Small accidental oil spills could have localized and temporary impacts. Pollutant levels from very large spills, including accidental spills associated with an unlikely CDE, and associated *in situ* burning if used, would generally be small. Plumes from *in situ* burning could temporarily degrade visibility in PSD Class I areas.

Acoustic Environment—Routine operations could affect ambient noise conditions, and impacts to ambient noise levels are expected to be minor to moderate. Noise generating sources associated with routine operations include seismic surveys, drilling and production, infrastructure placement and removal, and vessel traffic. Depending on the source and activity, changes in ambient noise levels could be short-term and localized (e.g., from vessel traffic), long-term and localized (from production), or short-term and less localized (from seismic surveys). Seismic surveys could result in short-term changes in ambient noise levels, but the changes could extend well beyond the survey boundary.

Coastal and Estuarine Habitats—Routine operations would result in minor to moderate localized impacts primarily due to facility construction, pipeline trenching and landfalls, channel dredging, and vessel traffic. The effects of accidental oil spills will depend on the specific habitat affected; the size, location, duration, and timing of the spill; and on the effectiveness of spill containment and cleanup activities. Small spills would likely result in short-term impacts while large spills, including a CDE-level spill, could incur both short-term and long-term impacts depending on habitat type and location and effectiveness of spill containment and cleanup activities.

Marine Habitats—Routine operations could result in moderate short and long-term impacts to benthic and pelagic habitats. Benthic habitat could be disturbed by platform and pipeline placement, dredging, and operational discharges (produced water and cuttings). Soft sediment habitats can recover within a few years from most disturbances. Existing mitigation measures should eliminate most direct impacts to sensitive and protected benthic habitats. Marine benthic habitat could be affected by a large oil spill, including a CDE-level spill. Impacts could be long-term and range from small to medium, depending on the habitat affected; the size, duration, timing, and location of the spill; and the effectiveness of spill containment and cleanup activities. Impacts to high density deepwater communities from routine operations and accidental spills are unlikely, but may be permanent if they do occur. Major impacts to coral reef habitats could occur if the Flower Gardens Banks are heavily oiled and high mortality occurs.

Essential Fish Habitat—Routine operations could result in no more than moderate, short- and long-term impacts to EFH and managed species. Existing mitigation measures should eliminate most direct impacts to coral EFH. Impacts from accidental oil spills, including a CDE-level spill, could be long-term, depending on the size, duration, timing, and location of the spill; the habitats affected; and the effectiveness of spill containment and cleanup activities.

Marine Mammals—Impacts to marine mammals from routine operations include noise disturbance from seismic surveys, vessels, helicopters, construction and operation of platforms, and removal of platforms with explosives; potential collision with vessels; and exposures to discharges and wastes. Impacts to cetaceans could range from negligible to moderate, with species or stocks inhabiting continental shelf or shelf slope waters most likely to be affected. The West Indian manatee and rare or extralimital whale species, i.e. those from outside the area, are not likely to be affected. Meeting the requirements of the Endangered Species Act (ESA) and the Marine Mammal Protection Act (MMPA) would reduce the likelihood and magnitude of adverse impacts from routine operations to most species. A large accidental oil spill, including a CDE-level spill, would have minor to moderate impacts to marine mammals; impacts from spill response activities are expected to be minor.

Terrestrial Mammals—The four federally endangered GOM coast beach mice species and the federally endangered Florida salt marsh vole and their habitats would not be significantly affected by normal operations under the proposed action. Impacts are expected to be minimized through appropriate mitigation and the existence of these species' habitats in protected areas. While the habitat of the Florida salt marsh vole could be affected by an oil spill, this species and its habitat are located far from areas where oil leasing and development may occur under the proposed action. Because of their locations on inner dunes, the habitats of the beach mice are unlikely to be affected by an accidental offshore oil spill, but the occurrence of a CDE would increase the threat of extinction to these species.

Marine and Coastal Birds—Routine operations may result in negligible to moderate localized short-term impacts associated primarily with infrastructure construction, and ship and helicopter traffic. Impacts of routine operations on important coastal habitats such as nesting areas and overwintering sites could result in greater, more long-term impacts should normal breeding and nesting activities be disrupted. Small accidental oil spills are expected to have largely local, small effects. Large spills, including a CDE-level spill, may result in large, long-term, and possibly population-level effects. The magnitude of the effects will depend on the size, duration, and timing of the spill; the species and habitats affected; and the effectiveness of spill containment and cleanup activities.

Fish Resources—Negligible to minor impacts to fish and negligible impacts to threatened or endangered fish species are expected from routine operations. A large accidental oil spill, including a CDE-level spill, is not likely to result in population-level impacts except potentially for spills that significantly affect overfished species and their spawning grounds. Oil contacting shoreline areas could result in large-scale lethal and long-term sublethal effects on early life stages of some species, but no permanent population level effects are expected.

Reptiles—Routine operations would result in minor to moderate localized impacts to marine turtles primarily due to seismic exploration, facility construction, pipeline landfalls, channel dredging, and vessel traffic. Accidental oil spills could result in large impacts depending on the size, location, duration and timing of the spill, and on the effectiveness of spill containment and cleanup activities. Small spills would likely result in short-term impacts while large spills, including a CDE-level spill, could incur both short-term and long-term potentially population-level impacts depending on the species and habitat type affected, and on the size and duration of the spill.

Invertebrates and Lower Trophic Levels—Routine operations could result in negligible to moderate impacts to primarily benthic invertebrates, primarily from habitat disturbance associated with infrastructure placement and from routine discharges. Recovery could be short term to long term. Large accidental oil spills, including a CDE-level spill, could measurably depress invertebrate populations especially in intertidal areas, but no permanent impacts are expected.

Areas of Special Concern—Impacts resulting from routine activities are expected to be negligible to moderate because of existing protections and use restrictions. Large accidental oil spills, including a CDE-level spill reaching such areas, could negatively affect fauna and habitats, individuals fishing for food, commercial or recreational fisheries, recreation and tourism, and other uses of these areas.

Population, Employment and Income—Direct expenditures associated with routine operations would result in negligible impacts from small increases in population, employment and income in the region over the duration of the leasing period, corresponding to less than 1 percent of the baseline. Given existing levels of leasing activity, impacts on property values would be negligible. In areas where tourism and recreation provide significant employment, accidental oil spills, including a CDE-level spill, could result in the short-term loss of employment, income and property values. Expenditures associated with spill cleanup activities would create short-term employment and income in some parts of the affected coastal region(s).

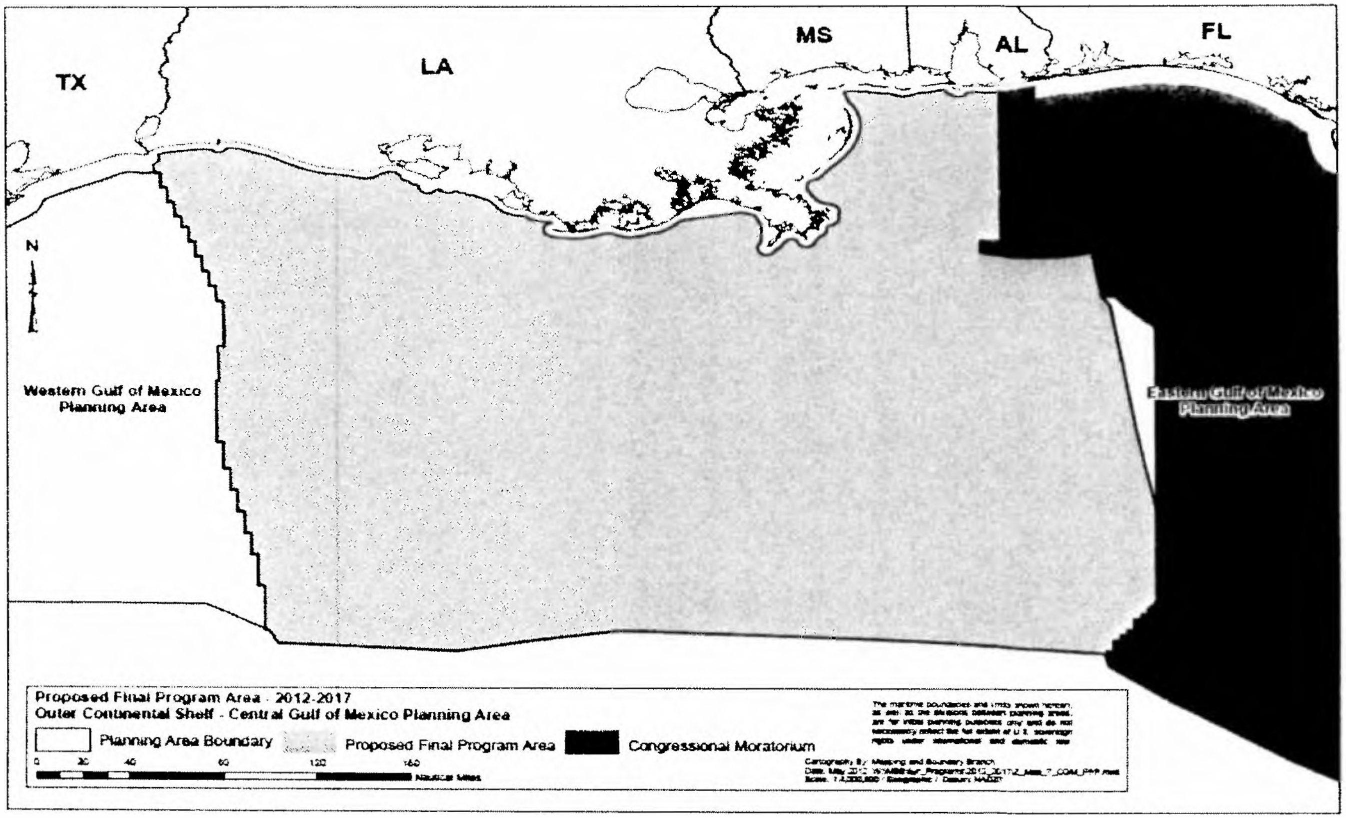
Land Use and Existing Infrastructure—Negligible to minor impacts on land use, development patterns, and infrastructure could result from routine operations. Existing infrastructure generally would be sufficient to handle exploration and development associated with potential new leases. Projected impacts from an accidental oil spill, including a CDE-level spill, would likely include stresses of the spill response on existing infrastructure, and restrictions of access to a particular area while the cleanup is being conducted. Impacts would be expected to be temporary and localized.

Fisheries—Routine operations would have a minor impact on individuals fishing for food, the cost of commercial fishing, or on the number of recreational fishing trips, in the region over the duration of the leasing period. Large accidental oil spills, including a CDE-level spill, may have small to medium, short-term impacts on fisheries resources, including lethal and sublethal toxic effects on exposed eggs, larvae, juveniles, and adults, and small to medium impacts on commercial trawling and recreational charter fishery activities and individuals fishing for food. The magnitude and duration of effects will depend on the location, size, duration, and timing of the spill; the fisheries affected; and the duration and effectiveness of spill containment and cleanup activities.

Recreation and Tourism—Routine operations would produce minor impacts to beach recreation, sightseeing, boating, and fishing, while offshore structures would create positive impacts to diving and recreational fishing. The impact of an accidental oil spill, including a CDE-level spill, on tourism and recreation will depend on the size, location, duration, and timing of the spill, as well as on the effectiveness and timeliness of spill containment and cleanup activities.

Sociocultural Systems and Environmental Justice—Because of the well developed and long established oil and gas industry in the GOM, routine operations are expected to have minor impacts on sociocultural systems. Expansion of deepwater development could lead to longer offshore work shifts, which could increase stress to workers, families and communities. Impacts from accidental oil spills would be small, except in the case of very large spills. Very large spills, including a CDE-level spill, may temporarily halt and impact economies associated with the oil and gas industry, but also other sectors of the economy. Depending on the duration of such halts and the magnitude of economic impacts, this could result in social and cultural stress, leading to possible social pathologies. Because of the non-coastal location of the majority of low income and minority population groups, routine operations are not expected to add additional environmental justice concerns and impacts would be negligible. Impacts of accidental oil spills, including a CDE-level spill, would be minimal.

Archaeological Resources—Impacts could range from negligible to major depending on the presence of significant archaeological or historic resources in the area of potential effect. Archaeological and historic resources (especially offshore resources), may be affected by platform and pipeline construction and by dredging, which could damage or destroy affected resources. Onshore impacts (resource damage or loss; visual impacts) are possible from pipeline landfall, onshore pipeline, and road construction. Anchor drags could affect seafloor resources such as shipwrecks. Most resources are expected to be avoided.



Map 4 – Central Gulf of Mexico Program Area

Option 2 (No Sale)

Valuation. The net benefits of production would be zero since no activity would occur. However, foregoing the production anticipated to result from a sale(s) in the Central GOM would result in environmental and social costs incurred to obtain the energy substitutes, including additional imports of oil and increased onshore production of oil and natural gas, among others.

Environmental Impacts. This option is analyzed in the Five Year Final EIS under Alternatives 4 and 8. A summary of the Five Year Final EIS findings follows.

Under this option the potential direct effects of routine operations in the Central GOM that are described under the analysis of the proposed action would not occur. No oil spills would originate within the Central GOM from new leasing, although marine and coastal resources there would be exposed to effects from spills that originated from existing leases in the Central GOM or from elsewhere including the Western and Eastern GOM. Energy substitutions for the foregone hydrocarbon production in the Central GOM would be moderate and would be accounted for largely by increased import tankering, a considerable proportion of which is expected to be destined for terminals requiring transit through the Central GOM. This option would create a discontinuity in the regular occurrence of lease sales in the Central GOM that would result in reduced local employment and labor income, as well as potential outmigration and reductions in community services.

Eastern Gulf of Mexico

Key Comparative Results. Given current information, no production is expected from the Eastern GOM Program Area in the low-price case.[23] After exploration, however, this assessment may change. Therefore, the net benefits of anticipated production in this PFP area are estimated at about $2.73 billion in the mid-price case and $5.99 billion in the high-price case. The area ranks "Most Sensitive to Impact" as a component of environmental sensitivity and 2nd of 6th for marine productivity.

Selected Comments The Florida DEP was concerned about effects from oil and natural gas activities from all of the GOM, not just the Eastern Gulf. DEP requested consideration be given to long-term protection of the state's coastal and marine resources. DOE and DOD support the OCS program. However, DOD referred to its concerns expressed in April 2010, about areas of the Eastern Gulf and requested early coordination on any sales in those areas due to ongoing military testing and training. Several environmental public interest groups opposed any OCS drilling, particularly in deep

[23] If exploration occurs, whether on nearby blocks leased previously or on blocks leased under this program, the results could change the ultimate net benefits at any price level. However, exploration without eventual production would create negative net benefits (costs only).

water and/or in the Eastern Gulf, due to the high risk and low net benefit. Five companies in the oil and gas industry supported the PP which included this area.

Responses. The relatively small area considered for leasing in the Eastern Gulf is that area that is available pursuant to GOMESA, more than 125 miles off the Florida coast and west of 86°41'W longitude. DOD and DOI have a long history of successfully coordinating dual use of areas of the Eastern Gulf under the 1983 Memorandum of Agreement, with early and continuing coordination being the linchpin. DOI has made significant progress in accelerating reforms that have improved the safety and environmental protection of the OCS since the *Deepwater Horizon* event, improving both the safety of offshore drilling to reduce the risk of another loss of well control in the oceans, and the collective ability to respond to a blowout and spill.

(1) Two sales in 2014 and 2016 in the program area depicted on Map 5.

(2) One sale in 2014 in the program area depicted on Map 5.

(3) No sale

Discussion

Option 1 (2 Sales)

Valuation. Given current information, no production is expected from the Eastern GOM Program Area at the low-price case; therefore net benefits are assumed to be zero. If exploration occurs, net benefits could be either negative if no production results, or positive if successful exploration leads to production. The net benefits of anticipated production from two sales in this PFP area are estimated at about $2.73 billion in the mid-price case and $5.99 billion in the high-price case.[24]

Environmental Impacts. This option is analyzed in the Five Year Final EIS under Alternative 1. A summary of the Five Year Final EIS findings follows.

