We use a staged consultation process for designating a lease as part of a field. As explained in section D, our GOM Regional office will contact affected lessees and offer them a chance to review and discuss the proposed designation before finalizing a new field designation or a change to an existing one. Our Regional office's final lease designation on a field may be appealed to the Director, MMS, in the same manner bid rejections are appealed. You should file a written request for this administrative review within 15 days of our notifying you of such designation. The Director's response to this request, either affirming or reversing the earlier decision, cannot be appealed further within the Department of the Interior.

You may file a written request with the Director, MMS for an extension if you are unable to comply with the performance condition specified in section J 2 above for reasons beyond your control (e.g., strike at the fabrication yard or weather caused delays in construction). We may grant an extension of up to six months to comply. Again, the Director's decision on this request is the final decision of the Department.

Except as explained above, our relief determinations and redeterminations are final agency actions. You are not entitled to further administrative review, including review by the Secretary of the Interior. Like all final agency actions, our decisions are judicially reviewable under Section 10(a) of the Administrative Procedures Act (5 U.S.C. 702). You must file your request for judicial review of our determination or redetermination under 43 U.S.C. 1337 (a)(3)(*C*) within 30 days of our decision.

O. Other Issues (supplements 30 CFR 203.73 & 78)

Gas-to-oil conversion factor - Your royalty suspension volume is measured in barrels of oil equivalent (BOE). For the purposes of this rule, 5.62 thousand cubic feet of natural gas equals one BOE. We measure natural gas in accordance with 30 CFR 250, Subpart L. We have traditionally used this conversion factor in the GOM and it is the same ratio used in 30 CFR 260.116 for calculating royalty suspension volumes for Eligible leases.

Non-royalty bearing production - We don't count any lease-use production that otherwise isn't subject to royalty toward the royalty suspension volume.

Price thresholds - Section 302 of the DWRRA directs us to retract royalty relief during periods when prices are very high. We continue the practice for post-2000 leases, but at a different price threshold level. Current price threshold information can be found on our website at: http://www.mms.gov/econ.

1. We retract royalty relief on the oil portion of production from pre-Act and certain eligible leases (refer to your lease document) when oil prices are too high. Oil prices are too high when the arithmetic average of daily closing prices during a calendar year on the NYMEX for light sweet crude oil exceeds $28.00 per barrel, escalated as in paragraph 3 below. We retract royalty relief on the oil portion of post-2000 lease production if the NYMEX light sweet crude oil price exceeds the level we specify in the notice of sale when we issued your lease. In both cases, we average the daily NYMEX closing prices quoted for the next nearest delivery month. For

instance, the average reported for July is typically the closing prices for August delivery for July 1 – 25 and for September delivery for July 26 – 31. You can determine the average oil price and inflation rate only after the end of the year, so a finding that price thresholds have been exceeded applies to royalties on the previous year's oil production.

a) You owe royalties at the lease stipulated royalty rate on your previous years' production of oil from a field with approved volume suspension. This production will count as part of the established royalty suspension volume. You should pay royalty due plus interest within 90 days of the end of the period specified for the average price calculation. When this period is specified as the previous calendar year, as it is for pre-Act and certain eligible leases, this payment is due by March 31 of the current calendar year. For post-2000 leases, this payment is due by the date specified in your notice of sale. Payment should be made in accordance with 30 U.S.C. 1721 and 30 CFR 218.54, on any volume of oil from the previous year for which you did not pay royalty.

b) For pre-Act and post-2000 leases, you also owe royalties on all your oil production in the current calendar year. However, you may seek a refund or credit with interest the oil royalties that otherwise would be suspended for your pre-Act lease if prices fall enough. Specifically, the arithmetic average of the current calendar year's closing oil prices on the NYMEX must be $28.00 per barrel or less, escalated as in paragraph 3 below. Likewise, you may seek a refund oil royalties paid by your post-2000 lease that has royalty relief if the NYMEX light sweet crude oil price is below the level specified in your lease document.

2. We also retract royalty relief on the natural gas portion of production from pre-Act and certain eligible leases (refer to your lease document) when gas prices are too high. Gas prices are too high if the arithmetic average of daily closing prices on the NYMEX for natural gas at Henry-Hub in the previous calendar year exceeds $3.50 per million British thermal units (Btu), escalated as in subparagraph 3 below. We retract royalty relief on the natural gas portion of your post-2000 lease production if the NYMEX gas price exceeds the level we specify in the notice of sale when we issued your lease. In both cases, we average the daily NYMEX closing prices quoted for the next nearest delivery month.

a) You owe royalties at the lease stipulated royalty rate on your previous year's production of natural gas from a field with approved volume suspension. This production will count as part of the established royalty suspension volume. You should pay royalty due plus interest within 90 days of the end of the period specified for the average price calculation. When this period is specified as the previous calendar year, as it is for pre-Act and certain eligible leases, this payment is due by March 31 of the current calendar year. For post-2000 leases, this payment is due by the date specified in your notice of sale. Payment should be made in accordance with 30 U.S.C. 1721 and 30 CFR 218.54, on any volume of natural gas from the previous year for which you did not pay royalty.

b) For pre-Act and Post 2000 leases, you also owe royalties on all your natural gas production in the current calendar year. However, you may seek a refund or credit with interest the natural gas royalties that otherwise would be suspended for your pre-Act lease if prices fall enough.

Specifically, the current calendar year's arithmetic average of the closing prices on the NYMEX for natural gas at Henry-Hub must be $3.50 per million BTU or less, as adjusted in paragraph 3 below. Likewise, you may seek a refund natural gas royalties paid by your post-2000 lease that has royalty relief if the NYMEX natural gas price is below the level specified in your lease document.

3. We escalate the prices referred to in paragraphs 1 and 2 above for pre-Act and certain eligible leases for each calendar year after 1994 by the percentage by which the implicit price deflator for the gross domestic product has changed since 1994. For post-2000 leases, we escalate prices from other base years, as specified in your notice of sale and lease document.

Administrative Report
(supplements 30 CFR 203.83)

a. General

You use this report to identify your field or project and to summarize its background and what relief you seek. You or your authorized representative should certify that all the information submitted in an application or post-production development report is accurate, complete, and that the presentation of data and information conforms to our guidelines. All the non-historical eligible costs you claim should be either direct or allocable indirect costs for the field or project. You should certify, either by independent review or company official, that all these costs are relevant to the field in question and that only those costs necessary for the proper operation of the field operations have been included.

b. Format

This report should be a hard copy text, with separate numbered paragraphs for each of the boxes in the following table. Any attachments, such as for paragraph 4 should immediately follow the relevant paragraph. You should mark any data or information you consider to be proprietary.

Administrative Information
Field Name
Serial number of leases in the field, names of the title holders of record, the lease operators, and the identification of whether the field/lease is part of a unit
Lessee's well designation, the API number, location, spud date, and status of each well that has been drilled on the field/lease or project; identify the discovery well
Location of any new wells proposed under the terms of the request
Description of field/project/lease history including royalty rate(s) and water depth
Full information as to whether royalties or payment out of production will be paid to anyone other than the United States, the amount to be paid, and the amount of reduction in such payment if relief is granted
Your opinion as to the amount of relief needed to make the field or project economic.[1]
For an Expansion project, confirmation that a DOCD or supplemental DOCD has been approved
A narrative description of the development activities associated with the proposed capital investments and an explanation of proposed timing of the activities and the affect on production
Management certification (30 CFR 203.81(b)) that all information in the application is accurate, complete, and conforms to the guidelines. This certification can be included in the application transmittal letter.

[1] If you have relief and seek more, we ask that this opinion be supplemented with a certification that you are voluntarily relinquishing any previous relief.

Economic Viability & Relief Justification Report
(supplements 30 CFR 203.85)

a. General

You use this report to show that your development would be viable (have a positive before tax net present value or NPV) without paying royalties when using our RSVP model and the economic inputs we supply. Costs you incur before the date of application are not relevant for this report. You are not to use ineligible costs as defined in the Cost Report section in this DCF analysis either. Attachment E explains how to get the RSVP model along with documentation.

You may use your own model in addition to ours if you can justify why our model doesn't adequately represent your situation. However, we reserve the right to use our model in the evaluation and subsequent determination.

b. Economic Assumptions

Under the regulations, you must use the economic assumptions listed and discussed below. You should justify all your other inputs with the G&G, Engineering, Production, and Costs Reports discussed elsewhere in these guidelines.

We may update these economic assumptions on a quarterly basis. It is your responsibility to revise the cell entries and the Crystal Ball input windows in the RSVP area labeled "Oil Price and Gas Price Input". Current values for the following assumptions are listed on our website at www.mms.gov/econ/update.

Starting Prices - The RSVP model selects starting oil and gas prices for each trial from triangular distributions with the parameters shown above. We determine these prices using the Refiner Acquisition Cost for imported crude in the Petroleum Administration for Defense District (PADD) III (compiled by the DOE/EIA) and the landed natural gas price represented by the NYMEX Henry Hub price for the next delivery month. The starting oil prices are independent random variables. The starting gas prices are dependent on the starting oil prices with a +1 correlation factor.

Price Adjustments - Starting oil prices apply to 30° API gravity crude oil. Starting gas prices apply to 1,028 Btus per cubic foot of gas. You should certify the existence and specify the size of any gravity differences or Btu content differences between the expected product of your field or project and these standards. You may specify these quality differences as distributions.

The RSVP model computes oil quality adjustments from the 30° API basis, using the following table. Note these adjustments may differ from those used by EIA and other sources.

Oil Price Quality Adjustment Table

API Gravity	Price Adjustment	API Gravity	Price Adjustment
65	($2.13)	41	$0.87
50.8	$0.00	35	$0.75
50	$0.12	30	$0.00
45	$0.87	0	($4.50)

The model interpolates the price adjustment it uses for gravity values between those in the table. For example, if the model samples your crude oil gravity on a trial as 37.6, then it linearly interpolates between price adjustment values $0.75 and $0.87 using the following equation:

$$[((37.6 - 35)/(41 - 35)) * (0.87 - 0.75)] + 0.75 = \$0.802$$

The model would then increase whatever starting oil price it picked on that trial by $0.802.

The RSVP model also increases or decreases the starting gas price when you specify a Btu content that is different than the standard of 1,028 Btu per cubic foot of gas. The size of the adjustment depends on the price and hydrocarbon content sampled on each trial. For example, if the model picks a Btu content of 950 Btu/mcf together with a starting gas price of $2.00/mcf, it adjusts the starting gas price actually used on that trial by the ratio of trial-specific Btu content to the standard BTU content (950/1,028). The resulting starting gas price used on this trial would be $1.85, i.e., $2.00 * (950/1,028).

Real Price Growth Rates - We base these annual rates primarily on long-term oil and gas price projections inherent in the three world price scenarios published in the DOE/EIA Annual Energy Outlook. When we believe it is appropriate, we adjust by projections from other major forecasters. We may use decline rates (negative growth rates). The growth rate for the real gas price in the first period (RIGP1) has a direct dependency on the growth rate for the real oil price in period 1 (RIOP1). The growth rate for the real oil price in period 2 (RIOP2) has a direct dependency on RIOP1, and RIGP2 has a direct dependency on RIOP2.

Real Cost Growth or Decline Rates - We may use an annual rate to represent an expected change in costs. This change may be partially related to the expected price changes. Cost growth rates are generally some fraction of the price growth rates. Decline rates may also be employed.

Year Scenario Starts - The year the first, second, and third economic scenarios commence.

Discount Rate Range - A range of risk-free annual, real before-tax rates from which you choose a value for us to use for the profitability test DCF analyses. The value you use for the viability test performed in connection with the application is the bottom of this range.

Tax Rate - The federal income tax rate we use for determining after-tax sunk costs.

Random Number Seed - We specify an arbitrary seed value to start the random number generator in the model. We do this to allow for output reproducibility.

Overhead Cost Allowance - We specify a modest overhead allowance rate that you may use for Labor, Material, Abandonment and Other Costs categories for joint cost items which you are unable to clearly allocate to your field.

c. Cash Flow

You should provide your output from running our RSVP model. If you use your own model as well, at least provide the following information:

1. discount rate you use,
2. annual oil and gas production,
3. annual oil and gas revenue,
4. total gross revenue,
5. oil and gas transportation costs,
6. operating costs,
7. capital expenditures,
8. total net revenue,
9. before-tax cash flow without royalties, overrides, sunk costs, and ineligible costs.
10. the before-tax NPV your model calculates or implies.

You should show that all costs, gross production, capital costs, and scheduling are compatible with the data you provide in the G&G, engineering, production, and cost reports.

d. Format

You should provide the input data in the RSVP model format specified in its documentation on a 3.5-inch diskette. You should also give us a hard copy of your output results in the RSVP model format to ensure the results we obtain are the same. You should mark on the hard copy as well as electronic files any data or information that you consider proprietary.

e. Check list Table

The table below is provided for quick reference.

Deep Water Royalty Relief Economic Viability Report	
Economic Assumptions (Provided by MMS)	- Starting oil and gas prices - Real price growth - Real cost growth or decline rate, if any - Base year - Range of discount rates - Tax rate (for use in determining after-tax sunk costs)
Price Adjustment	- Quality adjustments for gravity, Btu content
Projected Cash Flow Analysis as of Application Date Using Annual Totals and Constant Dollar Values	- All costs, gross production, and scheduling should be consistent with the data in the G&G, engineering, production, and cost reports - The up to three development and production scenarios (conservative, most likely, and optimistic) you provide in the various reports should be consistent with each other and your proposed development system - Oil/gas production - Total revenues - Capital expenditures - Operating costs - Transportation costs - Before-tax net cash flow
Discounted Values	- Discount rate that you select from within the range we prescribe - Show before-tax NPV without royalties, overrides, sunk costs, and ineligible costs

Geologic and Geophysical Report
(supplements 30 CFR 203.86)

a. General

You use this report to describe the resources in the field you propose to develop. A number of definitions exist for resources and reserves. In this country, the definitions standardized by the Society of Petroleum Evaluation Engineers (SPEE) are the most common. SPEE figures for proved reserves are generally conservative, despite the inclusion of established improved recovery methods, thus contributing to a large reserve growth. DOE has estimated this growth can be as large as eight times the initial figure. In order to minimize the effects of this conservatism and to provide an analysis that considers the uncertainties involved, we don't mandate a specific definition of resources and reserves. Rather, the model has you list the specific reservoirs you've found along with their attendant risk of occurrence and provide distributions for certain characteristics for each reservoir.

b. Detailed Data

You should provide seismic data, well data, and map interpretations as listed in the table under paragraph g below.

c. Reservoir Data

You develop the resource and reserve distributions for your field using the resource module of our RSVP model. The resource module uses two kinds of estimates that you provide to develop this standardized calculation of the reserves and resources.

One, you should submit probability estimates for the chance of hydrocarbon occurrence (constant) as well as the chance that it is all oil or all gas for each reservoir that will be included in the viability and suspension analysis. If a reservoir in your application is penetrated by a well, then the chance of hydrocarbon occurrence is 100 percent. Since your application is predicated on a discovery well, at least one reservoir always has a 100 percent chance of hydrocarbon occurrence. Any risk that a well will not produce due to mechanical problems should be included in your cost report with an appropriate input to RSVP as an estimate for remedial action. An explanation and justification of your risk assumption and estimated cost of remedial action is required.

Two, in order to assist in our data validation, you should also provide probability distributions for acres, net thickness, gas-oil ratio or yield, and oil and gas recoveries per acre-foot for each reservoir. You may use any of the distributions available with our RSVP v2.1 model, but you should carefully defend a choice other than a triangular distribution. You should submit maps showing the aerial extent of each reservoir for the minimum, most likely, and maximum cases. Where delineation with drilling or seismic data has eliminated your uncertainty about the size of any of these characteristics, you may substitute point estimates for distributions. However, you should explain why other values have no chance of occurrence, if you use point estimates in lieu of distributions.

Also, you must specify the degree of dependency, if any, among the expectations for individual reservoirs and defend the correlation between those reservoirs.

d. Aggregation

The resource module combines reservoir estimates into a resource distribution for your field or project. The aggregation model uses a random number generator to determine reservoir existence on a specific trial. On each trial where an individual reservoir is found to exist, the module samples the distributions of its characteristics and computes a resource size. Those reservoirs found to exist are then aggregated to get the resource estimate for that trial.

The outputs from this module, which on each trial are represented by a field BOE value with an attendant oil percentage, become the inputs to the viability module of the RSVP model. Thus, the resource module is incorporated into the RSVP model to provide trial specific inputs throughout the economic viability simulation analysis.

Attachment E explains how you can get the RSVP v2.14 model template that you and we use to aggregate this data into estimates of resources and reserves for the purposes of royalty relief evaluation.

e. Consistency

The development system you choose, as well as prospective costs and production profiles are all interrelated and tied to the resource and reserve level. You may specify up to three scenarios (conservative, most likely, and optimistic) to portray scales, costs and production profiles appropriate to different parts of your field's resource distribution. As we explain for the other reports necessary for a complete application, you should develop an internally consistent development schedule, cost schedule, and production profile for each scenario that you submit. Also, you should tie each scenario to a specific range on the resource (BOE) distribution. Provide careful justification for the break points between the scenario ranges that you pick.

f. Format

Our letter to lessees of October 1, 1990 describes the format you are to use for digital velocity surveys. You may submit the rest of the detailed G&G data as described in the table under paragraph g. or, if not indicated otherwise, in the format of any state-of-the-art processing technique that is readable by our GOM Regional office. The distributions put out by the RSVP model will satisfy your requirements under 30 CFR 203.86 (d) or paragraph c above. You should provide additional explanation if you substitute point estimates for distributions for any of the data specified in this section.

You should mark on hard copy as well as electronic files any data or information you consider to be proprietary. See Attachment D for a schematic of the format of the RSVP v2.1 model template.

g. Check list Table

The table below is provided for quick reference.

Geologic and Geophysical Report	
Seismic Data	- Non-interpreted 2D or 3D survey lines (8mm tape) (SEGY format or IES format) - Interpreted 2D or 3D seismic survey lines identifying all known and prospective pay horizons, wells, and fault cuts - Digital velocity surveys - Plat map of "shot points" - "Horizon slices" of potential horizons
Well Data	- Hard copies of all well logs 1" electric log should show: = pay zones and pay counts, = lithologic and paleo correlation markers at least every 500 ft. 1" type log should show: = missing sections from other logs where faulting occurs 5" electric log should show: = pay zones and pay counts and = labeled points used in establishing Ro and Rt 5" porosity logs should show: = pay zones and pay counts and = labeled points used in establishing reservoir porosity or labeled points showing values used in calculating reservoir porosity such as bulk density or transit time - Digital copies of all well logs spudded before December 1, 1995 in either LAS or LIS format - Core data, if available - Well correlation sections - Pressure data, including the maximum shut-in pressure at the wellhead - Production test results - PVT analysis, if available - Summary table of wells indicating which sands and fault blocks will be targeted for completion/recompletion

Map Interpretations	For each reservoir included in the application: - Structure maps, top and base of sand maps showing well and seismic shot point locations - Maps for min, max, and most likely aerial extent of each reservoir - Isopach maps for net sand, net oil, net gas, all with well locations - Maps indicating well surface and bottom hole locations, location of development facilities, and shotpoints - Identification of reservoirs not contemplated for development and justification for preclusion of these reservoirs
Reservoir Data	For each reservoir included in the application: - Probability of reservoir occurrence with hydrocarbons and an explanation of how you determined each chance of occurrence that is less than 100 percent - Probability the hydrocarbon in the reservoir is all oil, and the probability it is all gas - Distributions or point estimates for the parameters used to estimate the reservoir size i.e., acre, net thickness, etc. - Most likely values for porosity, salt water saturation, oil and/or gas volume formation volume factor, and recovery factors (%) - Distributions for oil and/or gas recovery per acre-foot with an explanation or example of how the minimum and maximum values were calculated for each unique calculation - Gas/oil ratio distribution or point estimates for each oil reservoir. - Yield distribution or point estimates for each gas reservoir
Reserves and Resources Data	- Reservoir simulation report, if available - Aggregated BOE reserve and resource distributions for the field or project. - Description of anticipated crude quality (e.g., gravity). - Break points on the aggregated reserve/resource distribution showing the portion of the range over which to use each of the up to three (conservative, most likely, and/or optimistic) production profiles specified in the production report.

Engineering Report
(supplements 30 CFR 203.87)

a. General

You use this report to elaborate on the design of the production facilities you need to develop this field or project. We take your submission of such a design as evidence of your belief that the field or project merits development and qualifies for royalty relief. The development scenarios and timing assumptions you submit in your royalty relief application should be consistent with any and all documents previously filed for activities on your lease. You should describe alternative development options that were considered but not chosen along with the reason for non-selection. You should fully explain the rationale for your choice of the selected approach and show why it is the most economical (least-cost) one. If a different system would be more economical without royalty relief, you should indicate where and how it differs from what you proposed. You should also show that development and production of all of the project's recoverable resource were reasonably considered in the formulation of the selected approach.

b. Development Concept

You should provide us with a complete description of the type, size, and location of the system you intend to use along with a schedule for its construction.

c. Planned Wells

You should tell us the number of wells you intend to drill, their measured depths, and their type (platform, subsea, vertical deviated, horizontal) as well as your drilling schedule (number and type by year). Also, you should tell us the intended type for each completion, the intended reservoir for each completion, and your schedule (number of completions by year).

d. Production System Equipment

The production schedule is a very sensitive component of net present value. In the event that the actual production rate exceeds your initial planned rate, we need to know the limiting component(s). You should tell us the production system capacity for oil and gas. Also, you should tell us the number, size, length, and location of any and all flow lines tying together subsea wells and or subsea structures with the producing facility.

e. Multi-phase Development Plans

In some cases, you may intend to develop a field in several phases as opposed to entirely at once. We may or may not agree with such an intention due to considerations such as resource conservation, diligence, technical capability, etc. If you submit a multi-phase plan, you should describe the conceptual basis for developing in phases as well as the goals and milestones you require to continue with subsequent phases.

f. Uncertainty

We are referring to your uncertainty about the size of the actual reserve and resource and thus the attendant number of wells, initial production rates, decline rates, etc., not any uncertainty about the type of development concept you'll use. You may provide up to three schedules of development (conservative, likely, optimistic). A schedule of development includes the development system construction schedule, drilling schedule, completion schedule, and the production system installation schedule. Make each one consistent with its counterpart production profile (conservative, likely, optimistic) you provide in the Production and Cost reports. If you submit fewer than three distinct scenarios, you should explain why other development scales or schedules are not efficient for part of the possible range of resource size.

g. Format

You should mark on hard copy as well as electronic files any data or information that you consider proprietary. See Attachment E for the RSVP v2.14 model format. We prefer that you provide the data described in paragraphs a, b, c, d, and e. in hard copy text with separate lettered divisions for each of the applicable sections of this report.

h. Check list Table

The table below is provided for quick reference.

Engineering Report	
Development Concept	- Description of the proposed development concept (fixed, floater, subsea tieback, etc.) including basic design specifications. - Description of alternative development options along with the reasons for non-selection. - Construction and installation schedule.
Planned Wells	- Number of wells planned - Type of well (platform, subsea, vertical, deviated, horizontal) - Well depth - Drilling schedule - Completion description: normal, dual, horizontal, etc. - Completion schedule

Production System Equipment	- General process description including the production capacity for oil and gas and a description of the limiting component - Surface facilities - Subsea structures - Flowlines and umbilicals - Production system construction and installation - Special problems such as hydrates, paraffin, sand, etc.
Multi-phase Development Plans	- Conceptual basis for developing in phases and goals/milestones required for commencing subsequent phase
Uncertainty	- Schedules of development consistent with each of the up to three field production profiles (conservative, likely, optimistic) provided in the production report

Production Report
(supplements 30 CFR 203.88)

a. General

You use this report to justify the future flow rates that you expect for wells from your field or project. You should explain any significant deviation from flow rates at comparable wells and fields. Your projections may be based on analogy, actual production tests, decline curves, computer modeling, or other accepted engineering methods. However, your discussion in this report should explain the methods used in developing the estimates along with any attendant assumptions.

b. Production Profiles

You should estimate the expected production for each well completion and for the field or project, by year for each year of production for oil, condensate, gas, and associated gas as well as the composite BOE production. You should also estimate water production if any of your operating costs (processing fees, chemical costs, etc.) are based on these volumes. You may submit up to three separate production profiles (conservative, most likely, optimistic). Each profile for the field should represent the production schedule you expect if a specific range on the field's aggregated reserve and resource distribution exists (conservative, most likely, optimistic). You should justify these ranges in the G&G Report. Also, you should insure that each production profile for the field is consistent with the applicable (conservative, most likely, optimistic) scenarios used in the Engineering Report and the Cost Report.

You should describe the specific production drive mechanism you expect for each reservoir.

c. Format

You should mark on hard copy as well as electronic files any data or information that you consider proprietary. See Attachment D for the format for the RSVP v2.1 model. We prefer that you submit annual production data by product in hard copy.

d. Check list Table

The table below is provided for quick reference:

Production Report	
Production Profile	- Projected production for each well completion and for the field, by year for each year of production for oil, condensate, and gas as well as the composite BOE. Water production should also be provided if directly related to any operating costs. - Explanation of the methods used to develop the profiles.
Uncertainty	- Up to three production profiles (conservative, most likely, optimistic) as described above - Each production profile for the field should be consistent with a specific point on the aggregated reserve and resource distribution and represent a conservative, most likely, and an optimistic case
Miscellaneous	- Production drive mechanism for each reservoir

Cost Report
(supplements 30 CFR 203.81(b) & (c), 89 & 91)

a. General

You use this report to justify and explain how you estimated the various costs that you have and will incur to develop and produce this field or project. You should limit your cost estimates to the items identified in paragraphs b through f below and report them in the categories listed in Attachment C. We believe they cover all the elements that clearly benefit the development and operation of your field or project. Allowable costs include the portion of joint costs in those categories that you can reasonably attribute to your field or project and a 5 percent overhead rate on costs in the Labor, Material, Abandonment, and Other Costs categories. We review your cost estimates, and once validated, use them to evaluate the application. As part of our validation we will consider the consistency of up to three cost scenarios (conservative, most likely, optimistic) with the applicable production and engineering scenarios as well as the applicable resource and reserve ranges. You should document the basis for all your cost estimates (e.g., contract with supplier, cost for a project of similar size and water and drilling depth, vendor estimate, commercially available cost estimating software, etc.). If you expect to encounter any unusual conditions or if you are considering alternative development options that could cause costs to vary significantly from the estimates presented, you should fully describe those conditions or options.

b. Sunk Costs

You should report sunk costs, defined in Attachment B, as follows:

(1) by the cost categories listed in Attachment C; indicate the overhead allowance for each applicable category,
(2) in AFE format for each eligible well; indicate the cost code (Attachment C) and the overhead allowance, if any, for each item, and
(3) in an itemized format for non-well costs; indicate the cost code, overhead allowance, and time period the costs were incurred.

We count only eligible sunk costs for which you provide documentation. Eligible sunk costs include only those historical costs incurred by you or your current partners in the application, not those of third parties. To help identify which sunk costs we should count, you should report separately by lease the size and timing of proportionate shares and breaks in ownership for all current owners, along with the timing and distribution by lease of the eligible sunk costs.

We count sunk costs on an after-tax, expensed basis using nominal (current dollar) amounts without any interest or discount rate adjustments. We may audit your sunk costs as discussed in sections G and L. An independent CPA must certify these historical costs in the same manner as explained in paragraph m of this Cost Report. We use these sunk costs only in the DCF evaluation for the profitability test (as explained in section H) and in determining whether there has been a change in material fact (as explained in section J).

c. Delineation and Development Costs

You should submit all the cost elements for this component listed in the table under paragraph o. You should associate applicable costs with specific reservoirs whenever possible. For example, tell us the specific reservoir intended for completion with each completion cost item. You may base your estimates on actual costs (such as the cost of previous wells drilled in the field), engineering estimates from vendors, or equivalent costs at analogous projects. Cost estimates should be itemized in an Authorization for Expenditure (AFE) format. Specific items that may be included in the cost elements are as follows:

Wells - Rig cost, casing and tubing, mud, consumables, equipment (wellhead valves and other equipment necessary for interaction with topside facilities), services (cement, chemicals, insurance, transportation), drill bits, etc.

Completions - additional cementing, perforating, sand control, packers, etc.

Subsea Completions - wellhead production tree, flowline controls and valves, miscellaneous equipment provided for both cluster and satellite wells, etc.

Production System - where applicable, platform fabrication or conversion and installation; topside facilities (production processing equipment; production control system; power, utility, and safety equipment; accommodations; wellhead equipment; storage facilities, etc.); riser system; mooring system; subsea equipment; pipelines, flowlines, and umbilicals; engineering design; project management; etc.

d. Production Costs

You should submit all the cost elements for this component listed in the table under paragraph o. You should specify the bases for these costs (historical, engineering estimate, or analogous project). Specific items that may be included in the elements are as follows:

Operating Costs - your costs for inspection, maintenance, repair, payroll, support and crew transport, insurance, workovers, consumables.

Equipment Leasing - your cost to lease any equipment.

Overrides* - royalty overrides and other forms of payment you incurred to acquire a financial position in lease(s) associated with this field.

* We will not use these costs in our DCF evaluations.

e. Transportation Costs and Allowances

You should submit all the cost elements for this component listed in the table under paragraph o. This component should include all costs, both arm's length and non-arm's-length, that are likely to be allowed as a deduction (transportation allowance) by MMS for royalty computation purposes, based on existing rules and recent precedents. You should specify the basis for these costs (historical, engineering estimate, or analogous project). Specific items that may be included in the elements are as follows:

Tariffs - Your cost per bbl or MCF to be paid to a third party to use their pipeline system to bring the product to market.

Transportation system costs – All of your costs that can be used to calculate a transportation allowance other than tariffs. Note that these costs can overlap items reported elsewhere in the application. You must indicate the specific costs items and amounts where such an overlap occurs. Transportation system cost elements may include:

(1) Annual capital investment, repair and maintenance costs for:
(a) Flowlines delivering bulk product from subsea manifolds or wellheads to a remote host facility not located on an adjacent lease/block;
(b) Portions of umbilicals dedicated to flow assurance (chemical transport);
(c) Platform based treatment for additional dehydration and enhanced liquids extraction performed solely for a transportation purpose, above what is required to meet sales contract specifications and needed to cope with flow assurance issues caused the colder temperatures, increased pressures, and greater distances experienced in deep water;
(d) Platform modifications (including extra buoyancy)to accommodate items under (c) above.

(2) Specific volumes and costs of chemicals needed for flow assurance.

(3) Your cost per barrel or MCF to be paid to a third party for platform based additional dehydration and enhanced liquids extraction costs. As for the similar "other than arm's-length capital and maintenance costs" (item 1c, above), these costs are solely for transportation purposes required to meet sales contract specifications and needed to cope with flow assurance issues caused by colder temperatures, increased pressures, and greater distances experienced in deep water.

Non-royalty bearing fractions of the flowline – Transportation allowances are intended only for the flowline capacity dedicated to the transportation of oil and gas, not for water. Therefore, you must give annual projections of water production so we can estimate the fraction of the flowline cost that is not royalty bearing.

Gas plant processing costs - Your annual or per barrel or per MCF non-tariff costs expended off lease to process the gas to increase liquid recovery.

f. Abandonment

You should tell us your estimate for future costs to plug and abandon wells and to remove production systems that did not exist at the date of application. Separately, tell us the cost to abandon wells or facilities that do exist at the time of your application that you plan to use to produce the field or project. You should include an estimate or distribution of prospective salvage value for all potentially reusable facilities and materials.

g. Overhead Costs

We allow you to add an overhead charge of up to 5 percent of the sum of the direct costs for labor, materials, abandonment, and other costs, as defined in Appendix C. This allowance is designed to cover your finance, administration, and management activities appropriate for the field. We do not require documentation of this amount, but neither do we allow other calculations of an overhead charge

You should indicate the overhead cost for each item in your cost estimates and sunk costs. The following provides clarification regarding which specific items are eligible for an overhead allowance:

Drilling and CompletionCosts – your tangible drilling and completion costs are considered material costs and your direct supervision is a labor cost. Any intangible materials (bits, cement, etc.) that you purchase and provide to the contractor can be included in the material category. All of these costs are eligible for the 5 percent overhead allowance. All other drilling and completion costs are considered contract services and are ineligible for an overhead allowance.

Production System Costs – your fabrication expenses are considered material costs and are eligible for an overhead allowance. Installation and contract engineering and project management are contract services, which are ineligible for the allowance.

Operating Expenses – items such as company personnel costs (labor) and chemical and fuel expenses (material) are eligible for an overhead allowance. Overhead is not allowed for cost categories such as transportation, insurance, communication, and contract services. For well and subsea system repairs, some overhead may be allowed in accordance with the above rules for drilling and completion costs.

Technical and Operations Support – these activities, if conducted by company personnel, are eligible for an overhead allowance, otherwise, they are considered a contract service.

Abandonment Cost – the 5 percent overhead allowance may be applied to all abandonment costs.

h. Ineligible Costs

We will not consider certain types of costs in our royalty relief analysis, either due to the requirements of the law or because they are not properly associated with the production for which the relief is being granted. A partial list of such costs are your:

1) acquisition costs,
2) royalty relief application fees,
3) lease rentals,
4) exploration costs,
5) damages and loses,
6) taxes,
7) interest or finance charges,
8) legal expenses and fines or penalties,
9) Costs associated with obligations existing before the application. These may include but are not limited to royalty overrides or other forms of payment for acquiring a financial position in a lease. Also, they include expenditures for plugging wells and removal and abandonment of facilities existing on the date of application and that are not to be used to produce oil or gas for sale from the field or project,
10) Costs of producing and using hydrocarbons on the lease, either for fuel or re-injected into the reservoir for disposal or pressure maintenance (since these volumes do not count against any royalty suspension volumes), and
11) Any historical costs incurred by third parties.

We reserve the right to add to this list and to make determinations regarding the eligibility of all costs you submit in the application.

i. Uncertainty

In order to model the uncertainty inherent in applications submitted at an early project stage, you may describe your costs in one of three ways. One, you may provide a separate cost scenario (conservative, most likely, optimistic) for each of up to three field production profiles you listed in the Engineering Report. For the purpose of this discussion, we consider a scenario to be a listing of total costs, in constant dollar terms for the base year, by category as well as an annual scheduling of such costs by category. The base year is the year of application. Two, you may also model uncertainty about capital costs within each scenario by specifying a confidence interval (i.e., a minimum and maximum percentage of the scenario value). Three, as with the resource data, you may model uncertainty about drilling, operating, and transportation charges with probability distributions. You must explain the basis you used for selecting the number of scenarios, each probability distribution, and confidence interval you use.

j. Contingency

You may not include explicit contingency factors in your cost estimates. Uncertainty you have about omitted costs items, remedial action on a well that does not produce at first, or about future cost inputs (e.g., rig day rates) should be incorporated into the way you configure your scenarios, cost distributions, and confidence intervals. We allow the average of your distribution of capital and well costs to be as much as 7.5 percent above your best itemized estimate for these costs. In effect, we allow you to include up to a 7.5 percent contingency on these costs when they are accounted for in the configuration of your scenarios, cost distributions and confidence intervals. Separate contingencies built into your itemized estimates of capital or well costs would constitute a redundant inclusion of uncertainty.

k. Scheduling

You should include, for each of the up to three cost scenarios, an annual listing (in constant, base year dollars) of your anticipated cost expenditures by category. The term category is intended to refer specifically to the items under "delineation and development costs" in the right hand column of the table in paragraph o.

l. Post-production Development Report

To retain the approved DWRR, you should file a post-production development report within 120 days after you start production. If your development plans call for a rolling start of production, say as you complete several wells sequentially on the same rig mobilization, we will define start of production as production from all wells included in the startup campaign. The only exception to this requirement occurs if the Regional Director for the GOM grants you an extension. You should submit actual costs for all of the elements of the development cost component (listed in paragraph c. above) with supporting records. In addition, you should provide costs by category in the Allowable Cost Report format as listed in Attachment C. We use this information for decisions involving changes of material fact.

m. Certification

Your application and post-production development report should be accompanied by a report prepared by an independent CPA that expresses at least a qualified opinion that the historical financial information in the application and post-production development report is accurate and that the presentation of data and information conforms to our guidelines. You should identify the individuals in the CPA firm who prepared these reports and you should make them available to us to respond to questions which may arise regarding the evaluation of your historical information. We reserve the right to also review your records on the historical financial information in your report.

n. Format

The documentation for the RSVP model shows and explains the model's format for data and can be found at http://www.gomr.mms.gov/homepg/offshore/royrelef.html.

o. Check list Table

The table below is provided for quick reference.

Deep Water Royalty Relief Cost Report	
Ownership history and sunk costs - certified by CPA	- All documented eligible costs, in nominal (current dollar) amounts, actually incurred subsequent to and including the first discovery well on the field. We count sunk costs on an after-tax, expensed basis - All changes in lease ownership since discovery of the field as well as the timing and distribution by lease of all sunk costs - Provide sunk costs in the formats referred to in paragraph b
Delineation and development costs - from historical records, engineering estimate, or analogous project in AFE format	- Platform well drilling costs and average well depth - Platform well completion costs - Subsea well drilling costs and average well depth - Subsea well completion costs - Production system costs (platform, topside facilities, subsea equipment, flowlines, umbilicals, engineering, project management, etc.)
Production Costs - historical, engineering estimate or analogous project review or company official.	- Itemized operating and processing costs - Equipment leasing costs - Taxes (won't be used in our DCF evaluations) - Existing royalty overrides (won't be used in our evaluation)
Transportation Costs - historical, engineering estimate or analogous project	- Transportation system costs (used to determine transportation allowance, see paragraph e) - Percent Water content of bulk movements - Oil and/or gas tariffs from pipeline or tankerage - Gas plant processing costs for NGL

Uncertainty	- A cost scenario consistent with each one of the up to three field development and production profiles (conservative, likely, optimistic) - If desired, express the uncertainty of capital cost for each scenario with confidence intervals and of drilling, operating, and transportation costs with probability distributions
Contingency Costs	- Not allowed
Scheduling	- Provide costs on an annual basis (in real dollars for the base year) for the delineation and development cost component
Abandonment	- Estimate the costs that have not been incurred at the time of application to plug and abandon wells needed to produce the field or project. - Include an estimate of the salvage value of reusable facilities and materials
File a post-production development report 120 days after you start the production subject to an approved royalty suspension. Report actual expenditures for the above cost components up to the date production starts. Retain supporting records for these costs and make them available to us upon request.	

