within the same OCS area, regardless of whether the lease is a State or Federal lease. BOEM is also proposing to **allow any lessee that has posted area-wide lease financial assurance, to modify that lease surety bond to also cover any RUE(s) in the area owned by the same lessee.** The ability to use areawide lease financial assurance to cover the RUE base financial assurance obligation would be subject to the requirement that the area-wide lease financial assurance would be in an amount equal to or greater than the RUE base financial assurance requirement.

BOEM also proposes a new regulation to establish conditions under which the assignment of RUE interests may be disapproved. If an assignee has not satisfied all regulatory obligations, any BOEM or BSEE order, or has not satisfied the financial assurance requirements, BOEM may disapprove the assignment.

Pipeline Right-of-Way Grants

Existing BOEM bonding requirements for pipeline right-of-way ("ROW") grants require a $300,000 area-wide base bond, although the Regional Director may require additional security if the $300,000 area-wide bond is determined to be insufficient. **BOEM is proposing to revise the financial assurance regulations to provide that the Regional Director will demand that a pipeline ROW grant holder provide supplemental financial assurance when the grant holder does not meet the same credit rating or proxy credit rating criteria proposed to be used for lessees.** Proved reserves would not be considered because ROW grants do not authorize holders to produce hydrocarbon reserves.

Third-party Guarantees

Existing guidance states that that a guarantor's total outstanding and proposed guarantees are not allowed to exceed 25 percent of its unencumbered net worth in the United States. This provision requires BOEM to consider the unencumbered net worth of the company in the United States, while another provision requires BOEM to consider the guarantor's unencumbered fixed assets in the United States. Interior stated that both criteria are difficult to apply when the company being evaluated has domestic and international assets, and BOEM has no ability to confirm whether the 25 percent net worth criteria has been exceeded.

BOEM proposes to (1) **apply the same credit rating or proxy credit rating criteria proposed for lessees** and (2) **remove the requirement for a third-party guarantee to ensure compliance** with the obligations of all lessees, operating rights owners, and operators on the lease, and would allow a guarantee limited to a specific amount, as agreed to by BOEM, or limited to the liabilities of specific parties and (3) **allow third-party guarantees to be used as supplemental assurance for RUE or ROW grant, as well as a lease**. The Proposed Rule would also allow BOEM to cancel a third-party guarantee under the same terms and conditions that apply to other types of financial assurance. The value of proved oil and gas reserves will not be considered because the guarantor would not have an interest and does not impact the guarantor's overall financial strength.

Lease-specific Abandonment Accounts

The current guidance allows lessees to establish a lease-specific abandonment account in lieu of a bond. BOEM proposes to rename these accounts ''Decommissioning Accounts'' to remove any perceived limitation to a single lease, and to allow these accounts to be used to ensure compliance with additional security requirements for ROU and ROW grants, as well as a lease.

BOEM determined that the risk of loss through a bank failure is minimal, so it also proposes to **remove the requirements to pledge Treasury securities to fund the account** before the amount of funds in the account equals the $250,000 FDIC maximum insurable amount.

Transfer of Lease Interests

The Proposed Rule clarifies that BOEM will not approve the transfer of a lease interest, whether a record title interest or an operating interest, until the transferee complies with all applicable regulations and orders, including financial assurance.

BOEM Evaluation Methodology

Credit Ratings

BOEM is proposing to **use an issuer credit rating or proxy credit rating** to evaluate the financial health of lessees and grant holders. S&P's and Moody's rating methodologies analyses are wide-ranging and include factors beyond corporate financials, including the entity's ability to honor senior unsecured debt and debt-like obligations. If an entity does not have an issuer credit rating, BOEM would use S&P's Credit Analytics Credit Model to calculate proxy credit ratings based on audited financial information for the most recent fiscal year so that BOEM could compare the company with similar public companies in the same industry segment.

BOEM has determined that **establishing an issuer credit rating threshold of BBB- (S&P) or Baa3 (Moody's), an equivalent credit rating** provided by another SEC-recognized NRSRO, or an equivalent proxy credit rating, is the best means for accomplishing these objectives.

BOEM is proposing to add a new provision to the regulations that would authorize BOEM to **require a company requesting a proxy credit rating to provide information on its ownership of other OCS facilities and leases**. This new provision authorizes BOEM to take the contingent liabilities associated with the company's coownership of these assets into consideration in determining the appropriate proxy credit rating.

Valuing Proved Oil and Gas Reserves

For lessees requesting BOEM to consider the value of the underlying proved reserves in determining whether additional security is required, BOEM would require the lessee to submit a SEC price case reserve report[31] for the proved oil and gas reserves located on a given lease.

BOEM will use this proved oil and gas reserves per-lease value when determining whether the value of the reserves on any given lease **exceeds three times the cost of the P70 decommissioning estimate** associated with the production of those reserves. The valuation

[31] as defined by the SEC regulations at 17 CFR 210.4–10(a)(22)

analysis would be based on a reserve report for the proved oil and gas reserves that includes the following:

- The projected future production quantities of proved oil and gas reserves
- The production cost for those reserves
- The discounted future cash flows from production
- The net present value of the proved oil and gas reserves

BOEM stated it believes that "a property with a high enough 'reserves-to decommissioning cost' ratio would likely be purchased by another lessee if a current lessee defaults on its obligations, thereby reducing the risk that decommissioning costs would be borne by the government, and consequently reducing the need for additional security."

Phased Compliance

BOEM is proposing to **phase in the new bonding requirements over a three-year period** for existing leaseholders. BOEM will require that any company receiving a supplemental financial assurance demand post one-third of the total amount by the deadline listed on the demand letter. A second one-third would be required by the end of the second year (i.e., within 24 months of the receipt of the demand letter). The final one-third payment would be due within 36 months of receipt of the demand letter.

BOEM will discontinue collection of and return any supplemental financial assurance previously provided if a lessee's credit rating improves above the required threshold.

Bond Appeals

BOEM is proposing a new requirement whereby any company seeking to stay a supplemental financial assurance demand pending appeal must, as a condition of obtaining a stay of the order, **post an appeals bond in the amount of supplemental financial assurance required**. If the appeal is successful, the amount of the appeals bond in excess of the amount of supplemental financial assurance determined to be required would be released. If the appeal is unsuccessful, the appeals bond could be replaced or converted into bonds to cover the supplemental financial assurance demand.

C. UPDATE TO BSEE P&A CALCULATIONS

Currently, BSEE displays the abandonment cost estimate as the sum of two different determinations for each lease, ROW or RUE: a distribution estimate and a deterministic estimate.

The distribution estimate applies a probabilistic approach using a P50, P70 and P90 distribution based on actual decommissioning costs reported to BSEE by OCS lessees since mid-2016. A P50, P70 or P90 determination means that there is a 50%, 70% or 90% chance that the actual abandonment costs will be less than the BSEE estimated cost. As the certainty of the estimate increases, so does the cost estimate; therefore, P90 estimates will generally be higher than the P70 and P50 estimates.

The deterministic amount is calculated by BSEE based on its evaluation of abandonment cost data. Using this model, the output is determined by the input parameters and does not include elements of randomness.

Historically, BSEE relied upon their proprietary algorithms and methodologies to calculate abandonment estimates. The primary sources of data used in those estimates came from BSEE studies, lessee presentations to bankers, professional experience, industry publications, and other sources. The issue with this approach was that some data sources of information were decades old and did not reflect current technologies. In 2016, BSEE indicated that the algorithms to calculate abandonment estimates had not materially changed since 2011.

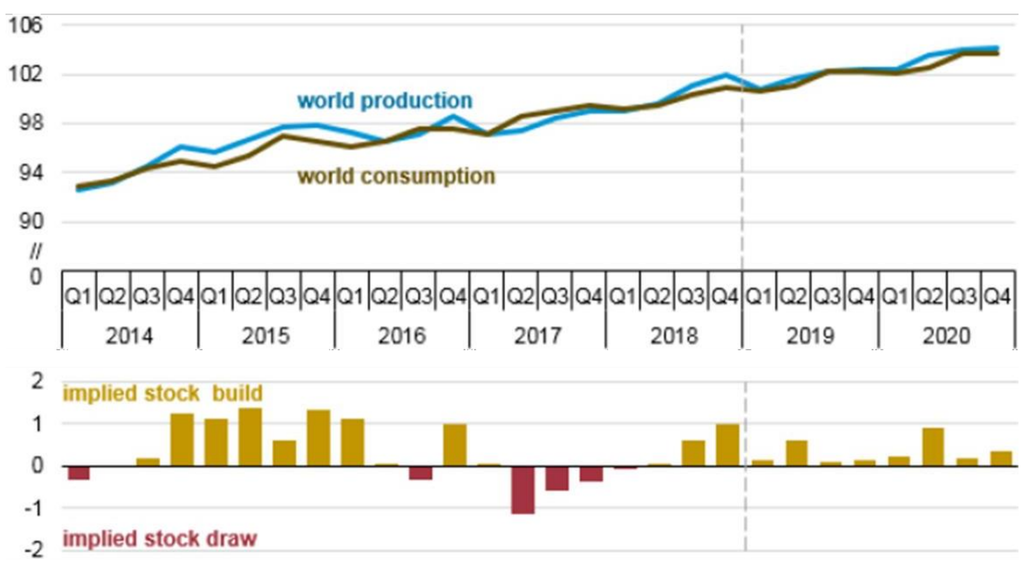
To address this issue, Interior published a rule obligating lessees and operating right owners to submit actual expenditures for abandonment activities. BSEE now relies on those reported expenditures to develop its cost estimates. Opportune noted the following about BSEE's updated cost estimates:

- Cost estimates assume the U.S. Taxpayer would potentially pay for the abandonment; thus, the cost estimate uses a cost that represents what a third-party (as opposed to the lessee in question) would require to complete the abandonment work.
- Estimates include a third-party profit margin.
- Estimates do not allow for economies of scale. The estimates assume all work will be performed on a one-off basis and not as a part of a larger project including multiple assets.
- Estimates do not consider any salvage values of components that could be recovered from the structures during abandonment.

D. SUMMARY OF 2016–2022 INDUSTRY AND OCS ECONOMIC ACTIVITY

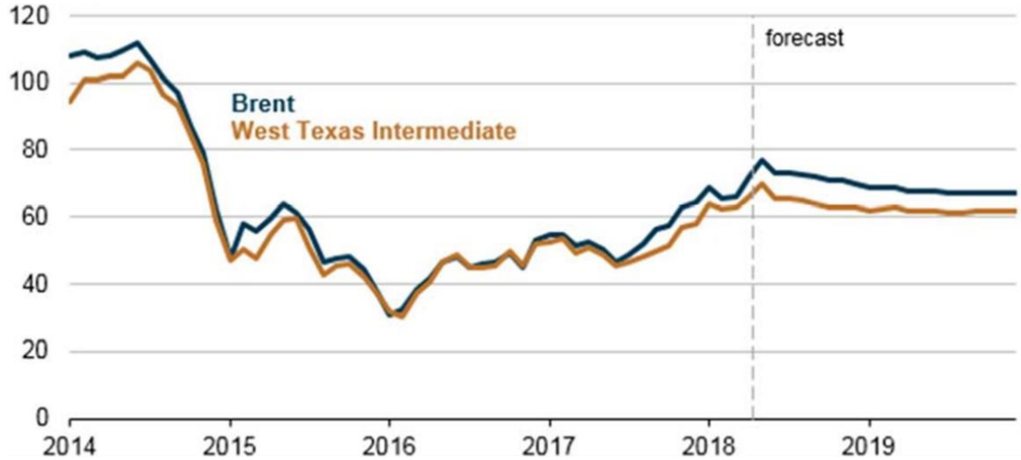
Subsequent to publication of the 2016 Study, liquidity across the Industry deteriorated under the weight of bloated balance sheets resulting from the combination of overheated commodity prices from 2011 to 2015 and capital markets that fueled excessive acquisition and development spending during the shale boom. The result was a volumetric supply overhang from late 2014 to 2016 that prevented commodity prices from recovering enough to offset the Industry's constrained capital.

WORLD LIQUID FUELS PRODUCTION AND CONSUMPTION BALANCE
MILLION BARRELS PER DAY



SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION, SHORT-TERM ENERGY OUTLOOK, JANUARY 2019

MONTHLY CRUDE OIL SPOT PRICES (JAN 2014 – DEC 2019)



SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION, SHORT-TERM ENERGY OUTLOOK, JUNE 2018

Since July 2016, a total of 12 U.S. small independent oil and gas companies filed bankruptcy with respect to approximately $18.8 billion in total capital, including approximately $4.0 billion in future P&A obligations.[32] All related P&A liabilities were either assumed by the reorganized Debtor, subsequent buyers of the underlying assets, co-lessees and/or predecessors in title, or funded through a liquidation trust – at no cost to the American taxpayer.

Commodity prices stabilized through 2019 as global demand eroded excess supply and the Industry began to recover. Oil and gas bankruptcy fears waned and the BOEM delayed its previous proposals to streamline the financial assurance regulations. However, a once-in-a-century COVID-19 pandemic that shut down the global economy and "threw the supply chain and demand completely out of whack."[33] Within three months of the start of 2020, U.S. production fell from a record 13.1 million barrels a day to 10.5 million and stayed there for nearly a year.[34] Consequently, public and private companies across the Industry shut-in production and drastically cut drilling plans. Companies that couldn't survive on their own were acquired, merged with peers to create enough scale, or were forced into bankruptcy.

[32] See Exhibit A – Summary of Offshore Operator Bankruptcies: 2016 – 2023. Amounts include two Ch. 11 filings by Fieldwood Energy. $18.8 billion represents the combination of $14.8 billion in Pre-petition Capital plus $4.0 billion in P&A Obligation.

[33] President Biden, White House Press Briefing, May 10, 2022

[34] Bloomberg, February 16, 2022

IV. OPPORTUNE 2023 STUDY

As a result of the Proposed Rule, Opportune is updating its previous study to independently review the following:

- Current BOEM estimated P&A liabilities for OCS leases and the underlying BSEE historical data
- Actual historical costs of OCS P&A liabilities borne by U.S. taxpayers
- Current distribution of OCS P&A liabilities by major integrated ("Majors"), large independent ("Large Independents") and small independent ("Small Independents") operators[35]
- Estimated effect to U.S. Taxpayers and the Gulf Coast

A. INDEPENDENT COST-BENEFIT ANALYSIS FOR THE U.S. TAXPAYER

Cost-benefit analysis is a widely used technique for evaluating a possible course of action. It is a systematic way to look at the expected benefits compared to the expected costs for the course of action. To be rational and justifiable, the expected benefits must, at least, outweigh the costs. The cost-benefit analysis presented in the Opportune 2023 Study examines benefits of the proposed bonding requirements compared to the costs to Industry and the regional and national economy. The stakeholder is taken to be the American public, either as taxpayers funding the federal government or as citizens being impacted by a government policy. **Details of Opportune's cost-benefit analysis are given in Appendix A.**

The benefit of the Proposed Rule is to protect the public from paying for decommissioning of OCS oil and gas infrastructure using tax dollars because lessees default on their obligations. Under the Proposed Rule, the risk to the taxpayer is a function of the number of jointly and severally liable lessees in the chain of title and the financial strength of the individual lessees. If a lease includes a Major or a Large Independent, with high financial strength in the chain of title, then the risk of default for these leases is near zero. If there is no Major or Large Independent, the risk is tied to the financial condition of the Small Independents in the chain of title. Current regulations operate to greatly reduce or maintain the current minimal risk to taxpayers. For example, a current lessee would have to default, file for bankruptcy, unsuccessfully auction the properties due to no interested buyers, and have no solvent co-owner(s) of previous owner in the chain of title for the taxpayer to be liable. The greater the number of companies in the chain of title for the lease, the less likely it is that they would all default and the less risky the lease. The riskiest leases would be those with only one lessee in the chain of title. In such case, the risk of default is directly tied only to the individual lessee's financial strength.

Opportune analyzed BOEM lease data to understand the benefit of reducing the risk. The results of Opportune's analysis indicate that 1,706 leases have decommissioning liabilities considering all water depths with a total estimated OCS P&A liability of over $16.4 billion. Of those leases with liabilities, 378 have no Major or Large Independent in the chain of title. These leases have a total estimated P&A liability of about $1.2 billion. The vast majority of leases, over 93 percent of the total P&A liabilities, or $15.3 billion, have a Major or a Large Independent in the chain of title and have a minimal likelihood of default. Only 7 percent of total P&A liabilities in

[35] Majors and Large Independents are defined as having a tangible net worth, or market capitalization, of over $10.0 billion as of March 15, 2023. Small Independents are defined as all other OCS operators who have a tangible net worth that is either less than $10.0 billion or unavailable from public sources. See Appendix C of the Opportune 2022 Study for a listing of lessees considered to be Majors and Large Independents (including subsidiaries and successors); Small Independents represent all other lessees.

the OCS are associated with Small Independents.

Opportune also analyzed the collateral associated with these leases. The results indicate that collateral requirements increase with increasing risk. For the lowest risk category, leases with at least one Major in the chain of title, collateral covers only about 11.5% of the total P&A liability. Coverage for Small Independents increases to about 66% on average. This level of coverage for the higher risk categories suggests that the previous bonding requirements did act to place extra security where it was needed.

Risk Category	Number of Leases	Total Cost	ARO	Percent of Total	Collateral	Percent of Total	Uncovered	Percent Liability Covered
Leases - Active								
Major Included	1,063	65,100	13,670	83.1%	1,571	47.9%	12,100	11.5%
Large Independent Included	265	8,391	1,620	9.9%	520	15.9%	1,100	32.1%
Small Independents								
>= 5 Lessees	184	7,560	410	2.5%	334	10.2%	77	81.3%
4 Lessees	18	280	21	0.1%	44	1.3%	-22	205.1%
3 Lessees	35	519	77	0.5%	83	2.5%	-6	107.9%
2 Lessees	63	2,152	455	2.8%	271	8.3%	183	59.7%
1 Lessee	78	843	189	1.1%	29	0.9%	160	15.5%
Subtotal Independents	**378**	**11,354**	**1,152**	**7.0%**	**761**	**23.2%**	**391**	**66.1%**
Subtotal All Leases	**1,706**	**84,845**	**16,442**	**100.0%**	**2,852**	**87.0%**	**13,590**	**17.3%**
General Allocations	-			-	425	13.0%	-	-
Total	**1,706**	**84,845**	**16,442**	**100.0%**	**3,276**	**100.0%**	**13,166**	**19.9%**

Opportune concludes that the benefit in the reduction of risk from the Proposed Rule is relatively small because the riskiest categories do not comprise a large part of the total liability. If the increase in collateral from the new bonding requirement provides 100 percent coverage for all leases without a Major or Large Independent, then the benefit is a reduction in risk of $391 million (the "Uncovered Risk"). This amount is determined as the total P&A liability for leases with no Major or Large Independent in the chain of title, $1.2 billion, less collateral already in place of $761 million.

BOEM's goal of protecting taxpayers from paying decommissioning liabilities comes at a significant cost. This cost results from changes in the way producers will choose to operate as a result of increased bonding requirements. Using more of producers' available financial resources to protect the public reduces the funds available for exploration and production activities in the OCS. In turn, these reductions in spending will have a negative impact on economic activity of the Gulf Coast states as well as in other parts of the country.

The potential impact of the Proposed Rule is difficult to predict but is likely to be very significant. Majors are expected to be largely unaffected; however, Small Independents are expected to significantly reduce their development spending.

In our analysis, we assume that the funds used to pay the premiums for the proposed supplemental bonding are funds that would have otherwise been spent on exploration or development drilling or recompletions in the Gulf OCS. Our model assumes a $25/boe finding and development cost and other parameters that are described in the Appendix. We also assumed that the lost positive cash flows that would have been generated by developing reserves would have been re-invested in additional future development activities in the year after they are received. As a result, the estimated reduction in future activity is greater than what would be suggested merely by considering the bonding premiums.