Water Quality—Routine operations are likely to result in small, localized, short-term impacts as a result of structure placement and construction (pipelines, platforms) and operational discharges (produced water, bilge water, and drill cuttings) and sanitary and domestic wastes. Structure placement and removal could increase suspended sediment loads, while operational discharges, sanitary and domestic wastes, and deck drainage could affect chemical water quality. Compliance with NPDES permits and USCG regulations would reduce most impacts of routine operations. The effects of accidental oil spills will depend upon material, spill size, location, and remediation activities. Small spills would likely result in short-term, localized impacts. Impacts from a large oil spill (including those from a very large spill associated with an unlikely CDE, defined as a

[24] Current information indicates no difference in anticipated production for the Eastern GOM, whether from one sale or two sales. However, having two sales on the schedule would allow the Secretary the flexibility to adapt to the information available at the time of lease sale decisions.

discharge of a volume of oil into the environment that could result in catastrophic effects, could persist for an extended period of time if oil were deposited in wetland and beach sediments or low-energy environments because of potential remobilization.

Air Quality—Routine operations are expected to result in only minor impacts to air quality. Sources of air pollutants (NO_2, SO_2, PM_{10}, and CO_2) associated with OCS oil and gas development include diesel and gas engines, turbines, and support vessels. Routine operations would not result in exceeding the NAAQS or impact visibility. Small accidental oil spills could have localized and temporary impacts on marine air quality. Pollutant levels from very large spills, including accidental spills associated with an unlikely CDE, and associated *in situ* burning if used, would generally be small. Plumes from *in situ* burning could temporarily degrade visibility in PSD Class I areas.

Acoustic Environment—Routine operations could affect ambient noise conditions, and impacts to ambient noise levels are expected to be very small. The small area of the Eastern GOM available for leasing would result in the noise generating sources associated with routine operations include seismic surveys, drilling and production, infrastructure placement and removal, and vessel traffic to be localized and not widespread.

Coastal and Estuarine Habitats—Since all available leases are located 100 or more miles offshore from the Florida coast, and all onshore facilities to service the OCS operations will be located in ports along the Central GOM coast, routine operations are not expected to affect the coastal habitats of the Eastern GOM. The effects of accidental oil spills would likely be confined to marine habitats except for large spills, including a CDE-level spill that could incur both short-term and long-term impacts depending on habitat type and location and effectiveness of spill containment and cleanup activities.

Marine Habitats—Routine operations could result in minor short- and long-term impacts to benthic and pelagic habitats. Benthic habitat could be disturbed by platform and pipeline placement, dredging, and operational discharges (produced water and cuttings). Existing mitigation measures should eliminate most direct impacts to sensitive and protected benthic habitats. Marine benthic habitat could be affected by a large oil spill, including a CDE-level spill. Impacts could be long-term and range from small to medium, depending on the habitat affected; the size, duration, timing, and location of the spill; and the effectiveness of spill containment and cleanup activities.

Essential Fish Habitat—Routine operations would result in minor, short- and long-term impacts to EFH and managed species. Existing mitigation measures should eliminate most direct impacts to coral EFH should it occur. Impacts from accidental oil spills, including a CDE-level spill, could be long-term, depending on the size, duration, timing, and location of the spill; the habitats affected; and the effectiveness of spill containment and cleanup activities.

Marine Mammals—Impacts to marine mammals from routine operations include noise disturbance from seismic surveys, vessels, helicopters, construction and operation of platforms, and removal of platforms with explosives; potential collision with vessels; and exposures to discharges and wastes. Because of the small area of the Eastern GOM available for leasing, impacts to cetaceans would be small and would affect only a small area. The West Indian manatee and rare or extralimital whale species, i.e. those from outside the area, are not likely to be affected. A large accidental oil spill, including a CDE-level spill, would have minor to moderate impacts to marine mammals. Impacts from spill response activities are expected to be minor.

Terrestrial Mammals—No endangered terrestrial mammals of the Eastern GOM would be impacted by routine activities or small to large oil spills under the proposed action. A large accidental oil spill, including a CDE-level spill, could contact areas near coastal endangered beach mouse habitats.

Marine and Coastal Birds—Routine operations may result in negligible to moderate localized short-term impacts associated primarily with infrastructure installation and ship and helicopter traffic within a small area of the Eastern GOM. Impacts of routine operations to important coastal habitats such as nesting areas and overwintering sites would be small since existing support bases will be used that are located in areas of the Central GOM. Small accidental oil spills are expected to have largely local, small effects. Large spills, including a CDE-level spill, may result in large, long-term, and possibly population-level effects.

Fish Resources—Negligible impacts to fish and threatened or endangered fish species are expected from routine operations. A large accidental oil spill, including a CDE-level spill, is not likely to result in population-level impacts except potentially for spills that significantly affect overfished species and their spawning grounds. Oil contacting shoreline areas could result in lethal and sublethal effects on early life stages of some species, but no permanent population level effects are expected.

Reptiles—Routine operations could result in minor localized impacts to marine turtles primarily due to seismic exploration, facility construction, pipelines and vessel traffic. Accidental oil spills could result in large impacts depending on the size, location, duration and timing of the spill, and on the effectiveness of spill containment and cleanup activities. Small spills would likely result in short-term impacts while large spills, including a CDE-level spill, could incur both short-term and long-term potentially population level impacts depending on the species and habitat type affected, and on the size and duration of the spill.

Invertebrates and Lower Trophic Levels—Routine operations could result in negligible to moderate impacts to primarily benthic invertebrates, primarily from habitat disturbance associated with infrastructure placement, and from routine discharges. Recovery could be short-term to long-term. Large accidental oil spills, including a CDE-level spill, could measurably depress invertebrate populations especially in intertidal areas, but no permanent impacts are expected.

Areas of Special Concern—Impacts resulting from routine activities are expected to be negligible to moderate because of existing protections and use restrictions. Large accidental oil spills, including a CDE-level spill, reaching such areas could negatively affect fauna and habitats, individuals fishing for food, commercial or recreational fisheries, recreation and tourism, and other uses of these areas.

Population, Employment and Income—Direct expenditures associated with routine operations would result in negligible impacts. Effects are expected to be minimal because of the small amount of activity that is projected to occur in the Eastern GOM, and the fact that onshore support facilities will be located in ports along the Central GOM. In areas where tourism and recreation provide significant employment, accidental oil spills, including a CDE-level spill, could result in the short-term loss of employment, income and property values. Expenditures associated with spill cleanup activities would create short-term employment and income in some parts of the affected coastal region(s).

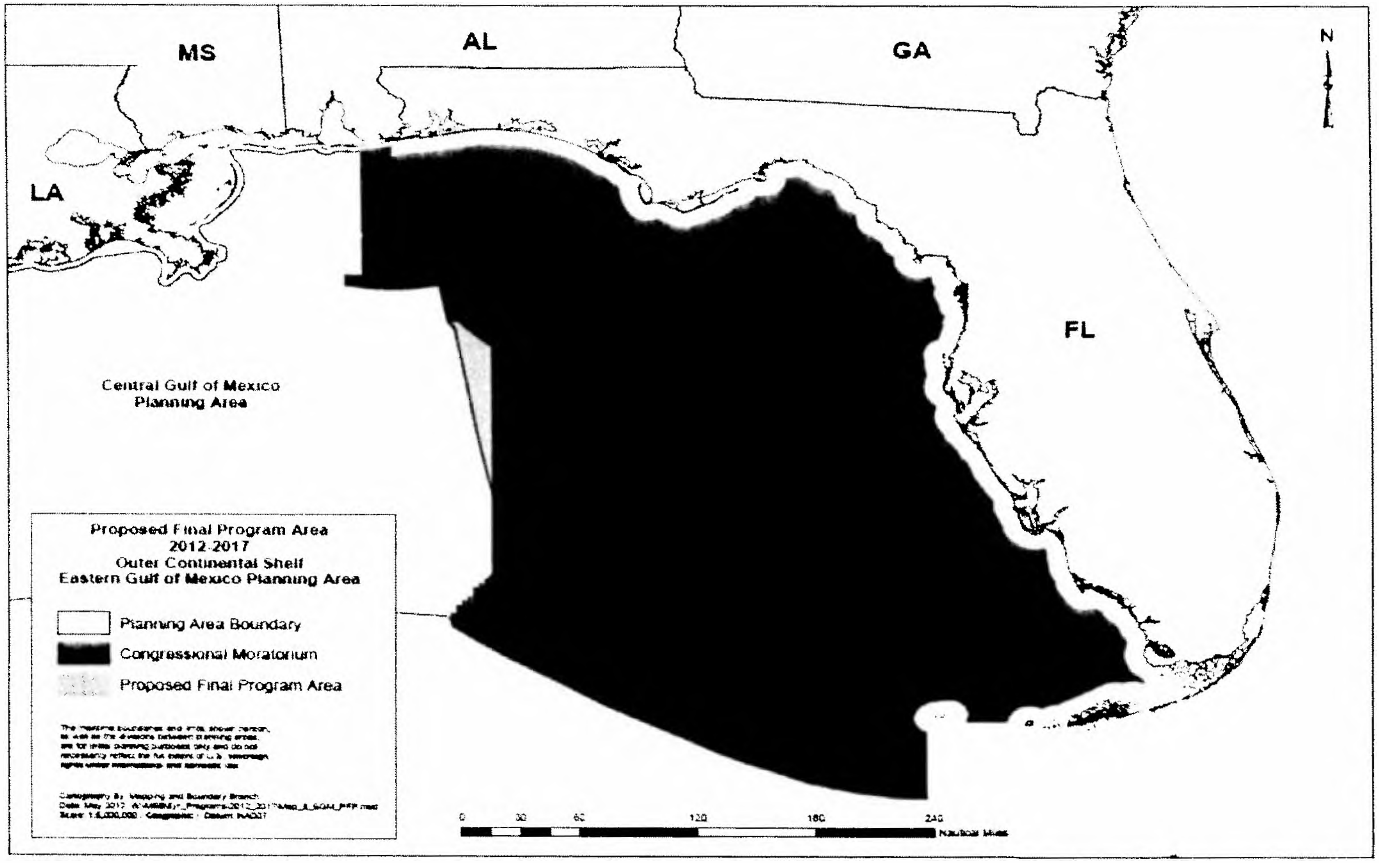
Land Use and Existing Infrastructure—No impacts to land use, development patterns, and infrastructure in the Eastern GOM would occur. Facilities and service bases will be located in ports along the Central GOM coast. Employment needs will likely be small and supplied by the experienced offshore work force located in all GOM coastal states. Projected impacts from an accidental oil spill, including a CDE-level spill, would likely include restrictions of access to a particular area while the cleanup is being conducted. Impacts would be expected to be temporary and localized.

Fisheries—Routine operations would have a minor impact on fishing, the cost of commercial fishing, or on the number of recreational fishing trips, in the region over the duration of the leasing period. Large accidental oil spills, including a CDE-level spill, may have small to medium, short-term impacts on fisheries resources, including lethal and sublethal toxic effects on exposed eggs, larvae, juveniles, and adults, and small to medium impacts on commercial trawling and recreational charter fishery activities and individuals fishing for food. The magnitude and duration of effects will depend on the location, size, duration, and timing of the spill; the fisheries affected; and the duration and effectiveness of spill containment and cleanup activities.

Recreation and Tourism—Routine operations would result in minimal impacts to beach recreation, sightseeing, boating, and fishing since OCS structures and facilities will be located at least 100 miles from the Florida shoreline, and onshore support facilities will be located in coastal areas of the Central GOM. Offshore structures would create positive impacts to diving and recreational fishing. The impact of an accidental oil spill,(including a CDE-level spill, on tourism and recreation will depend on the size, location, duration, and timing of the spill, as well as on the effectiveness and timeliness of spill containment and cleanup activities.

Sociocultural Systems and Environmental Justice—Because of the well developed and long established oil and gas industry in the GOM, routine operations are expected to have minor impacts on sociocultural systems. Very large spills, including a CDE-level spill, may temporarily halt and impact economies associated with the oil and gas industry, but also other sectors of the economy. Depending on the duration of such halts and the magnitude of economic impacts, this could result in social and cultural stress, leading to possible social pathologies.

Archaeological Resources—Assuming compliance with existing Federal, State, and local archaeological regulations and policies, most impacts to archaeological resources resulting from routine activities under the proposal will be avoided. Some impacts could occur to marine historic and prehistoric archaeological resources from accidental oil spills. Although it is not possible to predict the precise numbers or types of sites that would be affected, contact with archaeological sites would probably be unavoidable, and the resulting loss of information would be irretrievable.



Map 5 – Eastern Gulf of Mexico Program Area

Option 2 (1 Sale)

Valuation. The net benefits of anticipated production from one sale in this PFP area are estimated at about $2.73 billion in the mid-price case and $5.99 billion in the high-price case.[25] There is no production anticipated in the low-price case; therefore, net benefits are zero.

Environmental Impacts. This option is analyzed in the Final EIS under Alternative 1. A summary of the Five Year Final EIS findings follows.

The difference in environmental impacts between one and two sales in the small area available for leasing under Alternative 1 is negligible. The expected amount of activities and hydrocarbon development represents about 1 percent of the total for the entire GOM. These amounts are expected to remain essentially the same for the one and two-sale program options.

Option 3 (No Sale)

Valuation. The net benefits of production would be zero since no activity would occur. However, foregoing the production anticipated to result from any sales in the Eastern GOM would result in environmental and social costs incurred to obtain the energy substitutes, including additional imports of oil and increased onshore production of oil and natural gas, among others.

Environmental Impacts. This option is analyzed in the Five Year Final EIS under Alternatives 2 and 8. A summary of the Five Year Final EIS findings follows.

Because of the small area of the OCS that would be removed from leasing under the No Sale Option and the small amount of resource potentially expected to occur within this area, this option would only slightly reduce risks of oil spill occurrence on the OCS or of routine operation effects within the small area

ALASKA REGION

Draft Proposed Program Decision

The 2009 DPP scheduled two sales in the Beaufort Sea, three sales in the Chukchi Sea, and two "special interest" sales in Cook Inlet. See the discussion under the Cook Inlet Options for a description of the proposed special interest sale process.

[25] Current information indicates no difference in anticipated production for the Eastern GOM, whether from one sale or two sales.

Proposed Program Decision

The PP scheduled one sale each in the Beaufort and Chukchi Seas and one special interest sale in the Cook Inlet.

Proposed Final Program Options

Chukchi Sea

Key Comparative Results. The net benefits of anticipated production from this PFP area are estimated at $8.07 billion in the low-price case, $39.54 billion in the mid-price case, and $161.28 billion in the high-price case. The area ranks as "Less Sensitive to Impact" as a component of environmental sensitivity and 5th of 6 for marine productivity.

Selected Comments. The State of Alaska requested that the sales in the Chukchi Sea not be delayed until late in the program as it also delays economic development, jobs, and securing energy independence. The Arctic Slope Regional Corporation expressed similar concerns. DOE and DOD support the program. The North Slope and Northwest Arctic Boroughs, the Inupiat Community of the Arctic Slope, and the Native Village of Kotzebue, prefer that the Chukchi Sea be excluded from the program. However, if there were a sale proposed, some or all of these Native entities wanted some or all of the following: more areas deferred at the five year stage, a more comprehensive and coordinated approach to filling information gaps, more realistic scenarios to address the effects of a large spill on the communities, and revenue sharing at all stages. Many environmental public interest groups expressed the same concerns. Five companies in the oil and gas industry supported the PP, which included this area.