Attachment A: Royalty Relief System Summary

Royalty Relief Procedure	**Deep Water**		
	Expansion Project	**Pre-Act Lease**	**Development Project**
Information Elements (§§ 203.62, and 203.81 through 203.89)			
(1) Administrative information report	x	x	x
(2) Economic viability and relief justification report (Royalty Suspension Viability Program (RSVP) model inputs justified with Geological and Geophysical (G&G), Engineering, Production, & Cost reports)	x	x	x
(3) G&G report	x	x	x
(4) Engineering report	x	x	x
(5) Production report	x	x	x
(6) Deep water cost report	x	x	x
Confirmation Elements (§§ 203.70, 203.81 and 203.90 through 203.91)			
(1) Fabricator's confirmation report	x	x	x
(2) Post-production development report approved by an independent certified public accountant (CPA)	x	x	x
Approval Conditions (§§ 203.60 and 203.67)			
(1) Already producing	x (Field)		
(2) A producible well into a reservoir that has not produced before	x	x	x
(3) Royalties for qualifying months exceed 75% of net revenue (NR)			
(4) Substantial investment on a pre-Act lease (e.g., platform, subsea template)	x		
(5) Determined to be economic only with relief	x	x	x
Redetermination Conditions (§§ 203.74 through 203.75)			
(1) For material change in geologic data, prices, costs, or available technology	x	x	x

Royalty Relief Procedure	Deep Water Expansion Project	Deep Water Pre-Act Lease	Deep Water Development Project
Relief Rate and Volume, subject to certain conditions (§§ 203.69)			
(1) Zero royalty rate on the suspension volume and the original lease rate on additional production	x	x	x
(2) Suspension volume is at least 17.5, 52.5 or 87.5 million barrels of oil equivalent (MMBOE)		x	
(3) Suspension volume is at least the minimum set in the Notice of Sale, the lease, or the regulations	x		x
(4) Amount needed to become economic	x	x	x
Full Royalty Resumes When (§§ 203.78)			
(1) Average NYMEX price for last calendar year exceeds $28/bbl or $3.50/mcf, escalated by the gross domestic product (GDP) deflator since 1994.	x (Pre-Act leases)	x	
(2) Average prices for designated periods exceed levels we specify in the Notice of Sale and the lease.	x (Post-200 leases)		x
Relief Withdrawn or Reduced (§§ 203.76 through 203.77)			
(1) If recipient requests.	x	x	x
(2) Recipient does not submit post-production report that compares expected to actual costs.	x	x	x
(3) Recipient changes development system.	x	x	x
(4) Recipient excessively delays starting fabrication.	x	x	x
(5) Recipient spends less than 80 percent of proposed pre-production costs prior to start of production.	x	x	x
(6) Amount of relief volume is produced.	x	x	x

Attachment B: Definitions (from 30 CFR 203.0)

Authorized field - A field
(1) Located in a water depth of at least 200 meters and in the Gulf of Mexico (GOM) west of 87 degrees, 30 minutes West longitude;
(2) That includes one or more pre-Act leases; and
(3) From which no current pre-Act lease produced, other than test production, before November 28, 1995;

Complete application - The fee specified in 30 CFR 203.3 and an original and two copies of the six reports consisting of the data specified in 30 CFR 203.81, 83 and 85-89, which we've reviewed and found complete.

Determination - Our binding decision on whether your field qualifies for relief or on how large a royalty-suspension volume must be to make your field economically viable.

Development project - A project that is located on one or more contiguous leases that:
(1) Were issued in a sale held after November 28, 2000;
(2) Are located in a water depth of at least 200 meters and in the GOM wholly west of 87 degrees, 30 minutes West longitude; and
(3) Have had no production (other than test production) before the current application for royalty relief.

Draft application - The preliminary set of information and assumptions you submit to seek a nonbinding assessment on whether a field could be expected to qualify for royalty relief.

Eligible lease - A lease that:
(1) Is issued as part of an OCS lease sale held after November 28, 1995, and before November 28, 2000;
(2) Is located in the Gulf of Mexico in water depths of 200 meters or deeper;
(3) Lies wholly west of 87 degrees, 30 minutes West longitude; and
(4) Is offered subject to a royalty suspension volume.

Expansion project - A project you propose in a DOCD or a Supplement approved by the Secretary of the Interior after November 28, 1995, that will significantly increase the ultimate recovery of resources from a pre-Act lease or a lease issued in a sale held after November 28, 2000. A significant increase adds new resources, not simply extends recovery of reservoirs already in production. For a pre-Act lease, the expansion project must also involve a substantial capital investment (e.g., fixed-leg platform, subsea template and manifold, tension-leg platform, multiple well project, etc.). For a lease issued after November 28, 2000, the expansion project must involve a new well drilled into a reservoir that has not previously produced. In all cases, an expansion project must be located in a water depth of at least 200 meters and in the GOM wholly west of 87 degrees, 30 minutes West longitude.

Fabrication (or start of construction) - Evidence of an irreversible commitment to a concept and scale of development, including copies of a binding contract between you (as applicant) and a fabrication yard, a letter from a fabricator certifying that continuous construction has begun, and a receipt for the customary down payment.

Field - An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same general geological structural feature or stratigraphic trapping condition. Two or more reservoirs may be in a field, separated vertically by intervening impervious strata or laterally by local geologic barriers, or both.

Lease - Either a lease or a unit of multiple leases.

New production - Any production from a current pre-Act lease from which no royalties are due on production, other than test production, before November 28, 1995. Also, it means any additional production resulting from new lease-development activities on a current pre-Act lease or a lease issued in a sale after November 28, 2000, under a DOCD or a Supplement approved by the Secretary of the Interior after November, 28, 1995, that significantly expands production.

Nonbinding Assessment - An opinion by us of whether your field could qualify for royalty relief. It's based on your draft application and doesn't entitle the field to relief.

Performance Conditions - Minimum conditions you must meet, after we've granted relief and before production begins, to remain qualified for that relief. If you don't meet each one of these performance conditions, we consider it a change in material fact significant enough to invalidate our original evaluation and approval.

Pre-Act lease - A lease that:

(1) Results from a sale held before November 28, 1995;
(2) Is located in the GOM in water depths of 200 meters or deeper; and
(3) Lies wholly west of 87 degrees, 30 minutes West longitude.

Production (for purposes of Deep Water Royalty Relief) - All oil, gas, and other relevant products you save, remove or sell from a tract, or those quantities allocated to your tract under a unitization formula, as measured for the purposes of determining the amount of royalty payable to the United States.

Redetermination – Our reconsideration of our determination on royalty relief because you request it after:

(1) We have rejected your application;
(2) We have granted relief but you want a larger suspension volume;
(3) We withdraw approval; or
(4) You renounce royalty relief.

Renounce - Action you take to give up relief after we've granted it and before you have produced an amount equal to the royalty suspension volume with which we issued your lease.

Royalty suspension (RS) lease - A lease that:
(1) Is issued as part of an OCS lease sale held after November 28, 2000;
(2) Is in locations or planning areas specified in a particular Notice of Sale offering that lease; and
(3) Is offered subject to a royalty suspension volume specified in a Notice of OCS Lease Sale published in the Federal Register.

Sunk costs for on an authorized field means the after-tax eligible costs that you (not third parties) incur for exploration, development, and production from the spud date of the first discovery on the field to the date we receive your complete application for royalty relief. The discovery well must be qualified as producible under part 250, subpart A of this title. Sunk costs include the rig mobilization and material costs for the discovery well that you incurred prior to its spud date.

Sunk costs for an expansion or development project means the after-tax eligible costs that you (not third parties) incur for only the first well on each of the project's leases, as approved by us, that encounters hydrocarbons in the reservoir(s) included in the application and meets the producibility requirements under part 250, subpart A of this title on each lease participating in the application. Sunk costs include rig mobilization and material costs for the discovery wells that you incurred prior to their spud dates.

Withdraw (our) approval - Action we take on a field that has qualified for relief if you haven't met one or more of the performance conditions. (This is different from a withdrawal application in which the applicant removes the application from consideration before any MMS determination or action.)

Attachment C: Allowable Cost Categories
Associated with the Cost Variables Used to Determine Qualification for Royalty Relief
(supplements 30 CFR 203.89)

The text of these guidelines refers to several different cost variables we use to determine your qualification for royalty relief. Each of these variables consists of expenditures associated with several different cost categories. This attachment summarizes categories of allowable costs, drawn from 30 CFR 220.011 and describes what expenditures we view as eligible costs in the respective cost categories. Our companion guidelines on End-of-Life Royalty relief includes an almost identical attachment (Attachment 1) on allowable costs. *Italics* in this Attachment C denote passages that deviate from Attachment 1 to Appendix II (the End-of-Life Lease guidelines).

Table 1 - Cost Codes and Categories

Cost Code	Cost Category
100	Labor
200	Material
300	Transportation
400	Contract Services
500	Lessee Owned Rentals
600	Insurance
700	Communications
800	Ecological and Environmental
900	Abandonment
1000	Other Costs
1100	Other Credits

Many of the allowable cost definitions we use for royalty relief are the same as those we allow for Net Profit Share Leases (NPSL). Where the definition of terms is identical, we refer to the corresponding cite in the Code of Federal Regulations. In those instances where the definitions differ, we specify the definition appropriate for royalty relief purposes.

Costs associated with Labor, Material, Abandonment and Other Costs categories are eligible for an overhead allowance of 5 percent, slightly more generous than the share allowed during the relief period in the NPSL regulations at 30 CFR 220.012. Other categories tend to be contract costs which already have an overhead included in them. Joint costs and credits should be allocated to the lease in the same manner as described in the NPSL regulations at 30 CFR 220.014.

There are two basic rules you should follow when making decisions on whether to include particular costs in the application. First, we count and you should submit only your costs or portions of your costs that you can validate as necessary for the proper conduct of your lease operations.

Second, we don't allow and you should not submit costs for any obligation *that would continue should lease operations cease. For example, we don't allow installment payments for a capital expenditure that was financed* or the costs of abandonment for pre-existing wells and facilities *that will not be used to produce the field or project.* These obligations remain regardless of the economic performance of your lease, so they are not considered relevant to whether you continue to produce on an otherwise profitable lease.

A. Labor (cost code 100) covers:

   1. Salaries and wages of field employees, first level supervisors, and technical employees employed in the operation of your lease, in the area of your lease.

   2. Salaries and wages of technical employees within technical branches of your organization who are working "full time" on some particular technical problem or operations aspect of your lease. Excluded from this category are employees assigned a role in your lease's operations as a duty collateral with other duties that do not directly benefit that lease.

   3. Salaries and wages of technical employees within technical branches of your organization who are assigned technical tasks directly related to the operation of your lease provided they are supported by adequate time records showing the nature of the task and the hours spent on the task. This is an example of a joint allocable cost.

   4. Employee benefits allowable according to 30 CFR 220.011(b)(2-6).

   5. Overhead allowance up to 5 percent of the sum of the other costs in this category. This allowance, together with the corresponding amounts in items B, I, and J below is designed to cover your finance, administration, and management activities appropriate for the field.

B. Material (cost code 200) covers items you purchase or furnish as lease property. We look for the following attributes in costs you claim in this category.

   1. You charge or credit material at amounts specified in 30 CFR 220.015. Your purchase and inventorying of material conforms to the conditions and provisions of 30 CFR 220.032.

2. You charge to the lease only such material purchased or furnished as lease property that is consistent with efficient and economical operations. You have not accumulated surplus stocks.

3. You credit to your lease costs for salvaged or returned material.

4. Overhead allowance up to 5 percent of the sum of the other costs in this category.

C. Transportation (cost code 300) covers charges for transportation of employees and material necessary for your lease operations to, from and within the lease area. Joint transportation costs must be allocated pursuant to the above referenced NPSL regulations. We look for the following attributes in transportation charges you claim.

1. You only charge transportation costs for material for a distance not greater than the distance from where like material is normally available.

2. You count transportation charges for material shipped from the lease only for lease material and then only to the nearest reliable supply store, barge terminal, or railway receiving point.

3. You do not include expenditures under $200 in transportation charges for material.

D. Contract Services (cost code 400) covers the cost of services and utilities provided to your lease under contract by outside parties and rental charges paid to outside parties for the use of equipment in the lease area in support of lease operations. These services must be provided under an arm's- length contract as defined in 30 CFR 206. Actual costs, rather than fees, for services, provided under a non-arm's-length contract, must be included in the appropriate cost categories described above and below. We look for the following attributes in the costs you claim for contract services.

1. The contract services constitute proper and necessary lease operations or support for lease operations.

2. You charge the contract rate for contract services (including consulting services or contracted technical personnel) established exclusively for the lease.

3. You allocate the cost of contracted services shared among this lease and others pro-rata to the applicable leases.

4. You do not count the costs of contract services for research and development.

E. Rental of Equipment and Facilities Furnished by Lease Owner(s) or affiliated parties (cost code 500) covers the use of equipment and facilities that you *own or* acquire that are proper and necessary for lease operations and are not lease property.

1. These may include shore base and offshore facilities, and pipelines from the tract to shore based facilities.

2. The methodology for determining allowable charges for the use of non-lease equipment furnished by the lessee is specified at 30 CFR 220.011(g).

F. Insurance (cost code 600) covers net premiums you pay for insurance you are required to carry for lease operations.

G. Communications (cost code 700) cover the costs of leasing, acquiring, installing, operating, repairing, and maintaining communication systems, including radio, microwave facilities, and computer production controls for lease operations according to the proportion of those costs that are allocable to lease operations.

H. Ecological and Environmental (cost code 800) cover three items.

1. Those costs you incur in the lease area as a result of statutory regulations for archeological and geophysical surveys relative to the identification and protection of cultural resources.

2. Your cost to provide or to have made available pollution containment or removal equipment, including payments to organizations or funds which supply equipment or assistance in the event of oil spills or other environmental damage.

3. Your costs for the actual control and cleanup of oil spills and resulting responsibilities required by applicable laws and regulations except in cases of your negligence or willful misconduct. We don't allow any costs from an incident resulting in civil or criminal penalties.

I. Abandonment (cost code 900) covers three items.

1. We allow costs associated with abandonment of wells *you plan to drill if we approve royalty relief and wells that have been drilled and will be used to produce the field or project.*

2. We allow costs associated with abandonment of a well bore for the purpose of using it to drill into *another* reservoir included in the project and with modification of platform equipment for project specific purposes.

3. Overhead allowance up to 5 percent of the sum of the other costs in this category.

J. Other Costs (cost code 1000) covers costs not included above that you incur in the necessary and proper conduct of the lease operation. You must identify and explain any costs in this category. These costs may include up to a 5 percent overhead.

K. Other Credits (cost code 1100) cover credits to lease operations for:

1. Lease property you lease to or use in non-lease operations,

2. Your sale of information derived from test wells and geological and geophysical surveys, and

3. For any and all amounts earned or otherwise due you as a result of lease operations.

Ineligible costs are listed in the Cost Report.

Attachment D: Suggestions to Streamline CPA Certification

The purpose of CPA certification is for an independent expert to confirm that only allowable costs incurred by the applicant are used for qualification. This certification must be submitted along with the completed application and conform to the following guidance to start our evaluation period.

At a minimum, we expect the CPA to confirm or identify deviations from at least the following items:

1. Application includes only charges incurred on or for the sole benefit of the subject lease(s) or discovery well(s).

2. Application includes only allowable charges as described in Appendix C of these guidelines.

3. Application includes only allowable costs that were incurred for services rendered or goods bought for the discovery well(s) and, for fields with pre-Act leases, between the discovery and the application date.

4. Application values for large cost elements are supported by backup invoices or other, comparable sub-ledger records.

The applicant's own accounting system may not match that described in Attachment C. When that is the case, the following procedural checks should suffice to certify accuracy of historical financial information and conformity to MMS guidelines.

To confirm applicability and accuracy of costs, identify and list other audits performed for the qualifying period used in the application that contain these lease(s) and associated facilities.

a. If one or more other audits have been performed, review cost structure provided in the application to be sure it is consistent with costs for the application lease(s) shown in the other audits. Identify any inconsistencies.
b. If no other audits have been performed for the qualifying period, audit a random sample of sub-ledger records for charges assigned to the lease(s). Check invoices for any unusually large or erratic items (e.g., double previous month's level).

To confirm inclusion of only allowable costs, determine which categories in the applicant's own accounting system are likely to record charges not allowed under MMS regulations and guidelines (30 CFR 220.013 and Attachment C of these guidelines). Review cost elements in these categories of the applicant's own accounting system which should record any non-allowed costs. Eliminate charges for any items found to be non-allowable from the amount confirmed in procedure 1 above.

To confirm inclusion of only costs incurred during the qualification period, examine the dates services were rendered or goods were received for allowable costs. Costs should be recorded in the period when they actually occurred. Review cost elements in the beginning months of the qualification period to ensure they were actually incurred during the qualification period. Eliminate costs that were incurred prior to the qualification period.

Attachment E: RSVP Computer Model Layout
(supplements 30 CFR 203.85)

We've constructed a template model, Royalty Suspension Viability Program (RSVP), for the Economic Viability and Relief Justification report. It is to be used with Windows, Excel version 7 and Crystal Ball version 4.0 software. You may obtain the RSVP template from:

Regional Supervisor for Production and Development
Minerals Management Service
Gulf of Mexico OCS Region
1201 Elmwood Park Boulevard
New Orleans, LA 70123-2394

Crystal Ball is a registered trademark of Decisioneering, Boulder, Colorado, (www.decisioneering.com; phone (303) 337-0900 or 800-289-2550; FAX (303) 337-3560).

The RSVP model uses probability (Monte Carlo) methodology to develop a resource estimate from your input data and a net present value for your field from the production profile and cost components you supply. We provide details on how the model works in extensive documentation available with the model.

Also, you may download these guidelines, the model and its documentation from the MMS home page (http://www.gomr.mms.gov/homepg/offshore/royrelef.html). From that screen, you then go to Managing Offshore Resources, Gulf of Mexico, Offshore Information, Royalty Relief Information.

The Documentation for the RSVP Model offers an example complete with inputs and results. We highly recommend that you confirm the example outputs before proceeding with extensive additional analyses.

The reserve model is integrated into RSVP as shown in the template. You can get resource output distributions in addition to those programmed in RSVP by alternative selection of Crystal Ball output parameters as discussed in the model documentation. Outputs of the Resource module are in columns X through AR. Those for the viability module are in columns BX through CW. The inputs and outputs should be provided on a 3.5-inch diskette.

UNITED STATES DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE

Appendix II to NTL No. 2010-N03

GUIDELINES FOR THE APPLICATION, REVIEW, APPROVAL, AND ADMINISTRATION OF ROYALTY RELIEF FOR END-OF-LIFE LEASES

March 2010

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ATTACHMENTS

Recovery of Costs

Under Federal policy and statute, we'll charge you a fee for applying for royalty relief to recover our cost of processing your application. The Administrative Procedures Act (31 U.S.C. 9701) and Office of Management and Budget Circular A-25 require that we recover our costs when we provide services that confer special benefits or privileges to identifiable non-Federal recipients. Processing of applications for royalty relief clearly falls within this mandate.

The Omnibus Appropriations Bill (PL. 104-134, 110 Stat. 13221, April 26, 1996) authorizes our fees. The statute provides "That beginning in fiscal year 1996 and thereafter, fees for the royalty rate relief applications shall be established (and revised as needed) in Notices to Lessees, ... for the costs of administering the royalty rate relief authorized by 43 U.S.C. 1337(a) (3)."

We may issue a revised notice to lessees (NTL), updating NTL 98-5N, to provide more detailed information on the royalty relief application fees and when and how you make payments. Currently, we charge $8,000 to review your application and an additional $12,500 if we decide we need to audit your historical data to confirm that you qualify for relief. We will revise the NTL periodically to reflect our cost experience in administering this program.

OVERVIEW OF GUIDELINES FOR END-OF-LIFE ROYALTY RELIEF UNDER 30 CFR PART 203

We issued final regulations (30 CFR Part 203) in January 1998 to implement the Outer Continental Shelf Deep Water Royalty Relief Act (Public Law 104-58 (DWRRA)). As part of that rule-making, we simplified and revised the way we implement authority the Secretary of the Interior has under 43 U.S.C. 1337(a)(3)(A) to reduce or eliminate royalties. This authority applies to oil and gas leases anywhere in the Federal Outer Continental Shelf (OCS). Leaseholders who have inadequate revenues to sustain production qualify for royalty relief if we determine that a modification in the royalty arrangement will result in recovery of additional resources.

Affected lessees may apply to the Minerals Management Service (MMS) for a reduced royalty rate by submitting the information specified under the final regulations. The specific data, reports, and spreadsheets in an application are described in supplementary guidelines, issued as an attachment to this Notice to Lessees and Operators (NTL). These supplementary guidelines also explain the procedures we will follow for evaluating applications and implementing royalty relief, and our rationale for excluding selected cost items from consideration.

We advise that you carefully review a copy of these guidelines if you intend to request End-of-Life Royalty Relief. They do not add any requirements to the regulations, but they will help you structure your application so as to expedite our evaluation. Be sure to use the most current version of these guidelines as we will periodically update them to reflect our experience in processing applications.

The NTL, the computer spreadsheet, and these guidelines are available from your regional office or on the MMS website at http://www.mms.gov.

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

Dated: 5 March 1999

Carolita U. Kallaur
Carolita U.Kallaur,
Associate Director for
Offshore Minerals Management

UNITED STATES DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE

Effective Date: March 5, 1999

Guidelines for the Application, Review, Approval, and Administration of Royalty Relief for End-of-Life Leases

A. Introduction

These guidelines interpret regulations (30 CFR Part 203.50 through 203.56 and 203.81 through 203.84) which establish the terms and conditions for granting reductions in royalty rates to end-of-life leases under the Outer Continental Shelf (OCS) Lands Act. This form of relief applies to Federal leases anywhere on the OCS that have meaningful levels of production. Other guidelines interpret regulations for deep water royalty relief.

As with the rule, we have written these guidelines in the "plain English" or conversational style. We (Minerals Management Service) instruct you (applicants, lessees, operators) on how to determine when you qualify for royalty relief and how you apply for it in a way that most efficiently facilitates our review. Also, we explain how we administer relief you may receive.

Guidelines are not strict rules like regulations, so we may deviate from individual elements of them if an applicant makes a convincing argument to do so. We will consider requests for departure from the guidelines only when an applicant provides compelling reasons for deviating from a provision before, or when submitting, a royalty relief application.

For purposes of royalty relief, designated unit operators may act as the applicant on behalf of all lessees (payors). Operators acting as applicants are responsible for assuring that the application contains accurate revenue, royalty, and transportation and processing allowance data on all sales from the lease. When not privy to all actual revenue, royalty and cost allowance data, operators must fully explain how they estimated those amounts and alert all payors that we may require such data and explanation from each one before we can make a final decision on an application.

B. Royalty Rate Reductions - General

Under 43 U.S.C. 1337 (a)(3)(A), we may reduce or eliminate the royalty or net profit share specified for your producing OCS lease to promote increased production. The purpose of royalty relief is to allow you reasonable financial returns so as to increase ultimate resource recovery (e.g., oil, gas, or sulphur) and augment receipts to the Federal Treasury. Therefore, we will modify the royalty rate where sound engineering and economic principles indicate that this change will extend the productive life of your lease.

We use only historic data to determine if you need end-of-life royalty relief. That reliance presumes that you continue to operate your lease in a way that does not significantly alter historical practice. We rely on certain procedures to protect the integrity of a decision based on historic data. If you have recently instituted or plan significant changes to your operation, you should implement such changes and operate for 12 months in your new configuration before seeking to qualify for royalty relief. Otherwise, we will defer action on your application until that circumstance is achieved. Until your application fully reflects the effect of recent significant changes to your operation, we cannot be confident that you need royalty relief to continue operations. We will wait up to 2 years for you to provide updated data reflective of your new configuration. Further, we will terminate your relief if you subsequently do things that we have notified you are significant changes to your operation.

C. Qualifications for Relief

Producing leases that have inadequate revenues to sustain continued production, i.e., end-of-life leases, can apply for royalty relief. The term "lease" refers to either a lease or an approved unit. To qualify for royalty relief, you need to show that your lease satisfies the following production and economic conditions.

1. To be eligible for royalty relief, the rule specifies that your lease must satisfy certain production requirements during a qualification period. By ***production***, we mean the sum of dispositions for oil and gas reported by the operator on MMS-4054 Form (OGOR-B report) to MMS. Under the rule, ***qualification months*** consist of the most recent 12 of the last 15 calendar-months in which you satisfy the following production requirements.

   For an oil and gas lease, the production requirement during a *qualifying month* is an average of at least 100 barrels of oil equivalent (BOE) per day. For a non-oil and gas lease, any positive level of production will satisfy the production requirement needed in a *qualifying month.*

   To allow for lags in data availability and you time to prepare an application, your 15 month period may end up to 120 days before the date we receive your certified application. Part of your application is an independent opinion from a certified public accountant (CPA). To expedite a CPA review, Attachment 3 outlines the confirmation procedures we believe are necessary for an independent opinion on the reliability of the data in your application.

2. To demonstrate that your lease is becoming uneconomic, the rule specifies that you must show that royalties you paid ***(ROY)*** exceed 75 percent of ***net revenues (NR)*** generated during your qualification months. The clearest way to show this is by substituting your data into the formulas below. Define ***Royalty Share*** (*RS*) as:

$$RS = \frac{ROY}{NR}\ (100\%) \quad \text{where}$$

ROY is the net royalty that you have paid under the existing royalty arrangement, after determining royalty due and deducting any ***transportation and processing allowances*** (*TPA*) that you are permitted under regulations at 30 CFR 206 and recent precedents.

NR is your net revenues as defined by: $NR = GVP - AC - TPC$, where

Gross Value of Products (GVP) is gross proceeds all lease owners receive under arm's-length contracts for sale of production in marketable condition. Our Oil and Gas Payor Handbook, Volume III, Product Valuation gives details on how to compute this *GVP* as well as *TPA*.

In cases where a unit operator serves as the applicant on behalf of multiple payors, he must illustrate how he calculated *GVP*, *ROY*, and *TPA* on his part of sales. Integral to that illustration is a careful explanation of the basis for determining the amounts authorized by regulation at 30 CFR 206 and recent precedents. We will compare those amounts attributed to other payors on the lease from operator's calculation with what they actually reported to MMS. Where we find material discrepancies, we will request documented calculations from those payors.

Allowable Costs (AC) is a variable representing the sum of your expenses during the qualification months that are necessary for the continued operation of your lease. We follow the cost accounting structure prescribed for Net Profit Share Leases in 30 CFR 220.011 - 220.015 because it describes actual expenditures that benefit the on-going operation of your lease. Attachment 1 summarizes costs we consider allowable for end-of-life royalty relief qualification.

Generally, you may include expenses for operating and maintaining the existing wells and facilities on your lease and costs for replacement or side track wells completed in the same producing reservoir because these expenses are necessary for full recovery of the resources. With the exception of certain rentals described in Attachment 1, you may not include charges for recovering the capital cost of equipment or reserves (i.e., amortization, depreciation, depletion) because they are development costs not consistent with an end of life circumstance.

If you expend funds to place production in salable condition to obtain the *GVP* used for royalty calculation, you may include expenses for the requisite treatment activities (separation, dehydration, stabilization, etc.) that take place prior to the sales point. If these activities are carried out under an arm's-length contract with a nonaffiliated plant, allowable expenses equal the fees you pay for the treatment activities. Otherwise, we only allow fees in the amount that you can show reflect the actual costs incurred by the affiliated plant in treating your production. We follow the definition of affiliation (10 percent or more ownership) used in 30 CFR 206.101. Gas plant processing costs for activities designed to remove elements or compounds (hydrocarbon and nonhydrocarbon) from gas, including absorption, adsorption, or refrigeration should be included in the transportation and processing allowance category described below.

You may also include reasonable portions of joint costs which rightfully should be allocated to this lease. Joint costs mean any of the cost items listed in Attachment 1 that benefit this lease and one or more other operations or leases. For instance, costs associated with producing reservoirs or part of reservoirs in State waters from a facility on a Federal lease are generally not allowable costs for Federal royalty relief purposes. However, if the State/Federal parts of the field are unitized, then we may allow the portion of unitized costs allocated to production from the Federal part of the lease. Because some joint costs may be difficult to allocate, we also allow you to assign a 5 percent overhead amount to certain cost items.

As the rule states, we may, in our review and evaluation of your application, disallow certain costs when we consider them to be unnecessary for the ongoing operation of your lease.

Transportation and Processing Costs (TPC) is a variable representing the sum of your reasonable, actual costs for transportation and processing associated with the oil and gas produced from your lease. *TPC* is based on the ***transportation and processing allowance (TPA)*** you are permitted under the regulations at 30 CFR 206 and recent precedents. You should illustrate and explain how you determined the *TPA* shown on the Report of Sales and Royalty Remittance (Form MMS-2014) you submitted during the qualifying period.

The *TPA* represents the part of your total *TPC* incurred to handle the lessor (royalty) share of the total product. Your *TPC* should never exceed your *TPA* divided by your royalty rate.

An example helps clarify the calculation for relief qualification.

Suppose $GVP = 100$, $AC = 54$, $TPA = 2$, and the effective royalty rate in the qualifying months is 1/3.

Then, $TPC = 2 / (1/3) = 6$;
$ROY = (1/3) * (100 - 6)$ or $= [(1/3) * 100] - 2 = 31.33$; and
$RS = [31.33/(100 - 54 - 6)] *100$ percent $=$ 78.3 percent

If your actual *TPC* is less than the amount calculated in this way, you should use the actual amount of your costs, with one exception. The exception is that in cases where you have approval of the MMS Royalty Management Program to report a tariff approved by the Federal Energy Regulatory Commission (FERC) in lieu of actual transportation costs, you may claim the part of the tariff associated with the royalty portion of production as the transportation allowance. However, for the remaining non-royalty portion of production, you must count only the reasonable actual costs, as opposed to any imputed costs or tariffs, incurred in transportation of the non-royalty portion of your production.

Processing costs can be claimed only for gas plant products, as defined in the regulations. The processing costs approved by the MMS Royalty Management Program can be claimed as part of the actual costs associated with the royalty portion of gas plant production. For the remaining non-royalty portion of the gas plant products, you must count only the actual costs, as opposed to any imputed costs, incurred in the processing of these products.

D. Form of Relief

Upon qualification, we will reduce the royalty rate to a fixed ***royalty relief rate*** of half of the lease's effective royalty rate, where the ***effective royalty rate*** represents the average royalty rate applied to the gross production volume during the 12 months included in the qualifying period. You may still claim the *TPA* credit against royalties owed after we grant relief.

If we have given relief to this lease before, the original lease rate may not be the same as the *effective royalty rate*. The following example illustrates how to find your *effective royalty rate* when more than one fixed rate has applied during the qualifying period.

Suppose that for 4 months production totals 500 (that is, averages 125/month) and one royalty rate (1/6) applies, and for the other 8 months production totals 2,000 while another royalty rate (1/3) applies.

The production-weighted average royalty rate over the qualifying period or the *effective royalty rate* is {[(500 * (1/6)) + (2,000 * (1/3))]/(500 + 2,000)} * 100 percent = 30 percent, so the *royalty relief rate* would be 15 percent.

If you operated under a net revenue share royalty system, you must derive an *effective royalty rate* for each month by dividing royalties owed by well-head value (*GVP* - *TPC*). The following example illustrates how to find your *effective royalty rate* for one month when your royalty was determined by a net revenue or net profit share system.

Suppose your monthly royalty obligation is 50 percent of *GVP* (of say 3,000) less *TPC* (of say 700) and less an allowable operating cost (of say 920).

Your *effective royalty rate* for the month is {[(0.5 * (3,000 - 700 - 920))]/(3,000 - 700} * 100 percent = 30 percent

The calculation must be repeated for each of the 12 qualifying months and the result for each month weighted by the production volume in the same month. If the production-weighted average of your *effective royalty rates* in all 12 qualifying months worked out to be 30 percent, your *royalty relief rate* would again be 15 percent.

The royalty relief rate will apply to production up to the ***royalty relief volume***. It is equal to the monthly average number of barrels of oil equivalent produced over the 12 months in the qualification period. For natural gas production, 5,620 cubic feet of gas is equivalent to one barrel of oil.

With the production numbers from the above example, the *royalty relief volume* would be (500 + 2,000)/12 = 208.3.

Any monthly volume of production above and up to 2 times the *royalty relief volume* will bear royalties at 1.5 times the effective royalty rate. Production above 2 times the relief volume amount pays the effective royalty rate. The following illustration continues the example.

Suppose production reaches 300 in a month after relief is granted.

You would owe royalties on the first 208.3 at a 15 percent rate, while you would owe royalties on the remaining 91.7 at a 45 percent rate (1.5 * 30 percent).

You should compute an average royalty rate each month, which serves as the rate for calculating actual royalties due. You find it by taking the production-weighted average of the rate associated with production up to the relief volume (equal to ½ the *effective royalty rate*), and the rate associated with additional production (equal to 1.5 times the *effective royalty rate* for up to double the *royalty relief volume* and the effective royalty rate for any greater volume). The following illustration completes the example.

The average royalty rate for a month with production of 300 is {[(208.3 * 0.15) + (91.7 * 0.45)]/300} * 100 percent = 24.17 percent.

If production climbs to 420, the average royalty rate is {[(208.3 * 0.15) + (208.3 * 0.45) + (3.4 * 0.3)]} * 100 percent = 30 percent. In effect, the average *relief royalty rate* gradually increases (as monthly production) rises to a cap at the pre-relief *effective royalty rate*.

E. Suspension of Relief

You owe royalties at the *effective royalty rate* on all production during any month in which sweet crude oil and natural gas prices increase by more than 25 percent. You should calculate the increase as the difference between the current weighted 12 calendar-month rolling average of NYMEX (New York Mercantile Exchange) and the weighted 12 calendar-month average of NYMEX prices during your qualification months. The weighting factors for oil and gas are the percentages of your total production provided by each product during the 12 qualifying months. In these cases, the *effective royalty rate* will apply to all your production.

Suppose you produced an average of 3,500 bbls of oil and 2,810 mcf of gas (with 1.1 MMbtu per mcf) per month during your 12 qualifying months. Converting gas to BOE using a factor of 5,620 scf/bbl, your production weighting factors are {3,500/[(3,500 + (2,810/5.62)]} * 100 percent = 87.5 percent oil and 12.5 percent gas.

Suppose over your 12 qualifying months average NYMEX oil prices were $12/bbl and average NYMEX gas prices were $2 per million Btu. Your base price level is ($12 * 0.875) + [(2 * 1.1) * 0.125] = $10.775/BOE. If average NYMEX prices weighted by these factors exceed ($10.775 * 1.25) = $13.47/BOE, you would owe royalties at your pre-relief or effective rate. This happens if the average NYMEX oil price rises to $15/bbl and the average NYMEX gas price rises to $2.50/MMBtu over the same 12 month period. It also would happen if the average NYMEX oil price rose to $15.08/bbl and gas prices remained at $2/MMBtu.

F. Termination of Relief

End-of-Life royalty relief ends in any of three situations.

1. At any time you may renounce, by written notification to the MMS Regional Director for your area, the royalty relief granted under these guidelines. After we acknowledge the change, you will owe royalties at the pre-relief or effective rate as of the next full month when royalties are due.

2. Relief ends when your average royalty rate equals the effective rate for 12 consecutive months. This would happen if prices remain more than 25 percent above their average level in your qualifying months or if your production is double or more the relief volume for 12 consecutive months.

3. We reserve the right in individual cases to specify activities that will end relief because they are not compatible with an end-of-life circumstance. If we choose to reserve this right in your individual case, we will notify you in our letter approving your end-of-life relief what activities are incompatible with continuation of relief and when relief would terminate. Also, we will indicate the terms to which your royalty obligation will revert in the event such activities occur.

G. Withdrawal of Relief

If we find that you provided false or intentionally inaccurate information that was material to our granting you relief, you must pay full royalties and late payment interest determined under 30 U.S.C. 1721 on all production on which you used the royalty relief. You may also be subject to penalties under other provisions of law.

H. Review And Audit

All data you submit in support of the relief application is subject to review and audit.

I. Procedures for Submitting Applications

You should file your application for royalty relief with the MMS Regional Director for your area. Under the rule, your application must contain two reports: (1) Administrative Information; and (2) Net Revenue and Relief Justification. Attachment 2 describes what should be in these reports.

Attachment 3 outlines procedures for an acceptable CPA certification. Attachment 4 illustrates a spreadsheet format you should use in the Net Revenue and Relief Justification Report.

Ordinarily we would not expect the operator and owners who file an application for royalty relief to change while we are evaluating the application. To preserve the integrity of a pending application, we insist that the designated operator remain unchanged until we render a relief decision. However, owners may change during our evaluation period without affecting a pending application. After we have rendered a relief decision, operators as well as owners are free to change without affecting relief we have already granted.

Before you can reapply either for relief after your previously held relief has ended, or for more relief, the rule holds that your lease must have 12 qualifying months under the same royalty or relief terms. When you have had the same royalty terms for 12 qualifying months, you still have to pass the qualifications listed in Section C above.

J. Procedures for Review, Evaluation, And Decision

We will review the royalty relief application for completeness and verify that the data are reasonable. If we determine that you do indeed meet the qualification requirements, then we'll give you royalty relief because it should induce meaningful quantities of incremental production. We will notify you in writing of the *royalty relief volume* amount, the *effective royalty rate*, the threshold average oil and gas price level at which suspension and possible termination of relief occur (for an oil and gas lease), other conditions or clarifications of the arrangement, and the date on which the new terms would begin. Your new arrangement normally would start on the first day of the month following the date we approve your relief.

If your application is incomplete or we decide your data are not reasonable, we will give you the opportunity to submit additional or revised information. If your response cannot clear up our concerns, we will deny your request for royalty relief. If we deny your request, we will explain our decision and rationale to you in writing. We retain the application fee. You may appeal any of our decisions to the Director, MMS, within 30 days, under the provisions of 30 CFR 290.

Attachment 1
Allowable Cost Categories Associated with the Cost Variables
Used to Determine Qualification for Royalty Relief

The text of these guidelines refers to several different cost variables we use to determine your qualification for royalty relief. Each of these variables consist of expenditures associated with several different cost categories. This attachment summarizes categories of allowable cost, drawn from 30 CFR 220.011, and describes what expenditures we view as eligible costs in the respective cost categories. Our companion guidelines on deep water royalty relief includes an almost identical attachment (Attachment C) on allowable costs. *Italics* in this Attachment 1 denote passages which deviate from Attachment C in the other guidelines.

