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MMS 2007-050

Fiscal Cost-Benefit Analysis to Support the Rulemaking Process for 30 CFR 285 Governing Alternative Energy Production and Alternate Uses of Existing Facilities on the Outer Continental Shelf

Final Technical Report

U.S. Department of the Interior
Minerals Management Service

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Final Technical Report

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Any economic effects characterized by the EA is predicated upon the assumption that there is available transmission capacity to carry the energy generated on the OCS to demand centers.

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TABLE OF CONTENTS

PAGE

LIST OF TABLES

LIST OF TABLES (cont.)

LIST OF TABLES (cont.)

LIST OF FIGURES

EXECUTIVE SUMMARY

The Energy Policy Act of 2005 *(*EPAct), specifically section 388, amended the Outer Continental Shelf (OCS) Lands Act to authorize the Secretary of the Interior to (1) issue leases, easements, or rights-of-way on the OCS for producing or supporting the production of energy resources other than oil and gas, and (2) to authorize other energy and marine-related activities that involve the use of existing facilities on the OCS. The EPAct also required the Department of the Interior to develop any necessary regulations to implement this new authority and to implement alternative energy revenue sharing requirements.[1] On March 20, 2006, the Secretary officially delegated this new authority, and responsibility for developing any necessary regulations, to the Minerals Management Service (MMS). The implementing regulations and the revenue sharing regulations have been assigned Regulation Identifier Number 1010-AD30 ("AD30").

The importance of these regulations stems from the growing interest in harnessing the energy production potential that is available on the OCS and the current lack of a formal system to facilitate such activity. Prior to the EPAct, the Federal government did not have clear authority to seek payment for private interests' access to and use of Federal submerged lands, nor authority to establish a comprehensive program for regulating all aspects of alternative energy development on the OCS, including siting, construction, operation, and decommissioning. These regulations will serve an important social purpose by establishing a payment structure to ensure a fair return to the United States for any lease, easement, or right-of-way granted; by creating a comprehensive “cradle-to-grave” regulatory program with provisions for regular inspections and environmental monitoring; and by providing a degree of regulatory certainty to those proposing, planning, or potentially financing an offshore alternative energy project.

MMS is required to conduct economic analyses of proposed regulations if they are determined to be significant, as that term is defined in Executive Order 12866. Regulation AD30 is considered significant because, by establishing a new regulatory program, it would raise novel legal or policy issues. If actual development of OCS alternative energy projects were consistent with the scenario presented in this analysis, net Federal revenues may exceed $100 million in some years, but payments to Federal agencies represent a transfer of money from one set of entities to another, not the actual effect on the economy.

Discussions between MMS and OMB resulted in a determination that the appropriate analysis of the proposed regulation is one that focuses on its fiscal impacts. While fiscal revenues (i.e., the revenues the Federal government will receive due to economic activity that occurs under the regulation) are traditionally considered a transfer payment,[2] in this analysis they are treated as a benefit. The cost side of the analysis comprises the Federal government's costs to implement the program that will administer the proposed regulation. In addition, as required by the Regulatory

[1] The EPAct requires distribution of 27 percent of revenue from any qualified alternative energy/alternate use project, to be shared among eligible States.

[2] The effects of transfer payments typically are ignored in national cost-benefit equations, because they tend not to create any net costs or benefits to society on their own; the recipients’ gains are offset by the costs to the payers.

Flexibility Act (RFA) of 1980 (as amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBRFA) and Executive Order 13272 ("Proper Consideration of Small Entities in Agency Rulemaking")), this analysis considers whether the fiscal payments made by the developers of regulated projects to MMS will significantly affect a substantial number of small entities.

Regulatory alternative

For the purposes of this analysis, the baseline condition is a continuation of the regulatory regime that existed prior to passage of the EPAct, under which other Federal agencies, such as the Army Corps of Engineers (in the case of wind energy) and the Federal Energy Regulatory Commission (FERC, in the case of wave and ocean current energy), assumed primary responsibility for reviewing and permitting alternative energy projects on the OCS. The regulatory alternative to the baseline, as described in this rulemaking, is the MMS program authorized by Section 388 of the EPAct, comprising the granting of property rights, collection of payments for alternative energy and other uses of the OCS (in the form of lease rentals and operating fees), and establishment of a comprehensive "cradle-to-grave" regulatory program for authorizing alternative energy activity on the OCS. The analysis further considers three different sets of fiscal terms (identified as the "Low," "Intermediate," and "High" payment cases), which vary in the way fees and rental payments are calculated. These payment cases are explained in Section 4 of the report. The main analysis uses the same assumptions regarding electricity prices and other such phenomena for each case. Other scenarios, based on the same payment cases, are presented in Appendix B and Appendix D. The analysis considers projects that are constructed and that begin operations (i.e., begin to generate electricity for sale) or that are in development during the 20-year period from 2008-2027. While these projects would have revenue and cost impacts that extend beyond this period (based on 20 years of electricity generation over an assumed 25-year operational term), the only fiscal impacts reported are those that occur during the period 2008-2027.

Analytic methodology

The process of estimating the revenues and costs associated with 20 years of future project development (and subsequent operations that occur during that 20-year period) requires a number of key assumptions regarding individual project characteristics, project financing, and electric power market conditions. Our specific methodology for calculating net revenues comprised three general steps: the development of a forecast of OCS project activity during the period 2008-2027; the creation of an Excel-based spreadsheet model that tracks annual cash flow for each project in the forecast and permits a calculation of each project's annual payments to the Federal government (in the form of rentals and fees); and the assessment of the costs the Federal government is expected to incur to administer the program created by this rule (principally the review of project development plans). Net revenues, on an annual or a cumulative basis, are the difference between estimated Federal revenues and estimated Federal costs.

Creation of a forecast of OCS alternative energy project activity is subject to considerable uncertainty, as these will be the first projects of their kind in United States waters and will be entering a market that is, and will continue to be, evolving. For the purposes of this rulemaking, a forecast is constructed on a foundation of existing project proposals, with growth from that base predicated on the general presumption that regulatory, technical, and financial conditions during the period of analysis will support rather than constrain development activity. The forecast includes wind, wave, and ocean current energy projects in three geographic regions (Atlantic, Gulf of Mexico, and Pacific). Refinement of an initial forecast was based on a review of readily available literature and other sources of information that address estimates of renewable energy resources on the OCS; descriptions of existing and planned renewable energy generation technologies that might be used to exploit OCS resources; estimates of potential cost trends over time for different renewable energy technologies; estimates of when different technologies are expected to be "economically deployable"; estimates of OCS renewable energy generating capacity expansion on an annual or semi-annual basis; and discussions about the integration of OCS electricity generation into the onshore transmission grid. The resultant preliminary forecast includes 76 projects that begin generating electricity prior to 2028.

Annual costs are based on MMS forecasts of the personnel that will be required for program activities and per-project level of effort estimates for each position in the personnel mix at each stage of a project's lifecycle. The level of effort estimates are expressed as fractions of annual full time equivalents (FTEs). The project lifecycle stages are divided into one-year increments. Costs are assigned to each position based on an assumed pay grade, specified by MMS, with a fixed indirect cost rate applied to base compensation for each grade. MMS also specified an annual cost of living adjustment (three percent) to use in determining future year costs. In addition, MMS estimated additional program-related costs that cannot be assigned to individual projects but that are directly related to implementation of the regulations (e.g., preparatory work for an anticipated lease sale).

The cash flow model used to estimate payments to the Federal government incorporates both project-specific and general assumptions. The project-specific assumptions include technical details (e.g., size, capacity factor, capital and operations and maintenance costs, years to construct) as well as the initial value of financial incentives (i.e., the Production Tax Credit (PTC) and renewable energy certificates (RECs), as appropriate) for each of the projects in the development forecast. General assumptions address factors such as regional electricity price forecasts and construction financing terms. In addition, the model incorporates assumptions consistent with the financial assurance requirements as specified in the rule. For each project in the preliminary development forecast, the cash flow statement covers the entire project lifetime, from pre-development through operations to decommissioning. Thus, the last project in the forecast begins operation in 2027 and operates through 2046. However, as described above, for the purposes of this analysis we only report the Federal revenues and costs that are realized during the period 2008-2027.

In general, assumptions incorporated into the model reflect the electricity and alternative energy markets and policy landscapes as they existed at the time of the analysis. With one exception, we did not assume any market or policy changes that might provide an advantage or disadvantage to OCS alternative energy projects during the period of analysis. Furthermore, we assumed that any factor in place at the time of the analysis would remain in place throughout the period of analysis. The exception to this rule was an assumption that the Federal PTC would become available to wave and ocean current energy projects prior to the operational phases of the first projects of these kinds.

As part of our examination of the cash flow for each project in the development forecast (given model assumptions), we established specific, internal rate of return (IRR)-based criteria for the evaluation of economic viability. Below a certain IRR, we assumed that the project might be proposed but would not formally enter the pre-development phase, and thus would not result in any Federal revenues or costs. For projects that exhibited an IRR above a minimum value but below a target value, we assumed that some pre-development activity would occur but that construction and operation of the project would not. In these cases, we calculated and recorded Federal revenues and costs associated only with the predevelopment period. We calculated and recorded all Federal revenues and costs for the projects with an IRR above the target value. The effect of this viability analysis was a reduction (from the original universe of 76) in the number of projects included in the net revenue calculation for the Low, Intermediate, and High payment cases.

We analyzed the sensitivity of our results to key assumptions. Variations in electricity price had the greatest influence on evaluation results, followed by variations in capacity factor. We also analyzed the impact of the REC and PTC financial incentives on project viability. Total viable projects might be reduced by 25 percent without revenue from REC sales. Thus, renewable portfolio standards implemented by coastal states could be essential to the economic success of many OCS projects. A reduction in total viable projects of more than 40 percent may occur if the PTC is not available, suggesting that this incentive is the most significant one for investors.

Results

As of January 1, 2008, at a three percent discount rate, the present value of cumulative net Federal revenues over the 20-year period of the analysis ranges from approximately -$9.3 million and -$57.3 million in the Baseline and Low cases, respectively, to approximately $357 million and $538 million in the Intermediate and High payment cases, respectively. With a 7 percent discount rate, the present value of cumulative net Federal revenues over the period of the analysis ranges from approximately -$7.8 million and -$46.5 million in the Baseline and Low cases, respectively, to approximately $190 million and $291 million in the Intermediate and High payment cases, respectively. The significant difference in net revenues is attributable to the inclusion of operating fee payments to MMS in the latter two cases.[3] These operating fees are relatively large in comparison to the other fees paid to MMS in all three cases. Categorization of the results by technology and region highlights the impact of wind energy projects and the Atlantic region, which, respectively, account for over 99 percent and approximately 79 percent of the present value cumulative net revenues in the Intermediate payment case.

Regulatory Flexibility Act analysis

Under the requirements of the RFA, as amended by SBRFA and Executive Order 13272, Federal agencies must consider the potential distributional impact of new rules on small businesses, small governmental jurisdictions, and small organizations. MMS is required to prepare a

[3] This difference would increase beyond the period of analysis, when the later years of operation for each project occur. For the High case, the later years also would include the higher net benefits produced by the graduated operating fee rate.

regulatory flexibility analysis and take other steps to assist small entities, unless it certifies that the rule will not have a “significant economic impact on a substantial number of small entities.” Certification of the rule must include a statement providing the factual basis for this determination. The remainder of this section summarizes the results of MMS’s screening analysis used to determine whether it can certify the rule.

Given the immaturity of the offshore alternative energy industry, it is difficult to develop an accurate count of the number and size of entities that will or may be subject to this rule in order to determine whether the rule will affect a "substantial" number of small entities. The most appropriate North American Industry Classification System (NAICS) code for the industry affected by the proposed rule is 221119 (Other Electric Power Generation).[4] An entity within this classification is “small” if it is "primarily engaged in the generation, transmission, and/or distribution of electric energy for sale and its total electric output for the preceding fiscal year did not exceed four million megawatt hours” (MWh). We assume that many of the entities subject to the rule will likely exist, during the period of analysis, solely to develop one or more offshore alternative energy projects that combined will not have a total electric output greater than 4 million MWh (corresponding to an offshore wind project with a rated capacity of more than 1,100 MW, which is larger than the largest project included in our 20-year forecast). Some entities, either through a combination of projects or through the incorporation of offshore alternative energy projects into a larger portfolio of electricity generating stations, will exceed the four million MWh threshold.

Several companies have formally or informally expressed interest in being granted access to the OCS for electricity generation purposes. At least 40 to 50 entities are identifiable as potential project or technology developers with a focus on utilizing offshore wind, wave, or ocean current resources. The U.S. Census Bureau's 2002 Economic Census reported 411 entities within NAICS code 221119. However, for the purposes of this analysis we assume that most of the relevant entities will be considered "small," and therefore can conclude that a substantial number of small entities will be affected.

The significance of the impact on small entities is assessed in this case by comparing the compliance costs (i.e., the payments to the Federal government) required under the rule to the total revenues generated by the subject entities. For this analysis, we consider all project revenues and payments to the Federal government associated with the projects that meet the target IRR value, regardless of when they occur (i.e., the analysis considers revenues and payments that occur post-2027). For each payment case, we calculate the ratio of annualized per project payments to annualized per project revenues over the lifetime of each project. This ratio provides a conservative estimate of the impact of compliance costs on small entities because it assumes that (1) all of the affected projects are undertaken by small entities, (2) each entity undertakes a single project, and (3) all revenues for each entity are derived solely from this

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[4] It is possible that the proposed rule may eventually govern hydrogen production, affecting entities that fall under NAICS Code 325120, Industrial Gas Manufacturing. However, it is unlikely that hydrogen will be produced on the OCS in significant amounts during the 20-year period of analysis, and MMS has no means to predict what kinds of entities would likely be involved in hydrogen production, given the lack of proposals for projects that would produce hydrogen.

renewable energy project (i.e., the companies involved do not have groups of projects or other business interests). Therefore, the results of this screening analysis are more likely to overstate than understate the significance of compliance costs to affected entities.

The highest ratio of payments to revenues for a single project in the Intermediate payment case is 2.1 percent, while the lowest ratio is 0.81 percent, depending on the discount rate applied. The average ratio across all projects in the Intermediate payment case is 1.2 percent and 1.4 percent, applying discount rates of three and seven percent respectively. The highest ratio of 4.1 percent occurs under the High payment case assuming a discount rate of seven percent.

Initial Regulatory Flexibility Analysis

MMS is considering the impact of these regulations on small businesses and may decide to conduct an initial regulatory flexibility act analysis (IRFA). A description of the information required for an IRFA is provided at the end of this report.

1.0 INTRODUCTION

Increasing the share of electricity generated by alternative sources of energy is widely recognized as an important element of any strategy to ensure future supplies of clean, affordable, and reliable power.[5] Among the resources available to help achieve this goal are those associated with the offshore environment, including wind energy, wave energy, and ocean current energy. Growing interest in the utilization of these resources to generate electricity has brought into focus the need for a clear regulatory framework to grant access to Federal submerged lands where development activities might occur.

The Energy Policy Act (EPAct) of 2005, specifically section 388, amended the Outer Continental Shelf (OCS) Lands Act to authorize the Secretary of the Interior to issue leases, easements, or rights-of-way on the OCS for producing or supporting the production of energy resources other than oil and gas and to authorize other energy and marine-related activities that involve the use of existing OCS facilities. The EPAct also required the Department of the Interior to develop any necessary regulations to implement this new authority. On March 20, 2006, the Secretary officially delegated this new authority, and responsibility for developing any necessary regulations, to the Minerals Management Service (MMS).[6] The proposed regulations (Regulation Identifier Number 1010-AD30, or "AD30") would establish a program to allow access to Federal submerged lands (generally referred to as the Outer Continental Shelf, or OCS) for alternative energy projects and alternate uses of existing facilities.

Prior to the passage of the EPAct, the Federal government lacked the authority to oversee all aspects of alternative energy project development on the OCS, including siting, construction, operation, and decommissioning. Additionally, prior to the passage of the EPAct, the Federal Government lacked the authority to seek payments from private interests for use of our Nation’s OCS. These regulations will provide the framework for MMS's management of an Alternative Energy-Alternate Use Program. This program will create a system that provides a degree of regulatory certainty to those proposing, planning, or potentially financing an offshore alternative energy project on the OCS, as it will address lease and grant issuance, activity authorization, payment collection, financial assurance, and project decommissioning.

1.1 Need for a regulatory impact analysis

Executive Order 12866, dated September 30, 1993, and amended on January 18, 2007, requires Federal agencies to conduct economic analyses of significant regulatory actions as a means to improve regulatory decision making. A regulatory action may be considered "significant" if it is expected to meet one or more of the following conditions.

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[5] National Energy Policy: Report of the National Energy Policy Development Group, May 2001; Advanced Energy Initiative, National Economic Council, February 2006.

[6] Existing MMS regulations for offshore activities apply specifically to oil and natural gas activities or to other minerals; these existing regulations could not accommodate alternative energy and alternate uses of the OCS.

1. Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities.

2. Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency.

3. Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof.

4. Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in Executive Order 12866.[7]

With respect to AD30:

1. The regulations would govern an industry that is at an early stage of development but which could have developed even without the subject regulations. The proposed rule would do two things: it would set forth clear regulatory guidelines that facilitate industry financing and development, and it would institute payments to the Government as a fair return for use of public lands. MMS considered three sets of terms for the payments that would be made to the Federal government pursuant to these regulations ("Low," "Intermediate," and "High" cases). As described in Section 5, if actual development of OCS alternative energy projects were consistent with the scenario presented in this analysis, net Federal revenues may exceed $100 million in some years. However, payments to Federal agencies represent a transfer of money from one set of entities to another, not the actual effect of the regulations on the economy. As anticipated in the EPAct, the new rule would provide for an increase in the revenue flow from industry to the Federal government and, in some cases, to coastal States, but it would not create or prevent industry activities that produce those revenues. Furthermore, because the rule does not create these revenues but merely causes them to be spent in the government sector instead of by the private entities involved, the impact numbers represent an extreme upper limit to the effects of the rule on the economy.

2. The proposed rule would not create a serious inconsistency or otherwise interfere with action taken or planned by another agency. EPAct granted to the Secretary of the Interior (who delegated to MMS) discretionary authority to authorize and regulate alternative energy activities on the OCS only to the extent such activities were not previously authorized by other applicable law. Therefore, through the passage of

7 Executive Order 12866, Regulatory Planning and Review, September 30, 1993, Section 3(f). This text was unchanged by the recent amendments to the Executive Order. See Executive Order: Further Amendment to Executive Order 12866 on Regulatory Planning and Review, as viewed at http://www.whitehouse.gov/news/releases/2007/01/print/20070118.html on May 24, 2007.

EPAct, Congress ensured that there would be no overlapping areas of Federal jurisdiction on the OCS for alternative energy projects.

3. The proposed rule would not alter the budgetary effects of entitlements, grants, user fees or loan programs, or the rights or obligations of their recipients.

4. The proposed rule would raise novel legal or policy issues because the rulemaking would establish a new regulatory program for the development of alternative energy resources on the OCS and for the alternate use of existing OCS facilities. For this reason, it has been determined that AD30 is a significant rule requiring further economic analysis.

Primarily for the reason that the proposed rule would raise novel legal or policy issues, MMS is required to conduct an economic analysis of AD30.

1.2 Scope of the analysis

Discussions between MMS and OMB resulted in a determination that the appropriate analysis of the proposed rulemaking is one that focuses on the fiscal impacts of the rule. While fiscal revenues (i.e., the revenues the Federal government will receive due to economic activity that occurs under this rule) are traditionally considered a transfer payment, in this analysis they are treated as a "benefit." The cost side of the analysis comprises the Federal government's costs to implement the program that will administer the proposed rules. In addition, as required by the Regulatory Flexibility Act (RFA) of 1980 (as amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBRFA) and Executive Order 13272 ("Proper Consideration of Small Entities in Agency Rulemaking")), this analysis considers whether the fiscal payments made by the developers of regulated projects to MMS will significantly affect a substantial number of small entities.

The time period for the analysis is 2008-2027. More specifically, the analysis includes Federal program costs and revenues that (1) are associated with projects that become operational during this period and that (2) are incurred or collected during this period. In other words, the stream of costs and revenues that would occur in connection with a project that has a lifetime extending beyond 2027 is truncated, for the purposes of this analysis, at 2027. The technical scope of the analysis (with respect to alternative energy projects) includes wind energy, wave energy, and ocean current energy projects. The geographic scope of the analysis includes the OCS on the Atlantic and Pacific coasts and in the Gulf of Mexico, but does not include the waters off Alaska and Hawaii.

1.3 Description of the baseline and alternative

The baseline condition, against which the impact of the proposed rule is to be compared, is a continuation of the regulatory regime that existed prior to the EPAct, under which the Army Corps of Engineers (Corps) assumed principal responsibility for reviewing and permitting wind energy projects and the Federal Energy Regulatory Commission (FERC) asserted authority for wave and ocean current projects on the OCS. For the purposes of this analysis, we assume that the project development forecast is independent of the regulatory regime; the locations, types, and timing of development would be the same with or without the MMS program contemplated by the EPAct.[8] MMS is considering only one alternative to the baseline—a regulatory program under which MMS grants property rights, collects payments for activities conducted on the OCS, and establishes a comprehensive "cradle-to-grave" regulatory program for authorizing alternative energy activity—but has developed three different cases with varying payment terms ("Low," "Intermediate," and "High"). Section 4 provides a detailed description of the three payment cases. The main analysis provides a single scenario, or set of results based on identical assumptions regarding electricity prices and other conditions, for each payment case. Other scenarios based on the same payment cases are presented in Appendix B and Appendix D.

1.4 Report outline

The remainder of this report is organized as follows.

- Section 2 presents a general forecast of alternative energy development on the OCS during the period 2008-2027. Based on available literature, input from third party experts, and professional judgment, the section concludes with a forecast of individual projects by technology, location, and first year of operation.

- Section 3 describes the calculation of annual and cumulative estimated costs to the Federal government to implement the MMS program that will regulate the use of the OCS for alternative energy projects and the alternate use of existing OCS facilities.

- Section 4 generally describes the cash flow model constructed to analyze the feasibility of projects in the development forecast and to produce estimates of the transfer payments (i.e., the Federal revenues) that would result from the projects included in the development forecast. This section also provides additional detail concerning the alternative energy development forecast, including descriptions of the various assumptions (technology- and market-specific) that were made to complete the quantitative estimation of costs and revenues.

- Section 5 discusses the sensitivity of model results to specific input assumptions and presents analytical results showing the effect of renewable energy certificates on project viability.