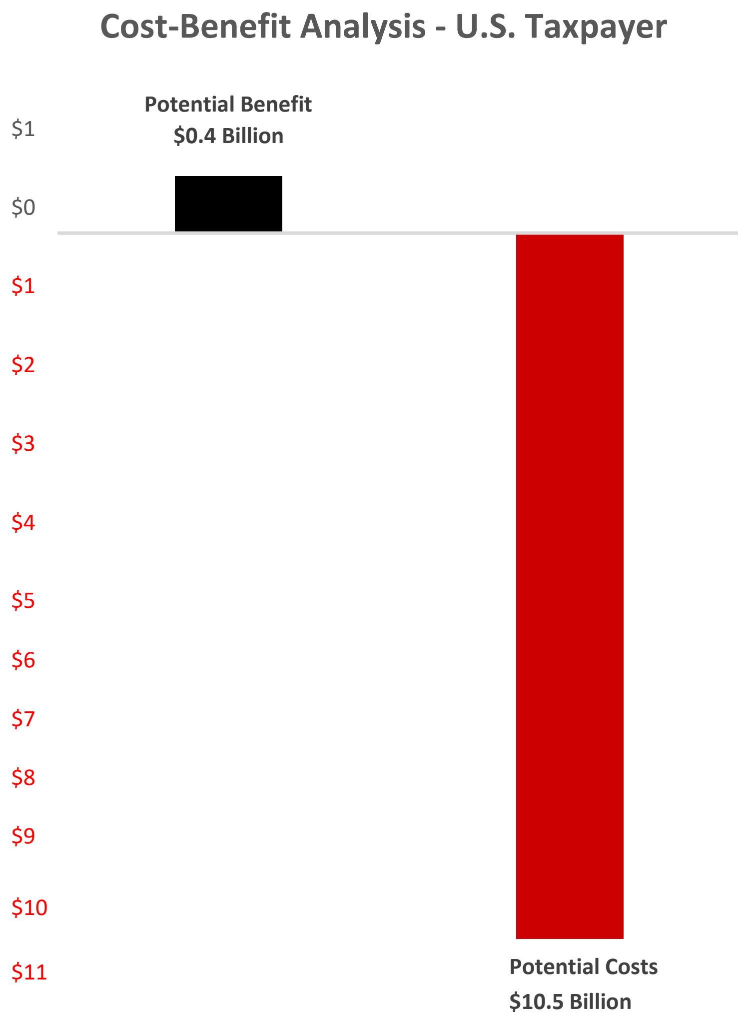
These development activities would not only result in additional capital spending, but also lead to additional operating cost expenditures. We have assumed that both classes of expenditure would be spent in the Gulf Coast states (Alabama, Florida, Louisiana, Mississippi, and Texas) since this is where most of the industries that support the offshore oil industry, and their employees, reside.

The broader economic effects of this decreased spending are estimated using the parameters from the Regional Input-Output Modeling System ("RIMS II") that is provided by the Bureau of Economic Analysis, US Department of Commerce. RIMS II is a tool for economic planners that provides a systematic analysis of the economic impacts of projects or programs on regional economies. The economic impact is estimated for the Gulf Coast states, namely, Alabama, Florida, Louisiana, Mississippi, and Texas, based on RIMS II multipliers that were generated in June 2023.

The decrease in spending over the ten-year study period is estimated under our Base Case assumptions to be approximately $4.7 billion. The result in a reduction of approximately 36,000 jobs. Similarly, output, earnings, and value added are all reduced by billions of dollars as a result of the decrease in spending. **In our Base Case, the decrease in spending results in a $9.9 billion reduction in GDP.**

The results of this cost-benefit analysis indicate the reduction in the risk for taxpayers is not justified given the impact on Industry and the regional/national economy. The benefits of the Proposed Rule are relatively small and the cost is very high in terms of the decreased development of OCS resources and associated losses in production, Industry revenue, taxes, economic activity, and jobs. The benefit of reduced risk of approximately $391 million is far outweighed by the decline OCS development. Based on the Base Case estimate, producers will see 55 million boe less production, over $2.8 billion less revenue, as well **as nearly $573 million in lost royalties to the federal government.**

Total direct and indirect costs of the Proposed Rule to the taxpayer are estimated to be approximately $10.5 billion.



B. INDEPENDENT ANALYSIS OF ADDITIONAL BONDING REQUIREMENTS AND RECOMMENDATIONS FOR IMPROVEMENT

GAO suggestions and the resulting NTL were predicated on the false presumption that the U.S. taxpayer is at risk vis-à-vis decommissioning costs posing potential financial liabilities to the federal government. Existing federal regulations[36] require previous owners to remain responsible for the future decommissioning costs of assets sold if current owners fail to meet their obligations. Additionally, sellers acknowledge that they may be held responsible for the future P&A of the properties being sold by typically requiring buyers to post private bonds or pay additional cash to the seller upon closing of the sale. Unlike the $2.1 trillion paid to other industries since 1970, <u>the potential Industry P&A cost to the U.S. taxpayer is infinitesimal</u>.[37] [38]

For the first time in Industry history, BSEE recently announced a Draft for Proposal seeking bids to decommission 15 orphan wells located in the Matagorda Island, High Island, and

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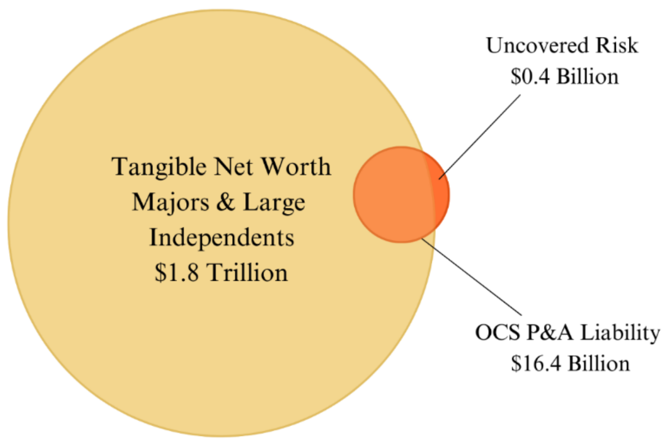
[36] Title 30 CFR Part 556, Subpart I § 556.62 and § 556.64
[37] See Exhibit B – Summary of Historical U.S. Government Bailouts, by Industry.
[38] Per the 2015 GAO Report, Interior officials cite an event in 1989 whereby a company in Ch. 11 proceedings was permitted to divert $13 million in royalties toward decommissioning costs as part of the company's agreement to fund two decommissioning trusts.

West Delta areas of the OCS[39]. The decommissioning costs will be funded from the 2021 Infrastructure and Jobs Act appropriations. Based on BOEM's database, the P&A liability associated with these wells and their related infrastructure is approximately $37.7 million[40] – an infinitesimal amount (~0.8%) compared to the $4.5 billion in royalties and revenue the U.S. government (i.e., taxpayer) received in 2021 from offshore Gulf of Mexico production.

To put in perspective how minimal the U.S. taxpayers' risk is in relation to the chain of title's wherewithal to pay, in a worst-case scenario, BSEE's $84 billion undiscounted estimate of the total P&A liability represents only 4.6% of the $1.8 trillion in collective tangible net worth of the Majors and Large Independents.



Out of BSEE's $11.3 billion undiscounted liability related to Small Independents, $2.9 billion (3.5% off the total undiscounted liability) relates to properties with less than three lessees. Given the Industry's history for always covering P&A obligations and the relatively small P&A amount that relates to uncovered leases, there appears to be very little risk to the U.S. taxpayer.

[39] "Orphaned Wells on the U.S. Outer Continental Shelf", BSEE Virtual Industry Day Presentation; February 2, 2022.
[40] See Exhibit C.

Leases by Risk Category	BOEM Estimated Total Cost[41]
Major Included	65,100,035,911
Large Independent	8,390,974,983
No Major or Large Ind -1	842,588,808
No Major or Large Ind -2	2,151,525,433
No Major or Large Ind -3	519,034,023
No Major or Large Ind -4	280,293,184
No Major or Large Ind -5	26,215,872
No Major or Large Ind >5	7,533,964,549
Grand Total	**$ 84,844,632,763**

Estimate of the P&A Liability is Overstated

BSEE's $84 billion estimate of the P&A liability falsely assumes that all related decommissioning costs occur tomorrow, not over the next 20 or 30 years in which such costs will actually be incurred – that is, BSEE fails to discount the estimated future costs back to today's present value.

The Financial Accounting Standards Board ("FASB"), the authoritative accounting standard-setting organization for the U.S., issued Accounting Standards Codification 410-20, *Asset Retirement Obligations* ("ASC 410-20) to address the accounting for environmental remediation liabilities (also referred to as asset retirement obligations, or "ARO") that results from the normal operation of a long-lived asset and that is associated with the retirement of that asset[42].

Paragraph 25-4 of ASC 410-20 address the timing of when an ARO should be recorded, as follows (***emphasis added***):

> "***An entity shall recognize the fair value of a liability for an asset retirement obligation in the period in which it is incurred if a reasonable estimate of fair value can be made.*** If a reasonable estimate of fair value cannot be made in the period the asset retirement obligation is incurred, the liability shall be recognized when a reasonable estimate of fair value can be made. If a tangible long-lived asset with an existing asset retirement obligation is acquired, a liability for that obligation shall be recognized at the asset's acquisition date as if that obligation were incurred on that date."

Paragraph 25-7 of ASC 410-20 addresses the required valuation of an ARO, as follows (***emphasis added***):

> "The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement. ***Thus, the timing and (or) method of settlement may be conditional on a future event. Accordingly, an entity shall recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be***

[41] Note the $84.8 billion represents the sum of the undiscounted P70 and the deterministic costs of all leases in the OCS, excluding ROW and RUE properties, per the BOEM Database.
[42] ASC 410-20, paragraph 15-2.

> ***reasonably estimated.*** In some cases, sufficient information about the timing and (or) method of settlement may not be available to reasonably estimate fair value. ***An expected present value technique incorporates uncertainty about the timing and method of settlement into the fair value measurement.*** Uncertainty is factored into the measurement of the fair value of the liability through assignment of probabilities to cash flows."

Every oil and gas company with operations in the OCS has measured and recorded the present value of its ARO, in accordance with ASC 410-20. These valuations and the assumptions used therein are then audited annually by each company's respective independent external certified public accountant ("CPA") firm as a part of the annual audit of their historical financial statements.

Opportune's mathematical calculation uses four variables: 1) estimated cost to decommission; 2) estimated time until the decommissioning occurs; 3) an inflation rate factor to arrive at an estimated future cash out flow ("FCOF"); and 4) an estimated credit adjusted risk free rate ("CARF") to calculate the present value ("PV") of the estimated FCOF as of the date of evaluation. **See Opportune's independent calculation of the OCS P&A Liability within Appendix B.**

In determining the estimated P&A dates for the fields in BOEM's database, we utilized an analysis conducted by Opportune's reserve engineering firm Ralph E. Davis Associates ("RED"). Because most of the reservoirs in the Gulf of Mexico have water drives, decline curve analysis is not suitable to estimate their remaining life. RED's analysis used the operators' reported estimates of reserves originally in place (at the field level effective 2019), combined with the reported historical field-level production, to generate a forecast of percentage or original reserves remaining. These forecasts were extrapolated to 99% or more of the original reserves to determine each field's remaining life.

The inflation rate should approximate the life of the assets in calculating a P&A obligation. In this case, we used 2.5% based on the consumer price index annual expect growth over the next 10 years as published in June 2022 the Livingston Survey.

In calculating the Credit Adjusted Risk Free Rate ("CARF") typically we relied on a corporate cost of debt as the discount rate. The cost of debt is a reasonable proxy of an entity's ability to meet its debt obligations. We've concluded on the CARF for each lease, as follows, based on the mix of lessees and their respective credit ratings:

- Majors only: 6.5%
- Large Independents and other lessees: 8.0%
- Small Independents only: 9.5%.

Based on the analysis and procedures described above we have concluded that the **OCS P&A Liability is approximately $16.4 billion**. See **Appendix B** for the report and exhibits detailing the ARO calculations.

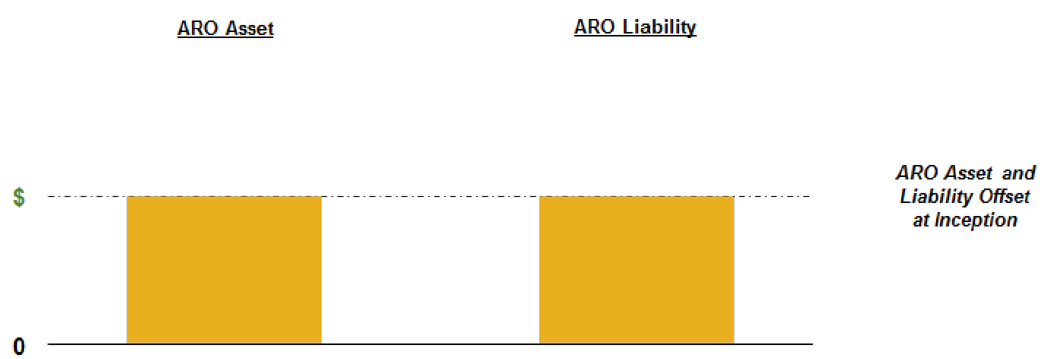
Financial Strength of OCS Companies is Understated

Although the financial strength of many companies operating in the OCS is currently diminished, certain errors in BOEM's estimates thereof should be eliminated so that financial strength can be fairly assessed in all economic environments.

First, the **estimated P&A liability (or audited ARO) should be added back to the calculation of tangible net worth.** By not doing so and then using the estimated tangible net worth as a measuring stick of whether a company has the financial wherewithal to pay its future P&A obligations, BOEM is effectively counting the P&A liability twice.

When an ARO liability is initially recorded, ASC 410-20 requires that an equal, but offsetting ARO asset be recorded at the same time so that there is no immediate impact to a company's earnings.

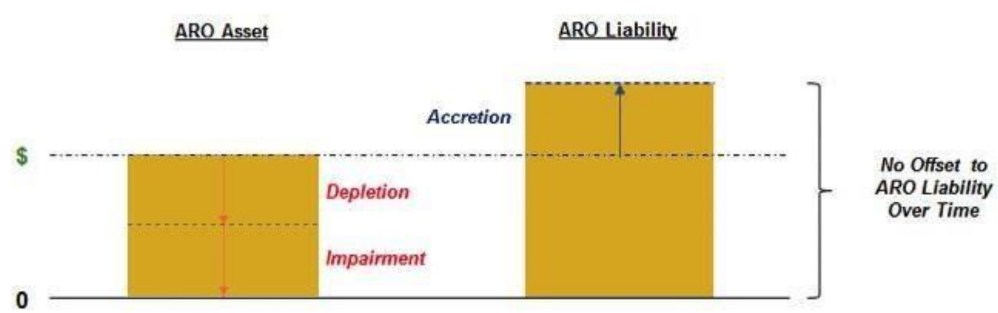
Offsetting ARO Asset and Liability at Inception



Over time, the ARO liability is "accreted" (to expense) up to the estimated future cost that will be spent at the P&A date; however, the related ARO asset is "depleted" (also to expense) down to zero as the related reserves are produced and/or "impaired" due to reductions in economic reserves and prices.

In the current economic environment, most E&P companies have experienced significant impairments of their reserves and related assets, which likely means that little to none of the initially recorded ARO assets remain on their balance sheets. As conditions improve, the ARO liability continues to increase until the P&A date, while the ARO asset decreases or no longer exists at all. As such, the company's tangible net worth is being reduced by the full amount of its ARO liability.

Changes in ARO Asset and Liability Over Time



Second, the impaired historical book value of the company's proved reserves may permanently underestimate its financial strength in future periods. **When assessing financial strength, BOEM should incorporate the value of each company's proved oil and gas reserves using forward strip pricing, discounted at 10% ("PV10"), rather than using the historical book value of proved reserves.**

GAAP requires companies to record impairments, immediately, when economic conditions dictate under the accounting rules; however, **GAAP never allows impaired asset values to be written back up as the underlying economic conditions improve and/or reserve volumes increase**. As commodity prices rise over time, debt and liabilities (including the PV of the ARO liability) on a company's financial statements reflect current reality, but the offsetting assets are forever stuck at their historical impaired (and further depleted) cost basis. As a result, assessing a company's financial strength may be artificially underestimated without considering the market value of its proved reserves.

Consideration was given to valuing proved reserves using the Standardize Measure[43]. Standardized Measure is a required disclosure by the Securities and Exchange Commission to conservatively compare reserve values across all public companies (not required for public companies), regardless of whether they use the Full Cost and Successful Efforts method of accounting for oil and gas operations. Because the Standardized Measure utilizes historical average pricing, the results are conservatively high in periods of declining prices and conservatively low in periods of rising prices; therefore, it's not the best measure for measuring current financial strength.

Incorporating the PV10 value of proved reserves is forward-looking with respect to both price and a company's expected drilling plans.

Use Standard Industry Forms and Independent CPA Firms to Improve Data Gathering

The Proposed Rule states that, absent a credit rating from a SEC-approved Nationally Recognized Statistical Rating Agency, a proxy credit rating should be determined by BOEM using the entity's audited financial statements. To this point, the Proposed Rule states, "BOEM has concluded that audited financial statements, prepared in accordance with Generally Accepted Accounting Principles (GAAP) and accompanied by an auditor's certificate, provide a level of certainty that the financial statements accurately represent the company's economic position and operational performance."

As such, BOEM should avoid a duplication of costs and efforts by utilizing the audited financial statements of every public and private OCS lessee when determining each entity's P&A liabilities and the value of future production underlying such liabilities.

BOEM would also benefit from following practices already in place within the refining industry where CFR[44] requires that independent CPA firms attest to the accuracy and completeness of certain biofuel information submitted to the Environment Protection Agency ("EPA"). Under the Energy Policy Act of 2005, the EPA sets annual quotas dictating what percentage of the motor fuels consumed in the United States must be represented by biofuel blended into fossil fuels. Individual quotas are then assigned to refineries based on the volume of fuel they introduce into the U.S. market. Refineries track the percentage of blended biofuel in each batch of production

[43] Valuation based on SEC pricing, which is the arithmetic average of the first of month pricing for the preceding 12 months.
[44] 40 CFR Title 80 Subpart F § 80.75, 80.125 and 80.150

through an assigned Renewable Information Number ("RIN"), which is uploaded to an EPA database through a "unified form report". To ensure compliance, CFR requires that independent CPA firms being engaged to perform Agreed-Upon Procedures

By analogy, legislators should consider amending CFR to require that **OCS lessees confidentially file their ARO balances by the type of structure on each property (e.g., wells platforms and pipelines), quarterly, on forms specified by BOEM. In addition, OCS lessees should be required, annually, to engage the same independent CPA firm that already audits the ARO balances within their financial statements (on an annual basis) to perform agreed-upon procedures attesting that the ARO information submitted to BOEM is complete and accurate.**

Supplemental bonding is not the only mechanism available.

In February 2016, a presentation[45] by BOEM's Gulf Coast Regional Director stated (***emphasis added***):

- "BOEM's role is to ***encourage oil and gas development activities on the OCS*** to increase the nation's energy independence and promote U.S. taxpayers' interests while simultaneously protecting natural resources and the environment."
- "The current general lease surety bond is too low to effectively cover any substantive offshore decommissioning costs, as necessary. Therefore, ***BOEM must ultimately rely on the sufficiency of its supplemental bond program*** for the purpose of assuring decommissioning performance."
- "BOEM strives to ensure appropriate procedural and operational safeguards ***without unduly discouraging exploration and development****."*

Chain of title regulations in the CFR have always encouraged development of the OCS by allowing Majors and Large Independents to shift their budgets away from the re-development and P&A of older assets in the shallow water toward more material development projects in the deepwater. Meanwhile, Smaller Independents used the older infrastructure acquired to improve economics on new drilling projects that are more material to them than the larger companies that initially sold the assets.