Table 1 - Cost Codes and Categories

Cost Code	Cost Category
100	Labor
200	Material
300	Transportation
400	Contract Services
500	Lessee Owned Rentals
600	Insurance
700	Communications
800	Ecological and Environmental
900	Abandonment
1000	Other Costs
1100	Other Credits

Many of the allowable cost definitions we use for royalty relief are the same as those we allow for Net Profit Share Leases (NPSL). Where the definition of terms is identical, we refer to the corresponding cite in the Code of Federal Regulations. In those instances where the definitions differ, we specify the definition appropriate for royalty relief purposes.

Costs associated with Labor, Material, Abandonment and Other Costs categories are eligible for an overhead allowance of 5 percent, slightly more generous than the share allowed during the relief period in the NPSL regulations at 30 CFR 220.012. Other categories tend to be contract costs which already have an overhead included in them. Joint costs and credits should be allocated to the lease in the same manner as described in the NPSL regulations at 30 CFR 220.014.

There are two basic rules you should follow when making decisions on whether to include particular costs in the application. First, we count and you should submit only costs or portions of costs that you can validate as necessary for the proper conduct of your lease operations.

Second, we don't allow and you should not submit costs for any obligation that *you incurred before the qualifying period. For example, we don't allow amortization or depreciation charges for equipment or facilities you acquired before the qualifying months. You incurred such capital costs because you anticipated being able to recover them without royalty relief.* Likewise we don't allow the costs incurred for the abandonment of pre-existing wells and facilities. These obligations remain regardless of the economic performance of your lease, so they are not relevant to whether you continue to produce on an otherwise profitable lease.

A. Labor (cost code 100) covers:

1. Salaries and wages of field employees, first level supervisors, and technical employees employed in the operation of your lease, in the area of your lease.

2. Salaries and wages of technical employees within technical branches of your organization that may not work in the area of the lease but are working "full time" on some particular technical problem or operations aspect of your lease. Excluded from this category are employees assigned a role in your lease's operations as a duty collateral with other duties that do not directly benefit that lease.

3. Salaries and wages of technical employees within technical branches of your organization who are assigned technical tasks directly related to the operation of your lease provided they are supported by adequate time records showing the nature of the task and the hours spent on the task.

4. Employee benefits allowable according to 30 CFR 220.011(b)(2-6).

5. Overhead allowance up to 5 percent of the sum of the other costs in this category. This, together with the corresponding amounts in items B, I, and J, below is designed to cover your finance, administration, and management activities appropriate for the lease.

B. Material (cost code 200) covers items you purchase or furnish as lease property. We look for the following attributes in costs you claim in this category.

1. You charge or credit material at amounts specified in 30 CFR 220.015. Your purchase and inventorying of material conforms to the conditions and provisions of 30 CFR 220.032.

2. You charge to the lease only such material purchased or furnished as lease property that is consistent with efficient and economical operations. You have not accumulated surplus stocks.

3. You credit to your lease costs for salvaged or returned material.

4. Overhead allowance up to 5 percent of the sum of the other costs in this category.

C. Transportation (cost code 300) covers charges for transportation of employees and material necessary for your lease operations to, from and within the lease area. We look for the following attributes in transportation charges you claim.

1. You only charge transportation costs for material for a distance not greater than the distance from where like material is normally available.

2. You count transportation charges for material shipped from the lease only for lease material and then only to the nearest reliable supply store, barge terminal, or railway receiving point.

3. You do not include expenditures under $200 in transportation charges for material.

D. Contract Services (cost code 400) covers the cost of services and utilities provided to your lease under contract by outside parties and rental charges paid to outside parties for the use of equipment in the lease area in support of lease operations. These services must be provided under an arm's-length contract as defined in 30 CFR 206. Actual costs, rather than fees, for services provided under a non-arm's-length contract must be included in the following cost categories. We look for the following attributes in the costs you claim for contract services.

1. The contract services constitute proper and necessary lease operations or support for lease operations.

2. You charge the contract rate for contract services (including consulting services or contracted technical personnel) established exclusively for the lease.

3. You allocate the cost of contracted services shared among this lease and others pro-rata to the applicable leases.

4. You do not count the costs of contract services for research and development.

E. Rental of Equipment and Facilities Furnished by Lease Owner(s) or affiliated parties (cost code 500) covers the use of equipment and facilities which you acquire *during the qualifying months* that are proper and necessary for lease operations and are not lease property.

1. These may include shore base and offshore facilities, and pipelines from the lease to shore based facilities.

2. The methodology for determining allowable charges for the use of non-lease equipment furnished by the lessee is specified at 30 CFR 220.011(g).

F. Insurance (cost code 600) covers net premiums you pay for insurance you are required to carry for lease operations.

G. Communications (cost code 700) cover the costs of leasing, acquiring, installing, operating, repairing, and maintaining communication systems, including radio, microwave facilities, and computer production controls for lease operations according to the proportion of those costs that are allocable to lease operations.

H. Ecological and Environmental (cost code 800) cover three items.

1. Those costs you incur in the lease area as a result of statutory regulations for archeological and geophysical surveys relative to the identification and protection of cultural resources.

2. Your cost to provide or to have made available pollution containment or removal equipment, including payments to organizations or funds which supply equipment or assistance in the event of oil spills or other environmental damage.

3. Your costs for the actual control and cleanup of oil spills and resulting responsibilities required by applicable laws and regulations except in cases of your negligence or willful misconduct. We don't allow any costs from an incident resulting in civil or criminal penalties.

I. Abandonment (cost code 900) covers three items.

1. We allow costs associated with abandonment of wells *you drilled during the qualification period* but not costs associated with wells existing before *the start of the qualification period.*

2. We allow costs associated with abandonment of a well bore for the purpose of using it to drill into *a producing* reservoir included in the project and with modification of platform equipment for project specific purposes.

3. Overhead allowance up to 5 percent of the sum of the other costs in this category.

J. Other Costs (cost code 1000) covers costs not included above that you incur in the necessary and proper conduct of the lease operation. You should have any costs in this category specifically approved by the Director, MMS, or appropriate delegated authority. You may include an overhead allowance of up to a 5 percent of the other costs in this category.

K. Other Credits (cost code 1100) cover credits to lease operations for:

1. Lease property you lease to or use in non-lease operations,

2. Your sale of information derived from test wells and geological and geophysical surveys, and

3. For any and all amounts earned or otherwise due you as a result of lease operations.

In addition to those costs listed at 30 CFR 220.013, the following costs are not allowable:

1. OCS rental payments on the lease(s) in the application.

2. Damages and losses.

3. Taxes.

4. Any costs associated with activities that are exploratory in nature.

5. Civil or criminal fines or penalties.

6. Royalty relief application fees.

7. Costs associated with prior existing obligations (e.g., royalty overrides or other forms of payment for acquiring a financial position in a lease).

Attachment 2
Reports Required for a Complete Application

The rule specifies that your application must include the following information.

1. **Administrative Information Report** - You use this report to identify your lease or unit and to summarize its background. It includes:

   - Serial number and block designation of your lease, names of the titleholder of record, the lease operator, the identification of whether the lease is part of a unit and description of lease or unit history.

   - Company designation, the API number, location and status of each well that has been drilled on the lease.

   - Full information as to whether you are obligated to pay royalties or payment out of production to anyone other than the United States, the amount to be paid, and your efforts to reduce them.

2. **Net Revenue and Relief Justification Report** - You use this report to summarize your lease or unit's production, revenue and cost history for your qualifying months.

- It consists of a cash flow statement with the following items for each of 12 qualifying months (i.e., those most recent 12 of the last 15 months which had production of at least 100 barrels of oil equivalent per day). Attachment 4 illustrates the spreadsheet format we recommend that you use for your cash flow statement.
  1. All lease production subject to royalty computed in accordance with the lease and applicable regulations.
  2. Total revenues received on all lease production.
  3. Total royalties paid on all lease production.
  4. Allowable costs (using the cost categories identified in Attachment 1).
  5. Total transportation and processing costs allowed under MMS regulations.
  6. Calculation of net income and revenue share.

- The spreadsheet should demonstrate that royalties paid exceed 75 percent of net revenues generated during the qualifying months.

- You must have this report certified by an independent certified public accountant (CPA) expressing any specific reservations or the lack of any reservations about the accuracy of the historical financial information and that the presentation and interpretation of the data elements conform to the MMS guidelines. Attachment 3 describes the essential elements of this CPA certification.

- You should carefully explain any significant variability within a cost variable or category.

Attachment 3
Procedures For Streamlining CPA Certification

The purpose of CPA certification is for an independent expert to confirm that only allowable operating, transportation, and processing costs are used for qualification. Three steps are critical: (1) separating charges incurred on the subject lease(s) from ones incurred elsewhere; (2) identifying and eliminating any charges not allowed under MMS regulations and guidelines; and (3) dividing the remaining operating charges into two parts, those authorized to claim a 5 percent overhead and those not authorized to claim overhead.

The applicant's own accounting system may not match that described in Attachment 1 of the MMS end-of-life Guidelines. When that is the case, the following procedural checks should suffice to certify accuracy of historical financial information and conformity to MMS guidelines.

1. To confirm applicability and accuracy of costs, identify and list other audits performed for the qualifying period used in the application that contain these lease(s) and associated facilities.
   a. If one or more other audits have been performed, review cost structure provided in the application to be sure it is consistent with costs for the application lease(s) shown in the other audits. Identify any inconsistencies.
   b. If no other audits have been performed for the qualifying period, audit a random sample of sub-ledger records for charges assigned to the lease(s). Check invoices for any unusually large or erratic items (e.g., $2 million, or double previous month's level).

2. To confirm inclusion of only allowable costs, determine which categories in the applicant's own accounting system are likely to record charges not allowed under MMS regulations and guidelines (30 CFR 220.013 and Attachment 1 of end-of-life guidelines).
   a. Review cost elements in these categories of the applicant's own accounting system which should record any non-allowed costs. Eliminate charges for any items found to be non-allowable from the amount confirmed in procedure 1 above.
   b. Compare any transportation and processing costs shown in the application with transportation and processing allowances claimed against past royalty payment obligations. Certify that the two figures are consistent.

3. To confirm that only authorized overhead is claimed, allocate cost categories from the applicant's accounting system either to those authorized to charge overhead (labor, material, abandonment, or other as described in Attachment 1) or to those not allowed to (contract services, transportation, rentals, insurance, communications, ecological and environmental). Either of two options may be used to check the size of the overhead subset of allowed costs.
   a. If a majority (>50 percent) of charges in an applicant's cost category fall into MMS categories that are authorized overhead, the whole category of costs is allocated to the overhead subset, otherwise the whole category of costs is allocated to the non-overhead subset.
   b. In each category of the applicant's accounting system, charges authorized overhead may be identified and combined with like charges in the other categories of the applicant's accounting system.

Attachment 4
Spreadsheet Format for Production, Revenue and Cost Data

We urge you to report your data in the format shown on this and the next two pages. You may get a computer (Excel) version of this spreadsheet, which includes formulas to preform the appropriate calculations, from your Regional MMS Director or MMS website at http://www.mms.gov.

Zeros or "ROY/NR" in the following spreadsheet tables indicate cells where formulas calculate values based on entries in the blank cells. Entries in the "Month/Year" column are simply illustrations to be replaced by the qualification period relevant to your application.

End-of-Life Royalty Relief
Relief Qualification Worksheet (page 1)

Month/Year	Royalties Paid (ROY)	Gross Value of Production (GVP)	Allowable Costs (AC)	Transportation & Processing Costs (TPC)	Net Revenue (NR) (GVP - AC - TPC)	Royalty Share
Jan-98	$0.00	$0	$0	$0	$0	ROY/NR
Feb-98	$0.00	$0	$0	$0	$0	ROY/NR
Mar-98	$0.00	$0	$0	$0	$0	ROY/NR
Apr-98	$0.00	$0	$0	$0	$0	ROY/NR
May-98	$0.00	$0	$0	$0	$0	ROY/NR
Jun-98	$0.00	$0	$0	$0	$0	ROY/NR
Jul-98	$0.00	$0	$0	$0	$0	ROY/NR
Aug-98	$0.00	$0	$0	$0	$0	ROY/NR
Sep-98	$0.00	$0	$0	$0	$0	ROY/NR
Oct-98	$0.00	$0	$0	$0	$0	ROY/NR
Nov-98	$0.00	$0	$0	$0	$0	ROY/NR
Dec-98	$0.00	$0	$0	$0	$0	ROY/NR
12 month total/average	$0	$0	$0	$0	$0	ROY/NR

End-of-Life Royalty Relief

Production/Royalty Summary - All Products by Month/Year (page 2)

Product	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98
Oil												
Sales Volume												
Sales Value												
Transportation												
Royalties Paid												
Gas												
Sales Volume												
Sales Value												
Transportation												
Royalties Paid												
NGL												
Sales Volume												
Sales Value												
Transportation												
Processing												
Total T&P	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Royalties Paid												
Other Products												
Sales Value												
Total T&P												
Royalties Paid												
All Products												
Sales Value	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total T&P	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Royalties Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

End-of-Life Royalty Relief
Allowable Costs (page 3)

Code	Category	Jan-98	Feb-98	Mar-98	Apr-98	May-98	Jun-98	Jul-98	Aug-98	Sep-98	Oct-98	Nov-98	Dec-98
100	Labor												
	5% Overhead	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
200	Material												
	5% Overhead	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
300	Transportation												
400	Contract Services												
500	Lessee Owned												
	Rentals												
600	Insurance												
700	Communications												
800	Ecological &												
	Environmental												
900	Abandonment												
	5% Overhead	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1000	Other Costs												
	5% Overhead	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1100	Other Credits												
	Total Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

UNITED STATES DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE
GULF OF MEXICO OCS REGION

NTL No. 2010-G01

Effective Date: February 1, 2010
Expiration Date: January 31, 2015

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL AND GAS LEASES
OUTER CONTINENTAL SHELF, GULF OF MEXICO OCS REGION

Clarification of Deep Gas Royalty Relief Regulation Regarding Natural Gas Liquids and Pipeline (Retrograde) Condensate

This Notice to Lessees and Operators (NTL) supersedes and updates NTL No. 2004-G11. The royalty relief regulations at 30 CFR 203.0 and 30 CFR 203.30-49 suspend royalty on qualified deep gas production volumes, including gas associated with oil production, reported on the Oil and Gas Operations Report, Part A (OGOR-A). Sections 203.34(c) and 203.43(e)(3) of the regulations state that the royalty suspension does not apply to oil and condensate volumes.

While royalty is not suspended for oil and condensate volumes reported on the OGOR-A, the royalty suspension does apply to natural gas liquids and pipeline (retrograde) condensate that are recovered from qualified deep gas production. The hydrocarbons that comprise these liquids are in the gas phase as they depart each platform and are reported as gas on the OGOR-A.

Instructions for reporting royalty-free production volumes to our Minerals Revenue Management office will be attached to the letter from the Regional Supervisor for Production and Development confirming the royalty suspension volume earned by your lease.

Guidance Document Statement

The MMS issues NTLs as guidance documents in accordance with 30 CFR 250.103 to clarify, supplement, and provide more detail about certain MMS regulatory requirements and to outline the information you must provide in your various submittals. Under that authority, this NTL sets forth a policy on and an interpretation of a regulatory requirement that provides a clear and consistent approach to complying with that requirement.

Paperwork Reduction Act of 1995 Statement

This NTL does not refer to or impose any new information collection subject to the Paperwork Reduction Act of 1995.

Contact

Please contact Mr. Al Durr by telephone at (504) 736-2659 if you have any questions regarding deep gas royalty relief.

[original signed]

Lars T. Herbst
Regional Director

Current Outline for the BOEM Interim Comprehensive Report

- Executive Summarry
    - Report Objective
    - Status of the OCS Oil and Gas Leasing Program
    - Overview of Current OCS Challenges and Summary of Recommendations
- Introduction
    - Objective
    - Background
        - Overview of the OCS Oil and Gas Leasing Program
            - The Outer Continental Shelf
            - The National OCS Oil and Gas Leasing Program
            - The Lease Sale Process
            - Oil and Gas Resource Estimates
            - Status of OCS Oil and Gas Leasing, and Development
            - The Permitting Review and Approval Process
                - Division of Responsibility
                - Status of OCS Oil and Gas Permitting Activities
            - Benefits of the OCS Oil and Gas Leasing Program
            - Criticisms of the OCS Oil and Gas Leasing Program
            - Revenues and Fiscal Terms
            - Royalty Relief Program
            - OCS Employment
            - OCS Revenues
    - Summary of Overarching Issues
        - Challenges and Opportunities Identified
        - Toolkit for Effecting Policy Change
            - Executive Withdrawals
            - Scheduling Sales
            - Lease Terms, including Stipulations to Lease Agreements
            - Analysis
            - Changes to Regulations
            - FACA Committees
        - Potential Near-Term Solutions to be Analyzed
        - Longer-Term Actions for Consideration
    - OCS Role in the Changing Energy Landscape
    - Stewardship of the OCS
        - Challenges and Opportunities Identified
        - Potential Near-Term Solutions to be Analyzed
            - Social Cost of Greenhouse Gases
            - Incorporating SC-GHG into Royalty Rates
        - Longer-Term Actions for Consideration
            - Rule: Carbon Sequestration
            - Rule: Regulate GHGs (pending SOL opinion)

            - Rule: Curbing Methane Emissions
- Environmental Justice
    - Challenges and Opportunities Identified
    - Potential Near-Term Solutions to be Analyzed
        - Formation of FACA or other Committees
    - Longer-Term Actions for Consideration
- Tribal Considerations in Decision-Making
    - Challenges and Opportunities Identified
    - Potential Near-Term Solutions to be Analyzed
    - Longer-Term Actions for Consideration
- Other Environmental Considerations
    - Challenges and Opportunities Identified
    - Potential Near-Term Solutions to be Analyzed
    - Longer-Term Actions for Consideration
- Other Changes: Improving the Oil and Gas Program
    - Challenges and Opportunities Identified
        - Adopted Bid Adequacy Changes
        - Other Impacts of OCS Oil and Gas Development
    - Potential Near-Term Solutions to be Analyzed
        - Continued BOEM (and BSEE?) Workforce Analysis
        - Rule: Risk Management, Financial Assurance, and Loss Prevention
        - Fiscal Term Evaluation
            - Minimum Bid
            - Rentals
            - Royalties
        - Rule: Bid adequacy
        - Decommissioning and Abandonment Review
        - OCS Studies
    - Longer-Term Actions for Consideration
        - Reducing the Number of Lease Sales
        - Targeted versus Areawide Leasing (Concept 1: Narrow GOM Sale Area)
        - Targeted Leasing (Concept 2: Through Royalty Rates)
        - Bidder Qualifications
        - G&G Survey Approval Criteria
        - Partial Decommissioning
        - Condition Leases and Approvals on Payment
        - Compensatory Mitigation
        - Executive Withdrawals
- Interested Party Engagement and Intergovernmental Coordination
    - Challenges, Opportunities, and Potential Near-Term Solutions to be Analyzed
        - Overview
        - Federal Agencies
        - State and Local Governments

        - Tribes
        - Conventional Energy Industries
        - Commercial Fisheries
        - Academia
        - Underrepresented Communities
  - Summary of Recommendations
    - Reform Agenda versus Phase 2 analysis
  - Next Steps
    - Public Outreach Strategy
    - Request for Information and Comment Analysis
    - Public Meetings
    - Potential Preliminary Decisions
  - Potential Resource Needs for Phase 2
    - Studies and Analyses Needed
    - Predicted Resource Needs
  - References
  - Glossary

ASLM Information Request for DOI Oil and Gas Review
(Royalty Relief, Decommissioning, and Abandoned Assets)

Royalty Relief

- ***Department of the Interior Royalty Relief***. Background information on DOI's Royalty Relief Program is provided on this web page. https://www.kirkland.com/publications/blog-post/2020/06/blm-bsee-royalty-relief.

- ***Bureau of Safety and Environmental Enforcement Special Case Royalty Relief.*** Background information on BSEE's Special Case Royalty Relief process is provided on this web page. https://www.bsee.gov/sites/bsee.gov/files/special-case-royalty-relief-overview-1.pdf

- ***Congressional Research Service Royalty Relief Information***. Background information on offshore royalty relief during the COVID-19 pandemic is provided on this web page. https://crsreports.congress.gov/product/pdf/IN/IN11380

- ***OIG 2021-CR-006 (Inspection of the Bureau of Safety and Environmental Enforcement's Royalty Relief Program During COVID-19).*** The Office of Inspector General (OIG) initiated this inspection review on November 23, 2020. The scope of the review is to determine whether BSEE consistently and appropriately evaluated and processed royalty relief applications as a result of COVID-19 (see Attachment 1 OIG Announcement Letter).
    - The OIG released a Notice of Proposed Findings and Recommendations (NPFR) on April 1, 2021 (see Attachment 2). The notice includes three potential findings.
        - BSEE did not issue policy for the newly developed Special Case Royalty Relief (SCRR) Option 1 program before implementing the program.
        - BSEE did not develop written procedures to evaluate SCRR Option 1 applications or to reconcile the required monthly and quarterly reports.
        - BSEE did not conduct formal training for staff responsible for implementing the new SCRR Option 1 program.
    - BSEE is reviewing the NPFR and will provide a response to the OIG by April 15, 2021.

- ***GAO-08-792R (Litigation over Royalty Relief Could Cost the Federal Government Billions of Dollars).*** The Government Accountability Office (GAO) issued this report in June 2008 concerning the potential cost impacts of litigation over royalty relief (see Attachment 3).

- ***GAO-07-369T (Royalty Relief Will Likely Cost the Government Billions, but the Final Costs Have Yet to Be Determined).*** GAO provided testimony to Congress in January 2007 regarding royalty relief under the Outer Continental Shelf Deep Water Royalty Relief Act of 1995 (see Attachment 4). GAO's statement concerned (1) the likely fiscal impacts of royalty relief on leases issued under the Outer Continental Shelf Deep Water Royalty Relief Act of 1995 and (2) other authority for granting royalty relief that could further impact future royalty revenue. A report with three recommendations for the program was released in April 2007 (see GAO-07-590R that follows).

- ***GAO-07-590R (Royalty Relief Will Cost the Government Billions of Dollars but Uncertainty Over Future Energy Prices and Production Levels Make Precise Estimates Impossible at this Time).*** The Government Accountability Office released this report on April 12, 2007 with three recommendations directed to the Minerals Management Service (see Attachment 5).
    - MMS report to the Congress the status of the leases and the annual amount of royalties that have been foregone on the 1998 and 1999 DWRRA leases until the issue is resolved.
    - MMS report to the Congress the status of the leases and the annual amount of royalties collected to date from the 1996, 1997, and 2000 DWRRA leases until the Kerr-McGee suit is resolved.
    - MMS report to the Congress periodic estimates, as MMS resources allow, of future foregone royalties from 1998 and 1999 DWRRA leases and future royalties that may be at risk from 1996, 1997, and 2000 DWRRA leases until both of these situations are resolved.

- ***OIG 99-I-387 (Opportunity to Increase Offshore Oil and Gas Rental Revenues, Minerals Management Service).*** The OIG released a report in March 1999 that evaluated potential increases in revenues for certain leases subject to the Deep Water Royalty Relief Act of 1995 (see Attachment 6). The report included two recommendations for the Minerals Management Service.
    - Ensure that offshore oil and gas leases which will be issued in the future under the provisions of the Deep Water Royalty Relief Act of 1995 require that annual rental fee payments continue during royalty suspension periods until royalty payments meet or exceed the annual rental fees for leased tracts covered by the Act.
    - Request a Solicitor's opinion as to whether the Service has authority to modify terms of existing leases to require rental payments of lessees during royalty suspension periods. If this authority does not exist, the Service should request a Solicitor's opinion as to whether legislation can be sought to remedy this situation.

- ***GAO-RCED-85-6 (Selectively Reducing Offshore Royalty Rates in the Gulf of Mexico Could Increase Oil Production and Federal Government Revenue).*** The GAO released a report in May 1985 that examined steps the federal government could take to encourage environmentally sound enhanced oil recovery (EOR) in the Outer Continental Shelf and Gulf of Mexico (see Attachment 7). The report analyzed how royalty reductions could be used to encourage industry to initiate EOR in the Gulf. By initiating action to reduce royalties in certain instances, both domestic production and federal government revenue could be increased.

- ***Notice to Lessees and Operators.*** BSEE has provided guidance to lessees and operators on the Royalty Relief Program.
    - NTL 2010-N03 Guidelines for Royalty Relief Under 30 CFR Part 203 (see Attachment 8)
    - NTL 2010-G01 Clarification of Deep Gas Royalty Relief Regulation Regarding Natural Gas Liquids and Pipeline (Retrograde) Condensate (see Attachment 9)
    - NTL 2009-N08 Application and Audit Fees for Requests for Royalty Relief or Adjustment Under 30 CFR Part 203 (see Attachment 10)

Decommissioning

- ***BSEE Decommissioning Overview.*** Background information on BSEE's Decommissioning Program is provided on this web page. https://www.bsee.gov/what-we-do/environmental-compliance/decommissioning

- ***OIG 2016-EAU-063 (The Bureau of Safety and Environmental Enforcement's Decommissioning Program)***. The OIG initiated a review of BSEE's Decommissioning Program in August 2016. In March 2019, the OIG issued a Closeout Memorandum that concluded BSEE had not implemented decommissioning policies and procedures at the national level (see Attachment 11). The OIG indicated it planned to initiate a follow-up review within two years of release of the Closeout Memorandum. To date, BSEE has not received OIG notification requesting a follow-up review.

- ***GAO-17-642T (Information on Infrastructure Decommissioning and Financial Risk)***. The GAO provided Congressional testimony in May 2017 concerning offshore oil and gas infrastructure in the Gulf of Mexico and Interior's requirements and procedures for overseeing decommissioning, and the risks posed by its financial assurance procedures (see Attachment 12). The GAO statement is based on a GAO-16-40 report released in December 2015 (see below).

- ***GAO-16-40 (Actions Needed to Better Protect Against Billions in Federal Exposure to Decommissioning Liabilities)***. The GAO released this report in December 2015 (see Attachment 13). The report examined Interior's (1) procedures for overseeing decommissioning and estimating its costs, (2) procedures for obtaining financial assurances for these liabilities, and (3) challenges managing these liabilities. GAO reviewed agency regulations and procedures and interviewed officials from Interior, credit rating agencies, academia, and trade associations. GAO made six recommendations to BSEE and BOEM.
    - Ensure that BSEE collects all relevant data associated with decommissioning from lessees.
    - Direct BSEE to establish documented procedures for estimating decommissioning liability.
    - Develop a plan and set a time frame to ensure that Interior's data 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.

- ***National Academy of Public Administration.*** In March 2017, the National of Academy Public Administration released a Strategic Organizational Assessment of the Bureau of Safety and Environmental Enforcement (see Attachment 14). The report discusses decommissioning on pages 45-48.

- ***Internal Draft Paper on Decommissioning.*** In September 2020, BSEE drafted an internal management document that provides an overview of decommissioning (see Attachment 15).

- ***Notice to Lessees and Operators.*** BSEE has provided guidance to lessees and operators on the Decommissioning Program.
    - NTL 2020-P02 Decommissioning of Pacific Outer Continental Shelf Region Facilities (see Attachment 16)
    - NTL 2019-G05 Site Clearance and Verification for Decommissioned Wells, Platforms, and Other Facilities (see Attachment 17)

- NTL 2018-G03 Idle Iron Decommissioning Guidance for Wells and Platforms (see Attachment 18)
- NTL 2017-N02 Reporting Requirements for Decommissioning Expenditures on the OCS (see Attachment 19)
- NTL 2010-P05 Decommissioning Cost Report Update (see Attachment 20)
- NTL 2009-G25 Shutting In Producible Wells During Rig Moves (see Attachment 21)

Abandoned Assets

- ***GAO-RCED-94-82 (Interior Can Improve Its Management of Lease Abandonment).*** In May 1994, GAO issued a report on Interior's management of lease abandonment (see Attachment 22). The report discusses actions taken by the Minerals Management Service to minimize the environmental impact of the abandonment of federal oil and gas leases on the Outer Continental Shelf and (2) the estimated costs of lease abandonment and the Minerals Management Service's approach for ensuring that the government is not burdened with these costs. The report made four recommendations to DOI and MMS.
    - Encourage the use of nonexplosive technologies for removing offshore structures, whenever possible, that will eliminate or minimize the risk of harm to the environment, in accordance with OCSLA's purpose.
    - Study the feasibility, benefits, and costs (including the potential effects on the environment and the safety of humans) of mandating the use of nonexplosive methods of removing offshore structures, whenever possible, because of the harm that explosives do to marine life.
    - Require MMS to develop an inspection strategy for targeting its limited resources to ensure the proper plugging and abandonment of OCS wells and the clearance of lease sites.
    - Complete a rulemaking to place time limits on the phase-in of both the increased general bond amounts and supplemental bonding under the new criteria. Establishing such limits would help ensure that the government is adequately protected from incurring costs associated with OCS lease abandonment that should be paid by the companies responsible for the leases.

BOEM
Bureau of Ocean Energy Management

Royalty Rates Overview

BOEM OSR Economics Division

February 18, 2021

OCS Lands Act Provisions

- **The OCSLA governs OCS leasing, exploration, development, and production.**
  - Provides that the OCS is a vital national resource made available for **expeditious and orderly development**.
  - Leasing activities shall be conducted to **assure receipt of fair market value.**
  - The broader concept of “fair return” is also referenced by GAO in its audits.
- **Royalties are payments based on the value of marketed production.**
  - Minimum royalty rate is 12.5%.
  - No maximum
  - Royalty relief can be offered

Lease and Fiscal Terms

- **Multiple lease and fiscal terms contribute to OCSLA goals and mandates:**
  - **Bonus Bid**: Lease awarded to highest $/acre bid meeting minimum bid threshold, pending BOEM's determination that the high bid provides fair market value
  - **Rental**: Holding cost per acre
  - **Primary Term**: Length of time a lease can be held before production begins
  - **Royalty**: Payment based on value of production
  - **Royalty Relief**: (if offered)
- **Fiscal terms are reviewed and determined during the decision process for each individual lease sale.**
- **Most recent royalty rates:**
  - 12.5% in the GOM shallow water and frontier areas
  - 18.75% in the GOM deepwater

Conventional Energy Revenues (FY 2020, $MM)		
Rentals	Bonuses	Royalties
$97.3	$241.2	$3,393.7

Royalty Function

- **The lessor receives a royalty share of the revenue but does not share in the lessee's cost obligations.**
  - Royalty paid on marketed production
- **U.S. jurisdictions tend to prefer a flat royalty.**
  - Administrative simplicity
  - Provides strong efficiency and production incentives for the lessee
  - Regressive
  - Few profit sharing or royalty bidding leases

Assessment of BOEM's Oil and Gas Fiscal System

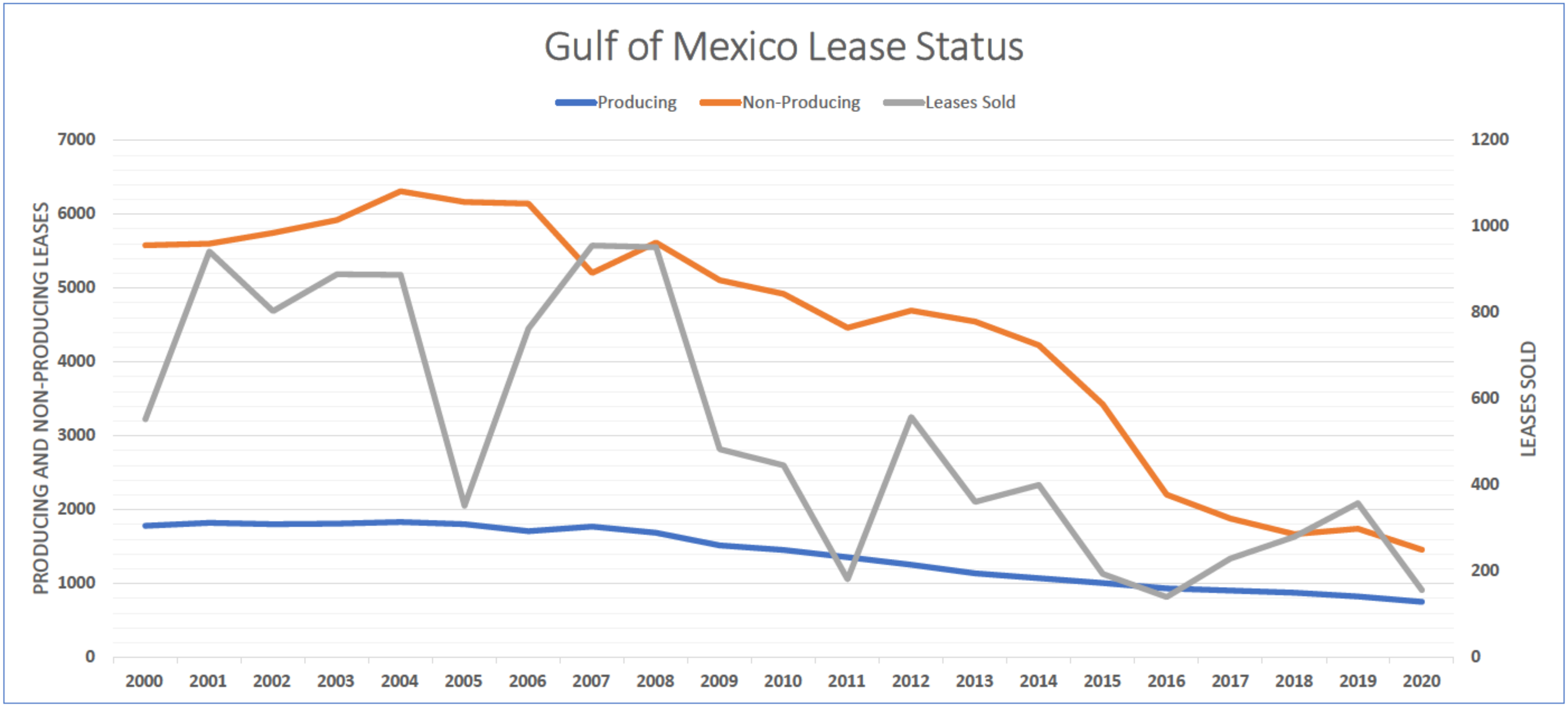
- **BOEM assesses the Federal fiscal system and its performance.**
  - Prepares an annual report covering offshore activity, market performance and resource endowment.
  - Conducts periodic external reviews of investment attractiveness and government take compared to other resource owners.
- **2011 Comparative Assessment of the Federal Oil and Gas Fiscal System (IHS-CERA)**
- **2018 Comparative Analysis of the Federal Oil and Gas Fiscal Systems (IHS Markit)**
  - Gulf of Mexico Report
  - Offshore Frontiers Report

Market and Resource Landscape

- **Current market trends**
  - Lower for longer price environment
  - GOM resources are becoming less prospective and attractive compared to other resource owners
  - GOM Oil Production was at a record high in 2019
  - Declining deepwater leasing, drilling, and development activity
    - Smaller and more challenging discoveries
    - Fewer standalone facilities, more subsea tiebacks
    - Operators are targeting oil developments
    - Number of bidders and operating companies declining
  - GOM shelf has been explored and produced for 70 years and has only very little activity and production

FY20 OCS Production		% of Total US Production	
Oil (bbl)	Gas (mcf)	Oil	Gas
641,337,499	881,722,959	15%	2%

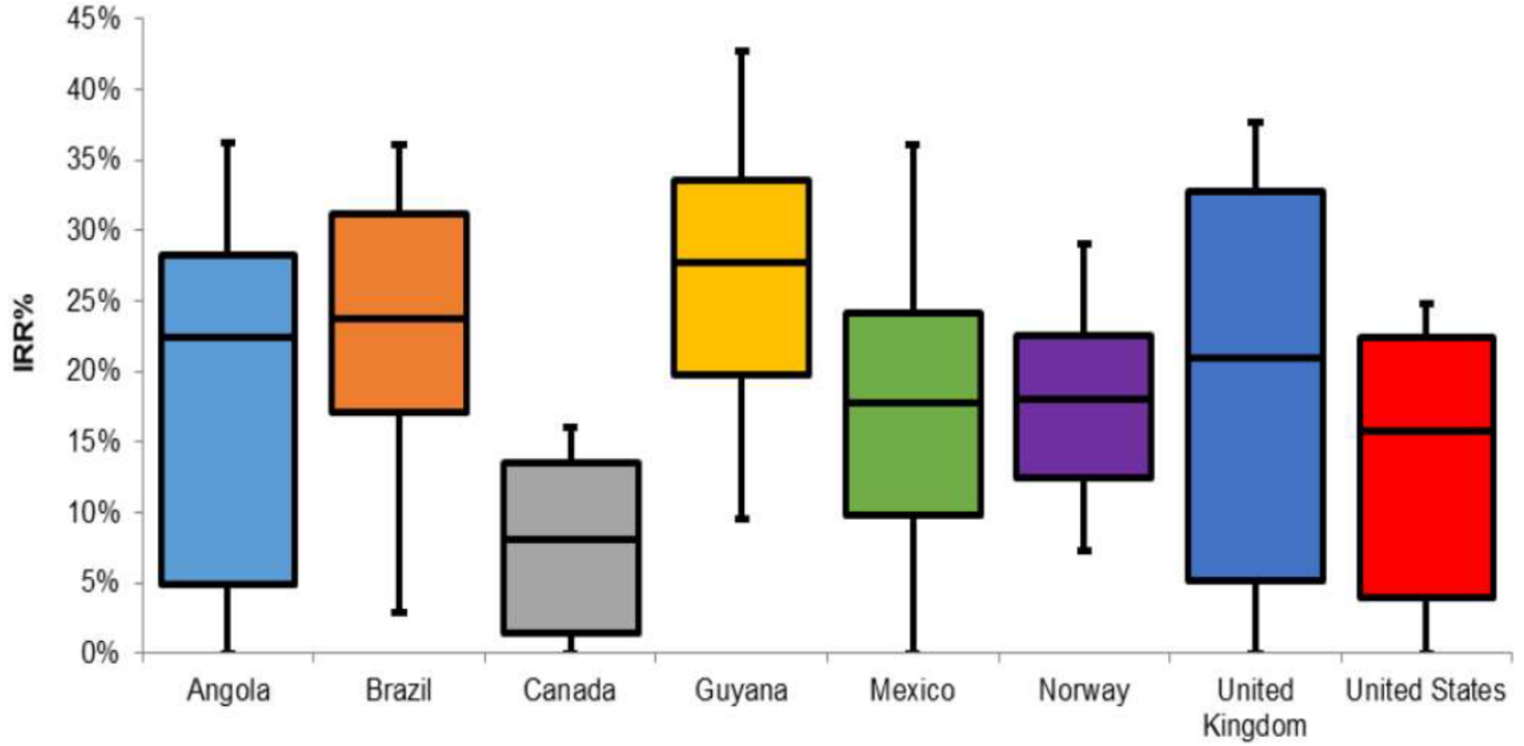
Decline of GOM Leasing



2018 IHS Report Findings (GOM)

- **The current US deepwater royalty rate (18.75%) provides an internal rate of return above the rate most operators require to justify an investment.**
- **Corporate rates of return in the US GOM are not as attractive as Guyana, Brazil, Angola, UK, and Mexico, all of which provide rates of return above 20% under IHS's base price case (~$60/bbl).**
  - International players are likely to prioritize these jurisdictions over the GOM
- **Recent shallow water GOM discoveries have been small.**
  - Returns for small fields are not attractive enough to trigger activity

IHS Markit: GOM Deepwater Oil Results



Note: The distribution of values from all cases are represented here. The boxes show the upper and lower quartile ranges of the government take in the respective jurisdictions. The whiskers show the extreme ranges. The lines in the middle represent the median

Source: IHS Markit

Price-Based Royalty

- **A sliding or price-based royalty lowers the royalty rate at low prices and increases it at high prices.**
  - Reduces regressivity
- **GAO's 2019 report: *Offshore Oil and Gas: Opportunities Exist to Better Ensure a Fair Return on Federal Resources***
  - GAO recommended "[t]he BOEM director should develop a documented plan for determining whether and how to develop a progressive royalty structure that clearly defines what is to be achieved, who is to achieve it, how it will be achieved, and the time frames for achievement."
  - BOEM completed internal analysis on a price-based royalty structure and presented the results to the Department in 2018.
    - Given this analysis, the Department provided concurrence to the GAO recommendation, but said the implementation of the recommendation was complete as BOEM had already conducted analysis and the decision had been made not to move forward with a price-based royalty system.