Responses. The PFP provides for lease sales in six offshore areas, including the Chukchi Sea where there are currently active leases and where there is known or anticipated hydrocarbon potential. In Alaska and off its coast, government and industry are actively working towards the development of infrastructure, and limited exploration activities that may proceed in the near future would help to identify further needs. The program schedules one sale in the Chukchi Sea, deliberately set late in the program to allow time for further study and infrastructure development. In addition to the 25-mile buffer area that has been excluded from leasing in the current 2007-2012 program and throughout preparation of this program, the Secretary also has decided at this program stage to exclude from leasing a subsistence area in the northeast portion of the program area, based on current information regarding both resource potential and areas of significant subsistence use. Furthermore, as discussed in part I of this document, in an effort to increase transparency and accountability in this process, DOI is committing to enhance several aspects of the leasing program. This includes publishing a tracking table, starting in the Five Year Final EIS, which tracks the lineage and treatment of suggestions for spatial exclusions, temporal deferrals, and/or mitigation from the program stage, to the lease sale, and then to the plans stage. The tracking table in the EIS will be accompanied by an online tracking table and interactive, web-based maps. Two deferral suggestions often mentioned were Hanna Shoal and a 60-mile coastal buffer. Both of these suggestions will be included for later consideration in the tracking table discussed in the introduction to this document.

(1) One sale in 2016 in the program area depicted in Map 6

(2) No sale

Discussion

Option 1 (1 Sale)

Valuation. The net benefits of anticipated production in the PFP area are estimated at \$8.07 billion in the low-price case, \$39.54 billion in the mid-price case, and \$161.28 billion in the high-price case

Environmental Impacts. This option is analyzed in the Five Year Final EIS under Alternative 1. A summary of the Five Year Final EIS findings follows. As noted above, the single sale for the Chukchi Sea is proposed late in the program in light of the time needed to review and analyze new information, including ongoing and future scientific studies and the results from any exploration that may occur. Lease-specific decisions, including decisions about additional deferral areas and environmental stipulations, will address new information, as well as feedback from other Federal agencies, state government, native communities, and other stakeholders.

Water Quality—Routine operations would result in minor to moderate, short-term, localized impacts such as disturbing sediments and increasing turbidity near construction sites and altering water chemistry from operational discharges. Minor water quality impacts could also occur from fluids entrained in ice roads when they break up in the spring. Compliance with NPDES permits and USCG regulations would reduce impacts of routine operations. The effects of accidental oil spills will depend upon material, spill size, location, season, response, and remediation activities. In the presence of cold temperatures and ice, cleanup activities would be extremely difficult. Small spills would likely result in short-term impacts. Impacts from a large oil spill, including those from a very large spill associated with an unlikely CDE, defined as a discharge of a volume of oil into the environment that could result in catastrophic effects, could persist for an extended period of time if oil were deposited in wetland and beach sediments or low-energy environments because of potential remobilization. Spills under ice could affect water quality for relatively long periods.

Air Quality—Routine operations are expected to result in minor impacts to air quality. Routine operations would not result in exceeding the NAAQS in public access areas or impact visibility. Smaller oil spills could have localized and temporary impacts. Pollutant levels from very large spills, including accidental spills associated with an unlikely CDE, and associated *in situ* burning, if used, could be major during the initial leak and again during cleanup efforts. Plumes from *in situ* burning could temporarily degrade visibility, but eventually, air quality is expected to return to normal or near normal. The long-term air quality effects associated with a spill and cleanup would be minor.

Acoustic Environment—Routine operations could affect ambient noise conditions, but impacts to ambient noise levels are expected to be minor. Noise generating sources associated with routine operations include seismic surveys, drilling and production, infrastructure placement and removal, and vessel traffic. Depending on the source and activity, changes in ambient noise levels could be short-term and localized (e.g., from vessel traffic), long-term and localized (from production), or short-term and less localized (from seismic surveys). Seismic surveys could result in short-term changes in ambient noise levels, but the changes could extend well beyond the survey boundary.

Coastal and Estuarine Habitats—Routine operations would be expected to result in minor to moderate localized impacts primarily due to road and facility construction, and vessel traffic. These operations could have a major effect on the local indigenous residents most proximate to development if it interferes with their subsistence practices for the greater part of a season. The effects of accidental oil spills will depend on habitats affected; the size, location, duration and timing of the spill; and on the effectiveness of spill containment and cleanup activities. Large, including CDE-level and small spills, could result in long-term and short-term impacts, depending on the habitats affected; the duration and size of the spill, and on the effectiveness of spill containment and cleanup activities.

Marine Habitats—Routine operations associated with platform and pipeline placement could result in moderate and long-term impacts to benthic habitats, primarily soft sediments. Accidental releases of oil could be long-term and range from small to medium depending on the habitat affected, cleanup method, and the size, duration, timing, and location of the spill. Routine operations could result in negligible to minor, short-term to long-term impacts to pelagic habitat. The effects of accidental releases of oil, including a CDE could result in minor, but long-term impacts to pelagic habitat and sea ice habitat, depending on the size, duration, timing, and location of the spill; the habitat affected; and the effectiveness of spill containment and cleanup activities. Severe winter weather and ice cover may be expected to limit containment and cleanup efforts in winter.

Essential Fish Habitat—Routine operations could result in no more than moderate short- and long-term impacts to EFH and managed species. Accidental releases of oil could result in moderate and long-term impacts. Impacts from accidental oil spills, including a CDE-level spill could be long-term depending on the size, duration, timing, and location of the spill; the habitats affected; and the effectiveness of spill containment and cleanup activities, which could be hampered by extreme winter conditions and ice cover.

Marine Mammals—Collisions with OCS-related vessels may injure or kill some individuals, although the incidence of such collisions is expected to be low. Vessels, construction of ice roads, on-ice vehicles, and aircraft have been known to temporarily disturb some individuals. For example, polar bears may abandon dens. However, these effects would likely be short-term and mitigation can reduce the disturbance. Negligible to minor impacts to fauna from disturbance or habitat loss from construction and operation of onshore pipeline are expected. Disturbance from noise sources is the most likely impact. A large oil spill, including a CDE-level spill in the Arctic, would most likely affect marine mammals by oil-contaminated ice leads, polynyas, rookeries, beaches, and haulouts.

Terrestrial Mammals—Impacts to terrestrial mammals from routine operations would be negligible to minor. A spill, especially from an onshore pipeline, could contaminate habitats used by caribou, grizzly and brown bears, Arctic foxes, and muskoxen. Coastal beaches are particularly critical to species including caribou seeking relief from mosquitoes. Aircraft overflights could also cause short-term disturbances to terrestrial mammals.

Marine and Coastal Birds—Routine operations may result in negligible to moderate localized short-term impacts; impacts associated primarily with infrastructure construction, and ship and helicopter traffic. Impacts of routine operations to important coastal habitats such as nesting areas and overwintering sites could result in greater, more long-term impacts should normal breeding and nesting activities be disrupted. Small accidental oil spills are expected to have largely local, small effects. Large spills, including a CDE-level spill, may result in large, long-term, and possibly population-level effects. The actual magnitude of the effects will depend on the size, duration, and timing of the spill; the species and habitats affected; and the effectiveness of spill containment and cleanup activities. Because of the importance of certain habitat areas for some migrating and breeding birds, spills affecting those birds and habitats could result in long-term population level impacts for some species if the spills affect important nesting colonies, migratory staging areas, or wintering grounds.

Fish Resource —Negligible to minor impacts to fish are expected from routine operations. The impact magnitude of a large oil spill, including a CDE-level spill, would depend on the location, timing, and size of the spill, and the distribution and ecology of affected fish species. Oil contacting shoreline areas could result in large-scale lethal and long-term sublethal effects on early life stages, but no permanent population level effects are expected. Spills occurring near or under ice could be difficult to clean and may persist in the water column and continue to affect fish for an extended period.

Invertebrates and Lower Trophic Levels—Routine operations could result in negligible to moderate impacts to primarily benthic invertebrates. Recovery could be short- to long-term. Large accidental oil spills, including a CDE-level spill, could measurably depress invertebrate populations, especially in intertidal areas. Spills occurring under ice would result in prolonged exposure of invertebrates and lower trophic level biota. However, no permanent impacts are expected.

Areas of Special Concern—Impacts resulting from routine activities are expected to be negligible to moderate because of the existing protections and use restrictions. Impacts from large accidental oil spills, including a CDE-level spill reaching such areas, could negatively affect fauna and habitats, subsistence use, commercial or recreational fisheries, recreation and tourism, and other uses.

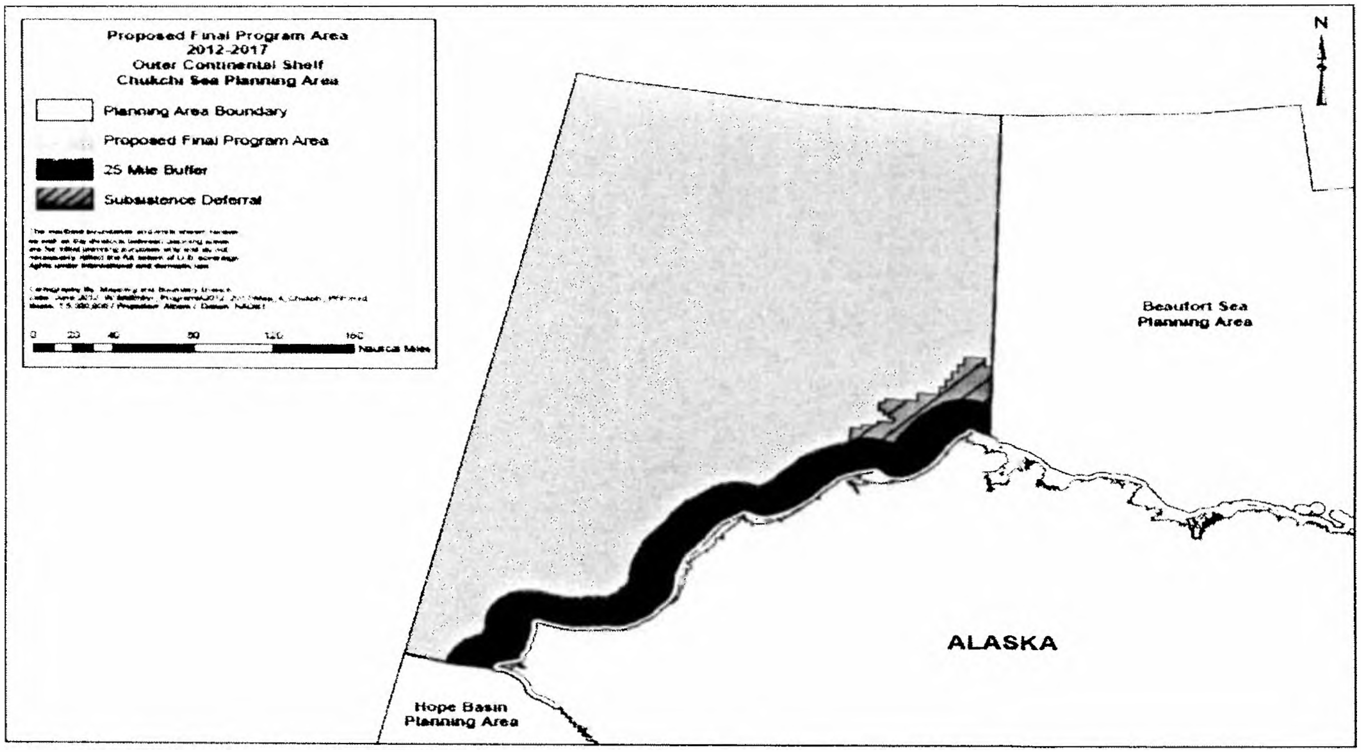
Population, Employment, and Income—Direct expenditures associated with routine operations would result in minor impacts from small increases in population, employment and income in arctic communities over the duration of the leasing period, corresponding to less than 5 percent of the baseline. Expenditures associated with spill cleanup activities would create short-term employment and income in some parts of the affected coastal region(s).

Land Use and Existing Infrastructure—Routine operations would result in minimal to moderate impacts to land use, development patterns, and infrastructure. The construction and operation of offshore facilities would expand the area potentially at risk from accidental oil spills, along with the requirement to maintain oil-spill response equipment. An accidental oil spill, including a CDE-level spill, could alter land use temporarily but would not likely result in long-term changes. The magnitude of the impacts would depend on the size and location of the spill.

Fisheries—Routine operations would have a minor impact on subsistence fishing over the duration of the leasing period. Large accidental oil spills, including a CDE-level spill, may have small to medium, short-term impacts on fisheries resources, including (lethal and sublethal toxic effects on exposed eggs, larvae, juveniles, and adults, and small to medium impacts on commercial, recreational, and subsistence fishery activities, such as trawling and charter fishing. The magnitude and duration of effects will depend on the location, size, duration, and timing of the spill; the fisheries affected; and the duration and effectiveness of spill containment and cleanup activities.

Sociocultural Systems and Environmental Justice—Potential impacts of routine operations can range from minor to major on sociocultural systems in the Arctic planning areas, depending on shore base infrastructure and proximity to existing communities. Accidental oil spills, including a CDE-level spill, however, may result in larger impacts, especially in the Arctic where impacts to subsistence could result in major impacts to affected communities.

Archaeological Resources—Routine operations could affect significant archaeological and historic resources especially in offshore locations through construction activities such as platform and pipeline construction. Onshore impacts including visual impacts are also possible from pipeline landfall, onshore pipeline, and road construction. Impacts could range from negligible to major, depending on the presence of significant archaeological or historic resources in the area of potential effect. Most resources are expected to be avoided. Accidental oil spills, including a CDE-level spill, could impact archaeological and historic resources, depending on the spill location, size, and duration, as well on the effectiveness and nature of spill containment and cleanup activities.



Map 6 – Chukchi Sea Program Area

Option 2 (No Sale)

Valuation. The net benefits of production would be zero since no activity would occur. However, foregoing the production anticipated to result from a Chukchi Sea sale would result in environmental and social costs incurred to obtain the energy substitutes, including additional imports of oil and increased onshore production of oil and natural gas, among others. This also could affect the long-term viability of the Trans Alaska Pipeline (TAPS).

Environmental Impacts. This option is analyzed in the Five Year Final EIS under Alternatives 6 and 8. A summary of the Five Year Final EIS findings follows.

Under this option the potential direct effects of routine operations in the Chukchi Sea that are described under the analysis of the proposed action would not occur. No oil spills would originate within the Chukchi Sea from new leasing, although marine and coastal environmental resources there could be affected by a spill that originates from existing leases in the Chukchi Sea or from the Beaufort Sea. Energy substitutions for the forgone hydrocarbon production in the Chukchi Sea under this option could increase tanker import spill risks (including the risk of a CDE) in OCS areas along the Pacific, GOM, and Atlantic coasts that contain tanker ports and terminals.

Beaufort Sea

Key Comparative Results. The net benefits of anticipated production in this PFP area are estimated at $1.28 billion in the low-price case, $6.14 billion in the mid-price case, and $25.71 billion in the high-price case. The area ranks as "More Sensitive to Impact" as a component of environmental sensitivity and 6th of 6 for marine productivity.

Selected Comments. The State of Alaska requested that the sale in the Beaufort Sea not be delayed until late in the program as it also delays economic development, jobs, and securing energy independence. The Arctic Slope Regional Corporation expressed similar concerns. DOE and DOD support the program, but DOD said it might need site-specific stipulations at the lease sale stage for radar facilities. The North Slope and Northwest Arctic Boroughs, the Inupiat Community of the Arctic Slope, and the Native Village of Kotzebue, prefer that the Beaufort Sea be excluded from the program. However, if there were sales proposed, some or all of these Native entities wanted some or all of the following: more areas deferred at the five year stage, a more comprehensive and coordinated approach to filling information gaps, more realistic scenarios to address the effects of a large spill on the communities, and revenue sharing at all stages. Many environmental public interest groups expressed the same concerns as the Native entities. Five companies in the oil and gas industry supported the PP which included this area.

Responses. The PFP provides for lease sales in six offshore areas, including the Beaufort Sea, where there are currently active leases and/or exploration and where there is known or anticipated hydrocarbon potential. In Alaska and off its coast, government and industry are actively working towards the development of infrastructure, and limited exploration activities that may proceed in the near future would help to identify further needs. This program schedules one sale in the Beaufort Sea, deliberately set late in the program to allow time for further study and infrastructure development. As discussed in part I of this document, in an effort to increase transparency and accountability in this process, DOI is committing to enhance several aspects of the leasing program. This includes publishing a tracking table, starting in the Five Year Final EIS, which tracks the lineage and treatment of suggestions for spatial exclusions, temporal deferrals, and/or mitigation from the program stage, to the lease sale, and then to the plans stage. The tracking table in the EIS will be accompanied by an online tracking table and interactive, web-based maps. Such suggestions, for example, as the request for additional whaling deferral areas such as Cross Island will be included for further consideration in the tracking table discussed in the introduction to this document.