P&A liabilities in the North Sea are also a concern; however, governmental authorities under the Decommissioning Security Agreement of October 2015 (the "DSA") do not require supplemental bonding until the P&A liability exceeds the estimated discounted present value of the underlying reserves. Simply, the DSA rule encourages future offshore oil and gas exploration and development.

BOEM should consider a proposal that all **OCS producers self-fund the uncovered P&A liability of the Uncovered Properties ("Uncovered Risk")[46] through an additional 1% overriding royalty, payable to BOEM as beneficiary, which would supplement (but not eliminate) the chain of title in the event current OCS lessees fail to fulfill their P&A obligation (the "BOEM Reserve").**

Based on current commodity prices and approximately 627 million BOE in OCS

[45] BEOM Feb 2016 presentation.
[46] $0.4 billion, as discounted by Opportune.

production during 2022, OCS producers would self-fund the present value of the Uncovered Risk within approximately one year. Once the BOEM Reserve equaled the present value of the Uncovered Risk, the additional 1% override would stop until i) additional net liabilities were incurred or accreted; or ii) the BOEM Reserve was reduced by funds used to pay the P&A obligations of bankrupt lessees.

Absent capacity in the bond market, the Industry is adapting by developing cutting-edge financial insurance products to eliminate the uncertainty of future P&A funding and help defray the residual risk that remains with the previous chain of title. **If the U.S. government believes the taxpayer is really at risk, the Administration should allow a federal agency to issue bonds on Sole-Liability Properties, allowing the taxpayers to participate in the upside of the associated premium float.**

V. SUMMARY CONCLUSIONS

Historically low commodity prices and the exit of Majors and Large Independents from the shallow water, or from the OCS entirely, raises concerns of whether the U.S. taxpayer is at risk for the cost of existing P&A obligations if current lessees file bankruptcy. However, existing CFR regulations and BOEM boding rules have historically protected the U.S. taxpayer through previous economic and commodity price down-turns, and there is little-to-no evidence to suggest additional risks to the taxpayer exist today.

The BOEM-estimated $84 billion in undiscounted existing P&A liabilities is miniscule compared to the tangible net worth of the Industry, particularly the Majors and Large Independents who remain potentially responsible for the decommissioning costs of the assets they sold. Only $11.3 billion of the BOEM's estimate relates solely to Small Independents as current or chain of title owners; in today's dollars, the discounted un-bonded liability related solely to Small Independents is $0.4 billion.

Under the Proposed Rule, the balance sheets of Small Independents will be unable to fund collateral requirements to obtain surety bonds in a market that is too thin and for P&A liability estimates that are overstated. Although tailored plans may alleviate Industry concerns that existing wells will be shut-in, the uncertainty over future bonding that remains will prevent Small Independents from drilling new wells or selling their assets, both of which will lead to additional bankruptcies.

Increased bonding requirements is not the only solution. The Opportune 2023 Study proposes solutions that encourages the exploration and development of the OCS, while also protecting the environment and the chain of title from the uncertainty of unmet P&A obligations.

EXHIBITS

EXHIBIT A– SUMMARY OF OFFSHORE OPERATOR BANKRUPTCIES: 2016– 2023

Company Name	Filing Date	*Pre-petition Capital	*Post-petition Capital	*Difference	*P&A Obligation		Notes
Whistler Energy II, LLC	3/24/2016	$156.5	$75.0	$(81.5)	$78.8		Argonaut Insurance retained its collateral rights post-bankruptcy related to P&A bonds. $75mm was held in escrow for Argo, the remaining amount Argo asserted (~$3mm was treated as a GUC).
Energy XXI LTD	4/14/2016	$2,858.0	$301.7	$(2,556.3)	$613.0		All decommissioning obligations were assumed by the Reorganized Debtors
Bennu Titan LLC	8/11/2016	$180.4	Liquidated	$(180.4)	$3.6		Same as above, cases jointly administered
Bennu Oil & Gas, LLC	11/30/2016	$180.4	Liquidated	$(180.4)	$28.0-41.0		BOG's trustee sold the company's Clipper assets in the Gulf of Mexico in July 2017 to Murphy Exploration & Production Company for USD 3.3m in cash plus the assumption of USD 28m to USD 41m in plugging and abandonment (P&A) liabilities.
Stone Energy Corp,	12/14/2016	$1,507.9	$386.0	$(1,121.9)	$139.0		$75m escrowed for P&A obligations. A condition precedent to the Plan going effective was the resolution of issues related to the provision of additional collateral required by BOEM.
Castex Energy Partners, L.P.	10/16/2017	$390.0	$90.0	$(300.0)	$17.0		Plan of Reorganization states the debtors will continue with their decommissioning obligations
Cobalt International Energy, Inc.	12/14/2017	$2,840.8	Liquidated	$(2,840.8)	$205.0	1	Assets sold to 5 parties. Each sale contemplates the assumption of P&A liabilities with the purchase of the asset.
Fieldwood Energy LLC	2/15/2018	$3,287.0	$2,186.0	$(1,101.0)	$844.0	2	Reorganized Fieldwood Energy assumed liability for future environmental remediation and obligations related to plugging and abandoning wells and decommissioning facilities.
Fieldwood Energy LLC	8/3/2020	$1,800.0	$1,030.0	$(770.0)	$1,179.0	3	For assets purchased during case, P&A obligations were assumed as part of the sale. For abandoned properties, Fieldwood anticipated BSEE seeking payment from predecessor operators.
Arena Energy, LP	8/20/2020	$1,068.7	Liquidated	$(1,068.7)	$530.0		Sold all assets to San Juan Offshore VIII LP (owned by Lime Rock) and P&A obligations were assumed by Buyer.
Castex Energy 2005	2/26/2021	$251.7	$160.0	$(91.7)	$36.0		"Castex's Chapter 11 plan called for the creation of a liquidation trust to fund the company's plugging and abandonment obligations for certain oil and gas wells. Aside from those funded P&A obligations, Castex proposed to abandon all of its other interests in oil and gas wells." - Debtwire April 20, 2022 article. In April 2022, DOI agreed to withdraw a $245m decommissioning claim.
MLCJR LLC (Cox Operating)	5/14/2023	$270.0	Pending Case	Pending	$329.0		Companies reserve report forecasts PV10 of P&A obligations at $329mm, however, the company also has P&A obligations related to asset purchases for an undisclosed amount. At this time, no Plan of Reorganization has been filed proposing treatment of P&A obligations.
		$14,791.4	**$4,228.7**	**$(10,292.6)**	**$3,974.4**		

** Capital, difference, and P&A amounts in millions of dollars*

[1] *205mm as per BSEE claim for future obligations; Annual Report shows 7.4mm in ARO*

[2] *844mm figure includes Apache, P&A obligation excluding Apache is 346*

[3] *Includes 177mm to BOEM, 504mm to third parties (excluding Apache), and 498mm to Apache*

I. Whistler Energy II, LLC

Whistler Energy II, LLC Prepetition Capital Structure (in millions)	
Note Purchase Agreement	125.00
Unsecured Notes	31.50
Total Debt*	**156.50**

*does not include accrued and unpaid interest

Postpetition Capital Structure (in millions)	
Revolving Credit Facility	75.00
Series A Units	
Series B Units	
Total	**75.00**

Notes
Argonaut Insurance retained its collateral rights post-bankruptcy related to P&A bonds. $75mm was held in escrow for Argo, the remaining amount Argo asserted (~$3mm was treated as a GUC).

II. Energy XXI LTD

Energy XXI Ltd. Prepetition Capital Structure (in millions)	
Revolving Credit Facility	99.00
Second lien notes	1,450.00
Total Debt	946.00
Convertible notes	363.00
Total Debt*	**2,858.00**

*does not include 227.7 million in undrawn letters of credit under RCF

Postpetition Capital Structure (in millions)	
Revolving Credit Facility	227.74
Term Loan	74.00
Total	**301.74**

Notes
Dkt. 1340 "The Reorganized Debtors shall assume and succeed to all decommissioning obligations in connection with the Federal Lease Interests assumed pursuant to the Plan and BOEM's consent. The assumed and succeeded obligations shall include all obligations due under the applicable statutes, regulations and any idle iron plan accepted and approved by the Department of the Interior."

III. Bennu Titan LLC

Bennu Titan LLC Prepetition Capital Structure (in millions)	
Total Debt	180.40

Postpetition Capital Structure (in millions)
Liquidated

Notes
Case jointly administered with Bennu Oil & Gas, LLC

IV. Bennu Oil & Gas, LLC

Bennu Oil & Gas, LLC Prepetition Capital Structure (in millions)	
Total Debt	**180.40**

Postpetition Capital Structure (in millions)
Liquidated

Notes
Dkt. 171 "The purchase price for the Assets shall include (i) Three Million Three Hundred Thousand and 00/100 Dollars (USD $3,300,000.00) or such higher amount as the (Purchaser bids at the Auction and (ii) **Purchaser shall agree to indemnify the Estate for all decommissioning or plugging and abandonment or other environmental Labilities related to the Assets** (the “Purchase Price”), subject to adjustment as set forth in Section 3.2. The Purchase Price shall be paid by the Purchaser to the Seller at the Closing in cash, by wire transfer in immediately available funds)." "Acknowledgment of Obligations. Purchaser acknowledges that as the initial lessee under Lease Serial Number OCS-G 22939, dated July 1, 2001, between Purchaser and the United States of America, Purchaser may have certain obligations under applicable Law to plug, dismantle or abandon the Wells, and nothing contained herein shall either (a) increase the aforementioned obligations; or (b) relieve any Person from the rights of Purchaser to seek contribution, subrogation, and/or indemnity from, or assert any other related rights against, such Person for plugging and abandonment, decommissioning, or other environmental-related Liabilities associated with the Assets, all of which rights Purchaser hereby expressly reserves unto itself"

V. Stone Energy Corp.

Stone Energy Corporation Prepetition Capital Structure (in millions)	
Bank Borrowings	447.00
Term Loan	11.70
Total Debt	**458.70**
Senior Convertible Notes	279.20
Senior Notes	770.00
Total Debt	**1,507.90**

Postpetition Capital Structure (in millions)	
Revolving Credit Facility	150.00
Second Lien Notes	225.00
Building Loan	11.00
Total	**386.00**

Notes

Dkt. 216-2 "$75 million escrow on the Effective Date related to projected plugging and abandonment expenditures which shall be reduced dollar for dollar for any payments made by the Reorganized Debtors related to any plugging and abandonment related liabilities" A condition precedent to the Plan going effective is the resolution of issues related to the provision of additional collateral required by BOEM.

VI. Castex Energy Partners, L.P.

Castex Energy Partners, L.P. Prepetition Capital Structure (in millions)	
Total Debt*	**390.00**

*does not include accrued unpaid interest, fees, and expenses

Postpetition Capital Structure (in millions)	
Revolving Credit Facility	90.00

Notes

Plan of Reorganization states the debtors will continue with their decommissioning obligations.

VII. Cobalt International Energy, Inc.

Cobalt International Energy Prepetition Capital Structure (in millions)	
First lien notes	500.00
Second lien notes	934.70
Total Debt	1,406.10
Total Debt	**2,840.80**

Postpetition Capital Structure (in millions)
Liquidated

Notes
Dkt. 562 details out the sale of all assets to 5 parties. Each sale contemplates the assumption of P&A liabilities with the purchase of the asset.

VIII. Fieldwood Energy LLC

Fieldwood Energy LLC Prepetition Capital Structure	
(in millions)	
First Lien Debt Obligations	1,282.00
Second Lien Debt Obligations	518.00
Total Debt	**1,800.00**

Postpetition Capital Structure	
(in millions)	
Credit Bid Sale	1,030.00
Total	**1,030.00**

Notes
Following the consummation of the credit bid deal, Fieldwood's Chapter 11 plan calls for the company to undergo a divisive merger into Fieldwood Energy I LLC (FWE I) and Fieldwood Energy III LLC (FWE III). FWE I will vest with shelf assets that Fieldwood previously acquired from Apache Corp, as well as related liabilities tied to the plugging, abandonment and decommissioning of those oil and gas wells. FWE III, meanwhile, will own, operate, plug and abandon any assets that are neither legacy Apache assets nor assets transferring to the purchaser under the credit bid transaction. Related to the Abandoned Properties, Dkt. 1285 states " Abandoned Properties: Immediately upon the occurrence of the Effective Date, certain of the Debtors' assets (the "Abandoned Properties") will be abandoned pursuant to sections 105(a) and 554(a) of the Bankruptcy Code. The Debtors anticipate that BSEE will issue orders compelling either all or certain entities who are in the chain of title (collectively, the "Predecessors") and/or current co- working interest owners (collectively, the "CIOs") for each of the Abandoned Properties to perform the P&A Obligations for each respective property. A schedule of the oil and gas leases, rights-of-way, and rights-of-use and easement related to the Abandoned Properties is annexed hereto as Exhibit F12 (which may be amended, modified, or supplemented from time to time).13 As further detailed below, the Debtors have taken several steps to facilitate the safe and orderly operational transfer of the Abandoned Properties currently operated by the Debtors and are working to reach long-term commercial agreements similar to the FWE I and FWE IV structures with interested Predecessors for assuming operational control for Abandoned Properties operated by the Debtors. The Debtors (i) have dedicated approximately $6 million, in addition to amounts spent in the ordinary course, on safety related repairs and improvements on the Abandoned Properties and (ii) have provided Predecessors detailed operational information on the Abandoned Properties. Additionally, for any Predecessor with whom a consensual arrangement has not yet been agreed to, Credit Bid Purchaser will offer a 90-day transition period post-Effective Date during which Credit Bid Purchaser will offer to manage at the requesting Predecessor's cost and on its behalf any of the Abandoned Properties."

IX. Fieldwood Energy LLC

Fieldwood Energy LLC Prepetition Capital Structure	
(in millions)	
First Lien Term Loans & Reserve Based Term Loans	1,143.00
Prepetition FLLO Loans	518.00
Total Debt	**1,626.00**
Total Funded Debt	**3,287.00**
Prepetition RBL Facility (Undrawn)	148.00

Postpetition Capital Structure	
(in millions)	
First Lien Term Loan	1,143.00
Second Lien Term Loan	518.00
Rights Offering	525.00
Total	**2,186.00**

Notes

Dkt. 34 "Additionally, Reorganized Fieldwood Energy will assume liability for future environmental remediation and obligations related to plugging and abandoning wells and decommissioning facilities. In connection with the assumption of this plugging and abandonment and decommissioning liability and to secure its obligations with respect thereto, Reorganized Fieldwood Energy will be required to post an aggregate of approximately $240 million 3 of surety bonds for the benefit of Seller and an additional prior owner of certain of the Purchased Assets."

X. Arena Energy, LP

Arena Energy, LP Prepetition Capital Structure (in millions)		
RBL Facility		
	Principal Outstanding	599.64
	Total Debt	29.94
RBL Obligation		**629.58**
Term Loan		
	Principal Outstanding	410.01
	Unpaid Interest	29.06
Term Loan Obligation		**439.07**
Total Debt Obligation		**1,068.65**

Postpetition Capital Structure (in millions)
Liquidated

Notes
Sold all assets to San Juan Offshore VIII LP (owned by Lime Rock). Dkt. 13 "The Initial Plan Sponsor Proposal was attractive for a variety of reasons, including that it: (a) contemplated the acquisition of all of the Debtors' assets and equity as a going concern on an "as is, where is" basis, without potential title or environmental contingencies; (b) provided for the assumption of all the Debtors' plugging, abandonment, and decommissioning liability and the replacement of the Debtors' existing surety bonds, and included a bonding support letter demonstrating that existing surety providers of the Debtors were willing to support the proposal and continue to provide surety bonding to the Plan Sponsor"

XI. Castex Energy 2005

Castex Energy 2005 Prepetition Capital Structure (in millions)	
Total Secured Debt	199.60
P&A Liabilities	36.10
Total Debt	16.00
Total Funded Debt	**251.70**

Postpetition Capital Structure (in millions)	
Revolving Credit Facility	105.00
Term Loan	55.00
Total Debt	**160.00**

Notes

"Castex's Chapter 11 plan called for the creation of a liquidation trust to fund the company's plugging and abandonment obligations for certain oil and gas wells. Aside from those funded P&A obligations, Castex proposed to abandon all of its other interests in oil and gas wells." Debtwire April 20, 2022 article.
In April 2022, DOI agreed to withdraw a $245m decommissioning claim.

XII. MLCJR LLC (Cox)

MLCJR Capital Structure		
$ in millions	**Maturity**	**Prepetition Outstanding Amount**
Prepetition Revolver Facility	8/31/2024	80.0
ISDA Agreement	n/a	190.0
Prepetition Funded Obligations		**270.0**

EXHIBIT B – SUMMARY OF HISTORICAL U.S. GOVERNMENT BAILOUTS, BY INDUSTRY[47]

Industry	Size in 2008 U.S. Dollars ($ Billions)
Aerospace / Airlines	$ 20.0
Auto	$ 29.0
Banking	$ 1,862.8
Insurance	$ 180.0
Municipality	$ 9.4
Railroad	$ 3.2
	$ 2,104.4

Industry / Corporation	Year	What Happened	Size in 2008 U.S. Dollars ($ Billions)
Penn Central Railroad	1970	In May 1970, Penn Central Railroad, then on the verge of bankruptcy, appealed to the Federal Reserve for aid on the grounds that it provided crucial national defense transportation services. The Nixon administration and the Federal Reserve supported providing financial assistance to Penn Central, but Congress refused to adopt the measure. Penn Central declared bankruptcy on June 21, 1970, which freed the corporation from its commercial paper obligations. To counteract the devastating ripple effects to the money market, the Federal Reserve Board told commercial banks it would provide the reserves needed to allow them to meet the credit needs of their customers.	$3.2
Lockheed	1971	In August 1971, Congress passed the Emergency Loan Guarantee Act, which could provide funds to any major business enterprise in crisis. Lockheed was the first recipient. Its failure would have meant significant job loss in California, a loss to the GNP and an impact on national defense.	$ 1.4
Franklin National Bank	1974	In the first five months of 1974 the bank lost $63.6 million. The Federal Reserve stepped in with a loan of $1.75 billion.	$7.8
New York City	1975	During the 1970s, New York City became over-extended and entered a period of financial crisis. In 1975 President Ford signed the New York City Seasonal Financing Act, which released $2.3 billion in loans to the city.	$9.4
Chrysler	1980	In 1979 Chrysler suffered a loss of $1.1 billion. That year the corporation requested aid from the government. In 1980 the Chrysler Loan Guarantee Act was passed, which provided $1.5 billion in loans to rescue Chrysler from insolvency. In addition, the government's aid was to be matched by U.S. and foreign banks.	$4.0
Continental Illinois National Bank and Trust Company	1984	Then the nation's eighth largest bank, Continental Illinois had suffered significant losses after purchasing $1 billion in energy loans from the failed Penn Square Bank of Oklahoma. The FDIC and Federal Reserve devised a plan to rescue the bank that included replacing the bank's top executives.	$9.5

[47] Information and, in some cases, direct excerpts in this section were based on the ProPublica article History of U.S. Gov't Bailouts, Updated April 15, 2009.