Social Cost of Carbon: Royalty Surcharge

- **Executive Order 14008, Section 208**
  - In conducting the comprehensive review, DOI shall consider "*whether to **adjust royalties** associated with oil, coal, and gas resources extracted from public lands and offshore waters, or take other appropriate action, **to account for corresponding climate costs***".
  - BOEM Economics is currently evaluating ways to adjust royalties in future lease sales to account for climate costs.
- **Beginning GOM analysis**
  - Reviewing the data from the *OCS Emissions Inventory* (2017 data).
  - Evaluating upstream GHG emissions to quantify them and apply proportionally to production for new leases.

A. History of Bonding Regulations and Guidance

BOEM's existing bonding regulations for leases (30 CFR 556.900 – 907) and pipeline right-of-way grants (30 CFR 550.1011) published by BOEM's predecessor, the Minerals Management Service (MMS) on May 22, 1997 (62 FR 27948), provide the authority for the Regional Director to require bonding for leases and pipeline right-of-way grants. Section 556.900(a) and § 556.901(a) and (b) require lease-specific base bonds or areawide base bonds in prescribed amounts, depending on the level of activity on a lease or leases. Section 556.901(d) authorizes the Regional Director to require additional security for leases above the prescribed amounts for lease and areawide base bonds. Similarly, § 550.1011 authorizes the Regional Director to require an areawide base bond in a prescribed amount and additional security above the prescribed amount for pipeline right-of-way grants.

BOEM's existing bonding regulations for right-of-use and easement grants (30 CFR 550.160 and 550.166), published by the MMS on December 28, 1999 (64 FR 72756), provide the authority for the Regional Director to require bonds or other security for right-of-use and easement grants. Section 550.160, which applies only to an applicant for a right-of-use and easement that serves an OCS lease, provides that the applicant "must meet bonding requirements." While there is no requirement for an applicant for a right-of-use and easement that serves an OCS lease to provide a base bond in a prescribed amount, § 550.160 authorizes the Regional Director to require bonding if the Regional Director determines it is necessary.

Section 550.166 requires an applicant for a right-of-use and easement that serves a State lease to provide a base bond of $500,000. Section 550.166 also provides that BOEM may require additional security above the prescribed $500,000 base bond from the holder of a right-of-use and easement that serves a State lease to cover additional costs and liabilities.

MMS, and now BOEM, has employed the criteria for determining whether additional security should be required for leases to also determine whether additional security should be required for right-of-use and easement grants or pipeline right-of-way grants, since there are no criteria specified in the existing Part 550 for these purposes. The existing lease bonding regulations under § 556.901(d) provide five criteria the bureau uses to determine whether a lessee's potential inability to carry out present and future financial obligations warrants a demand for additional security. However, these regulations do not specifically describe how the agency weighs those criteria. To provide guidance, MMS issued Notice to Lessees (NTL) No. 98-18N, effective December 28, 1998, which provided details on how it would apply these regulations and the five criteria. This NTL was replaced by NTL No. 2003-N06, effective June 17, 2003, which was later replaced by NTL No. 2008-N07, effective August 28, 2008.

Pursuant to BOEM's standard, historical practice under NTL No. 2008-N07, a lessee or grant holder that passed established financial thresholds would be waived from providing additional security to cover its decommissioning liabilities. Additionally, co-lessees (regardless of their own financial strength), were not required to provide additional security for the decommissioning liability for that lease if one lessee was waived. The decommissioning liability on a lease, on which there were two waived lessees, was not attributed to either lessee in calculating whether a lessee's cumulative potential decommissioning liability was less than 50% of the lessee's net worth, which was the standard for a lessee to qualify for a supplemental bonding waiver. The policy assumed that the chances were very remote that both lessees would become financially distressed and not be able to meet their obligations.

While NTL No. 2008-N07 was the most recent, fully implemented NTL, BOEM did not fully enforce it during the oil price collapse of 2014-2016. BOEM was concerned that fully enforcing NTL No. 2008-N07 would have led to an increase of bond demands that, in turn, would have contributed to an increase in bankruptcy filings.

Since 2009, there have been 30 corporate bankruptcies of offshore oil and gas lessees, involving owned or partially owned offshore decommissioning liability of approximately $7.5 billion in total. This figure includes properties with co-lessees and predecessors, and properties held by companies that successfully emerged from a Chapter 11 reorganization bankruptcy. While BOEM cannot predict the outcomes of bankruptcy proceedings, the actual financial risk is significantly less than that total offshore decommissioning liability associated with offshore corporate bankruptcies. Several of these companies experienced financial distress when oil prices fell sharply at the end of 2014.

The fact that recent bankruptcies and reorganizations have involved un-bonded decommissioning liabilities demonstrates that BOEM's regulations and the waiver criteria in NTL No. 2008-N07 were inadequate to protect the public from potential responsibility for OCS decommissioning liabilities, especially during periods of low hydrocarbon prices. Specifically, ATP Oil & Gas was a mid-sized company with a financial assurance waiver when it filed for bankruptcy in 2012. Similarly, Bennu Oil & Gas was waived at the time of its bankruptcy filing, and Energy XXI and Stone Energy did not lose their waivers until less than 12 months prior to filing bankruptcy. While most affected OCS properties were ultimately sold or the companies reorganized under Chapter 11 of the U.S. Bankruptcy Code, several bankruptcies, including those of ATP and Bennu, demonstrated the weaknesses in BOEM's financial assurance program. These weaknesses were apparent because the unsecured decommissioning liabilities exceeded the value of the leases to potential purchasers or investors. BOEM cannot forecast the outcome of bankruptcy proceedings, which may lead to liquidation of an insolvent company. If BOEM has insufficient financial assurance at the time of bankruptcy, there may be no recourse for obtaining additional funds, resulting in the Department of the Interior needing to perform the decommissioning with the cost coming from the American taxpayer.

In 2009, MMS issued a proposed rule (74 FR 25177) to rewrite the entirety of the leasing provisions of Part 256 (now designated as Part 556). However, because of uncertainty associated with revising the bonding requirements, BOEM deferred revision of the bonding regulations to a separate rulemaking. This separate rulemaking commenced August 14, 2014, with an advance notice of proposed rulemaking (79 FR 49027) to solicit ideas for improving the bonding regulations.

In December 2015, the Government Accountability Office (GAO) reviewed BOEM's financial assurance procedures (see GAO-16-40, https://www.gao.gov/ products/GAO-16-40) (the GAO Report). While acknowledging BOEM's ongoing efforts to update its policies, the

GAO Report recommended, *inter alia*, that "BOEM complete its plan to revise its financial assurance procedures, including the use of alternative measures of financial strength." GAO-16-40 at 34. Following further analysis and a series of stakeholder meetings in 2015 and 2016 to solicit industry input, BOEM attempted to remedy the weaknesses in its financial assurance program as administered under NTL No. 2008-N07 with new NTL No. 2016-N01, *Requiring Additional Security*, which became effective September 12, 2016. The NTL sought to clarify the procedures and explain how BOEM would use the regulatory criteria to determine if, and when, additional security may be required for OCS leases, right-of-use and easement grants, and pipeline right-of-way grants. The NTL continued to use net worth of a lessee as a measure of financial strength because this measure was required by the regulations.

The NTL also detailed several changes in policy and refined the criteria used to determine a lessee's or grant holder's financial ability to carry out its obligations. On August 29, 2016, BOEM requested GAO to close the above stated recommendation in the GAO Report, stating that BOEM had implemented the recommendation by issuance of the NTL. GAO found that the recommendation had been implemented and closed the audit recommendation later in fiscal year 2016.

In December 2016, BOEM began implementing the NTL and issued numerous orders to lessees and grant holders to provide additional security for "sole liability properties," i.e., leases, right-of-use and easement grants, and pipeline right-of-way grants for which the lessee or grant holder is the only party liable for meeting the lease or grant obligations.

On January 6, 2017, BOEM issued a Note to Stakeholders extending implementation of NTL No. 2016-N01 for six months. The extension applied to leases, right-of-use and easement grants, and pipeline right-of-way grants for which there were co-lessees, predecessors in interest, or both, except where BOEM determined there was a substantial risk of nonperformance of the interest holder's decommissioning obligation. The extension of the implementation timeline allowed BOEM an opportunity to evaluate whether certain leases and grants were sole liability properties. On February 17, 2017, BOEM issued a second Note to Stakeholders announcing that it would withdraw the December 2016 orders issued on sole liability properties to allow time for the new Administration to review BOEM's financial assurance program.

B. Regulatory Reform - New Executive and Secretary's Orders

C.

On March 28, 2017, the President issued Executive Order (E.O.) 13783—*Promoting Energy Independence and Economic Growth*. The E.O. directed Federal agencies to review all existing regulations and other agency actions that potentially burden the development of domestic energy resources; to provide recommendations that, to the extent permitted by law, could alleviate or eliminate aspects of agency actions that burden domestic energy production; and to pursue appropriate processes for implementing such recommendations. While the E.O. directed Federal agencies to review regulations, the E.O. did not direct any changes or outcomes.

On April 28, 2017, the President issued E.O. 13795, *Implementing an America-First Offshore Energy Strategy*, which ordered the Secretary of the Interior to direct the BOEM Director to take all necessary steps consistent with law to review BOEM's NTL No. 2016-N01 and determine whether modifications are necessary, and if so, to what extent, to ensure operator compliance with lease terms while minimizing unnecessary regulatory burdens. This E.O. also required the Secretary of the Interior to review BOEM's financial assurance regulatory policy to determine the extent to which additional regulation is necessary but did not direct that any additional regulations be drafted.

Secretary's Order No. 3350 of May 1, 2017, *America-First Offshore Energy Strategy*, implemented E.O. 13795 and directed BOEM to promptly complete its previously announced review of NTL No. 2016-N01 and "provide to the Assistant Secretary – Land and Minerals Management (ASLM), the Deputy Secretary, and the Counselor to the Secretary for Energy Policy, a report describing the results of the review and options for revising or rescinding NTL No. 2016-N01." Secretary's Order No. 3350 further specified that BOEM's previously announced extension of the implementation timelines for NTL No. 2016-N01 would remain in effect pending completion of the review.

On June 22, 2017, BOEM issued a third Note to Stakeholders announcing that it was in the final stages of its review of NTL No. 2016-N01, but had determined that "more time was necessary to work with industry and other interested parties," and therefore, it would be appropriate to extend the implementation timeline beyond June 30, "except in circumstances where there would be a substantial risk of nonperformance of the interest holder's decommissioning liabilities."

BOEM continued to review the provisions of NTL No. 2016-N01 and examine options for revising or rescinding the NTL. BOEM also continued to review its financial assurance regulatory policy to determine the extent to which regulatory revision is necessary. As a result, BOEM recognized the need to develop a comprehensive program to assist in identifying, prioritizing, and managing the risks associated with industry activities on the OCS.

D. Purpose of BOEM's Portion of the Proposed Rulemaking

BOEM's goal for its financial assurance program continues to be the protection of the American taxpayers from exposure to financial loss associated with OCS development, while ensuring that the financial assurance program does not detrimentally affect offshore investment or position American offshore exploration and production companies at a competitive disadvantage. After carefully considering the recommendations of the GAO report, as well as feedback received during the review of NTL No. 2016-N01 indicating that the policy changes identified in the NTL could result in significant economic hardships for companies operating on the OCS, particularly during times of low oil prices, BOEM reconsidered its approach for identifying, prioritizing, and managing the risks associated with industry activities on the OCS.

The proposed rule would implement the recommendation of the GAO report that BOEM look to alternative measures of financial strength. Under the proposed rule, instead of relying primarily on net worth to determine whether a lessee must provide additional security, BOEM would consider a lessee's or its predecessor's credit rating. Credit rating agencies take many factors into account when evaluating a company, particularly those that emphasize cash flow, such as debt-to-earnings ratios and debt-to-funds from operations. These are more forward-looking factors, whereas a net worth analysis tends to be backward-looking. A lessee's financial deterioration can occur quickly. Relying on the more forward-looking credit rating analysis, both to determine whether additional security may be necessary and to determine whether a company can be a guarantor on the OCS, would allow BOEM to foresee a lessee's possible financial distress sufficiently ahead of time to take appropriate action.

Further, the proposed rule's new approach would be rooted in the joint and several liability of all lessees, co-lessees, and predecessor lessees for all non-monetary obligations on a lease. In most cases of default by the current lessee, a predecessor lessee can be called upon to perform decommissioning. This proposed rule would rely on the combined responsibility of all current and predecessor lessees to perform required decommissioning. The proposed rule would acknowledge the larger universe of companies to whom BOEM can look for performance, and so would reduce the circumstances under which BOEM would need to require additional security.

BOEM's proposed regulatory changes would allow the bureau to address a number of complex financial and legal issues more effectively (e.g., joint and several liability and economic viability of offshore assets) associated with decommissioning liability on the OCS. By addressing the issues through rulemaking, BOEM will afford all interested and potentially affected parties the opportunity to provide additional substantive feedback to the agency.

In summary, BOEM is proposing this rulemaking to clarify and simplify its financial assurance requirements with the goal of providing regulatory changes that would continue to protect taxpayers while providing certainty and needed flexibility for OCS operators.

BOEM

Bureau of Ocean Energy Management

Financial Assurance Bankruptcy Analysis and Proposed Rulemaking

December 8, 2020

In coordination with:

BSEE

Bureau of Safety and Environmental Enforcement

Overview

- **Bankruptcy Analysis**
  - Macro Bankruptcy Trends
  - Gulf of Mexico Bankruptcies
  - Pacific Bankruptcies/Troubled Lessees
- **Proposed Rule - BOEM Regulations**
- **Proposed Rule - Economic Impact**
- **Proposed Rule - BSEE Regulations**

Bankruptcy Analysis

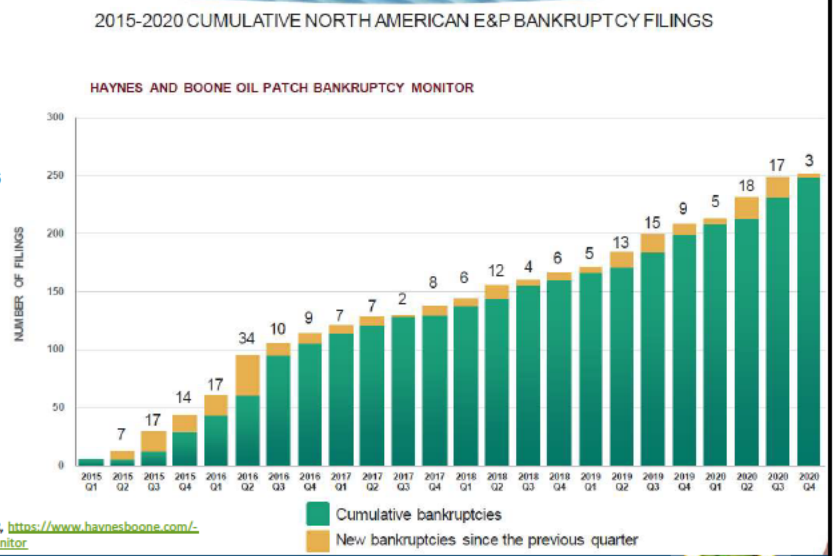
Macro Trends – Oil Prices - EIA Europe Brent Spot Price Free on Board (FOB)

- **Recent significant downward pressure on oil prices beginning in July 2014, and occurring again in March 2020**
- **Gulf transactions more closely mirror Brent over WTI prices**

Source: US Energy Information Administration, https://www.eia.gov/dnav/pet/hist/rbrteD.htm

Macro Trends – North American E&P Oil & Gas Bankruptcies

- **Low oil price environment has resulted in sustained period of numerous bankruptcies**
- **Cumulatively, North America has hit 250 E&P bankruptcies since 2015**
- **Tracker includes Canada, onshore, and offshore bankruptcies**
- **2020 Q4 data as of October 31, 2020**

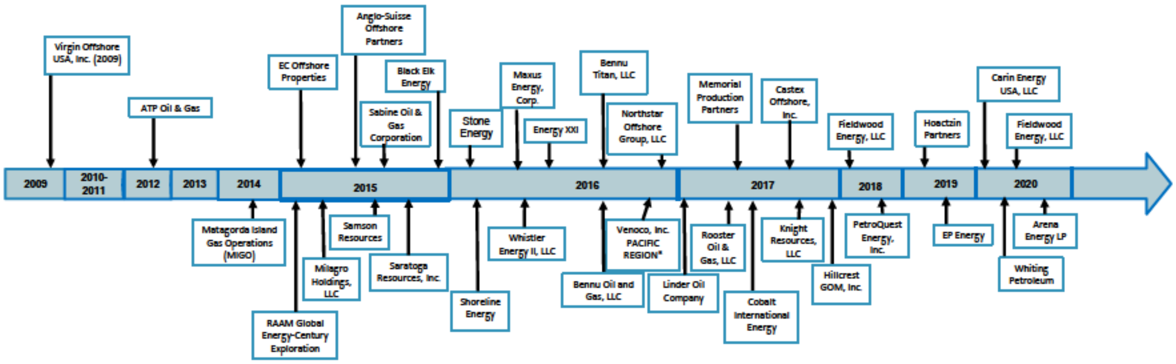


Source: HAYNES AND BOONE, LLP OIL PATCH BANKRUPTCY MONITOR, https://www.haynesboone.com/-/media/Files/Energy_Bankruptcy_Reports/Oil_Patch_Bankruptcy_Monitor

Macro Trends – Offshore

- **Deepwater Developments**
  - Most significant new development and production from deepwater developments
- **Aging Infrastructure**
  - Gulf of Mexico is a relatively mature offshore basin, especially early developed infrastructure typically found in shallow water
- **Sunset Operators**
  - Aging properties, again typically shallow water, often taken over by smaller, less-capitalized, and less-financially secure operators as end-of-life profit margins thin
- **Private Equity**
  - Gradual increase in private equity ownership of offshore assets

Outer Continental Shelf Bankruptcy Timing



- Venoco bankruptcy in 2016 in Pacific Region, all others in Gulf of Mexico Region

Gulf Of Mexico – Bankruptcy Complexity - Fieldwood Energy LLC Bankruptcy

- **Fieldwood Energy, LLC filed Chapter 11 bankruptcy on August 3, 2020, in an effort to manage its debt obligations and emerge from bankruptcy as a reorganized entity.**
- **Fieldwood has one of the largest holdings of record title and operating rights interests in the GOM Region.**
- **Fieldwood's property and decommissioning obligations include 329 record title leases, 50 operating rights only leases, 181 ROWs, and 19 RUEs with an estimated decommissioning liability of approximately $5.1 billion, of which approximately $14 million is considered the sole liability of Fieldwood.**
- **DOI continues to work closely with Fieldwood and related representatives in order to ensure an orderly approach to addressing the government's interest in this bankruptcy.**

Pacific Region – Decommissioning and Bankruptcy Status

- **The Pacific OCS Region currently has 23 existing oil and gas platforms located in Federal waters offshore Southern California**
- **Seven of the 23 Platforms, Gail, Grace, Harvest, Hermosa, Hidalgo, Hogan, and Houchin, are in the beginning stages of the decommissioning process**
  - Well work and conductor removal are ongoing at platforms Gail, Grace, Harvest, Hermosa, and Hidalgo
  - Lease relinquished in October 2020 at Hogan and Houchin
- **In 2020, BSEE Pacific updated their decommissioning estimates for the platforms in the Region**
  - Estimates per platform range from $32 to $188.7 Million, with an average of $71.1 Million

Pacific Region – Bankrupt and Troubled Lessees

- Venoco, LLC declared bankruptcy, relinquished their leases, and defaulted on their decommissioning obligations for Platforms Gail and Grace in 2018
- BSEE ordered Chevron, as the prior lessee, to assume responsibility for the platforms and fulfill decommissioning obligations
- In 2020, BOEM, BSEE, and Chevron signed an agreement in which Chevron agreed to decommission the Venoco sole liability wells for approximately $21 Million in bond funds that were recovered by BOEM from surety bonds submitted by Venoco to cover its lease obligations
- BSEE's 2020 decommissioning estimate for Platforms Gail and Grace is approximately $152.6 Million

BOEM Bureau of Ocean Energy Management

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Pacific Region – Bankrupt and Troubled Lessees

- **Signal Hill Service, Inc has not filed for bankruptcy but relinquished their lease in October 2020**
- **BSEE Pacific has determined Signal Hill has defaulted on their decommissioning obligations for Platforms Hogan and Houchin**
- **BSEE ordered the prior lessees to assume responsibility for the platforms in November 2020**
- **BSEE's 2020 decommissioning estimate for platforms Hogan and Houchin is approximately $85.6 Million**


Proposed Rule – BOEM Regulations
U.S. DEPARTMENT OF THE INTERIOR
MARCH 3, 1849
12

Need for Rulemaking – Objective and Proposed Approach

- **BOEM and BSEE's objective continues to be ensuring that taxpayers never bear the cost of obligations (primarily decommissioning) incurred by lessees and grant holders. At the same time, BOEM must balance this objective against the costs and disincentives imposed by requiring unnecessary financial security.**

- **In furtherance of this objective, BOEM proposes to require additional security only where there is a significant risk of default by the current lessee or grant holder, taking into account the mitigation of the risk occasioned by jointly and severally liable co-lessees, co-holders of grants, and predecessors, all of which may be called upon to perform decommissioning when a current lessee or grant holder is unable to perform.**

- **Risk Management, Financial Assurance and Loss Prevention proposed rule published in the *Federal Register* on October 16, 2020**
  - Federal Register Document Number 2020-20827; 85 Fed Reg 65904
  - Comment period closes December 15, 2020
  - Four comments submitted as of December 3, 2020

BOEM's NPRM Key Provisions

- **Streamline the criteria BOEM would use to determine the need for additional bonds or other security above the prescribed amounts of base bonds for leases, RUE grants and ROW grants.**
  - Issuer credit rating greater than or equal to either BB- from S&P Global Ratings or Ba3 from Moody's or an equivalent proxy credit rating determined by BOEM using audited financials
  - Lessees or grant holders that meet the credit rating or proxy credit rating criteria above are considered "Tier 1" and would not be required to provide additional security; all others are considered "Tier 2" and would be required to provide additional security.
  - Additional financial assurance will not be sought from Tier 2 companies for properties where the value of proved reserves (leases only) is at least 3 times the decommissioning liability for the property.
  - BOEM would consider the financial strength and reliability of lessees, co-lessees, grant holders, co-grant holders (ROW grants only), and predecessors when determining the need for current lessees and grant holders to provide additional security.

BOEM's NPRM Key Provisions (continued)

- **Revise the terms of third-party guarantees.**
  - Guarantor qualifies by issuer credit rating or proxy credit rating.
  - Guarantee may be limited as to the amount and obligations covered.
  - Guarantee may be cancelled on the same terms as bonds and other security.
- **Revise the terms of decommissioning accounts.**
  - May be used for RUE grants and ROW grants in addition to leases.
  - Removes requirement to fund account with treasuries.
- **Specify additional circumstances, not covered by the existing regulations, when BOEM may cancel additional bonds provided to ensure compliance with obligations under a lease, a RUE grant or a ROW grant.**
  - BOEM determines that the lessee or grant holder no longer needs to provide the additional bond.
  - The operations for which the bond was provided ceased prior to accrual of any decommissioning obligations.
  - Cancellation of the bond is appropriate because, under the regulations, BOEM determines such bond never should have been required.

Streamlined Evaluation Criteria

CURRENT CRITERIA (30 CFR 556.901(d)):

(i) Financial Capacity (audited financial statements)
(iv) Reliability (credit rating)

(ii) Projected Financial Strength in excess of obligations (value of proved reserves)

(iii) Business Stability, and
(v) Record of Compliance

PROPOSED CRITERIA:

(1) Issuer Credit Rating, or Proxy Credit Rating determined by BOEM based on audited financials using credit model

(2) Proved Oil and Gas Reserves with NPV that exceeds 3x the cost of the decommissioning (as estimated by BSEE) associated with production of those reserves (leases only)

Dropped

BOEM Bureau of Ocean Energy Management

Overview – Evaluation Criteria for Lessees and Grant Holders

The BOEM Regional Director may require a lessee or grant holder to provide additional security if the lessee or grant holder does not meet at least one of the criteria provided below:

1) The lessee or grant holder has an issuer credit rating from a nationally recognized statistical rating organization greater than or equal to either BB- (S&P) or Ba3 (Moody's); or an equivalent proxy credit rating determined by BOEM; or

2) If the lessee or grant holder does not meet the criteria in paragraph (1),

(i) A co-lessee or co-grant holder (ROWs only) meets the issuer credit rating or proxy credit rating criteria;

(ii) There are proved oil and gas reserves on the lease the net present value of which exceeds three times the cost of the decommissioning associated with the production of those reserves (not applicable to grants); or

(iii) A predecessor lessee or grant holder liable for decommissioning any facilities on the lease or grant meets the issuer credit rating or proxy credit rating criteria. The Regional Director may require additional security for decommissioning obligations for which such a predecessor is not liable.

Reserves Requirement

- **"(ii) There are proved oil and gas reserves on the lease, as defined by the SEC at 17 CFR 210.4-10(a)(22), the net present value of which exceeds three times the cost of the decommissioning associated with the production of those reserves;" (proposed reg text)**
  - Oil and gas reserves determined in accordance with the accounting and reporting standards set forth in SEC Regulation S-X at 17 CFR 210.4-10 and SEC Regulation SK at 17 CFR 229.1200 (text in the proposed rule preamble)
  - Note this applies only to leases, as ROWs and RUEs do not have authorization to develop hydrocarbon reserves


Proposed Rule Economic Impacts
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Effects of Proposed Rule on Bonding Cost (2018)

Estimated 2018 total required bonding cost under the proposed rule	$115,557,607
Required Bonding Cost for Tier 2 Sole-Liability Properties [This bonding cost is part of the regulatory baseline.]	$22,160,743
Estimated additional 2018 Bonding Cost for Tier 2 Joint Liability Properties. [This is an additional compliance cost of the proposed rule.] BOEM is currently holding many of the bonds that will cover this liability.	$93,396,863
Estimated total adjustments	-$129,545,297
Estimated bonding cost for bonds currently held by BOEM	-$106,852,849
Reduction in Bonding Requirement based on 3X Reserves of Tier 2 bonding	-$22,692,448
Net Cost Savings for Bonds that will be cancelled ($115,557,607 + -$129,545,297 = -$13,987,690). [This is the estimated 2018 cost savings of the proposed rule.]	-$13,987,690

10-Year and 20-Year Compliance Cost Estimates

Industry is expected to realize a savings in aggregate compliance costs over the 20-year period of $347 million undiscounted, $256 million discounted at 3%, and $180 million discounted at 7%.

Year	Undiscounted	Discounted at 3%	Discounted at 7%
10 Year Annualized	$16,668,194	$16,584,362	$16,473,168
10 Year Net Present Value (NPV)	$166,681,940	$141,467,969	$115,700,639
20 Year Annualized	$17,340,296	$17,191,929	$16,988,417
20 Year NPV	$346,805,916	$255,772,485	$179,975,527

BOEM Bureau of Ocean Energy Management

BSEE's provisions have no effect on compliance burden

Proposed Rule – BSEE Regulations

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Proposed BSEE Regulations

- **The proposed rule would require BSEE to issue orders to liable predecessors who held interests in the lease or grant within the same general timeframe.**
  - The orders would be issued to predecessors in reverse chronological order.
  - The orders would be issued to predecessors in “groups” organized by:
    - Changes in designated operator(s) over time (i.e., all predecessors who held relevant lease or grant interests during the tenure of a particular designated operator or during the tenure of contemporaneous designated operators); and
    - Predecessors who assigned interests to a lessee that subsequently defaulted.

BOEM Bureau of Ocean Energy Management

Proposed BSEE Regulations

- **When BSEE issues an order to predecessors to perform accrued decommissioning obligations, the predecessors must:**
  - Within 30 days of receiving the order, begin maintaining and monitoring all infrastructure as identified by BSEE in the order (e.g., testing safety valves and sensors, draining vessels, performing pollution inspection);
  - Within 60 days of receiving the order, identify a single entity to serve as operator for the decommissioning operations;
  - Within 90 days of receiving the order, submit a decommissioning plan for approval that includes the scope of work and a reasonable decommissioning schedule for all infrastructure identified in the order.

Proposed BSEE Regulations

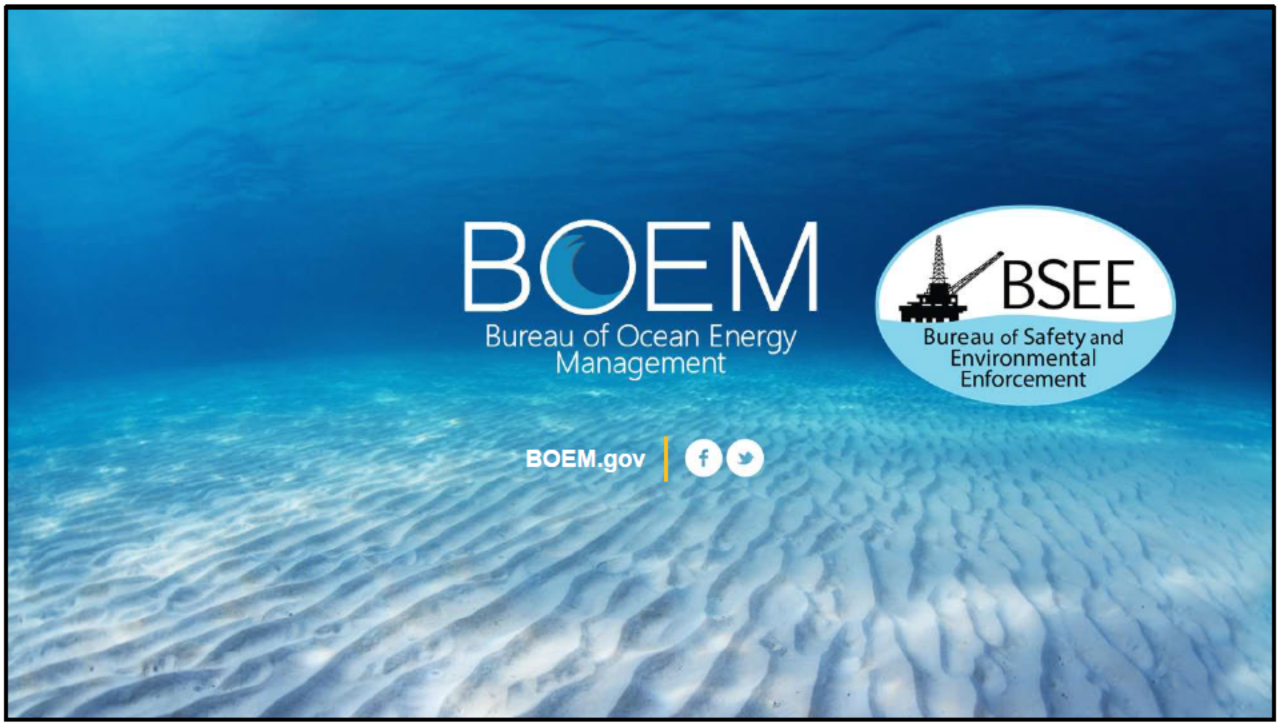
- **The draft rule provides circumstances for when BSEE may depart from this order of recourse and issue orders to any or all predecessors for the performance of their respective accrued decommissioning obligations. These circumstances include, but are not limited to:**
  - Failure to obtain approval of a decommissioning plan or to execute the approved decommissioning plan according to the schedule set forth in the plan;
  - Determination by the Regional Supervisor that there is an emergency condition, safety concern, or environmental threat, including, but not limited to, facilities not being properly maintained and monitored; or
  - Determination by the Regional Supervisor that proceeding through the order of recourse would unreasonably delay decommissioning.

Proposed BSEE Regulations

- **Other key provisions of this draft proposed rule:**
  - Failure to comply with an order to maintain and monitor a facility or to submit a decommissioning plan may result in an Incident of Noncompliance (INC) and potentially other enforcement actions, including civil penalties and disqualification as an operator.
  - Adds provisions to make clear, consistent with BOEM practice, that all holders and predecessors of a right-of-use and easement grant are jointly and severally liable for meeting decommissioning obligations on their right-of-use and easement.
  - A pending appeal of any decommissioning order does not preclude BSEE from proceeding against any or all predecessors other than the appellant.
  - If an appeal is filed, a surety bond in an amount that BSEE determines will be required.

Effects of Proposed Rule on Decommissioning Compliance

- **BSEE's provisions have no effect on compliance burden:**
  - 30 CFR 250.1701 – RUE holders are already responsible for decommissioning under current practices and existing BOEM regulations.
  - 30 CFR 250.1704 – Codifies current practice – decommissioning plan required as part of current BSEE decommissioning orders.
  - 30 CFR 250.1708 – Under the existing joint and several liability framework, lessees and grant holders individually carry a contingent burden for the full amount of the accrued decommissioning obligation. Compliance order does not affect that burden.
  - 30 CFR 250.1709, 290.7 - Premium of surety bond for appeal of a decommissioning order could be up to, but not more than, the cost of decommissioning.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Please list references and sources below—this can include external (e.g., reports from the GAO, IG, CRS and internal sources, and may include both references you plan to cite directly in the report as well as other materials that may be useful for background. Please include a few words describing what the resource is.

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- 2017-2022 Proposed Final Program, Section 5.4 (pp. 5-23 and 5-24) includes some considerations regarding the social cost of carbon and explains the connection with OCS Report 2016-065

https://www.boem.gov/sites/default/files/oil-and-gas-energy-program/Leasing/Five-Year-Program/2017-2022/2017-2022-OCS-Oil-and-Gas-Leasing-PFP.pdf

References for Royalties and Royalty Relief

Historical Gulf of Mexico Lease Terms and Royalty Relief Summary: https://www.boem.gov/sites/default/files/documents/newsroom/GOMLeaseTermsRRSummary_0.pdf

Gulf of Mexico Rental Rate, Minimum Bid, and Royalty Rate History (Excel File) : https://www.boem.gov/GOM-Lease-Term-History/

Comparative Assessment of the Federal Oil and Gas Fiscal System Reports

- 2011 Gulf of Mexico and Onshore Report (IHS CERA): https://www.boem.gov/sites/default/files/oil-and-gas-energy-program/Energy-Economics/Fair-Market-Value/CERA-Final-Report-November-2011.pdf
- 2018 Gulf of Mexico Report (IHS Markit): https://www.boem.gov/sites/default/files/oil-and-gas-energy-program/Energy-Economics/Fair-Market-Value/2018-GOM-International-Comparison.pdf
- 2018 Offshore Frontiers Report (IHS Markit): https://www.boem.gov/sites/default/files/documents//BOEM%20Offshore%20Frontiers%20Final%20Report%202019.pdf

Areawide Leasing Study: https://www.boem.gov/oil-gas-energy/energy-economics/areawide-leasing-study

- OCS Study BOEMRE 2011-014. Final Report. Policies to Affect the Pace of Leasing And Revenues in the Gulf of Mexico. https://www.boem.gov/sites/default/files/boem-newsroom/Library/Publications/2011/2011-014-Part2.pdf

References for Decommissioning

- Gulf of Mexico Decommissioning Trends and Operating Cost Estimation (May 2018 Study with Energy Research Group, LLC) https://www.boem.gov/sites/default/files/oil-and-gas-energy-program/Energy-Economics/External-Studies/BOEM-2019-023.pdf

References for Economic Contribution

- BOEM/BSEE's 2019 Economic Contribution: https://www.boem.gov/oil-gas-energy/energy-economics/economic-contribution
- Methodology for estimating BOEM/BSEE Economic Contribution: https://espis.boem.gov/final%20reports/BOEM_2020-032.pdf
- DOI Economic Contribution Report: https://doi.sciencebase.gov/doidv/
- Revenue Sharing (general information): https://www.boem.gov/oil-gas-energy/energy-economics/revenue-sharing
- External to BOEM, but additional resources
  - BW Research Partnership, The National Association of State Energy Officials, and the Energy Futures Initiative. 2021. Wages, Benefits, and Change. Website: https://static1.squarespace.com/static/5a98cf80ec4eb7c5cd928c61/t/606d1178a0ee8f1a53e66206/1617760641036/Wage+Report.pdf

- Louisiana State University. 2020. Gulf Coast Energy Outlook 2021. Website: https://www.lsu.edu/ces/publications/2020/gulf-coast-energy-outlook-2021-df_finaldigital2.pdf
- McDowell Group. 2020. The Role of the Oil and Gas Industry in Alaska's Economy: Website: https://www.aoga.org/wp-content/uploads/2021/01/Reports-2020.1.23-Economic-Impact-Report-McDowell-Group-CORRECTED-2020.12.3.pdf

References on Carbon Sequestration:

- DOE, and in particular it's National Energy Technology Laboratory (NETL), has been looking into carbon sequestration as a potential means to dispose of CO_2 and reduce the amount released into the atmosphere. For more info see: https://netl.doe.gov/coal/carbon-storage.
- Additionally, DOE has been studying the most ideal locations on the OCS for carbon storage based on factors such as ideal reservoir properties. For more info see: https://netl.doe.gov/coal/carbon-storage/storage-infrastructure/offshore-projects.
- Analysis of the Costs and Benefits of CO_2 Sequestration on the U.S. Outer Continental Shelf (September 2012 report by ICF International) https://www.boem.gov/sites/default/files/uploadedFiles/BOEM/Oil_and_Gas_Energy_Program/Energy_Economics/External_Studies/OCS%20Sequestration%20Report.pdf

References Being Reviewed as Part of BOEM's Comprehensive Review

This list includes some of the references that BOEM is reviewing in conjunction with the comprehensive review.