(3) One sale in 2017 in the program area depicted in Map 7

(4) No sale

Discussion

Option 1 (1 Sale)

Valuation. The net benefits of anticipated production in the PFP area are estimated at $1.28 billion in the low-price case, $6.14 billion in the mid-price case, and $25.71 billion in the high-price case.

Environmental Impacts. This option is analyzed in the Final EIS under Alternative 1. A summary of the Final EIS findings follows. As noted above, the single sale for the Beaufort Sea is proposed late in the program in light of the time needed to review and analyze new information, including ongoing and future scientific studies and the results from any exploration that may occur. Lease-specific decisions, including decisions about additional deferral areas and environmental stipulations, will address new information, as well as feedback from other Federal agencies, state government, native communities, and other stakeholders.

Water Quality—Routine operations would result in minor to moderate, short-term, localized impacts such as disturbing sediments and increasing turbidity near construction sites and altering water chemistry from operational discharges. Minor water quality impacts could also occur from fluids entrained in ice roads when they break up in the spring. Compliance with NPDES permits and USCG regulations would reduce impacts of routine operations. The effects of accidental oil spills will depend upon material, spill size, location, season, response, and remediation activities. In the presence of cold temperatures and ice, cleanup activities would be extremely difficult. Small spills would likely result in short-term impacts. Impacts from a large oil spill, including those from a very large spill associated with an unlikely CDE, defined as a discharge of a volume of oil into the environment that could result in catastrophic effects, could persist for an extended period of time if oil were deposited in wetland and beach sediments or low-energy environments because of potential remobilization. Spills under ice could affect water quality for relatively long periods.

Air Quality—Routine operations are expected to result in minor impacts to air quality. Routine operations would not result in exceeding NAAQS in public access areas or impact visibility. Smaller oil spills could have localized and temporary impacts. Pollutant levels from very large spills, including accidental spills associated with an unlikely CDE, and associated *in situ* burning if used, could be major during the initial leak and again during cleanup efforts. Plumes from *in situ* burning could temporarily degrade visibility, but eventually, air quality is expected to return to normal or near normal. The long-term air quality effects associated with a spill and cleanup would be minor.

Acoustic Environment—Routine operations could affect ambient noise conditions, but impacts to ambient noise levels are expected to be minor. Noise generating sources associated with routine operations include seismic surveys, drilling and production, infrastructure placement and removal, and vessel traffic. Depending on the source and activity, changes in ambient noise levels could be short-term and localized (e.g., from vessel traffic), long-term and localized (from production), or short-term and less localized (from seismic surveys). Seismic surveys could result in short-term changes in ambient noise levels, but the changes could extend well beyond the survey boundary.

Coastal and Estuarine Habitats—Routine operations would be expected to result in minor to moderate localized impacts primarily due to road and facility construction, and vessel traffic. These operations could have a major effect on the local indigenous residents most proximate to development if it interferes with their subsistence practices for the greater part of a season. The effects of accidental oil spills will depend on habitats affected; the size, location, duration and timing of the spill; and on the effectiveness of spill containment and cleanup activities. Large, including a CDE-level, and small spills could result in long-term and short-term impacts, depending on the habitats affected; the duration and size of the spill, and on the effectiveness of spill containment and cleanup activities.

Marine Habitats—Routine operations associated with platform and pipeline placement could result in moderate and long-term impacts to benthic habitats, primarily soft sediments. Accidental releases of oil could be long-term and range from small to medium depending on the habitat affected, cleanup method, and the size, duration, timing, and location of the spill. Major impacts to hard bottom kelp habitat could occur if these areas were heavily oiled and high mortality occurs. Routine operations could result in negligible to minor, short-term to long-term impacts to pelagic habitat. The effects of accidental releases of oil, including a CDE, could result in minor, but long-term impacts to pelagic habitat and sea ice habitat, depending on the size, duration, timing, and location of the spill; the habitat affected; and the effectiveness of spill containment and cleanup activities. Severe winter weather and ice cover may be expected to limit containment and cleanup in winter.

Essential Fish Habitat—Routine operations could result in no more than moderate short- and long-term impacts to EFH and managed species. Accidental releases of oil could result in moderate and long-term impacts. Impacts from accidental oil spills, including a CDE-level spill, could be long-term depending on the size, duration, timing, and location of the spill; the habitats affected; and the effectiveness of spill containment and cleanup activities, which could be hampered by extreme winter conditions and ice cover.

Marine Mammals—Collisions with OCS-related vessels may injure or kill some individuals, although the incidence of such collisions is expected to be low. Vessels, construction of ice roads, on-ice vehicles, and aircraft have been known to temporarily disturb some individuals. For example, polar bears may abandon dens, but these effects would likely be short-term and mitigation can reduce the disturbance. Negligible to minor impacts to fauna from disturbance or habitat loss from construction and operation of onshore pipeline are expected. Disturbance from noise sources is the most likely impact. A large oil spill, including a CDE-level spill, in the Arctic would most likely affect marine mammals by oil-contaminated ice leads, polynyas, rookeries, beaches, and haulouts.

Terrestrial Mammals—Impacts to terrestrial mammals from routine operations would be negligible to minor. A spill, especially from an onshore pipeline, could contaminate habitats used by caribou, grizzly and brown bears, Arctic foxes, and muskoxen. Coastal beaches are particularly critical to species including caribou seeking relief from mosquitoes. Aircraft overflights could also cause short-term disturbances to terrestrial mammals.

Marine and Coastal Birds—Routine operations may result in negligible to moderate localized short-term impacts; impacts associated primarily with infrastructure construction, and ship and helicopter traffic. Impacts of routine operations to important coastal habitats such as nesting areas and overwintering sites could result in greater, more long-term impacts should normal breeding and nesting activities be disrupted. Small accidental oil spills are expected to have largely local, small effects. Large spills, including a CDE-level spill, may result in large, long-term, and possibly population-level effects. The actual magnitude of the effects will depend on the size, duration, and timing of the spill; the species and habitats affected; and the effectiveness of spill containment and cleanup activities. Because of the importance of certain habitat areas for some migrating and breeding birds, spills affecting those birds and habitats could result in long-term population level impacts for some species if the spills affect important nesting colonies, migratory staging areas, or wintering grounds.

Fish Resource— Negligible to minor impacts to fish are expected from routine operations. The impact magnitude of a large oil spill, including a CDE-level spill, would depend on the location, timing, and size of the spill, and the distribution and ecology of affected fish species. Oil contacting shoreline areas could result in large-scale lethal and long-term sublethal effects on early life stages, but no permanent population level effects are expected. Spills occurring near or under ice could be difficult to clean and may persist in the water column and continue to affect fish for an extended period.

Invertebrates and Lower Trophic Levels—Routine operations could result in negligible to moderate impacts to primarily benthic invertebrates. Recovery could be short- to long-term. Large accidental oil spills, including a CDE-level spill, could measurably depress invertebrate populations, especially in intertidal areas. Spills occurring under ice would result in prolonged exposure of invertebrates and lower trophic level biota. However, no permanent impacts are expected.

Areas of Special Concern—Impacts resulting from routine activities are expected to be negligible to moderate because of the existing protections and use restrictions. Impacts from large accidental oil spills, including a CDE-level spill, reaching these areas could negatively affect fauna and habitats, subsistence use, commercial or recreational fisheries, recreation and tourism, and other uses.

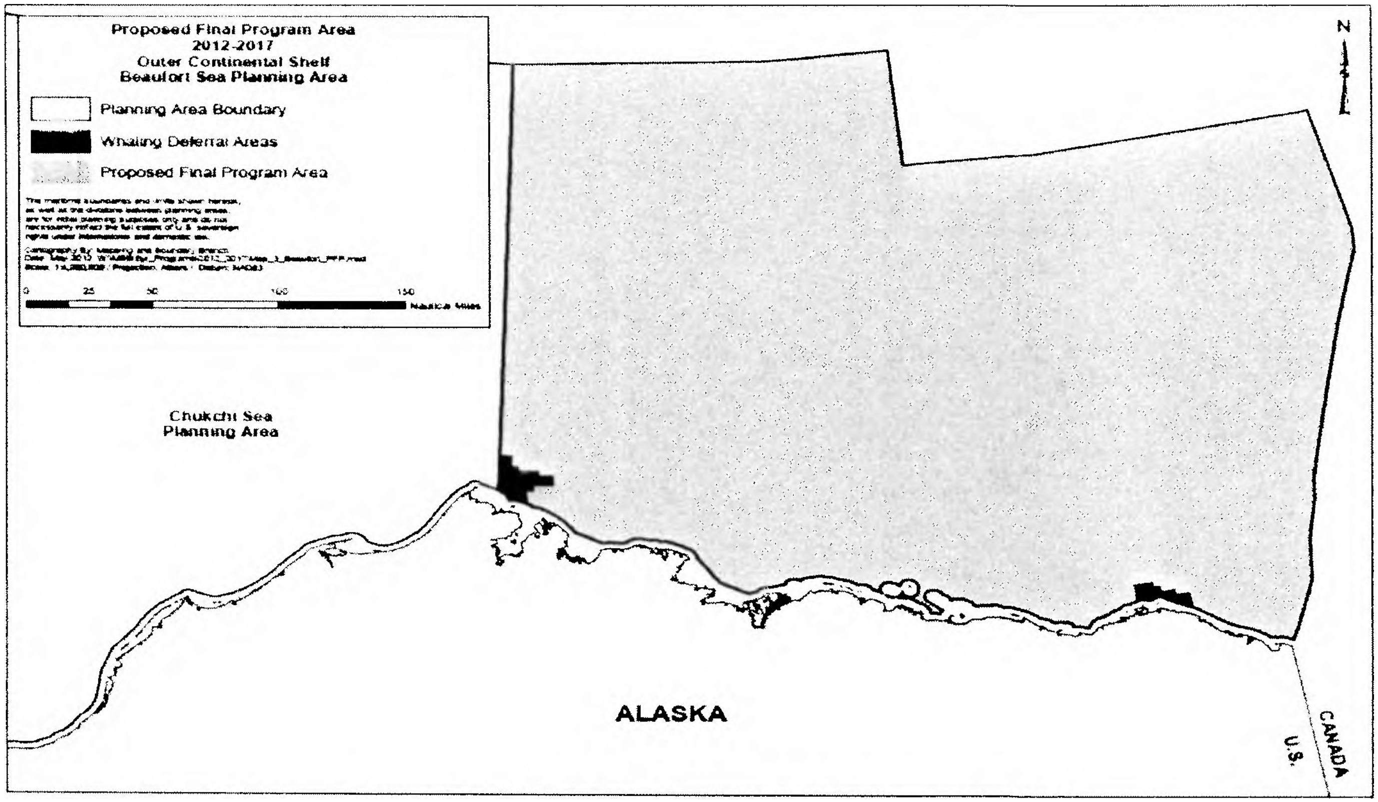
Population, Employment, and Income—Direct expenditures associated with routine operations would result in minor impacts from small increases in population, employment and income in arctic communities over the duration of the leasing period, corresponding to less than 5 percent of the baseline. Expenditures associated with spill cleanup activities would create short-term employment and income in some parts of the affected coastal region(s).

Land Use and Existing Infrastructure—Routine operations would result in minimal to moderate impacts to land use, development patterns, and infrastructure. The construction and operation of offshore facilities would expand the area potentially at risk from accidental oil spills, along with the requirement to maintain oil-spill response equipment. An accidental oil spill, including a CDE-level spill, could alter land use temporarily but would not likely result in long-term changes. The magnitude of the impacts would depend on the size and location of the spill.

Fisheries—Routine operations would have a minor impact on subsistence fishing over the duration of the leasing period. Large accidental oil spills, including a CDE-level spill, may have small to medium, short-term impacts on fisheries resources, including lethal and sublethal toxic effects on exposed eggs, larvae, juveniles, and adults, and small to medium impacts on subsistence fishery and other commercial and recreational fishing activities, such as trawling and charter fishing. The magnitude and duration of effects will depend on the location, size, duration, and timing of the spill; the fisheries affected; and the duration and effectiveness of spill containment and cleanup activities.

Sociocultural Systems and Environmental Justice—Potential impacts of routine operations can range from minor to major on sociocultural systems in the Arctic planning areas, depending on shore base infrastructure and proximity to existing communities. Accidental oil spills, including A CDE-level spill; however, may result in larger impacts, especially in the Arctic where impacts to subsistence could result in major impacts to affected communities.

Archaeological Resources—Routine operations could affect significant archaeological and historic resources especially in offshore locations through construction activities such as platform and pipeline construction. Onshore impacts including visual impacts are also possible from pipeline landfall, onshore pipeline, and road construction. Impacts could range from negligible to major, depending on the presence of significant archaeological or historic resources in the area of potential effect. Most resources are expected to be avoided. Accidental oil spills, including a CDE-level spill, could impact archaeological and historic resources, depending on the spill location, size, and duration, as well on the effectiveness and nature of spill containment and cleanup activities.



Map 7 – Beaufort Sea Program Area

Option 2 (No Sale)

Valuation. The net benefits of production would be zero since no activity would occur. However, foregoing the production anticipated to result from a Beaufort Sea sale would result in environmental and social costs incurred to obtain the energy substitutes, including additional imports of oil and increased onshore production of oil and natural gas, among others. This also could affect the long-term viability of TAPS.

Environmental Impacts. This option is analyzed in the Final EIS under Alternatives 5 and 8. A summary of the Final EIS findings follows.

Under this option the potential direct effects of routine operations in the Beaufort Sea that are described under the analysis of the proposed action would not occur. No oil spills would originate within the Beaufort Sea from new leasing, although marine and coastal environmental resources there could be affected by a spill that originates from existing leases in the Beaufort Sea or from the Chukchi Sea. Energy substitutions for the foregone hydrocarbon production in the Beaufort Sea under this option could increase tanker import spill risks (including that of a catastrophic discharge event) in OCS areas along the Pacific, GOM, and Atlantic coasts that contain tanker ports and terminals.

Cook Inlet

Key Comparative Results. The net benefits for this PFP area are estimated at $1.99 billion in the low-price case, $4.17 billion in the mid-price case, and $13.98 billion in the high-price case. The area ranks as "Less Sensitive to Impact" as a component of environmental sensitivity and 1st of 6 for marine productivity.

Selected Comments. While many commenters were either in favor of or opposed to the OCS program as a whole, there was little said about leasing in Cook Inlet. DOD requested caution to avoid submarine communications cables. Five companies in the oil and gas industry supported the PP which included this area.

Reponses. The Cook Inlet is included as a special interest sale. The March 27, 2012, Request for Interest resulted in a sufficient expression of interest with respect to the Cook Inlet planning area. In light of responses to the Request, BOEM decided to proceed with the pre-sale process for the Cook Inlet and to place the date for a potential lease sale in 2016 to allow time to complete the necessary steps under the Act, develop additional resource and environmental information, and conduct analysis under NEPA.

(1) **One special interest sale in 2016 in the program area depicted in Map 8**

(2) No sale

Discussion

Option 1 (1 Sale)

Valuation. The net benefits of anticipated production for this PFP area are estimated \$1.99 billion in the low-price case, \$4.17 billion in the mid-price case, and \$13.98 billion in the high-price case.

Environmental Impacts. This option is analyzed in the Final EIS under Alternative 1. A summary of the Final EIS findings follows.

Water Quality—Normal operations in the Cook Inlet could adversely impact water quality. However because of dilution, settling, and flushing, these impacts are expected to be localized and temporary. Similarly, spills to coastal waters could adversely impact water quality. The impacts of these spills will be localized and short term, unless chronic spills occur in a localized area. Impacts from a large oil spill including those from a very large spill associated with an unlikely CDE, defined as a discharge of a volume of oil into the environment that could result in catastrophic effects, could persist for an extended period of time if oil were deposited in wetland and beach sediments or low-energy environments because of potential remobilization. The extent and magnitude of the impact would depend on the size, location, and season of the spill. Recovery times could be decreased by oil-spill cleanup activities.