Industry / Corporation	Year	What Happened	Size in 2008 U.S. Dollars ($ Billions)
Savings & Loan	1989	After the widespread failure of savings and loan institutions, President George H. W. Bush signed, and Congress enacted the Financial Institutions Reform Recovery and Enforcement Act in 1989.	$293.3
Airline Industry	2001	The terrorist attacks of September 11 crippled an already financially troubled industry. To bail out the airlines, President Bush signed into law the Air Transportation Safety and Stabilization Act, which compensated airlines for the mandatory grounding of aircraft after the attacks. The act released $5 billion in compensation and an additional $10 billion in loan guarantees or other federal credit instruments.	$18.6
Bear Stearns	2008	JP Morgan Chase and the federal government bailed out Bear Stearns when the financial giant neared collapse. JP Morgan purchased Bear Stearns for $236 million; the Federal Reserve provided a $30 billion credit line to ensure the sale could move forward.	$30.0
Fannie Mae/ Freddie Mac	2008	On Sep. 7, 2008, Fannie and Freddie were essentially nationalized: placed under the conservatorship of the Federal Housing Finance Agency. Under the terms of the rescue, the Treasury has invested billions to cover the companies' losses. Initially, Treasury Secretary Hank Paulson put a ceiling of $100 billion for investments in each company. In February, Tim Geithner raised it to $200 billion. The money was authorized by the Housing and Economic Recovery Act of 2008.	$400.0
American International Group(A.I.G.)	2008	On four separate occasions, the government has offered aid to AIG to keep it from collapsing, rising from an initial $85 billion credit line from the Federal Reserve to a combined $180 billion effort between the Treasury ($70 billion) and Fed ($110 billion). ($40 billion of the Treasury's commitment is also included in the TARP total.)	$180.0
Auto Industry	2008	In late September 2008, Congress approved a more than $630 billion spending bill, which included a measure for $25 billion in loans to the auto industry. These low-interest loans are intended to aid the industry in its push to build more fuel-efficient, environmentally-friendly vehicles. The Detroit 3 -- General Motors, Ford and Chrysler -- will be the primary beneficiaries.	$25.0
Troubled Asset Relief Program	2008	In October 2008, Congress passed the Emergency Economic Stabilization Act, which authorized the Treasury Department to spend $700 billion to combat the financial crisis. Treasury has been doling out the money via an alphabet soup of different programs. Here's our running tally of companies getting TARP funds.	$700.0
Citigroup	2008	Citigroup received a $25 billion investment through the TARP in October and another $20 billion in November. (That $45 billion is also included in the TARP total.) Additional aid has come in the form of government guarantees to limit losses from a $301 billion pool of toxic assets. In addition to the Treasury's $5 billion commitment, the FDIC has committed $10 billion and the Federal Reserve up to about $220 billion.	$280.0
Bank of America	2009	Bank of America has received $45 billion through the TARP, which includes $10 billion originally meant for Merrill Lynch. (That $45 billion is also included in the TARP total.) In addition, the government has made guarantees to limit losses from a $118 billion pool of troubled assets. In addition to the Treasury's $7.5 billion commitment, the FDIC has committed $2.5 billion and the Federal Reserve up to $87.2 billion.	$142.2
			$ 2,104.4

EXHIBIT C– SUMMARY OF CURRENT GULF OF MEXICO ORPHANED ASSETS

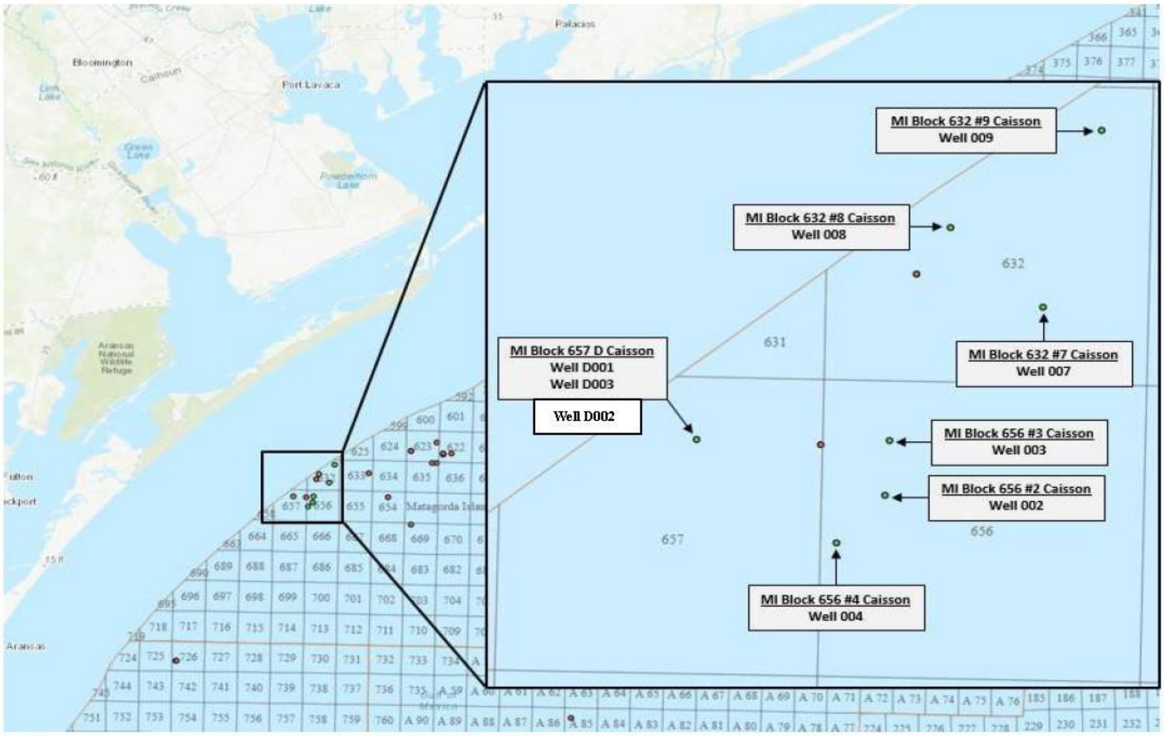
On February 2, 2022, BSEE hosted a virtual workshop to discuss and provide information in anticipation of issuing a Request for Proposal (RFP) for the decommissioning of orphaned wells and infrastructure located in the Gulf of Mexico Outer Continental Shelf. Below is a summary of those assets and the estimated decommissioning costs.

Wells identified for decommissioning

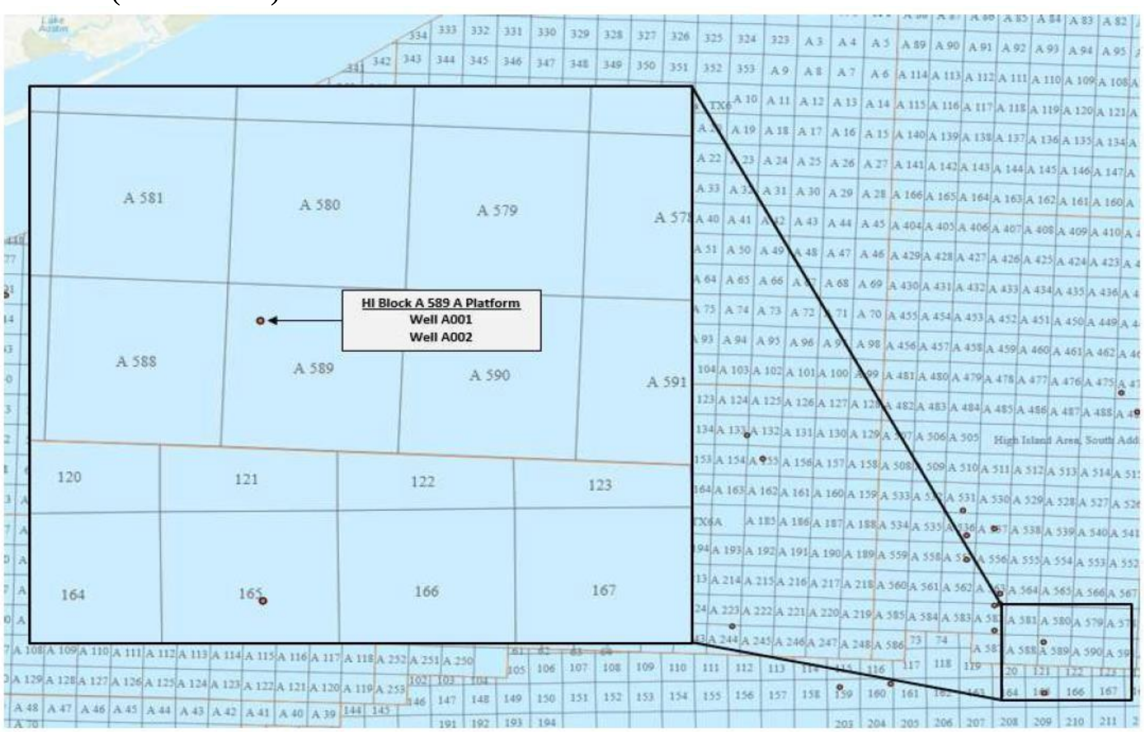
Lease	Area Block	Well Name	API Number	Well Status	Water Depth	MD TVD	Spud Date	Comp Date	Last Produced
G03096	MI 656	002	427034056702	COM	77'	5850' 5847'	23-Oct-06	02-Dec-06	Aug-2010
G03096	MI 656	003	427034056800	COM	75'	5831' 5820'	05-Dec-06	17-Feb-07	Sep-2013
G03096	MI 656	004	427034056900	COM	77'	5850' 5849'	13-Jan-07	25-Mar-07	Jan-2012
G03091	MI 632	007	427034057100	COM	74'	5850' 5849'	16-Feb-07	30-Apr-07	Sep-2009
G03091	MI 632	008	427034057500	COM	70'	2380' 2380'	17-Apr-08	29-Apr-08	Jul-2011
G03091	MI 632	009	427034057600	COM	75'	2359' 2359'	10-May-08	02-Jun-08	Sep-2013
G04139	MI 657	D001	427034057200	COM	71'	3560' 2350'	28-Jan-08	01-Apr-08	Sep-2013
G04139	MI 657	D002	427034057300	TA	71'	3485' 2315'	18-Feb-08	N/A	N/A
G04139	MI 657	D003	427034057400	COM	71'	3032' 2047'	08-Mar-08	13-Apr-08	Sep-2013
G01101	WD 117	H001	177204017301	COM	200'	9796' 9040'	13-May-06	26-Jul-06	Oct-2015
G01101	WD 117	H002	177204017500	COM	205'	11418' 10294'	25-Mar-06	19-Aug-06	Aug-2015
G01101	WD 117	H003	177204017200	COM	200'	11646' 10118'	27-Dec-05	18-Sep-06	Oct-2015
G01101	WD 117	H004	177204017400	COM	200'	9570' 8706'	23-Feb-06	28-Sep-06	Feb-2015
G27532	HI A589	A001	427094116502	COM	477'	11934' 11451'	05-Mar-08	07-Jul-08	Jul-2016
G27532	HI A589	A002	427094116600	COM	477'	10702' 10401'	08-Apr-08	23-Jun-08	Apr-2014

Well Locations

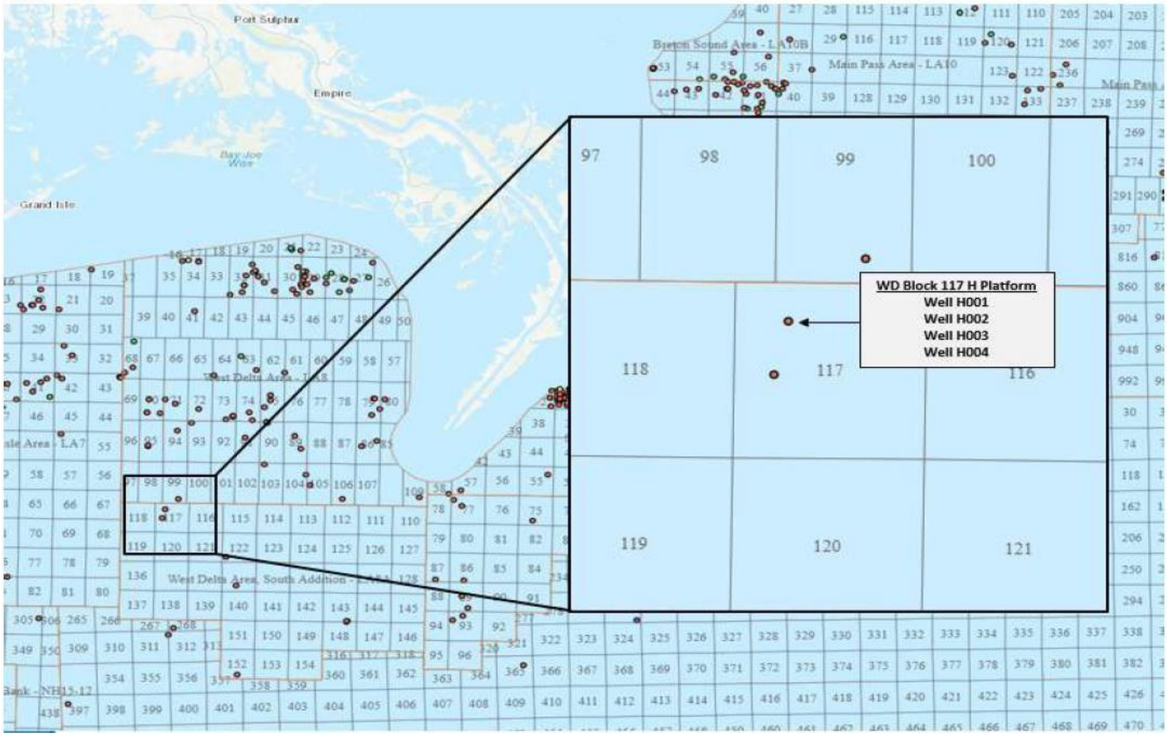
MI Wells (Blocks 632, 656 and 657)



HI Wells (Block A 589)



WD Wells (Block 117)



Lease	API Number	Well Name	Protraction Area	Block Number	Surface Location Latitude	Surface Location Longitude
OCS-G 03096	427034056702	002	Matagorda Island (MI)	656	28.033860	-96.576398
OCS-G 03096	427034056800	003	Matagorda Island (MI)	656	28.041805	-96.575704
OCS-G 03096	427034056900	004	Matagorda Island (MI)	656	28.026901	-96.583688
OCS-G 03091	427034057100	007	Matagorda Island (MI)	632	28.061401	-96.552252
OCS-G 03091	427034057500	008	Matagorda Island (MI)	632	28.073045	-96.566436
OCS-G 03091	427034057600	009	Matagorda Island (MI)	632	28.087336	-96.543297
OCS-G 04139	427034057200	D001	Matagorda Island (MI)	657	28.042068	-96.604989
OCS-G 04139	427034057300	D002	Matagorda Island (MI)	657	28.042090	-96.605001
OCS-G 04139	427034057400	D003	Matagorda Island (MI)	657	28.042090	-96.604976
OCS-G 01101	177204017200	H003	West Delta (WD)	117	28.817060	-89.798527
OCS-G 01101	177204017400	H004	West Delta (WD)	117	28.817065	-89.798550
OCS-G 01101	177204017500	H002	West Delta (WD)	117	28.817080	-89.798521
OCS-G 01101	177204017301	H001	West Delta (WD)	117	28.817085	-89.798543
OCS-G 27532	427094116502	A001	High Island (HI)	A 589	27.893154	-94.323778
OCS-G 27532	427094116600	A002	High Island (HI)	A 589	27.893135	-94.323787

Abandonment Cost Estimates

Matagorda Island (MI 632, 656, 657)					
Type	Assets	P50	P70	P90	Deterministic
Pipelines Decom Cost	8	$0.00	$0.00	$0.00	$2,425,082.00
Platforms Decom Cost	9	$7,400,283.00	$9,679,223.00	$13,022,378.00	$0.00
Platforms Site Clear Cost	9	$743,256.00	$1,300,158.00	$2,529,096.00	$0.00
Wells Decom Cost	9	$2,626,056.00	$4,461,845.00	$7,119,552.00	$0.00
Totals		**$10,769,595.00**	**$15,441,226.00**	**$22,671,026.00**	**$2,425,082.00**

High Island (589 A)					
Type	Assets	P50	P70	P90	Deterministic
Pipelines Decom Cost	1	$0.00	$0.00	$0.00	$1,482,300.00
Platforms Decom Cost	1	$0.00	$0.00	$0.00	$8,433,619.00
Platforms Site Clear Cost	1	$260,731.00	$321,433.00	$424,275.00	$0.00
Wells Decom Cost	2	$0.00	$0.00	$0.00	$1,162,902.00
Totals		**$260,731.00**	**$321,433.00**	**$424,275.00**	**$11,078,821.00**

West Delta (117 H)					
Type	Assets	P50	P70	P90	Deterministic
Pipelines Decom Cost	3	$0.00	$0.00	$0.00	$966,222.00
Platforms Decom Cost	1	$2,418,075.00	$2,868,687.00	$3,525,366.00	$0.00
Platforms Site Clear Cost	4	$6,503,860.00	$10,571,159.00	$20,832,103.00	$0.00
Wells Decom Cost	4	$3,299,686.00	$4,193,375.00	$5,487,095.00	$0.00
Totals		**$12,221,621.00**	**$17,633,221.00**	**$29,844,564.00**	**$966,222.00**

Assignment History

Matagorda Island (Blocks 632, 656 and 657)

Lease Number	Area	Block	Date Received	Date Returned	Date Approved	Assignment Type	Assignor Name	Assignee Name	Returned Remark
G03091	MI	632	8/4/2004		8/25/2004	OR	Exxon Mobil Corporation	LLOG Exploration Offshore, Inc.	
G03091	MI	632	9/30/2004		11/9/2004	OR	LLOG Exploration Offshore, Inc.	Hunt Petroleum (AEC), Inc.	
G03091	MI	632	9/30/2004		11/9/2004	OR	LLOG Exploration Offshore, Inc.	Hassie Hunt Exploration Company	
G03091	MI	632	9/30/2004		11/9/2004	OR	LLOG Exploration Offshore, Inc.	Haroldson L. Hunt, Jr. Trust Estate	
G03091	MI	632	9/30/2004		11/9/2004	OR	LLOG Exploration Offshore, Inc.	Margaret Hunt Trust Estate	
G03091	MI	632	9/30/2004		11/9/2004	OR	LLOG Exploration Offshore, Inc.	Lyda Hunt-Margaret Trusts-Lyda Hill	
G03091	MI	632	9/30/2004		11/9/2004	OR	LLOG Exploration Offshore, Inc.	Bushhill, L.P.	
G03091	MI	632	9/30/2004		11/9/2004	OR	LLOG Exploration Offshore, Inc.	AGH Energy, LLC	
G03091	MI	632	3/7/2005		5/25/2005	RT	Exxon Mobil Corporation	Paloma Offshore, LLC	
G03091	MI	632	3/7/2005		5/25/2005	OR	Exxon Mobil Corporation	Paloma Offshore, LLC	
G03091	MI	632	3/7/2005	5/25/2005		OR	Paloma Offshore, LLC	Exxon Mobil Corporation	Attempts more than 2 levels of OR.
G03091	MI	632	8/28/2008		9/12/2008	OR	Haroldson L. Hunt, Jr. Trust Estate	Hunt Petroleum (AEC), Inc.	
G03091	MI	632	8/28/2008		9/12/2008	OR	Margaret Hunt Trust Estate	Hunt Petroleum (AEC), Inc.	
G03091	MI	632	8/28/2008		9/12/2008	OR	Lyda Hunt-Margaret Trusts-Lyda Hill	Hunt Petroleum (AEC), Inc.	
G03091	MI	632	8/28/2008		9/12/2008	OR	Bushhill, L.P.	Hunt Petroleum (AEC), Inc.	
G03091	MI	632	8/28/2008		9/12/2008	OR	AGH Energy, LLC	Hunt Petroleum (AEC), Inc.	
G03091	MI	632	5/25/2011	6/9/2011		OR	XTO Offshore Inc.	Matagorda Island Gas Operations, LLC	DOO description incorrect
G03091	MI	632	5/25/2011	6/9/2011		OR	HHE Energy Company	Matagorda Island Gas Operations, LLC	DOO description incorrect
G03091	MI	632	7/6/2011		8/3/2011	OR	XTO Offshore Inc.	Matagorda Island Gas Operations, LLC	
G03091	MI	632	7/6/2011		8/3/2011	OR	HHE Energy Company	Matagorda Island Gas Operations, LLC	