GHG Intensity:

- **"US tops upstream oil & gas CO2 emitters list – Canada has highest intensity, Norway lowest"** Rystad Energy. May 28, 2020. Available online at: https://www.rystadenergy.com/newsevents/news/press-releases/us-tops-upstream-oilgas-co2-emitters-list-canada-has-highest-intensity-norway-lowest/#:~:text=For%202018%2C%20the%20year%20with,Canada%20(114%20million%20tons)
- **"An analysis of the upstream industry's dirty laundry: Whose production has the lowest CO2 intensity?"** Rystand Energy. January 12, 2021. Available online at: https://www.rystadenergy.com/newsevents/news/press-releases/an-analysis-of-the-upstream-industrys-dirty-laundry-whose-production-has-the-lowest-co2-intensity/

UK North Sea Transition Deal

- **Policy paper: North Sea Transition Deal.** Department for Business, Energy & Industrial Strategy. Open Government Licence v3.0, Crown. March, 2021. Available for download online at: https://www.gov.uk/government/publications/north-sea-transition-deal
- **Energy white paper: Powering our net zero future.** Department for Business, Energy & Industrial Strategy. Open Government Licence v3.0, Queen's Printer and Controller of HMSO 2020. December, 2020. Available online at: https://www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future/energy-white-paper-powering-our-net-zero-future-accessible-html-version

Net Zero Scenarios Analysis

- **Net-Zero America: Potential Pathways, Infrastructure, and Impacts, interim report.** Princeton University, Princeton, NJ, December 15, 2020. Available online at: https://netzeroamerica.princeton.edu/the-report
- National Academies of Sciences, Engineering, and Medicine. 2021. **Accelerating Decarbonization of the U.S. Energy System.** Washington, DC: The National Academies Press. doi: https://doi.org/10.17226/25932. Available online at: https://www.nationalacademies.org/our-work/accelerating-decarbonization-in-the-united-states-technology-policy-and-societal-dimensions
- **BP Energy Outlook: 2020 Edition.** Available online at: https://www.bp.com/en/global/corporate/energy-economics/energy-outlook.html
- **The Energy Transformation Scenarios report**. Shell International B.V. 2021. Available online at: https://www.shell.com/promos/energy-and-innovation/download-full-report/_jcr_content.stream/1612814283728/d14d37b7dd060d78b65bfee3c7654520e10381aa/shell-energy-transformation-scenarios-report.pdf

Carbon Emissions and Royalty Rates

- **Producing Oil and Gas on the U.S. Outer Continental Shelf CO2E Emissions and the Social Cost of Carbon.** TBD Economics, LLC, January 2021
- **Climate Royalty Surcharges**. Brian C. Prest and James H. Stock. March 9, 2021
- **A Carbon Fee as Mitigation for Fossil Fuel Extraction on Federal Lands.** Michael Burger. 2017
- **Reconsidering Coal's Fair Market Value.** Institute for Policy Integrity. October 2015
- **Putting a Carbon Charge on Federal Coal: Legal and Economic Issues**. Resources for the Future. 2015.
- **Supply Side Reforms to Oil and Gas Production on Federal Lands**. Resources for the Future. September 2020.

Oil and Gas Reserves on the OCS

- **OCS Report BOEM 2020-028: Estimated Oil and Gas Reserves Gul of Mexico OCS Region December 31, 2018.** Online at: https://www.boem.gov/sites/default/files/documents/oil-gas-energy/BOEM%202020-028.pdf
- **BOEM Pacific OCS Region Field Reserve Estimate Summary as of December 2019.** Online at: https://www.boem.gov/sites/default/files/documents/regions/pacific-ocs-region/oil-gas/2019%20Field%20Reserve%20Estimate%20Summary%20Report.pdf

OEP Environmental Studies Program

Studies Development Plan 2021-2022
https://www.boem.gov/sites/default/files/documents/environment/environmental-studies/SDP%20FY2021-2022.pdf

From:	Knodel, Marissa S
To:	Sanchez, Alexandra L
Subject:	Re: Background information - O&G
Date:	Friday, April 9, 2021 10:13:45 AM

Hey Alex,

We will do our absolute best, but I know that both Amanda's and my schedules are crazy next week with a couple wind energy task force meetings, plus two all-afternoon senior leadership meetings.

Will I be able to share the draft with a couple select folks on BOEM's review team?

Peace,

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

From: Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>
Sent: Friday, April 9, 2021 10:03 AM
To: Knodel, Marissa S <Marissa.Knodel@boem.gov>
Subject: RE: Background information - O&G

That's fine, I'm just trying to get everything incorporated and done this weekend so that you and Amanda can review and then Laura mid-next week! Do you think that is doable?

From: Knodel, Marissa S <Marissa.Knodel@boem.gov>
Sent: Friday, April 9, 2021 10:00 AM
To: Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>
Subject: Re: Background information - O&G

No, sorry. I was told end of this week, so hopefully this afternoon.

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

From: Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>
Sent: Friday, April 9, 2021 9:50 AM
To: Knodel, Marissa S <Marissa.Knodel@boem.gov>

Subject: RE: Background information - O&G

Any idea on the ETA of the other info? Laura may be asking at the 11am so wanted to flag for you! Thanks!

From: Knodel, Marissa S <Marissa.Knodel@boem.gov>
Sent: Thursday, April 8, 2021 11:26 AM
To: Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>; Nguyen, Davie T <davie_nguyen@ios.doi.gov>
Subject: Fw: Background information - O&G

Hello Alex and Davie,

Find attached the resources requested a few weeks ago about OCS leasing and revenues.

The additional resources we requested earlier this week are still forthcoming.

Peace,

Marissa

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

From: Frank, Wright J <Wright.Frank@boem.gov>
Sent: Thursday, April 8, 2021 10:37 AM
To: Knodel, Marissa S <Marissa.Knodel@boem.gov>; Nguyen, Davie T <davie.nguyen@boem.gov>
Cc: Cruickshank, Walter <Walter.Cruickshank@boem.gov>; Carr, Megan E <megan.carr@boem.gov>; Frye, Matt <Matt.Frye@boem.gov>; Coffman, Sarah <Sarah.Coffman@boem.gov>; Dake, Joshua L <Joshua.Dake@boem.gov>
Subject: RE: Background information - O&G

Marissa,

We have collected responses to the request for background information that you sent several weeks ago. Per the request, much of the data is relatively unprocessed (UERR/UTRR; leasing statistics, etc), and we are certainly available to give further background and context.

Thanks!

Wright

The request:

- Recent leasing statistics (leases awarded, acreage leased, leases idle/undeveloped, leases w/ approved exploration and development plans) *See* "Lease Activity by Region as of Jan 21" and "Recent Leasing Statistics 3-1-21"
- Map of geologic plays for leasing consideration *See* 4 maps with "RegionalPlay" in title;
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- Lease Sales from 2001 – 2020 *See* "Sale and Revenue Data" (Sale Data tab); and
- Revenue from 2001- 2020 (bonus bids, rentals, etc.) *See* "Sale and Revenue Data" (Revenue Data tab).

From: Knodel, Marissa S <Marissa.Knodel@boem.gov>
Sent: Tuesday, March 16, 2021 3:48 PM
To: Frank, Wright J <Wright.Frank@boem.gov>
Subject: Re: Background information - O&G

Hello Wright,

Yes, this would be for DOI's public interim report. I think our internal report can have a different format and content because it will go into much more detail and analysis. As this is public-facing, I think DOI is looking for an "O&G leasing 101" for both BLM and BOEM to establish a baseline of where we are (without too much policy gloss) before the report launches into a summary of the feedback and recommendations.

As a model, I know they are looking at the 2017 coal programmatic review scoping report (attached).

Peace,

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

From: Frank, Wright J <Wright.Frank@boem.gov>
Sent: Tuesday, March 16, 2021 3:40 PM
To: Knodel, Marissa S <Marissa.Knodel@boem.gov>
Subject: RE: Background information - O&G

We have most or all of that information, though it will take a little time to pull it all together in one place—was this for Phase 1 of the Comprehensive Review? At least the way I've been envisioning the Phase 1 Report, this kind of detailed background information would be outside the scope of what we were putting together.

Wright

From: Knodel, Marissa S <Marissa.Knodel@boem.gov>
Sent: Tuesday, March 16, 2021 3:30 PM
To: Frank, Wright J <Wright.Frank@boem.gov>
Subject: Fw: Background information - O&G

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

From: Nguyen, Davie T <davie_nguyen@ios.doi.gov>
Sent: Tuesday, March 16, 2021 1:02 PM
To: Knodel, Marissa S <Marissa.Knodel@boem.gov>
Cc: Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>
Subject: RE: Background information - O&G

Hi Marissa,

Here's the document I shared with potential data needs. Let me know if you need to follow-up or have any additional questions.

Thanks!

From: Nguyen, Davie T
Sent: Monday, March 15, 2021 2:19 PM
To: Knodel, Marissa S <Marissa.Knodel@boem.gov>
Cc: Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>
Subject: RE: Background information - O&G

No worries- can we snag that noon time slot tomorrow?

From: Knodel, Marissa S <Marissa.Knodel@boem.gov>
Sent: Monday, March 15, 2021 11:55 AM
To: Nguyen, Davie T <davie_nguyen@ios.doi.gov>

Cc: Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>
Subject: Re: Background information - O&G

Hello Davie,

Apologies, my only Tuesday opening is now between noon and 1:30 p.m. ET. If that doesn't work, I can do between noon and 1:00 p.m. ET on Wednesday or Friday.

Peace,

Marissa Knodel
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To: Knodel, Marissa S <Marissa.Knodel@boem.gov>
Cc: Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>
Subject: RE: Background information - O&G

Great! Also sorry Alex I can definitely keep you in the loop.

Marissa does 2:30 pm still work for you? Let me know and I'll send the invite.

Thanks!

From: Knodel, Marissa S <Marissa.Knodel@boem.gov>
Sent: Friday, March 12, 2021 6:05 PM
To: Nguyen, Davie T <davie_nguyen@ios.doi.gov>
Cc: Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>
Subject: RE: Background information - O&G

Hey Davie!

Looping in Alex Sanchez for awareness.

Good news is that BOEM can definitely assist with all those data gaps listed. Let's chat next week to discuss their context for the report and how I can facilitate the "data transfer."

Do you have an opening on Tuesday between 2:30-3:30 p.m. ET or 4:30-5:30 p.m. ET?

Peace,

Marissa

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Subject: RE: Background information - O&G

Hi Marissa,

Hope all is well- was hoping to set up a meeting with you early next week to discuss some data needs. We're pulling what we can find online but suspect the BOEM team probably has the latest and greatest. We'll likely have a better idea of other gaps over the weekend but here are some examples where we can use an assist:

- Recent leasing statistics (leases awarded, acreage leased, leases idle/undeveloped, leases w/ approved exploration and development plans)
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Happy to chat these out because context might also be helpful. Just wanted to give you a rough idea of what we're looking for in the interim.

Let me know if you might have availability potentially Monday or Tuesday late afternoon, or Weds.

Thanks and talk soon!

Davie Nguyen
Office of Policy Analysis
U.S. Department of Interior
(202) 208 - 3561

From: Knodel, Marissa S <Marissa.Knodel@boem.gov>
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To: Nguyen, Davie T <davie_nguyen@ios.doi.gov>; Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>
Subject: Re: Background information - O&G

That sounds like a great plan, thanks Davie!

Marissa Knodel

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

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To: Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>; Knodel, Marissa S <Marissa.Knodel@boem.gov>
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Awesome- thanks Alex!

Marissa- we're meeting internally to figure out our plan of attack so will follow-up with you on potential data needs. Might be helpful to schedule a quick call once we've identified those items to see if that's something you might already have or something the BOEM team can pull.

Thanks all!

Davie Nguyen
Office of Policy Analysis
U.S. Department of Interior
(202) 208 - 3561

From: Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>
Sent: Wednesday, March 10, 2021 4:06 PM
To: Nguyen, Davie T <davie_nguyen@ios.doi.gov>; Knodel, Marissa S <Marissa.Knodel@boem.gov>
Subject: Background information - O&G

Hi Davie!
Connecting you with Marissa from our team who can help coordinate background research gathering from the BOEM team.
Thanks,
Alex

Alexandra Sanchez
Special Assistant
Office of the Assistant Secretary - Land and Minerals Management
U.S. Department of the Interior

From:	Knodel, Marissa S
To:	Sanchez, Alexandra L; Nguyen, Davie T
Subject:	Fw: Background information - O&G
Date:	Thursday, April 8, 2021 11:26:23 AM
Attachments:	Lease Activity by Region as of Jan 21 v2.xlsx Recent Leasing Statistics 3-1-21.pdf Map RegionalPlay ATL v3.pdf Map RegionalPlay GOM v3.pdf Map RegionalPlay POCS v3.pdf Map RegionalPlay AK v3.pdf Map ActiveOG Leases GOM v3.pdf Map ActiveOG Leases POCS v2.pdf Map ActiveOG Leases AK v2.pdf 2021 UTRR UERR tables.xlsx Sale and Revenue Data.xlsx

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Awesome- thanks Alex!

Marissa- we're meeting internally to figure out our plan of attack so will follow-up with you on potential data needs. Might be helpful to schedule a quick call once we've identified those items to see if that's something you might already have or something the BOEM team can pull.

Thanks all!

Davie Nguyen
Office of Policy Analysis
U.S. Department of Interior
(202) 208 - 3561

From: Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>
Sent: Wednesday, March 10, 2021 4:06 PM
To: Nguyen, Davie T <davie_nguyen@ios.doi.gov>; Knodel, Marissa S <Marissa.Knodel@boem.gov>
Subject: Background information - O&G

Hi Davie!
Connecting you with Marissa from our team who can help coordinate background research gathering from the BOEM team.
Thanks,
Alex

Alexandra Sanchez
Special Assistant
Office of the Assistant Secretary - Land and Minerals Management
U.S. Department of the Interior

Table 1: US Offshore Lease Activity (as of January 2021)			
Region	Total Leased Acres	Inactive Lease Acres	Active Lease Acres
GOM	12,173,189 2,290 leases	6,645,021 1,193 leases	5,528,168 1,097 leases
PAC *	158,956 32 leases	0 0 leases	158,956 32 leases
AK	155,918 33 leases	76,615 14	79,303 19 leases
Total Offshore:	12,488,063 2,355 leases	6,721,636 1212 leases	5,766,427 1,148 leases

* No sales in Pacific Region since 1984.

Table 2: US Offshore Active Leases (as of January 2021)				
Region	Total Active Acres	Acres with Approved Development Plans	Acres with Approved Exploration Plans	Producing Acres *
GOM	5,528,168 1,097 leases	4,473,479 911 leases	1,054,689 186 leases	2,389,241
PAC	158,956 32 leases	158,956 32 leases	0 0 leases	158,956
AK	79,303 19 leases	10,833 6 leases **	58,042 13 leases	10,425
Total:	5,766,427 1,148 leases	1,343,268 946 leases	1,054,702 199 leases	2,558,622

* Producing acreage is a subset of the acreage subject to approved plans/DOCDs.

** 3 of which are currently subject to litigation (Liberty)

"Active Leases," or leased areas that are subject to exploration, development, or production.

"Inactive Leases," or leased areas that are not producing nor currently covered by an approved exploration or development plan.

TABLE 1.			
Alaska OCS	**Acres**	**Leases**	**Descriptions**
Total leased acres	155,918	33	Northstar[1], Nikaitchuq North[1], Liberty[2], Cook Inlet[3]
Active leases[1,2]	79,303	19	Northstar[1], Nikaitchuq North[1], Liberty[2]
Inactive leases[3]	76,615	14	Cook Inlet[3]

TABLE 2.			
Alaska OCS	**Acres**	**Leases**	**Descriptions**
Total active acres[1, 2]	79,303	19	Northstar[1], Nikaitchuq North[1], Liberty[2]
Acres with approved DPPs[1]	10,424	3	Northstar[1]
Acres with approved DPP Subject to Litigation[2]	10,833	3	Liberty[2]
Acres with approved EPs[1]	58,042	13	Nikaitchuq North[1]
Producing Acres[1]	10,425	3	Northstar[1]

(1) "Active Leases," or leased areas that are subject to exploration, development, or production.
(2) In 2018, BOEM approved a DPP for three Liberty Unit leases. The DPP is currently subject to litigation. The Liberty Unit
(3) "Inactive Leases," or leased areas that are not producing nor currently covered by an approved exploration or development

Table 1. U.S. Offshore Lease Activity (As of January 2012)

Region	Total Leased Acres	Inactive Lease Acres	Active Lease Acres
Gulf of Mexico	31,385,068 [5,828 leases]	21,322,290 [3,800 leases]	10,062,778 [2,028 leases]
Pacific[1]	241,023 [49 leases]	23,354 [6 leases]	217,669 [43 leases]
Alaska[2]	3,723,465 [670 leases]	3,650,974 [656 leases]	72,491 [14 leases]
Total Offshore	35,349,556 [6,547 leases]	24,996,618 [4,462 leases]	10,352,938 [2,085]

[1] No lease sales have been held in the Pacific region since 1984.
[2] Approximately three-quarters of leased Alaska acreage is subject to litigation (from 2008 Chukchi Sea Lease Sale 193).

Table 2. U.S. Offshore Active Leases (As of January 2012)

Region	Total Active Acres	Acres with Approved Development Plans	Acres with Approved Exploration Plans	Producing Acres[3]
Gulf of Mexico	10,062,778 [2,028 leases]	7,853,315 [1,633 leases]	2,209,463 [395 leases]	6,574,667
Pacific[1]	217,669 [43 leases]	217,669 [43 leases]	0	217,669
Alaska[2]	72,491 [14 leases]	21,254 [5 leases]	51,237 [9 leases]	10,414
Total	10,352,938 [2,085]	8,270,038 [1,712 leases]	2,082,900 [373 leases]	6,813,597

[1] No lease sales have been held in the Pacific region since 1984.
[2] Approximately three-quarters of leased Alaska acreage is subject to litigation (from 2008 Chukchi Sea Lease Sale 193).
[3] Producing acreage is a subset of the acreage subject to approved development plans/DOCDs.

Combined Leasing Report

As of March 1, 2021

Planning Areas by Region[1]		Total Blocks	Total Acres	Number of Active Leases[2]	Acreage of Active Leases	Number of Producing Leases[3]	Acreage of Producing Leases	Number of Non-Producing Leases[3, 4]	Acreage of Non-Producing Leases
Gulf of Mexico [4]									
	Western	5,240	28,576,813	249	1,415,042	26	147,451	223	1,267,591
	Central	12,409	66,446,351	2,016	10,623,707	415	2,180,181	1,601	8,443,526
	Eastern	11,537	64,357,859	18	103,680	0	0	18	103,680
Region Subtotal		29,186	159,381,023	2,283	12,142,429	441	2,327,632	1,842	9,814,797
Pacific [5]									
	Southern California	16,164	88,979,051	32	158,956	32	158,956	0	0
Region Subtotal		16,164	88,979,051	32	158,956	32	158,956	0	0
Alaska [6]									
	Beaufort Sea	11,876	65,075,663	19	79,301	3	10,424	16	68,877
	Cook Inlet	1,093	5,356,420	14	76,615	0	0	14	76,615
Region Subtotal		12,969	70,432,083	33	155,916	3	10,424	30	145,492
Totals		58,319	318,792,157	2,348	12,457,301	476	2,497,012	1,872	9,960,289

Updated Monthly

Footnotes/Definitions:

1. A Planning Area is a large, contiguous portion of the OCS, consisting of defined OCS blocks, considered as an entity for administrative planning purposes. The quantity and size of a planning area can vary by Region.

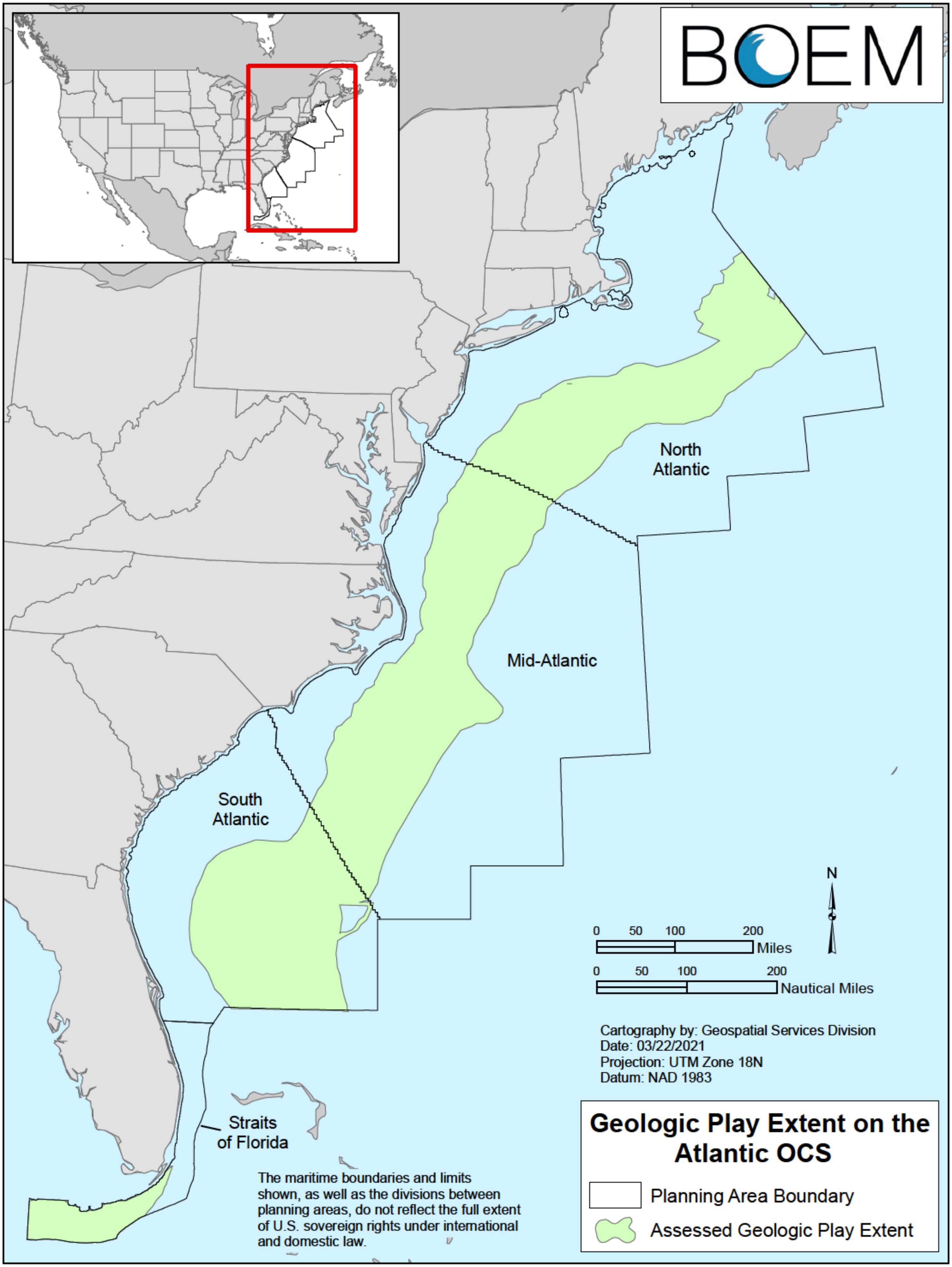
2. An Active Lease is a lease that has been executed by the Lessor and the Lessee(s), has an effective date and has not been relinquished, expired, or terminated. Some leases have more than one block. Blocks are generally 9 square miles but can be vary. Slight numerical discrepancies are the result of the processes used during the rounding of acreage.

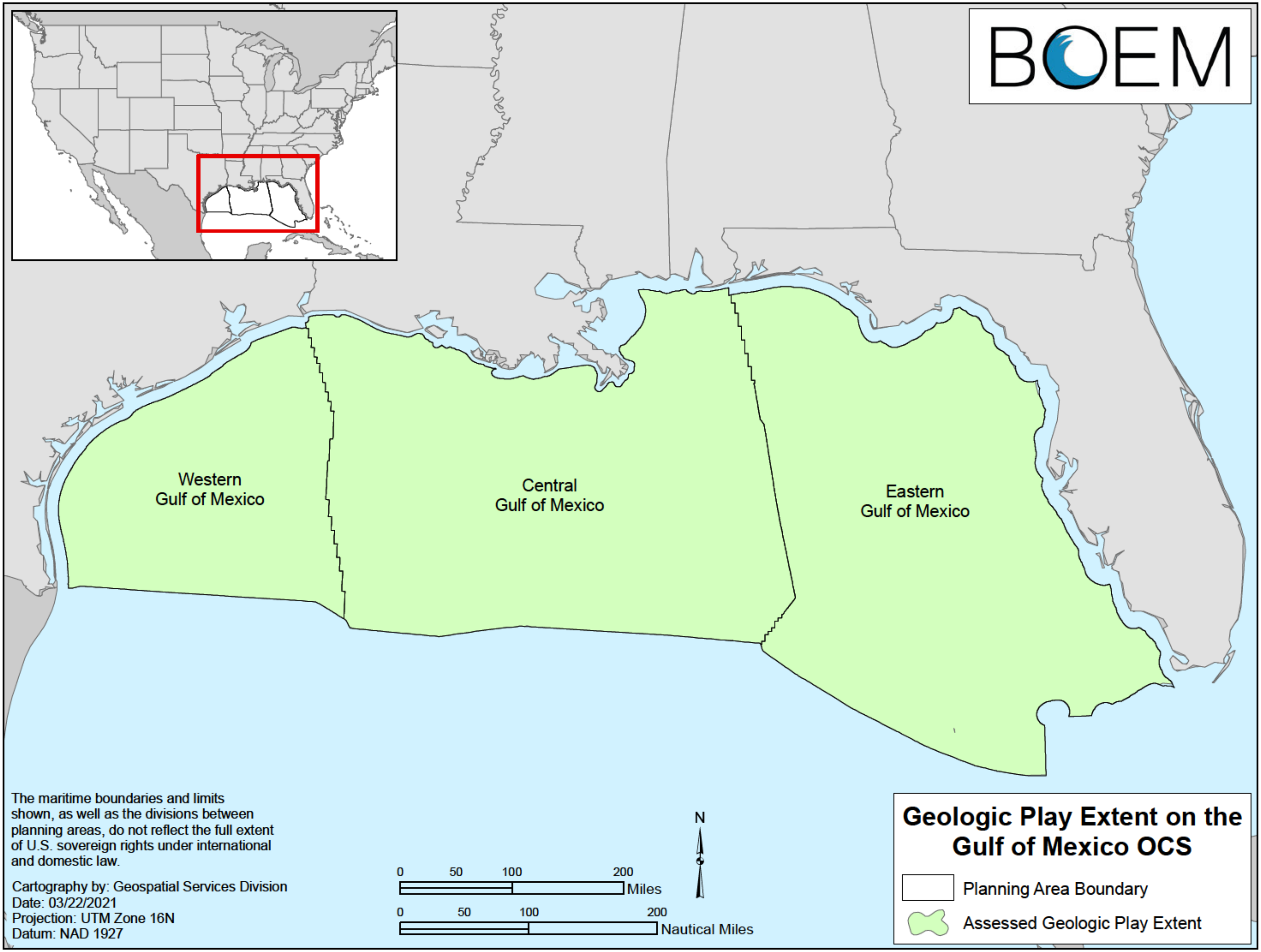
3. A Producing lease is an active lease that has produced product i.e. oil or gas, or both. A non-producing lease is an active lease that has not produced product. NOTE: There can be a difference in the definition for producing and non-producing leases between BOEM and ONRR (i.e. time lag, fiscal versus calendar year, etc) because of different purposes in collecting data (i.e. operations versus revenue collection.)

4 . There are currently no active leases split between CGOM and EGOM; thus there is no longer a small variation in acreage and production.

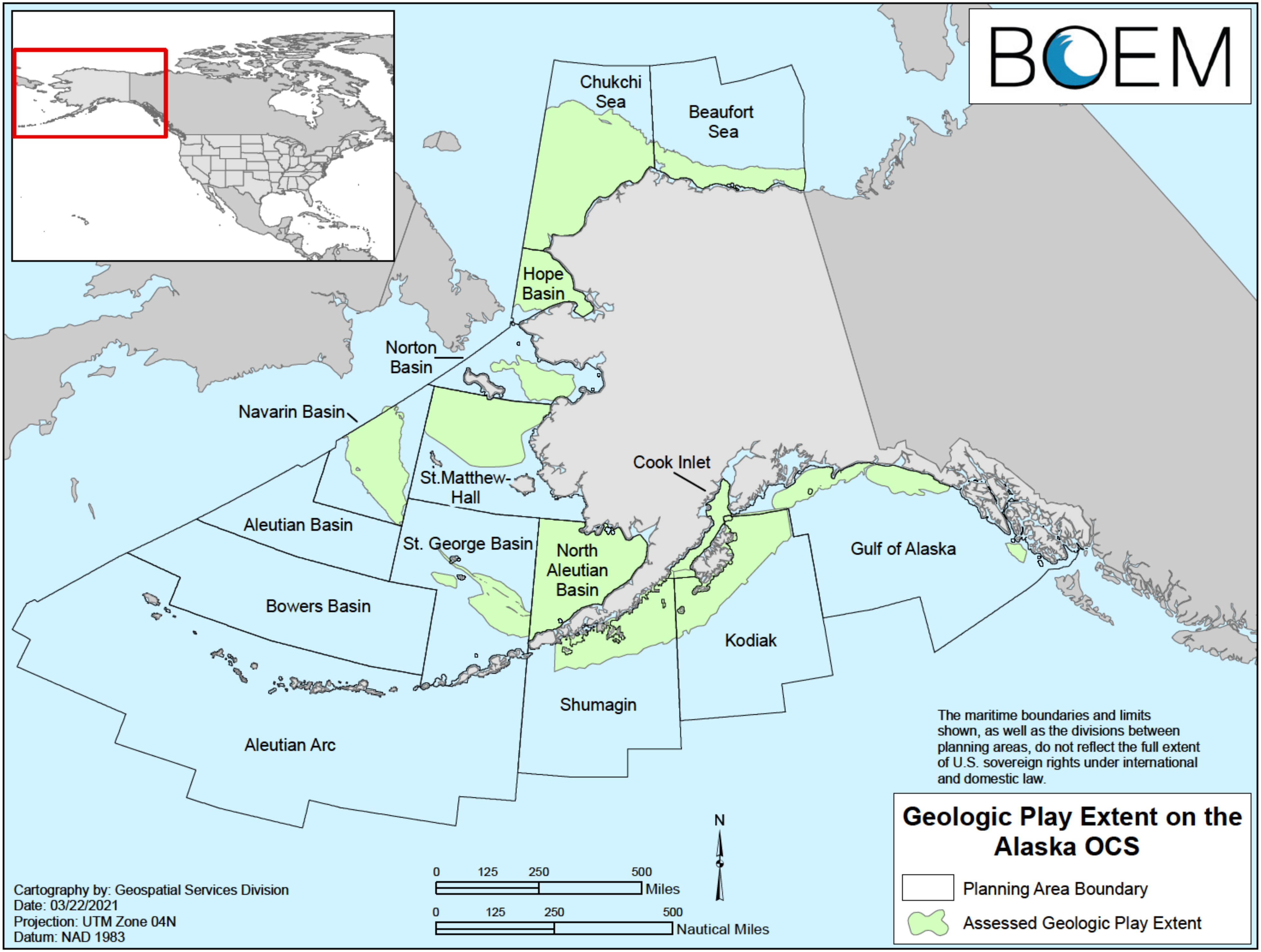
5 . There are 4 planning areas in the Pacific Region but only 1 planning area with existing leases.

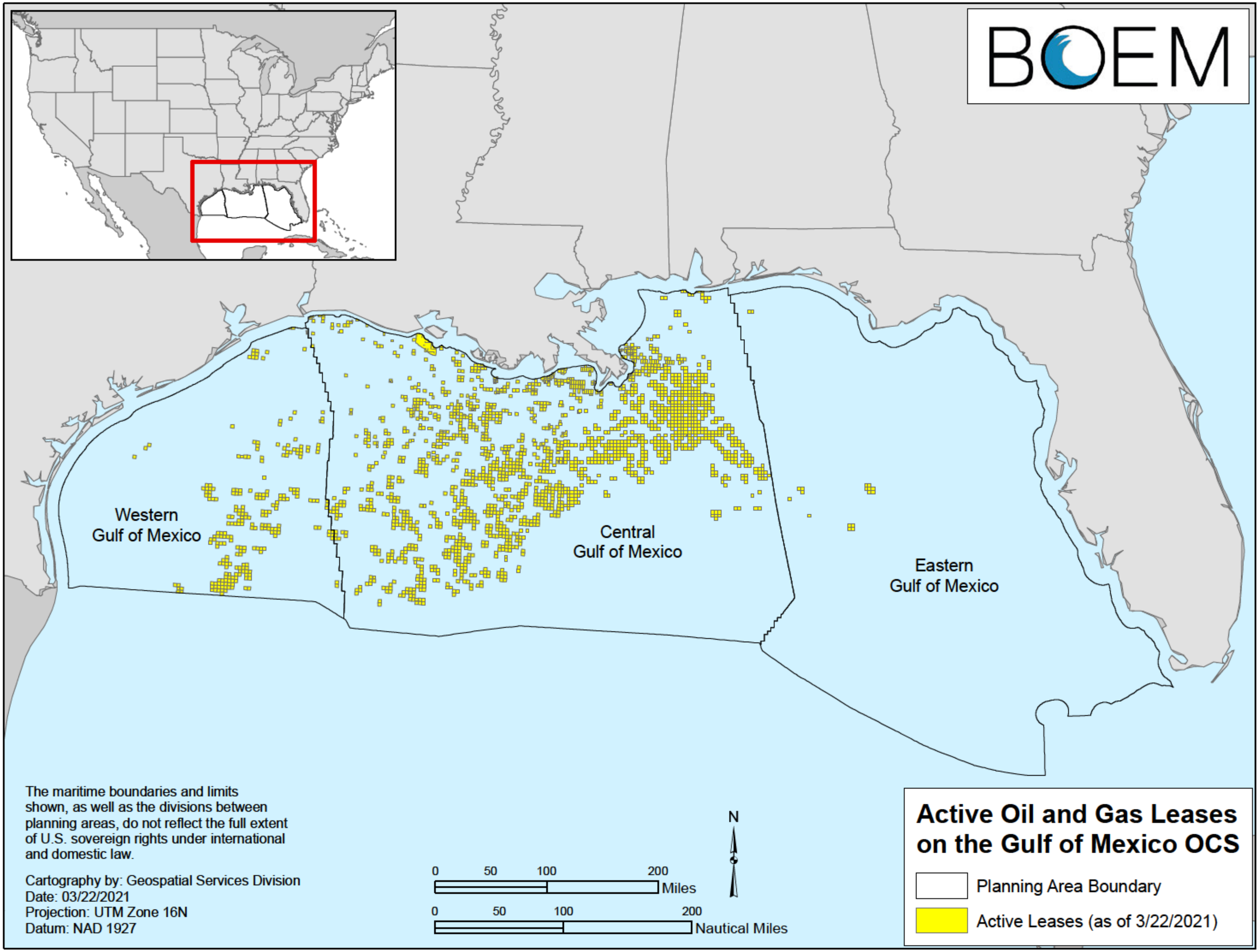
6 . There are 15 planning areas in the Alaska Region, but only two planning areas with leases.