Air Quality—Concentrations of NO_2, SO_2, and PM_{10} from any routine activities associated with the proposed Five Year Program activities in the Cook Inlet would be within the applicable maximum allowable increases. The concentrations of NO_2, SO_2, PM_{10}, and CO_2 would remain well within the NAAQS. Any air quality impacts from oil spills would be localized and of short duration. Pollutant levels from very large spills, including accidental spills associated with an unlikely CDE, and associated *in situ* burning if used, could be major during the initial leak and again during cleanup efforts. For example, plumes from *in situ* burning could temporarily degrade visibility, but eventually, air quality is expected to return to normal or near normal. The long-term effects associated with a spill and cleanup would be minor.

Acoustic Environment—Routine operations could affect ambient noise conditions, but impacts to ambient noise levels are expected to be minor. Noise generating sources associated with routine operations include seismic surveys, drilling and production, infrastructure placement and removal, and vessel traffic. Depending on the source and activity, changes in ambient noise levels could be short-term and localized (e.g., from vessel traffic), long-term and localized (from production), or short-term and less localized (from seismic surveys). Seismic surveys could result in short-term changes in ambient noise levels, but the changes could extend beyond the survey boundary.

Coastal and Estuarine Habitats—Routine operations would be expected to result in minor to moderate localized impacts primarily due to one potential pipeline landfall and vessel traffic. The effects of accidental oil spills will depend on habitats affected; the size, location, duration and timing of the spill; and on the effectiveness of spill containment and cleanup activities. Large, including CDE-level, and small spills could result in long-term and short-term impacts, depending on the habitats affected; the duration and size of the spill, and on the effectiveness of spill containment and cleanup activities.

Marine Habitats—Routine operations associated with platform and pipeline placement could result in moderate and long-term impacts to benthic habitats, primarily soft sediments. Accidental releases of oil could be long-term and range from small to medium depending on the habitat affected, cleanup method, and the size, duration, timing, and location of the spill. Routine operations could result in negligible to minor, short-term to long-term impacts to pelagic habitat. The effects of accidental releases of oil, including a CDE, could result in minor, but long-term impacts to pelagic habitats depending on the size, duration, timing, and location of the spill; the habitat affected; and the effectiveness of spill containment and cleanup activities.

Essential Fish Habitat—Routine operations could result in no more than moderate short- and long-term impacts to EFH and managed species. Accidental releases of oil could result in moderate and long-term impacts. Impacts from accidental oil spills, including a CDE-level spill, could be long-term depending on the size, duration, timing, and location of the spill; the habitats affected; and the effectiveness of spill containment and cleanup activities.

Marine Mammals—Noise, contaminants, human activity, and ship and helicopter traffic associated with routine OCS operations in the Cook Inlet could affect marine mammals. Noise generated during exploration, construction, and operations may temporarily disturb some individuals, causing them to leave or avoid the area, but the effects would likely be short-term not result in population-level effects. While collisions with OCS-related vessels may injure or kill some individuals, collisions would be relatively unlikely because of the low level of traffic expected from the proposed action. Accidental oil spills may result in the direct and indirect exposure of marine mammals and their habitats to the oil and subsequent weathering products. The magnitude of effects from accidental spills would depend on the location, timing, and volume of the spills; the habitats affected by the spills, such as coastal habitats; and the species exposed. The greatest risk to marine mammals would be associated with large spills, including a CDE, in coastal habitats. Spill cleanup operations could result in short-term disturbance of marine mammals in the vicinity of the cleanup activity, while a collision with a cleanup vessel could injure or kill the affected individual. Disturbance of adults with young during cleanup could reduce survival of the young animals.

Terrestrial Mammals—The construction and normal operations of a potential new onshore pipeline landfall could result in short-term and long-term impacts to terrestrial mammals. Short-term impacts would be largely behavioral in nature, with affected animals avoiding or vacating the construction areas. Similarly, vehicle and aircraft traffic from the proposed action in the Cook Inlet could temporarily disturb mammals along pipelines or roadways or along flight paths. The disturbance of animals by these activities would be short-term in nature and not expected to result in population-level effects. In the event of an accidental spill, including a CDE, terrestrial mammals may be exposed via ingestion of contaminated food, inhalation of airborne oil droplets, and direct ingestion of oil during grooming, which may result in a variety of lethal and sublethal effects. However, because most spills would be relatively small, less than 50 barrels, relatively few individuals would likely be exposed. While some individual, especially oil-sensitive species, such as the river otter, may incur lethal effects, population-level impacts would not be expected for most species. Cleanup activities could temporarily disturb terrestrial mammals in the vicinity of the cleanup operation, causing those animals to move from preferred to less optimal habitats, which in turn, could affect the overall condition. Such displacement would be limited to only those relatively few animals in the vicinity of the cleanup activity thus would not be expected to result in population-level effects.

Marine and Coastal Birds—Marine and coastal birds may be affected by the construction of offshore facilities, by boat and aircraft traffic servicing offshore platforms, and by noise and human activities during normal operations and maintenance activities. For most routine operations, the primary effect would be the disturbance of birds in the vicinity of the operation, causing them to temporarily leave the area. Depending on the time of year, construction activities near coastal habitats could disrupt nesting, foraging, and overwintering activities of some species, potentially impacting local populations. Accidental oil spills, including a CDE, pose the greatest threat to marine and coastal birds, affecting both birds and their habitats. Exposed birds may experience a variety of lethal or sublethal effects, and the magnitude and ecological importance of any effects would depend upon the size and location of the spill, the species and life stage of the exposed birds, and the size of the local bird population. Spill cleanup activities may also disturb birds in the vicinity of the cleanup, causing them to leave the vicinity of the cleanup activity.

Fish Resources—Fishes could be disturbed and displaced from the immediate vicinity of drilling discharges for short time periods. Offshore construction also could temporarily disturb and/or displace fishes proximate to the construction activity. Although seismic surveys may kill or injure eggs and fry of some fishes, this injury is limited to within 1 or 2 meters of the airgun-discharge ports. Thus, seismic surveys probably would have no appreciable adverse effects on fish subpopulations. Oiled intertidal areas could lead to considerable mortality of eggs and juvenile stages of some pelagic species in the affected areas. Studies indicate that impacted eggs and juvenile stages could lead to reduced adult survival. Eggs and fry of some bentho-pelagic and demersal fishes could experience lethal and sublethal effects from oil contact. Although multiple small spills or a single large spill, including a CDE, could cause declines of subpopulations of multiple species inhabiting the Cook Inlet, it is anticipated that there would be no long-term effects on overall fish populations. Accidental oil spills could impact EFH and the species that depend upon them. The nature of the impact would be largely dependent on the size of spill, location, environmental factors, and uniqueness of the affected EFH. Large spills that reach coastal streams and intertidal areas used for spawning by anadromous salmon could have more persistent impacts and require remediation.

Invertebrates and Lower Trophic Levels—Routine operations during exploration, development, and production activities under the proposed action probably would not measurably affect local populations of lower trophic-level organisms. In the event of a large oil spill, populations of lower trophic-level organisms in pelagic waters would not be greatly affected by the spill and associated cleanup activities. However, a large spill could contact some shoreline areas in Cook Inlet and lower trophic-level organisms in sensitive intertidal and shallow subtidal habitats could experience lethal and sublethal effects.

Areas of Special Concern—No development of onshore facilities is anticipated in the Cook Inlet area thereby making impacts from routine OCS operations unlikely in these coastal areas. However, offshore construction of pipelines and platforms could have temporary effects on wildlife due to noise and activity levels and on scenic values for park visitors. It is anticipated that reviews of individual lease sales would minimize the potential for impacts from routine operations due to development activities. No OCS-related development would occur in the Alaska Peninsula Unit of the Alaska Maritime National Wildlife Refuge (NWR). Effects from oil spills that occur adjacent to national park or NWR boundaries would depend on spill location, spill size, weather conditions at the time of the spill, and the effectiveness of cleanup operations. Large oil spills, including a CDE, in areas adjacent to the Gulf of Alaska or Alaska Peninsula Units of the Alaska Maritime NWR could negatively impact coastal habitats and fauna and could also affect subsistence use, commercial or recreational fisheries, and tourism.

Employment, Population, and Income—Potential effects on population, employment, and regional income from routine operations and oil spills are expected to be limited except for local effects from a large oil spill.

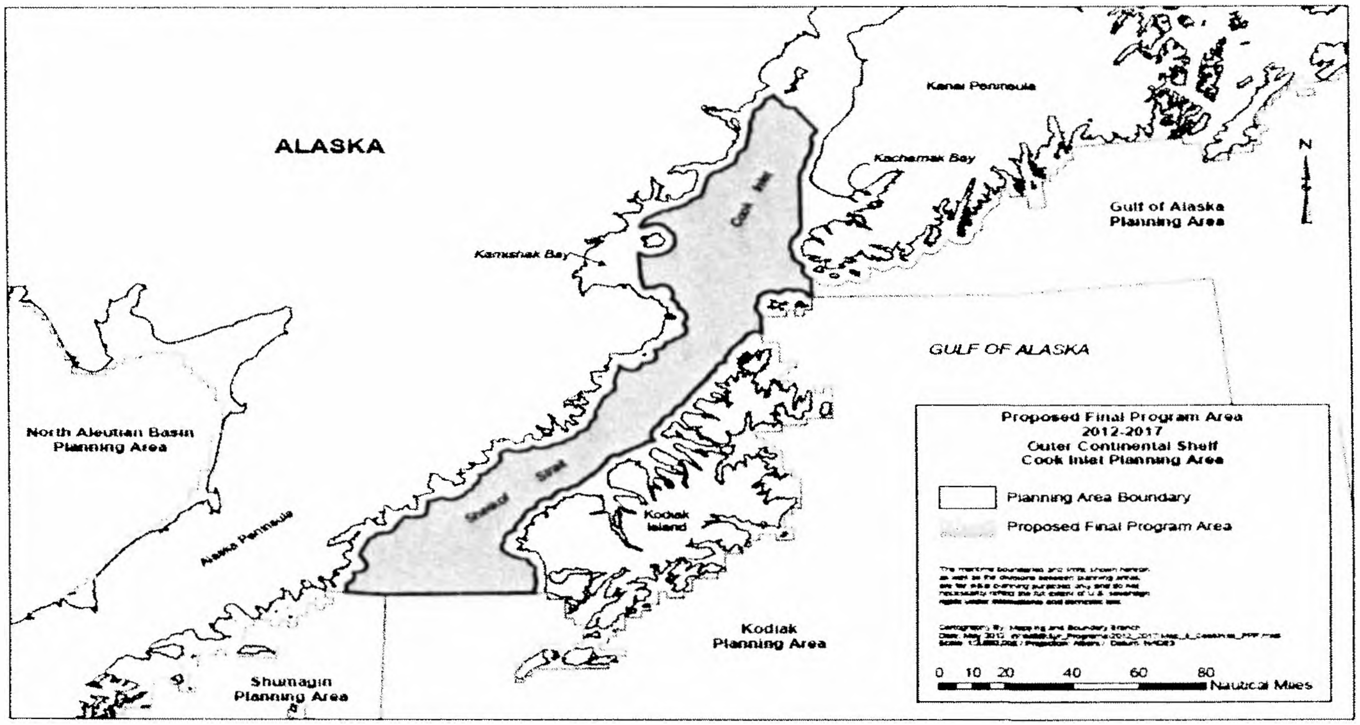
Land Use and Existing Infrastructure— Routine operations from the proposed action would have a low impact on the land use and infrastructure of the affected areas of the Cook Inlet. Accidents from the anticipated low level of activity also are expected to have minimal impact on land use and infrastructure.

Fisheries—Overall populations of biological resources that serve as the basis for commercial fisheries in the Cook Inlet are not expected to be altered by routine exploration, development, or production activities conducted as a result of lease sales under the proposed action. The level of effects from accidental spills would depend on the location, timing, and volume of spills, spill response activities, and other environmental factors. Small spills that may occur under the proposed action are unlikely to have a substantial effect on commercial fishing. A single large spill could affect a small proportion of a given fish population within Cook Inlet, although substantial temporary effects on populations could occur if important habitat areas were contaminated. Large accidental spills, including a CDE-level spill, may have small to medium short term impacts on fisheries. The effects could be as a consequence of reduced catch, loss of gear, or loss of fishing opportunities during cleanup and recovery periods

Tourism and Recreation—Routine operations would have limited effects on recreation and tourism, with potential adverse impacts to sightseeing, boating, fishing, and hiking activities. Temporary impacts would occur if a spill reached a recreational-use area. The magnitude of these impacts would depend on factors such as the size and location of the spill, and it would likely be greatest if the spill occurred during the peak recreational season.

Sociocultural Systems and Environmental Justice—Potential direct and indirect impacts on sociocultural systems due to noise, visual, and traffic disturbances, as a result of offshore operations for the proposed action, are expected to be limited. The Cook Inlet already is experiencing oil and gas development on state lands so the addition of a small amount of OCS activity should not disrupt sociocultural systems in the area. Potential impacts on sociocultural systems from accidents under the proposed action could range greatly, depending on the location and timing of a spill.

Archaeological Resources—Assuming compliance with existing Federal, State, and local archaeological regulations and policies, most impacts to archaeological resources in the Alaska region resulting from routine activities under the proposal will be avoided. Some impact may occur to coastal historic and prehistoric archaeological resources from accidental oil spills. Although it is not possible to predict the precise numbers or types of sites that would be affected, contact with archaeological sites would probably be unavoidable, and the resulting loss of information would be irretrievable, if spills should occur. The magnitude of the impact would depend on the significance and uniqueness of the information lost.



Map 8 – Cook Inlet Program Area

Option 2 (No Sale)

Valuation. The net benefits of production would be zero since no activity would occur. However, foregoing the production anticipated to result from a Cook Inlet sale would result in environmental and social costs incurred to obtain the energy substitutes, including additional imports of oil and increased onshore production of oil and natural gas, among others.

Environmental Impacts. This option is analyzed in the Final EIS under Alternatives 7 and 8. A summary of the Final EIS findings follows.

Under this option the potential direct effects of routine operations in Cook Inlet that are described under the analysis of the proposed action would not occur. No oil spills would originate within the Cook Inlet OCS area, however there is oil and natural activity in state waters. Energy substitutions for the foregone hydrocarbon production in the Cook Inlet would be small given the limited amounts of hydrocarbons that are expected to be developed there.

B. Fair Market Value Options

Introduction

The Act grants the Secretary the authority to issue leases on the OCS. Section 18(a)(4) of the Act states that "[L]easing activities shall be conducted to assure receipt of fair market value for the lands leased and the rights conveyed by the Federal Government." Furthermore, the Act states that the OCS is a "vital national reserve held by the Federal Government for the public, which should be made available for expeditious and orderly development, subject to environmental safeguards, in a manner which is consistent with the maintenance of competition and other national needs."

The FMV determination, made at the time of lease issuance, is not based on the value of the oil and natural gas eventually discovered or produced. Instead it is related to the value of the right to explore and, if there is a discovery, to develop and produce hydrocarbons. This value therefore is based on the expected, not actual, activities and results that are anticipated to occur after the sale. Moreover, this value depends upon the conditions imposed on lessees by BOEM, such as diligence and drilling requirements, which may restrict lessee flexibility in attaining certain timing milestones and hence have a negative effect on expected or actual tract value. Also, this value is based on certain assumptions such as expected oil and gas prices at the time of sale and not actual prices in the future when a discovery is made.

There are several major elements in designing OCS auctions, such as lease sale timing, bidding systems, and sale terms and conditions, for assuring that OCS leases are not awarded prematurely or for less than FMV. This section discusses important considerations used to evaluate options under these elements and includes an overview of the post-sale OCS bid adequacy process.