Lease Number	Area	Block	Date Received	Date Returned	Date Approved	Assignment Type	Assignor Name	Assignee Name	Returned Remark
G03096	MI	656	8/4/2004		8/25/2004	OR	Exxon Mobil Corporation	LLOG Exploration Offshore, Inc.	
G03096	MI	656	9/30/2004		11/9/2004	OR	LLOG Exploration Offshore, Inc.	Hunt Petroleum (AEC), Inc.	
G03096	MI	656	9/30/2004		11/9/2004	OR	LLOG Exploration Offshore, Inc.	Hassie Hunt Exploration Company	
G03096	MI	656	9/30/2004		11/9/2004	OR	LLOG Exploration Offshore, Inc.	Haroldson L. Hunt, Jr. Trust Estate	
G03096	MI	656	9/30/2004		11/9/2004	OR	LLOG Exploration Offshore, Inc.	Margaret Hunt Trust Estate	
G03096	MI	656	9/30/2004		11/9/2004	OR	LLOG Exploration Offshore, Inc.	Lyda Hunt-Margaret Trusts-Lyda Hill	
G03096	MI	656	9/30/2004		11/9/2004	OR	LLOG Exploration Offshore, Inc.	Bushhill, L.P.	
G03096	MI	656	9/30/2004		11/9/2004	OR	LLOG Exploration Offshore, Inc.	AGH Energy, LLC	
G03096	MI	656	3/7/2005		5/25/2005	RT	Exxon Mobil Corporation	Paloma Offshore, LLC	
G03096	MI	656	3/7/2005		5/25/2005	OR	Exxon Mobil Corporation	Paloma Offshore, LLC	
G03096	MI	656	3/7/2005	5/25/2005		OR	Paloma Offshore, LLC	Exxon Mobil Corporation	Attempts more than 2 levels of OR.
G03096	MI	656	8/28/2008		9/12/2008	OR	Haroldson L. Hunt, Jr. Trust Estate	Hunt Petroleum (AEC), Inc.	
G03096	MI	656	8/28/2008		9/12/2008	OR	Margaret Hunt Trust Estate	Hunt Petroleum (AEC), Inc.	
G03096	MI	656	8/28/2008		9/12/2008	OR	Lyda Hunt-Margaret Trusts-Lyda Hill	Hunt Petroleum (AEC), Inc.	
G03096	MI	656	8/28/2008		9/12/2008	OR	Bushhill, L.P.	Hunt Petroleum (AEC), Inc.	
G03096	MI	656	8/28/2008		9/12/2008	OR	AGH Energy, LLC	Hunt Petroleum (AEC), Inc.	
G03096	MI	656	5/25/2011	6/9/2011		OR	XTO Offshore Inc.	Matagorda Island Gas Operations, LLC	DOO description incorrect
G03096	MI	656	5/25/2011	6/9/2011		OR	HHE Energy Company	Matagorda Island Gas Operations, LLC	DOO description incorrect
G03096	MI	656	7/6/2011		7/19/2011	OR	XTO Offshore Inc.	Matagorda Island Gas Operations, LLC	
G03096	MI	656	7/6/2011		7/19/2011	OR	HHE Energy Company	Matagorda Island Gas Operations, LLC	

Lease Number	Area	Block	Date Received	Date Returned	Date Approved	Assignment Type	Assignor Name	Assignee Name	Returned Remark
G04139	MI	657	8/4/2004		8/25/2004	OR	Exxon Mobil Corporation	LLOG Exploration Offshore, Inc.	
G04139	MI	657	9/30/2004		11/9/2004	OR	LLOG Exploration Offshore, Inc.	Hunt Petroleum (AEC), Inc.	
G04139	MI	657	9/30/2004		11/9/2004	OR	LLOG Exploration Offshore, Inc.	Hassie Hunt Exploration Company	
G04139	MI	657	9/30/2004		11/9/2004	OR	LLOG Exploration Offshore, Inc.	Haroldson L. Hunt, Jr. Trust Estate	
G04139	MI	657	9/30/2004		11/9/2004	OR	LLOG Exploration Offshore, Inc.	Margaret Hunt Trust Estate	
G04139	MI	657	9/30/2004		11/9/2004	OR	LLOG Exploration Offshore, Inc.	Lyda Hunt-Margaret Trusts-Lyda Hill	
G04139	MI	657	9/30/2004		11/9/2004	OR	LLOG Exploration Offshore, Inc.	Bushhill, L.P.	
G04139	MI	657	9/30/2004		11/9/2004	OR	LLOG Exploration Offshore, Inc.	AGH Energy, LLC	
G04139	MI	657	3/7/2005		5/25/2005	RT	Exxon Mobil Corporation	Paloma Offshore, LLC	
G04139	MI	657	3/7/2005		5/25/2005	OR	Exxon Mobil Corporation	Paloma Offshore, LLC	
G04139	MI	657	3/7/2005	5/25/2005		OR	Paloma Offshore, LLC	Exxon Mobil Corporation	Attempts more than 2 levels of OR.
G04139	MI	657	8/28/2008		9/12/2008	OR	Haroldson L. Hunt, Jr. Trust Estate	Hunt Petroleum (AEC), Inc.	
G04139	MI	657	8/28/2008		9/12/2008	OR	Margaret Hunt Trust Estate	Hunt Petroleum (AEC), Inc.	
G04139	MI	657	8/28/2008		9/12/2008	OR	Lyda Hunt-Margaret Trusts-Lyda Hill	Hunt Petroleum (AEC), Inc.	
G04139	MI	657	8/28/2008		9/12/2008	OR	Bushhill, L.P.	Hunt Petroleum (AEC), Inc.	
G04139	MI	657	8/28/2008		9/12/2008	OR	AGH Energy, LLC	Hunt Petroleum (AEC), Inc.	
G04139	MI	657	5/25/2011	6/9/2011		OR	XTO Offshore Inc.	Matagorda Island Gas Operations, LLC	DOO description incorrect
G04139	MI	657	5/25/2011	6/9/2011		OR	HHE Energy Company	Matagorda Island Gas Operations, LLC	DOO description incorrect
G04139	MI	657	7/6/2011		7/19/2011	OR	XTO Offshore Inc.	Matagorda Island Gas Operations, LLC	
G04139	MI	657	7/6/2011		7/19/2011	OR	HHE Energy Company	Matagorda Island Gas Operations, LLC	

High Island (Block A 589)

Lease Number	Area	Block	Date Received	Date Returned	Date Approved	Assignment Type	Assignor Name	Assignee Name	Returned Remark
G27532	HI	A 589	4/15/2014		4/16/2014	RT	ATP Oil & Gas Corporation	Bennu Oil & Gas, LLC	

West Delta (Block 117)

Lease Number	Area	Block	Date Received	Date Returned	Date Approved	Assignment Type	Assignor Name	Assignee Name	Returned Remark
G01101	WD	117	4/3/2000	4/18/2000		OR	Chevron U.S.A. Inc.	W & T Offshore, Inc.	Assignor does not own operating rights.
G01101	WD	117	6/23/2000		7/13/2000	OR	Kewanee Industries, Inc.	W & T Offshore, Inc.	
G01101	WD	117	7/30/2004		8/24/2004	OR	Kewanee Industries, Inc.	Chevron U.S.A. Inc.	
G01101	WD	117	9/9/2004		10/12/2004	OR	Chevron U.S.A. Inc.	Anglo-Suisse Offshore Partners, LLC	
G01101	WD	117	11/24/2004		2/28/2005	OR	Chevron U.S.A. Inc.	Anglo-Suisse Offshore Partners, LLC	
G01101	WD	117	11/24/2004		2/28/2005	OR	Kewanee Industries, Inc.	Chevron U.S.A. Inc.	
G01101	WD	117	1/10/2005		3/8/2005	RT	Chevron U.S.A. Inc.	Anglo-Suisse Offshore Partners, LLC	
G01101	WD	117	5/4/2005	12/21/2005		P	Anglo-Suisse Offshore Pipeline Partners, LLC	Anglo-Suisse Offshore Partners, LLC	Cannot assign a lease term pipeline

APPENDICES

APPENDIX A– COST-BENEFIT ANALYSIS OF ADDITIONAL BONDING REQUIREMENTS

I. COST-BENEFIT ANALYSIS

Cost-benefit analysis is a widely used technique for evaluating a possible course of action. It is a systematic way to look at all of the expected benefits of the course of action compared to all of the expected costs. For the course of action to be rational and justifiable, the expected benefits must, at least, outweigh the costs. The technique is often used by public policymakers in determining if a proposed policy is sound as well as by businesses in making decisions.

The cost-benefit analysis presented in this Study examines the proposed bonding requirements expected to be implemented by BOEM. In conducting this cost-benefit analysis, the stakeholder is taken to be the American public, either as taxpayers funding the federal government or as citizens being impacted by a government policy. Here, BOEM is merely an intermediary managing the public's resources. Similarly, oil & gas companies affected by the new bonding requirements as lessees are also intermediaries making investment/spending decisions based on the new bonding requirements. Benefits and costs are ultimately measured as impacts to the public.

II. DETERMINATION OF BENEFITS

The goal of BOEM in implementing the Proposed Rule is to protect the public from paying for decommissioning of offshore oil and gas infrastructure in the OCS using tax dollars because lessees default on their obligations. To address these concerns, BOEM has proposed to tighten requirements for supplemental bonding for individual lessees seeking to increase the level of financial assurances.

BOEM's approach includes certain factors that operate to mitigate some of the risk of default. Key among these factors is BOEM requirement that the lessees have "joint and several" liability for the decommissioning costs. In particular, BOEM attributes all decommissioning liabilities for a lease to any waived lessee even if there are other lessees present on the lease. The waived lessee is, with all other lessees, jointly and severally liable for decommissioning and relies on its financial strength to secure the costs of decommissioning, on behalf of all jointly and severally liable parties.

Consider how a default leading to taxpayer funding might arise. Typically, leases have more than one lessee in the chain of title. For the taxpayer to have to pay decommissioning costs on the lease, all of the lessees in the chain of title would have to default on their obligation simultaneously. Thus, the risk to the taxpayer of default on an individual lease becomes a function of the number of jointly and severally liable lessees and the financial condition of the individual lessees.

Using these factors, leases can be divided into a several risk profiles. First is a lease with a waived lessee in the chain of title. Joint and several liability ensures that any decommissioning costs are placed on the waived lessee. Typically, the waived party is a Major or a Large Independent with high financial strength, so the risk of default for these leases is near zero. Next, if there is no Major or Large Independent in the chain of title, the risk of default falls to Small Independents. The risk is tied to the financial condition of these individual companies. However, all of the companies in the chain would have to default simultaneously. The greater the number of companies in the chain of title for the lease, the less likely it is that they would all default and the less risky the lease. Obviously, the riskiest leases would be those with only one lessee in the chain of title. In such cases, the risk of default is directly tied only to the lessee's financial condition.

It is important to acknowledge the presence of systematic and unsystematic risk in the above profiles. Systematic risk refers to exogenous changes that affect all lessees at the same time. The recent downturn in the price of oil is a classic example. While all lessees are impacted by the downturn at the same time, they are not all impacted the same. Majors and Large Independents are less affected than Small Independents due to their greater financial strength. Unsystematic risk refers to changes affecting individual lessees that are independent of other lessees. Even in the current market, the more lessees in the lease chain of title, the less likely all will default simultaneously.

The following risk categories are used in this study for the purpose of evaluating the magnitude of the decommissioning liabilities that fall into different risk profiles in order to assess the benefit of the new bonding requirements. Note that these categories are presented from least risky to most risky.

1. **Major Included in Lease** – This category includes leases that have at least one Major in the chain of title (see Appendix C). These leases are viewed as having nearly zero risk of default since the Majors are very large with robust balance sheets and are very unlikely to default on these obligations.

2. **Large Independent Included in Lease** – This category includes leases that have no major in the chain of title, but have at least one Large Independent company (see Appendix C). These companies are large enough to be viewed as having very low risk of default although slightly above the majors.

3. **No Major or Large Independent, 5 or More Small Independents Included in Lease** – This category includes no Majors or Large Independents, but has five or more Small Independents in the chain of title. Individually, the Small Independent companies are smaller, so each has a higher possibility of defaulting than a Major or Large independent. However, because there are five or more companies in the chain of title for the lease and all would have to default simultaneously, the likelihood of default is small, but viewed as higher than for categories 1 and 2.

4. **No Major or Large Independent, 4 Small Independents Included in Lease** – Same as category 3 above, except four lessees are in the chain of title for the lease. The risk is viewed as higher than for category 3 because there are fewer lessees on the lease.

5. **No Major or Large Independent, 3 Small Independents Included in Lease** – Same as category 4 above, except three lessees are in the chain of title for the lease. The risk is viewed as higher than for category 4 because there are fewer lessees on the lease.

6. **No Major or Large Independent, 2 Small Independents Included in Lease** – Same as category 5 above, except two lessees are in the chain of title for the lease. The risk is viewed as higher than for category 5 because there are fewer lessees on the lease.

7. **No Major or Large Independent; 1 Small Independent Included in Lease** – This category includes only one lessee in the chain of title for the lease. This company is not a Major or a Large Independent. This category is viewed as having the highest risk of the seven categories because the possibility of default is tied only to one Small Independent.

To understand the distribution of lease decommissioning liabilities among these risk categories, Opportune analyzed selected lease data for all water depths from the BOEM website using the P&A

calculation. Most companies active in deep water regions of the OCS are larger due to the high capital requirements to explore and produce these areas. However, a few independents operate in depths greater than 500 ft. These companies are captured in the data for all depths.

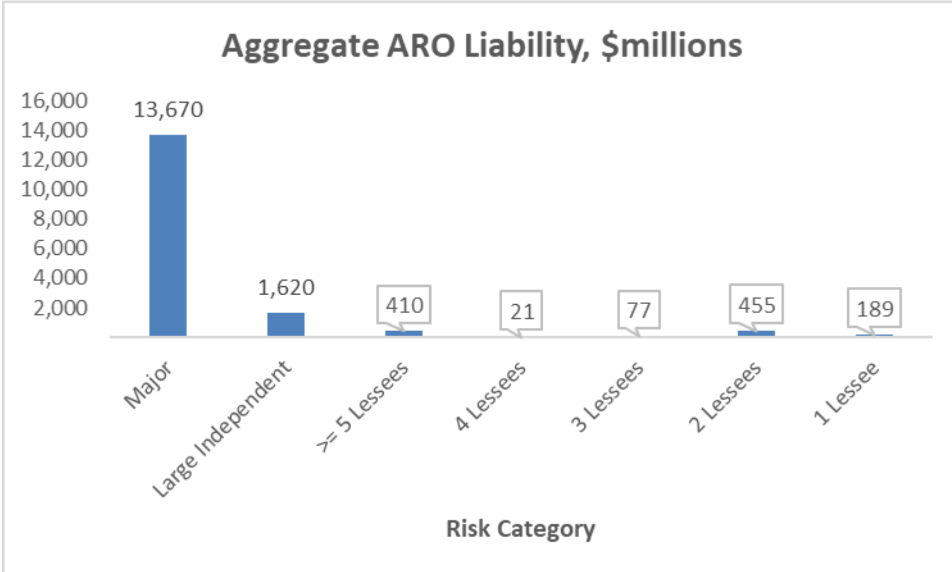
The results of Opportune's analysis of the BOEM lease data are shown in Table 1 and graphically in Figure 2. In the data, 1,706 leases have decommissioning liabilities considering all water depths with a total estimated P&A liability of over $16.4 billion. Of those leases with liabilities, 378 have no Major or Large Independent in the chain of title. These leases have a total estimated ARO liability of about $1.2 billion. The vast majority of leases, over 93 percent of the total ARO liabilities, or $15.3 billion, have a Major or a Large Independent in the chain of title and have a minimal likelihood of default. Only 7 percent of total P&A liabilities in the OCS are associated with only Small Independents.

Table 1
Summary of ARO by Risk Category – All Depths

Risk Category	Number of Leases	Total Cost	ARO	Percent of Total	Collateral	Percent of Total	Uncovered	Percent Liability Covered
Leases - Active								
Major Included	1,063	65,100	13,670	83.1%	1,571	47.9%	12,100	11.5%
Large Independent Included	265	8,391	1,620	9.9%	520	15.9%	1,100	32.1%
Small Independents								
>= 5 Lessees	184	7,560	410	2.5%	334	10.2%	77	81.3%
4 Lessees	18	280	21	0.1%	44	1.3%	-22	205.1%
3 Lessees	35	519	77	0.5%	83	2.5%	-6	107.9%
2 Lessees	63	2,152	455	2.8%	271	8.3%	183	59.7%
1 Lessee	78	843	189	1.1%	29	0.9%	160	15.5%
Subtotal Independents	**378**	**11,354**	**1,152**	**7.0%**	**761**	**23.2%**	**391**	**66.1%**
Subtotal All Leases	**1,706**	**84,845**	**16,442**	**100.0%**	**2,852**	**87.0%**	**13,590**	**17.3%**
General Allocations	-			-	425	13.0%	-	-
Total	**1,706**	**84,845**	**16,442**	**100.0%**	**3,276**	**100.0%**	**13,166**	**19.9%**

Breaking the data for Small Independents down by risk category provides further insight into the risk exposure. First, $410 million of the total $1.2 billion in ARO liabilities for Small Independents, or 36 percent, are associated with leases having five or more lessees. While somewhat risker than leases that have a Major or Large Independent, these leases still have a low likelihood of default since all of the lessees would have to default simultaneously. Second, the liability associated with the highest risk category is only $189 million or 16 percent of the total ARO liability for Small Independents and a mere 1 percent of all ARO liabilities for the OCS.

Figure 2: Breakdown of ARO by Risk Category – All Depths



Source: Opportune Analysis

In addition to the decommissioning liability data, the BOEM website provides a measure of the level of financial assurance associated with each lease under the previous bonding requirements. The website refers to this measure as "collateral." Collateral is used as measure of how much of the decommissioning liability are covered with the balance being uncovered liabilities. Collateral listed on the website total approximately $3.4 billion for all 1,706 leases with decommissioning liabilities or about 20 percent of total ARO liabilities.

Table 1 also summarizes the collateral associated with the leases by risk category. Breaking up the collateral for the leases among the various risk categories indicates that collateral requirements increase with increasing risk. For the lowest risk category, leases with at least one Major in the chain of title, collateral covers only about 11.5 percent of the total ARO liability. Coverage for Small Independents increases to about 66.1 percent on average. This level of coverage for the higher risk categories suggests that the previous bonding requirements did act to place extra security where it was needed.

The Proposed Rule will likely result in increased collateral coverage across all risk categories. While the impact on collateral will not be fully known for some time as implementation proceeds, it appears that it will provide only limited benefit to the public. For the low-risk categories, increased collateral represents an unnecessary burden since these categories are well secured through large companies in the chain of title. However, even if the new bonding requirements provide 100 percent coverage for the riskiest categories, the benefit is small because these categories do not comprise a large part of the total liability. Specifically, if the increase in collateral from the new bonding requirement provides 100 percent coverage for all Small Independents, this decreases uncovered liability by $391 million. This reduction in uncovered liabilities, then, is the measure of the benefit of the Proposed Rule to the public.

III. Determination of Costs

Achieving BOEM's goal of protecting the public from paying for decommissioning of offshore oil and gas infrastructure in the OCS using tax dollars because lessees default on their obligations comes at a significant cost to the public. This cost results from changes in the way producers will choose to operate as a result of increased bonding requirements. Using more of producer's available financial resources to protect the public reduces the funds available to them for exploration and production activities in the OCS. In turn, these reductions in spending will have a negative impact on the economic activity of the Gulf Coast states as well as in other parts of the country.

The potential impacts of the Proposed Rule are difficult to predict. Increased bonding requirements will have a negative impact on the creditworthiness of each producer. Some producers could become insolvent and be reorganized or auctioned off. Others will experience a decrease in the amount of capital each can raise for exploration and production activities. As a minimum, producers will reduce spending on activities in the OCS. Producers' reduced spending is the major driver for the purposes of analyzing the costs of the increased bonding requirements.