BOEM
North Atlantic
Mid-Atlantic
South Atlantic
Straits of Florida
0 50 100 200 Miles
0 50 100 200 Nautical Miles
N
Cartography by: Geospatial Services Division
Date: 03/22/2021
Projection: UTM Zone 18N
Datum: NAD 1983
The maritime boundaries and limits shown, as well as the divisions between planning areas, do not reflect the full extent of U.S. sovereign rights under international and domestic law.
Geologic Play Extent on the Atlantic OCS
Planning Area Boundary
Assessed Geologic Play Extent


BOEM
Western
Gulf of Mexico
Central
Gulf of Mexico
Eastern
Gulf of Mexico
Geologic Play Extent on the Gulf of Mexico OCS
Planning Area Boundary
Assessed Geologic Play Extent
The maritime boundaries and limits shown, as well as the divisions between planning areas, do not reflect the full extent of U.S. sovereign rights under international and domestic law.
Cartography by: Geospatial Services Division
Date: 03/22/2021
Projection: UTM Zone 16N
Datum: NAD 1927
0 50 100 200 Miles
0 50 100 200 Nautical Miles
N

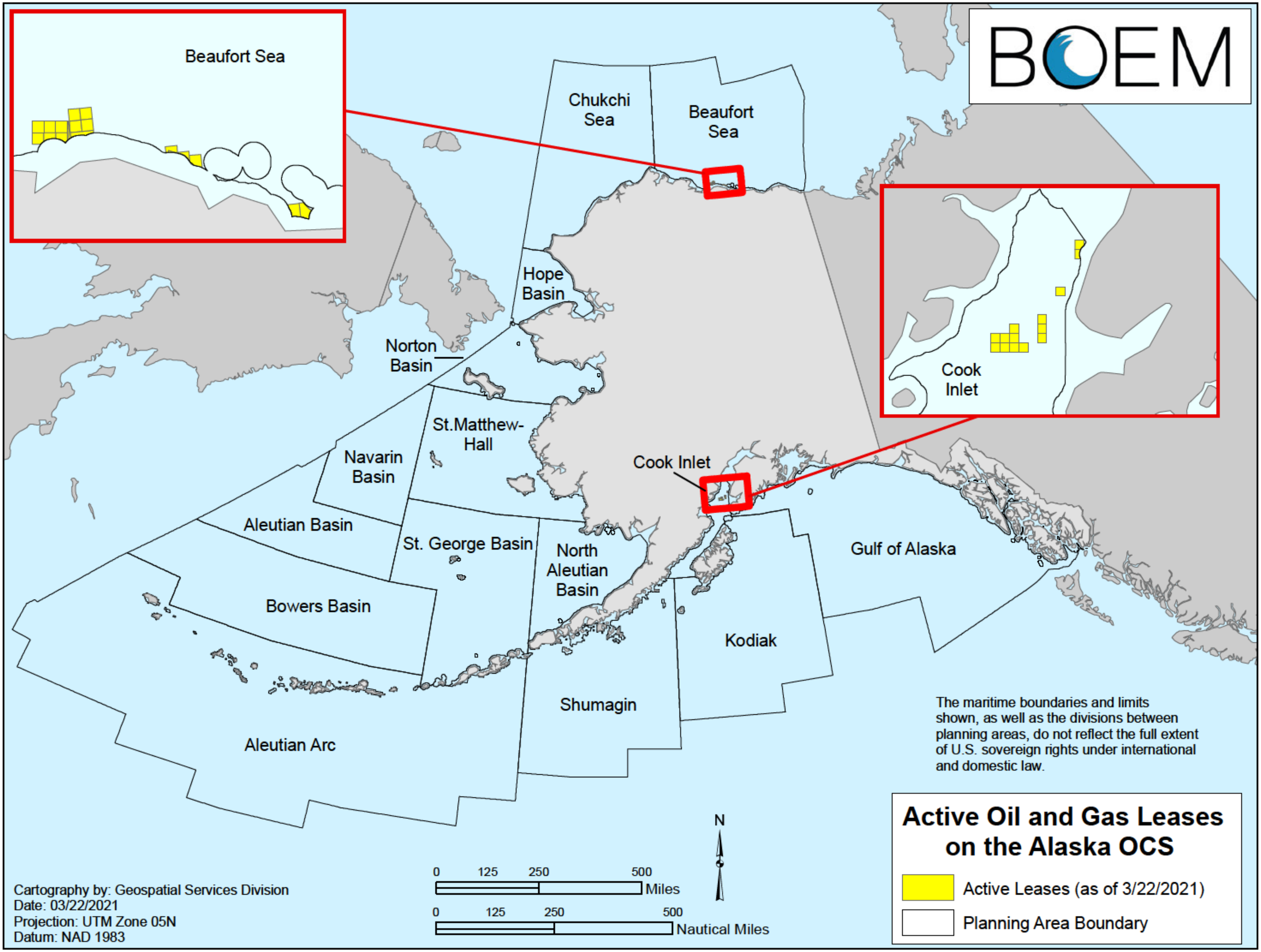

Geologic Play Extent on the Pacific OCS
Planning Area Boundary
Assessed Geologic Play Extent
Washington-Oregon
Northern California
Central California
Southern California
The maritime boundaries and limits shown, as well as the divisions between planning areas, do not reflect the full extent of U.S. sovereign rights under international and domestic law.
Cartography by: Geospatial Services Division
Date: 03/22/2021
Projection: UTM Zone 10N
Datum: NAD 1983
0 50 100 200 Miles
0 50 100 200 Nautical Miles
N


BOEM
Chukchi Sea
Beaufort Sea
Hope Basin
Norton Basin
Navarin Basin
St.Matthew-Hall
Cook Inlet
Aleutian Basin
St. George Basin
North Aleutian Basin
Gulf of Alaska
Bowers Basin
Kodiak
Shumagin
Aleutian Arc
The maritime boundaries and limits shown, as well as the divisions between planning areas, do not reflect the full extent of U.S. sovereign rights under international and domestic law.
Geologic Play Extent on the Alaska OCS
Planning Area Boundary
Assessed Geologic Play Extent
N
0 125 250 500 Miles
0 125 250 500 Nautical Miles
Cartography by: Geospatial Services Division
Date: 03/22/2021
Projection: UTM Zone 04N
Datum: NAD 1983



BOEM
Western
Gulf of Mexico
Central
Gulf of Mexico
Eastern
Gulf of Mexico
The maritime boundaries and limits shown, as well as the divisions between planning areas, do not reflect the full extent of U.S. sovereign rights under international and domestic law.
Cartography by: Geospatial Services Division
Date: 03/22/2021
Projection: UTM Zone 16N
Datum: NAD 1927
0 50 100 200 Miles
0 50 100 200 Nautical Miles
N
Active Oil and Gas Leases on the Gulf of Mexico OCS
Planning Area Boundary
Active Leases (as of 3/22/2021)


Active Oil and Gas Leases on the Pacific OCS
Active Leases (as of 3/22/2021)
Planning Area Boundary
BOEM
Washington-Oregon
Northern California
Central California
Southern California
Southern California
The maritime boundaries and limits shown, as well as the divisions between planning areas, do not reflect the full extent of U.S. sovereign rights under international and domestic law.
Cartography by: Geospatial Services Division
Date: 03/22/2021
Projection: UTM Zone 10N
Datum: NAD 1983
0 50 100 200 Miles
0 50 100 200 Nautical Miles
N


Active Oil and Gas Leases on the Alaska OCS
Active Leases (as of 3/22/2021)
Planning Area Boundary
Beaufort Sea
Chukchi Sea
Beaufort Sea
Hope Basin
Norton Basin
St.Matthew-Hall
Navarin Basin
Cook Inlet
Cook Inlet
Aleutian Basin
St. George Basin
North Aleutian Basin
Gulf of Alaska
Bowers Basin
Kodiak
Shumagin
Aleutian Arc
The maritime boundaries and limits shown, as well as the divisions between planning areas, do not reflect the full extent of U.S. sovereign rights under international and domestic law.
N
0 125 250 500 Miles
0 125 250 500 Nautical Miles
Cartography by: Geospatial Services Division
Date: 03/22/2021
Projection: UTM Zone 05N
Datum: NAD 1983

Region	2021 Undiscovered Technically Recoverable Resources (UTRR)								
	Oil (Bbo)			Gas (Tcfg)			BOE (BBOE)		
	F95	Mean	F5	F95	Mean	F5	F95	Mean	F5
Alaska OCS	17.00	24.69	34.08	91.07	124.03	161.63	33.21	46.76	62.84
Atlantic OCS	0.64	4.31	9.94	5.94	34.09	70.10	1.70	10.38	22.41
Gulf of Mexico OCS	23.31	29.59	36.27	46.88	54.84	62.56	31.65	39.35	47.40
Pacific OCS	6.91	10.20	14.20	10.15	16.07	23.43	8.72	13.06	18.37
Total OCS	**57.32**	**68.79**	**81.75**	**183.46**	**229.03**	**278.22**	**89.96**	**109.54**	**131.25**

Bbo = Billion barrels of oil
Tcfg = Trillion cubic feet of gas
BBOE = Billion barrels of oil equivalent

Region	2021 Undiscovered Economically Recoverable Oil and Gas Resources (UERR)					
	$40/Barrel $2.14/Mcf		$100/Barrel $5.34/Mcf		$160/Barrel $8.54/Mcf	
	Oil (Bbo)	Gas (Tcfg)	Oil (Bbo)	Gas (Tcfg)	Oil (Bbo)	Gas (Tcfg)
Alaska OCS	0.02	0.01	5.62	5.68	12.24	18.82
Atlantic OCS	2.88	0.00	3.83	0.92	3.95	4.38
Gulf of Mexico OCS	13.73	12.20	23.53	27.17	25.14	30.85
Pacific OCS	4.69	6.11	7.15	9.05	7.63	9.73
Total U.S. OCS	**21.32**	**18.32**	**40.12**	**42.83**	**48.95**	**63.77**

Bbo = Billion barrels of oil
Tcfg = Trillion cubic feet of gas
Mcf = Thousand cubic feet of gas

Sale Specific Leasing Data

Lease Sale	Date	Location	Number of Tracts Offered	Acres Offered	Number of Tracts Bid On	Acres Bid On	Total Bonus High Bid	Number of Tracts Leased	Acres Leased	Total Bonus Leased Tracts	Number of Bids Rejected or Withdrawn	Total Bonus Rejected or Withdrawn	Average Per Acre	Number of Bids Received	1st Yr Rental Amount	Total Amount Exposed
256	11/18/2020	GOM	14,909	79,605,338	93	517,733	$120,868,274.00	86	477,413	$111,559,312.00	7	$9,308,962	$233.67	105	$5,043,089.00	$135,558,336.00
254	3/18/2020	GOM	14,641	78,167,224	71	397,286	$93,083,453.00	63	351,206	$86,240,453.00	8	$3,533,266	$245.56	84	$3,743,266.00	$108,587,185.00
253	8/2/12019	GOM	14,600	77,948,087	151	835,007	$159,386,761.00	147	811,967	$154,994,527.00	4	$4,392,234.00	$190.89	165	$8,607,260.00	$174,922,200.00
252	3/20/2019	GOM	14,699	78,539,807	227	1,261,134	$244,299,344.00	211	1,171,260	$231,790,063.00	15	$12,437,161.00	$197.90	257	$12,473,926.00	$283,782,480.00
251	8/15/2018	GOM	14,622	78,113,186	144	801,289	$178,069,406.00	141	784,009	$175,489,464.00	3	$2,579,942.00	$225.11	171	$7,983,507.00	$202,667,923.00
250	3/20/2018	GOM	14,474	77,318,918	148	815,404	$124,763,581.00	139	764,324	$115,329,139.00	9	$9,434,442.00	$150.89	159	$7,582,399.00	$139,122,383.00
249	8/16/2017	GOM	14,220	75,940,190	90	508,096	$121,143,055.00	81	456,256	$110,878,164.60	7	$9,294,188.00	$243.02	99	$4,827,935.00	$137,006,181.00
244	6/21/2017	Cook Inlet	224	1,093,533	14	76,615	$3,034,815.00	14	76,615	$3,034,815.00	0	$0.00	$39.61	14	$403,078.00	$3,034,815.00
247	3/22/2017	CGOM	9,118	48,531,940	163	913,542	$274,797,434.00	148	832,176	$263,398,527.00	10	$10,848,507.00	$316.52	189	$8,861,598.00	$315,303,884.00
248	8/24/2016	WGOM	4,399	23,778,011	24	138,240	$18,067,020.00	24	138,240	$18,067,020.00	0	$0.00	$130.69	24	$1,520,640.00	$18,067,020.00
226	3/23/2016	EGOM	162	595,475	0	0	$0.00	0	0	$0.00	0	$0.00	$0.00	0	$0.00	$0.00
241	3/23/2016	CGOM	8,349	44,312,985	128	693,962	$156,385,610.00	116	632,998	$139,723,622.60	7	$5,259,013.00	$220.73	148	$6,528,006.00	$179,172,819.00
246	8/19/2015	WGOM	4,083	21,957,863	33	190,080	$22,675,212.00	33	190,080	$22,675,212.00	0	$0.00	$119.29	33	$2,044,800.00	$22,675,212.00
235	3/18/2015	CGOM	7,788	41,250,689	169	923,711	$538,780,056.00	161	879,911	$533,090,640.00	8	$5,689,416.00	$605.85	195	$8,897,520.00	$583,201,520.00
238	8/20/2014	WGOM	4,026	21,604,036	81	433,822	$109,951,644.00	80	428,062	$109,086,059.00	1	$865,585.00	$254.84	93	$4,571,666.00	$135,463,114.00
225	3/19/2014	EGOM	134	465,201	0	0	$0.00	0	0	$0.00	0	$0.00	$0.00	0	$0.00	$0.00
231	3/19/2014	CGOM	7,511	39,649,713	326	1,695,243	$850,809,921.00	320	1,662,203	$845,892,132.00	5	$4,371,639.00	$508.90	380	$16,004,588.00	$1,085,372,484.00
233	8/28/2013	WGOM	4,036	21,401,701	56	313,121	$123,685,562.00	54	301,601	$121,473,196.00	2	$2,212,366.00	$402.76	64	$3,242,558.00	$166,019,096.00
227	3/20/2013	CGOM	7,299	38,613,043	320	1,722,191	$1,214,675,536.00	307	1,648,831	$1,199,052,037.00	13	$15,623,499.00	$721.27	407	$16,665,971.00	$1,595,397,446.00
229	11/28/2012	WGOM	3,873	20,753,797	116	652,522	$133,767,074.00	116	652,522	$133,767,074.00	0	$0.00	$205.00	131	$6,948,676.00	$157,683,267.00
222	6/20/2012	CGOM	7,434	39,303,865	454	2,402,919	$1,704,500,995.00	442	2,335,646	$1,681,578,390.00	12	$22,922,605.00	$719.96	593	$22,100,647.00	$2,602,563,726.00
218	12/14/2011	WGOM	3,913	21,010,306	191	1,093,805	$337,688,341.00	181	1,036,205	$324,971,001.00	9	$12,596,540.00	$313.62	241	$11,147,202.00	$712,726,998.00
213	3/17/2010	CGOM	6,958	36,957,957	468	2,484,107	$949,265,959.00	446	2,369,101	$919,881,068.40	19	$11,497,715.00	$388.28	642	$23,445,796.00	$1,300,075,693.00
210	8/19/2009	WGOM	3,435	18,393,357	162	924,487	$115,466,321.00	155	884,167	$111,385,124.00	7	$4,081,197.00	$125.98	189	$8,999,588.00	$145,186,365.00
208	3/18/2009	CGOM	6,458	34,594,940	348	1,883,356	$703,048,523.00	328	1,784,242	$690,163,194.40	19	$12,673,983.00	$386.81	476	$17,978,055.00	$933,649,315.00
207	8/20/2008	WGOM	3,412	18,304,659	319	1,827,358	$487,297,676.00	313	1,792,798	$483,959,404.00	6	$3,338,272.00	$269.95	423	$15,807,707.50	$607,134,968.00
206	3/19/2008	CGOM	5,569	29,787,264	615	3,323,048	$3,677,688,245.00	603	3,255,448	$3,671,052,702.40	11	$6,477,661.00	$1,127.66	1,057	$28,172,003.50	$5,740,047,263.00
224	3/19/2008	EGOM	118	546,971	36	190,297	$64,713,213.00	36	190,297	$64,713,213.00	0	$0.00	$340.06	58	$1,807,888.00	$72,137,645.00
193	2/7/2008	Chuk.Sea	5,354	29,389,241	488	2,758,408	$2,662,059,883.00	487	2,758,377	$2,662,059,563.00	0	$0.00	$965.08	667	$2,790,705.00	$3,389,919,496.00
205	10/3/2007	CGOM	5,359	28,729,114	723	3,869,701	$2,904,321,011.00	682	3,729,654	$2,812,953,879.40	18	$18,509,402.00	$754.21	1,428	$32,794,967.75	$5,245,583,944.00
204	8/22/2007	WGOM	3,338	17,900,238	282	1,585,758	$289,953,066.00	274	1,540,438	$287,081,023.00	8	$2,872,043.00	$186.36	358	$13,031,096.25	$369,496,840.00
202	4/18/2007	BeauSea	1,654	8,734,194	92	502,088	$42,165,195.00	90	490,701	$42,017,145.40	0	$0.00	$85.62	95	$532,412.50	$42,339,231.00
200	8/16/2006	WGOM	3,865	20,865,105	381	2,147,619	$340,935,514.00	371	2,090,019	$331,950,865.00	10	$8,984,649.00	$158.83	541	$18,002,044.00	$462,760,912.00
198	3/15/2006	CGOM	4,040	21,371,545	405	2,099,848	$588,309,791.00	392	2,032,684	$581,820,861.00	12	$6,274,930.00	$286.23	707	$16,544,225.25	$978,310,887.00
196	8/17/2005	WGOM	3,762	20,331,612	346	1,958,708	$285,192,865.00	342	1,935,668	$283,441,874.00	4	$1,750,991.00	$146.43	422	$16,484,194.50	$335,628,130.00
195	3/30/2005	BeauSea	1,728	9,301,423	121	618,751	$46,735,081.00	117	607,285	$46,572,379.00	2	$161,302.00	$76.69	121	$823,357.50	$46,735,081.00
197	3/16/2005	EGOM	124	714,240	12	69,120	$6,974,531.00	10	57,600	$6,595,753.40	0	$0.00	$114.51	12	$432,000.00	$6,974,531.00
194	3/16/2005	CGOM	4,063	21,429,724	428	2,131,741	$353,961,798.00	403	2,035,414	$342,027,467.00	19	$11,931,635.00	$168.04	651	$12,626,567.50	$540,254,193.00
192	8/18/2004	WGOM	3,907	21,205,117	351	1,997,177	$171,387,285.00	346	1,970,949	$169,928,999.00	4	$1,257,085.00	$86.22	421	$12,913,110.00	$197,395,164.00
191	5/19/2004	Cook Inlet	445	2,197,497	0	0	$0.00	0	0	0	0	$0.00	$0.00	0	$0.00	$0.00
190	3/17/2004	CGOM	4,324	22,727,885	557	2,797,036	$368,763,482.00	542	2,718,753	364,024,583	14	$4,537,449.00	$133.89	829	$16,571,750.00	$636,819,534.00
189	12/10/2003	EGOM	138	794,880	14	80,640	$8,376,765.00	14	80,640	8,376,765	0	$0.00	$103.88	16	$604,800.00	$9,081,842.00
186	9/24/2003	BeauSea	1,756	9,459,743	34	181,810	$8,903,538.00	34	181,810	8,903,538	0	$0.00	$48.97	37	$309,650.00	$10,175,949.00
187	8/20/2003	WGOM	3,996	21,705,925	335	1,896,647	$148,715,127.00	330	1,867,847	145,917,314	5	$2,797,813.00	$78.12	407	$12,506,962.50	$258,716,307.00
185	3/19/2003	CGOM	4,459	23,353,043	561	2,800,287	$315,531,229.00	545	2,717,819	297,598,165	16	$17,933,064.00	$109.50	793	$16,167,185.00	$414,738,677.00
184	8/21/2002	WGOM	4,102	22,270,482	323	1,772,471	$151,265,255.00	315	1,727,068	148,558,145	7	$2,400,830.00	$86.01	391	$11,149,157.50	$181,551,965.00
182	3/20/2002	CGOM	4,446	23,422,552	506	2,551,575	$363,210,467.00	489	2,465,836	355,792,253	15	$5,478,221.00	$144.29	697	$15,279,060.00	$442,441,036.00
181	12/5/2001	EGOM	233	1,342,080	95	547,200	$340,474,113.00	95	547,200	340,474,113	0	$0.00	$622.21	190	$4,104,000.00	$458,936,089.00
180	8/22/2001	WGOM	4,114	22,370,704	320	1,790,133	$165,571,777.00	313	1,754,860	163,627,562	7	$1,944,215.00	$93.24	386	$11,498,545.00	$189,971,325.00
178-2	8/22/2001	CGOM	53	250,788	0	0	$0.00	0	0	0	0	$0.00	$0.00	0	$0.00	$0.00
178-1	3/28/2001	CGOM	4,390	23,185,334	547	2,772,512	$505,468,501.00	534	2,702,412	499,683,478	13	$5,785,023.00	$184.90	780	$16,400,325.00	$663,406,963.00
Totals			**270,114**	**1,441,592,522**	**11,868**	**63,947,605**	**22,596,189,305**	**11,470**	**61,920,612**	**22,222,651,280**	**336**	**262,056,845**		**16,346**	**486,975,485**	**32,437,797,434**

Revenue from Sales

Year	Royalties	Bonus	Rents	Inspections	Other	Total Revenue
2003	$4,566,717,100.93	$1,301,146,202.00	$264,857,123.56	$0.00	$27,468,595.83	$6,160,189,022
2004	$4,832,826,842.18	$543,541,315.00	$219,289,047.49	$0.00	-$16,301,049.27	$5,579,356,155
2005	$5,681,030,913.77	$401,831,322.00	$213,303,567.60	$0.00	-$7,229,043.73	$6,288,936,760
2006	$6,828,556,003.08	$1,197,213,600.00	$237,765,808.20	$0.00	-$48,810,663.22	$8,214,724,748
2007	$6,461,644,319.51	$598,061,105.00	$199,198,139.17	$0.00	$40,340,063.65	$7,299,243,627
2008	$7,775,926,841.46	$9,158,005,828.00	$241,951,305.73	$0.00	-$1,647,202.38	$17,174,236,773
2009	$3,154,500,452.13	$1,049,624,054.00	$235,118,441.28	$0.00	$84,736,194.66	$4,523,979,142
2010	$5,337,725,799.49	$876,933,370.64	$233,834,635.94	$10,053,526.23	$78,343,123.04	$6,536,890,455
2011	$6,355,106,104.21	$36,678,158.30	$211,163,196.00	$9,563,746.07	$44,066,916.26	$6,656,578,121
2012	$5,949,903,710.27	$2,006,549,391.00	$241,351,214.74	$86,885,809.54	$40,840,239.58	$8,325,530,365
2013	$6,185,625,664.35	$1,437,672,025.50	$247,622,802.90	$53,246,992.07	$34,802,337.74	$7,958,969,823
2014	$6,184,759,920.96	$947,838,659.00	$235,095,697.37	$66,079,060.23	$55,578,180.86	$7,489,351,518
2015	$3,339,625,805.62	$593,240,014.00	$213,353,533.79	$52,239,171.25	-$8,872,482.24	$4,189,586,042
2016	$2,437,967,506.40	$157,143,226.00	$139,542,601.73	$54,047,456.05	$25,131,356.10	$2,813,832,146
2017	$3,298,398,962.94	$419,195,572.00	$116,019,225.68	$20,904,891.39	$33,081,415.65	$3,887,600,068
2018	$4,770,509,741.42	$300,019,387.00	$110,239,167.69	$41,711,630.49	$54,532,343.37	$5,277,012,270
2019	$4,905,734,409.48	$712,646,205.00	$113,087,450.95	$46,595,264.00	$15,265,184.48	$5,793,328,514
2020	$2,748,900,865.91	$165,460,808.00	$101,096,417.60	$33,868,755.00	-$13,687,621.49	$3,035,639,225
Totals	$90,815,460,964.11	$21,902,800,242.44	$3,573,889,377.42	$475,196,302.32	$437,637,888.89	$117,204,984,775.18

From: Culver, Nada L
To: Jackson, Danna R; Diera, Alexx A; Sanchez, Alexandra L
Subject: this article was in the clips, too, but
Date: Tuesday, April 6, 2021 10:28:22 AM

It really gets into the situation faced in Northern New Mexico and more broadly with the BLM, BIA, etc. and the need for FPIC as a commitment (b) (5) [redacted] and of course quotes Mario Atencio so thought it might be worth sharing amongst us, too: https://newrepublic.com/article/161940/kick-fracking-industry-indian-country

Nada

From:	Daniel-Davis, Laura E
To:	Sanchez, Alexandra L
Subject:	Re: report next rounds
Date:	Monday, April 5, 2021 1:19:50 PM

Thanks.

Get Outlook for iOS

From: Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>
Sent: Monday, April 5, 2021 1:00:21 PM
To: Daniel-Davis, Laura E <laura_daniel-davis@ios.doi.gov>
Subject: FW: report next rounds

FYI

From: Sanchez, Alexandra L
Sent: Monday, April 5, 2021 1:00 PM
To: Culver, Nada L <nada_culver@ios.doi.gov>
Subject: RE: report next rounds

I'm sure we will get her able eyes on it when the time is right! Happy to discuss with her directly.

In the meantime, I have plenty of action items to add and revise before it gets sent anywhere else.

And for now I need her help with offshore, actually, as Laura is well aware.

From: Culver, Nada L <nada_culver@ios.doi.gov>
Sent: Monday, April 5, 2021 12:05 PM
To: Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>
Subject: report next rounds

Hi Alex – I was communicating with Marissa Knodel and she's willing to take a run through the next draft when we're ready. She has been so involved in these issues for so long that I think it would be great if you are okay with sharing it after your next round of drafting.

Nada

From:	Culver, Nada L
To:	Sanchez, Alexandra L
Subject:	Accepted: Report Review
Start:	Sunday, April 4, 2021 8:30:00 PM
End:	Sunday, April 4, 2021 9:30:00 PM

From: Culver, Nada L
To: Sanchez, Alexandra L
Subject: RE: Draft for review
Date: Sunday, April 4, 2021 4:45:12 AM
Attachments: DRAFT Report - Onshore.docx
image00001.png

<!--[if lte mso 15 || CheckWebRef]-->

Culver, Nada L has shared a OneDrive for Business file with you. To view it, click the link below.

DRAFT Report - Onshore.docx

<!--[endif]-->

This is an amazing amount of work – you should be very proud and I am really impressed at where you are already. I put a lot of thoughts in along the way so looking forward to discussing. I used the sharepoint document so hopefully you can see it all. Guess we're both doing some serious night owl-ing on this.

Nada

From: Sanchez, Alexandra L <alexandra_sanchez@ios.doi.gov>
Sent: Saturday, April 3, 2021 2:26 AM
To: Culver, Nada L <nada_culver@ios.doi.gov>
Subject: Draft for review

Nada,

Enjoy, it's currently clocking in at 35 pages and I still have ~5 more that I need to look at again tomorrow before including.

I've attached a doc and included the link, so feel free to use whichever format you prefer.

Very much looking forward to your input!

Alex

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

From: Culver, Nada L
To: Sanchez, Alexandra L
Subject: Culver, Nada L left a comment in "DRAFT Report - Onshore"
Date: Sunday, April 4, 2021 4:25:24 AM
Attachments: 67876cb6-afaa-429f-bd54-81ae68c301cd
4b08c883-58b2-418f-8add-b799d9366b2e
c1a8c0aa-55fa-4b1f-83ce-25f8736e9fc1
fe71ee9e-5159-4dd0-a654-c3448f2199e3

SharePoint

Culver, Nada L left 4 comments

DRAFT Report - Onshore.docx

Culver, Nada L added a comment
Culver, Nada L added a comment
Culver, Nada L added a comment
Culver, Nada L added a comment

Open

From: Culver, Nada L
To: Sanchez, Alexandra L
Subject: Culver, Nada L left a comment in "DRAFT Report - Onshore"
Date: Sunday, April 4, 2021 3:56:29 AM
Attachments: 23765700-b1d4-4c5e-a3bf-0f4062488a06
666e2892-89c6-4360-b9e0-286e7511f168
fd713bec-98a8-4061-b282-63aba2982b19
2c0be369-faf5-4cc2-af5d-a575b2182ca4

SharePoint

Culver, Nada L left 9 comments

DRAFT Report - Onshore.docx

Culver, Nada L added a comment
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Culver, Nada L added a comment
Culver, Nada L added a comment
Culver, Nada L replied to Sanchez, Alexandra L's comment

Open

From: Culver, Nada L
To: Sanchez, Alexandra L
Subject: Culver, Nada L left a comment in "DRAFT Report - Onshore"
Date: Sunday, April 4, 2021 3:30:25 AM
Attachments: ba8b7aa1-8326-4476-a852-00ecf0040021
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d218d5fd-08d4-418d-a981-c1120ab75eac

SharePoint

Culver, Nada L left 15 comments

DRAFT Report - Onshore.docx

Culver, Nada L added a comment
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Culver, Nada L added a comment
Culver, Nada L replied to Sanchez, Alexandra L's comment
Culver, Nada L added a comment
Culver, Nada L added a comment
Culver, Nada L added a comment
Culver, Nada L added a comment
Culver, Nada L replied to Sanchez, Alexandra L's comment
Culver, Nada L added a comment

Open

From:	Buckner, Shawn M
To:	Sanchez, Alexandra L
Cc:	Steele, Jonathan; Nguyen, Davie T
Subject:	Section 208 Background Document and BLM Update
Date:	Friday, March 19, 2021 4:06:10 PM
Attachments:	Oil and Gas Review Background_PPA Working Draft.docx

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Hi Alex,

Attached is a copy of the background information document that you requested.

There are some placeholders where BOEM/BLM may need to update some of this information in the future. Hopefully this provides you with some initial information to form the basis of your analysis.

Let us know if you have any questions.

Thank you,
Shawn

Shawn M. Buckner
Director
Office of Policy Analysis
U.S. Department of the Interior
1849 C Street, N.W.
Washington, DC 20240
Mobile: (202) 669-1320

CONTENTS

Figures and Tables

OIL AND GAS LEASING AND PERMITTING ON FEDERAL LANDS

This paper describes the Federal oil and gas program and provides baseline information intended to provide context for the consideration of program review opportunities. This section includes: historical information, authorities, overview of the Federal oil and gas leasing and permitting process, status of the oil and gas industry, leasing and production data, fiscal terms and revenues, and discussion of greenhouse gas emissions and socioeconomic considerations. The information presented in this paper focuses on the responsibilities of the Bureau of Land Management (BLM) and the Bureau of Ocean Energy Management (BOEM) programs.

HISTORICAL INFORMATION

Onshore

The BLM was established in 1946, but its roots go back to the years after America's independence, when the nation began acquiring additional lands. At first, these lands were used to encourage homesteading and westward migration. The General Land Office (GLO) was created in 1812 to support this national goal. Over time, values and attitudes regarding public lands shifted, and Congress merged the GLO and the U.S. Grazing Service to create the BLM.[1] In 1976, the Federal Land Policy and Management Act (FLPMA) established additional land and resource management authorities for BLM, bringing to the forefront multiple use, sustained yield, and environmental protection as the guiding principles for public land management. Specifically, BLM must take any action necessary to prevent unnecessary or undue degradation of the lands. One of the multiple uses that BLM oversees is the management of energy and mineral resource development on approximately 700 million acres of Federal onshore lands.

Offshore

The U.S. Geological Survey managed oil and gas leasing, development, and payments prior to the creation of the Minerals Management Service in 1982. BOEM was created in 2010, when the Minerals Management Service (MMS) was reorganized into three separate organizations to separate conflicting missions of promoting resource development, enforcing safety regulations, and maximizing revenues from offshore operations. BOEM took on the offshore leasing, economic analysis, resource evaluation and environmental analysis functions; the Bureau of Safety and Environmental Enforcement (BSEE) took on the safety and enforcement responsibilities including operations, inspections, and environmental compliance; and the Office of Natural Resources Revenue (ONRR) took on the responsibility of ensuring full payment of revenues owed for the development of OCS resources. The reorganization of the former MMS was designed to remove those conflicts by clarifying and separating missions across three agencies and providing each of the new agencies with clear missions and additional resources necessary to fulfill those missions.[2]

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[1] https://www.blm.gov/about/history
[2] https://www.boem.gov/oil-gas-energy/leasing/ocs-lands-act-history

AUTHORITIES

Onshore

The Bureau of Land Management (BLM) manages the Federal government's onshore subsurface mineral estate – about 700 million acres (30% of the United States) held by the BLM, U.S. Forest Service and other Federal agencies and surface owners -- for the benefit of the American public. It also manages some aspects of the oil and gas development for Indian tribes from the Tribal 1872 mineral estate.[3]

The following laws and regulations give the BLM the authority to approve or deny onshore oil and gas leases or to impose environmental restrictions on leases when appropriate. Forest Service oil and gas regulations are also identified.[4]

The General Mining Act of 1872 was the seminal law regarding mineral management on federal lands in the United States. However, this act was implemented primarily to deal with hard-rock mining, and it was not until the enactment of the Mineral Leasing Act of 1920 that a comprehensive system was developed for managing oil and gas development on federal lands. Since 1920, the Mineral Leasing Act has been modified by several amendments and elaborated upon by the implementation of new statutes. These are discussed below.

Mineral Leasing Act of 1920 (30 U.S.C. § 181 et seq.) - The Mineral Leasing Act established the authority of the Secretary of the Interior to oversee oil and gas operations on federal land. "The Secretary of the Interior is authorized to prescribe necessary and proper rules and regulations and to do any and all things necessary to carry out and accomplish the purposes of this Act." 30 U.S.C. § 189

Mineral Leasing Act for Acquired Lands of 1947 (30 U.S.C. § 351 et seq.) - Extends the provisions of the Mineral Leasing Act and the authority of the Secretary of the Interior over oil and gas operations to federal "acquired lands."

Mining and Minerals Policy Act of 1970 (30 U.S.C. § 21 et seq.) - An amendment to the Mineral Leasing Act, this statute encompasses both hard rock mining and oil and gas and established modern federal policy regarding mineral resources in the United States. The Act articulates a national interest to foster and encourage private enterprise while mitigating adverse environmental impacts.

Federal Land Policy and Management Act of 1976 (43 U.S.C. §1701 et seq.) - FLPMA, also called the BLM Organic Act, consolidated and articulated BLM management responsibilities and delegated many management responsibilities pertaining to federal land from the Secretary to the Director of the BLM, including oversight of oil and gas leases. FLPMA provides an express congressional policy aimed at retaining federal control and possession over valuable lands and mineral resources.

Federal Oil and Gas Royalty Management Act of 1982 (30 U.S.C. § 1701 et seq.) - The Royalty Management Act affirmed the authority of Secretary to administer and enforce all rules and regulations governing oil and gas leases on Federal or Indian Land, and established a policy aimed at developing a comprehensive system to manage royalties derived from leased oil and gas operations

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[3] About Oil and Gas | Bureau of Land Management (blm.gov)

[4] http://www.oilandgasbmps.org/laws/federal_law.php (12/31/19)

Federal Onshore Oil and Gas Leasing Reform Act of 1987 (FOOGLRA) (30 U.S.C. § 181 et seq.) - Another amendment to the Mineral Leasing Act, The Federal Onshore Oil and Gas Leasing Reform Act of 1987 granted the USDA Forest Service the authority to make decisions and implement regulations concerning the leasing of public domain minerals on National Forest System lands containing oil and gas. The Act changed the analysis process from responsive to proactive. The BLM administers the lease but the Forest Service has more direct involvement in the leasing process for lands it administers. The Act also established a requirement that all public lands that are available for oil and gas leasing be offered first by competitive leasing.

The following are brief summaries to some of the major environmental statutes applicable to onshore oil and gas development:

National Environmental Policy Act (NEPA) (42 U.S.C. § 4321 et seq.) - Enacted in 1970, NEPA established a national policy to encourage productive and enjoyable harmony between man and his environment and to promote the prevention and elimination of damage to the environment and biosphere. At the heart of NEPA is the requirement that environmental impact statements (EISs) be prepared for all major federal agency actions significantly affecting the human environment.

Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA) (42 U.S.C. § 9601 et seq.) - CERCLA, commonly known as Superfund, provides broad federal authority to respond directly to releases or threatened releases of hazardous substances that may endanger public health or the environment. CERCLA established prohibitions and requirements concerning closed and abandoned hazardous waste sites, provided for liability of persons responsible for releases of hazardous waste as these sites, and established a trust, funded by a tax on the chemical and petroleum industries, to provide cleanup when no responsible party could be identified.

Clean Water Act (CWA) (33 U.S.C. § 1251 et seq.) - The Clean Water Act was established to restore and maintain the chemical, physical, and biological integrity of the nation's waters. The CWA aims to protect water quality through development of water quality standards, anti-degradation policies, water quality permitting procedures, water body monitoring and assessment programs, and elimination or point and nonpoint pollution sources. The CWA regulates the National Pollutant Discharge Elimination System (NPDES) permitting process, which establishes, through a permit, pollutant limits on the discharge of produced water that generally include a volume (quantity) and concentration (quality).

Pollutants under the NPDES program fall into one of three categories: conventional, toxic, and non-conventional. There are two types of permits under the NPDES program that allow for the discharge of pollutants from point sources. These are individual permits, which are specific to an individual facility, and general permits, which cover multiple facilities within a specific permit category.

Clean Air Act (CAA) (42 U.S.C. § 7401 et seq.) - Congress passed the CAA in 1970 in order to combat air pollution in the United States and protect the health and general welfare of United States citizens against air pollutants. The act prescribes the measures that federal agencies, state and local governments, and polluters in business and industry must take in order to decrease air pollution in the country. This act was last amended in 1990.

Offshore

The Bureau of Offshore Ocean Energy Management (BOEM) is responsible for all Outer Continental Shelf (OCS) leasing policy and program development issues for oil, gas and other marine minerals. The Bureau of Safety and Environmental Enforcement (BSEE) oversees the safety and enforcement responsibilities including operations, inspections, and environmental compliance. The Office of Natural Resources Revenue (ONRR) has the responsibility of ensuring full payment of revenues owed for the development of OCS resources.

The Submerged Lands Act (SLA) of 1953 grants individual States rights to the natural resources of submerged lands from the coastline to no more than 3 nautical miles (5.6 km) into the Atlantic, Pacific, the Arctic Oceans, and the Gulf of Mexico. The only exceptions are Texas and the west coast of Florida, where State jurisdiction extends from the coastline to no more than 3 marine leagues (16.2 km) into the Gulf of Mexico. [5]

The SLA also reaffirmed the Federal claim to the OCS lands, which consists of those submerged lands seaward of State jurisdiction. The SLA led to the passage of the Outer Continental Shelf Lands Act later in 1953 (OCSLA). The OCSLA and subsequent amendments, in later years, outlined the Federal responsibility over the submerged lands of the OCS. Additionally, it authorized the Secretary of the Interior to lease those lands for mineral development.

In 1982, Congress passed the Federal Oil & Gas Royalty Management Act, which mandates protection of the environment and conserves Federal resources. The Secretary of the Interior designated the Minerals Management Service (MMS) as the administrative agency responsible for mineral leasing of OCS lands and for the supervision of offshore operations after lease issuance.

On March 10, 1983, President Ronald Reagan signed a Presidential Proclamation (5030) which set up the U.S. Exclusive Economic Zone (EEZ). The EEZ consists of those areas adjoining the territorial sea of the United States, the Commonwealth of Puerto Rico, the Commonwealth of Northern Mariana Islands, and U.S. overseas territories and possessions. The EEZ extends up to 200 nautical miles (370 km) from the coastline. About 15 percent of this area lies on the geologic continental shelf and is shallower than 200 m (656 ft). Another 10 to 15 percent lies on the continental slope and rise, between 200 and 2,000 m (656 and 6,562 ft) water depth. The remaining 70–75 percent is abyssal plain where water depths reach 3,000–5,000 m (9,843–16,405 ft).

Federal lands and their subsequent development has made the OCS a major source of the Nation's supply of crude oil and natural gas. Offshore operators have also produced salt and sulphur from OCS leases. In 1985, an amendment to the OCSLA authorized the creation of an OCS sand and gravel leasing program.