- Section 6 presents an alternative set of results that illustrate the impact of the Federal production tax credit on project viability.

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[8] We note one possible exception to this assumption. The timing of some projects is subject to a single assumed lease sale which, in the MMS alternative, occurs in 2012. In the baseline case no lease sale occurs and the Corps and FERC would have considered applications on a rolling basis. In the MMS alternative, as soon as MMS begins to receive expressions of interest in overlapping geographical areas, the agency would delineate the areas subject to competition through one or more lease sales. For this analysis, therefore, the applications for projects within the area subject to competition would not be accepted until after the lease sale in 2012. However, given the lack of legal and regulatory certainty inherent in the baseline, many investors and lenders might have withheld funding until more certainty regarding regulatory, legal, and economic risk was established by a few early projects. Therefore, it is not at all certain that the baseline scenario would have differed substantially from the one underlying the MMS alternative.

- Section 7 presents the results from the cost and transfer payment analyses and reports annual and cumulative estimates of the net revenues associated with the proposed rule. This section also presents summary results categorized by technology and by geographic region.

- Section 8 provides a qualitative analysis of costs and revenues associated with possible alternate uses of existing OCS facilities.

- Section 9 discusses and presents an analysis of the distributional impacts, as required by the RFA/SBRFA and Executive Order 13272 ("Proper Consideration of Small Entities in Agency Rulemaking").

- Appendix A provides a more detailed description of the model constructed to estimate Federal revenues and costs.

- Appendix B provides electricity production and financial performance information for projects in the development forecast that would be operational by 2027.

2.0 FORECAST OF ALTERNATIVE ENERGY DEVELOPMENT ON THE OUTER CONTINENTAL SHELF

The analysis of program management costs and projected transfer payments to the Federal treasury between 2008 and 2027 depends on a forecast of the number and type of OCS alternative energy projects that might generate Federal costs and revenues during that period. Creation of such a forecast is subject to considerable uncertainty, as these will be the first projects of their kind in United States waters and will be entering a market that is, and will continue to be, evolving. For the purposes of this rulemaking, a forecast is constructed using information about existing project proposals, market and technology research, and a general presumption that regulatory, technical, and financial conditions during the period of analysis will support rather than constrain development activity.

While our focus was on projects that could begin generating electricity by 2027, our forecast must extend nine years beyond that (based on the presumed period from project application to electricity generation, as described in Section 4) to account for projects that will be "in process" (i.e., that will result in the Federal government incurring program costs and that will pay pre-operational fees to the Federal government).

It is very important to note that the forecast developed for this analysis includes details (general project locations, types, and sizes) that are necessary for a complete cost-benefit analysis but that are not meant to be indicative of any Federal government preferences, plans, or intentions with regard to OCS alternative energy development. While the forecast represents one possible development path (i.e., one "scenario"), a combination of market and government factors will ultimately determine the type, scale, and timing of actual activity.

In order to ensure the development of a reasonable forecast, we collected and reviewed readily available literature and other sources of information that address one or more elements relevant to future development of OCS renewable energy. As directed by MMS, we focused on:

- Estimates of renewable energy resources on the OCS;
- Descriptions of existing and planned renewable energy generation technologies that might be deployed on the OCS;
- Estimates of cost trends over time for different renewable energy technologies;
- Estimates of when different technologies are expected to be "economically deployable";
- Estimates of OCS renewable energy generating capacity expansion on an annual or semi-annual basis; and
- Discussions about the integration of OCS electricity generation into the onshore transmission grid.

In general, we found relatively little information that describes in any detail potential development over the next 20 years. Therefore, the development scenario that serves as the basis for the fiscal impact analysis is constructed from available information (including the preliminary MMS forecast) and a set of assumptions such that the resultant projects can be described as both technically reasonable and economically viable (i.e., profitable, subject to the limitations of the assumptions required to assess future economic viability). The following sections describe our findings with respect to each of the above elements, differentiated by resource, as appropriate. The final section describes how we constructed the development forecast.

2.1 Renewable energy resources on the OCS

The amount of energy contained in the wind, waves, and ocean currents that exist within the area subject to federal jurisdiction is vast. Several efforts have been undertaken in recent years to quantify the wind and wave energy potential in different coastal regions. The amount of energy contained in ocean current resources located in federal waters is less well-defined; estimates produced during the 1970s are the best, readily available indications of the scale of this resource.

2.1.1 Wind

Musial and Butterfield (2004) developed a detailed estimate of wind resources at a distance of five to 50 nautical miles (nm) offshore in key Atlantic and Pacific coastal regions. Although this estimate excludes part of MMS's jurisdictional area (three to five nm and 50 to 200 nm) as well as the Southeast and Gulf of Mexico regions, it captures the area where substantial development can be anticipated to occur through 2027. Table 2-1 presents the results of this analysis. Note that for the zone between five and 20 nm offshore, two-thirds of the area is excluded from the estimate to account very conservatively for restricting factors such as environmentally sensitive habitats and viewshed conflicts. Similarly, one-third of the area between 20 and 50 nm offshore is excluded (the lower number reflecting the assumption that there would be fewer environmental or viewshed issues at a greater distance from shore). The Department of Energy has more recently developed a refined internal analysis of offshore wind energy resources, as summarized in Table 2-2.

Table 2-1
Estimate of U.S. Offshore Wind Energy Resources (Megawatts) by Region and Water Depth

	5 - 20 Nautical Miles		20 - 50 Nautical Miles	
Region	**Shallow <30 meters**	**Deep**	**Shallow <30 meters**	**Deep**
New England	9,900	41,600	2,700	166,300
Mid Atlantic	46,500	8,500	35,500	170,000
California	2,650	57,250	0	238,300
Pacific Northwest	725	34,075	0	93,700
Totals	**59,775**	**141,425**	**38,200**	**668,300**

Source: Musial, W. and S. Butterfield, "Future for Offshore Wind Energy in the United States," NREL/CP-500-6313, June 2004.

Table 2-2
DOE Estimate of U.S. Offshore Wind Energy Resources
by North American Electric Reliability Corporation Region
(Megawatts, Class 5+, >3 nautical miles offshore)

	Water Depth		
Region	**Shallow (< 30m)**	**Transitional (30-60m)**	**Deep (> 60m)**
New England	9,100	117,590	32,500
New York	1,680	33,240	29,400
Mid Atlantic (NJ, DE, MD)	17,645	10,000	67,115
Southeast (VA-GA)	10,105	20,955	23,560
California	25	210,535	280
Pacific Northwest	0	176,780	1,615
Totals	**38,555**	**569,100**	**154,470**

Source: Chris Namowicz, Energy Information Administration, personal communication, April 2, 2007.

Other studies have looked at the wind resource potential in specific areas, and support the conclusion that the wind resource will not be a constraint on future development.

- Kempton et al (2007) examined the wind resource in the Middle-Atlantic Bight (from Massachusetts to North Carolina) and determined that it has the potential to deliver approximately 330 gigawatts (GW) of power (based on a nameplate capacity of 835 GW and an average capacity factor of 39.5 percent). This study does not separate resources that are less than three nm from shore from those that are more than three nm from shore.

- AWS Scientific, Inc. (2002) conducted a preliminary assessment of Long Island's offshore wind energy resource. AWS estimates that the area that is at least three miles offshore, has a water depth of less than 30 meters, and exhibits average wind speeds greater than eight meters per second could support up to 5,200 megawatts (MW) of generating capacity.

- A 2004 study by Atlantic Renewable Energy Corporation (AREC) and AWS Scientific of New Jersey's offshore wind energy development potential concluded that the State had a maximum theoretical potential of 24,500 MW of offshore wind energy, largely in waters more than three miles from shore (AREC and AWS 2004).

- An analysis by Stanford University researchers (Dvorak et al. 2007) concluded that existing and next-generation support structure technology (enabling development in up to 50 meters of water) could support the development of more than 3,000 MW of wind energy capacity off the northern California coast (assuming Class 5 winds). More than 20,000 MW of additional capacity is estimated to be potentially available if development could occur in waters between 50 and 200 meters in depth.

- A 2007 presentation by AWS Truewind LLC (formerly AWS Scientific) (Freedman 2007) summarized the analysis of offshore wind energy potential in the coastal zone off North Carolina, South Carolina, and Georgia. AWS estimated that the resource potential is in the tens of thousands of megawatts, with a "substantial amount" of this potential in shallow (< 50 foot depth) waters.

2.1.2 Wave

The Electric Power Research Institute's (EPRI) Ocean Energy Program estimates the combined wave energy resource in four U.S. regions (Washington/Oregon/California, New England/Mid-Atlantic, southern Alaska, northern Hawaii) to be approximately 2,100 terawatt-hours (TWh) per year (based on a minimum mean power flux of 10 kilowatts per meter; a mean flux less than 10 kW/m is highly unlikely to be considered an economically viable resource) (Bedard 2007). EPRI further assumes that 15 percent of this energy can be converted to mechanical energy, that wave energy conversion devices will operate at 90 percent efficiency, and that they will have a 90 percent availability, resulting in an estimate of approximately 260 TWh of available energy per year. The resources in the continental U.S. (the Atlantic and Pacific coast regions) are estimated to be approximately 67 TWh per year, or 25 percent of the total. This is equal to a capacity of approximately 7,600 MW. Approximately 80 percent of the continent-specific resource is associated with the region off the Washington, Oregon, and California coasts.

2.1.3 Ocean current

OCS development of ocean current resources is likely limited to the Florida Current, which flows between Florida and the Bahamas. Estimates of the energy present in the Florida Current date back to the mid-1970s, when the use of this resource for electricity generation was first proposed. While these early studies indicate an energy flux of as much as 25,000 MW through a single cross-sectional area, the amount of energy that could be extracted is uncertain, primarily because of concerns that reducing the energy in this portion of the Gulf Stream could have negative environmental consequences. Early modeling suggested that an array of turbines totaling 10,000 MW of capacity would not reduce the current's speed by more than what has been observed as its natural variation, and thus might be feasible (Lissaman and Radkey 1979; Charlier and Justus 1993). Further investigation is required to determine the magnitude of the technically available resource.

2.2 Renewable energy generation technologies

Based on more than 20 years of onshore deployment in the U.S., as well as several years of experience in the offshore environment in Europe, wind power technologies (and the technical issues that future offshore development will face) are well defined. A summary is provided below with a focus on issues relevant to forecasting the development of offshore wind energy capacity. Wave energy and ocean current energy technologies are far less mature in their development. In these cases, we provide only a descriptive summary of the technologies that appear to be most likely to be deployed first on a commercial scale.

2.2.1 Wind

The primary components of an offshore wind energy project are the wind turbine (the nacelle and rotor assembly), tower, foundation, intra-project electricity collection system (i.e., cables and offshore substation), and project-to-shore transmission cabling. The turbine and tower are relatively mature technologies, with offshore components differing from their onshore analogues primarily in scale. Foundations and transmission comprise the key differences between onshore and offshore wind energy technology.

Offshore wind farms constructed in the 1990s (all in Europe) utilized wind turbines rated at 450 to 600 kW. The second generation of European offshore wind farms, constructed since 2000, have utilized turbines rated at 1.5 to 3.6 MW. Projects developed over the period of this analysis can be expected to utilize turbines in the 3.6 to 5 MW range, though even larger scale machines (perhaps up to 10 MW) are in development. Site-specific capacity factors will depend on the turbine that is matched to the resource at each project site. However, the typical range for offshore wind farms is 35 to 40 percent; we assume a fixed capacity factor of 38 percent for all wind projects in the development forecast. Based on the first projects and proposals, it can be assumed that the rated capacity of offshore wind projects will range from 150 MW to 1,000 MW or more.

The most important technological (and cost) consideration for future offshore wind energy development is the type of support structure used, especially as development is considered for deeper waters, where much of the available resource is located. All offshore development to date has occurred in relatively shallow waters (5-18 m depth) using monopile and concrete gravity base foundations. These types of foundations are generally appropriate (i.e., economic) to a depth of approximately 30 m. At "transitional" depths (up to approximately 60 m), support structures will necessarily begin to look more like those used in the offshore oil and gas industry, with wider bases and multiple anchor points. In the long term, the use of floating platforms would enable maximum exploitation of the offshore wind resource. Floating platforms will need to have sufficient buoyancy to support the weight of a large turbine while also countering the effects of wind and wave motion (pitching, rolling, heaving). Development of floating platforms is at an early stage, but will benefit from the experience of the oil and gas industry. As Musial and Butterfield (2004) described, floating wind turbine platforms will have several design and cost advantages over the floating platforms used for oil and gas exploration and production, including:

- Deployment in much shallower water than is common for oil and gas structures; and

- Minimal above-water deck area requirements compared to oil and gas platforms, resulting in an ability to submerge more of the structure and minimize the area subject to wave loading.

A discussion of issues related to the transmission of electricity from an offshore project to the onshore grid is provided below.

2.2.2 Wave

As of April 2007, EPRI had identified 32 companies or organizations (e.g., academic institutions) in the United States, Europe, and Australia that are currently developing wave energy conversion technology. In general, these technologies fall into one of five categories based on the way in which they harness the wave energy:

- Oscillating water column - a partly submerged structure with air trapped above the surface of an enclosed water column. The water column acts as a piston, driving air through a turbine, as waves enter and exit the structure.

- Overtopping - a structure that allows waves to enter a reservoir at the bottom of which are hydroelectric turbines. Water flowing out of the reservoir turns the turbines and generates electricity.

- Symmetrical point absorber - a bottom-mounted or floating structure that absorbs energy in all directions and converts this energy to electricity. Power take-off from a point absorber can take a number of forms.

- Terminator - a floating structure that absorbs energy in a single direction (i.e., is oriented normal to the wave direction). As with point absorbers, power take-off can take a number of forms.

- Attenuator - a floating structure, oriented parallel to wave direction, that translates the movement of the waves along its length into energy.

The development stage of the identified technologies ranges from lab-scale proof-of-concept to full-scale field demonstration and commercial development. Among the more advanced technologies are:

- AquaBuoy, a floating point absorber developed by the AquaEnergy Group Ltd. (a division of Finavera Renewables). An AquaBuoy project is in development near Makah Bay, WA.

- The Oceanlinx (formerly Energetech) oscillating water column device, a 500kw prototype of which has been successfully deployed in Australia.

- The Archimedes Wave Swing, a seabed-mounted point absorber developed by AWS Ocean Energy. A full-scale AWS unit has been installed and tested off the coast of Portugal.

- The Pelamis, a free-floating hinged contour attenuator device developed by Ocean Power Delivery. Deployment of the first commercial scale units (with a total capacity of 2.25 MW) began off the Portugal coast in 2006.

- The PowerBuoy, a floating point absorber developed by Ocean Power Technologies. The PowerBuoy was successfully tested off the New Jersey coast during a 12-month field trial that ended in October 2006. The planning phase of a commercial project off the Spanish coast has also recently been completed.

It is not possible to predict whether these will be the technologies that account for all or most of the wave development activity that occurs in the next 20 years. A 2004 EPRI review of wave energy conversion devices assumes capacity factors ranging from 20 to 50 percent depending on the technology (Previsic 2004a).[9] For the purpose of our analysis we apply a capacity factor of 35 percent to all wave energy projects in the development forecast. Based on early project proposals, it can be assumed that the rated capacity of offshore wave projects during the period of analysis will range from 50 MW to 100 MW. To simplify the analysis, we initially assume a standard size of 75 MW for all projects in the development forecast.

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[9] As with wind energy, technology and resource considerations will influence project-specific capacity factors.

2.2.3 Ocean current

Available information indicates at least two technologies proposed for use in harnessing the energy contained in the Florida Current.

- The SeaGen twin rotor turbine, developed by Marine Current Turbines Limited and licensed for use in U.S. development projects by Ocean Renewable Power Company (dba Red Circle Systems Corporation). The SeaGen unit operates much like a wind turbine and is secured to a monopile foundation in the seafloor. Sea trials of this technology have occurred in the waters off the United Kingdom.

- The Open Hydro concept, an open-center turbine comprising a self-contained, disc-shaped rotor with a solid state permanent magnet generator enclosed within a fixed outer rim. Each turbine is expected to be mounted on the seafloor with a gravity base.

The first proposals for ocean current energy production on the continental U.S. OCS (i.e., in the Florida Current) suggest total rated capacities of 20-40 MW. We do not have additional information with which to estimate the likely scale of ocean current projects during the period of analysis, so we assume a constant size of 30 MW per project. Given the constant flow in the current, we assume a relatively high capacity factor of 80 percent for each project.

2.3 Renewable energy technology cost trends

2.3.1 Wind

Substantial work has been undertaken to forecast cost reductions for offshore wind energy. In general, these reductions will result from a combination of "learning" and economies of scale. Learning is usually expressed as a "progress ratio" (PR) that indicates a percentage reduction in costs for each doubling of cumulative capacity (industry-wide). For example, a PR of 90 percent indicates a 10 percent reduction in costs for each capacity doubling. Several studies have addressed the issue of future cost reductions for offshore wind energy.

Junginger et al. (2004) examined the potential for cost reductions related to specific elements of the initial investment costs associated with offshore wind farms and arrived at the conclusion that these costs could decline by 25 to 39 percent by 2020. This reduction reflects the cumulative effect of (1) potential reductions in wind turbine costs (at a PR of 81 to 85 percent); (2) the potential increased use of high voltage direct current (HVDC) cables to transmit electricity to the onshore grid from more distant offshore locations (at a PR determined to be 62 percent); (3) reductions in the cost of HVDC converter stations (PR equal to 71 percent); and (4) reductions in the costs of tower and foundation installations (PRs of 77 and 95 percent, respectively).

Junginer et al. (2005) also used data from the United Kingdom and Spain to create a global experience curve for wind energy (onshore and offshore), in which the focus was on total project costs rather than just the cost of the wind turbines. The results of their analysis suggest a global progress ratio in the range of 77 to 85 percent, with an average of 81 percent. The authors note, however, that development of a global ratio carries with it certain limitations. For example, while a global market for wind turbines exists, other components may depend more highly on local factors that give rise to different, location-specific learning effects.

Coulomb and Neuhoff (2006) used an engineering-based model to examine cost changes as a function of turbine size using 1,500 individual observations from the period 1991 to 2003. After incorporating a correction for the fact that larger turbines produce more energy per installed megawatt, they concluded that wind turbine costs have decreased by 12.7 percent with each doubling of capacity.

Other than Junginger et al. (2004), most examinations of cost reductions of wind energy do not focus exclusively on offshore development. As Garrad Hassan (2003) note, several factors must be considered before applying PRs based on onshore experience to offshore projects, including: the marine-based cost elements that do not apply to onshore wind; the relative immaturity of some offshore cost elements, suggesting that initial cost reductions may be more rapid than the current onshore PR would suggest; and the larger scale of offshore wind projects.

A recent study of the costs of offshore wind energy (ODE 2007) suggests there is ample room for cost reductions. Using a "typical" 108 MW (30 x 3.6 MW) project as its base, the ODE model predicts a two to three percent capital cost increase through 2010 followed by a reduction of up to 30 percent by 2018, at which point costs begin to plateau. ODE further predicts a reduction in operation and maintenance (O&M) costs from the current expectation of approximately 23 percent of capital costs, though it does not specify the magnitude or timing of the anticipated reduction.

For this analysis, we developed projections for wind energy capital costs over time for projects of varying sizes based on the assumption that larger projects will always exhibit economies of scale and that learning effects will reduce all costs over time. First, we used cost data for the 108 MW project described in the ODE (2007) report and for two projects (30MW and 200 MW) described in a report prepared for the State of Rhode Island (ATM 2007) to construct a trendline for projects between 100 MW and 1,000 MW. We then assumed three doublings of global capacity between 2008 and 2018 with a conservatively estimated 10 percent reduction in costs for each doubling. We believe this capacity growth trend is reasonable given the number and scale of projects currently in development in Europe. Table 2-3 presents the results of our analysis for the three size classes that we use in our forecast.

Table 2-3
Assumed Capital Costs (per kW) for U.S. Offshore Wind Energy (2007$)[10]

Period	Project Size (MW)		
	150	**500**	**1000**
2008 - 2011	$3,200	$2,700	$2,100
2012 - 2015	$2,900	$2,400	$1,900
2016 - 2019	$2,600	$2,200	$1,700
2020 - 2027	$2,300	$2,000	$1,500

2.3.2 Wave

Given its relative immaturity and lack of development to date, far less work has been undertaken to project cost trends for wave energy technologies. However, it can be expected that they will eventually follow trajectories similar to those that have reduced the costs of onshore and offshore wind. Bedard (2007) suggests that the progress ratio for wave energy technology will be 82 percent and that a 90 MW Pelamis project with a 38 percent capacity factor could achieve economic competitiveness with onshore wind at cumulative global capacities of 15 GW (for a Hawaii or northern California location), 20 GW (for an Oregon location), or 40 GW (for a Massachusetts location).

Gumerman and Marnay (2004) describe an approach for considering learning-based cost reductions associated with initial commercialization of new technologies. The first units of such technologies often cost more than anticipated, resulting in the need to assign a "technological optimism factor" (TOF), or cost premium, to these units. Technological optimism learning is the process by which this factor is eventually eliminated. As Gumerman and Marnay describe, the National Energy Modeling System (NEMS) has previously applied TOFs of five to ten percent to four technologies (fuel cells, biomass, solar thermal, and photovoltaics), with the premium eliminated upon construction of the fifth commercial plant. A similar trend might be expected for the first commercial wave and ocean current plants.

Total capital costs for wave energy projects will certainly vary by technology. However, the only reliable estimate we have for wave energy capital costs comes from EPRI's assessment of a hypothetical commercial-scale project off the Oregon coast (Previsic 2004b). This analysis

[10] Note that capital cost data for both wind and wave power were collected in 2007 and are therefore presented in 2007 dollars.

assumes an array of 180 Pelamis units with a total rated capacity of 90 MW. The total installed cost for this project is calculated to be approximately $215 million, indicating a unit cost of approximately $2,400 per kW. We propose to use this value as a base and apply Gumerman and Marnay's as well as Bedard's learning assumptions (i.e., an initial premium, in our case an assumed initial capital cost of $2,600, followed by subtraction of the premium and then an 18 percent cost reduction for each additional doubling of capacity) to estimate future capital costs. We do not have estimates of global wave energy capacity growth that would allow us to predict when capacity doublings might be achieved, and therefore must make what we believe are reasonably conservative assumptions. Table 2-4 provides our assumed capital cost schedule, which reflects three doublings during the period of analysis.