The decrease in spending will have direct effects on the OCS producers as well as on federal tax revenues. Reduced spending will result in decreased production and less development of OCS by producers. Current production may decrease from reduced spending on operating expenses, although producers will first attempt to maintain current production in the face of funding constraints. Future production will be less as a result of less investment in exploration and development. This will directly reduce producer's current and future revenue and curtail many expansion plans. Finally, the reduction in current and future production will directly impact royalty revenue to the federal government.

The decrease in spending will have indirect effects on economic activity and growth as well. These indirect effects will have the greatest impact in states along the Gulf Coast where most of the spending takes place. The rest of the country can also be expected to see some negative impact. Major indirect effects will include a decrease in economic output in the affected regions and a decrease in employment by producers and suppliers. In this analysis, Opportune looks at these effects over a 10-year time horizon.

A. Decrease in Spending

The expected decrease in operator spending is difficult to predict. Major operator spending in the deepwater Gulf is expected to remain unchanged by changes in bonding requirements; however, independent producers on the shelf are expected reduce their spending due to the loss of available capital that accompanies bonding requirement expenditures. The distribution of spending reductions will not be uniform among producers.

The magnitude of the decrease depends on a number of factors such as the availability and cost of surety bonds and the outlook for the oil and gas industry. Effects of the new bonding requirement are assumed to be independent of other regulations coming into effect, such as the recent Well Control Regulation, which affect OCS producers.

Economic Impact Model

We developed an economic model to determine the impact of bonding requirements on development activity in the Gulf, and the related impact on the regional economies of the bordering coastal states. Our model is driven by the following high-level assumptions:

1. The premium expenses associated with the increased bonding requirements will be $257 million per year, based on the BOEM estimates for small companies. The requirements are phased in uniformly over the first three years.

2. Bonding requirements have no direct impact on existing production rates.
3. Funds spent on bonding requirements are funds that would otherwise be invested in Gulf of Mexico exploration and development activities.
4. The positive cash flows resulting from these exploration and development activities would likewise be re-invested in additional exploration and development activities in the Gulf of Mexico.
5. The resulting cash flows (revenues and costs) can be modelled using broad assumptions of finding and development costs, future commodity prices, operating costs, and average royalty rates, combined with an assumed production rate behavior of the developed hydrocarbon resources.
6. The production rate behavior of the future-developed resources can be modeled using a four-segment decline curve that describes the typical water drive nature of the reservoirs.
7. Capital and operating costs associated with these development activities would be spent in the Gulf Coast region
8. The economic impact of these expenditures can be estimated using the RIMS II multipliers from the United States Bureau of Economic Analysis.

Economic Impact Model Assumptions

Our base case economic assumptions are shown below. A key assumption is the finding and development (F&D) cost. From this value, we determine the amount of resources developed and placed on production for each $1 million spent. In the section that follows are the parameters that describe the four-segment production curve.

Exploration & Development Assumptions

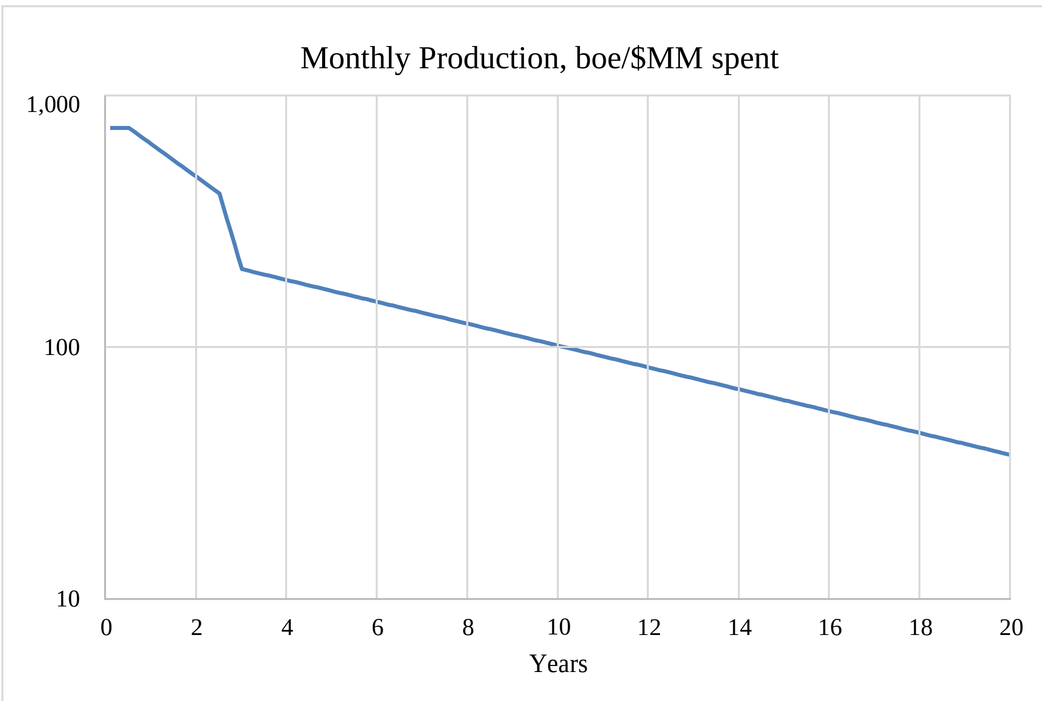
Finding and Development Cost, $/boe	25.00
EUR/$MM spent, boe	40,000
Initial production rate, boe/mo	750
Flat rate period, years	0.5
Initial period duration, years	2.0
Initial period decline rate, %pa	30%
Water breakthrough period duration, years	0.5
Water breakthrough period final rate, fraction	50%
Post-breakthrough decline rate, %	10%
Final production rate, fraction of initial	5%
Royalty rate, %	17%
Revenue, $/boe (net)	61.00
Opex, $/boe (gross)	20.00
Reinvestment rate, %	100%

Our model relies on several assumptions that are difficult to validate. Nevertheless, we think our straightforward approach should provide a reasonable estimate of the magnitude of economic impact.

In the case shown above, we have assumed an average finding and development cost of $25/barrel of oil equivalent (boe). Therefore, each $1 million of exploration and development spending would place 40,000 boe on production.

This production would be recovered according the production decline assumptions. In our model, there are four segments to the production rate behavior: 1) a flat period of no decline, 2) an initial decline period of gradual decline, 3) a water breakthrough period during which hydrocarbon production rapidly declines, and 4) a post-breakthrough period of gradual decline to the economic limit. We express the economic limit as a percentage of the initial rate. By providing the parameters that describe these four segments, we can calculate the initial production rate required to produce the developed reserves.

Using the assumptions above, the following monthly production function is generated per $1 million spent. This production is scaled up by the amount of exploration and development assumed to occur.



In our model, the positive free cash flow generated from these investments is re-invested in similar projects. We assume that positive free cash flow from one year, whether from reductions in bonding requirements or newly developed production, is spent evenly across the following year.

Annual Cash Flows	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Reduced bonding expenses, $MM	85.7	171.3	257.0	257.0	257.0	257.0	257.0	257.0	257.0	257.0
Incremental Investment, $MM	85.7	171.3	269.6	302.0	350.7	400.5	445.3	489.4	535.4	582.3
Gross production, mmboe		0.4	1.5	3.1	4.7	6.1	7.6	9.1	10.6	12.2
Royalty, mmboe		0.1	0.2	0.5	0.8	1.0	1.3	1.5	1.8	2.1
Net production, mmboe		0.3	1.2	2.5	3.9	5.1	6.3	7.5	8.8	10.1
Revenue, $MM		20.8	74.4	154.9	237.2	311.3	384.1	460.1	537.8	617.1
Opex, $MM		8.2	29.4	61.2	93.7	123.0	151.7	181.8	212.4	243.8
Net cash flow		12.6	45.0	93.7	143.5	188.3	232.4	278.4	325.3	373.3

Our model generates a forecast of incremental capital investment and operating expense expenditures over the ten-year forecast period. We use the sum of these expenditures to estimate their impact on the economies of the states that border the Gulf (Texas, Louisiana, Mississippi, Alabama, and Florida) using the RIMS II multipliers. The multipliers we used were retrieved from the Bureau of Economic Analysis website in June 2023 and are applied over the entire region rather than state-by-state.

In the RIMS II system, there are several types of multipliers that are used to estimate various economic impacts on the region resulting from increased expenditure. "Final Demand Change" is the term that defines the amount of incremental spending in the region. In our model, this is the sum of the capital invest and operating expense expenditures resulting from the change in exploration and development activity.

1. **Final Demand Output** – The output multipliers represent the total change in local sales per dollar of final demand change.

2. **Final Demand Earnings** – The earnings multipliers measure the total change in local household earnings per dollar of final demand change. Earnings consist of wages and salaries and of proprietors' income, which is the net earnings of sole-proprietors and partnerships. Employer contributions for health insurance are also included.

3. **Final Demand Employment** – The employment multipliers measure the total change in the number of local jobs per million dollars of final demand change. Employment consists of full- and part-time jobs.

4. **Final Demand Value Added** – The value-added multipliers measure the total change in local value added per dollar of final demand change. Value added is comparable to regional measures of GDP.

Using our assumptions and the RIMS II multipliers, **we estimate a final demand change of $9.9 billion** if the increased bonding premiums estimated by BOEM for small companies in the GOM OCS were instead spent on exploration and development activities. The table below shows the estimated economic impact of this level of final demand change.

Metric	Multiplier	Impact
Final demand output	2.0945	$9,922 million
Final demand earnings	0.5908	$2,799 million
Final demand employment	7.6391	36,189 jobs
Final demand value added	1.2310	$5,832 million

IV. CONCLUSION - COMPARISON OF BENEFITS AND COSTS

The results of this cost-benefit analysis indicate the reduction in the risk that taxpayers will have to pay for decommission costs provided by Additional Bonding Requirements is not justified given the impact on Industry and the regional/national economy. The benefits of Additional Bonding Requirements are relatively small, and the cost is very high in terms of the decreased development of OCS resources and associated losses in production, Industry revenue, taxes, economic activity, and jobs.

BOEM's approach is a very inefficient way to protect the taxpayer. It looks only at the absolute magnitude of the decommissioning costs and requires additional financial guarantees to cover a greater proportion of the total liabilities. It does not fully consider the actual risk of default at the lease level. For the low-risk leases, increased collateral represents an unnecessary burden since these categories are well secured through large companies in the chain of title. For risker leases, it does provide incremental protection. However, the incremental benefit is small, estimated in this analysis to be about $950 million, because these risky leases do not comprise a large part of the total liability.

By comparison, the costs of BOEM's plan are very high. Using our assumptions, Industry spending is expected to be over $4.7 billion less than it otherwise would over the 10-year time horizon because of bonding requirements. Future production from the OCS is estimated to be reduced by approximately 55 million boe. Associated with this reduction are approximately $2.8 billion in reduced revenue to the Industry, plus $573 million fewer royalties to the federal government. Gulf Coast states will forego significant increases in economic activity and jobs. Reducing the bonding expenses by the amount shown would generate over $9.9 billion of growth over the next 10 years and add 36,000 jobs.

APPENDIX B– OPPORTUNE INDEPENDENT CALCULATION OF THE P&A LIABILITY

I. BACKGROUND INFORMATION

In order to assess the discounted P&A liability of the oil & gas infrastructure ("Subject Assets") located in the OCS of the Gulf of Mexico, Opportune has independently calculated the asset retirement obligation ("ARO") pertaining to the Subject Assets in accordance with Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 410-20: Asset Retirement Obligation ("ASC 410-20").

ASC 410-20

ASC 410-20 is the accounting standard for the recognition and measurement of a liability for an ARO. The ARO for companies engaged in the production and transportation of hydrocarbons in the Gulf of Mexico stems from a legal obligation to decommission the infrastructure used for such activities when no longer used. The decommissioning includes plugging and abandonment of wells, decommissioning of pipelines, removal of production platforms, and site clearance.

The mathematical calculation uses three variables: 1) estimated cost to decommission, 2) estimated time until the decommissioning occurs, 3) an inflation rate factor to arrive at an estimated future cash out flow ("FCOF"), and an estimated credit adjusted risk free rate ("CARF") to calculate the present value ("PV") of the estimated FCOF as of the date of evaluation.

We discuss herein our independent estimate of the ARO. Our analyses have been developed in accordance with ASC 410-20.

Procedures

In general, the procedures used in our analysis consisted of the following:

- Determining the population of infrastructure assets in the Gulf of Mexico;
- Analysis of BOEM's estimated decommissioning costs by asset type;
- Analysis of general market data, including economic, financial, governmental, and environmental forces;
- Determination of market-based assumptions to support the inflation rates and CARF used in the calculation;
- Estimation of the expected life of the population of assets in the Gulf of Mexico

Estimated ARO

Based on the analysis discussed in this report, we believe that the ARO as of the evaluation date ("Evaluation Date") is $16.4 billion. The Evaluation Date is March 15, 2023. The population of infrastructure assets and the decommissioning costs for this population of assets are developed from a download of BOEM data on March 15, 2023.

In arriving at our conclusions, we calculated the obligation under generally accepted accounting standards based upon an investigation of economic and market factors as of the Evaluation Date. Opportune prepared the estimate on the basis of public information, Industry knowledge, third party financial and economic information, and other information.

In addition, Opportune has not independently verified the data obtained from certain public databases and other third-party sources of information utilized in our analysis. The results and conclusions presented in this Report may be materially affected to the extent that actual information differs from that which was provided to us.

II. INDUSTRY OVERVIEW[48]

Fluctuating commodity prices and unstable energy markets have caused the oil drilling and gas extraction industry to endure an extremely high level of revenue volatility over the five years to 2022. Revenue grew at the outset of the period as the world prices of crude oil and natural gas rebounded off of decade lows fueled by booming US production. Despite hydrocarbon prices having remained far below record highs achieved in 2012 and 2013, domestic production flourished as unconventional and highly efficient drilling techniques such as hydraulic fracturing and horizontal drilling have become upstream mainstays. More oil and gas companies have deployed these recovery methods to fulfill a greater portion of aggregate demand, leading revenue to grow an annualized 8.2 percent to $463.8 billion over the five years to 2022. Revenue is expected to increase 71.8 percent and 0.5 percent in 2021 and 2022, respectively, as global oil demand improves amid the retracement of macroeconomic restrictions instilled during the COVID-19 (coronavirus) pandemic.

Industry exports have been a catalyst for industry growth over the past five years. Since the introduction of the Energy Policy Conservation Act in 1975 in wake of the Arab oil embargo, exports of crude oil and natural gas from the United States have been banned. However, the Consolidated Appropriations Act of 2016 overturned this decision, enabling domestic producers to access foreign markets with strong energy appetite. This has given US producers a new avenue to offload burgeoning production which has stemmed from greater use of unconventional drilling methods. Since industry profit is largely a function of commodity prices, profit has exhibited significant fluctuations throughout the period.

Industry revenue is projected to decline an annualized 0.3 percent to $456.8 billion over the five years to 2027 as volatile global demand subsides and prices of industry-specific resources are pressured lower. Although IBISWorld forecasts world commodity prices to fall slightly, energy prices are expected to remain highly volatile. The future of the industry is expected to hinge on improvements in drilling technology and techniques. Improving technology is likely to assist operators in meeting environmental concerns and maximizing well efficiency. As industry operators deplete reserves, it will likely become necessary to improve efficiency and minimize waste. Operators may choose to replenish reserves either through acquisitions or exploration.

Recent Performance

Over the five years from 2017 through 2022, the oil drilling and gas extraction industry's production capacity has grown tremendously, benefiting from greater technological adoption and the push toward domestic energy independence. Greater use of hydraulic fracturing (fracking) and horizontal drilling techniques have enabled industry operators to restore production to fields historically viewed as marginal and uneconomic. Booming domestic production, along with 2015 legislation overturning a ban on US exports of crude, enabled the US to become a leading global supplier of energy during the period. However, burgeoning US capacity contributed to an amassing global energy oversupply which suppressed global hydrocarbon prices for most of the current

[48] Information and, in some cases, direct excerpts in this section were based on IBISWorld Industry Report: Oil Drilling & Gas Extraction in the US, February 2022.

period. Also, the ongoing economic turndown authored by the COVID-19 (coronavirus) pandemic has caused revenue to collapse as global travel and business prohibitions aimed at combatting the health crisis have weighed tremendously on oil demand. Overall, revenue is estimated to increase an annualized 8.2 percent to $463.8 billion over the five years to 2022, including an increase of 71.8 percent and 0.5 percent in 2021 and 2022, respectively, as economic activity and oil demand is restored.

Oil and natural gas are highly globalized commodities that serve a variety of purposes. Best known for gasoline, oil provides many downstream industries with component materials that are staples of everyday life. Additionally, natural gas is the fuel of choice for a sizeable share of electricity generation in the United States. Without these commodities, many facets of the global economy would not be able to function as they currently do. Consequently, this industry is highly dependent on global energy markets. When demand is strong, the industry generally benefits, and it becomes more economical to seek new deposits. However, the current period has also served as a reminder that supply plays a critical role in the global commodity market.

In late 2015, Congress overturned the 40-year-old ban on U.S. crude oil exports due to pressure from industry operators. Advocates of free trade of crude oil expect US producers will benefit from selling products abroad, which may command premiums. The United States exported record amounts of hydrocarbons during the period, aided by greater pipeline infrastructure from the United States to and within Mexico. Greater domestic production and reduced reliance on imports has led the US to post its first-ever petroleum trade surplus in September 2019, a feat that is anticipated to continue moving forward. However, the Energy Information Administration and IBISWorld research asserts that the United States will lose its positive balance of trade in 2021 and 2022 due to short-term disruptions in global energy markets and international trade flows. Over the five years to 2022, the value of exports is estimated to increase an annualized 22.2 percent to $139.8 billion, accounting for 30.1 percent of industry revenue in 2022. Conversely, due to increasing domestic production, diminishing world oil prices, and declining energy demand amid the pandemic, the value of imports has increased at a much more subdued annualized rate of 1.0 percent to $142.3 billion during the current period. Global commodity markets are expected to remain volatile; the strength of the global economic recovery will likely dictate near-term industry trends.

Industry Outlook

Over the five years to 2027, the oil drilling and gas extraction industry is expected to rebound alongside restored output and recovering energy prices. Global economic growth is anticipated to support commodity price gains at the outset of the outlook period as renewed economic activity jump-starts demand for oil and natural gas. Natural gas is also expected to remain a hotbed for investment as operators continue to extract from hydrocarbon-rich basins in North Dakota and the Appalachians. However, energy prices are likely to fall in the event energy producers supply the market with more hydrocarbons than what is required by downstream consumers. Overall, industry revenue is forecast to decline an annualized 0.3 percent to $456.8 billion over the next five years. Nevertheless, IBISWorld expects average industry profit to improve as recently volatile energy prices are anticipated to become more expectable. Gains in revenue will likely flow through to the bottom line as companies focus on containing costs and using technology to improve exploration and production efficiencies.

Global demand for oil recovered to pre-COVID-19 (coronavirus) levels in the second half of 2022 and continues to improve. Emerging economies will likely remain pivotal as they continue to build essential infrastructure and consume greater amounts of petroleum-based products. Accordingly, demand from emerging markets is anticipated to grow at a faster rate compared with more developed nations. As global demand increases, more companies will likely serve these emerging economies, slowing expansion opportunities in the US despite overall higher demand. Over the next five years, the number of industry enterprises is projected to increase an annualized 0.2 percent to 68,676 companies.

The volatile conditions that the industry has experienced in recent years are expected to moderately subside over the five years to 2027. Early during the period, revenue is expected to expand alongside increases in energy prices and resumed production. However, as large oil-producing countries are eager to increase output, new capacity amid prolonged economic disruptions could likely subdue long-term energy price growth. In addition, more crude oil controlled by the Organization of Petroleum Exporting Countries is expected to be available during this period, which is typically of lighter and sweeter grade than most refineries seek.