The Oil Pollution Act of 1990 gave the Secretary of the Interior authority over offshore facilities and associated pipelines, with the exception of deepwater ports, for State and Federal offshore waters. The Secretary in turn delegated this authority to BOEM's predecessor agency, the Minerals Management Service. The resulting tasks for BOEM include the following:

- enforcing spill prevention measures,
- reviewing spill response plans,

[5] https://www.boem.gov/oil-gas-energy/leasing/federal-offshore-lands

- inspecting spill containment and cleanup equipment,
- reviewing spill financial liability limits, and
- certifying spill financial responsibility.

While the OCSLA and Oil Pollution Act define the bureau's jurisdiction and regulatory responsibility on Federal offshore lands, other Federal laws play a significant role in managing offshore operations. Some of those laws are:

- National Environmental Policy Act of 1970 (NEPA) - The NEPA requires a detailed environmental review before any major or controversial Federal action.
- Clean Air Act of 1970 (CAA, reauthorized in 1990) - The CAA regulates the emission of air pollutants from industrial activities.
- Coastal Zone Management Act of 1972 (CZMA, reauthorized in 1990) - The CZMA requires State review of Federal action that affects the land and water use of the coastal zone.
- Clean Water Act of 1977 (CWA) - The CWA, through the issuance of National Pollutant Discharge and Elimination System permits, regulates the discharge of toxic and nontoxic pollutants into the surface waters of the U.S.
- Federal Oil and Gas Royalty Management Act of 1982 (FOGRAMA) - The FOGRAMA requires that oil and gas facilities be built in a way that protects the environment and conserves Federal resources.
- Marine Mammals Protection Act of 1972 (MMPA) - The MMPA provides for the protection and conservation of all marine mammals and their habitats.
- Endangered Species Act of 1973 (ESA) - The ESA requires a permit for the taking of any protected species. It also requires that all Federal actions not significantly impair or jeopardize protected species or their habitats.

Oil and Gas Leasing and Permitting Process

Federal onshore oil and gas resources are managed by the Bureau of Land Management (BLM), and offshore federal oil and gas resources are managed by the Bureau of Ocean Energy Management (BOEM) and regulated by the Bureau of Safety and Environmental Enforcement (BSEE). The Office of Natural Resources Revenue (ONRR) is responsible for ensuring full payment of onshore and offshore revenues.

Onshore and offshore leases are awarded to oil and gas companies using competitive bonus-bid auctions. Winning bidders pay the bonus bid, a per-acre rent prior to first production, and royalties once production begins. There are some differences between the onshore and offshore leasing processes:

- Onshore, parcels are nominated for leasing by interested parties. Parcels identified by BLM as available for leasing are then sold at a competitive auction using an in-person or an electronic bidding process. For two years after a parcel is not sold at a competitive auction, the BLM offers it “over-the-counter” on a non-competitive basis, in accordance with statute.

- Offshore, BOEM identifies available acres using public comment and publishes a schedule of lease sales in a National OCS Oil and Gas Leasing Program. Leases are then sold using a sealed bid auction where the highest qualified bidder is awarded the lease (following a thorough fair market value evaluation). The currently approved 2017-2022 oil and gas leasing program makes available nearly 50 percent of the undiscovered technically recoverable oil and gas estimated to be on the OCS.[6]

Onshore
The BLM is the Federal agency that is responsible for leasing oil and gas onshore. The BLM coordinates with other Federal, state, and local agencies and governments that may be affected by oil and gas-related activities and with representatives of industry and environmental groups that may be affected by how oil and gas resources are leased and managed. The BLM leases oil and gas resources through a competitive sales process using a fixed royalty-variable cash bonus bidding system. The BLM prepares the paperwork necessary to evaluate tracts for sale, holds the lease sale using sealed bidding procedures, and evaluates the high bids received to determine if they constitute Fair Market Value (FMV).

Land Use Planning
Through the planning process the BLM determines what lands will be available for oil and gas leasing, what lease stipulations will be applied to lease parcels prior to leasing to protect other resource values and may describe possible "conditions of approval" to be placed on the applications for permit to drill (APDs) for additional resource protection. The land use planning process, mandated under the Federal Land Policy Management Act (FLPMA), requires extensive collaboration with local, state and tribal governments, the general public, local user groups and various industries on how the Federal lands will be used and protected during both the landscape level cumulative and site-specific NEPA processes.

Land with oil and gas leases are available for other multiple-use purposes. After oil and gas development is complete, the BLM requires reclamation of the land to return all land to multiple-use.

In 2010, in order to identify resource conflicts earlier in the leasing process, the BLM instituted a three-pronged approach to leasing reform, which includes standardizing lease requirements for consistency and fairness, providing a more thorough lease-sale parcel review process, and analyzing leasing and development areas defined in master leasing plans.

Leasing decisions are analyzed in the course of preparing the land management plan/environmental impact statement (EIS), which addresses the cumulative impacts of leasing, exploration, and development. These EISs include:

- reasonably foreseeable development scenario for long-term oil and gas development (e.g., an estimate of the number of oil and gas wells that might be drilled)
- cumulative impact analysis of existing and anticipated oil and gas activity
- lease stipulations that will be attached to each lease to ensure environmental protection (e.g., limits on seasons when drilling can occur and restrictions on surface occupancy by oil and gas operators

[6] For additional details see: https://www.boem.gov/2017-2022-ocs-oil-and-gas-leasing-program.

Additional programmatic NEPA is conducted when with larger projects involving hundreds or thousands of wells over 5, 10, 15, or even 20 years, depending on market condition. These large volumes of wells are analyzed cumulatively for impacts of all resources and values and landscape level mitigation is determined.

The EIS identifies the site-specific need for various types of impact-limiting or "mitigation" measures. These measures can include revegetation to curb erosion and the spread of weeds, placement and color of structures and machinery to reduce visual impacts, buffer zones so as not to impact wildlife habitat, and underground placement of powerlines. In addition, many operators routinely use best management practices -- such as remote sensing to monitor well production and flowlines to central processing facilities, which minimizes traffic to wells.

Leasing
The BLM generally issues two types of leases for oil and gas exploration and development on lands owned or controlled by the Federal government -- competitive and noncompetitive.

Congress passed the Federal Onshore Oil and Gas Leasing Reform Act of 1987 requiring that all public lands available for oil and gas leasing be offered first by competitive leasing. The BLM may issue noncompetitive leases only after the agency has offered the lands competitively at an auction in which the lands do not receive a bid.

The maximum competitive parcel size is 2,560 acres in the lower 48 states and 5,760 acres in Alaska outside of the National Petroleum Reserve-Alaska. The BLM issues both competitive and noncompetitive leases for a 10-year period.

BLM State Offices conduct lease sales quarterly when parcels are available for lease. Each State Office publishes a Notice of Competitive Lease Sale (Sale Notice), which lists parcels to be offered at the auction, usually 45 days before the auction. This notice is posted online by the State Office that administers the sale. The Sale Notice specifies lease stipulations applicable to each parcel. The BLM may conduct lease sales in-person or through internet-based auctions.

Lands offered in the Sale Notice come from three sources:

- Lands identified by informal expressions of interest from the public
- Lands included in offers filed for noncompetitive leases
- Lands identified by the BLM.

The successful bidder must submit a properly executed lease bid form, which constitutes a legally binding lease offer. The bidder must also pay an administrative fee, equal to the first year's advance rental ($1.50 per acre or fraction thereof), and not less than a $2-per-acre minimum bonus bid. The balance of the bonus bid must be paid within 10 working days from the last day of the auction.

Offshore

National Outer Continental Shelf Oil and Gas Leasing Program
Management of OCS oil and gas resources is governed by the OCS Lands Act (43 U.S. Code [U.S.C.] 1331 et seq.), which sets forth procedures for leasing, exploration, development, and production of those resources. Section 18 of the OCS Lands Act (43 U.S.C. 1344) calls for the preparation of a nationwide OCS oil and gas leasing program, setting forth a five-year schedule of lease sales designed to best meet the

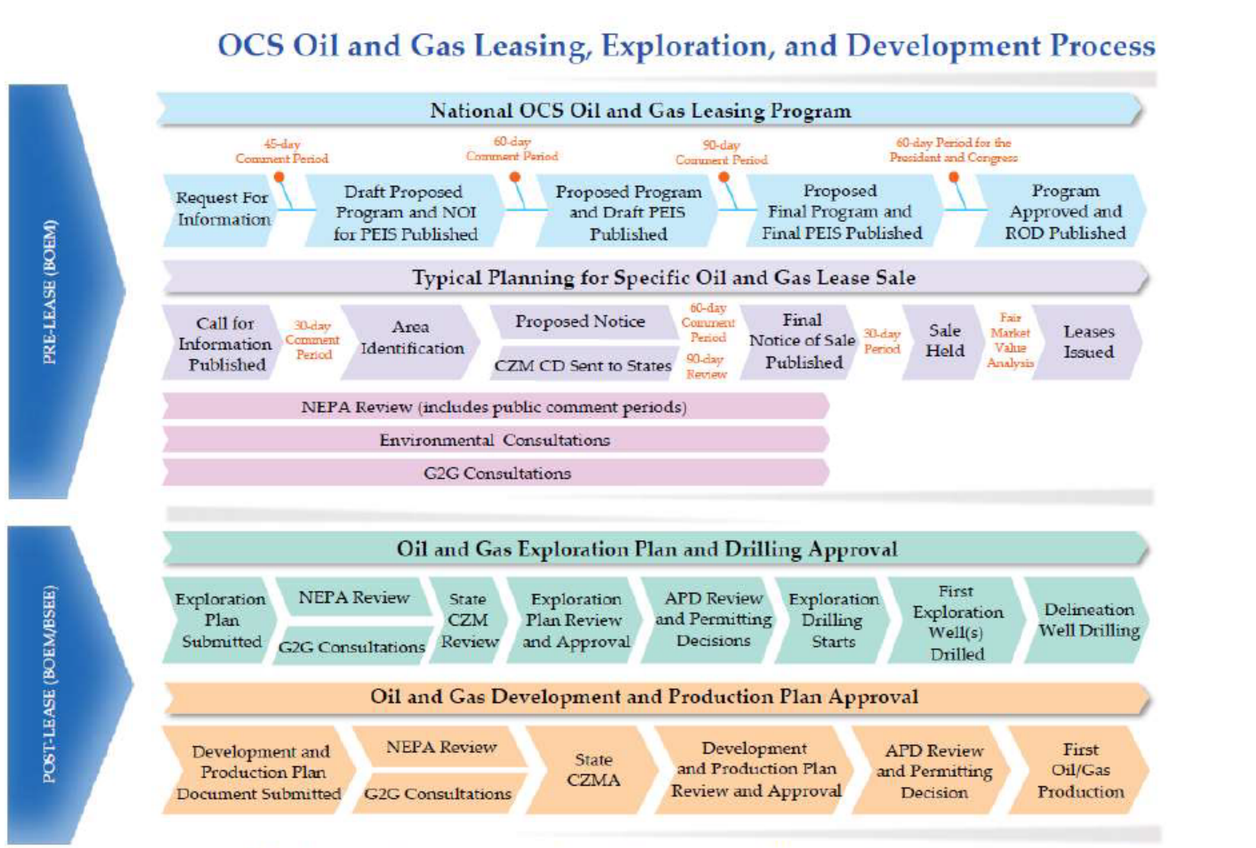
Nation's energy needs. The Bureau of Ocean Energy Management (BOEM) within DOI is responsible for implementing the requirements of the OCS Lands Act related to preparing the leasing program.

BOEM's development of a National Program typically takes place over two or three years, during which successive drafts of the program are published for review and comment. All available leasing areas are evaluated and narrowed based on the consideration of eight factors which contribute to the size, timing, and location of oil and gas activities among different areas of the OCS:

- Geographical, geological and ecological characteristics
- Equitable sharing of developmental benefits and environmental risks
- Location with respect to regional and national energy markets and needs
- Location with respect to other uses of the sea and seabed
- Laws, goals, and policies of affected states identified by Governors
- Interest of potential oil and gas producers
- Relative environmental sensitivity and marine productivity
- Environmental and predictive information

BOEM's outreach and coordination with other Federal agencies; state, local, and tribal governments; nongovernmental organizations; and the public is a crucial part of the program development process. The National OCS Program development process provides multiple opportunities for stakeholders and the general public to provide comments, with three comment opportunities under the OCS Lands Act process and two under the NEPA process. At the end of the process, the Secretary of the Interior must submit the final program to the President and to Congress for a period of at least 60 days, after which the program may take effect upon approval from the Secretary.

Figure 1. Offshore Leasing and Permitting Process



Key: APD – Application for Permit to Drill; BOEM – Bureau of Ocean Energy Management; BSEE – Bureau of Safety and Environmental Enforcement; CD – Consistency Determination; CZM – Coastal Zone Management; DNA = Determination of NEPA Adequacy; G2G = government-to-government; NEPA = National Environmental Policy Act; NOI = Notice of Intent; OCS = Outer Continental Shelf; PEIS = programmatic environmental impact statement; ROD = Record of Decision

Competitive Leasing Process

The leasing process has traditionally taken about two years to complete and contains multiple steps and decision points along the way. Generally, the process begins with a Call for Information and Nominations (Call), where BOEM solicits public input on areas of interest or concern, and specifically solicits industry interest on areas that should be considered for leasing. After the Call, BOEM completes and announces its Area Identification (Area ID), which determines the discrete area that will be considered for leasing and for further environmental analysis. BOEM then prepares and publishes a Proposed Notice of Sale (NOS), which announces the proposed sale's size, timing, and terms and conditions, including any mitigation measures necessary to protect the environment and reduce potential conflicts-of-use. After required consultations and environmental review are completed, BOEM publishes a Final NOS, which includes the date, time, and location of the bid opening, the OCS blocks being offered, and the terms and conditions of the lease sale. The full process is described below in more detail.[7]

1. Call for Information and Nominations (30 CFR 556.301)—In the first step of the lease sale process, BOEM issues a Call in the Federal Register on an area that was proposed for leasing in the National OCS Program. Potential bidders are invited to submit nominations or indications of interest in specific OCS blocks within the area included in the Call. The Call also solicits comments about geological conditions; archaeological sites; multiple uses of the area; sociological, biological, and other environmental information; and asks the public for information on areas of special concern that should be analyzed.

2. Review under NEPA—Each individual lease sale requires a NEPA review. This could include preparation of a programmatic EIS covering the sales identified in an approved National OCS Program for a given region or Program Area. Subsequent lease sales could then be covered by an EA, Determination of NEPA Adequacy (DNA), or, if new information or circumstances warrant, a Supplemental EIS.

3. Area Identification (30 CFR 556.302)—Area ID identifies the area proposed for leasing and further environmental analysis. Based on information gathered from responses to the Call and the NOI, BOEM will identify the Proposed Action to be analyzed in the NEPA document. BOEM publishes the Area ID decision in the Federal Register.

4. Government-to-Government Consultations—BOEM consults with federally recognized tribes. In Alaska, BOEM additionally consults with Alaska Native Claims Settlement Act Corporations. These consultations are conducted throughout the OCS oil and gas lease sale process.

5. Environmental Consultations—Consultations under various environmental statutes occur, such as the Endangered Species Act (ESA) of 1973 (16 U.S.C. § 1531 et seq.) and the Magnuson-Stevens Fishery Conservation and Management Act (16 U.S.C. § 1801 et seq.), with Federal agencies such as the U.S. Fish and Wildlife Service (USFWS) and National Marine Fisheries Service (NMFS). BOEM also consults with State Historic Preservation officers under Section 106 of the National Historic Preservation Act (54 U.S.C. § 306108).

[7] For additional details, see https://www.boem.gov/sites/default/files/oil-and-gas-energy-program/Leasing/Five-Year-Program/2019-2024/DPP/NP-Draft-Proposed-Program-2019-2024.pdf

6. Proposed NOS (30 CFR 556.304)—The Proposed NOS describes the timing, size, and location of a proposed oil and gas lease sale. It also provides potential bidders with information on proposed lease terms and conditions, including any proposed environmental mitigations. BOEM publishes a Notice of Availability of the Proposed NOS in the Federal Register.

7. Coordination with Governors of Affected States (30 CFR 556.304-305)—Section 19 of the OCS Lands Act (43 U.S.C. § 1345) requires BOEM to solicit input on the size, timing, and location of lease sales from governors of affected states. BOEM sends the Proposed NOS to governors of affected states requesting their recommendations on the proposed lease sale's size, timing and location. The governors have 60 days to submit their recommendations to BOEM.

8. Consistency Determination (30 CFR 556.305(b))—All Federal activities, including OCS oil and gas lease sales, must be consistent to the maximum extent practicable with the enforceable policies of an affected state's coastal zone management (CZM) program (see 16 U.S.C. § 1456(c)(1) and (2)). BOEM provides coastal states with a Consistency Determination on whether the proposed lease sale is consistent, to the maximum extent practicable, with the enforceable policies of federally approved state Coastal Management Plans (CMPs). Currently, the State of Alaska does not have a federally approved CMP.

9. Issuance of a Record of Decision (EIS-level), Finding of No New Significant Impact (EAlevel) or Determination of NEPA Adequacy—The NEPA review for each individual lease sale must be completed before the sale can occur. Depending on the NEPA review undertaken for a lease sale, this could be through the issuance of a ROD, a Finding of No New Significant Impact, or a DNA.

10. Final NOS (30 CFR 556.308(a))—BOEM will publish a Final NOS at least 30 days before a lease sale is held. The Final NOS includes information on (1) how to submit bids; (2) the date, time, and location of the bid opening and reading; (3) the OCS blocks being offered; and (4) terms and conditions of the lease sale, including required environmental mitigations.

11. Holding the Lease Sale (30 CFR 556.516)—BOEM opens the sealed bids at the place, date, and hour specified in the Final NOS for the sole purpose of publicly announcing and recording the bids. BOEM does not accept or reject any bids at that time. High bids are subject to further evaluation regarding the receipt of fair market value (FMV) for the United States and adequate competition before a lease can be issued.

12. Lease Issuance (30 CFR 556.520-522)—BOEM will issue a lease following completion of the FMV analysis and review by the Department of Justice, in consultation with the Federal Trade Commission. The Department of Justice, in consultation with the Federal Trade Commission, has 30 days to conduct antitrust review of the lease sale, but could agree to a shorter review period.

Permitting

After BOEM issues a lease, a lessee typically begins a process of exploration for oil and gas accumulations. An Exploration Plan is submitted to BOEM so that BOEM can perform environmental review and possibly approve the plan. In some cases, these potential resources could already be identified through analysis of existing data and information. In other cases, a lessee could need to utilize information collected through a much broader exploration program to identify potential resources in areas where exploration data coverage is less dense or non-existent. The general process for oil and gas exploration on a lease typically begins by conducting geophysical seismic surveys early in an exploration cycle to obtain information about subsurface geologic formations and potential oil and gas traps. Such activity on a lease is conducted pursuant to the lease and/or plan requirements and does not require a separate permit, as is the case for pre-lease survey activity. Seismic survey techniques and technologies are continuously becoming more sophisticated. Generally, areas with mature oil and gas development, such as in the GOM, have more recent, and therefore more sophisticated seismic data available (e.g., three-dimensional [3-D] seismic surveys), while older, less sophisticated seismic data (e.g., two-dimensional [2-D] seismic surveys) is often all that is available to delineate frontier areas, like in the Atlantic Region. As activity increases in frontier areas, new seismic data will be collected and more detailed information will become available.

Criticisms of Oil and Gas Leasing Programs

GAO has issued several reports over the last decade on DOI's leasing responsibilities. Reports have covered a wide range of issues, not limited to recommendations to making more lands available for leasing, ensuring expeditious recovery of resources, and periodically reviewing fiscal terms to ensure a fair return for Federal leases:

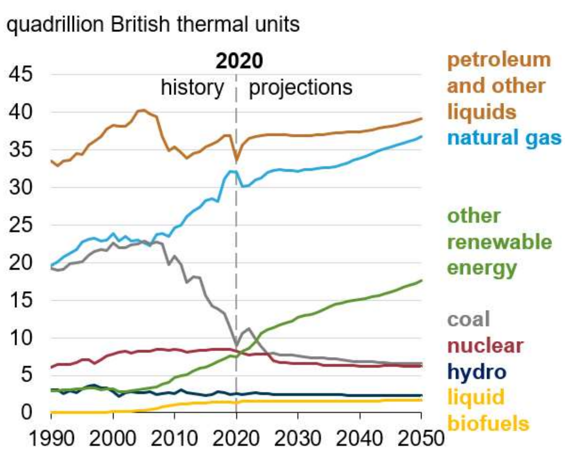
Report Name	**Key Conclusions/Recommendations**
2008: The Federal System for Collecting Oil and Gas Revenues Needs Comprehensive Reassessment	DOI should periodically collect information on how U.S. "government take" and attractiveness of oil and gas investment compares with that of other resource owners.
2013: Actions Need for Interior to Better Ensure a Fair Return	DOI should implement procedures for conducting periodic assessments of the overall fiscal system and establish procedures for determining when and how to adjust lease terms for new offshore leases.
2017: Raising Federal Rates Could Decrease Production on Federal Lands but Increase Federal Reserve	Raising federal royalty rates for onshore oil, gas, and coal resources could decrease oil, gas, and coal production on federal lands, but increase overall federal revenue. The report notes that this result depends on market conditions and prices.
2019: Challenges to Ensuring a Fair Return for Federal Energy Resources	Key federal lease terms are the same as they were decades ago, and Interior has not adjusted them for inflation or other factors that may affect the federal government's fair return

STATUS OF OIL AND GAS INDUSTRY

The Energy Information Administration's (EIA) Annual Energy Outlook (AEO) for 2021[8] reports a roughly 9% drop in global liquid fuels consumption following the worldwide shutdown during the COVID-19 pandemic. This demand shock is resulting in Deloitte calls the "great compression" of the oil and gas industry,[9] which may result in significant change in the industry. For example, this section discusses the trend in increasing bankruptcies (see below), driven by low oil prices and cash-flow limitations, including reduced investor confidence and access to capital.[10]

EIA forecasts that fuels consumption will return to 2019 levels by 2022. Gas has played an increasing role in U.S. electricity generation, meeting much of the demand for additional generation since 2000, and offsetting coal since 2007 (see Figure 26). Going forward, EIA predicts that gas will in turn be challenged by renewable energy sources, given falling technology costs, renewable production incentives, and increased government and consumer focus on reducing greenhouse gas emissions. As shown in Figure 2, over the next three decades, EIA forecasts a large increase in U.S. consumption of renewable energy, a moderate increase for natural gas, a small increase for oil and biofuels, and small declines for coal and nuclear.

Figure 2. U.S. Energy Consumption by Fuel, 1990-2050

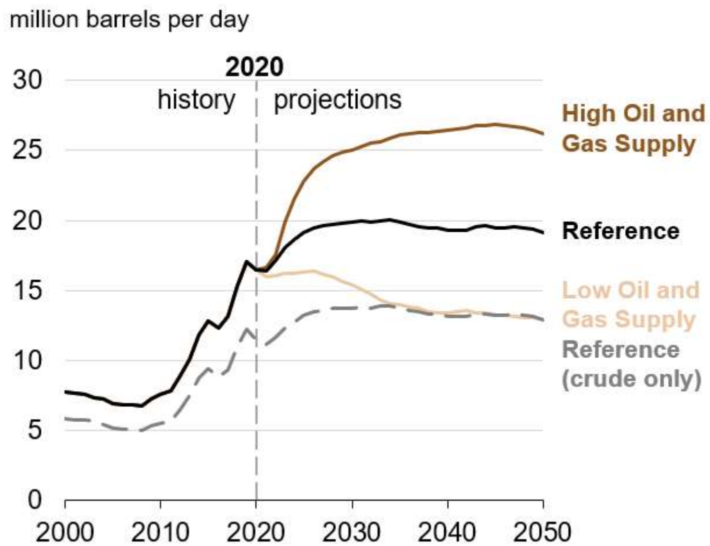


Source: EIA 2021 AEO

[8] https://www.eia.gov/outlooks/aeo
[9] Deloitte, Perspectives, 2021 oil and gas industry outlook, Exploring oil and gas trends and impact of COVID-19. https://www2.deloitte.com/us/en/pages/energy-and-resources/articles/oil-and-gas-industry-outlook.html. Accessed March 17, 2021.
[10] Forbes . Mar 10, 2021. "Challenges And Trends For The Oil And Gas Industry" https://www.forbes.com/sites/uhenergy/2021/03/10/challenges-and-trends-for-the-oil-and-gas-industry/?sh=10eb9cb9167f. Accessed March 15, 2021.

The 2021 AEO recognizes that the oil price is the primary driver of projected drilling activity and accompanying U.S. crude oil production rates. Thus, given the current economic downturn, EIA expects a lower price path in the short and medium term to decrease U.S. oil production rates compared with 2020. The 2021 AOE assumes a mid-range oil price of $95 per barrel by 2050 (the low-range price is $48, and the high-range is $173). As shown in Figure 3, EIA forecasts increased U.S. oil production to around 2025, continuing a trend since 2010, followed by a slight decline to 2050. Other scenarios EIA considered could result in stronger declines or continued increases until around 2045 before starting to decline.

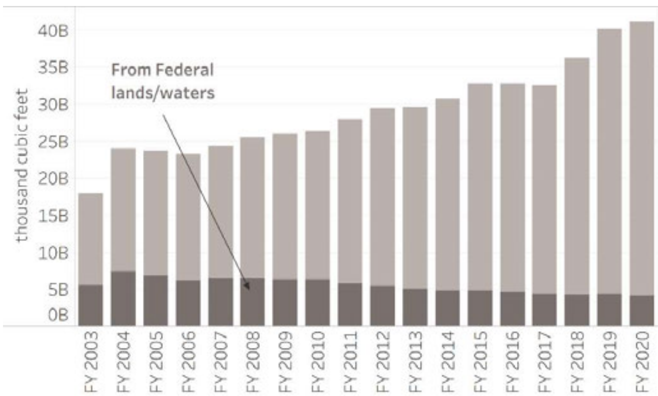
Figure 3. U.S. production of crude oil and natural gas liquids



Source: EIA 2021 AEO

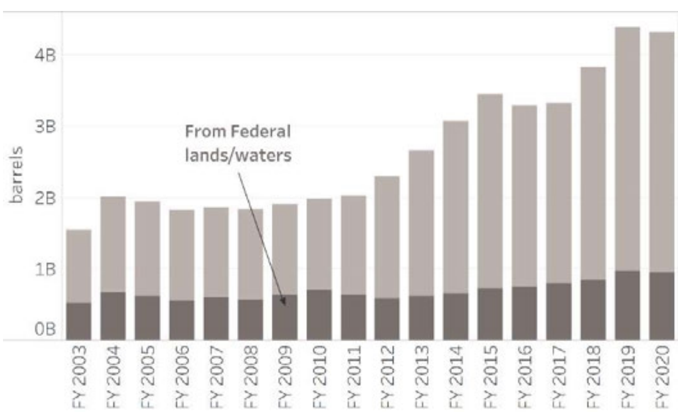
The figures below illustrate U.S. and Federal oil and gas production. Figure 4 shows an upward trend in U.S. natural gas production, though falling production from Federal lands. Figure 5 shows an increase in U.S. crude oil production (particularly from 2012 onward), with increasing production from Federal lands over most of this period.

Figure 4. US Natural Gas Production



Source: US production from EIA, Federal production from ONRR. Volumes from Federal lands/water does not include production from Native American lands. US production represents natural gas gross withdrawals and production, which is the most comparable measure to the Federal gas volumes provided by ONRR.

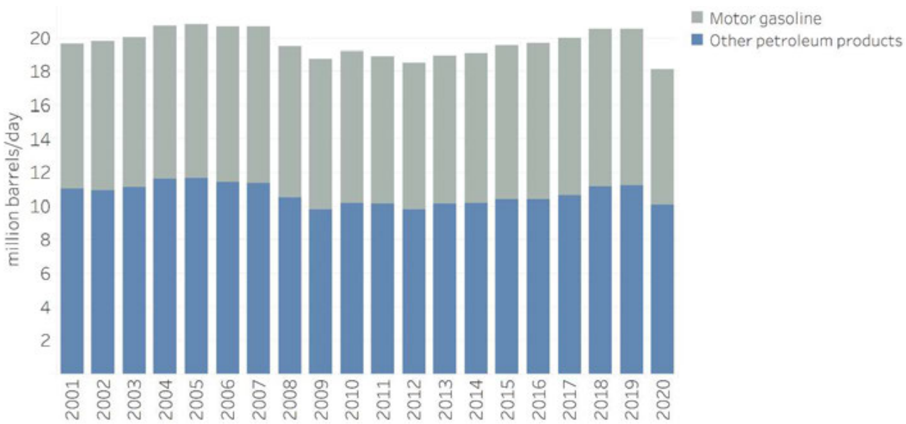
Figure 5. US Crude Oil Production



Source: US production from EIA, Federal production from ONRR. Volumes from Federal lands/water does not include production from Native American lands.

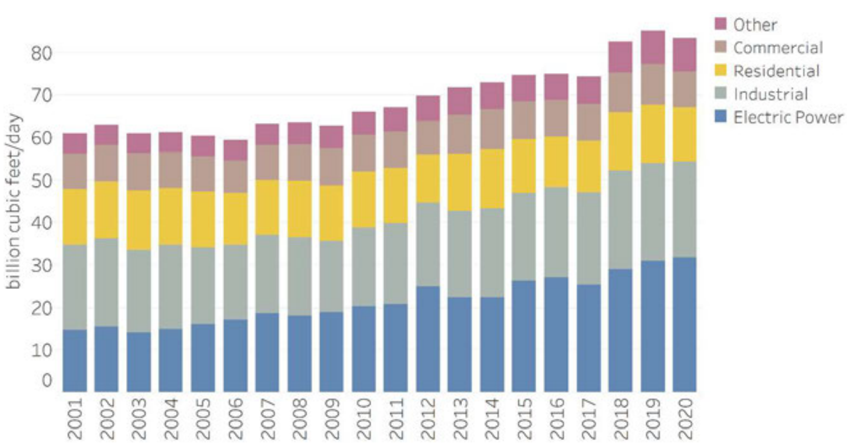
As shown in Figure 6, the largest end-use for oil is for refining into gasoline, accounting for about half of annual consumption over the past two decades. Figure 7 shows that the largest end-use for natural gas is electricity generation. This end-use has become increasingly prominent over the past two decades, accounting for most of the increase in natural gas consumption. Gas consumption for other uses (e.g., industrial, residential, commercial) has remained relatively constant since 2001.

Figure 6. US Consumption of Petroleum and Other Liquids (2001 - 2020)



Source: EIA Short Term Energy Outlook. "Other petroleum products" includes hydrocarbon gas liquids, unfinished oils, jet fuel, distillate fuel oil, residual fuel oil, and other oils.

Figure 7. US Consumption of Natural Gas (2001 – 2020)



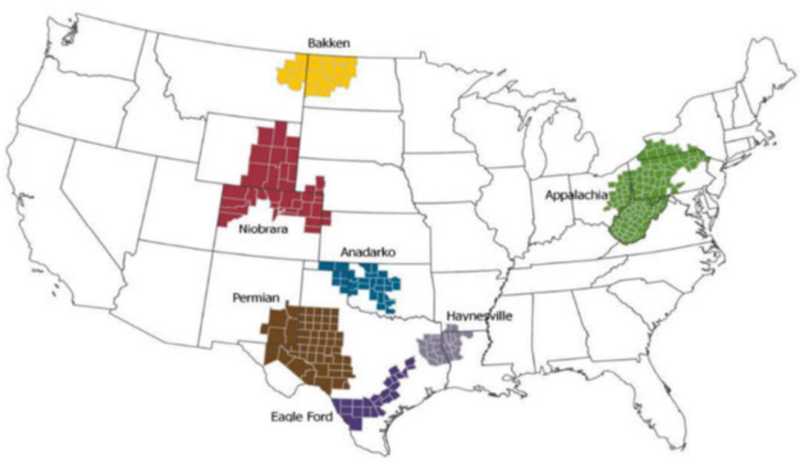
Source: EIA Short Term Energy Outlook. "Other" includes lease and plant fuel, pipeline and distribution use, and vehicle use.

For both liquid fuels and natural gas, the effects of COVID-19 are primarily a short-term demand-side shock. Uncertainty surrounding post-pandemic expectations for oil and natural gas demand translates to uncertainties in supply through prices.

The oil and natural gas industry was already headed toward relying on capital from cash flow instead of debt and equity. COVID-19 has accelerated this trend, leaving producers more dependent on internal sources of cash flow because outside funding sources are less available or require higher rates of return. Oil prices remain the most significant determining factor in oil production, and so if oil prices rapidly rise then production would follow suit.

Tight oil is primarily driving the growth in the oil production outlook, followed by offshore resources. Tight oil production from the Wolfcamp play in the Permian Basin (Southwest region) and the Bakken play in the Williston Basin (Northern Great Plains region) leads the growth in U.S. tight oil production. However, estimates of technically recoverable tight or shale crude oil and natural gas resources are uncertain. The high and low oil and gas supply cases explore the impact of higher and lower resource supply levels on domestic production, including tight oil.

Figure 8. Key Tight Oil and Shale Gas Regions



Source: EIA Drilling Productivity Report. These regions have been identified by EIA as the most commercially prominent at present. Most of the drilling activity and production growth over recent years has occurred in regions where shale gas and tight oil resources are being accessed.

Oil and gas are produced from Federal, state, private, and Tribal lands. The fiscal terms associated with one type of land ownership can affect the scope and nature of exploration, development, and production on the other types of land ownerships. For example, if the fiscal terms associated with Federal land make it more expensive for producers to operate on Federal land, it is likely that activity would shift at least partly to state, private and/or Tribal lands.

In response to reduced federal production, one can expect production increases on state, private, and Tribal land, as well as increases in supply from other countries. This offsetting increase in production elsewhere is termed “leakage,” as reductions in supply from regions covered by the policy (e.g., federal lands) “leak” in the form of supply increases in uncovered regions (e.g., state and private land). Figure 9 and Figure 10 below show trends in oil and gas imports and exports from 2001 – 2020.

It is important to note that research has indicated that the shift is unlikely to be one for one. Roughly speaking, each barrel (or barrel of oil equivalent for gas) of production reduced on federal lands is estimated to be offset by between 0.5 and 0.75 barrels of increased production from other sources, including state, private, and Tribal land as well as foreign producers.[11]

Figure 9. US Natural Gas Imports and Exports

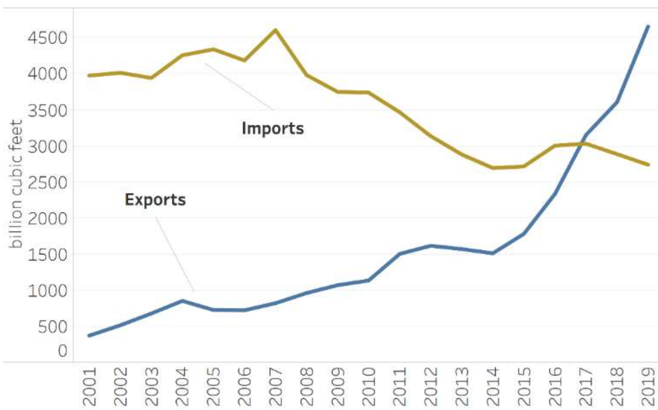
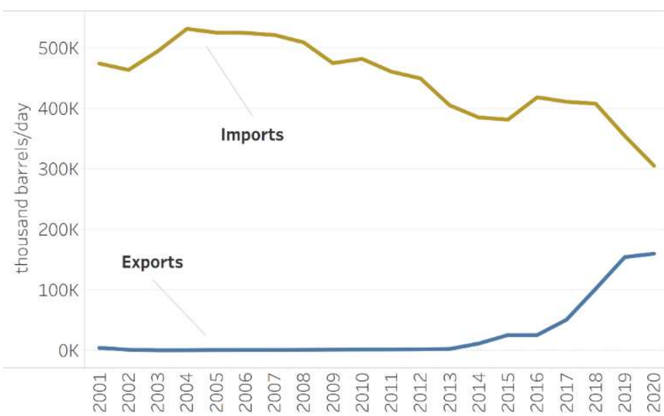


Figure 10. US Crude Oil Imports and Exports



Source: EIA, 2020

DOI Federal lands are comprised of geologic characteristics and petroleum system elements that provide an opportunity for the existence of oil and gas resources. Oil and gas are thermally generated as

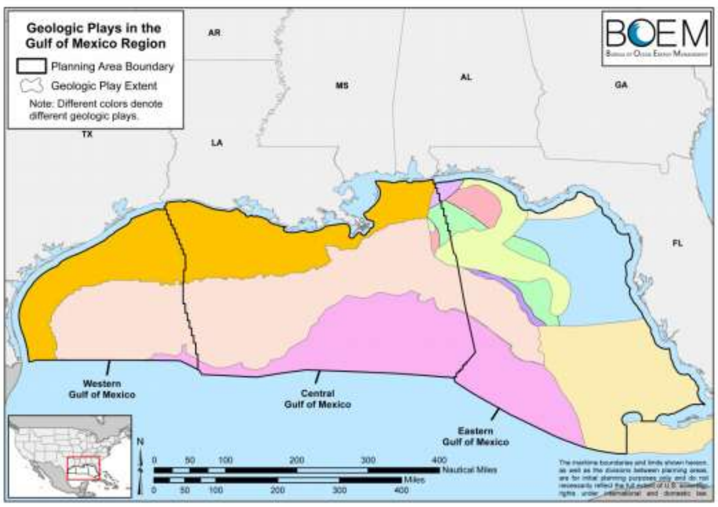
[11] https://www.rff.org/publications/working-papers/supply-side-reforms-oil-and-gas-production-federal-lands/

organic matter changes in composition with increasing burial depth and temperature. Once generated and expelled from source rocks, the hydrocarbons migrate laterally and/or vertically into porous reservoirs that are associated with an impermeable trap or seal. These petroleum system elements are not ubiquitous across all Federal lands.

As seen in Figure X, geologic plays are delineated and evaluated for oil and gas potential. DOI assesses undiscovered technically recoverable and undiscovered economically recoverable resources on Federal lands to form the basis of leasing decisions.