Table 2-4
Assumed Capital Costs for U.S. Offshore Wave Energy (2007$)

Period	Capital Cost ($/kW)
2008 - 2011	$2,600
2012 - 2015	$2,400
2016 - 2019	$1,970
2020 - 2023	$1,615
2024 - 2027	$1,325

2.3.3 Ocean current

We are not aware of readily available data describing capital costs or anticipated cost reductions for ocean current energy. We therefore assume costs equal to those described above for wave energy.

2.4 Renewable energy economics

Readily available information does not provide estimates of the point at which wind, wave, or ocean current technologies will be "economically deployable." As with any power generation technology, offshore renewables will be economically competitive when they can produce electricity at a cost that is less than or equal to onshore alternatives. Thus, competitiveness will be driven by factors that reduce the cost of electricity from offshore renewables and/or increase the cost of electricity from the onshore alternatives. As discussed above, the former includes capital and O&M cost reductions resulting from learning, economies of production scale, and research and development of advanced (lower cost) technologies, as well as government interventions (i.e., subsidies) that effectively lower the cost of electricity. Factors that can increase the costs of onshore alternatives include rising fuel costs and government actions. The economic competitiveness of offshore renewables is highly project- or location-specific. With subsidies, offshore renewable energy projects (particularly wind energy projects) can already be competitive, in general, when they are feeding into markets with relatively high electricity prices.

As described later in this report, we used a cash flow model, constructed for the purpose of estimating payments to the Federal government under the terms of the proposed regulations, to assess, based on selected performance criteria, whether or not a project should be considered economically feasible.

2.5 Renewable energy capacity expansion

Readily available information does not provide annual or semi-annual estimates of renewable energy generation capacity expansion on the OCS. For context, however, several sources discuss the overall potential for capacity growth in the near- to medium-term.

- Garrad Hassan (2003) projected the annual and cumulative growth of offshore wind energy capacity on a global basis, with cumulative capacity approaching 43 GW by 2020. During this period, Garrad Hassan assumed annual installations would increase each year, from 0.8 GW in 2004 to 8.9 GW in 2020.

- The European Wind Energy Association (2006) has established targets for the development of onshore and offshore wind energy in Europe. The current targets for cumulative offshore wind energy are 10 GW by 2010, 70 GW by 2020, and 150 GW by 2030.

- Musial et al. (2006) described a "moderately aggressive development scenario" that could result in the development of 50 GW of offshore wind energy capacity in the United States by 2026 (including development in OCS and non-OCS areas), with additional development resulting in another 50 GW of capacity by 2036. Based on personal communication with Musial, we believe it is reasonable to assume that approximately one-half of the offshore wind energy capacity development over the next 20 years (i.e., 25 GW) will occur in OCS areas.

In addition, EPRI ocean energy experts have developed an "optimistic" scenario for wave energy capacity development in the United States, resulting in approximately 15 GW of new capacity by 2020 (Table 2-5; Bedard 2007).

Table 2-5
EPRI "Optimistic" Forecast of U.S. Wave Energy Capacity Development

Year	Annual (MW)	Cumulative (MW)
2008	3	3
2009	1	4
2010	80	84
2011	130	214
2012	300	514
2013	500	1,014
2014	800	1,814
2015	1,200	3,014
2016	1,700	4,714
2017	2,500	7,214
2018	2,600	9,814
2019	2,600	12,414
2020	2,600	15,014

Source: Roger Bedard, EPRI, personal communication, April 16, 2007.

However, it is important to note that, according to Bedard, a significant amount of this development is forecast to occur in Alaska and Hawaii and in nearshore (non-OCS) waters, suggesting much less development that would be subject to MMS regulation.

We are unaware of any forecasts of the growth of ocean current energy over the next 20 years.

2.6 Integration of OCS electricity generation into transmission networks

During the period of analysis, the most significant transmission-related issues will be those associated with the development of offshore wind energy capacity, given both the scale of potential projects and their potential distance from shore. At approximately 20 percent of total project costs (exceeded only by turbine and support structure costs), the ability to collect electricity from multiple offshore wind turbines and transmit that electricity to the onshore grid cost-effectively will be an important determinant of the pace of future development.

Wright et al. (2002) note that the United States' substantial experience laying submarine cables is not directly applicable to offshore wind farms; oil and gas platforms, for example, require much lower voltage power, while providing electricity to an island from an onshore source utilizes medium- to high-voltage cables that only deliver power *to* a load rather than *from* a source of generation. In addition, they noted the lack of domestic manufacturers of high-voltage cable and, in comparison to Europe, the relative lack of experience and equipment for cable installation. We assume that the market would address these issues given sufficient and sustained growth in offshore wind energy, and that gains in experience would benefit other forms of offshore renewable energy as well.

Green et al. (2007) provide a simple model of the cost and performance of offshore wind farm electrical (i.e., collection and transmission) systems. Addressing the issue of alternating versus direct current transmission to shore, they note the current consensus that high voltage alternating current (HVAC) will be preferred on economic grounds up to a transmission distance of 50 km, while high voltage direct current (HVDC) will not be consistently more cost-effective before transmission distances reach at least 80 km. Between 50 and 80 km, the costs of HVAC and HVDC are expected to be comparable. Wright et al. suggest that HVDC's economies of scale will make it the preferred option as projects exceed 200 MW and at least 50 km from shore, and that the prospect of large, inter-regional offshore HVDC networks might eventually serve as cost-effective "substations" for offshore wind. Finally, Green et al. note that current cable designs may prove inadequate for use with floating wind turbine platforms, as they are not designed to withstand the various forces that will act on them if they are not laid on, or buried in, the seafloor. This could also be a concern for wave and ocean current energy projects.

2.7 Conclusions

The purpose of our review of readily available information was to determine whether, and if so how, this information should factor into the project development forecast that serves as the foundation for the fiscal impact analysis. The forecast must specify the number, type, size, and general location of OCS projects that are submitted for MMS review or that become operational during the period 2008 through 2027. In reality, the number, type, size, and location of OCS alternative energy projects will be driven by economic considerations. Our preliminary forecast is based on non-economic considerations—that is, it considers what might be reasonable given presumed physical and technical constraints. As described in Section 4, we use a financial model to determine whether each project in the preliminary forecast appears to be economically viable (given the assumptions used in the model).

Based on our review of available information as well as conversations with Roger Bedard (EPRI) and Walt Musial (NREL), we drew several conclusions to carry forward to the specification of a preliminary OCS development forecast, which we constructed in two parts. The first part describes projects that would become operational by 2027. The second part covers projects that would become operational after 2027, but would be in development during the 2008-2027 period. The following are assumptions relevant to the construction of the first part of the forecast.

- Offshore wind energy will dominate OCS development activity, both in terms of projects and generating capacity.

- The significant majority of offshore wind development will occur in the Atlantic region. Development in the Gulf of Mexico will likely be focused on Texas State submerged lands in the near term (given the 3 marine league, or 9 nm, State submerged land boundary). Gulf of Mexico wind projects begin to appear in the later years of the forecast to reflect the long-term potential for deeper-water projects that are further from shore. In the Pacific region, where shallower water depths extend a relatively short distance from shore, development will likely focus in the near-term on smaller-scale demonstrations of floating support structure technology. Larger-scale, commercial projects could emerge in the Pacific region later in the period of analysis with the maturation of floating support structure technology. Several California offshore wind projects are included in the forecast to reflect this possibility.

- All wave projects will be located in the Pacific region; all ocean current projects will be located off the Florida coast.

- Assuming 25 GW of total capacity (see above) and an average of 500 MW per wind energy project (some may be as large as 1,000 MW+, but others will be in the 150-500 MW range), suggests a total of approximately 50 individual wind energy projects. [In comparison, the 15 projects granted development licenses in the UK Round Two offer average 478 MW each.]

- MMS provided IEc with an assumed ratio of project types (17 wind:3 wave:5 current) for use in forecast development. Using this ratio, 50 wind projects suggests development of nine wave projects and 14 ocean current projects during the period of analysis (a total of 76 individual projects).

- No other generation will occur until 2018, reflecting MMS consideration of new project applications beginning in 2009.

- A large number of projects will begin generation during the period 2019-2022, driven in part by an anticipated lease sale in 2012.

- Between 2023 and 2027, the rate at which new projects begin electricity generation will slow, reaching a steady state of three per year.

The post-2027 period includes three new projects per year for nine additional years, or 27 projects (for a total of 103 projects with some degree of development activity during the period 2008-2027). Maintaining the same ratio of project types, this suggests an additional 19 wind projects, three wave projects, and five ocean current projects.

We distributed the 103 projects in our initial forecast temporally and geographically over the 2008-2036 period using professional judgment and the above assumptions (the year to which each project is assigned indicating the year in which electricity generation begins). Wind projects were assigned a generic capacity of either 150, 500, or 1,000 MW. All wave projects that are assumed to become operational by 2027 were assigned a capacity of 75 MW, increasing to 150 MW from 2028-2036. All ocean current projects that are assumed to become operational by

2027 were assigned a capacity of 30 MW. Ocean current projects that are assumed to become operational between 2028 and 2036 were assigned capacities of 60 MW.

The resultant preliminary forecast is presented in Table 2-6. Table 2-7 categorizes the projects in the initial development forecast by type and region. Section 4 describes our methodology for selecting the hypothetical projects from among our initial forecast universe that warrant inclusion in the calculation of estimated Federal revenues and costs (a combination of a financial viability test and an assumed drop-out rate for non-financial reasons).

Table 2-6
Preliminary OCS Development Forecast, 2008-2036*

Year**	Location	Type	Capacity
2008	---	---	---
2009	---	---	---
2010	---	---	---
2011	---	---	---
2012			
2013	New England	Wind	500
	New York	Wind	150
2014	---	---	---
2015	---	---	---
2016	---	---	---
2017	Mid-Atlantic	Wind	150
	Mid-Atlantic	Wind	500
	Mid-Atlantic	Wind	150
	New England	Wind	500
	New England	Wind	150
2018	Mid-Atlantic	Wind	500
	New England	Wind	500
	New York	Wind	150
	New York	Wind	500
	Southeast	Wind	150
	California	Wave	75
	California	Wave	75
	Oregon	Wave	75
	Oregon	Wave	75
2019	Mid-Atlantic	Wind	150
	Mid-Atlantic	Wind	150
	Mid-Atlantic	Wind	500
2019	New England	Wind	500

Year**	Location	Type	Capacity
	Southeast	Wind	150
	California	Wind	150
	California	Wind	150
	Florida	Current	30
	Florida	Current	30
	Florida	Current	30
	Florida	Current	30
	Florida	Current	30
	Florida	Current	30
2020	Mid-Atlantic	Wind	150
	Mid-Atlantic	Wind	500
	New England	Wind	500
	New England	Wind	500
	New York	Wind	1,000
	New York	Wind	500
	Gulf of Mexico	Wind	150
	Oregon	Wave	75
	Oregon	Wave	75
	Florida	Current	30
	Florida	Current	30
	Florida	Current	30
2021	Mid-Atlantic	Wind	150
	Mid-Atlantic	Wind	500
	Southeast	Wind	150
	Southeast	Wind	1,000
	California	Wind	1,000
2021	California	Wind	500

Year**	Location	Type	Capacity
2021 (cont.)	California	Wind	500
	California	Wind	500
	Washington	Wave	75
	Oregon	Wave	75
	California	Wave	75
	Florida	Current	30
	Florida	Current	30
2022	Mid-Atlantic	Wind	500
	New England	Wind	500
	New England	Wind	150
	New York	Wind	1,000
	Florida	Current	30
	Florida	Current	30
	Florida	Current	30
2023	New England	Wind	1,000
	Gulf of Mexico	Wind	500
	Gulf of Mexico	Wind	1,000
2024	New England	Wind	1,000
	New England	Wind	500
	Mid-Atlantic	Wind	500
2025	Mid-Atlantic	Wind	500
	Mid-Atlantic	Wind	1,000
	California	Wind	500
2026	California	Wind	1,000
	California	Wind	1,000
	California	Wind	1,000
2027	Mid-Atlantic	Wind	1,000
	Southeast	Wind	1,000

Year**	Location	Type	Capacity
2027	Florida	Current	60
2028	Gulf of Mexico	Wind	1,000
	California	Wind	1,000
	California	Wave	150
2029	New England	Wind	1,000
	New York	Wind	1,000
	Florida	Current	60
2030	Mid-Atlantic	Wind	1,000
	Southeast	Wind	1,000
	Florida	Current	60
2031	Gulf of Mexico	Wind	1,000
	California	Wind	1,000
	Oregon	Wave	150
2032	Oregon	Wind	1,000
	Washington	Wind	1,000
	Florida	Current	60
2033	New England	Wind	1,000
	New York	Wind	1,000
	Florida	Current	60
2034	Mid-Atlantic	Wind	1,000
	Southeast	Wind	1,000
	California	Wave	150
2035	Gulf of Mexico	Wind	1,000
	California	Wind	1,000
	California	Wind	1,000
2036	California	Wind	1,000
	California	Wind	500
	California	Wind	500

* This forecast is not indicative of any Federal government preferences, plans, or intentions with regard to OCS alternative energy development. While the forecast represents one possible development path, a combination of market and government factors will ultimately determine the type, scale, and timing of actual activity.

** First year of electricity generation.

Table 2-7
Preliminary OCS Development Forecast by Project Type and Region, 2008-2036

	Atlantic	**Gulf of Mexico**	**Pacific**	**TOTAL**
Wind	48	6	16	**70**
Wave	0	0	14	**14**
Ocean Current	19	0	0	**19**
TOTAL	**67**	**6**	**30**	**103**

3.0 ESTIMATION OF FEDERAL GOVERNMENT COSTS IN THE BASELINE AND ALTERNATIVE

This section describes the calculation of estimated costs to the Federal government for the MMS program created by the proposed regulation, as well as the calculation of Baseline costs.[11] These costs are to be compared on an annual and cumulative basis to the estimates of Federal revenues that would be generated by the projects included in the 20-year development forecast (2008-2027). The cost estimates are based on data and guidance provided by MMS staff, as described below.

3.1 General approach

In the alternative cases, annual costs are based on MMS forecasts of the personnel that will be required for program activities, as well as per-project level of effort estimates for each position in the personnel mix and for each stage of a project's lifecycle. The level of effort estimates are expressed as fractions of annual full time equivalents (FTEs). The project lifecycle stages are divided into one-year increments. Costs are assigned to each position based on an assumed pay grade, specified by MMS, with a fixed indirect cost rate applied to total annual personnel costs. MMS also specified an annual cost of living adjustment (three percent) to use in determining future year costs.

MMS combined these data into cost templates for the periods 2008-2012 and 2013-2027. MMS's assumption in specifying these two periods is that a "learning" process will be taking place during the first several years of program activity, leading up to the anticipated 2012 lease sale, and that costs will be lower beginning in 2013. The two cost templates are presented in Tables 3-1 and 3-2. We mapped the templates to our project forecast to generate annual cost estimates driven by the number of projects determined to be "in process" in a particular year.

In addition to the level of effort templates, MMS specified additional program and other costs (such as lease sale preparatory work) that cannot be assigned to individual projects but that should be incorporated into an estimate of total costs. The following additional elements are included in the cost formulation:

- A Program Manager (one FTE per year, grade GS-15/05) and an Administrative Assistant (one FTE per year, grade GS-07/05) for general program oversight.

[11] The data provided to us focus on the review of alternative energy projects proposed for the OCS. Since we do not have separate information that describes the anticipated level of effort associated with review of projects that involve alternate uses of existing facilities, our estimate does not include the Federal government's anticipated costs to review these proposed activities. We expect that these costs will be significantly lower than the costs associated with alternative energy projects (based on the assumption that the overall level of activity involving alternate uses will be relatively low during the period of analysis). Nevertheless, exclusion of these costs results in an understatement of estimated total program costs.

Table 3-1
MMS Per-Project Cost Template, 2008-2012 (Fractions of Full-Time Equivalent)

POSITION	GRADE	YEAR													TOTAL FTE[2]	TOTAL ANNUAL COST
		1	2	3	4	5	6	7	8	9	10	(11)	(12)	11-13[1]		
		REVIEW SAP AND BEGIN INTERNAL REVIEWS	SAP DRAFT EIS	SAP FINAL EIS	DATA COLLECTION	DATA COLLECTION	DATA COLLECTION	REVIEW COP AND BEGIN INTERNAL REVIEWS	COP DRAFT EIS	COP FINAL EIS	CONSTRUCTION	CONSTRUCTION	CONSTRUCTION	OPERATIONS		
Biologist, Avian/Wildlife	GS-13/05	0.104	0.008	0.008	0.001	0.001	0.001	0.044	0.008	0.008	0.001	0.001	0.001	0.001	0.187	$155,739
Biologist, Fish/Benthic	GS-13/05	0.104	0.008	0.008	0.001	0.001	0.001	0.044	0.008	0.008	0.001	0.001	0.001	0.001	0.187	$155,739
Archeologist	GS-14/05	0.104	0.008	0.008	0.001	0.001	0.001	0.044	0.008	0.008	0.001	0.001	0.001	0.001	0.187	$184,032
Air Quality Specialist	GS-14/05	0.014	0.008	0.008	0.001	0.001	0.001	0.044	0.008	0.008	0.001	0.001	0.001	0.001	0.097	$184,032
Social Scientist/Economist	GS-14/05	0.104	0.008	0.008	0.001	0.001	0.001	0.154	0.008	0.008	0.001	0.001	0.001	0.001	0.297	$184,032
Oceanographer	GS-13/05	0.044	0.008	0.008	0.001	0.001	0.001	0.504	0.008	0.008	0.001	0.001	0.001	0.001	0.587	$155,739
CZM Specialist	GS-14/05	0.104	0.008	0.008				0.044	0.008	0.008					0.180	$184,032
GIS Specialist	GS-12/05	0.004	0	0				0.040	0.000	0.000					0.044	$130,966
Attorney	GS-14/05	0.004	0.012	0.016				0.004	0.012	0.016					0.064	$184,032
Geophysicist/Geologist	GS-13/05	0.044	0.008	0.008				0.044	0.008	0.008					0.120	$155,739
Engineer	GS-14/05	0.004	0	0				0.004	0.000	0.000	0.160				0.168	$184,032
Multi-Disciplinary/Various	GS-13/05	0.008	0.008	0.008				0.008	0.008	0.008					0.048	$155,739
Subtotal		**0.642**	**0.084**	**0.088**	**0.006**	**0.006**	**0.006**	**0.978**	**0.084**	**0.088**	**0.166**	**0.006**	**0.006**	**0.006**	**2.166**	

Notes:
SAP = Site Assessment Plan or equivalent; COP = Construction and Operations Plan or equivalent
1. Since construction times vary from one to three years (depending on project size), the start year of the operations phase varies by project.
2. Annual MMS costs during the 20-year operations phase are assumed to be constant. Accordingly, the total FTE calculation sums values through the construction phase, then adds 20 times the operating phase value.

Table 3-2
MMS Per-Project Cost Template, 2013-2027 (Fractions of Full-Time Equivalent)

POSITION	GRADE	YEAR											TOTAL FTE[2]	TOTAL ANNUAL SUPPORT COST
		1	2	3	4	5	6	7	8	(9)	(10)	9 to 11[1]		
		SAP DRAFT EIS	SAP FINAL EIS	DATA COLLECTION	DATA COLLECTION	DATA COLLECTION	COP DRAFT EIS	COP FINAL EIS	CONSTRUCTION	CONSTRUCTION	CONSTRUCTION	OPERATIONS		
Biologist, Avian/Wildlife	GS-13/05	0.026	0.004	0.001	0.001	0.001	0.049	0.009	0.001	0.001	0.001	0.001	0.113	$155,739
Biologist, Fish/Benthic	GS-13/05	0.026	0.004	0.001	0.001	0.001	0.049	0.009	0.001	0.001	0.001	0.001	0.113	$155,739
Archeologist	GS-14/05	0.026	0.004	0.001	0.001	0.001	0.049	0.009	0.001	0.001	0.001	0.001	0.113	$184,032
Air Quality Specialist	GS-14/05	0.01	0.004	0.001	0.001	0.001	0.029	0.009	0.001	0.001	0.001	0.001	0.077	$184,032
Social Scientist/Economist	GS-14/05	0.01	0.004	0.001	0.001	0.001	0.029	0.009	0.001	0.001	0.001	0.001	0.077	$184,032
Oceanographer	GS-13/05	0.01	0.004	0.001	0.001	0.001	0.029	0.009	0.001	0.001	0.001	0.001	0.077	$155,739
CZM Specialist	GS-14/05	0.01	0.004				0.028	0.008					0.050	$184,032
GIS Specialist	GS-12/05	0.004	0				0.004	0.000					0.008	$130,966
Attorney	GS-14/05	0.008	0.008				0.008	0.008					0.032	$184,032
Geophysicist/Geologist	GS-13/05	0.01	0.004				0.028	0.008					0.050	$155,739
Engineer	GS-14/05	0.004	0				0.004	0.000	0.160				0.808	$184,032
Multi-Disciplinary/Various	GS-13/05	0.01	0.004				0.008	0.008					0.030	$155,739
Subtotal		**0.154**	**0.044**	**0.006**	**0.006**	**0.006**	**0.314**	**0.086**	**0.166**	**0.006**	**0.006**	**0.006**	**1.548**	

Notes:
SAP = Site Assessment Plan or equivalent; COP = Construction and Operations Plan or equivalent
1. Since construction times vary from one to three years (depending on project size), the start year of the operations phase varies by project.
2. Annual MMS costs during the 20-year operations phase are assumed to be constant. Accordingly, the total FTE calculation sums values through the construction phase, then adds 20 times the operating phase value.

- A Project Manager/NEPA Coordinator (one FTE, grade GS-14/05) for each project that has a Site Assessment Plan or Construction and Operations Plan under review.

- An Inspector/Engineering Tech function (grade GS-11/05) at 0.004 FTE for each operating plan that is approved in a given year.

- A total of $3 million per year for environmental assessments.