After the publication of the IBIS report, however, Russia invasion of Ukraine significantly impacted global energy markets. In particular, European countries began and are continuing to shift away from Russian supplies to alternative sources of hydrocarbons. In particular, we believe this will increase the demand for US natural gas as domestic LNG export and European LNG import facilities are expanded and new ones areconstructed.

Pent-up demand will likely drive industry revenue over the next five years, and US exports are expected to continue growing as a share of revenue. Though the US Energy Information Administration expects the United States to return to being net importer of crude oil in 2021 and 2022, recovering demand from global economies is expected to lift industry exports over the next five years. IBISWorld forecasts the value of exports to increase an annualized 0.1 percent to $140.3 billion over the five years to 2022. The value of industry imports is estimated to decline an annualized 1.0 percent to $135.3 billion during the outlook period.

Natural gas production is also forecast to expand. New producing fields, especially in the Marcellus Shale region of the Appalachian Basin and the Bakken Formation in North Dakota, will likely continue fueling supply growth over the next five years. Growing production is likely to spur employment growth, which is anticipated to grow an annualized 0.7 percent to 226,544 workers over the five years to 2027. Growing demand for natural gas will likely reflect its increasing use in electricity generation. Most new and nonrenewable electricity generation capacity planned for the United States during the period will likely be produced using natural gas. New technologies are expected to enhance natural gas-fired electricity generation, making it as or more affordable than coal-fired generation, which was formerly the lowest-cost fuel. Natural gas also has an environmental advantage over coal and crude oil in that its emission of most pollutants is lower. In addition, gas-fired generation has much lower capital costs than nuclear and coal-based generation, giving it a financial advantage in the uncertain environment surrounding electricity deregulation. Higher levels of natural gas output will likely meet most of the growth in demand, but imports are also expected to play an important role. For instance, Canada is forecast to continue expanding its exports of natural gas to the United States over the next five years.

III. ASSET RETIREMENT OBLIGATION

FASB ASC Topic 410-20: *Asset Retirement Obligation* is the authoritative guidance for asset retirement obligations.

Per ASC 410-20-30-1:

"An expected present value technique will usually be the only appropriate

> technique with which to estimate the fair value of a liability for an asset retirement obligation. An entity, when using that technique, shall discount the expected cash flows using a credit-adjusted risk-free rate. Thus, the effect of an entity's credit standing is reflected in the discount rate rather than in the expected cash flows. Proper application of a discount rate adjustment technique entails analysis of at least two liabilities—the liability that exists in the marketplace and has an observable interest rate and the liability being measured. The appropriate rate of interest for the cash flows being measured shall be inferred from the observable rate of interest of some other liability, and to draw that inference the characteristics of the cash flows shall be similar to those of the liability being measured. Rarely, if ever, would there be an observable rate of interest for a liability that has cash flows similar to an asset retirement obligation being measured. In addition, an asset retirement obligation usually will have uncertainties in both timing and amount…"

The mathematical calculation under an expected present value technique uses three variables 1) estimated cost to decommission 2) estimated time until the decommissioning occurs and 3) an inflation rate factor to arrive at an estimated future cash out flow ("FCOF"). The estimated FCOF is then present valued back to a date of evaluation through an estimated credit adjusted risk free rate ("CARF") to arrive at a present value ("PV").

IV. ARO METHODOLOGY AND ASSUMPTIONS

ARO Methodology

Estimated Abandonment Costs

In conducting our analysis, we relied on BOEM's estimated abandonment costs. These costs are detailed on BOEM's website for the respective leases in the Gulf of Mexico. BOEM's data provide current cost estimates for the pipeline removal, platform removal, well bore plugging, and site clearance by lease for all federal leases in the Gulf of Mexico. The BOEM cost estimates are shown as a distribution (P50, P70, P90) based on actual expenditure data reported by OCS operators. We totaled the P70 estimate and the deterministic estimate by lease to arrive at an estimate of total decommissioning costs for the Gulf of Mexico of approximately $84.8 billion. We also totaled the P50 estimate and the deterministic estimate to arrive at our ARO estimate of approximately $16.4 billion.

Estimated Remaining Field Life

Estimating the remaining economic life of the producing wells and related facilities is a challenging problem, particularly under conditions of very limited technical data. In many hydrocarbon reservoirs around the world, the primary recovery mechanism is depletion drive, and the future production performance of the wells producing from such reservoirs can be forecast using decline curve analysis. Such production forecasts can then be extrapolated to an "economic limit" to determine the remaining life.

Most offshore reservoirs produce under water drive conditions, however, and decline curve analysis is of limited utility. This is especially true in cases where the geologic structure results in rapid "watering-out" of the producers. Also, many offshore fields have multiple pay zones that are produced sequentially. Those "behind pipe" zones will extend the life of the field, but their future performance is not revealed in the historical performance of the actively producing zones. Predicting their performance requires detailed geologic and petrophysical data that was not available to us. Moreover, conducting such evaluations is prohibitively time-consuming for a study of this nature.

For the purpose of this study, we relied on the operators' estimate of each field's total recoverable reserves (including the cumulative production) that they disclose to BOEM on an annual basis. We combined this data with the reported cumulative production over time to calculate a time-series of the percent of recoverable reserves remaining to be produced. We observed that these series for each field often followed a decline trend that could be reasonably extrapolated on a semi-log graph. In most cases, we extrapolated these values to the point where 1% of the estimated recoverable reserves would remain, but in some cases (for instance, where they were already less than 1%) we extrapolated them to a lower value.

The estimated field life was matched to leases by area and block. Where a direct match could not be made the average for the area was used. Inactive fields, those awaiting decommissioning, were included with a zero life for calculation purposes which is equal to the estimated cost.

The estimated lives range from zero to fifty years with an average age of approximately 6.8 years. The actual decommissioning activities most likely will occur at a future date depending on individual circumstances and BOEM approval.

Inflation Rate

In performing our analysis, we have used an inflation rate of 2.5%. The 2.5% inflation factor was determined by the CPI growth of 2.5% over the next ten years from the June 2022 Livingston Survey.

Credit Adjusted Risk-Free Rate

In performing our analysis, we have used a CARF for each lease, as follows, based on the mix of lessees and their respective credit ratings:

- Majors only: 6.5%
- Large Independents and other lessees: 8.0%
- Small Independents only: 9.5%.

Typically, in valuing liabilities, we rely on a corporate cost of debt as the discount rate. The reason is the risk (or likelihood) the company will make “good” on the liability is comparable to the risk of the company paying debt liabilities. In our opinion this meets the requirements of a CAFR since essentially a company’s cost of debt is a risk-free borrowing rate plus a premium for the credit risk of the company.

We have analyzed the credit ratings of companies with operations in the Gulf of Mexico and split the companies into the groups (Majors, Large Independents, and Small Independents) based on their tangible asset value. We looked at each company’s S&P debt rating (when available) and the associated yields for long-term debt for the U.S. Energy Index per Bloomberg. Majors had credit ratings ranging from AA- to BBB+ with yields ranging from 4.81% to 5.72%, Large Independents had a range of credit ratings from A- to BB+ with yields ranging from 5.33% to 6.78%, and Small Independents had credit ratings ranging from BB to not rated with yields ranging from 7.67% to 8.36% (if the company’s debt was not rated we assumed the lowest quality of debt quoted in the index of B+). We then estimated the rounded average energy yield for each group to arrive at our concluded discount rates of 6.5% for Majors, 8.0% for Large Independents, and 9.5%

for Small Independents.

V. CONCLUSIONS

Based on the analysis and procedures discussed herein, we have concluded that the Asset Retirement Obligation is $16.4 billion.

Appendix C – Lessees Considered to be Majors and Large Independents

Companies Categorized as Majors

MMS Number	Business Name
00164	Aminoil Development, Incorporated
00368	Aminoil USA, Inc.
00735	Amoco Canyon Company
02244	Amoco Corporation
01679	Amoco Foundation, Inc.
00751	Amoco Pipeline Company
00114	Amoco Production Company
00635	ARCO Alaska, Inc.
00486	ARCO Pipe Line Company
00002	Atlantic Richfield Company
00967	Atlantic Richfield Company
00222	Aviara Energy Corporation
00368	BOAG Oil and Gas Company
00301	BP Alaska Exploration Inc.
00114	BP America Production Company
02367	BP Amoco Corporation
02367	BP Corporation North America Inc.
01680	BP Exploration & Oil Inc.
02481	BP Exploration & Production Inc.
00113	BP Exploration (Alaska) Inc.
00593	BP Exploration Inc.
00120	BP Exploration U.S.A., Inc.
01680	BP Oil Company
00120	BP Oil Corporation
00751	BP Pipelines (North America) Inc.
00751	BP Pipelines (North America) Inc.
00751	BP Pipelines (North America) Inc.
00751	BP Pipelines (North America) Inc.
02350	BP Prod. Corp.
02442	Burlington Resources Inc.
01904	Burlington Resources Offshore Inc.
01904	Burlington Resources Offshore Inc.
02229	Burlington Resources Oil & Gas Company
02229	Burlington Resources Oil & Gas Company LP

Companies Categorized as Majors (cont'd)

MMS Number	Business Name
00049	Burmah Oil & Gas Company
00368	Burmah Oil and Gas Company
00371	Burmah Oil Development 1974-1 Limited
00164	Burmah Oil Development, Inc.
00213	Burmah Oil Exploration, Inc.
00281	Burmah Oil Offshore Trading, Inc.
00095	Burmah Oil Western Exploration Company
00078	California Oil Company
02335	Chevron Corporation
02335	Chevron Corporation
02626	Chevron Natural Gas Pipe Line Company
00078	Chevron Oil Company
01443	Chevron Oil Company of the Netherlands
01750	Chevron PBC, Inc.
00400	Chevron Pipe Line Company
00078	Chevron U.S.A. Inc.
02544	Chevron U.S.A. LP
02335	ChevronTexaco Corporation
01866	CIECO Energy Ventures LLC
00222	Columbia Gas Development Corporation
00001	Conoco Inc.
00001	Conoco Inc.
01948	Conoco Offshore Inc.
00999	Conoco Pipe Line Company
02952	ConocoPhillips
00056	ConocoPhillips Company
01948	Continental Alaska Pipe Line Company
00001	Continental Oil Company
00999	Continental Pipe Line Company
02253	Coral Offshore Gathering, LLC
01934	Cross Timbers Oil Company
01240	Cross Timbers Oil Company, L.P.
01745	Cross Timbers Oil Company, L.P.
01240	Cross Timbers Partners
01216	Cross Timbers Production Company
01678	Domain Energy Production Corporation
01866	Domain Energy Ventures Corporation

Companies Categorized as Majors (cont'd)

MMS Number	Business Name
02253	Enbridge Offshore (Gas Gathering) L.L.C.
02117	Enterprise Oil Gulf of Mexico Inc.
01840	EPEC Offshore Gathering Company
02289	Equilon Pipeline Company LLC
02356	Exxon Asset Holdings LLC
02295	Exxon Asset Management Company
00276	Exxon Corporation
00276	Exxon Mobil Corporation
00276	Exxon Mobil Corporation
00103	Exxon Pipeline Company
01227	Exxon San Joaquin Production Company
00039	ExxonMobil Oil Corporation
00103	ExxonMobil Pipeline Company
00005	Four Star Oil & Gas Company
00005	Four Star Oil and Gas Company
00005	Getty Oil Company
01107	Getty Pipeline, Inc.
00112	Gulf Oil Corporation
00037	Humble Oil & Refining Company
00103	Humble Pipe Line Company
00222	Hunt Petroleum (AEC), Inc.
00921	Jet Oil Company
00174	Kern County Land Company
01904	Meridian Offshore Company
01904	Meridian Oil Offshore Inc.
02128	MG Gas Services Inc.
02254	Mississippi Canyon Gas Pipeline, LLC
02254	Mississippi Canyon Gas Pipeline, LLC
02215	Mobil California Exploration & Producing Asset Company
02221	Mobil Corporation
02203	MOBIL E&P U.S. DEVELOPMENT CORPORATION
02203	MOBIL E&P U.S. DEVELOPMENT CORPORATION
02209	Mobil E&P U.S. Development Fund, L.P.
00883	Mobil Eugene Island Pipeline Company
01055	Mobil Exploration and Producing North America Inc.
01933	Mobil Foundation, Inc.
00021	MOBIL NOC INC.
00039	Mobil Oil Corporation
00540	MOBIL OIL EXPLORATION & PRODUCING SOUTHEAST INC.

Companies Categorized as Majors (cont'd)

MMS Number	Business Name
00565	Mobil Producing Texas & New Mexico Inc.
00565	Mobil-GC Corporation
00637	Mobil-TransOcean Company
02418	Mobile Mineral Corporation
00021	Newmont Oil Company
00114	Pan American Petroleum Corp.
01750	Pennzoil Exploration and Production Company
01750	Pennzoil Petroleum Company
00788	Phillips Oil Company
00056	Phillips Petroleum Company
01866	Range Energy Ventures Corporation
00092	Richfield Oil Corporation
00025	Seaboard Oil Company
00728	Shell California Production Inc.
01940	Shell Consolidated Energy Resources Inc.
02139	Shell Deepwater Development Inc.
02140	Shell Deepwater Production Inc.
00688	Shell Energy Resources Inc.
01728	Shell Frontier Oil & Gas Inc.
02168	Shell Gas Gathering Company
02253	Shell Gas Gathering Company, L.L.C.
02253	Shell Gas Gathering, LLC
01070	Shell Gas Pipeline Company
02254	Shell Gas Pipeline Company, L.L.C.
02621	Shell GOM Pipeline Company LLC
02117	Shell Gulf of Mexico Inc.
02117	Shell Gulf of Mexico Inc.
01967	Shell Land & Energy Company
00689	Shell Offshore Inc.
02128	Shell Offshore Properties and Capital II, Inc.
01839	Shell Oil & Gas Investment Limited Partnership
00117	Shell Oil Company
01845	Shell Onshore Ventures Inc.
00124	Shell Pipe Line Corporation
02289	Shell Pipeline Company LP
02289	Shell Pipeline Company LP
02147	Shell Seahorse Company
00832	Shell Western E&P Inc.

Companies Categorized as Majors (cont'd)

MMS Number	Business Name
00049	Signal Oil and Gas Company
00044	Skelly Oil Company
00039	Socony Mobil Oil Co.
00113	Sohio Alaska Petroleum Company
00113	Sohio Natural Resources
00593	Sohio Petroleum Company
00113	Sohio Petroleum Company
00164	Southdown Burmah Oil Company
00113	Standard Alaska Production Company
00393	Standard Oil Company of California
00114	Stanolind Oil and Gas Company
00832	SWEPI LP
01866	Tammany Energy Ventures LLC
01866	Tammany Energy Ventures LLC
01866	Tammany Energy Ventures LLC
01866	Tammany Energy Ventures LLC
02253	Tejas Offshore Gathering, L.L.C.
00079	Tenneco Corporation
00121	Tenneco Exploration Company
00337	Tenneco Exploration II, Ltd.
00275	Tenneco Exploration, Ltd.
01840	Tenneco Gas Gathering Company
01678	Tenneco Gas Production Corporation
00014	Tenneco Inc.
00498	Tenneco OCS Company, Inc.
00500	Tenneco OCS Limited Partnership
00468	Tenneco Offshore Company, Inc.
01840	Tenneco Offshore Gathering Company
00081	Tenneco Oil Company
01866	TENNECO VENTURES CORPORATION
00174	Tenneco West, Inc.
00014	Tennessee Gas Pipeline Company
00014	Tennessee Gas Pipeline Company
00080	Tennessee Gas Supply Co.
00014	Tennessee Gas Transmission Company
02142	Texaco California Inc.
00771	Texaco Exploration and Production Inc.

Companies Categorized as Majors (cont'd)

MMS Number	Business Name
02758	Texaco Harvest LLC
00857	Texaco Oils Inc.
01107	Texaco Pipeline Inc.
00771	Texaco Producing Inc.
00025	Texaco Seaboard Inc.
02020	Texaco Trading and Transportation, Inc.
00002	The Atlantic Refining Company
00043	The Burmah Oil Western Company
02220	The Standard Oil Company
00111	The Standard Oil Company (Ohio)
00040	The Texas Company
00003	Union Oil Company of California
00003	Union Oil Company of California
00003	Union Oil Company of California
01550	Unocal Exploration Corporation
01113	Unocal Pipeline Company
01934	XTO Energy Inc.
00222	XTO Offshore Inc.
02079	Nexen Petroleum Offshore U.S.A. Inc.
00011	Transcontinental Gas Pipe Line Company, LLC
02227	Enterprise Field Services, LLC
01207	Petrobras America Inc.
01796	Manta Ray Gathering Company, L.L.C.
00207	Sea Robin Pipeline Company, LLC
02546	Trunkline Field Services LLC
00030	Trunkline Gas Company, LLC

Companies Categorized as Large Independents (cont'd)

MMS Number	Business Name
02516	Agip Oil US L.L.C.
00162	Agip Petroleum Co., Inc.
02248	Agip Petroleum Exploration Co. Inc.
01221	Amax Oil & Gas Inc.
00059	Amerada Hess Corporation
00059	Amerada Petroleum Corporation
00320	American Petrofina Company of Texas
00148	Anadarko E&P Company LP
00981	Anadarko Petroleum Corporation
00170	Anadarko Production Company
02219	Anadarko US Offshore Corporation
02219	Anadarko US Offshore Corporation
02219	Anadarko US Offshore LLC
02219	Anadarko US Offshore LLC
02534	Apache Clearwater Operations, Inc.
00105	Apache Corporation
03165	Apache Deepwater LLC
01762	Apache Gathering Company
02820	Apache GOM Pipeline, Inc.
02767	Apache Offshore Holdings, LLC
00904	Apache Oil & Gas Transmission, Inc.
00106	Apache Oil Corporation
03296	Apache Shelf Exploration LLC
02851	Apache Shelf, Inc.
02851	Apache Shelf, Inc.
02851	Apache Shelf, Inc.
00128	Aquitaine Oil Corporation
01247	Aran Energy Corporation
00320	ATOFINA Petrochemicals, Inc.
02525	Belco Oil & Gas Corp.
00362	BHP Billiton Petroleum (Americas) Inc.
02277	BHP Billiton Petroleum (Deepwater) Inc.
02010	BHP Billiton Petroleum (GOM) Inc.
02552	BHP Holdings (Resources) Inc.
02245	BHP Minerals International Inc.
00362	BHP Petroleum (Americas) Inc.
02277	BHP Petroleum (Deepwater) Inc.
02010	BHP Petroleum (GOM) Inc.
00768	BHP Petroleum Company Inc.

Companies Categorized as Large Independents (cont'd)

MMS Number	Business Name
02426	BHP Resources Inc.
01831	Bogert Oil Company
02361	British-Borneo Deepwater LLC
00075	Cabot Carbon Co.
00046	Cabot Carbon Company
00075	Cabot Corporation
01372	Cabot Exploration Corporation
01355	Cabot Oil & Gas Corporation
01241	Cabot Oil & Gas Production Corporation
00685	Cabot Petroleum Corporation
00148	Champlin Petroleum Company
02716	Cimarex Energy Co.
00777	Cities Service Oil and Gas Corporation
00362	Clinton Oil Company
00282	CNG Producing Company
00886	CNG Transmission Corporation
00159	Coastal States Gas Producing Co.
00886	Consolidated Gas Transmission Corporation
00748	DelMar Operating, Inc.
00769	DelMar Operating, Inc. (P. M.)
01525	DelMar/JHM 1989 Exploration Limited Partnership
00919	DelMar/MM 1982 Exploration Limited Partnership
01016	DelMar/MM 1985 Exploration Limited Partnership
01526	DelMar/MM 1989 Exploration Limited Partnership
01527	DelMar/NEW 1989 Exploration Limited Partnership
01528	DelMar/NFC 1989 Exploration Limited Partnership
00918	DelMar/PM 1984 Exploration Limited Partnership
00441	Devon Corporation
02410	Devon Energy Corporation
02410	Devon Energy Corporation
01010	Devon Energy Corporation
01010	Devon Energy Corporation (Nevada)
02638	Devon Energy Operating Company, L.P.
01901	Devon Energy Operating Corporation
01853	Devon Energy Petroleum Pipeline Company
02421	Devon Energy Production Company, L.P.
02421	Devon Energy Production Company, L.P.