[Placeholder for 2021 National Assessment Offshore; Placeholder for BLM Assessment]

Figure 11. Oil and Gas Plays in the Gulf of Mexico



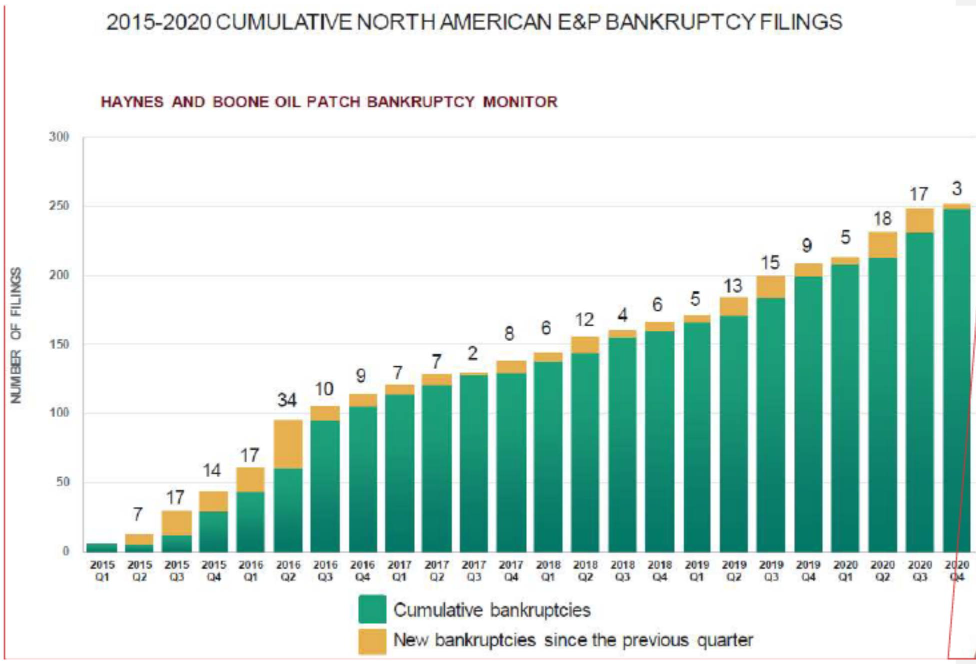
In the offshore environment, the Gulf of Mexico (GOM) is the most mature and active of all OCS planning areas, with extensive existing infrastructure. The GOM's Western and Central GOM planning areas, consisting of the OCS offshore Alabama, Mississippi, Louisiana, and Texas, remain the primary offshore source of oil and gas for the United States, generating about 98 percent of all OCS oil and gas production.[12] This high level of production and activity is supported by an oil and gas industry that includes hundreds of large and small companies, and an expansive onshore network of coastal infrastructure. The geology of the GOM basin and the complexity and abundance of its salt structures provides the setting that makes the GOM one of the richest oil and natural gas regions in the world. The greatest undiscovered resource potential in the OCS is forecast to exist in the deep and ultra-deep waters of the GOM.

[12] https://www.boem.gov/sites/default/files/oil-and-gas-energy-program/Leasing/Five-Year-Program/2019-2024/DPP/NP-Draft-Proposed-Program-2019-2024.pdf

Bankruptcies

As projects reach the end of their lifecycle, they are required to plug and abandon wells and decommission their oil and gas infrastructure. In the last five years, the oil and gas industry has seen an increase in bankruptcies driven predominantly by low oil prices. These increasing bankruptcies may result in companies unable to cover their decommissioning liabilities, resulting in orphaned wells and idle infrastructure. This highlights the need to strengthen financial assurance coverage to protect the government and taxpayer, ensuring that companies meet their decommissioning obligations.

Figure 12. Bankruptcy Trends

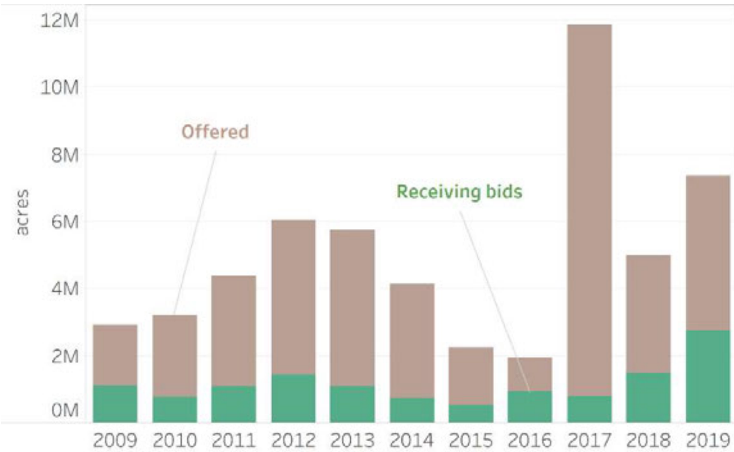


Commented [NDT1]: Note we should check if bureaus have their own version of a similar graph to show bankruptcies

Leasing and Production Data

In FY 2018, Federal onshore lands accounted for approximately 8 percent of all oil, and 9 percent of all natural gas produced in the United States. About 26 million Federal acres were under lease to oil and gas developers at the end of FY 2018. Of that, about 12.8 million acres are producing oil and gas in economic quantities. This activity came from over 96,000 wells on about 24,000 producing oil and gas leases. In FY 2018 oil and gas production on lands managed by the BLM generated nearly $3 billion in Federal royalties, rental payments and bonus bids. Figure 13 shows the number of acres offered for lease in previous years and Table 1 shows the number of producing acreage on Federal leases. This can be seen graphically in Figure 14.

Figure 13. Onshore Oil and Gas Lease Acres Offered and Acres Receiving Bids (2009 – 2019)

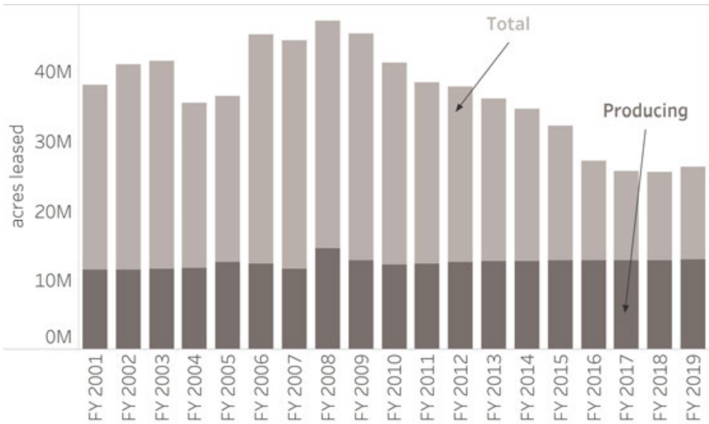


Source: BLM Oil and Gas Statistics, Table 11. Represents acres offered at competitive oil and gas lease sale auctions and how many of those acres received bids for calendar years 2009-2019.

Table 1. Onshore Oil and Gas Lease Activity (Federal leases, FY20)

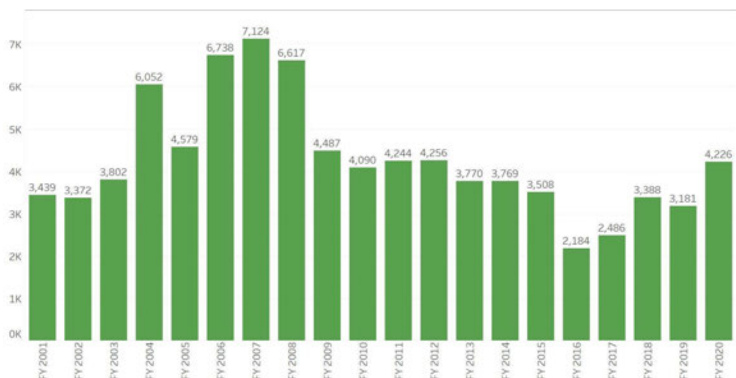
Lease Category	Acres Under Lease	Percent of Total Acres	Number of Leases	Percent of Total Leases
Production & Exploration	12,711,111	48%	23,878	63%
Not in Production or Exploration	13,893,058	52%	13,618	37%
Total	26,604,169	100%	37,496	100%

Figure 14. Federal Onshore Total and Producing Oil and Gas Acres Under Lease (FY 2001 – FY 2019)



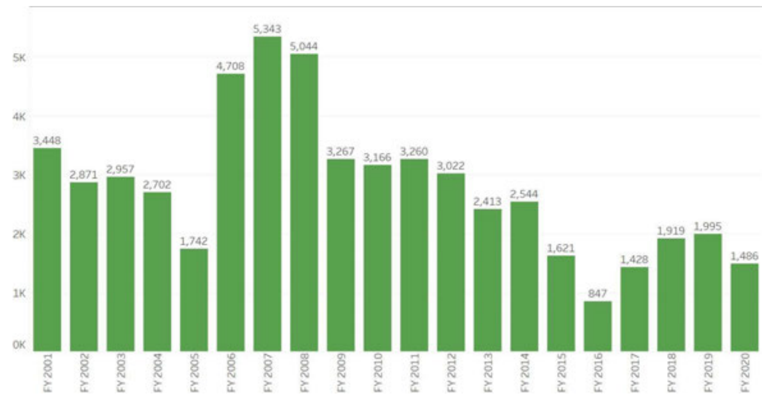
Source: BLM Oil and Gas Statistics, Tables 2 and 6

Figure 15. Number of Drilling Permits Approved by Fiscal Year on Onshore Federal Lands



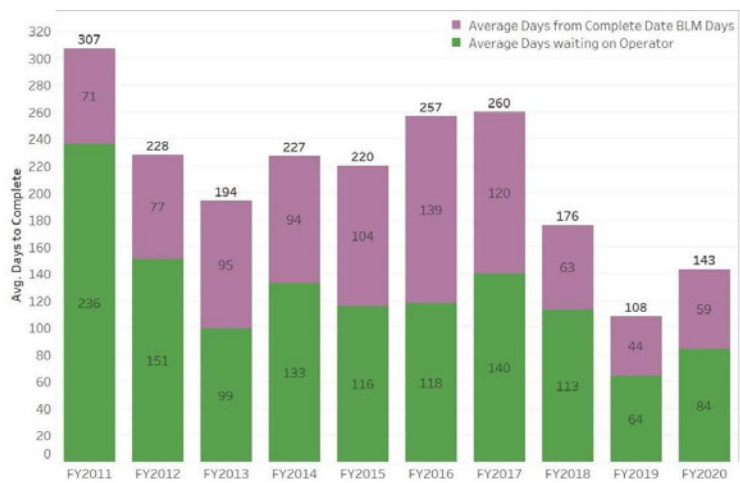
Source: BLM Oil and Gas Statistics, Table 7. Note: For all years, data is Federal-only; does not include Indian data. As a result, totals for some states will be less than in expanded reports that include both Federal and Indian data. Additional differences may result between these numbers and state-level Federal-only totals in expanded reports due to the timing of the data queries. Source of data is Public Land Statistics, which also includes data from previous years.

Figure 16. Number of Well Bores Started (Spud) During the Fiscal Year on Federal Lands



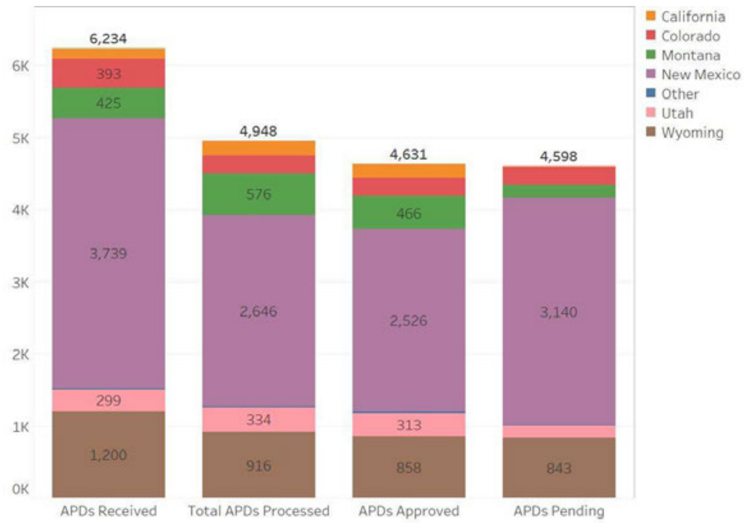
Source: BLM Oil and Gas Statistics, Table 8. Note: For all years, data is Federal-only; does not include Indian data. As a result, totals for some states will be less than in expanded reports that include both Federal and Indian data. Additional differences may result between these numbers and state-level Federal-only totals in expanded reports due to the timing of the data queries. Source of data is Public Land Statistics, which also includes data from previous years.

Figure 17. Time to Complete an Application for Permit to Drill (APD) Federal and Indian



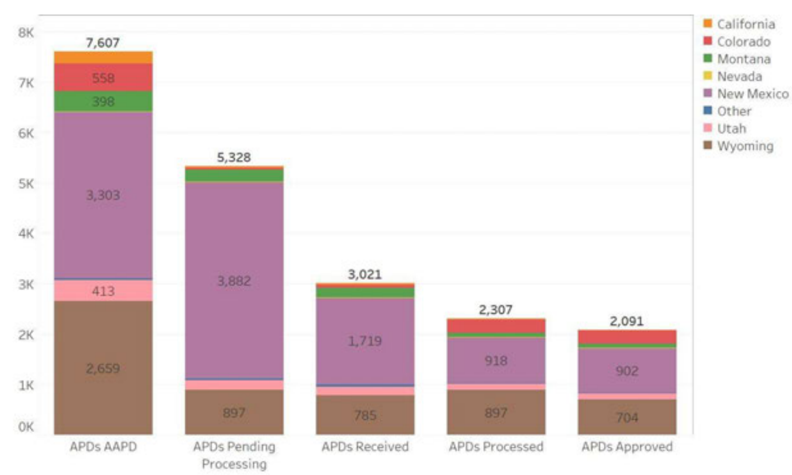
*Source: BLM Oil and Gas Statistics, Table 12. Notes: Processing times include Federal and Indian APDs; Effective April 20, 2017 electronic submission of APDs are required unless a waiver is granted by the BLM The BLM began accepting APDs through AFMSS 2 effective October 2015, with Bureau-wide adoption in May 2016; Time to complete is calculated based on approved APD times only, other than approved counts are not included; Fiscal Years 2017 and 2018 timeframes represent processing times from both AFMSS 1 and AFMSS 2 systems; FY 2017 AFMSS 2 only timeframes are 120 total days with 71 days waiting on the Operator and 50 BLM days; FY 2018 AFMSS 2 only timeframes are 130 total days with 62 days waiting on the Operator and 68 BLM days; *FY 2020 actual process times: Operator Days = 83.6, BLM Days = 58.7, Total Days = 142.3*

Figure 18. Number of Applications for Permit to Drill (APD) Status FY 2020 (Federal + Indian)



Source: BLM Oil and Gas Statistics, Table 16. Notes: (1) Cumulative Report FY 2020- APD approved/pending numbers may change with run date/time due to the Electronic Layer Transfer process between the Automated Fluid Minerals Support System (AFMSS) 1 and AFMSS 2. Data current as of October 1, 2020. (2) APDs Other Than Approved - Refers to APDs that have been completely reviewed and processed and assigned a disposition other than Approved (Accepted, Cancelled, Denied, Expired, Rejected, Rescinded, Returned or Withdrawn). (3) Pending APDs refers to the numbers of APDs pending on September 30, 2020.

Figure 19. Number of Applications for Permit to Drill Status Report: Oct 2020 – Jan 2021



Source: BLM Oil and Gas Statistics, Table 17. Includes APD activity for Federal lands only, does not include APD activity on Tribal lands.

In the offshore environment, BOEM currently administers approximately 2,348 oil and gas leases on more than 318 million acres.[13] In FY20, the OCS contributed to X percent of all oil production and X percent of natural gas production in the United States. Much of this production is located in the Gulf of Mexico, where a majority of offshore exploration and development activities occur. There have been more than 100 lease sales since 1953 in the GOM Region. There is production from leases in the Western and Central GOM planning areas, but as of March 2021, no production has occurred from leases anywhere in the Eastern GOM Planning Area.

Figure 20. Active leases in the Gulf of Mexico, March 2021

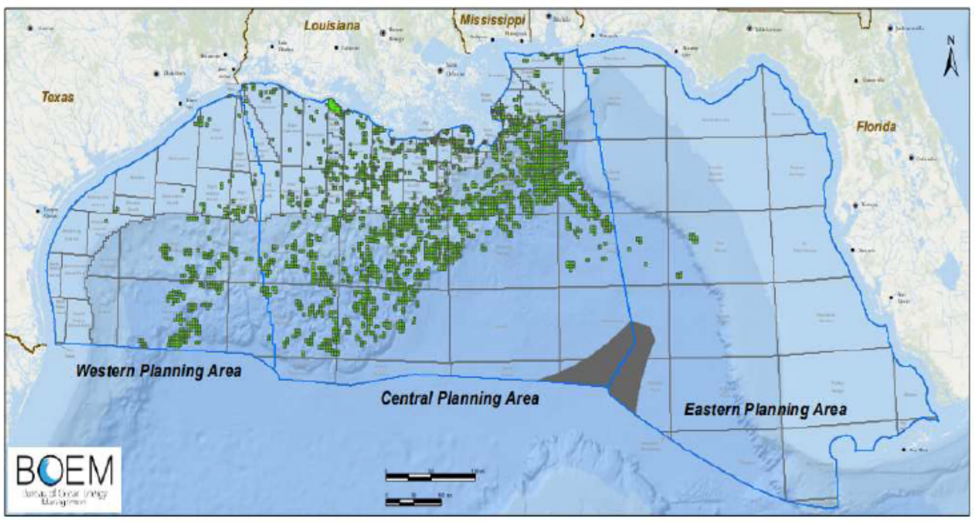


Table 2. US Offshore Lease Status

Region	Total Leased Acres	Non-Producing Lease Acres	Producing Lease Acres
Gulf of Mexico	12,142,429 [2,283 leases]	9,81,797 [1,842 leases]	2,327,632 [441 leases]
Pacific[1]	158,956 [32 leases]	0 [0 leases]	158,956 [32 leases]
Alaska	155,916 [33 leases]	145,492 [30 leases]	10,424 [3 leases]
Total Offshore	12,457,301 [6,621 leases]	9,960,289 [1,872 leases]	2,497,012 [476 leases]

[1] No lease sales have been held in the Pacific region since 1984.

[13] https://www.boem.gov/oil-gas-energy/leasing/combined-leasing-status-report

The Pacific Region is comprised of four planning areas: Washington/Oregon, Northern California, Central California, and Southern California. Lease sales have been held in all four planning areas, the most recent of which was held in 1984. There are existing leases and production from these leases in the Southern California Planning Area. Ten lease sales were held from 1963 through 1984 for Southern California. More than 1,500 exploratory and development wells have been drilled. As of March 2021, there are 32 active leases, all considered producing.

Table 3. US Offshore Lease Activity

Region	Total Active Acres	Acres with Approved Development Plans	Acres with Approved Exploration Plans	Producing Lease Acres
Gulf of Mexico	12,142,429 [2,283 leases]	PLACEHOLDER		2,327,632 [441 leases]
Pacific[1]	158,956 [32 leases]			158,956 [32 leases]
Alaska	155,916 [33 leases]			10,424 [3 leases]
Total	12,457,301 [6,621 leases]			2,497,012 [476 leases]

[1] No lease sales have been held in the Pacific region since 1984.

The Alaska Region is composed of 15 planning areas surrounding the state. Federal lease sales have been held in 8 of those planning areas. Existing Federal leases are present only in the Beaufort Sea Planning Area and the Cook Inlet Planning Area. The most recent sale occurred in the Cook Inlet in June 2017. There have been six lease sales in this area since 1977. As of March 2021, there are 14 existing leases in the planning area, all of which were issued as a result of Lease Sale 244 held June 2017.

[placeholder for BOEM maps- Pacific and Alaska leases]

Revenues and Fiscal Terms

There are several petroleum fiscal regimes in the US, and there is a wide array of systems in use around the world.

The private land arrangements that cover the largest share of US oil and gas reserves are individually negotiated. Most landowners are not interested in complicated arrangements, and they tend to use a straightforward lease similar to Federal leases. State government leasing also usually is similar to Federal. Further, Federal leases can be bought and sold in a secondary private market, and often additional private royalties are placed on such re-assigned leases.

Onshore, the Federal, state, and private lands can be in close proximity and sometimes intermixed. This situation creates a natural basis for comparison of the systems, and comparison is aided by the similarity of the leasing arrangements. Comparison is also possible with Canadian and Mexican onshore fiscal systems, although the systems are not the same as those used in the US, which complicates analysis.

Oil and gas royalty rates vary, depending on whether the production is off- or onshore. The onshore rate is typically 12.5%; the offshore rate can range from 12.5% to 18.75%. Some oil and gas revenues (bonus bids, annual rents, and royalties) are shared with states. While royalties are currently assessed as a percentage of total production value, other fiscal regimes have been proposed to address the impacts of climate change, e.g., a royalty payment or fee based on the marginal damages of carbon emissions. Such alternative fiscal regimes have been shown to produce significantly different impacts on overall emissions and revenues.[14]

States receive revenues directly from oil and gas extraction taking place on states' public lands in the form of rents, bonus bids, and royalties on production. A state may also receive a share of the bonus bid and royalty revenues paid to the Federal government for oil and gas leases on Federal lands within the state's borders. Four states bordering the Gulf of Mexico receive a share of revenues from certain qualified offshore oil and gas leases under the Gulf of Mexico Energy Security Act of 2006 (GOMESA). These revenues may then be further allocated to local communities and jurisdictions by each state government.

Table 4. Onshore Oil and Gas Fiscal Terms

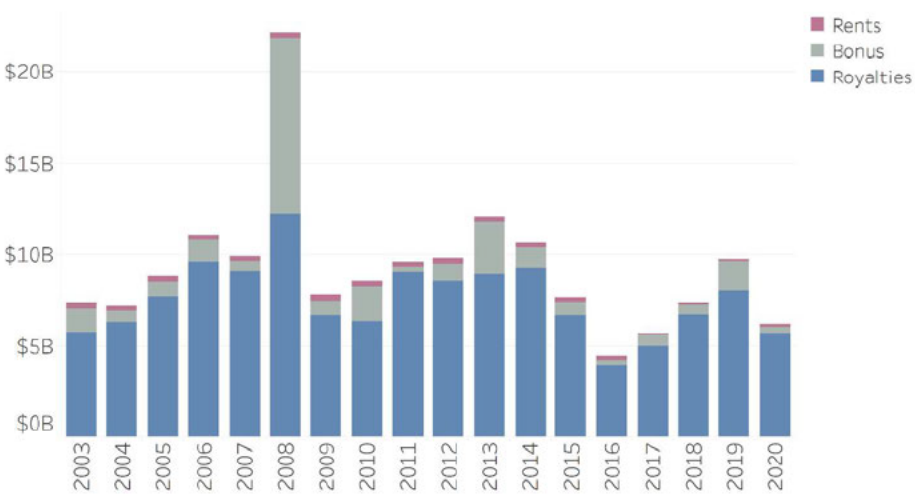
Commodity	Rent	MinimumBid/Acre Max Acres/Lease	Royalty Rate
Oil and gas: Federal **(Except Alaska NPR-A)**	$1.50/acre for first 5 years; $2/acre thereafter	Min $2/acre; max 2,650 acres	12.5%
Oil and gas: Alaska NPR-A	$5/acre high potential tracts$3/acre low potential tracts	$25/acre, high potential tracts $5/acres low potential tracts	16.67% - high potential tracts 12.5% - low potential tracts

[14] https://www.rff.org/publications/working-papers/supply-side-reforms-oil-and-gas-production-federal-lands/

Table 5. Offshore Oil and Gas Fiscal Terms

Water Depth (meters)	Rent		Royalty Rate			
	Years 1-5	Years 6, 7, 8+	Until 2007	2008	2009	2020 (Sale 256)
0 to < 200m	$7.00	$14.00, $21.00, $28.00	16.67%	16.67%	18.75%	12.5%
200 to < 400m	$11.00	$22.00, $33.00, $44.00	16.67%	16.67%	18.75%	18.75%
400m+	$11.00	$16.00	12.5%	16.67%	18.75%	18.75%

Figure 21. Revenues from Extraction on Federal Oil and Gas Leases (FY 2003 – FY 2020)



Source: ONRR. Represents rents, bonuses, and royalties paid for extraction of resources from Federal oil and gas leases. Commodities extracted include oil, gas, NGL, and to a much lesser extent, CO_2, helium, sulfur, and geothermal. Does not include revenues associated with Native American leases.

GREENHOUSE GAS EMISSIONS

This section presents data on U.S. greenhouse gas (GHG) emissions for recent years. We discuss the levels of various GHGs, the sources of these emissions, and the associated sectors or end-uses contributing. While carbon dioxide (CO_2) is the most prevalent GHG, there is a host of other gases that have even stronger effects on global climate. The largest contributing sector is transportation (almost entirely from combustion of petroleum), though industrial, commercial, and residential sectors are also major contributors (mostly from combustion of natural gas). All of these sectors use electricity, which is another major contributing sector, through combustion of coal and natural gas). The trend data show that as the U.S. economy has grown in recent decades, it has also become less carbon-intensive, and at a faster rate. This implies that the U.S. (and other countries) can meet emission-based climate goals while maintaining economic growth to address social goals like increased living standards and equity.

EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks

Since the early 1990s, the EPA has provided an annual report that tracks U.S. greenhouse gas emissions and sinks by source, by economic sector, and by greenhouse gas – the Inventory of U.S. Greenhouse Gas Emissions and Sinks report[15]. The inventory adheres to both (1) a comprehensive and detailed set of methodologies for estimating national sources and sinks of anthropogenic greenhouse gases, and (2) a common and consistent format that enables Parties to the United Nations Framework Convention on Climate Change (UNFCCC) to compare the relative contribution of different emission sources and greenhouse gases to climate change. The charts and figures below illustrate some of the data from the EPA's GHG inventory, which represents the most comprehensive inventory of national emissions data.[16]

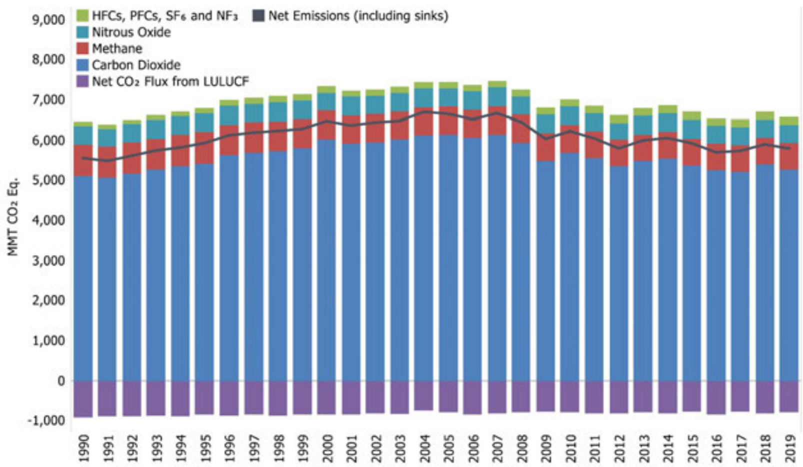
As shown in Figure 22, U.S. GHG emissions peakedin 2007, and have since been on a mostly downward trend. Net emissions have followed a similar pattern. Net emissions include

- all GHG sources (e.g., fossil fuel combustion, landfills, etc.)
- minus GHG sinks, including land use, land-use change, and forestry (LULUCF)

[15] EPA publishes the draft report annually in February to allow for public comment prior to publishing the final report by April of every year. The figures and charts shown in this document are from the DRAFT report available at https://www.epa.gov/ghgemissions/draft-inventory-us-greenhouse-gas-emissions-and-sinks-1990-2019

[16] Unless otherwise stated, all tables and figures provide total gross emissions and exclude the greenhouse gas fluxes from the Land Use, Land-Use Change, and Forestry (LULUCF) sector.

Figure 22. U.S. GHG Emissions by Gas



Source: EPA, Greenhouse Gas Emissions, Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2019. https://www.epa.gov/ghgemissions/draft-inventory-us-greenhouse-gas-emissions-and-sinks-1990-2019. Accessed March 15, 2021.

The largest portion of these emissions (by weight) is CO_2, though other gases can have a stronger effect on climate, as shown in Table 6. Methane emissions released directly to the atmosphere (without burning) are shorter-lived (lasting only 12 years in the atmosphere), though about 25 times more powerful than CO_2 in terms of their warming effect on the atmosphere.[17] N_2O lasts 114 years in the atmosphere, and has 298 times the warming effect of CO_2.[18] Fluorinated gases last hundreds to thousands of years, and may have thousands of times the warming effect of CO_2.

Table 6. Warming Potential of GHGs

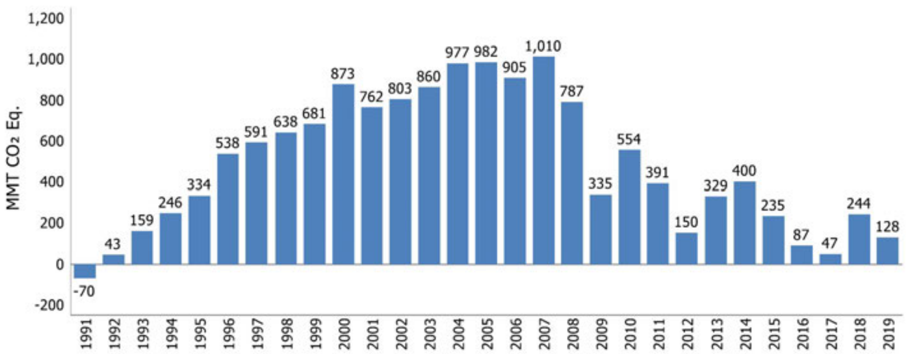
Gas	Lifespan in Atmosphere	Warming Potential (relative to CO_2 over 100 years)
carbon dioxide (CO_2)	varies as part of natural cycles	1
methane (CH_4)	12 years	25
nitrous oxide (N_2O)	114 years	298
hydrofluorocarbons (HFCs)	up to 270 years	up to 14,800
perfluorocarbons (PFCs)	2,600–50,000 years	up to 12,200
nitrogen trifluoride (NF_3)	740 years	17,200
sulfur hexafluoride (SF_6)	3,200 years	22,800

Source: data from EPA, Greenhouse Gas Emissions. https://www.epa.gov/ghgemissions/overview-greenhouse-gases. Accessed March 15, 2021.

[17] https://www.epa.gov/energy/greenhouse-gases-equivalencies-calculator-calculations-and-references
[18] https://www.epa.gov/ghgemissions/overview-greenhouse-gases

Figure 23 shows annual U.S. (gross) GHG emissions over the last three decades relative to 1990. 1990 is a common baseline year for reporting GHG emissions (e.g., Kyoto Protocol, UNFCCC). As seen above in Figure 22, 2007 was the year when emissions were at their highest point relative to 1990. This is also shown in Figure 23: 2007 saw 1,010 million tons of of CO_2 emitted beyond the 1990 level. In general emissions have declined substantially since then.

Figure 23. Change in Annual Gross U.S. GHG Emissions Relative to 1990 (1990=0)

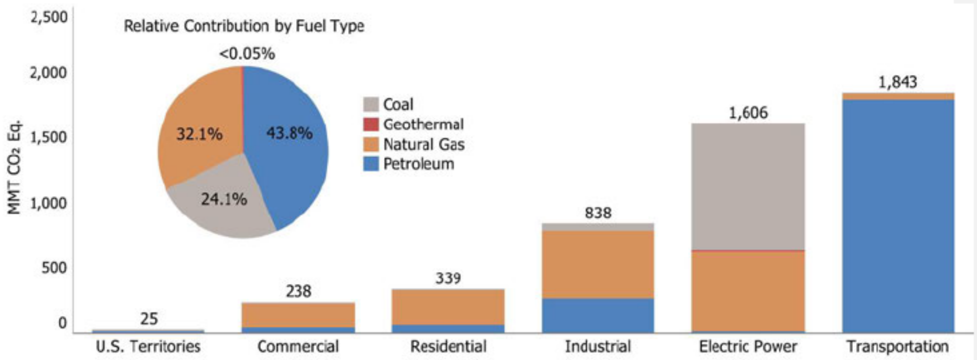


Source: EPA, Greenhouse Gas Emissions, Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2019. https://www.epa.gov/ghgemissions/draft-inventory-us-greenhouse-gas-emissions-and-sinks-1990-2019. Accessed March 15, 2021.

Focusing in on emissions for a single year, Figure 24. reports the 2019 emissions for fossil fuel combustion, which is the major source of CO_2 emission. The figure shows how these fossil fuel combustion emissions are associated with each of the sectors identified in EPA's report. Transportation accounts for the largest share of emissions related to fossil fuel combustion, and most of this is from petroleum. Generating electricity is a close second, with emissions related mostly to coal and natural gas.

In addition to looking across end-use sectors, Figure 24 also shows how emissions break out by fuel type. Looking acoss sources of combusted fuels, most 2019 emissions come from petroleum, which accounted for over 43% of 2019 emissions from fossil fuel combustion. As discussed above, most of these petroleum emissions are related to the transportation sector. Natural gas contribues about a third of the emissions related to combustion, spread across several sectors: generating electricity, plus industrial, residential, and commercial uses. Coal contributes about a quarter of the emissions related to combustion, almost entirely from generating electricity.

Figure 24. 2019 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type



Source: EPA, Greenhouse Gas Emissions, Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2019. https://www.epa.gov/ghgemissions/draft-inventory-us-greenhouse-gas-emissions-and-sinks-1990-2019. Accessed March 15, 2021.

Table 7 reports GHG emissions from fossil fuels by end-use sector for recent years. As was the case for all emissions (shown in Figure 22), fossil-fuel emissions for most sectors are generally trending slightly downward in recent years. Transportation is an exception, where emissions have been trending upward since 2015, though remaining slightly below 2005 levels.

Table 7. CO_2 Emissions from Fossil Fuel Combustion by End-Use Sector (MMT CO_2 Eq.)

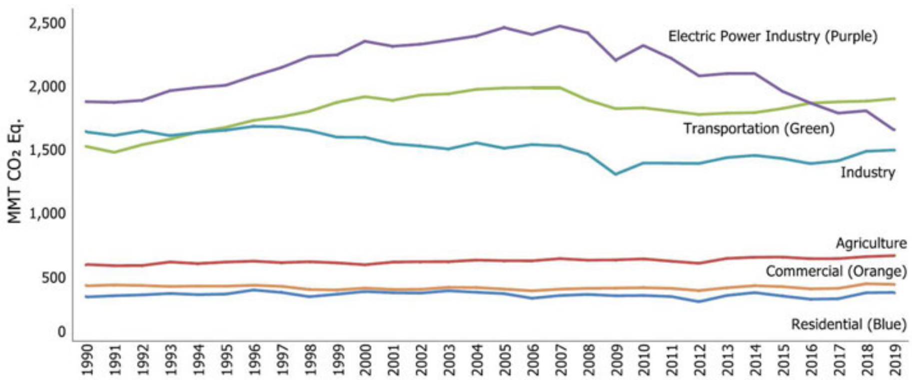
End-Use Sector	1990	2005	2015	2016	2017	2018	2019
Transportation	**1,472.2**	**1,873.5**	**1,754.8**	**1,801.5**	**1,816.9**	**1,825.9**	**1,847.9**
Combustion	1,469.1	1,868.8	1,750.5	1,797.3	1,812.6	1,821.2	1,843.2
Electricity	3.0	4.7	4.3	4.2	4.3	4.7	4.7
Industrial	**1,540.2**	**1,580.3**	**1,339.9**	**1,304.6**	**1,298.5**	**1,339.3**	**1,302.9**
Combustion	853.8	844.0	790.3	787.0	794.1	838.0	837.6
Electricity	686.4	736.3	549.5	517.6	504.4	501.3	465.3
Residential	**931.3**	**1,215.1**	**1,001.9**	**945.8**	**911.7**	**981.7**	**922.3**
Combustion	338.6	359.1	318.1	292.3	294.6	339.5	338.8
Electricity	592.7	856.0	683.8	653.5	617.1	642.1	583.5
Commercial	**766.0**	**1,029.0**	**887.9**	**844.0**	**818.5**	**851.7**	**790.7**
Combustion	228.3	226.0	224.9	210.4	212.3	246.9	238.3
Electricity	537.7	803.0	663.0	633.6	606.2	604.8	552.4
U.S. Territories[a]	**21.7**	**56.0**	**29.4**	**26.2**	**24.7**	**24.6**	**24.6**
Total	**4,731.5**	**5,753.8**	**5,013.8**	**4,922.0**	**4,870.4**	**5,023.1**	**4,888.5**
Electric Power	**1,820.0**	**2,400.1**	**1,900.6**	**1,808.9**	**1,732.0**	**1,752.9**	**1,606.0**

Notes: Combustion-related emissions from electric power are allocated based on aggregate national electricity use by each end-use sector and represent indirect fossil fuel combustion for each end-use sector. Totals may not sum due to independent rounding.
[a] Fuel consumption by U.S. Territories (i.e., American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands)

Source: EPA, Greenhouse Gas Emissions, Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2019. https://www.epa.gov/ghgemissions/draft-inventory-us-greenhouse-gas-emissions-and-sinks-1990-2019. Accessed March 15, 2021.

Figure 25 shows how GHG emissions from several sectors have changed over the past three decades. As will be discussed below (see Figure 26), emissions from the power sector have been trending downward since 2007. This is largely the result of coal being displaced in the power mix by lower-emissions fuels like gas and renewables. Emissions related to other sectors display less of a trend, though industrial emissions are somewhat lower after 2004, while transportation-related emissions halted a steady increase after 2007.

Figure 25. U.S. GHG Emissions Allocated to Economic Sectors



Source: EPA, Greenhouse Gas Emissions, Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2019. https://www.epa.gov/ghgemissions/draft-inventory-us-greenhouse-gas-emissions-and-sinks-1990-2019. Accessed March 15, 2021.

Figure 26 show how the mix of power sources for U.S. electricity generation has changed over the past three decades. While total generation has increased by roughly one-third since 1990, coal's share has steadily decreased, being offset by increased use of natural gas. Renewable sources make up an increasing share, especially after 2010. Generation from renewable sources is now approximately equal to generation from nuclear power, which has increased only slightly since 1990. Petroleum is playing an ever smaller role as a fuel for generating electricity.

The black line in Figure 26 shows the general decrease in emissions since 2007, even as total power generation has held roughly steady. GHG emissions from the power sector are currently below 1990 levels, and are expected to continue to fall as coal is displaced in the power mix by lower-emissions fuels like gas and renewables.