Draft Proposed Program Decision

The 2009 DPP decision was to set sale terms (called fiscal lease terms in the 2009 DPP) using the parameters in place for then-recent sales, subject to sale-by-sale reconsideration, and continue use of the current, two-phased bid adequacy process, subject to revision as appropriate.

Proposed Program Decision

The PP decision was the same as the 2009 DPP, but provided more analysis of the various terms and how sale-by-sale changes in those terms might affect FMV.

Proposed Final Program Options

Timing of OCS Lease Sales and Related Activities

(1) Evaluate area specific considerations, including a comparison of market prices with the hurdle prices for oil and for natural gas set in the Five Year Program document, to determine if the sale should be held as scheduled.

(2) Other.

Discussion: The first decision that must be made in the process of providing a solid foundation for ensuring receipt of FMV in a lease sale covered by the program is whether to include the entire proposed area for sale at the scheduled time or instead, to withhold some or all of the area until a later program. The value of the OCS resources can be optimized by identifying the most favorable time to sell leases. Because OCS leases have fixed initial lease periods, as long as exploration and development is expected to be privately profitable, lessees will explore and develop within that initial period. The Act calls for limited initial periods to serve several purposes, e.g., to accelerate revenue, reduce speculation, and others. However, the trade-off involved is that sometimes it would be better for the operator to wait longer to explore and develop but it cannot do so – for example, if the price of oil or natural gas seems to be trending down but might recover later. Thus, it is conceivable that greater benefits could be realized in certain cases by waiting longer to lease in the first place. An analogy can be made with bid adequacy, which is another FMV process. For many years, the accepted procedure for bid adequacy determination has included a delay analysis to estimate whether an individual lease that was bid on might attract a higher bid if withheld and reoffered in a subsequent sale. Expanding that concept to the level of the Five Year Program employs a hurdle-price screen at the program stage to assure that delaying a sale offering would not provide greater economic value from all anticipated fields in the program area. A hurdle price is defined for present purposes as the oil and gas price above which immediate exploration of at least one undiscovered prospect as identified by resource assessment is the most profitable option. This definition is explained further below.

The government's concession to the lessee is a conveyance of offshore oil and natural gas exploration and development rights for a limited initial lease period, subject to applicable regulatory and statutory requirements. Since future prices, risked resource endowments, required capital and operation costs, time needed to explore and delineate, available technologies, and the prevailing post-sale regulatory and legal environments are uncertain at the time of lease issuance, benefits for decision making may subsequently be gained when uncertainty is reduced through new information or events. This information may involve changes in resource prices and expectations, emergence of new technologies, imposition of added regulatory and legal requirements, and additional insights on the resource endowments. In the last instance, this uncertainty can only be fully resolved through the actual leasing and subsequent drilling of OCS acreage, although it also is possible to acquire better knowledge about the resource potential and risk from monitoring activities on nearby leases.

The most significant uncertainty to consider in sale planning analysis is the individual and aggregate volumes of oil and natural gas present, as well as when these undiscovered resources may become producing commercial reserves. These uncertainties are more pronounced in relatively less explored OCS areas. To estimate resource potential, BOEM uses computer models to calculate probability distributions of undiscovered recoverable oil and natural gas. The technically recoverable resource estimates assume that existing or reasonably foreseeable recovery technology will be used and operations are not constrained by the underlying economics of exploration, development and production. A second stage simulates recovery operations with cost estimates and resource price assumptions to calculate the economically recoverable resource volumes. The economically recoverable resource volumes do not include all the undiscovered resources reported as technically recoverable, but rather include those oil and natural gas resources judged to be contained in geologic fields whose sizes and locations make them economic under contemporary circumstances.

The uncertainties about the recoverable resource size and location can only be resolved by lease acquisition and drilling. Private companies must spend billions of dollars to acquire leases and analyze geologic information in their efforts to discover and ultimately produce new oil and natural gas reserves that are undiscovered today.

A good example of how exploration of an OCS province has changed the knowledge of resource potential is the GOM, where estimates of undiscovered oil resources have increased dramatically since the discovery of major deepwater oil and natural gas fields. Even with significant oil and natural gas production since 1975, amounting to nearly 14 billion barrels of oil (BBO) and 150 trillion cubic feet (tcf) of natural gas, the estimated undiscovered technically recoverable GOM oil resources have increased fivefold from that time to today and the estimated natural gas resources have more than doubled. In deep water, increases in oil and natural gas potential have been facilitated by industry's development of new technology to explore for and extract hydrocarbon resources. In all water depths, the expansion of offshore infrastructure and new technology has allowed industry to produce smaller and more geologically complex reservoirs.

Exploration also can lead to reduced resource endowment estimates. The Navarin Basin in the Alaska OCS is a good example of how exploration can render an area less attractive. A resource assessment published in 1985 reported that estimates of mean risked oil volumes in the Navarin Basin of 1.30 billion barrels (Bbbl) were much larger than the Chukchi Sea's 0.54 Bbbl. A 1983 lease sale in the Navarin Basin resulted in 163 tracts being leased for $633 million, followed by 8 exploration wells. None of the wells discovered oil or natural gas pools and the subsequent geologic analysis severely downgraded the resource potential to 0.13 Bbbl in BOEM's 2011 Assessment. There has been little or no subsequent industry interest in this area. Meanwhile, drilling results in the Chukchi Sea in 1990 and 1991, new technologies, and higher oil prices were key factors leading to the largest lease sale ever in the Alaska OCS, Chukchi Sea Sale 193, with 487 tracts leased for $2.66 billion in 2008. The current risked mean technically recoverable resource estimates for the Chukchi Sea increased 30 times over the 1985 estimate to 15.4 Bbbl of oil and over 25 times to 76.8 tcf of natural gas in this under-explored frontier area. Future exploration in this area will further decrease the uncertainties regarding its oil and natural gas resource potential.

While the value promised by a lease sale is related to the resource endowment concentration and composition and the likelihood of drilling a successful well, it also is associated with forecasts of future oil and natural gas prices. In general, a resource holder has some flexibility in conducting exploration or development activities, and the value of the resource is likely to be greater when it is optimally managed. In the case of a Federal lease, however, the lessee is constrained by the initial period limit. The government is not constrained by the limit and it can enhance value by optimal timing of the lease offering. Given the significant uncertainty of program area hydrocarbon resources as well as the inherent difficulty of accurately forecasting future oil and natural gas prices, calculating timing and composition of lease offerings is very difficult. However, managing this uncertainty becomes more feasible as resource potential is resolved through actual exploration. Moreover, the decisions needed at the Five Year Program stage focus on whether and when a particular area should be included in the sale schedule rather than the specific composition of the sale areas and the terms attached to the blocks to be included. The composition issue, along with the most effective way to achieve the desired economic results, is best left to be more fully resolved at the lease sale design stage, in part to incorporate the latest and most current information into the analysis.

Accordingly, at the program stage, BOEM's approach to determining whether an area is suitable for exploration and possible development is not based solely on a program area's aggregate resource estimates. Instead, it focuses more broadly on identifying a hurdle price below which immediate exploration for any one of a program area's potential undiscovered field sizes, as suggested by available resource assessments, would not provide the best value for society. Above the hurdle price, the program area may be considered ready for leasing, in conjunction with modification in sale configuration consistent with other program goals, because there likely exist at least one field whose resource endowment and underlying economic value are consistent with inclusion in the program's schedule. This approach reflects the insight that only as resource knowledge increases through exploration will BOEM learn more about the entire suite of available resources in order to make sound decisions about the composition of program areas along with the fiscal terms that should be included in specific future sales, as well as about which program areas to include in subsequent Five Year Programs.

The lease sale design stage involves among other things, deciding whether to hold or delay a sale that is included in a Five Year Program, which blocks to offer, setting the sale terms, and issuing leases that meet FMV requirements. Deferring these issues to the lease sale stage rather than the earlier program formulation stage provides more flexibility and allows decisions to be made closer to the time when economic conditions that influence sale decisions are better known and somewhat easier to forecast. Once leases are issued, BOEM is limited in its authority to mandate delays in activities for purely economic reasons as companies have contractual rights related to potential development and production within the regulatory framework during their initial lease term.

To formally assess the timeliness of offering program areas at the Five Year Program stage, BOEM subjected the assessment of undiscovered fields in each program area to an appropriate economic analysis to determine an area "hurdle" weighted average (i.e., barrels of oil equivalent (BOE)) price. The hurdle price is equated with the price below which delaying exploration for the largest potential undiscovered field in the sale area is more valuable than immediate exploration.[26] Given that, at the hurdle price, immediate exploration for that prospect is optimal, the initial period is not a constraint, and full value may be realized by leasing now. By this means, the economic screen indicates whether the option value from waiting might exceed the expected value from offering any of the area in this Five Year Program. Thus, these hurdle prices will provide the decision maker information on whether there are at least some undiscovered field sizes which are likely to exist within the program area that are favorable to being leased now, assuming the market price is at or above the level of the hurdle price. This approach has the advantage of including areas in the Five Year Program which show economic promise, while deferring certain timing, composition and sale design decisions to the lease sale stage. This approach is a consistent methodology for conducting program area evaluations during the Five Year Program stage and avoids having to prematurely forecast future prices, cost levels, resource endowments and the state of technology.

For this PFP, BOEM calculated the hurdle prices for two sample water depths in the Central GOM, and for the Chukchi and Beaufort Seas and Cook Inlet, offshore Alaska. The largest undiscovered field size deemed likely to be present in each area was selected for use in conjunction with cost estimates appropriate for the water depths and field sizes. These factors were inputted to an in-house dynamic programming model called WEB2

[26] All else being equal, the largest field tends to have the highest net value per equivalent barrel of resources, making it the least likely field to benefit from a delay in being offered for lease.

(When Exploration Begins, version 2). The first column in Table 1 shows the input field sizes for each area.

More specifically, the likely largest undiscovered field was identified using estimates of the 2011 Assessment.[27] In general, the Assessment addresses undiscovered resources in a framework of field size and probability. The field size framework is provided by the USGS field size classes, which enables grouping fields. For example, there might be 2 fields in a range of 2 - 4 million BOE (MMBOE), 3 fields in the next class covering 4 - 6 MMBOE, and so on. There will be one "largest field" class which typically has a lone field in it, and no class of a larger size has any fields. It is that largest field size (assumed to be the middle of the class-size range) that was the basis for the hurdle price analysis. The reason for focusing on just the largest field is that the decision criterion using the hurdle price is intended to avoid the risk of withholding, on economic grounds, an area that might have at least one field that ought to be developed immediately.

Regarding probability, the 2011 Assessment provides estimates of field counts at various levels of uncertainty. There are fewer fields estimated at a low level of uncertainty and more at a high level of uncertainty. Besides the percentiles, the 2011 Assessment also gives estimates at a mean level of uncertainty. This concept is defined in the 2011 Assessment documentation, and it means roughly a middle level of uncertainty. The hurdle price analysis used estimates at the mean probability, an accepted and unbiased statistical approach in the presence of uncertainty.

Cost inputs for the WEB2 model came from the commercial FieldPlan modeling system and from data collected by BOEM for the socio-economic analysis of the Five Year Program (MAG-PLAN). The initial lease period limits and other fiscal terms are assumed to continue at current settings. The price model in WEB2 represents the range of possible future prices by a specific algorithm that models a so-called mean-reverting stochastic process. That means that the change in price from one time to the next is random and the probability of a step up or down reflects a tendency for movement toward the mean level. The start price for the price process is a single number representing the known current price when the lease is initiated. To find the hurdle price, the model is run for various start prices, until a start price that implies immediate exploration is found and no lower start price does so. The hurdle price is equated to that start price.

The lease operator was modeled as having flexibility to time the investment in exploration and separately, any investment in development. Each such decision is based on the contrast of the expected current value of the project with exploring or developing versus waiting. The operator must, of course, make any decision to explore or develop before the initial period limit. If it would be optimal to wait until the end, the operator must decide then to act or let the lease expire. Because WEB2 includes a random price diffusion process and accounts for the operator's options to explore or wait and/or develop a discovery or wait, it can be called a "real options" model.

[27] http://www.boem.gov/Oil-and-Gas-Energy-Program/Resource-Evaluation/Gulf-OCS-Region-Activities/2011-Atlantic-Outer-Continental-Shelf-Assessment.aspx

Table 1 shows the assumptions made about area natural gas-oil ratios for determining the hurdle prices along with the oil and natural gas portions that ratio implies. WEB2 then estimates the BOE price shown in column 5 below, for which delaying exploration of an undiscovered field of the size shown in column 1 is more valuable than immediate exploration. The last two columns convert the BOE price to equivalent oil and natural gas prices using the natural gas-oil ratio typical of the area and a natural gas to oil value ratio that combines their thermal and market values. On a thermal basis, 5.62 mcf of natural gas provides the same heat content as a barrel of oil. On a market basis, this analysis has used oil-natural gas price pairs with a 40-percent economic value of natural gas relative to oil. For instance with the mid-price case, oil at $110/ bbl is 14.05 times the natural gas price of $7.83/mcf meaning natural gas sells at only (5.62/14.05) 0.4 times its relative heat content value.

In the deepwater Central GOM for example, the natural gas-oil ratio means a BOE consists of 72 percent oil and 28 percent natural gas. Since both oil and natural gas will be sold but natural gas is only 40 percent as valuable as oil, the oil price equivalent of the $13 per BOE hurdle price is determined by dividing it by the 0.722 oil split plus 40 percent of the 0.278 natural gas split to arrive at $15.60/bbl. At the market price ratio of 14.05, the corresponding natural gas price is $1.11/mcf. As long as oil and natural gas prices are at least this high, WEB2 evaluation indicates that a minimum of one undiscovered field in this area is ready for immediate exploration. As oil is more valuable than natural gas, the hurdle oil price is lower in the deepwater Central GOM than in the shallow water even though the costs are greater and the largest field size is smaller. The high natural gas-oil ratio in the shallow water Central GOM means this sample field would likely be classified as a natural gas field. Because the hurdle price for these two water depths in the Central GOM are safely below all three program price cases as well as the current market price, BOEM considers these results to be representative of the other GOM program areas. Due to doubts about Arctic natural gas reaching a market, the hurdle price for the Chukchi and Beaufort Seas was determined using only the oil portion of BOE that will be sold. Cost assumptions were for a development that will be able to handle both the oil and natural gas volumes, but the natural gas is treated like produced water and not transported to market to be sold. For both the Chukchi and Beaufort Seas, BOE hurdle price is then only the oil price for this optimal timing analysis. But with higher prices as analyzed in the net benefits analysis in part IV of this document, the scenario natural gas price exceeds its transport cost, so natural gas will be produced and sold eventually under the Program.

Table 1: Hurdle Prices

	Largest Undiscovered Field (MMBOE)	Natural Gas-Oil Ratio	Oil part of Field BOE	Natural Gas part of Field BOE	Hurdle Price		
					BOE	Oil Per bbl	Natural Gas per mcf
Shallow Water Central GOM (200 meters)	740	13.98	28.7%	71.3%	$10	$17.48	$1.24
Deepwater Central GOM (1200 meters)	670	2.16	72.2%	27.8%	$13	$15.60	$1.11
Cook Inlet	175	1.19	82.5%	17.5%	$34	$37.98	$2.70
Chukchi Sea	733 (only oil)				$27	$27	*
Beaufort Sea	444 (only oil)				$37	$37	*

*The natural gas transportation cost exceeds the prorata natural gas hurdle price, meaning oil would have to subsidize the sale of natural gas. Instead, the natural gas share of BOE likely would be reinjected.

This analysis indicates that in the Central GOM, current oil price is about six times, and in Alaska two times, the amount needed to justify holding a sale purely on the basis of the hurdle price criterion. The significant uncertainty surrounding the OCS exploration and development economics must be considered in the formulation of decision criteria for determining timing for lease issuance. At the lease sale stage, BOEM will compare then-current prices to these hurdle prices. If prices have dropped below these hurdle levels, BOEM will conduct additional analyses to determine whether or not to hold a sale and the specific parameters of that sale. Once the timing screen criteria are met at the Five Year Program stage, additional decisions on selected portions of these areas, along with appropriate lease terms and conditions, are included in the lease sale stage. This allows the more specific decisions to be made when uncertainty is reduced. The hurdle price analysis is another element helping ensure the OCS is being managed to generate the public's FMV for OCS resources.