In the Baseline case, Federal government costs are limited to the cost of one Corps FTE per new wind energy project application. We assume no net cost for FERC activities in the Baseline case, since that agency offsets its costs through the collection of various administrative fees. For each position in the personnel mix, the product of the annual cost per person, the number of FTEs per project, and the number of projects in a given year serves as an estimate of the annual programmatic cost, with adjustments to account for general costs of holding the lease sale in the scenario and of program development, especially in the early years. The sum of these programmatic costs across all positions in the personnel mix, along with $3 million per year to approximate the costs of necessary environmental studies as the program develops and expands, is the estimate of the Federal government's total cost for that year. During the period 2008-2012, we also make the simplifying assumption that program development activities will remain constant and that variations in annual costs will reflect only the differing numbers of projects that are in process during a particular year. Finally, for the purpose of this analysis, MMS assumes that project developers will bear the costs of the necessary environmental impact statements (EIS), with the exception of the EIS for the single lease sale assumed to occur in 2012, and that MMS will review each EIS. We do not account explicitly for a developer's EIS preparation costs in our cash flow model. Project developers also will pay for some independent inspections, which will be reviewed by MMS. MMS will also conduct scheduled or random inspections or will hire third-party inspectors to do so.[12]

3.2 Discussion

For this analysis, personnel compensation plus indirect cost and program support cost add-ons are used to estimate an all-inclusive measure of future MMS programmatic costs. To the extent there are relevant program costs that are not incorporated into the indirect and program support factors, our estimate would understate the total program costs. In addition, we note the following factors that may result in either an over- or under-statement of future costs.

1. Although we estimate anticipated non-tax Federal government revenues associated with the development of OCS alternative energy projects, we estimate only those Federal government costs incurred by MMS, not those that will be incurred by other Federal agencies (e.g., the US Fish and Wildlife Service) responsible for additional

[12] At the time this report was completed, it appeared likely that the MMS inspection program would be more rigorous than originally assumed. However, given that no formal decisions have been made in this regard and that the specifics of the program remain unclear, the MMS costs do not include the additional spending that might be required.

reviews of project planning and development activities. Exclusion of these costs results in an understatement of estimated total Federal government costs.

2. The level of effort associated with the operational phase may be highly site-specific and subject to considerable variation (e.g., monitoring requirements at one site might be suspended based on the results of confirmatory monitoring conducted during the first years of operation, whereas continuous monitoring (and oversight) might be required for the life of another project).

3. Institutional learning could occur at a rate that differs from that assumed by MMS and could continue to occur throughout the period of analysis. A more pronounced learning effect would result in estimated total program costs lower than those we have calculated.

4. Some or all of the program review and management function could eventually move out of the MMS headquarters offices and into regional offices, where costs may be lower, on average. If this were to happen as the program matures, our estimate would likely be an overstatement of total program costs.

5. Some of the attorney cost associated with program activities will likely be incurred by the Office of the Solicitor within the Department of the Interior, rather than by MMS directly. This factor also may cause our estimate to overstate total MMS costs.

6. Initially, the cost of ensuring that all revenues from OCS alternative energy and alternate use leases and grants are accurately collected, and disbursed to appropriate recipients in a timely manner, would be covered by funding presently utilized for discretionary activities. Over time, additional funding would be required for MMS to manage alternative energy and alternate use revenues. In addition, if MMS were to base operating fees on actual generation of electricity, rather than on generation capacity, it would have to collect and examine contracts and implement an audit program. These costs are not accounted for in the analysis, and their exclusion results in a potential understatement of total program costs.

7. No costs are included for the management review and decision process. This should result in only a minor understatement of program costs.

4.0 ESTIMATION OF TRANSFER PAYMENTS TO THE U.S. TREASURY RESULTING FROM PROJECTS INCLUDED IN THE ALTERNATIVE ENERGY DEVELOPMENT FORECAST

The Excel cash flow model used to estimate payments to the Federal government incorporates both project-specific and general assumptions. The project-specific assumptions include technical details (e.g., size, capacity factor, capital and O&M costs, years to construct) as well as the initial value of financial incentives (i.e., the production tax credit (PTC) and renewable energy certificates (RECs), as appropriate) for each of the projects in the development forecast. General assumptions address factors such as regional electricity price forecasts and construction financing terms. In addition, the model incorporates financial assurance requirements as specified in the rule. The cash flow statement covers a project's lifetime, from pre-development through a 20-year period of electricity generation to decommissioning. Thus, the last project in the forecast begins operation in 2027 and operates through 2046. However for the purposes of this analysis, we only report the revenues and costs that are realized during the period 2008-2027.

In general, assumptions incorporated into the model reflect the electricity and alternative energy markets and policy landscapes as they existed at the time of the analysis. With one exception, we did not assume any market or policy changes that might provide an advantage or disadvantage to OCS alternative energy projects during the period of analysis. Furthermore, we assumed that any factor in place at the time of the analysis would remain in place throughout the period of analysis. The exception to this rule was an assumption that the Federal PTC would become available to wave and ocean current energy projects, in addition to wind energy projects, prior to the operational phases of the first projects of these kinds.[13] Title 26 – Internal Revenue Code, Subtitle A, Chapter 1, Subchapter A, Part IV, Subpart D, Sec. 45(a) and 45(d)(1), specifies that wind energy generators may claim the credit for a qualified facility during the 10 year period beginning on the date the facility was originally placed in service. The credit amount for 2007 was $0.02 per kilowatt-hour, according to the Internal Revenue Service's Internal Revenue Bulletin 2007-21, Notice 2007-40, published on May 21, 2007.

As part of our examination of the cash flow for projects in the preliminary development forecast (given model assumptions), we applied specific, internal rate of return (IRR)-based criteria (as specified by MMS) for the evaluation of economic viability. Below an IRR of five percent, we assumed that the project might be proposed but would not formally enter the pre-development phase, and thus would result in minimal Federal costs and no Federal revenues. For projects that exhibited an IRR equal to or greater than five percent but less than 11 percent, we assumed that some pre-development activity would occur but that construction and operation of the project

[13] In April 2008, the U.S. Senate approved, as part of H.R.3221 – "Foreclosure Prevention Act of 2008", an extension of the Federal production tax credit through January 1, 2010, that would make the tax credit available for marine hydrokinetic technologies, including wave, current, and tidal energy. A similar bill is currently under consideration in the House of Representatives. While there remains uncertainty that this bill will be enacted, it is not unreasonable to assume that future Congressional action will expand and extend the tax credit.

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would not. In these cases, we calculated and recorded Federal revenues and costs associated only with the predevelopment period. We calculated and recorded all Federal revenues and costs for the projects with an IRR greater than or equal to 11 percent. Table 4-1 presents the effect of applying our economic viability screen to the projects in each of the three payment cases. Tables 4-2 through 4-4 present the screening results for wind (by size category), wave, and ocean current energy projects, respectively. Notable results from this analysis include:

- The initial development forecast comprised 76 projects that would begin construction before 2027, the last year of the period of analysis. We evaluated the financial viability of each project and found that 58 of the 76 might be considered viable under the payment requirements of the Baseline (no payments), Low and Intermediate cases. In fact, the categorization of wind energy projects by IRR does not vary between payment cases, with the exception of three 500 MW projects that drop below an 11 percent IRR in the High case.[14] This analysis implies that the magnitude of MMS payments under the assumed cases should not have a significant influence on decisions to invest in lease development on the OCS.

- For wind energy projects, in all cases, half of the 150 MW projects have an IRR greater than or equal to 11 percent, whereas a significant majority of the larger projects clear this rate.

- Of the nine wave energy projects included in our 2008 to 2027 forecast, none clear the lower hurdle rates due to their location exclusively in the Pacific region, particularly the Pacific Northwest, which in our model is a low electricity price market (driven by the presence of large, lower cost onshore hydroelectric resources). Wave energy projects developed over the next 20 years might be more economically viable in nearer-shore environments that are subject to State rather than MMS jurisdiction.

- In contrast, all of the 15 ocean current projects included in the 2008 to 2027 forecast have IRRs greater than or equal to 11 percent, primarily because of their relatively high capacity factors (80 percent compared to 38 percent for wind and 35 percent for wave).

- For the Intermediate case, we found that the number of viable projects modeled in the development forecast would drop from 58 to 43 without revenue from the sale of RECs. It is reasonable to assume, therefore, that the establishment and maintenance of renewable portfolio standards by coastal states would be essential to the economic success of many OCS projects. Section 5.0 includes more discussion on the sensitivity of project finances to REC revenue, electricity prices, and other assumptions for financing, generation and costs.

[14] The three projects in question are hypothetically placed in the California market with electricity production beginning in 2021. The calculated IRR is marginally below the 11 percent threshold at approximately 10.6 percent. In comparison, an identically sized project in the Mid-Atlantic region that hypothetically begins operation in the same year has an IRR over 15 percent in the High case. Since the model assumes the same REC price for both regions, the difference in IRR is explained solely by difference in projected electricity prices (which are generally lower in California).

Table 4-5 presents the total installed electricity capacity by technology for those projects that are forecast to be constructed before 2028. Installed capacity figures estimated for each technology correspond to the number of projects determined to be financially viable; that is, those projects with an IRR greater than or equal to 11 percent. For example, as shown in Table 4-2, the total estimated wind project installed capacity of 25,200 MW in the Baseline, Low, and Intermediate cases includes eight projects with nameplate capacities of 150 MW, 22 projects with nameplate capacities of 500 MW, and 13 projects with nameplate capacities of 1,000 MW. For project-specific information on electricity generation and financial performance for each payment case, see Appendix B.

We also analyzed the effect that elimination of the present Federal PTC could have on the viability of the wind, wave and current projects evaluated. We estimated that if the PTC were not extended beyond its current expiration date of December 31, 2008, only 33 of the 76 projects might have IRRs of greater than or equal to 11 percent, regardless of the payment case analyzed. The difference in the number of projects constructed, 25 fewer than the 58 viable for the Baseline, Low and Intermediate cases, may be less if a change to economic conditions creates a benefit approximately equivalent to the PTC. We concluded that project viability is more sensitive to the availability of the PTC benefit than REC benefits, or any of the fiscal requirements assumed in the payment cases. Section 6.0 provides results from this part of the analysis.

The MMS further reviewed 12 of the 25 projects that might not be constructed without the PTC, to discern how much the MMS payments could detract from the value of the PTC. Specifically, the value of MMS payments relative to the PTC value was calculated as a percentage: 1) for the 10 years that the PTC would be in effect for each project, and 2) over the life of each project. Lease interests would discount the values at private rates and the government would discount with social rates. To simplify presentation of the results here, percentages were calculated with undiscounted nominal dollar values. Results show that the value of MMS payments relative to the PTC value for the 10 years that the PTC would be in effect for each project ranged from of 4.5 to 6.5 percent. Percentages calculated using the total of all payments made to MMS over the life of the project, divided by the total value of the PTCs over the 10 years following the date that a project is placed in service, ranged from about 11.0 percent to 14.5 percent. The second set of percentages is higher than the first set because payments made before and after the 10 year PTC period are considered. The MMS recognizes that the alternative energy program payment requirements would effectively lower the value of the PTC. However, the payment cases analyzed would not reduce the value of the PTC by a significant amount. Of greater importance, this analysis seems to imply that the elimination of the requirement to make payments to MMS might not increase the rate of alternative energy development on the OCS.

As a final step before calculating annual and cumulative Federal revenues and costs, it would also be appropriate to assume that some percentage of "viable" projects would not reach the construction and operations stage due to reasons other than projected economic performance (e.g., MMS rejection of an application on technical grounds). In our analysis, we did not further reduce the number of projects on this basis due to our inability to define a credible rule for selecting the projects that would not proceed.

We did not complete cash flow analyses for, and thus did not apply the IRR test to, projects that are assumed to begin operations after 2027 (but that result in Federal revenues and costs during a pre-2028 development period). Rather, we simply assumed that the projects assigned to this period (the 27 that increase the preliminary forecast from 76 to 103 projects) would proceed through the pre-operational period. Since Federal revenues and costs associated with the operational phase of these projects would not figure into our results (as they would occur after 2027), it is unnecessary to undertake a complete cash flow analysis. In making this decision, we also recognized that the already considerable uncertainty associated with key model inputs, such as electricity prices, would border on pure speculation if we were to try to estimate values more than 20 years into the future.

Finally, we note that the treatment of Federal taxes, though not recorded as a source of government revenue in this analysis, is an important factor in the cash flow model's assessment of project viability.[15] In our model, we assume that renewable energy project developers would be able to apply net operating losses from a wind, wave, or ocean current energy project against income from other sources. We apply the reduced tax obligation on this income as a benefit to the renewable energy project. This accounting method is not intended to show how a taxpayer would complete a tax return; we apply it for analytical purposes only.

Table 4-6 lists and describes key cash flow model inputs. (Appendix A provides a more detailed description of the cash flow model.) Table 4-7 presents the terms of the three payment cases (Low, Intermediate, and High), as defined by MMS, that the cash flow model simulates. In each of the cases, rental payments would be required prior to the construction and operation of a generation facility. In the Intermediate and High cases, MMS would charge an annual operating fee during the construction and operations phases. In the Low case, a rental payment would substitute for an operating fee during construction and operations.

Table 4-1

Results of Economic Viability Screening for Projects Operational by 2027

Payment Case	**Number of Projects**		
	IRR < 5 %	5 % ≤ IRR < 11 %	11 % ≤ IRR
Baseline	13	5	58
Low	13	5	58
Intermediate	13	5	58
High	13	8	55

Table 4-2

Results of Economic Viability Screening for Wind Projects Operational by 2027

Payment Case	**Rated Plant Capacity (MW)**	**Number of Projects**		
		IRR < 5 %	5 % ≤ IRR < 11 %	11 % ≤ IRR
Baseline	150	4	4	8
	500	0	1	22
	1,000	0	0	13
	Total	**4**	**5**	**43**
Low	150	4	4	8
	500	0	1	22
	1,000	0	0	13
	Total	**4**	**5**	**43**
Intermediate	150	4	4	8
	500	0	1	22
	1,000	0	0	13
	Total	**4**	**5**	**43**
High	150	4	4	8
	500	0	4	19
	1,000	0	0	13
	Total	**4**	**8**	**40**

Table 4-3
Results of Economic Viability Screening for Wave Projects Operational by 2027

Payment Case	Number of Projects		
	IRR < 5 %	5 % ≤ IRR < 11 %	11 % ≤ IRR
Baseline	9	0	0
Low	9	0	0
Intermediate	9	0	0
High	9	0	0

Table 4-4
Results of Economic Viability Screening for Current Projects Operational by 2027

Payment Case	Number of Projects		
	IRR < 5 %	5 % ≤ IRR < 11 %	11 % ≤ IRR
Baseline	0	0	15
Low	0	0	15
Intermediate	0	0	15
High	0	0	15

Table 4-5

Installed Capacity of Constructed Wind, Wave, and Current Projects Operational by 2027

Payment Case	Technology	Installed Capacity of Constructed Projects (MW)
Baseline	Wind	25,200
	Wave	0
	Current	480
	Total	**25,680**
Low	Wind	25,200
	Wave	0
	Current	480
	Total	**25,680**
Intermediate	Wind	25,200
	Wave	0
	Current	480
	Total	**25,680**
High	Wind	23,700
	Wave	0
	Current	480
	Total	**24,180**

Table 4-6
Description of Key Cash Flow Model Inputs

Category	Input	Value	Description/Rationale
Project Finance	Inflation rate	1.9 %	Based on the GDP Chain-Type Index in Table 19 of the EIA Annual Energy Outlook (http://www.eia.doe.gov/oiaf/aeo/aeoref_tab.html, accessed on June 7, 2007) and corroborated by the Congressional Budget Office's Economic Projections for the Calendar Years between 2007 and 2017 (http://www.cbo.gov/budget/econproj.pdf, accessed on June 6, 2007). The inflation rate is assumed to remain constant through the period of analysis.
	Debt financing rate	6.86 %	Based on direction provided by MMS, set at 1.5% above the 3-month LIBOR rate (as reported at http://www.bloomberg.com/markets/rates/index.html, accessed most recently on July 9, 2007).
	Construction loan rate	5.0%	While construction is occurring, a portion of construction loan funds are available for re-investment (i.e., when the loan is first secured, only a portion of the funds are accounted for in construction costs). Therefore, the construction loan rate is the debt financing rate adjusted downward to reflect a reasonable return on reinvested funds. At MMS's direction, we set this rate at 5.0%.
	Initial debt fraction	70 %	We assume a current debt:equity ratio of 70:30, reflecting the above average risk associated with offshore alternative energy projects. We assume a shift over time toward a more balanced split, similar to that associated with conventional power plant projects. Specifically, we assume a 63:37 ratio beginning in 2012, a 56:44 ratio beginning in 2017, and a 50:50 ratio beginning in 2022.
	Debt distribution	Varies over time	Our analysis assumes that all non-construction related costs incurred prior to the revenue generating phase are funded using term debt rather than equity. These additional costs include any financial assurance payments, as well as any fee payments to MMS. Consequently, debt will make up a larger fraction of the total project funds than indicated by the debt:equity ratio for that year.

Category	Input	Value	Description/Rationale
Project Revenues	Electricity prices	Varies by location	Average of on- and off-peak spot prices as reported in the FERC 2006 State of the Markets Report (http://www.ferc.gov/oversight, accessed on June 6, 2007). Prices in future years are estimated using a multiplier derived from a combination of inflation and a "price growth factor" (see 2007 EIA AEO Reference Case Table 8, "Prices by Service Category/Generation," available at http://www.eia.doe.gov/oiaf/aeo/index.html).
	Renewable energy certificate (REC) value	Varies by location	We calculated REC sales revenues for those projects associated with States or regions where a Renewable Portfolio Standard (RPS) has been enacted and has created or will create a market for RECs. We further assume that each RPS, and the ability to realize REC sales revenues, will remain in place throughout the period of analysis. Current RPS information comes from the Database of State Incentives for Renewable Energy (http://www.dsireusa.org/). Limited data are available to describe REC prices in those areas where markets exist. We relied upon a data summary found in the *Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2006* (http://www.nrel.gov/docs/fy07osti/41435.pdf, accessed on April 15, 2007) to determine the appropriate order of magnitude for REC prices in those regions where data exist (New England, Mid-Atlantic, Texas). Lacking additional information, we assumed that similar prices will apply to sales from projects associated with the California, Oregon, and Washington markets.
Project Characteristics and Costs	Capacity factor	Varies by technology	We used default capacity factors of 38 percent, 35 percent, and 80 percent for wind, wave, and ocean current projects, respectively.
	Area	Capacity-dependent	As a rule of thumb we assumed one square mile for each 25 MW of capacity. MMS leases are measured in nine square mile blocks (i.e., with a presumed capacity of 225 MW). Therefore, the areal extent (in lease blocks) of a project is determined by dividing planned capacity by 225. Since MMS only leases full blocks, all results are rounded up (e.g., a 500 MW project would be required to lease three full blocks, with an area of 27 square miles).

Category	Input	Value	Description/Rationale
Project Characteristics and Costs (cont.)	Construction duration	1, 2, or 3 years	Construction is assumed to occur in one year for projects with rated capacities less than or equal to 150 MW, in two years for projects with rated capacities greater than 150 MW but less than or equal to 500 MW, and in three years for projects with rated capacities greater than 500 MW.
	Installed capital cost	Varies by technology	For wind projects, the installed capital costs ($/kW) are assumed to vary by project size according to the schedule presented in Section 2. Estimated wave and ocean current capital costs are as described in Section 2. For each technology, learning is assumed to result in cost reductions over time.
	Operations and maintenance (O&M) costs	Varies by technology	For wind projects, a base O&M cost is from the estimate provided in ATM (2007), the recent Rhode Island offshore wind energy siting study. The O&M estimate for wave energy is taken from Previsic (2004b). Lacking technology-specific information, O&M for ocean current energy is assumed to be the same as wave energy. In all three cases, O&M costs are assumed to decrease over time, due to learning, at the same rate at which capital costs decline.
Financial Assurance Requirements	Preliminary site assessment-related decommissioning bond of $100,000	$5,000/year	Proposed regulation §285.515(a) requires that a bond of at least $100,000 be provided to ensure the availability of funds for decommissioning of any site assessment-related equipment. The $5,000 payment (an MMS estimate of the annual cost of obtaining the required bond) is levied prior to the start of the electricity generation phase.
	Operating term decommissioning account	Deposit calculated based on installed capital cost	The value of the required post-operations decommissioning deposit is calculated as seven percent of total capital costs inflated to the year after the last year of operations and then discounted at 4.75 percent (under the assumption that the deposit will earn interest at this rate during the operational period). Proposed regulation §285.527 would allow this type of financial assurance.
	Project easement decommissioning bond of $300,000	$15,000/year	Proposed regulation §285.520(a) requires that a bond of at least $300,000 be provided to ensure the availability of funds for decommissioning of cables and other infrastructure within the OCS easement. The $15,000 payment (an MMS estimate of the annual cost of obtaining the required bond) is levied throughout the operating period.

Table 4-7
Low, Intermediate, and High Payment Cases

Payment type	**Fiscal Terms**		
	Low	Intermediate	High
Minimum bid (competitive) or acquisition fee (non-competitive)	$0.25/acre	Same as Low case	Same as Low case
Lease rental	$3/acre/year for the duration of the lease	$3/acre/year for the preliminary and site assessment terms	$3/acre/year for the preliminary term and the first two years of the site assessment term; increases to $4/acre in site assessment years 3-4 and to $5/acre in site assessment year 5 and beyond
Easement rental	$5/acre/year	Same as Low case	Same as Low case
Operating fee	None	Installed capacity x 8760 hours per year x capacity factor x power price x fee rate, as follows: • 1 % during first two years* • 2% during remaining years of the operational term	Same as Intermediate through the first two years with subsequent fee rates of: • 3% during operational years 3-8 • 5% during operational years 9-15 • 10% during operational years 16 and beyond

Payment type	Fiscal Terms		
	Low	Intermediate	High
Additional operating fee	None	None	10% of REC-derived income beginning in operational year 16
* Note: A fee rate of 1 percent is used for the first two years of the operational term, the time period in which construction would occur. Construction time assumptions for projects evaluated in this analysis vary depending on project type and size. Wave, ocean current and 150 MW wind projects would be constructed in one year, 500 MW wind projects in two years, and 1,000 MW wind projects in three years. Projects constructed in one year benefit from the lower fee rate during the first year of generation. Electricity sales for each generating facility are assumed to occur over a period of 20 years.			

5.0 SENSITIVITY OF ANALYSIS TO KEY ASSUMPTIONS

The fiscal impact analysis presented in this report is subject to uncertainty due to data limitations and numerous assumptions made to estimate Federal revenues and costs associated with MMS's proposed rule. The analysis presented in this appendix assesses two factors of particular interest to MMS: the sensitivity of the results to assumptions regarding electricity prices and the impact on net Federal revenues of the project revenues derived from the creation and sale of renewable energy certificates (RECs). We also present an analysis of the sensitivity of results to assumptions regarding other model inputs.