Companies Categorized as Large Independents (cont'd)

MMS Number	Business Name
01777	Devon Louisiana Corporation
01551	Devon SFS Operating, Inc.
00282	Dominion Exploration & Production, Inc.
02576	Dominion Oklahoma Texas Exploration & Production, Inc.
02576	Dominion Oklahoma Texas Exploration & Production, Inc.
02044	Dominion Reserves Gulf Coast, Inc.
02023	Dominion Reserves, Inc.
00886	Dominion Transmission, Inc.
15049	Dominion Wind Development, LLC
01015	Elf Aquitaine Exploration, Inc. (M. M.)
00769	Elf Aquitaine Exploration, Inc. (P. M.)
01141	Elf Aquitaine Oil Programs, Inc.
00748	Elf Aquitaine Operating, Inc.
00128	Elf Aquitaine, Inc.
01525	Elf Aquitaine/JHM 1989 Exploration Limited Partnership
00919	Elf Aquitaine/MM 1982 Exploration Limited Partnership
01016	Elf Aquitaine/MM 1985 Exploration Limited Partnership
01526	Elf Aquitaine/MM 1989 Exploration Limited Partnership
01527	Elf Aquitaine/NEW 1989 Exploration Limited Partnership
01528	Elf Aquitaine/NFC 1989 Exploration Limited Partnership
00918	Elf Aquitaine/PM 1984 Exploration Limited Partnership
01500	Elf Exploration, Inc.
00898	Energen Resources MAQ, Inc.
00362	Energy Reserves Group, Inc.
02361	Eni Deepwater LLC
02516	Eni Oil US LLC
00162	Eni Petroleum Co. Inc.
00162	Eni Petroleum Co. Inc.
02248	Eni Petroleum Exploration Co. Inc.
02361	Eni Petroleum US LLC
02920	Eni Petroleum US LLC
02361	Eni Petroleum US LLC
02782	Eni US Operating Co. Inc.
02782	Eni US Operating Co. Inc.
01103	Enron Oil & Gas Company
02414	EOG Resources Omega LLC
01103	EOG Resources, Inc.

Companies Categorized as Large Independents (cont'd)

MMS Number	MMS Number
02401	Equitable Production (Gulf) Company
02483	Fina E&P, Inc.
00964	Fina Exploration, Inc.
00910	Fina Oil & Gas, Inc.
00320	Fina Oil and Chemical Company
00481	Finadel, Incorporated
01777	Flores & Rucks, Inc.
02077	Flores & Rucks, Inc.
02851	Forest Energy Resources, Inc.
01688	Freeport Interstate Pipeline Company
00012	Freeport Minerals Company
00428	Freeport Oil Company
00469	Freeport Oil Company
00428	Freeport Petroleum Company
00374	Freeport Pipeline Company
00012	Freeport Sulphur Company
02225	Freeport Sulphur Company
01583	Freeport-McMoRan Acquisition Company
03303	Freeport-McMoRan Copper & Gold Inc.
02313	Freeport-McMoRan Energy LLC
03263	Freeport-McMoRan Exploration & Production LLC
03263	Freeport-McMoRan Exploration & Production LLC
01597	Freeport-McMoRan Inc.
01531	Freeport-McMoRan Oil & Gas Company
01583	Freeport-McMoRan Oil & Gas Company
03280	Freeport-McMoRan Oil & Gas LLC
03280	Freeport-McMoRan Oil & Gas LLC
03280	Freeport-McMoRan Oil & Gas LLC
01082	Freeport-McMoRan Resource Partners, Limited Partnership
02225	Freeport-McMoRan Sulphur Inc.
02313	Freeport-McMoRan Sulphur LLC
02820	FW GOM Pipeline, Inc.
02820	FW GOM Pipeline, Inc.
02250	GEL Offshore Pipeline, LLC
02250	GEL Offshore Pipeline, LLC
01570	Greenhill Petroleum Corporation
00819	Halliburton Company

Companies Categorized as Large Independents (cont'd)

MMS Number	MMS Number
00819	Halliburton Energy Services, Inc.
00818	Hardy Oil & Gas USA Inc.
03356	Hess Conger LLC
00059	Hess Corporation
00059	Hess Corporation
03359	Hess GOM Deepwater LLC
03360	Hess GOM Exploration LLC
03366	Hess Llano LLC
03365	Hess Shenzi LLC
03355	HESS STAMPEDE LLC
03358	HESS TUBULAR BELLS LLC
00919	Huffco 1982 Exploration Limited Partnership
00918	Huffco 1984 Exploration Limited Partnership
01015	Huffco Gas and Oil, Inc.
01141	Huffco Oil Programs, Inc.
00748	Huffco Petroleum Corporation
01016	Huffco/MM 1985 Exploration Limited Partnership
00769	Huffington Exploration Corporation
02169	Hydro Gulf of Mexico, L.L.C.
03280	IMONC LLC
03160	Kerr-McGee (Nevada) LLC
00035	Kerr-McGee Corporation
00707	Kerr-McGee Federal Limited Partnership I-1981
02859	Kerr-McGee Oil & Gas (Shelf) LLC
02219	Kerr-McGee Oil & Gas Corporation
00035	Kerr-McGee Oil Industries, Inc.
00647	KERR-McGEE PIPELINE CORP.
01831	Louis Dreyfus Natural Gas Corp.
01674	Louis Dreyfus Reserves Corp.
02249	Marathon Ashland Pipe Line LLC
02086	Marathon Energy Corporation
02250	Marathon Offshore Pipeline LLC
00724	Marathon Oil Company
00115	Marathon Oil Company
03123	Marathon Oil Corporation
00115	Marathon Petroleum Company
00310	Marathon Pipe Line Company

Companies Categorized as Large Independents (cont'd)

MMS Number	Company Name
02250	Marathon Pipe Line LLC
02249	Marathon Pipe Line LLC
02851	Mariner Energy Resources, Inc.
02851	Mariner Energy Resources, Inc.
00818	Mariner Energy, Inc.
02169	Mariner Gulf of Mexico LLC
00270	McMoRan Exploration Co.
00270	McMoRan EXPLORATION CO.
02320	McMoRan Exploration Co.
00212	McMoRan Exploration Company
02320	McMoRan Exploration LLC
00648	McMoRan Offshore Exploration Co.
00477	McMoRan OFFSHORE EXPLORATION CO.
00428	McMoRan Offshore Exploration Co.
03178	McMoRan Offshore LLC
03179	McMoRan Offshore LLC
03178	McMoRan Offshore LLC
00477	McMoRan Offshore Production Co.
01888	McMoRan Oil & Gas Co.
00961	McMoRan Oil & Gas Co.
00428	McMoRan Oil & Gas Co.
02312	McMoRan Oil & Gas LLC
00634	McMoRan Pipeline Company
00469	McMoRan-Freeport Oil Company
00428	McMoRan-Freeport Petroleum Company
02055	MESA Inc.
01025	Mesa Limited Partnership
00257	Mesa Offshore Co.
00753	Mesa Offshore Management Co.
01935	Mesa Operating Co.
01026	Mesa Operating Limited Partnership
00233	Mesa Petroleum Co.
01935	Mesa Sub 1, Inc.
02062	MidPar L.P.
00898	Minatome Corporation
00768	Monsanto Oil Company
02237	Noble Affiliates, Inc.

Companies Categorized as Large Independents (cont'd)

MMS Number	Company Name
02425	Noble Drilling Exploration Company
02237	Noble Energy, Inc.
02237	Noble Energy, Inc.
02528	Norsk Hydro USA Oil & Gas, Inc.
15013	Occidental Development & Equities, LLC
01061	Occidental of Alaska, Inc.
01045	Occidental of California, Inc.
00157	Occidental Petroleum Corporation
01777	Ocean Energy, Inc.
02575	Ocean Energy, Inc.
02077	Ocean Energy, Inc.
02242	Ocean Energy, Inc.
02859	Offshore Shelf LLC
00325	Oil Development Company of Texas
02848	OXY Deepwater USA, Inc.
00346	Oxy Petroleum, Inc.
00777	OXY USA Inc.
01912	Parker & Parsley Acquisition Company
02062	Parker & Parsley Development L.P.
01375	Parker & Parsley Petroleum Company
02001	Parker & Parsley Producing L.P.
00167	PennzEnergy Company
02332	PennzEnergy Exploration and Production, L.L.C.
00167	Pennzoil Company
01853	Pennzoil Petroleum Pipeline Company
00167	Pennzoil United, Inc.
00481	Petrofina Delaware, Incorporated
00907	Petrofina Exploration, Inc.
01247	Petrolex USA, Inc.
02279	PG&E Texas Pipeline, L.P.
01570	Pioneer Natural Resources (GPC) Inc.
02223	Pioneer Natural Resources Company
01935	Pioneer Natural Resources USA, Inc.
02681	Pioneer Natural Resources Alaska, Inc.
02847	Pioneer Shelf Properties Incorporated
02702	Plains Exploration & Production Company
03199	Plains Offshore Inc.
03200	Plains Offshore Operations Inc.

Companies Categorized as Large Independents (cont'd)

MMS Number	Company Name
01671	Plains Petroleum Operating Company
02885	Plains Pipeline, L.P.
01220	Plains Resources Inc.
03017	Pogo Producing Company LLC
02882	PXP Deepwater L.L.C.
02701	PXP Gulf Coast Inc.
03263	PXP Offshore LLC
03178	PXP Offshore LLC
03017	PXP Producing Company LLC
03192	PXP Resources Inc.
03192	PXP Resources LLC
02805	Repsol E&P USA Inc.
02805	Repsol E&P USA Inc.
02936	Repsol Offshore E&P USA Inc.
02936	Repsol Offshore E&P USA Inc.
00148	RME Petroleum Company
00325	Santa Fe Energy Company
01035	Santa Fe Energy Operating Partners, L.P.
01551	Santa Fe Energy Resources, Inc.
00977	Santa Fe International Company
00977	Santa Fe International Corporation
00784	Santa Fe International Corporation
00407	Santa Fe Minerals Co.- U.S.
00877	Santa Fe Minerals, Inc.
00407	Santa Fe Minerals, Inc.
01815	Santa Fe Minerals, Inc.
01551	Santa Fe Snyder Corporation
00899	Santa Fe-Andover Oil Company
00672	Seagull Energy Corporation
02242	Seagull Energy Corporation
00672	Seagull Energy E&P Inc.
01956	Seagull Energy E&P Inc.
00932	Seagull Interstate Corporation
01712	Seagull Natural Gas Company
01790	Snyder Oil Corporation
01117	Snyder Oil Partners L.P.
01118	Snyder Operating Partnership L.P.
00748	SOCO Offshore, Inc.

Companies Categorized as Large Independents (cont'd)

MMS Number	Company Name
02169	Spinnaker Exploration Company, L.L.C.
01247	Statoil Exploration (US) Inc.
02114	Statoil Exploration (US) Inc.
02748	Statoil Gulf of Mexico LLC
02748	Statoil Gulf of Mexico LLC
03019	Statoil Gulf Properties Inc.
15033	Statoil North America, Inc.
02528	Statoil USA E&P Inc.
03019	StatoilHydro Gulf Properties Inc.
02528	StatoilHydro USA E&P, Inc.
03285	Talisman GOM L.P.
01606	TEPCO Offshore, Inc.
00235	Texas Eastern Exploration Co.
00876	Texas Eastern Hydrocarbon Company
00875	Texas Eastern Petroleum Company
00176	Texas Eastern Transmission Corporation
00176	Texas Eastern Transmission, LP
00115	The Ohio Oil Company
01241	Thermal Exploration, Inc.
00313	Total American, Inc.
01500	TOTAL E&P USA, INC.
02280	TOTAL Exploration Production USA, Inc.
02754	TOTAL Holdings USA, Inc.
00312	Total Leonard, Inc.
00898	TOTAL MINATOME CORPORATION
00898	TOTAL Minatome Corporation
00312	Total Petroleum, Inc.
01500	TotalFinaElf E&P USA, Inc.
00818	Trafalgar House Oil and Gas Inc.
01221	Union Pacific Oil and Gas Company
00148	Union Pacific Resources Company
02239	Union Pacific Resources Group Inc.
00724	USS Holdings Company
00159	Valero Energy Corporation
00710	Valero Producing Company
02279	Valero Transmission, L.P.
01241	Washington Energy Exploration, Inc.
02148	Westport Oil and Gas Company, Inc.

Companies Categorized as Large Independents (cont'd)

MMS Number	Company Name
02148	Westport Oil and Gas Company, L.P.
02401	Westport Resources Corporation
02525	Westport Resources Corporation
03165	ZMZ Acquisitions LLC

APPENDIX D– TERMS AND CONDITIONS

The general terms and conditions pertaining to the value conclusion(s) stated in this Report are summarized below. If applicable, "special assumptions" are cited elsewhere in this Report.

1. To the best of our knowledge and belief, the statements of facts contained in this Report, upon which the analysis and conclusion(s) expressed are based, are true and correct. Information, estimates and opinions furnished to us and contained in the Report or utilized in the formation of the value conclusion(s) were obtained from sources considered reliable and believed to be true and correct. However, no representation, liability or warranty for the accuracy of such items is assumed by or imposed on us, and is subject to corrections, errors, omissions and withdrawal without notice.
2. The legal description of the appraised business, if exhibited in the Report, is assumed correct.
3. This valuation may not be used in conjunction with any other appraisal or study. The value conclusion(s) stated in this appraisal is based on the program of utilization described in the Report, and may not be separated into parts. The appraisal was prepared solely for the purpose, function and party so identified in the Report. Unless specifically stated, the appraisal Report may not be reproduced, in whole or in part, and the findings of the Report may not be utilized by a third party for any purpose, without the express written consent of Opportune LLP.
4. No change of any item in any of the appraisal Report shall be made by anyone other than Opportune and we shall have no responsibility for any such unauthorized change.
5. We are not required to give testimony or be in attendance at any court or administrative proceeding with reference to the property appraised unless additional compensation is agreed to and prior arrangements have been made.
6. The working papers for this engagement are being retained in our files and are available for your reference. We would be available to support our valuation conclusion(s) should this be required. Those services would be performed for an additional fee.
7. Neither all nor any part of the contents of this Report shall be disseminated or referred to the public through advertising, public relations, news or sales media, or any other public means of communication or referenced in any publication, including any private or public offerings including but not limited to those filed with Securities and Exchange Commission or other governmental agency, without the prior written consent and approval of and review by Opportune.
8. Good and marketable title to the Company is assumed. We are not qualified to render an "opinion of title," and no responsibility is assumed or accepted for matters of a legal nature affecting the Company. No formal investigation of legal title was made, and we render no opinion as to ownership of Subsidiaries or condition of their title.
9. Management is assumed to be competent, and the ownership to be in responsible hands. The quality of Management can have a direct effect on a business's economic viability and value. The financial projections contained in the appraisal assume both responsible ownership and competent Management. Any variance from this assumption could have a significant impact on the final value estimate.
10. We take no responsibility for any events, conditions or circumstances affecting the subject asset(s) or its value, that take place subsequent to either the effective date of value cited in the appraisal or the date of our field inspection, whichever occurs first.
11. This valuation is based on historical and prospective financial statements. Some assumptions or projections inevitably will not materialize and unanticipated events and circumstances may occur during the forecast period. These could include major changes in the economic environs;

significant increases or decreases in current interest rates and/or terms or availability of financing altogether; property assessment; and/or major revisions in current tax or regulatory laws. Therefore, the actual results achieved during the projected holding period and investor requirements relative to anticipated annual returns and overall yields could vary from the projection. Thus, variations could be material and have an impact on the value conclusion(s) stated herein.

12. Budgets/projections/forecasts relate to future events and are based on assumptions that may not remain valid for the whole of the relevant period. Consequently, this information cannot be relied upon to the same extent as that derived from audited accounts for completed accounting periods. We express no opinion as to how closely the actual results will correspond to those projected/forecast by Management.
13. While our work has involved an analysis of financial information and accounting records, our engagement does not include an audit in accordance with generally accepted auditing standards of the Company existing business records. Accordingly, we assume no responsibility and make no representations with respect to the accuracy or completeness of any information provided by and on behalf of the Company.
14. Our procedures did not constitute an attest service as that term is defined by the American Institute of Certified Public Accountants. Accordingly, we will be unable to express an opinion on any of the financial or other data that will be contained in our summary schedule(s) or other correspondence, nor will we make any representation as to the adequacy of our procedures for your purpose.
15. Our work with respect to prospective financial information did not constitute an examination, compilation, or agreed-upon procedures engagement of a financial forecast in accordance with standards established by the American Institute of Certified Public Accountants, and we do not express assurance of any kind on it.
16. The valuation conclusion(s) stated in this Report applies only to the effective date stated in the Report. Value is affected by many related and unrelated economic conditions within a local, regional, national and/or worldwide context, which might necessarily affect the prospective value of the subject assets or Company. We assume no liability for an unforeseen change in the economy, or at the subject property, if applicable.
17. The valuation of businesses is not a precise science and the conclusions arrived at in many cases will of necessity be subjective and dependent on the exercise of individual judgment. There is therefore no indisputable single value and we normally express our estimate of value as falling within a likely range. Whilst we consider our values to be both reasonable and defensible based on the information available to us, others may place a different value on the Company.
18. Any decision to buy or sell the Company and the structure to be utilized shall be the sole responsibility of the Board of Directors of the Company.
19. The conclusion(s) presented in this Report do not constitute a Solvency Opinion or a Fairness Opinion and should not be relied upon as such. Furthermore, the analysis we perform should not be taken to supplant any procedures that you should undertake in your consideration of the transaction.
20. The sale or purchase of assets in an actual business combination may require consideration of factors beyond the information we will provide. An actual transaction involving the Company might be concluded at a higher value or at a lower value than the conclusion(s) presented in this Report, depending upon the circumstances of the transaction and the business, and the knowledge and motivations of the parties at the time.

APPENDIX E – VALUATION CERTIFICATION

We certify that, to the best of our knowledge and belief:

- The statements of fact contained in this Report are true and correct.
- We have no present or prospective interest in the business or property that is the subject of this Report, and we have no personal interest or bias with respect to the parties involved.
- Our compensation is not contingent upon the reporting of a predetermined value or direction in value that favors the cause of the client, the amount of the value estimate, the attainment of a stipulated result, or the occurrence of a subsequent event.
- The engagement was not based on a requested minimum valuation, a specific valuation, or the approval of a loan.
- The analyses and conclusions are limited only by the reported assumptions and limiting conditions and represents our unbiased professional analyses and conclusions.
- This analysis and Report were prepared under the direction of Josh Sherman, with significant professional assistance provided by Steve Hendrickson, John Beaird, Darren Busch, Paul Legoudes, and Virginia Chan.

APPENDIX F– SOURCES OF INFORMATION

During our valuation analysis, we relied upon financial and other information from Management and various public, financial, and industry sources. Our conclusion is dependent on such information being complete and accurate in all material respects. The principal sources of information utilized in performing our analysis include:

- S&P Capital IQ financial database
- Kroll Cost of Capital Navigator
- FASB ASC 805: *Business Combinations*
- FASB ASC 820: *Fair Value Measurements and Disclosures*
- IBISWorld Industry Report: *Oil Drilling & Gas Extraction in the U.S.*, February 2022
- June 2022 Livingston Survey
- ProPublica: History of U.S. Gov't Bailouts, Updated April 15, 2009
- Bureau of Safety and Environmental Enforcement (BSEE) Formal solicitation for Temporary Abandonment Decommissioning Services - https://www.bsee.gov/formal-solicitation-issued-for-temporary-abandonment-decommissioning-services-virtual-pre
- Analysis of other facts and data resulting in our conclusions of value
- Historical production data retrieved from Enverus
- Rims II multipliers from the Department of Commerce