Size of Lease Sale

(1) **Assess the effect of recently raised minimum bid-levels within the areawide leasing framework before each lease sale to encourage timely leasing of the offered blocks**

(2) Other.

<u>Discussion:</u> After an affirmative decision to hold a lease sale, the next decision is selection of the leasing framework to be used for the sale. Since 1983, GOM lease sales have been conducted under the areawide leasing (AWL) format with, for the most part,

relatively low minimum bid requirements. The State of Louisiana requested on several occasions the use of schemes other than AWL, similar to those that were in place prior to 1983, such as industry nomination/agency tract selection (N/TS), which would tend to sell fewer tracts and allow more focused environmental analysis. BOEM contracted for an AWL Study evaluating alternative leasing schemes and received the final report in 2010.[28]

The AWL Study simulates OCS activity on leases sold over the next 50 years under the status quo leasing system of areawide sales, initially offering 8,000 GOM blocks per year, declining thereafter as accumulating information weeds out the barren blocks. The status quo is compared to, among other options, two restricted sale sizes - one-half the AWL scale (AWL half or AWLH) and an N/TS-scale offering of 400 blocks per year similar to sales before AWL.

Results in Table 2[29] indicate that N/TS would sacrifice substantial activity for increased high bids but would appear to provide little overall fiscal gain, because the loss and delay of royalty, rental, and tax[30] revenues would offset the higher bonus promised by N/TS relative to AWL.

Table 2: Long-term Assessment of Criteria under Alternative Lease Sale Scenarios

Performance Measure (Change from baseline offer of 8,000 tracts/year)	Cut Offerings in Half (offer 4,000 tracts/year)	Pre-1983 Scale (offer 400 tracts/year)
Average Annual Tracts Sold	-31%	-80%
Exploration Wells Drilled	-16%	-52%
Number of Fields Discovered	-7%	-28%
Discounted High Bids	+9%	+39%
Total Production	-2%	-10%
Expedited (discounted) Production	-4%	-17%
Discounted Federal Leasing Revenues	-1%	+5%
Discounted Leasing + Tax Receipts	-1%	0%
Coastal State Economic Benefits	-9%	-34%
State Revenue Sharing (uncapped)	2%	+10%

This long-term comparison presumes the same leasing framework will continue to be used over each of ten future Five Year Programs thereby incorporating enough time for significant evolution in technology, resource estimates and oil prices. Long term trends in those fundamental variables dominate the results reported. The model used for the AWL Study suggests somewhat smaller activity losses and larger bonus gain over just the

[28] *Policies to Affect the Pace of Leasing and Revenues in the Gulf of Mexico*, December 2010, BOEMRE 2011-014, available at boem.gov. http://www.boemre.gov/econ/PDFs/ExternalStudies/2011_014/Part2.pdf

[29] This table is extracted from the more extensive table in Ibid, pages 159-164.
[30] The effective tax rate in this study is assumed to be one-half the nominal tax rate.

next Five Year Program from reduced sale sizes. A near-term comparison of AWL and N/TS was extracted from one of the study's sub-models, the Area Model.

The results of this analysis suggest that the near-term reductions in leases sold, wells drilled, and discoveries made under the reduced sale sizes are less severe than the AWL Study reports in the long-term. Under N/TS, near term leases sold would be 75 versus 80 percent less long term, wells drilled would be 23 percent less near term versus 52 percent less long term, and discoveries 10 percent less near term versus 28 percent less long term. Under AWLH, near term leases sold would be 22 versus 31 percent less long term, wells drilled 4 versus 16 percent less long term, and discoveries 3 versus 7 percent less long term. This disparity is consistent with the notion that in the near term, restricted sale sizes have a better chance of including the richer set of undiscovered prospects. In the out years when the remaining prospects are less numerous and obvious, the AWL scheme increases the chances that someone will acquire an overlooked opportunity not recognized by a nomination process driven by consensus expectations.

The increased bonus amounts near term for the AWLH are roughly in line with the long term comparison (10 versus 9 percent more long term), but the near term gain of bonus under the N/TS framework (115 percent more) is 3 times the proportion shown in the long term results (39 percent). This disparity suggests that less aggressive bidding competition will be induced by N/TS relative to AWL in the out years after earlier activities have reduced the uncertainty about the value of still available tracts. However, the long term analysis in the fuller AWL Study finds that offsetting reductions in rentals, royalties, and taxes eliminate the net fiscal gain promised by higher cash bonus bids under N/TS leasing. There is no obvious reason that a similar proportional offset would not occur for the lease subset sold under the next Five Year Program alone.

In summary, the study findings suggest the N/TS framework reduces leasing from the AWL framework in about the same proportion near term as long term, drilling and discovery by less than half as much near term as long term, and increases aggregate bonuses about three times as much near term as long term. However, the AWL Study does not justify accepting even the less severe losses associated with a switch to N/TS leasing framework for the upcoming Five Year Program in anticipation of generating increased fiscal revenue. This is the case because the increase in cash bonus bids per block leased under N/TS would be largely offset by fewer blocks leased, less drilling, a reduced pace of discovery, lower rentals and royalties, and less annual future production of OCS oil and natural gas from newly issued leases.

For the GOM, where there is extensive infrastructure to support the oil and natural gas industry as well as a long history of exploration and development, BOEM believes it is advantageous to use the relatively flexible AWL model, while employing other tools, like minimum bid requirements, to help direct activity towards blocks that are considered to be the most valuable and economically mature. Setting a meaningful minimum bid level allows the auction market to determine which blocks are perceived to have the lowest values, so that the leasing program could make these blocks available in future sales. Improved technology would lower exploration and production costs and perhaps reduce drilling risks on these blocks. The block values would increase and they could be reoffered for sale at a more favorable time for society.

BOEM can set relatively high minimum bid levels to limit the resulting leasing to those blocks which the market judges to be favorably valued. Such blocks characteristically have an anticipated rate of growth in value less than the equivalently measured opportunity cost of holding them unsold. If a block has a perceived economic value less than the minimum bid, this will be revealed in the competitive auction market and the block will not be leased. So, the minimum bid can be structured specifically to ensure that certain blocks whose current value is either unknown or positive, but less than the level needed to justify selling at the present time, are in fact retained in the government's inventory. This is one way of ensuring that the blocks which have already matured economically are sold first, while those with the highest potential for economic growth are retained for a later sale, without actually knowing before a sale which blocks fall into each category. This strategy is consistent with the goal of maximizing the economic value of OCS resources to the Nation.

Rather than adjusting the size of the sale from the outset, BOEM will use the minimum bid (in conjunction with other fiscal terms) as a way to limit the sale size by allowing the market to choose which tracts to lease. BOEM will continue to evaluate the minimum bid level to ensure that it helps to maintain competition and to encourage timely leasing of offered blocks. The minimum bid is one of several fiscal policy elements of the sale-terms decision discussed later in this document.

Nonetheless, BOEM is exploring options for a more focused approach to leasing than AWL in certain instances as discussed in part I of this document. In particular, offshore Alaska, the Beaufort Sea and Chukchi Sea Program Areas are less explored than GOM areas and require extensive environmental analysis and coordination with other Federal agencies, Alaskan natives, the scientific community, industry, and state and local governments before leasing decisions can be made.

While BOEM has determined that it is appropriate to continue areawide leasing in the GOM, as described above, BOEM will not be conducting areawide leasing in the Arctic, consistent with rigorous internal analysis as well as a number of outside recommendations to develop alternative leasing approaches for Arctic areas.[31] Rather, potential sales, which are deliberately set late in the five-year program schedule to allow for further analysis and information-gathering. These would be geographically targeted in scope, in order to achieve an appropriate balance between making resources available while limiting conflicts with environmentally sensitive areas and subsistence use by making certain determinations from the outset about which blocks within the planning areas are most suitable for leasing

[31] Outside groups that have recommended adopting alternatives to areawide leasing for frontier areas like the Arctic include the USGS and the National Commission on the BP *Deepwater Horizon* Oil Spill and Offshore Drilling.

Sale Terms

(1) Leave current minimum bid levels, rental rates, fixed royalty rates, and lease terms as the baseline, subject to sale-by-sale reconsideration.

(2) Other.

Discussion: After deciding to hold a sale and the framework to be used, the next set of decisions deals with the sale terms to be offered, largely the fiscal terms and duration of the initial period of the lease. The fiscal terms include an upfront minimum bid level, annual rental payments and royalties. All of the financial obligations (bonus payments, rentals and royalties) reflect the value of the lessor's (i.e., Federal Government) property interest in the leased minerals and are fiscal components of FMV. When determining the appropriate lease terms for a sale, BOEM must balance the need to receive FMV with the other policy goals in the Act, such as expeditious and orderly development of OCS resources. BOEM evaluates sale terms on a sale-by-sale basis and has adjusted them in recent sales in response to emerging market conditions, competition, and the prospective nature of available OCS acreage.

In addition, BOEM, jointly with the Bureau of Land Management, recently completed a contract with IHS-CERA for a study entitled "Comparative Assessment of the Federal Oil and Gas Fiscal Systems."[32] The study compared other countries' petroleum extraction fiscal systems and terms to the U.S. Federal system. Once that study is fully assessed, the results and findings should be helpful in informing future decisions about whether and how to revise applicable fiscal terms to best balance the objectives of the offshore program.

Minimum Bid

The minimum bid serves as a floor value for acquiring the rights to OCS acreage. Historically, its primary utility has been to ensure receipt of FMV on blocks for which there is insufficient data to make a tract evaluation, or existing geologic or economic potential of the blocks is inadequate to support a positive tract value. The minimum bid in the GOM for water depths of 400 meters or deeper was recently increased from $37.50 to $100 per acre starting with Western GOM Sale 218 held in December 2011. GOM minimum bid remains at $25 per acre in water depths less than 400 meters. The most recent minimum bids in Alaska were $25 per hectare (about $10 per acre) in the Chukchi Sea, Cook Inlet and in Zone B (deeper water areas) of the Beaufort Sea; and $37.50 per hectare (about $15 per acre) in Zone A (near shore areas) of the Beaufort Sea.

As explained above, the minimum bid also can be used to help control the pace of leasing, especially under an AWL framework in which many marginally valued blocks are offered for sale and, when bid on, tend to receive low winning bids. In such large sales, increasing the minimum bid level can have a significant effect on the number of

[32] http://www.boem.gov/Oil-and-Gas-Energy-Program/Energy-Economics/Fair-Market-Value/Fair-Return-Report.aspx

blocks leased, but may impact aggregate cash bonuses very little or even cause them to increase, since raising the minimum bid level can push low bids to higher levels.

Rentals

During the initial period of a lease and before commencement of royalty-bearing production, the lessee pays annual rentals which generally are either fixed or escalating. The primary use of escalating rentals is to encourage faster exploration and development of leases, and earlier relinquishment when exploration is unlikely to be undertaken by the current lessee. Escalating rentals also are used when the initial lease period is extended following the spudding of a well, which in some cases must be targeted to be drilled to a depth of at least 25,000 feet subsea in the GOM.

The prevailing GOM rental rates are shown in Table 3. Rental rates were last adjusted in Central GOM Sale 208, March 2009. Alaska rental rates range from $2.50 to $30.00 a hectare (about $1.00 to $12.00 per acre), with escalating rentals used in the last four sales (Beaufort Sea Sales 186, 195 and 202 and Chukchi Sea Sale 193).

Table 3: GOM Rental Rates per Acre or Fraction Thereof

Water Depth in meters	Years 1-5	Years 6, 7, and 8+
0 to <200	$7.00	$14.00, $21.00, $28.00
200 to <400	$11.00	$22.00, $33.00, $44.00
400 to <800	$11.00	$16.00
800+	$11.00	$16.00

Rental payments also serve to discourage lessees from purchasing marginally valued tracts too soon because companies will be hesitant to pay the annual holding cost to keep a low-valued or currently uneconomic lease in their inventory. Rental payments provide an incentive for the lessee to timely drill the lease or to relinquish it before the end of the initial lease period, thereby giving other market participants an opportunity to acquire these blocks.

Royalties

The government also reserves a royalty interest, which is a share of the value of production at the lease, if the lease goes into production. Royalty rates can have a significant impact on bidder interest and are a key fiscal parameter in the calculation of the underlying economic value for a block. Considered in combination with increased resource prices, perceived improvements in discovery and extraction technology, especially in deep water, and the competitive market for OCS acreage, BOEM raised GOM deepwater royalty rates for new leases from 12.5 to 16.67 percent in 2007, then to 18.75 percent in 2008. GOM shallow water royalties for new leases increased from 16.67 to 18.75 percent in 2008. Currently, all COM royalty rates are 18.75 percent. Alaska sales have utilized a 12.5 percent royalty rate for the past 30 years.

Initial Period of the Lease

In cases where a high bid meets the FMV requirements, the lease rights are issued to the lessee for a limited term called the initial period. The Act sets the initial period at 5 years, or up to 10 years "where the Secretary finds that such longer period is necessary to encourage exploration and development in areas because of unusually deep water or other unusually adverse conditions…." The initial period promotes expeditious exploration while still providing sufficient time to commence development.

BOEM recently changed the lease terms in the deepwater GOM to account for improvements in deepwater technology and the decreased time necessary for exploration and infrastructure development. Using shorter initial lease periods for shallower areas helps to encourage timely development by providing a built-in incentive for drilling. Current GOM initial lease periods are shown in Table 4.

Table 4: GOM Initial Periods

Water Depth in meters	Initial Periods
0 to <400	5 years extended to 8 years if a well is spudded during the initial 5-year period targeting hydrocarbons below 25,000 feet TVD SS*
400 to <800	5 years extended to 8 years if a well is spudded during the initial 5-year period
800 to <1,600	7 years extended to 10 years if a well is spudded during the initial 7- year period
1,600+	10 years

*Total Vertical Depth Subsea

Lease terms on the Alaska OCS vary by area. Former leases in Cook Inlet had a 5-year initial period. In other areas, initial periods are from 8 to 10 years because of the historically longer lead times needed for exploration due to seasonal factors such as sea ice, remoteness and availability of suitable drilling platforms.

Bidding Systems

(1) **Continue use of a single round sealed bid auction format with a cash-bonus competitive bidding system, subject to periodic review.**

(2) Other.

Discussion: The next step in ensuring FMV is to identify the auction format and determine which competitive bidding system to use. The Act requires the use of a sealed bid auction format with a single bid variable on tracts no larger than 5,760 acres. The Act allows for different competitive bidding variables including royalty rates, bonus bids, work commitments, or profit sharing rates. The specific competitive bidding systems available under the Act and currently in the regulations in Title 30 of the Code of Federal Regulations at 560.110 mostly provide for variations of the cash bonus/royalty rate approaches.

In evaluating which competitive bidding terms to use, BOEM considers the goals of the Act, the costs and complications of implementing the selected approach, the ability of the bidding variables to accurately identify the bidder offering the highest value, and the economic efficiency of the selected approach. Some of the alternative approaches, such as profit sharing and work commitments, could have beneficial aspects, but they are difficult to apply. Profit sharing systems applied to production values could result in operators producing closer to the socially optimal output and rates than with royalty systems. However, these gains would likely be offset by the need for extensive administrative resources to audit and verify the measure of profits. Similarly, work commitment bids could be beneficial in identifying which bidder has the most optimistic view of geologic prospects. However, this system encourages wasted expenditures, especially in new areas where there is little resource knowledge, as well as difficulty in identifying, measuring and tracking qualified expenditures.

When Congress amended the Act in 1978, it instructed DOI to experiment with alternative bidding systems for OCS leasing, primarily to encourage participation of small companies by reducing upfront costs associated with the traditional cash-bonus bid system. DOI used four alternative bidding systems from 1978 through 1982. All the tested systems maintained the cash bonus bid, but varied the contingency variable with use of a sliding scale royalty which varied depending on the rate of production, a fixed net profit share, and a 12.5 and 33 percent royalty rate. These systems were not found to enhance program performance compared to the then-prevalent 16.67 percent fixed royalty rate system in shallow water. Among other things, they did not increase participation by small companies; were significantly more complex to administer; distorted bids, which made it more difficult to identify the high bid; and often were not beneficial to the taxpayer. As a result, BOEM has chosen to use the cash-bonus bidding system subject primarily to a mid-range fixed royalty rate since 1983.