5.1 Electricity Price Sensitivity Analysis

Prices drive both the financial feasibility of projects and the magnitude of operating fees, which are based on a fixed fraction of electricity sales revenues. This analysis measures the effect on net Federal revenues and project feasibility of adjusting prices across all regions and years simultaneously. We make no attempt to adjust the relative prices between regions, or to investigate how changes in the pattern of prices in future years may affect results.

Table 5-1 illustrates the relationship between (1) price level (where "0.0%" is the price used in the main analysis and "–50%" is 50 percent lower than that price), (2) the present value of cumulative net Federal revenues at a three percent discount rate, and (3) projects clearing the 11 percent hurdle rate and thus assumed to enter the construction phase. Three rows are highlighted in the table, corresponding to off-peak, on-peak, and average FERC prices. Off-peak and on-peak prices are roughly 20 percent below and above (respectively) the average prices used in our analysis. As observed in Table 5-1, if the analysis used off-peak prices, estimated net Federal revenues would be roughly 55 percent lower, and 18 fewer projects in our forecast would be constructed. On-peak prices would result in a 30 percent increase in net revenues and five additional projects in our forecast would be constructed.

Table 5-1
Effect of Electricity Price on Net Federal Revenues and Project Financial Feasibility

CHANGE IN PRICE LEVEL	3% DISCOUNT RATE (MILLIONS)			CHANGE IN NET REVENUES FROM FERC AVERAGE	PROJECTS CLEARING 11% HURDLE RATE
	Revenues	Costs	Net Revenues		
-50%	$115.7	$72.1	$43.6	-87.8%	30
-40%	$152.2	$73.5	$78.7	-78.0%	33
-30%	$195.1	$77.0	$118.0	-67.0%	37
FERC Off-Peak (-20%)	$245.1	$84.0	$161.2	-54.9%	40
-10%	$330.2	$85.5	$244.6	-31.5%	48
FERC Average	$444.1	$86.9	$357.2	0.0%	58
10%	$501.6	$88.2	$413.3	15.7%	61
FERC On-Peak (20%)	$552.0	$89.4	$462.6	29.5%	63
30%	$597.7	$91.9	$505.8	41.6%	64
40%	$651.3	$92.7	$558.5	56.4%	67
50%	$700.9	$93.3	$607.6	70.1%	71
60%	$750.0	$93.3	$656.6	83.8%	73
70%	$800.2	$93.4	$706.8	97.9%	74
80%	$849.7	$93.4	$756.3	111.8%	76
90%	$895.9	$93.4	$802.5	124.7%	76
100%	$942.0	$93.4	$848.6	137.6%	76

5.2 Sensitivity of Model Results to Inclusion of REC Payments

Rather than conduct a sensitivity analysis on a range of REC values, we create a scenario in which REC payments are reduced to zero. The resulting impacts vary across regions depending on the magnitude of assumed regional REC payments. Those regions with higher per kilowatt-hour payments, notably New England and New York, will be significantly affected relative to those areas with lower or negligible payments. Table 5-2 displays these prices as modeled. We note that the input values themselves are subject to considerable uncertainty given the limited amount of actual REC market data.

Table 5-2
Modeled REC Payments by Region

REGION	MODELED REC PAYMENT (PER KWH)
New England	$0.05
Mid-Atlantic	$0.005
New York	$0.03
Florida	$0
California	$0.005
Oregon	$0.005
Washington	$0.005
Southeast	$0
Gulf of Mexico	$0

Table 5-3 indicates that the number of projects constructed under the Intermediate No-REC scenario would be 43, 15 fewer than the scenario when REC sales are included in project revenue.

Table 5-3
Results of Economic Viability Screening for Projects Operational by 2027

Payment Case	Number of Projects		
	IRR < 5 %	5 % ≤ IRR < 11 %	11 % ≤ IRR
Baseline	13	5	58
Low	13	5	58
Intermediate	13	5	58
High	13	8	55
Intermediate–No REC	17	6	43

Table 5-4 shows the undiscounted results of this model run for the 2008 to 2027 period, alongside the Intermediate scenario for comparison. On an annual basis, the Intermediate-No REC scenario initially has higher net revenues than the Intermediate scenario because of lower management costs (without the REC, fewer projects clear hurdle rates); by 2027 the lack of REC revenues cause the No REC scenario to lag behind in net revenues by over $27 million. The present value of this stream of net revenues at a three percent discount rate is $225 million; at a seven percent discount rate the present value is $110 million. Under the Intermediate scenario, the present values at three and seven percent are $357 million and $190 million respectively, indicating that the presence of REC payments contributes a fairly significant percentage of the net Federal revenues modeled in our analysis.

Table 5-4
Net Federal Revenues 2008 to 2027 (Undiscounted) for the Intermediate-No REC Scenario

YEAR	INTERMEDIATE-NO REC (MILLIONS)			INTERMEDIATE (MILLIONS)
	Revenues	Costs	Net Revenues	Net Revenues
2008	$0.15	$6.27	-$6.12	-$6.34
2009	$0.32	$6.54	-$6.22	-$6.46
2010	$0.55	$6.64	-$6.09	-$6.32
2011	$1.03	$6.85	-$5.82	-$5.12
2012	$1.36	$7.01	-$5.65	-$4.68
2013	$1.71	$5.92	-$4.21	-$2.19
2014	$1.90	$5.78	-$3.88	-$1.44
2015	$2.01	$6.01	-$3.99	$0.41
2016	$2.28	$6.88	-$4.60	$3.08
2017	$6.26	$7.33	-$1.07	$9.37
2018	$14.42	$8.03	$6.39	$21.29
2019	$22.91	$6.93	$15.99	$34.51
2020	$38.66	$6.46	$32.20	$51.85
2021	$46.28	$6.30	$39.99	$63.30
2022	$58.99	$5.78	$53.21	$77.00
2023	$71.57	$5.79	$65.78	$90.67
2024	$78.76	$5.57	$73.19	$98.77
2025	$93.51	$5.86	$87.65	$113.82
2026	$100.25	$6.17	$94.08	$120.70
2027	$111.16	$5.88	$105.29	$132.43

5.3 Multivariate Analysis

Prices and REC payments are two of several variables that may influence model results. In this last component of our uncertainty analysis, we use an Excel-based program called Crystal Ball to identify those variables whose uncertainty may have the largest effect on model results.[16] Crystal Ball is a graphically oriented forecasting and risk analysis program that allows users to specify distributions for variables with uncertain magnitudes, and, using a Monte-Carlo type simulation, to assess the relative importance of each variable's uncertainty in estimating model outputs. In our context, the program is used to investigate the sensitivity of net Federal revenues (under the Intermediate payment scenario) to variation in uncertain model variables. In total, 15 variables are included in the Crystal Ball analysis; the uncertainty associated with these variables is described below.

[16] Crystal Ball Version 7.2.2, Decisioneering, Inc., Denver, Colorado.

Financial Variables

- **Debt Financing Share.** The debt/equity investment ratio is largely driven by the level of risk that debt and equity investors are willing to accept. Because offshore power projects are not yet an established market in the U.S., the response of investors is uncertain.

- **Debt Rate.** The debt rate was selected based on current bond rates. These rates will change in future years; however, whether these changes will be positive or negative is uncertain. As the cost of capital on these investment-intensive projects changes, the profitability of those projects will change as well.

- **Federal Tax Rate.** How the corporate Federal tax rate might change in future years is uncertain, but such changes may have pronounced effects on the Federal revenues estimated in this regulatory analysis.

- **Hurdle Rates (2 variables).** Internal Rate of Return (IRR) hurdle rates determine the number of projects that apply for construction permits and the number that initiate construction (currently set at five and 11 percent, respectively). These rates therefore directly influence Federal net revenues. Depending on the returns that equity investors demand, these values may be considerably higher than estimated.

- **Inflation.** Our analysis uses a point estimate for inflation of 1.9 percent. Although there are both historical precedence for and forecasts indicating the validity of this estimate, a wide range of factors may cause the inflation rate to change.

Project Revenue Variables

- **Electricity Price.** Although regional prices may be more certain than REC values, small shifts in this variable can have dramatic consequences on both Federal revenues (through changes in operations fees) and project profitability.

- **Production Tax Credits (PTCs).** Although PTCs are expected to be extended to future renewable projects (and expanded to include wave and current projects), it is uncertain whether such extensions will occur and whether the magnitude of the credit might change.

Technology-Specific Variables

- **Capacity Factors (3 variables).** The capacity factors for wind, wave, and current power were specified in the model based on existing information on the efficiency of onshore wind, offshore European facilities, and experimental wave and current facilities. Whether commercial scale operations in the U.S. will function at these levels is uncertain.

- **Installed Capital Costs and Annual O&M Costs (4 variables).** Both modeled installed capital cost and operations and maintenance costs for the three technologies are highly uncertain and based on limited information (particularly in the cases of wave and current power). Whether modeled values are underestimates or overestimates is unknown.

For each of the variables listed above, we develop a range of likely values under assumed probability distributions. Lacking greater information on the distributions of these variables, all variables have “triangle” distributions. Three points define a triangle distribution: a minimum value, a maximum value, and a likeliest value (here, the value used in our analysis). An example of a triangle distribution is illustrated in Figure 5-1. In this example, the probability that the debt financing share is either 40 percent or 80 percent is zero. As the share moves from these low and high estimates toward 60 percent (the approximate modeled value), the probability linearly increases, forming a triangle shaped distribution. If greater information indicating the distributions of these variables becomes available (e.g., indicating the actual underlying distribution is uniform or normal), the analysis can be adjusted accordingly.

Figure 5-1
Example of a Triangle Distribution

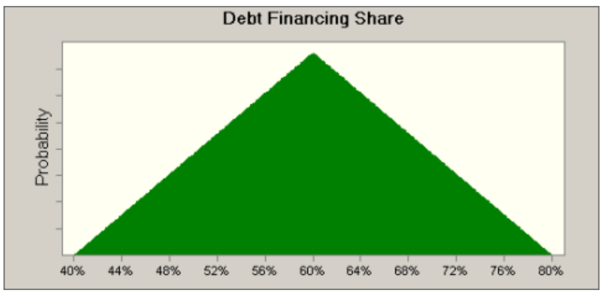


Table 5-5 summarizes the values used for the three points of the triangle distribution for each of the above variables. These ranges were developed using our professional judgment; this uncertainty analysis could be refined if additional information were available that more accurately characterizes the magnitude of variable uncertainty.

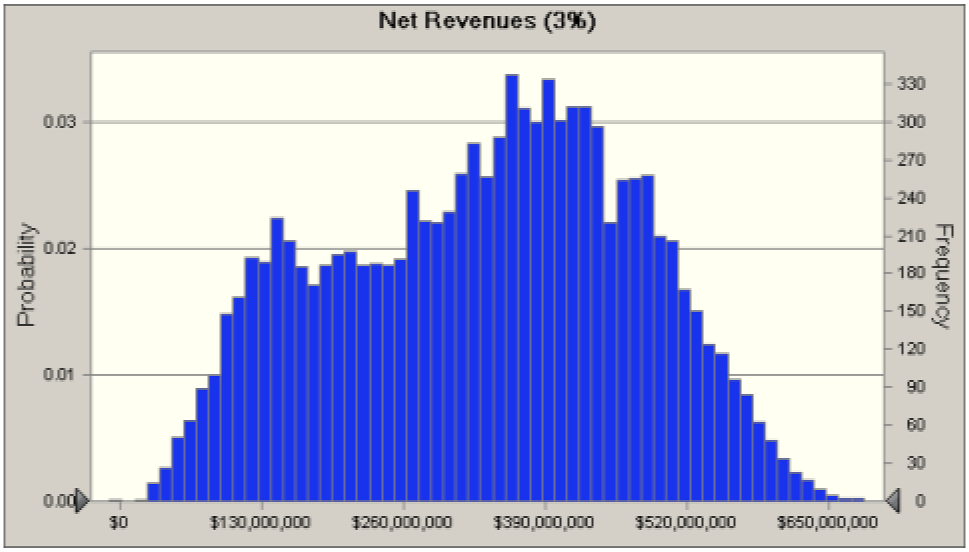
Table 5-5

Points Defining the Triangle Distribution of Uncertain Variables

ASSUMPTION	LOW ESTIMATE	LIKELIEST (REGULATORY ANALYSIS VALUE)	HIGH ESTIMATE
Financial Variables			
Debt Financing Share	40%	60%	80%
Debt Interest Rate	5.00%	6.86%	9.00%
Federal Tax Rate	30%	35%	40%
Lower Hurdle IRR	0%	5%	7%
Upper Hurdle IRR	7%	11%	15%
Inflation	1.0%	1.9%	4.0%
Project Revenue Variables			
Adjustment to Prices (per kWh)	-50%	0%	+50%
PTC Value (per kWh)	$0.00	$0.02	$0.04
Project-Specific Variables			
Wind Capacity Factor	0.33	0.38	0.43
Wave Capacity Factor	0.30	0.35	0.40
Current Capacity Factor	0.75	0.80	0.85
Average First Year Wind Installed Cost (per kW)	$2,267	$2,667	$3,067
Wave/Current First Year Installed Cost (per kW)	$2,200	$2,600	$3,000
Wind O&M (per kW-yr)	$50	$67	$80
Wave/Current O&M (per kW-yr)	$100	$127	$150

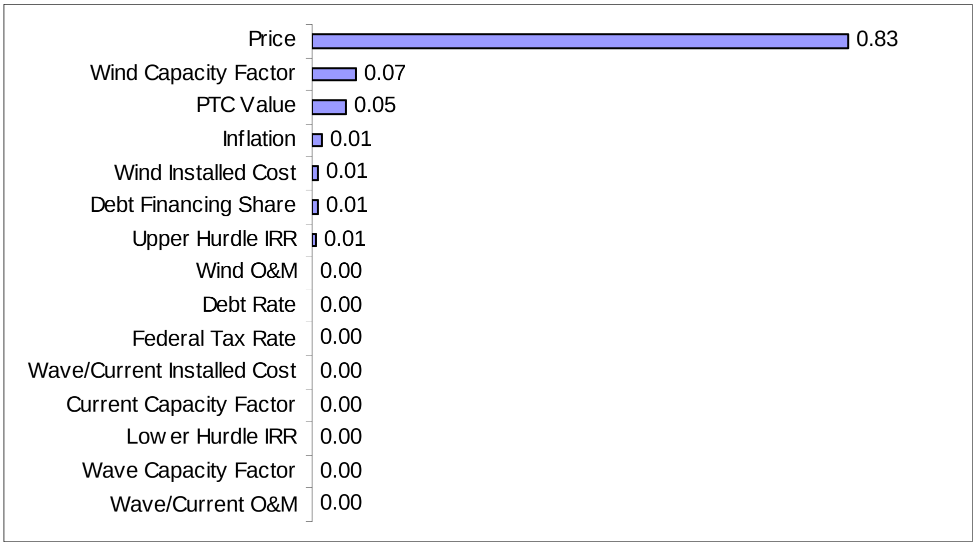
The ranges of values developed for each of these variables, as listed in Table 5-4, are used as inputs to the Crystal Ball analysis. This program runs Monte Carlo trials that consider all possible values within these designated ranges, with the assumed probability distribution influencing the value selected in each trial. For this uncertainty analysis, a total of 10,000 trials are run—each trial is independent and does not affect the outcome of other trials. As shown in Figure 5-2, the outcomes for all 10,000 trials result in a probability distribution of the net Federal revenues, at a discount rate of three percent. Net revenues under the Intermediate payment scenario from the regulatory analysis are $357 million, whereas the mean of the distribution below is roughly $333 million. The entire range of output values is from -$9.4 million to $681 million.

Figure 5-2
Probability Distribution of Net Federal Revenues (2008 to 2027) Given Variation of Assumptions, Discounted at 3 Percent, Variation in Price Included



To assess which variables influence the results most significantly, the simulation model provides sensitivity charts. Figure 5-3 shows a sensitivity chart ranking the uncertain variables listed in Table 5-4 according to their importance to the net Federal revenues estimated in our analysis (the values listed sum to one). Notably, variation in electricity price explains the majority (83 percent) of the variation in the discounted net revenues. Other significant parameters include the wind capacity factor, PTC value, inflation, wind installed cost, debt financing share, and upper hurdle IRR. Although not included in this sensitivity analysis, adjusting the operating fee or other MMS fees would result in commensurate changes to net revenues.

Figure 5-3
Sensitivity of Net Federal Revenues (Discounted at 3 Percent) to Model Assumptions, Variation in Price Included



Given the dominance of variations in price in the above sensitivity analysis, we reran Crystal Ball with price held constant to more closely investigate the sensitivity of net revenues to other parameters. As shown in Figure 5-4, the probability distribution of the discounted net Federal revenues without variations in price has a considerably narrower range (from $68 million to $463 million). Figure 5-5 shows the corresponding sensitivity chart; holding prices constant, variation in the wind capacity factor now explains 48 percent of the variation in net Federal revenues. For the remaining parameters, the pattern observed in Figure 5-3 is now magnified in Figure 5-5 to more clearly assess the relative importance of PTC value, inflation, wind installed cost, upper hurdle IRR, and debt financing share.

Figure 5-4
Probability Distribution of Net Federal Revenues (2008 to 2027) Given Variation of Assumptions, Discounted at 3 Percent, No Variation in Price

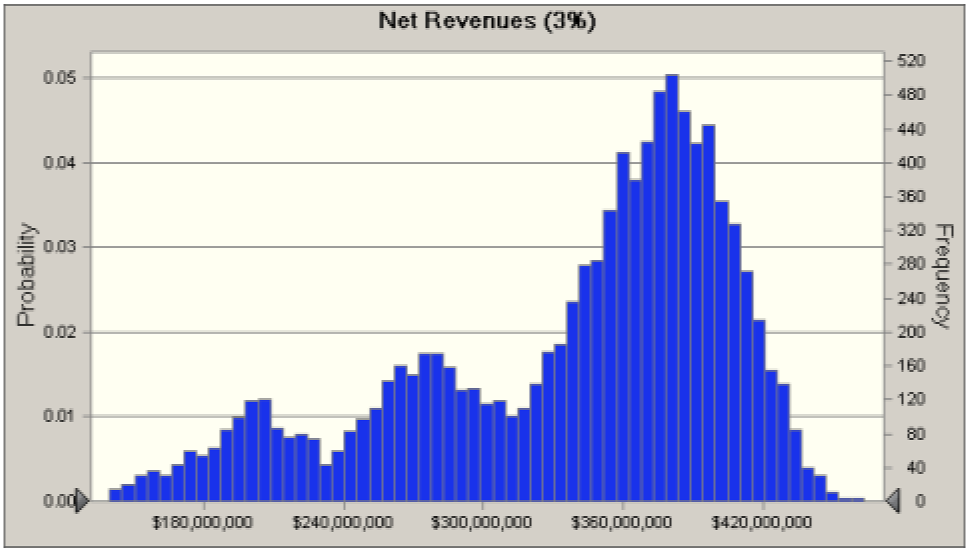
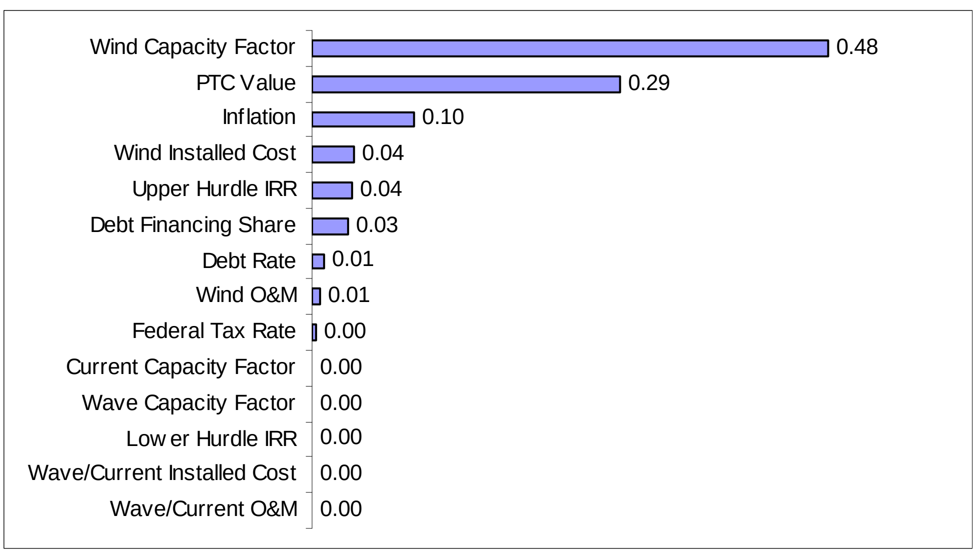


Figure 5-5
Sensitivity of Net Federal Revenues (Discounted at 3 Percent) to Model Assumptions, Variation in Price Not Included



6.0 IMPACT OF PRODUCTION TAX CREDIT ON PROJECT VIABILITY

Although Federal taxes are not included in the estimation of the net revenues attributable to the proposed rule, the analysis makes two important assumptions about tax policy that directly affect the viability of projects:

- The IRS will classify OCS wind, wave, and ocean current projects to allow an accelerated 5-year depreciation deduction.
- Congress will renew the inflation-adjusted renewable energy Production Tax Credit (PTC) so that it remains available throughout the period of analysis.

If either the accelerated depreciation allowance or the PTC were no longer available for future projects, the number of financially viable projects would decline, which would directly affect the net revenue results. Given the stop-and-start history of the PTC, it is a worthwhile exercise to evaluate the importance of the PTC to project viability within the model. Tables 6-1 through 6-5 present project performance results assuming that the PTC is not available. Table 6-1 presents the effect of applying our economic viability screen (discussed in Chapter 4) to the projects in the baseline and each of the three payment cases. Tables 6-2 through 6-4 present the screening results for wind, wave, and ocean current energy projects, respectively. Table 6-5 presents the production capacity by technology for those projects that are forecast to be operational between 2008 and 2027. Note that in our model the elimination of the PTC changes only the number of wind energy projects that are considered economically viable. No wave energy projects were viable even with the PTC, so eliminating the credit does not change the screening results, and all forecast ocean current energy projects continue to exhibit an IRR greater than 11 percent.

Table 6-1

Results of Economic Viability Screening for Projects Operational by 2027, No-PTC Scenario

Payment Case	**Number of Projects**		
	IRR < 5 %	5 % ≤ IRR < 11 %	11 % ≤ IRR
Baseline	29	14	33
Low	29	14	33
Intermediate	31	12	33
High	31	12	33

Table 6-2
Results of Economic Viability Screening for Wind Projects Operational by 2027, No-PTC Scenario

Payment Case	**Rated Plant Capacity (MW)**	**Number of Projects**		
		IRR < 5 %	5 % ≤ IRR < 11 %	11 % ≤ IRR
Baseline	150	12	2	2
	500	6	7	10
	1,000	2	5	6
	Total	**20**	**14**	**18**
Low	150	12	2	2
	500	6	7	10
	1,000	2	5	6
	Total	**20**	**14**	**18**
Intermediate	150	12	2	2
	500	7	6	10
	1,000	3	4	6
	Total	**22**	**12**	**18**
High	150	12	2	2
	500	7	6	10
	1,000	3	4	6
	Total	**22**	**12**	**18**

Table 6-3
Results of Economic Viability Screening for Wave Projects Operational by 2027, No-PTC Scenario

Payment Case	**Number of Projects**		
	IRR < 5 %	5 % $\leq$ IRR < 11 %	11 % $\leq$ IRR
Baseline	9	0	0
Low	9	0	0
Intermediate	9	0	0
High	9	0	0

Table 6-4
Results of Economic Viability Screening for Current Projects Operational by 2027, No-PTC Scenario

Payment Case	**Number of Projects**		
	IRR < 5 %	5 % $\leq$ IRR < 11 %	11 % $\leq$ IRR
Baseline	0	0	15
Low	0	0	15
Intermediate	0	0	15
High	0	0	15

Table 6-5
Installed Capacity of Constructed Wind, Wave, and Current Projects Operational by 2027, No-PTC Scenario

Payment Case	Technology	Installed Capacity of Constructed Projects (MW)	
		With-PTC (Table 4-5)	No-PTC
Baseline	Wind	25,200	12,300
	Wave	0	0
	Current	480	480
	Total	**25,680**	**12,780**
Low	Wind	25,200	12,300
	Wave	0	0
	Current	480	480
	Total	**25,680**	**12,780**
Intermediate	Wind	25,200	12,300
	Wave	0	0
	Current	480	480
	Total	**25,680**	**12,780**
High	Wind	23,700	12,300
	Wave	0	0
	Current	480	480
	Total	**24,180**	**12,780**

7.0 NET REVENUES ANALYSIS

In accordance with OMB guidance, we estimated the present value of cumulative net revenues in constant dollars for the Baseline, Low, Intermediate, and High payment cases assuming real discount rates of three and seven percent. These results were computed from project level nominal revenues which were aggregated annually for years from 2008 through 2027, then deflated and discounted as end-of-year cash flows back to 2008. Section 8(p)(2)(B) of OCSLA requires the distribution of 27 percent of fiscal revenues to the appropriate coastal states, when a project is located partially or wholly in the area extending 3 nautical miles seaward of state submerged lands. The revenue estimates reported for this analysis were adjusted assuming that 40 percent of the projects included in the development forecast would be subject to the revenue sharing provision.

Table 7-1 presents these results, as of January 1, 2008. At both three and seven percent, the present value net revenues are negative in the Baseline and Low payment cases and significantly positive in the Intermediate and High payment cases. Net revenues are negative in the Baseline because no fees exist to generate revenues for the Federal government, but inspection costs (under Corps management) are incurred for any projects that may be constructed. Table 4-7 summarizes the fiscal terms for the three payment cases. The estimated revenue flows to the U.S. Treasury vary considerably among the payment cases. In the Low payment case, which includes a project area-based rental fee, Federal revenues are consistently lower than costs between 2008 and 2027, resulting in negative discounted net revenues. In the Intermediate and High payment cases, the increase in net revenues is explained by the inclusion of capacity-based operating fees which are large in comparison to other proposed payments to the Federal government. The operating fees are calculated according to the following formula: **F** (annual operating fee in $ per year) **=** **M** (installed capacity in megawatts) x **H** (8760 hours per year) x **c** (a capacity factor defined as the actual production over a given period of time divided by the amount of power a facility would have produced if it had run at full capacity) x **P** (power price in $ per megawatt-hour) x **r** (the operating fee rate expressed as a fraction or decimal, similar to a royalty rate). When estimating revenues for the Intermediate payment case, operating fees are charged at a rate of one percent during the first two years of the operations term, and at a rate of two percent thereafter. In the High payment case, operating fees during the first two years of the operations term are still charged at a rate of one percent, but escalate to a rate of three percent for years three through eight, a rate of five percent for years nine through 15, and a rate of 10 percent thereafter.

Tables 7-2 through 7-5 present the undiscounted nominal streams of estimated annual Federal government revenues, costs, and net revenues for each case during the period 2008-2027. In the Baseline case, the Federal government does not collect any revenues but continues to incur costs associated with the oversight required by existing law and regulation (as described in Section 3, limited to Corps costs associated with wind energy projects). Note that in 2014 and 2015 we assume zero government costs based on the assumed lack of project construction activity during that two-year period (see Table 2-6). The Low, Intermediate, and High payment cases all exhibit a general pattern of increasing net revenues over the period of analysis, beginning with a period of negative net revenues. These negative net revenues largely reflect MMS costs associated with the first project applications in the years prior to the collection of any operating fee revenues, as well as programmatic costs (e.g., preparation for the anticipated 2012 lease sale) that are not expected to exist in later years. In the Low payment case, the program experiences a longer period of negative net revenues in comparison to the other cases, in part due to the lack of any operating fee revenues to offset costs in the years when the first projects begin generating electricity.

One additional result of note in the annual revenue and cost estimates is the large increase in net revenues in the Intermediate and High payment cases beginning in 2018. This increase is associated with the presumed 2012 lease sale, which would initiate development activity for a large number of projects, culminating in a surge in construction activity beginning in 2018. Since MMS begins collecting operating fees during the first year of project construction, revenues would increase accordingly.

Tables 7-6 through 7-8 report the present value of cumulative net revenues in constant dollars, by payment case, for each of the three technologies considered in the analysis (wind, wave, and ocean current energy). Tables 7-9 through 7-11 report the present value of cumulative net revenues in constant dollars, by case, for each of the regions considered in the analysis (Atlantic, Gulf of Mexico, and Pacific).[17] These results highlight the dominance of wind energy projects and the Atlantic region in the project forecast. Wind energy projects comprise approximately 70 percent of all projects in the development forecast and are, on average, much larger in generating capacity terms than wave or ocean current projects. In the Intermediate payment case, wind energy projects account for over 99 percent of cumulative net revenues, while Atlantic region projects account for more than 80 percent of cumulative net revenues. Although no wave projects are forecast to be constructed between 2008 and 2027 (see Table 4-3), wave projects have negative discounted net revenues in the Low, Intermediate, and High payment cases during that period. This result is attributable to the inclusion of three wave projects in our project forecast with construction occurring between 2028 and 2036. During the period of analysis (2008 to 2027), these three projects cost MMS more in pre-construction management expenses than they provide in pre-construction fees. The net revenues associated with ocean current projects under all payment cases are also negative. Compared to wind projects, current projects generate relatively low per project Federal revenues (due to their lower production capacities), whereas their per project Federal costs are very similar. As such, although these projects may be commercially viable, modeling results indicate that they do not contribute positive Federal net revenues in any of the payment cases.

[17] Due to rounding, the present value cumulative net revenue subtotals by technology and by region for each case do not sum to the overall present value cumulative net revenue totals.

Table 7-1
Present Value of Cumulative Net Revenues (Millions) in Constant 2008 $
All Projects, 2008-2027

Payment Case	**Real Discount Rate**	
	3%	**7%**
Baseline	-$9.33	-$7.78
Low	-$57.33	-$46.54
Intermediate	$357.18	$189.88
High	$537.68	$290.59

Table 7-2
Annual Revenues and Costs (Millions) in Undiscounted Nominal $
All Projects, Baseline Case

Year	**Revenues**	**Costs**	**Net Revenues**
2008	$0.00	$0.63	-$0.63
2009	$0.00	$2.54	-$2.54
2010	$0.00	$1.43	-$1.43
2011	$0.00	$1.11	-$1.11
2012	$0.00	$0.95	-$0.95
2013	$0.00	$0.48	-$0.48
2014	$0.00	$0.00	$0.00
2015	$0.00	$0.00	$0.00
2016	$0.00	$0.63	-$0.63
2017	$0.00	$0.32	-$0.32
2018	$0.00	$0.32	-$0.32
2019	$0.00	$0.48	-$0.48
2020	$0.00	$0.48	-$0.48
2021	$0.00	$0.48	-$0.48
2022	$0.00	$0.48	-$0.48
2023	$0.00	$0.48	-$0.48
2024	$0.00	$0.48	-$0.48
2025	$0.00	$0.63	-$0.63
2026	$0.00	$0.32	-$0.32
2027	$0.00	$0.32	-$0.32

Table 7-3
Annual Revenues and Costs (Millions) in Undiscounted Nominal $
All Projects, Low Payment Case

Year	Revenues	Costs	Net Revenues
2008	$0.16	$6.50	-$6.34
2009	$0.35	$6.82	-$6.46
2010	$0.58	$6.89	-$6.32
2011	$1.14	$7.14	-$6.00
2012	$1.47	$7.30	-$5.84
2013	$1.82	$6.10	-$4.28
2014	$2.01	$5.87	-$3.85
2015	$2.21	$6.13	-$3.91
2016	$2.65	$7.19	-$4.54
2017	$2.62	$7.58	-$4.97
2018	$2.86	$8.35	-$5.50
2019	$3.07	$6.95	-$3.88
2020	$3.31	$6.49	-$3.18
2021	$3.54	$6.33	-$2.80
2022	$3.77	$5.82	-$2.05
2023	$4.00	$5.83	-$1.83
2024	$4.23	$5.61	-$1.39
2025	$4.36	$5.90	-$1.54
2026	$4.24	$6.22	-$1.97
2027	$4.01	$6.03	-$1.93

Table 7-4
Annual Revenues and Costs (Millions) in Undiscounted Nominal $
All Projects, Intermediate Payment Case

Year	Revenues	Costs	Net Revenues
2008	$0.16	$6.50	-$6.34
2009	$0.35	$6.82	-$6.46
2010	$0.58	$6.89	-$6.32
2011	$2.02	$7.14	-$5.12
2012	$2.62	$7.30	-$4.68
2013	$3.91	$6.10	-$2.19
2014	$4.43	$5.87	-$1.44
2015	$6.54	$6.13	$0.41
2016	$10.27	$7.19	$3.08
2017	$16.96	$7.58	$9.37
2018	$29.65	$8.35	$21.29
2019	$41.46	$6.95	$34.51
2020	$58.34	$6.49	$51.85
2021	$69.64	$6.33	$63.30
2022	$82.82	$5.82	$77.00
2023	$96.49	$5.83	$90.67
2024	$104.38	$5.61	$98.77
2025	$119.72	$5.90	$113.82
2026	$126.92	$6.22	$120.70
2027	$138.36	$6.03	$132.42

Table 7-5
Annual Revenues and Costs (Millions) in Undiscounted Nominal $
All Projects, High Payment Case

Year	Revenues	Costs	Net Revenues
2008	$0.20	$6.50	-$6.30
2009	$0.40	$6.82	-$6.42
2010	$0.65	$6.89	-$6.24
2011	$2.12	$7.14	-$5.02
2012	$2.82	$7.30	-$4.49
2013	$5.28	$6.10	-$0.82
2014	$6.29	$5.87	$0.42
2015	$8.66	$6.13	$2.53
2016	$12.48	$7.19	$5.30
2017	$21.35	$7.58	$13.77
2018	$37.57	$8.35	$29.21
2019	$51.34	$6.95	$44.39
2020	$77.74	$6.49	$71.25
2021	$93.66	$6.33	$87.34
2022	$114.36	$5.81	$108.55
2023	$131.90	$5.82	$126.08
2024	$145.93	$5.60	$140.32
2025	$176.77	$5.89	$170.88
2026	$193.57	$6.21	$187.36
2027	$218.91	$6.02	$212.98

Table 7-6
Present Value of Cumulative Net Revenues (Millions) in Constant 2008 $
Wind Projects, 2008-2027

Payment Case	Real Discount Rate	
	3%	**7%**
Baseline	-$6.69	-$5.55
Low	-$38.52	-$32.23
Intermediate	$365.22	$198.17
High	$539.90	$295.67

Table 7-7
Present Value of Cumulative Net Revenues (Millions) in Constant 2008 $
Wave Projects, 2008-2027

Payment Case	Real Discount Rate	
	3%	**7%**
Baseline	$0	$0
Low	-$1.11	-$0.59
Intermediate	-$1.01	-$0.54
High	-$0.99	-$0.54

Table 7-8
Present Value of Cumulative Net Revenues (Millions) in Constant 2008 $
Ocean Current Projects, 2008-2027

Payment Case	Real Discount Rate	
	3%	**7%**
Baseline	-$2.41	-$2.09
Low	-$17.70	-$13.72
Intermediate	-$7.04	-$7.74
High	-$1.22	-$4.54

Table 7-9
Present Value of Cumulative Net Revenues (Millions) in Constant 2008 $
Atlantic Region Projects, 2008-2027

Payment Case	**Real Discount Rate**	
	3%	**7%**
Baseline	-$6.69	-$5.80
Low	-$47.64	-$39.30
Intermediate	$283.40	$151.81
High	$460.75	$251.41

Table 7-10
Present Value of Cumulative Net Revenues (Millions) in Constant 2008 $
Gulf Region Projects, 2008-2027

Payment Case	**Real Discount Rate**	
	3%	**7%**
Baseline	-$0.52	-$0.39
Low	-$2.27	-$1.73
Intermediate	$12.99	$6.47
High	$19.60	$10.02

Table 7-11
Present Value of Cumulative Net Revenues (Millions) in Constant 2008 $
Pacific Region Projects, 2008-2027

Payment Case	**Real Discount Rate**	
	3%	**7%**
Baseline	-$2.12	-$1.59
Low	-$7.42	-$5.51
Intermediate	$60.79	$31.61
High	$57.34	$29.17

8.0 QUALITATIVE ANALYSIS OF COSTS AND REVENUES ASSOCIATED WITH ALTERNATE USES OF EXISTING OCS FACILITIES

In addition to the promotion of alternative energy production on the OCS, other activities are anticipated by the EPAct amendments to the OCS Lands Act; namely the alternate use of existing facilities currently or previously used for activities authorized by the Act. MMS is establishing a regulatory program that will address alternative energy activities as well as energy- and non-energy related alternate use activities on the OCS. As part of its rulemaking process, MMS is undertaking a quantitative assessment of the revenues and costs of the proposed program with respect to alternative energy activities; an analysis made possible by MMS's ability to create a forecast of future alternative energy project development. The nature and scope of interest in alternate uses of existing facilities is less certain, making it difficult to analyze future revenues and costs quantitatively. Therefore, MMS is undertaking a qualitative analysis of these potential impacts.

8.1 Alternate Uses of Existing Facilities

As reported in the final Programmatic Environmental Impact Statement (EIS) for the Alternative Energy and Alternate Use Program, nearly 1,100 existing oil and gas platforms are expected to cease production over the next 15 years, creating, on paper, numerous potential opportunities for alternate uses. Historically, removal of retired platforms has comprised disassembly and onshore disposal of structural materials as scrap metal. A small percentage have been converted to artificial reefs (e.g., through the federal Rigs-to-Reefs program). While the reef program will continue, there may be interest going forward in one or more of the following alternate uses of some of these facilities (some of which may be possible while a platform is still operational).

8.1.1 Aquaculture

The large and growing demand for seafood, the substantial role of aquaculture as a supplement to native fisheries, and the fact that the best coastal locations for aquaculture are already developed suggest that moving aquaculture offshore may be an attractive opportunity. Use of the existing infrastructure offered by oil and gas platforms could expedite the growth of this sector. However, it should be noted that there are legislative proposals under consideration to establish a Federal regulatory program for offshore aquaculture activities that would be administered by the Department of Commerce. If such legislation were to become law, it is uncertain what regulatory role MMS would serve, and whether MMS jurisdiction under subsection 8(p) of the OCSLA would still be applicable. Accordingly, potential offshore aquaculture activities may eventually have no fiscal impacts in the context of this regulation.

8.1.2 Oil and gas support functions

A former oil and gas platform could serve to support the operations of existing or new platforms. A platform located at an intermediate location relative to multiple facilities further from shore could be used for fuel storage or as a supply depot, potentially reducing the cost of regularly transporting these materials offshore.

8.1.3 Education and research

Education or research institutions with a focus on the marine environment might be interested in establishing permanent or semi-permanent offshore facilities to advance their missions. Retired platforms might serve as cost-effective operational bases, particularly for activities that require extended stays at sea. As part of these activities, or independently, these facilities could also house various types of remote monitoring instrumentation (e.g., for military or homeland security purposes or for the collection of meteorological or other environmental data).

8.1.4 Desalination

If the need for, or opportunity to construct, a desalination facility were to exist in an area where siting such a facility might be difficult, an offshore platform (and associated pipelines) might serve as a suitable foundation for the construction of a desalination plant.

8.1.5 Telecommunications

As the offshore oil and gas industry becomes increasingly data intensive, with sophisticated techniques generating exploration and production information that must be transmitted to shore along with routine communications, offshore platforms that are no longer in use might be attractive as sites to locate centralized data and communications centers, or as links in larger communications networks.

8.1.6 Medical care

Offshore activities present numerous worker health and safety risks. Offshore platforms might therefore have a valuable alternate use as medical care facilities, especially if they were set up to provide emergency services for the stabilization of serious injuries prior to transfer to an onshore facility.

8.1.7 Leisure and recreation

The popularity of the coastal and marine environments for leisure and recreational activities suggests that an entrepreneur might see an offshore platform as an opportunity to develop a hotel or a staging area for shorter-term activities (e.g., scuba diving).

8.2 Potential Federal revenues

The types of revenues that alternate uses of OCS facilities could generate are similar to those associated with alternative energy projects, including rental and other payments to MMS for access to and use of the OCS. The scale of these revenues over the period 2008 to 2027 will be a function of how many alternate uses actually occur and whether they are of a type likely to compel MMS to seek rental or other payments. For example, purely commercial uses (desalination, leisure and recreation, etc.) might generate taxable income and would almost certainly require some form of payment to MMS, but the level of such activity during the period of analysis is likely going to be very low. As a result, revenue collections can be expected to be very low. Other types of uses, such as education and research or medical care, might be less likely to be required to make rental payments (and almost certainly would not generate taxable income or be subject to operating fee payments). This might be particularly true if the alternate use were in support of, and enhanced the value of, oil and gas-related activities. Overall, in contrast to the number of inquiries MMS has received regarding potential alternative energy projects on the OCS, the level of interest in alternate use activities has been extremely low. This, combined with the factors described above, suggests that federal revenues from alternate uses of OCS facilities will be relatively insignificant, at best, over the next 20 years.

8.3 Potential Federal costs

Federal programmatic costs attributable to alternate uses of OCS facilities will be a direct function of the level of activity. As with alternative energy projects, alternate use projects will require NEPA-compliant impact studies subject to MMS's review and approval. However, since the studies will not be assessing any significant new construction, it may be possible to build off of existing NEPA reviews of the original structures when the alternate use is not expected to result in a new or different impact. For example, a second archeological review of the site would likely be unnecessary in most if not all cases. This will serve to reduce program costs to some degree. At the same time, the first instance in which a particular alternate use is proposed may require closer scrutiny given MMS's lack of experience evaluating such a use. Over time, reviews of similar projects may occur more quickly (i.e., at lower cost) due to learning effects. In general, with relatively little expected activity, the costs are likely to be low.

8.4 Qualitative assessment of net fiscal impact

Whether revenues associated with any one project will exceed the program costs associated with the review of that project will depend on factors such as the project type and whether the same or similar projects have previously been proposed or approved (making it easier, and less costly, to review the project application). Non-commercial projects, such as educational or medical facilities, which are unlikely to generate significant, if any, Federal revenues might at best be subject to payments set at a level intended only to offset the Federal government's costs. Commercially-oriented projects are more likely to have a net positive impact (i.e., generation of revenues over the life of the project that exceed project-specific costs). The inability to evaluate whether the net fiscal impact of all alternate use projects that might occur over the next 20 years will be positive or negative is mitigated by the fact that, whatever the impact, it will likely be relatively small in the context of the net fiscal impacts of all projects contemplated under subsection 8(p) of OCSLA (alternative energy and alternate use). In absolute terms, the fiscal impacts (revenues and costs) associated with alternative energy projects on the OCS are expected to be much larger than those associated with alternate uses of existing facilities.

9.0 DISTRIBUTION OF FISCAL IMPACTS

Under the requirements of the Regulatory Flexibility Act (RFA) of 1980, as amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBRFA) and Executive Order 13272 ("Proper Consideration of Small Entities in Agency Rulemaking"), Federal agencies must consider the potential distributional impact of new rules on small businesses, small governmental jurisdictions, and small organizations. MMS is required to prepare a regulatory flexibility analysis and take other steps to assist small entities, unless it certifies that the rule will not have a "significant economic impact on a substantial number of small entities." Certification of the rule must include a statement providing the factual basis for this determination.

The Small Business Administration (SBA) provides guidelines on the analytical process for assessing the impact of a particular rulemaking on small entities.[18] The first requirement of a RFA/SBRFA assessment is a screening analysis to determine whether a rule is likely to have a significant economic impact on a substantial number of small entities. The screening analysis includes:

1. Identifying the types of small entities subject to the rule's requirements (e.g. businesses, nonprofit organizations, governments, etc.) to determine whether the number of small entities affected is "substantial."
2. Identifying the actions a small entity will have to take to comply with the requirements of the rule (e.g. installation of new technology, revised record keeping system) to determine whether the potential impacts are of sufficient magnitude and scope to be considered "significant."

The remainder of this section provides the results of MMS's screening analysis used to determine whether it can certify the rule. This screening analysis only addresses the impacts of the rule governing payments for access to and use of the OCS for alternative energy projects or other uses.

9.1 Number of small entities to which the rule will apply

The North American Industry Classification System (NAICS) code for the industry affected by the proposed rule is 221119 (Other Electric Power Generation). This classification includes generation that does not depend on fossil fuels, nuclear power, or hydroelectric power. An entity within this classification is "small" if it is "primarily engaged in the generation, transmission, and/or distribution of electric energy for sale and its total electric output for the preceding fiscal year did not exceed four million megawatt hours" (MWh). Many of the entities subject to the rule will likely exist, during the period of analysis, solely to develop one or more offshore alternative energy projects that combined will not have a total electric output greater than 4 million MWh (corresponding to an offshore wind project with a rated capacity of more than

[18] SBA, Office of Advocacy, "A Guide for Government Agencies: How to Comply with the Regulatory Flexibility Act, Implementing the President's Small Business Agenda and Executive Order 13272," May 2003.

1,100 MW, which is larger than the largest project included in the MMS forecast for the next 20 years). Some entities, either through a combination of projects or through the incorporation of offshore alternative energy projects into a larger portfolio of electricity generating stations, will exceed the four million MWh threshold.

Given the immaturity of the offshore alternative energy industry, it is difficult to develop an accurate count of the number of entities that will or may be subject to this rule in order to determine whether the rule will affect a "substantial" number of small entities. Several companies have formally or informally expressed interest in being granted access to the OCS for electricity generation purposes. At least 40 to 50 entities are identifiable as potential project or technology developers with a focus on utilizing offshore wind, wave, or ocean current resources. The U.S. Census Bureau's 2002 Economic Census reported 411 entities within NAICS code 221119. However, for the purposes of this analysis MMS assumes that most of the relevant entities will be considered "small," and therefore can conclude that a substantial number of small entities will be affected.

It is possible that the proposed rule may eventually govern hydrogen production, affecting entities that fall under NAICS Code 325120, Industrial Gas Manufacturing. (This general industry classification covers establishments primarily engaged in manufacturing industrial organic and inorganic gases in compressed, liquid, and solid forms.) However, it is unlikely that hydrogen will be produced on the OCS in significant amounts during the 20-year period of analysis, and MMS has no means to predict what kinds of entities would likely be involved in hydrogen production, given the lack of proposals for projects that would produce hydrogen.

9.2 Economic impact of the rule on affected small entities

The significance of the impact on small entities is assessed in this case by comparing the payments required under the rule to the total revenues generated by the subject entities. For this analysis, MMS considers all project revenues and payments to the Federal government associated with the 52 projects that meet the target IRR value, regardless of when they occur (i.e., the analysis considers revenues and payments that occur post-2027). For each payment case, Table 9-1 presents the annualized per project payments and annualized per project revenues. Annualized values are estimated over the lifetime of the project as modeled in this report. Dividing payments by revenues provides a conservative estimate of the impact of compliance costs on small entities because it assumes (1) all of the affected projects are undertaken by small entities, (2) each entity undertakes a single project, and (3) the entire revenues for each entity are derived solely from this renewable energy project (i.e., the companies involved to not have groups of projects or other business interests). Therefore, the results of this screening analysis are more likely to overstate than understate the significance of compliance costs to affected entities.

As shown in Table 9-1, the highest ratio of payments to revenues for a single project under the Intermediate payment case is 2.1 percent, while the lowest ratio is 0.81 percent, depending on the discount rate applied. The average ratio across all projects in the Intermediate payment case is 1.2 percent and 1.4 percent, applying discount rates of three and seven percent respectively. The highest ratio of 4.1 percent occurs under the High payment case assuming a discount rate of seven percent.

Table 9-1

Significance of Compliance Costs

Payment Case	Annualized Payments	Annualized Revenues	Ratio of Payments to Revenues
3% Discount Rate			
Baseline	$0	$72,300,000 ($7,000,000 - $224,000,000)	0.00%
Low	$32,400 ($9,680 - $84,100)	$72,300,000 ($7,000,000 - $224,000,000)	0.04% (0.03% - 0.15%)
Intermediate	$882,000 ($113,000 - $2,350,000)	$72,300,000 ($7,000,000 - $224,000,000)	1.2% (0.81% - 1.7%)
High	$2,140,000 ($254,000 - $5,780,000)	$72,900,000 ($7,000,000 - $224,000,000)	2.9% (2.3% - 3.7%)
7% Discount Rate			
Baseline	$0	$42,600,000 ($3,970,000 - $125,000,000)	0.00%
Low	$28,000 ($7,900 - $78,300)	$42,600,000 ($3,970,000 - $125,000,000)	0.07% (0.04% - 0.22%)
Intermediate	$604,000 ($71,800 - $1,720,000)	$42,600,000 ($3,970,000 - $125,000,000)	1.4% (0.92% - 2.1%)
High	$1,310,000 ($148,000 - $3,720,000)	$43,000,000 ($3,970,000 - $125,000,000)	3.1% (2.3% - 4.1%)

Note: The center value in each cell indicates the average across all projects under that payment case. The range provided below in parentheses represents the minimum and maximum values across the same projects.

9.3 Initial Regulatory Flexibility Analysis

This section provides the information required for an Initial Regulatory Flexibility Analysis (IRFA). Specifically, section 603 of the RFA requires a discussion of each of the following elements:

1. A description of the reasons why action by the agency is being considered;

2. A succinct statement of the objectives of, and legal basis for, the proposed rule;

3. A description of, and where feasible, an estimate of the number of small entities to which the proposed rule will apply;

4. A description of the projected reporting, record-keeping and other compliance requirements of the proposed rule, including an estimate of the classes of small entities that will be subject to the requirement and the type of professional skills necessary for preparation of the report or record;

5. An identification, to the extent practicable, of all relevant Federal rules which may duplicate, overlap or conflict with the proposed rule;

6. A description of any significant alternatives to the proposed rule that accomplish the stated objectives of applicable statutes and that minimize any significant economic impact of the proposed rule on small entities, such as,

   - The establishment of different compliance or reporting requirements or timetables that take into account the resources available to small entities;

   - The clarification, consolidation, or simplification of compliance and reporting requirements under the rule for such small entities;

   - The use of performance rather than design standards; and,

   - An exemption from coverage of the rule, or any part thereof, for such small entities.

As discussed in Section 1, the EPAct, specifically section 388, amended the OCS Lands Act to authorize the Secretary of the Interior to issue leases, easements, or rights-of-way on the OCS for developing or supporting the production of energy resources other than oil and gas and to authorize other energy and marine-related activities that involve the use of existing facilities on the OCS. The EPAct also required the Department of the Interior to develop any necessary regulations to implement this new authority. On March 20, 2006, the Secretary officially delegated this new authority, and responsibility for developing any necessary regulations, to the MMS.

The importance of these regulations stems from the growing interest in harnessing the energy production potential that is available on the OCS and the current lack of a formal system to facilitate activity. Prior to the EPAct, the Federal government did not have clear authority to seek payment for private interests' access to and use of Federal submerged lands. These regulations will serve an important social purpose by establishing a payment structure to ensure a fair return to the United States for any lease, easement, or right-of-way granted; by creating a comprehensive “cradle-to-grave” regulatory program with provisions for regular inspections and environmental monitoring; and by providing a degree of regulatory certainty to those proposing, planning, or potentially financing an offshore alternative energy project.

As discussed in Section 7.1, given the immaturity of the offshore alternative energy industry, it is difficult to characterize and count of the number of entities that will or may be subject to this rule. At least 40 to 50 entities are identifiable as potential project or technology developers with a focus on utilizing offshore wind, wave, or ocean current resources. For the purposes of this analysis MMS assumes that most of the relevant entities will be considered "small."

The compliance requirements and associated costs of the proposed regulation are discussed in detail in Sections 4 and 5 of this report. MMS considers three possible fiscal term cases, which vary in terms of the minimum bid or acquisition fee, lease rental terms, easement rental terms, and operating fees. The terms do not vary depending on the size of the applicant; however, as noted above, most of the entities entering this industry over the next 20 years are likely to be small.

We note that these regulations were developed knowing that the majority of affected entities would be small entities. Alternatives proposed in the regulations to address the needs of small entities include:

- The proposed rule allows alternative compliance as appropriate. Small entities may propose alternate reporting requirements and MMS may accept if human safety and the environment are not compromised. Other regulatory requirements may also be revised.

- Financial assurance requirements were drafted with maximum flexibility so they would not pose an unnecessary burden on small entities.

As discussed in Section 1, the proposed rule is unlikely to duplicate, overlap with, or conflict with other Federal rules. EPAct granted to the Secretary of the Interior (who delegated to MMS) discretionary authority to authorize and regulate alternative energy activities on the OCS only to the extent such activities were not previously authorized by other applicable law. Therefore, through the passage of EPAct, Congress ensured that there would be no overlapping areas of Federal jurisdiction on the OCS for alternative energy projects.

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APPENDIX A MODEL DESCRIPTION

This Appendix provides a description of IEc's Excel-based cash flow model used to estimate Federal revenues, costs, and net revenues associated with the proposed rule under different sets of fiscal (i.e., payment) terms (referred to in this Appendix as "scenarios"). Structurally, the Excel model contains 12 primary worksheets:

- Worksheets 1 through 3 contain parameter information used by the model.
- Worksheets 4 and 5 create project cash flow (for 2008 to 2027 projects) and MMS payment (for 2028 to 2036) worksheets for project/scenario combinations using parameter information.
- Worksheet 6 displays project-specific financial performance information for each project.
- Worksheets 7 and 8 include the information and calculations associated with the estimation of government revenues and MMS costs on a project- and year-specific basis.
- Worksheets 9 through 11 display net revenues results for all projects and for projects identified by technology (i.e., wind, wave, current) and region (i.e., Atlantic, Pacific, Gulf of Mexico).
- Worksheet 12 presents data necessary to complete the analysis required under the Regulatory Flexibility Act (RFA) of 1980, as amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBRFA).

Figure A-1 illustrates the basic model structure. Additionally, the model contains many secondary worksheets used for background calculations that are not essential for basic use of the model; accordingly, these worksheets are hidden within the workbook. They can be uncovered using the Format → Sheets → Unhide function in Excel.

Model results are of course highly dependent upon the parameter input values. Comments are attached to each worksheet cell where an explanation of the basis for a value or set of values is warranted.

Financial Parameter Worksheets

The first three worksheets (General Inputs, Project Inputs, and Financial Assurance) contain general fiscal information (e.g., interest rates for debt financing), and more specific, project-level information (e.g., project year, installed capacity). Any user-based modifications to general fiscal information, scenario assumptions, project data, or financial assurance assumptions will occur on these worksheets. Modifications to electricity price forecasts can be made on the hidden "FERC Prices" worksheet, which underlies calculation of first-year price information on the General Inputs worksheet. Each of these worksheets contains one or more tables, descriptions of which are provided in Table A-1.

Figure A-1
Structure of Excel-Based Cash Flow Model

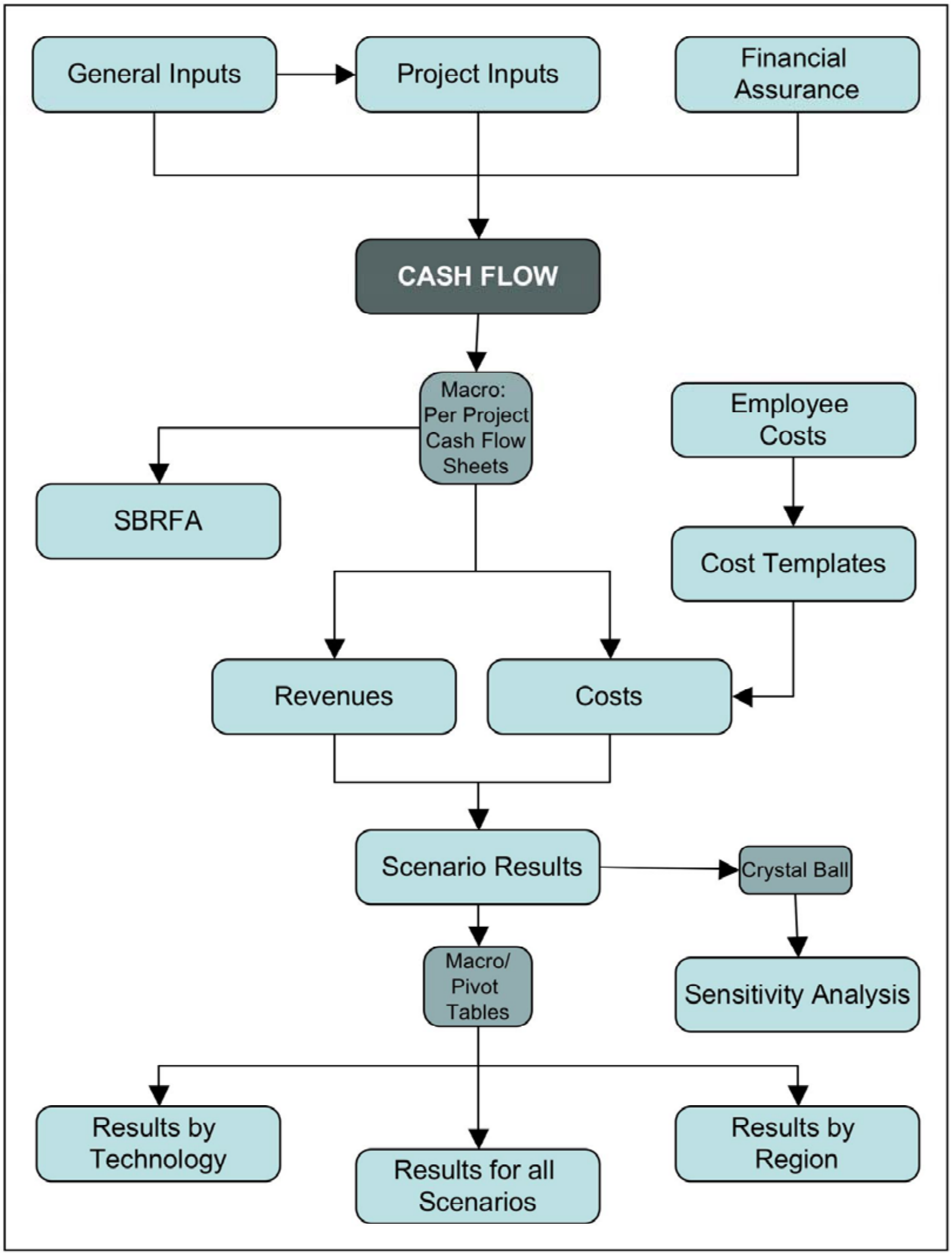

Table A-1
Descriptions of Tables in the General Inputs, Project Inputs, and Financial Assurance Worksheets

WORKSHEET	TABLE	DESCRIPTION
General Inputs	Shared Parameters	Financial parameters shared across all projects.
	MMS Scenarios	Fiscal parameters that generate government revenues (e.g., operations fees), based on information from MMS.
	PTCs and RECs by Region and Technology	Production Tax Credit and Renewable Energy Certificate values (the latter based on location and the existence of a State renewable portfolio standard (RPS)).
	Electricity Price: 2007 to 2046 by Region	Estimated prices for coastal regions of the U.S. from 2007 to 2046, based on historical information compiled and reported by FERC.
	Capacity Factors and Rated Capacities	Assumed capacity factors for wind, wave, and ocean current projects, and assumed rated capacities for wave and ocean current projects included in the development forecast (wind project capacities vary).
	O&M and Installed Capital Costs, and Debt/Equity Financing Share	Baseline installed capital costs, operations and maintenance costs, and debt/equity financing share, by technology.
	O&M, Installed Capital Costs, and Debt Financing Share Adjustments	Rates at which these parameters are projected to change based on industry growth and learning effects.
	2008 to 2027 O&M, Installed Capital Costs and Debt Financing	Using data from the previous two tables, forecast of installed capital costs, operations and maintenance costs, and debt financing shares for each year of the analysis.
Project Inputs	Project Specific Parameters	Characteristics of projects as specified in the Task 1 report, as amended based on MMS comments. Many of these parameters automatically update based upon user entries and information provided in the general inputs worksheet.
	Cash Flow Sheet Builder	A two-cell table that allows a user to quickly observe the cash flow statement for the project and MMS fiscal scenario of choice.
Financial Assurance	Bonding Payment Information	Fiscal information on pre-construction, operations, and easement decommissioning bonds, as specified by MMS.

These first three worksheets contain parameter values that have been developed based on research, IEc's professional judgment, and correspondence with MMS. These parameters can be easily adjusted, however; model users may enter information common to all projects on the General Inputs worksheet, information specific to individual projects on the Project Inputs worksheet, and any new information on financial assurance and bonding information on the Financial Assurance worksheet. A separate table in the Project Inputs worksheet allows the model user to generate the cash flow statement for a particular project and scenario (selected from pull down menus) using the button labeled Find.

Cash Flow and Payments Worksheets

The Cash Flow worksheet is the centerpiece of the model, as it provides information on Federal revenues and financial performance associated with each scenario for projects forecast to begin generating electricity between 2008 and 2027. The performance component is used to determine whether a project should be included among those that result in Federal revenues or costs. The Payments 2028-2036 worksheet incorporates the assumption that a certain set of projects will begin generating electricity during this period (rather than modeling specific hypothetical projects and evaluating their predicted financial performance). As such, this worksheet estimates only the Federal revenues associated with those projects (e.g., lease payment or operating fees collected during the construction period). The scenario selection cell in this worksheet is linked to the Cash Flow worksheet; any changes to the scenario – such as from Baseline to Low – within the model should therefore be done using the pull down menu on the Cash Flow worksheet. If the model user is interested in adjusting how the model calculates a project's financial performance or the payments it would make to the Federal government, the structure of the Cash Flow and Payments 2028-2036 worksheets can be adjusted. There are two ways to select a particular project and scenario:

- In the upper left corner of the Cash Flow worksheet, the Project Selection and MMS Scenario Selection tables both provide cells with pull down menus that allow the project and scenario numbers to be selected from a list. To select a project in the 2028 to 2036 period, select a project number on the Payments 2028-2036 worksheet. Adjustment of the scenario on the Cash Flow worksheet will automatically adjust the scenario on the Payments 2028-2036 worksheet.

- Alternatively, the model user can select the project and scenario from a table titled Cash Flow Sheet Builder in the upper right corner of the Project Inputs worksheet. In this table, once the user has selected the project and scenario numbers, the user can click on the Find button, which contains a macro that automatically switches to the Cash Flow worksheet and updates the project and scenario information according to user selections.

All other cells in the Project Selection, MMS Scenario Selection, and Financial Assurance tables are simply references to cells in Table 1 of the Project Inputs worksheet, Table 2 of the General Inputs worksheet, and/or Table 1 of the Financial Assurance worksheet, respectively.

The remaining tables in the Cash Flow and Payments worksheets include the following:

- **Financial Performance and Federal Revenues (Nominal)**, which are result summaries for the project currently selected; these outputs are described in more detail in the Results section below.

- **Summary Cash Flow Statement** (only on the Cash Flow worksheet), which contains summarized information from the Detailed Cash Flow Statement table immediately below. The latter references information from the tables at the top of the Cash Flow worksheet (Project Selection, MMS Scenario Selection, and Financial Assurance) as well as parameter information from the General Inputs worksheet. Explanations for each of the calculations are provided in comments embedded in the row headers of the detailed cash flow statement. On the Payments worksheet, the detailed cash flow statement is labeled MMS Payments.

- **Federal Revenues (Nominal)**. This table is presented to the right of the Detailed Cash Flow Statement (or MMS Payment table on the Payments 2028-2036 worksheet), and summarizes Federal revenues for each year of project operation. If projects do not reach financial performance hurdle requirements necessary for inclusion in the revenue or cost forecast (described below), this summary table will return zero revenues in those years when fees are not paid. Information in this table is then transferred to the Revenues worksheet.

An Excel macro built into the Cash Flow worksheet (activated using a button labeled Create Project Sheets) generates individual cash flow and payments worksheets for the projects forecasted to generate electricity during the study period (76 projects) and between 2028 and 2036 (27 projects). These 103 worksheets are hidden within the workbook and can be accessed using another macro button in the Cash Flow worksheet labeled Unhide Project Sheets. As with the Payments 2028-2036 worksheet, the MMS scenario for each of these individual project worksheets is linked to (and therefore changes with) the corresponding scenario pull down menu in the Cash Flow worksheet. All changes to the scenario should occur in the Cash Flow worksheet.

Rerunning the Model

Since all model calculations are based on these 103 worksheets, if there are any structural changes to the Cash Flow worksheet (e.g., adjustments to the schedule of MMS fees under a particular scenario), the cash flow worksheets need to be regenerated to incorporate these changes, and the model should be rerun. To regenerate cash flow worksheets, first click on the Delete Project Sheets button and then on the Create Project Sheets, both in the Cash Flow worksheet. The latter macro automatically hides the project worksheets once generated. Steps for rerunning the model are outlined below (see **Making Changes to the Model**).

Financial Performance

Worksheet 6 contains financial performance information for all projects under the scenario selected on the Cash Flow worksheet. As the scenario on the Cash Flow worksheet is adjusted, the values on this worksheet automatically adjust based on information from the 76 cash flow worksheets for projects generating electricity between 2008 and 2027. The most important column on this worksheet is After-Tax IRR, generated for all scenarios; this is the criterion by which projects are placed into one of three performance categories: (1) Project Does Not Apply, where the project does not clear the lower hurdle IRR (currently set at five percent) and therefore does not submit an application to MMS; (2) Project Applies but is not Constructed, where the project clears the lower hurdle rate, but not the upper rate (set at 11 percent) and therefore applies but is not constructed; and (3) Project is Constructed, where the project clears the upper rate and is therefore constructed. The weighted average cost of capital (WACC) – which is based on assumed debt and equity interest rates and debt-equity ratios – is provided for each project (values range from 10.24 percent to 11.43 percent). Calculation of the WACC is made from the debt financing rate and the base return on equity rate listed in Table 1 of the General Inputs worksheet. The cumulative cash flow for each project – discounted using the project's

WACC – is also provided. This information is summarized for an individual scenario on the Projects Exceeding Hurdle Requirements tables in the Performance worksheet. An Excel macro (a button labeled Generate Performance Table) summarizes the number of projects clearing each hurdle category for all scenarios and technologies.

Revenue and Cost Results

Worksheets 7 and 8, Revenues and Costs, contain summaries of Federal revenues and MMS costs for each of the 103 projects in each year between 2008 and 2027. The Revenues worksheet pulls information from the MMS Revenues table within the Cash Flow and Payments worksheets and realigns the data based on the year. The worksheet contains a table at the top of the page that sums the results for each column to generate the total annual Federal revenues for all projects under a particular scenario.

The Costs worksheet draws information from three hidden worksheets (2008-2012 Cost Template, 2013-2027 Cost Template, and Specialties, all provided by MMS), as well as project performance information from the Performance worksheet. The full-time equivalent (FTE) information in the Cost Templates was combined with cost information on the employee compensation ("EmplCompenstn") worksheet provided by MMS (also hidden) to develop costs in dollars for project-specific (e.g., drafting an EIS) and non-project-specific (i.e., project management or project administration) aspects of the program. As project-specific costs are transferred from the templates to the Costs worksheet, they are aligned according to the particular year in the Project-Specific Costs table. Annual non-project-specific costs are summarized in the table Total Costs for Each Year, which also sums project- and non-project-specific costs.

Both the Revenues and Costs worksheets contain pivot tables at the bottom of the worksheets that break down total revenues and costs by technology and region. Each of these worksheets has an Excel macro button adjacent to the Total Costs tables labeled Refresh; if any information in the model is adjusted, the model user should press this button to refresh the pivot tables with the most recent information.

Net Revenues

Worksheets 9 through 11 summarize the revenue and cost data generated in earlier worksheets and calculate net revenues (revenues minus costs) in both nominal and discounted terms. Given the model's construction, it is impossible to simultaneously calculate the net revenues from multiple scenarios. Accordingly, an Excel macro on the Results worksheet (with a button labeled "1. Generate All Results") pages through the scenarios on the Cash Flow worksheet and pulls resulting information from the hidden Scenario Results worksheet.[19] The hidden Scenario Results worksheet, which draws information from the Revenues and Costs worksheets, reports the total revenues, costs, and net revenues in nominal and discounted terms. Discounted revenues are calculated using real rates of three and seven percent. Worksheets 10 and 11 ("by Tech" and

[19] Note that the steps for rerunning the model and regenerating the results are outlined in the **Making Changes to the Model** section below.

"by Region") present the same information as worksheet 9, breaking down the results by technology and region. Finally, results are presented in report-ready tables in two hidden worksheets, Report Tables and Report Tables2. These worksheets are populated using two macros: Generate Report Tables (1) and Generate Report Tables (2).

SBRFA Analysis

Worksheet 12 generates comparisons of individual projects' costs (i.e., payments to the Federal government) to the forecast of revenues that the project will generate through electricity sales and renewable energy certificate sales (as appropriate) for the Most Likely scenario. An Excel macro (with an associated button labeled Run SBRFA Analysis) calls on the individual Cash Flow worksheets to generate the necessary information for each project in the development forecast, using two hidden worksheets in the process: SBRFA_temp and SBRFA_data.

Making Changes to the Model

The model user may also wish to make additional changes to the model, which requires that the model be rerun to create new results. To rerun the model, follow these steps:

Step 1: On the Cash Flow worksheet, click the Delete Project Sheets button followed by the Create Project Sheets button to regenerate the cash flow worksheets (note that the latter macro automatically hides the 103 project worksheets once generated);

Step 2: On the Performance worksheet, click the Generate Performance Data button to regenerate performance results; and

Step 3: On the Results worksheet, click, sequentially, the buttons labeled "1. Generate All Results", "2.Generate Report Tables (1)", and "3. Generate Report Tables (2)." This will regenerate the same variations on the analytical results that are included in the body of this report.

Three particular examples of modifications to the model are described in more detail below.

Adjustment of fiscal terms. The user may wish to adjust the fees associated with lease issuance, pre-production rentals, operation, or project easement for one or more of the scenarios. These fees can be found in Table 2 (cells C22 to L26) of the General Inputs worksheet (one row corresponds to each of the four MMS scenarios and one additional row to the Intermediate-No REC scenario). Note that as the values in Table 2 of the General Inputs worksheet are adjusted, cells C6 to L6 on the Cash Flow worksheet (with the appropriate scenario selected) update automatically. The fees can be adjusted on the General Inputs worksheet as follows:

- The per acre lease issuance fee (cells C22 to C26) and the project easement rental fee (cells L22 to L26) are straightforward to adjust: simply change the values in these cells from their currently assigned values (e.g., $0.25 per acre and $5 per acre under the Intermediate scenario) to new values and rerun the model by following Steps 2 and 3 above (when making this adjustment, the cash flow worksheets update automatically, so Step 1 is unnecessary).
- The per acre pre-production rental fee occupies three columns of cells on the General Inputs worksheet (cells D22 through F26) corresponding to three fee levels that occur

over sub-periods within the seven-year pre-production period: the first level occurs in years one and two (cells D22 to D26); the second in years three and four (cells E22 to E26); and the final level in years five through seven (cells F22 to F26; under the High payment case these fee levels are $3 per acre, $4 per acre, and $5 per acre, respectively).[20] Once the user has developed an alternate set of fees corresponding to the three fixed sub-periods, these can simply be entered into cells D22 through F26 and the model can be rerun. Note that in the Low payment case, the fee contained in cells F22 to F26 (i.e., corresponding to the third sub-period) serves as a substitute for the operating fee and occurs over the entire operating period.

- The operating fee is contained within cells G22 through K26 and is similar to the pre-production rental fee in that different fee levels occur over the construction and operations period. Rather than a per acre fee, the operating fee is a percentage of a capacity-based projection of electricity revenues (as displayed in these cells). The first fee level (cells G22 to G26) occurs in the two years following initiation of project construction (see the note in Table 4-7); the second (cells H22 to H26) occurs until year eight of electricity generation (i.e., if project construction lasts one year, the construction fee extends through the first year of electricity generation, so this second fee extends an additional six years); the third fee level (cells I22 to I26) occurs over the next seven years (to year 15 of electricity generation); and the fourth level (cells J22 to J26) occurs over the final five years of project operation.[21] The user can enter new fees corresponding to these four fixed sub-periods into cells G22 through K26 and can then rerun the model. Under the High scenario only, the user also has the option of levying, in the last five years of project operation, an additional fee calculated as a percentage of a project's renewable electricity credit (REC) revenues or production tax credits (PTCs) (cells K22 to K26). If interested in evaluating the effects of such a fee, the user must first select the High scenario and then adjust one or more of the cells between K22 and K26.

Modification of project characteristics or the project schedule. The user may also wish to reduce the number of projects being evaluated or to modify the characteristics of particular projects.[22,23] To reduce the number of projects being evaluated, the user should first select which

[20] The model is not currently constructed to allow adjustments in the timing of changes in the rental fee levels (e.g., allowing the first level to occur in years one through three rather than years one and two). To make such an adjustment, the user would need to modify the conditional reference formulas contained in cells D50 to AD53 in the Cash Flow worksheet.

[21] Here too, the model is not currently constructed to allow adjustments in the timing of changes in the operating fee levels.

[22] Because these steps involve making changes to the Project Inputs worksheet (and possibly the General Inputs worksheet), the user may want to make these changes in a separate copy of the model to ensure that none of the original project information is lost.

[23] Increasing the number of projects in the schedule is a more complex modeling exercise and is not discussed in this Appendix.

projects will be removed from the list of 103 projects on the Project Inputs worksheet. Next, simply enter a letter, such as “A”, after the project number contained in the cells down column A. For example, if the user were interested in no longer including project 1 in the forecast, simply change “1” in cell A5 to “1A”. This preserves the characteristics of the project while making it unrecognizable to the performance and results macros. The user can now develop new output tables, by rerunning these macros.

The characteristics of particular projects can be changed in two ways: by modifying the information on the General Inputs worksheet, which influences groups of projects on the Project Inputs worksheet automatically; or by directly changing project information on the Project Inputs worksheet. Note that the latter approach eliminates the reference formulas in the modified Project Inputs cells, such that changes to the previously referenced cells (e.g., on the General Inputs worksheet) will no longer update these project characteristics. Once the user has modified project characteristics using one (or both) of these approaches, rerun the model as described above (Steps 1, 2, and 3).

No-PTC Scenario. Appendix D reports project performance assuming that the PTC is not available to any projects in the 2008 to 2027 period of analysis. The user may be interested in more detailed information on this scenario, such as net revenues by technology or region. Cell K2 on the Project Inputs worksheet contains a pull down menu with either $0 or $0.02 (per kilowatt-hour), where $0 corresponds to the no-PTC scenario and $0.02 corresponds to the with-PTC scenario. Developing the output from the no-PTC scenario is straightforward: simply adjust this pull down menu and rerun the model as described above (Steps 2 and 3 only).

APPENDIX B PROJECT FINANCIAL INFORMATION

Table B-1
Forecasted Electricity Production and Financial Performance Information for Projects Operational by 2027

Startup Year	Location	Technology	Capacity Factor	Rated Plant Capacity (MW)	Annual Electricity Production (MWH)	Production Before 2027 (MWH)	Project Lifetime Production (MWH)	Weighted Average Cost of Capital	Discounted Cash Flow: Intermediate Payment Case (Millions)	Project IRR by Payment Case			
										Baseline	Low	Intermediate	High
2013	New England	Wind	0.38	500	1,665,540	24,983,100	33,310,800	10.24%	$448.2	25.26%	25.25%	24.92%	24.62%
	New York	Wind	0.38	150	499,662	7,494,930	9,993,240	10.24%	$37.2	15.75%	15.74%	15.30%	14.73%
2017	Mid-Atlantic	Wind	0.38	150	499,662	5,496,282	9,993,240	10.88%	-$19.6	8.80%	8.78%	8.24%	7.42%
	Mid-Atlantic	Wind	0.38	500	1,665,540	18,320,940	33,310,800	10.88%	$61.1	12.68%	12.66%	12.16%	11.56%
	Mid-Atlantic	Wind	0.38	150	499,662	5,496,282	9,993,240	10.88%	-$19.6	8.80%	8.78%	8.24%	7.42%
	New England	Wind	0.38	500	1,665,540	18,320,940	33,310,800	10.88%	$513.4	25.28%	25.27%	24.98%	24.71%
	New England	Wind	0.38	150	499,662	5,496,282	9,993,240	10.88%	$116.0	23.18%	23.16%	22.86%	22.56%
2018	Mid-Atlantic	Wind	0.38	500	1,665,540	16,655,400	33,310,800	10.88%	$64.5	12.77%	12.75%	12.25%	11.64%
	New England	Wind	0.38	500	1,665,540	16,655,400	33,310,800	10.88%	$525.3	25.35%	25.34%	25.04%	24.78%
	New York	Wind	0.38	150	499,662	4,996,620	9,993,240	10.88%	$62.4	18.11%	18.10%	17.73%	17.32%
	New York	Wind	0.38	500	1,665,540	16,655,400	33,310,800	10.88%	$337.1	20.84%	20.83%	20.47%	20.12%
	Southeast	Wind	0.38	150	499,662	4,996,620	9,993,240	10.88%	-$89.3	-4.77%	-4.80%	-5.66%	-7.92%
	California	Wave	0.35	75	230,108	2,301,075	4,602,150	10.88%	-$40.5	-7.39%	-7.50%	-8.71%	-12.87%
	California	Wave	0.35	75	230,108	2,301,075	4,602,150	10.88%	-$40.5	-7.39%	-7.50%	-8.71%	-12.87%
	Oregon	Wave	0.35	75	230,108	2,301,075	4,602,150	10.88%	-$48.1	-14.34%	-14.44%	-15.73%	-20.85%
	Oregon	Wave	0.35	75	230,108	2,301,075	4,602,150	10.88%	-$48.1	-14.34%	-14.44%	-15.73%	-20.85%
2019	Mid-Atlantic	Wind	0.38	150	499,662	4,496,958	9,993,240	10.88%	$15.9	13.58%	13.56%	13.05%	12.44%
	Mid-Atlantic	Wind	0.38	150	499,662	4,496,958	9,993,240	10.88%	$15.9	13.58%	13.56%	13.05%	12.44%
	Mid-Atlantic	Wind	0.38	500	1,665,540	14,989,860	33,310,800	10.88%	$152.2	16.16%	16.14%	15.66%	15.17%
	New England	Wind	0.38	500	1,665,540	14,989,860	33,310,800	10.88%	$621.7	28.69%	28.68%	28.37%	28.13%
	Southeast	Wind	0.38	150	499,662	4,496,958	9,993,240	10.88%	-$55.5	1.34%	1.30%	0.56%	-1.00%
	California	Wind	0.38	150	499,662	4,496,958	9,993,240	10.88%	-$20.8	8.23%	8.20%	7.66%	6.80%

Startup Year	Location	Technology	Capacity Factor	Rated Plant Capacity (MW)	Annual Electricity Production (MWH)	Production Before 2027 (MWH)	Project Lifetime Production (MWH)	Weighted Average Cost of Capital	Discounted Cash Flow: Intermediate Payment Case (Millions)	Project IRR by Payment Case			
										Baseline	Low	Intermediate	High
2019 (cont.)	California	Wind	0.38	150	499,662	4,496,958	9,993,240	10.88%	-$20.8	8.23%	8.20%	7.66%	6.80%
	Florida	Current	0.8	30	210,384	1,893,456	4,207,680	10.88%	$56.0	54.31%	54.24%	53.60%	53.29%
	Florida	Current	0.8	30	210,384	1,893,456	4,207,680	10.88%	$56.0	54.31%	54.24%	53.60%	53.29%
	Florida	Current	0.8	30	210,384	1,893,456	4,207,680	10.88%	$56.0	54.31%	54.24%	53.60%	53.29%
	Florida	Current	0.8	30	210,384	1,893,456	4,207,680	10.88%	$56.0	54.31%	54.24%	53.60%	53.29%
	Florida	Current	0.8	30	210,384	1,893,456	4,207,680	10.88%	$56.0	54.31%	54.24%	53.60%	53.29%
	Florida	Current	0.8	30	210,384	1,893,456	4,207,680	10.88%	$56.0	54.31%	54.24%	53.60%	53.29%
2020	Mid-Atlantic	Wind	0.38	150	499,662	3,997,296	9,993,240	10.88%	$16.9	13.67%	13.65%	13.14%	12.53%
	Mid-Atlantic	Wind	0.38	500	1,665,540	13,324,320	33,310,800	10.88%	$157.4	16.24%	16.23%	15.75%	15.25%
	New England	Wind	0.38	500	1,665,540	13,324,320	33,310,800	10.88%	$635.6	28.75%	28.74%	28.44%	28.20%
	New England	Wind	0.38	500	1,665,540	13,324,320	33,310,800	10.88%	$635.6	28.75%	28.74%	28.44%	28.20%
	New York	Wind	0.38	1,000	3,331,080	26,648,640	66,621,600	10.88%	$1,212.4	29.20%	29.18%	28.84%	28.59%
	New York	Wind	0.38	500	1,665,540	13,324,320	33,310,800	10.88%	$440.4	24.18%	24.17%	23.81%	23.50%
	Gulf of Mexico	Wind	0.38	150	499,662	3,997,296	9,993,240	10.88%	-$49.2	3.01%	2.98%	2.28%	0.92%
	Oregon	Wave	0.35	75	230,108	1,840,860	4,602,150	10.88%	-$30.3	-2.62%	-2.72%	-3.76%	-6.92%
	Oregon	Wave	0.35	75	230,108	1,840,860	4,602,150	10.88%	-$30.3	-2.62%	-2.72%	-3.76%	-6.92%
	Florida	Current	0.8	30	210,384	1,683,072	4,207,680	10.88%	$57.3	54.50%	54.43%	53.79%	53.48%
	Florida	Current	0.8	30	210,384	1,683,072	4,207,680	10.88%	$57.3	54.50%	54.43%	53.79%	53.48%
	Florida	Current	0.8	30	210,384	1,683,072	4,207,680	10.88%	$57.3	54.50%	54.43%	53.79%	53.48%
2021	Mid-Atlantic	Wind	0.38	150	499,662	3,497,634	9,993,240	10.88%	$17.9	13.75%	13.74%	13.23%	12.62%
	Mid-Atlantic	Wind	0.38	500	1,665,540	11,658,780	33,310,800	10.88%	$162.5	16.32%	16.31%	15.83%	15.33%
	Southeast	Wind	0.38	150	499,662	3,497,634	9,993,240	10.88%	-$56.7	1.49%	1.46%	0.71%	-0.84%
	Southeast	Wind	0.38	1,000	3,331,080	23,317,560	66,621,600	10.88%	$167.0	13.49%	13.47%	12.96%	12.39%
	California	Wind	0.38	500	1,665,540	11,658,780	33,310,800	10.88%	$34.7	11.71%	11.69%	11.20%	10.57%
	California	Wind	0.38	500	1,665,540	11,658,780	33,310,800	10.88%	$34.7	11.71%	11.69%	11.20%	10.57%
	California	Wind	0.38	500	1,665,540	11,658,780	33,310,800	10.88%	$34.7	11.71%	11.69%	11.20%	10.57%
	California	Wind	0.38	1,000	3,331,080	23,317,560	66,621,600	10.88%	$407.6	18.11%	18.09%	17.65%	17.24%

Startup Year	Location	Technology	Capacity Factor	Rated Plant Capacity (MW)	Annual Electricity Production (MWH)	Production Before 2027 (MWH)	Project Lifetime Production (MWH)	Weighted Average Cost of Capital	Discounted Cash Flow: Intermediate Payment Case (Millions)	Project IRR by Payment Case			
										Baseline	Low	Intermediate	High
2021 (cont.)	Washington	Wave	0.35	75	230,108	1,610,753	4,602,150	10.88%	-$30.7	-2.54%	-2.64%	-3.68%	-6.84%
	Oregon	Wave	0.35	75	230,108	1,610,753	4,602,150	10.88%	-$30.7	-2.54%	-2.64%	-3.68%	-6.84%
	California	Wave	0.35	75	230,108	1,610,753	4,602,150	10.88%	-$22.4	2.56%	2.49%	1.65%	-0.28%
	Florida	Current	0.8	30	210,384	1,472,688	4,207,680	10.88%	$58.6	54.69%	54.63%	53.99%	53.67%
	Florida	Current	0.8	30	210,384	1,472,688	4,207,680	10.88%	$58.6	54.69%	54.63%	53.99%	53.67%
2022	Mid-Atlantic	Wind	0.38	500	1,665,540	9,993,240	33,310,800	11.43%	$127.1	14.90%	14.88%	14.45%	13.98%
	New England	Wind	0.38	500	1,665,540	9,993,240	33,310,800	11.43%	$602.6	26.18%	26.17%	25.89%	25.65%
	New England	Wind	0.38	150	499,662	2,997,972	9,993,240	11.43%	$148.5	25.31%	25.30%	25.02%	24.76%
	New York	Wind	0.38	1,000	3,331,080	19,986,480	66,621,600	11.43%	$1,167.1	26.79%	26.77%	26.45%	26.20%
	Florida	Current	0.8	30	210,384	1,262,304	4,207,680	11.43%	$56.1	48.95%	48.89%	48.30%	48.00%
	Florida	Current	0.8	30	210,384	1,262,304	4,207,680	11.43%	$56.1	48.95%	48.89%	48.30%	48.00%
	Florida	Current	0.8	30	210,384	1,262,304	4,207,680	11.43%	$56.1	48.95%	48.89%	48.30%	48.00%
2023	New England	Wind	0.38	1,000	3,331,080	16,655,400	66,621,600	11.43%	$1,679.6	32.73%	32.72%	32.45%	32.25%
	Gulf of Mexico	Wind	0.38	500	1,665,540	8,327,700	33,310,800	11.43%	-$12.6	10.20%	10.18%	9.69%	9.07%
	Gulf of Mexico	Wind	0.38	1,000	3,331,080	16,655,400	66,621,600	11.43%	$262.1	15.31%	15.29%	14.85%	14.41%
2024	New England	Wind	0.38	1,000	3,331,080	13,324,320	66,621,600	11.43%	$1,714.2	32.78%	32.77%	32.49%	32.29%
	New England	Wind	0.38	500	1,665,540	6,662,160	33,310,800	11.43%	$711.0	29.50%	29.50%	29.20%	28.98%
	Mid-Atlantic	Wind	0.38	500	1,665,540	6,662,160	33,310,800	11.43%	$217.4	17.96%	17.95%	17.51%	17.10%
2025	Mid-Atlantic	Wind	0.38	500	1,665,540	4,996,620	33,310,800	11.43%	$222.4	17.99%	17.98%	17.54%	17.13%
	Mid-Atlantic	Wind	0.38	1,000	3,331,080	9,993,240	66,621,600	11.43%	$742.5	22.23%	22.22%	21.81%	21.47%
	California	Wind	0.38	500	1,665,540	4,996,620	33,310,800	11.43%	$89.3	13.93%	13.91%	13.49%	13.01%
2026	California	Wind	0.38	1,000	3,331,080	6,662,160	66,621,600	11.43%	$486.7	18.59%	18.58%	18.18%	17.82%
	California	Wind	0.38	1,000	3,331,080	6,662,160	66,621,600	11.43%	$486.7	18.59%	18.58%	18.18%	17.82%
	California	Wind	0.38	1,000	3,331,080	6,662,160	66,621,600	11.43%	$486.7	18.59%	18.58%	18.18%	17.82%
2027	Mid-Atlantic	Wind	0.38	1,000	3,331,080	3,331,080	66,621,600	11.43%	$773.9	22.28%	22.27%	21.86%	21.52%
	Southeast	Wind	0.38	1,000	3,331,080	3,331,080	66,621,600	11.43%	$237.9	14.54%	14.53%	14.08%	13.62%
	Florida	Current	0.8	60	420,768	420,768	8,415,360	11.43%	$136.2	54.66%	54.63%	53.99%	53.70%

The Department of the Interior Mission

As the Nation's principal conservation agency, the Department of the Interior has responsibility for most of our nationally owned public lands and natural resources. This includes fostering sound use of our land and water resources; protecting our fish, wildlife, and biological diversity; preserving the environmental and cultural values of our national parks and historical places; and providing for the enjoyment of life through outdoor recreation. The Department assesses our energy and mineral resources and works to ensure that their development is in the best interests of all our people by encouraging stewardship and citizen participation in their care. The Department also has a major responsibility for American Indian reservation communities and for people who live in island territories under U.S. administration.

The Minerals Management Service Mission

As a bureau of the Department of the Interior, the Minerals Management Service's (MMS) primary responsibilities are to manage the mineral resources located on the Nation's Outer Continental Shelf (OCS), collect revenue from the Federal OCS and onshore Federal and Indian lands, and distribute those revenues.

Moreover, in working to meet its responsibilities, the **Offshore Minerals Management Program** administers the OCS competitive leasing program and oversees the safe and environmentally sound exploration and production of our Nation's offshore natural gas, oil and other mineral resources. The MMS **Minerals Revenue Management** meets its responsibilities by ensuring the efficient, timely and accurate collection and disbursement of revenue from mineral leasing and production due to Indian tribes and allottees, States and the U.S. Treasury.

The MMS strives to fulfill its responsibilities through the general guiding principles of: (1) being responsive to the public's concerns and interests by maintaining a dialogue with all potentially affected parties and (2) carrying out its programs with an emphasis on working to enhance the quality of life for all Americans by lending MMS assistance and expertise to economic development and environmental protection.