Bid Adequacy Review

(1) Continue use of the current, two-phased bid adequacy process, subject to revision as appropriate.

(2) Other.

Discussion: Following a lease sale, the high bids on each block are evaluated to determine whether they satisfy the FMV requirements for acceptance. The bid adequacy process in use since 1983 evaluates high bids in two phases. The first phase assesses bid adequacy and relative block value by applying long-standing rules and procedures to determine whether acceptance of the high bids is consistent with the objective of ensuring receipt of FMV. The assessments involve consideration of such factors as the number of bids received on the block, the distribution of those bids as well as the ranking of high bids across blocks, and BOEM's assessment of the block's geologic and economic viability. If not accepted during this first phase, high bids are evaluated in a second phase using detailed analytical assessment procedures to generate an independent evaluation of each remaining block's value. This procedure is employed in conjunction with the distribution of the losing bids on each block and with an adjustment for the delay cost, if any, from not selling the block in the current sale to determine each block's ultimate reservation "price". This price cannot be lower than the minimum bid level used for all blocks within a comparable water depth range. If the high bid does not exceed the reservation price, the bid is rejected and the block is available to be reoffered at the next lease sale in that area. Thus, BOEM reviews all high bids received and evaluates all blocks using some combination of block-specific bidding factors and detailed block-specific resource evaluation factors to ensure that FMV is received for each OCS lease issued. FMV and the bid adequacy process also are discussed in part IV.F of this document.

IV. PROGRAM ANALYSIS

A. Analysis of Energy Needs

Introduction

Energy plays a central role in the operation of the U.S. economy. In recent years, American consumers spent well over a trillion dollars a year on energy, more than 8 percent of gross domestic product (GDP). As noted in its report "Annual Energy Review 2010"[33], the Energy Information Administration (EIA) recognizes the United States as a world leader in total energy consumption and that it imports almost 30 quadrillion British thermal units (Btu) of energy each year to satisfy almost 100 quadrillion Btu of total consumption in transportation, industrial, commercial, and residential sectors. Although the United States is a leading producer of coal, natural gas, and oil, growing demand for energy in developing countries, especially China and India, means that competition for limited energy sources may become more intense. EIA predicts costs for imported energy will increase in real terms over the coming decades. To address these issues, the United States needs to pursue investments in renewable energy technologies and existing domestic energy production throughout the United States, both onshore and on the OCS.

Section 18 of the Act requires the Secretary to formulate an OCS leasing program to "best meet national energy needs for the five-year period following its approval or re-approval." In formulating the program, the Secretary must consider "the location of such [OCS oil- and gas-bearing] regions with respect to, and the relative needs of, regional and national energy markets." The long lead times required for OCS oil and natural gas leasing and permitting and production activities, along with the extended life of oil and natural gas projects, dictate that the analysis of energy needs look at long term projections beyond the end of the five-year schedule of sales in the program. The energy needs analysis conducted here relies heavily on EIA energy forecasts. These forecasts are carried out to 2035, so this contextual analysis uses this shorter period rather than the 40 to 50 years used for other analyses in this document.

High and volatile energy prices, especially for crude oil, and continued dependence on foreign sources, raise important energy policy issues about supply options and their effects on the economy and the environment. The following sections discuss national and regional energy needs in the presence of a large, continuing gap between domestic energy production and consumption; ongoing concern over the amount of U.S. dollars sent overseas; and potential supply contributions of OCS production and other sources of energy.

[33] EIA, Annual Energy Review 2011; http://www.eia.gov/totalenergy/data/annual/

Forecast of National Energy Needs

Domestic energy security and dependence on unreliable sources of oil imports are key topics in the national energy debate, aggravated by a challenging international political climate, increasing competition for resources, energy supply instability, and price volatility. EIA's *Annual Energy Outlook (AEO) 2012* forecasts changes in domestic energy production, energy imports, and energy consumption over 25 years from 2010-2035.[34] While there are many factors that simultaneously affect such forecasts, the primary engine behind the projected changes in domestic production-consumption gaps and import requirements are assumptions about economic growth. The average annual GDP growth rate for the U.S. economy projected in *AEO 2012* is 2.6 percent. Although the decreasing ratio of energy expenditures to GDP over time from 7.1 percent in 2012 to 4.4 percent in 2035 reflects an extended economic recovery period and declines in energy intensity, uncertain supplies could contribute to tight petroleum markets, which could raise oil prices sufficiently to cause the energy expenditure rate to creep back up, constraining economic growth.

In 2010, the United States accounted for approximately 21 percent of the world's oil and 22 percent of the world's natural gas consumption.[35] EIA and the International Energy Agency (IEA) project the quantity of energy demand in the United States and in the world will increase 12 percent and 33 percent[36] in the coming decades as a result of economic growth in the United States and in developing economies. Depending on economic access to non-Organization of Petroleum Exporting Countries (OPEC) resources and resulting OPEC price behavior, world crude oil price estimates for 2035 range from $55 to nearly $200 per barrel (expressed in 2010 dollars). New production from domestic areas such as the GOM and Alaska OCS would help meet the continued demand for energy and help retain the diversity of supply, helping to mitigate the effects of disruptions on imports and cushioning the consequences of hurricanes and other disruptive forces on parts of the GOM as well as on refining and processing operations.

Oil and Natural Gas Production Estimates

Petroleum and natural gas supply nearly 63 percent of the Nation's energy needs. EIA forecasts that net U.S. demand for oil and natural gas will increase over the next two decades. EIA projections, shown in Table 5 below, indicate that while the *share* of energy obtained from oil and natural gas decreases slightly, the *amount* of energy obtained from oil and gas increases between 2012 and 2035.[37] Accordingly, the

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[34] This analysis uses estimates for energy projections based on the reference case in the *AEO 2012* Early Release. The following estimates will vary somewhat from those included in the complete *AEO* that will be released later in 2012.

[35] BP Statistical Review 2011;
http://www.bp.com/sectionbodycopy.do?categoryId+7500&contentId+7068481

[36] IEA, World Energy Outlook 2012; http://www.worldenergyoutlook.org

[37] The AEO's reference case is a policy neutral forecast based on the most likely trajectories for primary energy prices, technology adoption, and global economic growth. It incorporates only existing laws, rules and regulations, taking into account the effective start and end date of each.

Nation is projected to continue to rely heavily on oil and natural gas to meet its energy needs, even as alternative sources of energy supply an increasing share of our energy.

Table 5: U.S. Energy Consumption (quadrillion British thermal units (Btu))

	2012	2015	2020	2025	2030	2035
Liquid Fuels and Other Petroleum	36.11 (37.3%)	36.89 (37.8%)	37.15 (36.8%)	37.04 (36.0%)	37.31 (35.4%)	38.00 (35.2%)
Natural Gas	25.67 (26.5%)	25.99 (26.6%)	26.13 (25.9%)	25.80 (25.1%)	26.49 (25.2%)	27.11 (25.1%)
Other	35.02 (36.2%)	34.78 (35.6%)	37.65 (37.3%)	40.09 (38.9%)	14.49 (39.4%)	42.86 (39.7%)
Total	96.80	97.66	100.93	102.93	105.29	107.97

Source: EIA *Annual Energy Outlook 2012* (Reference Case)
Note: Numbers in parentheses are percentages of total. Totals may not sum to column totals due to independent rounding.

Table 6 summarizes EIA's forecast for U.S. crude oil production from 2012 to 2035.[38] It shows projected offshore crude oil production in the GOM increasing from 1.5 million barrels (MMbbl) per day in 2012 to 1.97 MMbbl in 2020, or a little less than half a percent annually. From 2020 to 2030, production would decrease to 1.55 MMbbl but would return to 1.64 MMbbl by 2035 as new large development projects are started over time. Over this period, GOM production accounts for approximately 25 percent of U.S. domestic oil production.

Table 6: U.S. Crude Oil Production (MMbbl of oil per day)

	2012	2015	2020	2025	2030	2035
Gulf of Mexico OCS	1.50 (25.5%)	1.72 (27.5%)	1.97 (29.3%)	1.62 (25.2%)	1.55 (24.3%)	1.64 (26.8%)
Other	4.38 (74.5%)	4.54 (72.5%)	4.76 (70.7%)	4.80 (74.7%)	4.82 (75.7%)	4.48 (73.2%)
Total	5.88	6.26	6.73	6.42	6.37	6.12

Source: EIA *Annual Energy Outlook 2012* (Reference Case) Note: Numbers in parentheses are percentages of total. Totals may not sum to column totals due to independent rounding. EIA does not publish Alaska OCS numbers separately.

[38] EIA projections assume that all laws and regulations remain intact, i.e., EIA does not make assumptions as to which legal and regulatory proposals will eventually be adopted.

Overall, total U.S. offshore and onshore crude oil production would increase from 5.88 MMbbl per day in 2012 to 6.12 MMbbl per day in 2035. Production would be higher in the later years of the forecast when real prices are predicted to be higher. The higher levels of production would stem mainly from increased onshore oil production, predominately from the application of recent technology advances in the development of tight oil resources,[39] and the slowing of Alaska's oil production decline by the development of offshore projects. Even with the 5 percent increase in production, imported oil will continue to account for a very large share of domestic consumption. While EIA projections show a decrease in imports of approximately one half percent per year between 2012 and 2035, coupled with a slight increase in domestic production over current levels, imports still would supply nearly 40 percent of the liquid fuel used in the United States. Projected increases in domestic production, refinery gains, ethanol and biodiesel, and liquids from gas, coal, and biodiesel all contribute to the overall gain in domestic liquid fuels production by 2035.

Table 7 summarizes EIA's forecast of U.S. natural gas production from 2012 to 2035. The projected large increases in domestic natural gas production come from the abundance of discovered and undiscovered shale gas resources in the United States and increased exploration and development of these resources. The combination of two technologies, horizontal drilling and hydraulic fracturing, has made it economic to produce shale gas at today's prices. These discoveries and technologies have resulted in a large expansion of domestic supplies, holding down natural gas prices even as oil prices have risen. Shale gas production in the United States grew from 1.0 tcf in 2006 to 4.8 tcf, or 23 percent of total U.S. dry natural gas production, in 2010. EIA expects another threefold increase by 2035.

Table 7: U.S. Natural Gas Production (Trillions of Cubic Feet/Year)

	2012	2015	2020	2025	2030	2035
Gulf of Mexico	2.12 (9.0%)	2.11 (8.91)	2.63 (10.43%)	2.38 (9.15%)	2.51 (9.37%)	2.60 (9.34%)
Other	21.55 (91.0%)	21.56 (91.09%)	22.58 (89.57%)	23.62 (90.85%)	24.28 (90.63%)	25.24 (90.66%)
Total	23.67	23.67	25.21	26.0	26.79	27.84

Source: EIA *Annual Energy Outlook 2012* (Reference Case)
Note: Numbers in parentheses are percentages of total. Totals may not sum to column totals due to independent rounding. EIA does not publish Alaska OCS numbers separately.

Much of the growth in natural gas production comes from shale plays with high concentrations of natural gas liquids and crude oil, which have a higher value in energy equivalent terms than dry natural gas. EIA anticipates the United States will become a net exporter of liquefied natural gas (LNG) by 2016, exporting as much as 0.74 tcf by

[39] There are very recent indications that increases in tight oil production, fueled by advances in technology, may be greater than anticipated. However, it is too early to determine whether long-term trends may be affected.

2035. U.S. net pipeline imports of natural gas, primarily from Canada and Mexico, are expected to decline by 15 percent from 2012 to 2035, while pipeline gas exports to Mexico would grow by over 400 percent over the same period. This conversion from net importer to exporter reflects reserve depletion in foreign countries, a growing demand from other markets outside of the United States, and an abundant natural gas supply and accompanying low prices in the United States.

The *AEO 2012* shows annual offshore natural gas production for the GOM increasing from 2.12 tcf to 2.60 tcf over the period studied, representing an increase of a little under 1 percent annually. Unlike onshore production, EIA predicts GOM natural gas production will decrease slightly in the intermediate term since many undiscovered offshore fields are uneconomic at the natural gas prices projected over the next few years. Total offshore natural gas production fluctuates between 2.0 and 2.8 tcf per year over the period studied as new large projects directed towards liquids development are started over time. While GOM natural gas production thus contributes a small percentage of the Nation's natural gas supplies over the next two decades, it remains an important and stable source of domestic natural gas.

EIA expects the Nation to rely on more oil and natural gas to meet its yearly energy demands over the next 20 years, even as alternative sources of energy supply an increasing share of energy. Estimates by USGS and BOEM indicate the majority of the Nation's remaining oil and natural gas resources lie on Federal OCS and onshore lands. Therefore, continued oil and natural gas leasing activity in the GOM, the primary OCS region currently available for energy production and development activities, is clearly in the national interest. Outside the GOM, the Alaska OCS holds promise and lease sales are proposed in the Chukchi Sea, Beaufort Sea, and Cook Inlet Program Areas. Production from other OCS areas also could help meet the country's energy needs. However, after the *Deepwater Horizon* event and in line with recently implemented regulations to minimize the possibility of such events in the future, the Secretary's weighing of section 18 factors results in a cautious approach toward leasing in new areas and is reflected in a decision for this upcoming Five Year Program that focuses on activities in the GOM and in selected areas of the Alaska OCS.

Meeting Energy Needs

Contribution of OCS Oil

EIA expects the quantity of petroleum consumed in the United States to grow from 19.04 MMbbl per day in 2012 to 20.08 MMbbl per day in 2035, an average annual increase of about 0.2 percent. This growth would be led by the industrial sector, which would increase from around 20 percent of U.S. petroleum consumption in 2012 to over 22 percent in 2035. The transportation sector will continue to account for the vast majority of petroleum consumption, with projections showing that the transportation sector is expected to consume nearly 75 percent of petroleum in 2035, a small increase compared to 73 percent today, owing to modest projected economic and employment growth, which puts downward pressure on vehicle miles traveled.

From a national energy and economic security standpoint,[40] OCS production is an important part of U.S. efforts to maintain domestic oil supplies to meet domestic demand and as a means to reduce exposure to the unpredictability and price volatility of some foreign oil sources. In 2012, offshore oil will account for more than 27 percent of domestic oil production. The GOM is the second largest supplier of crude oil for the U.S. market after Canada, and ahead of Saudi Arabia. From 2000 to 2010, deepwater production of oil from the GOM increased by 70 percent,[41] from 270 MMbbl per year to over 461 MMbbl per year, due mostly to the development of very large fields with high flow rates located in over 1,000 feet of water. The increase in deepwater production served to mitigate the decline in other categories of domestic production over the same 10-year period and mitigate its economic effects. This trend should continue, due to high levels of leasing activity in GOM deep water.

According to EIA, imports of crude oil account for 47 percent of domestic liquid fuel demand in 2012 but will decline to 37 percent of demand in 2035. In 2011, crude oil imports decreased to their lowest level since 1999, down 12 percent from their peak in 2005. Even with recent decreases in oil imports, their contribution to the U.S. balance of payments deficit has been significant and has represented a growing percentage of the U.S. balance of payments.[42] From 2006 to 2012, the percent of the monthly U.S. goods and services trade deficit attributed to petroleum products increased from 34.8 percent in January 2006 to over 56 percent in the beginning of 2012.[43] Estimates by the Bureau of Economic Analysis (BEA) of annual petroleum and petroleum product imports, show the export of nearly half a trillion dollars in 2011 from the United States to other countries.[44]

Although the decline in the U.S. balance of trade from 2001 to 2011 was largely due to increased world oil prices, the contribution of a weakening U.S. dollar was also a factor, given that oil prices are denominated in dollars.[45] As Chart 1 indicates, given a weaker dollar, oil prices have risen more rapidly in U.S. dollars than in euros.

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[40] While oil prices are set on the world market, making it difficult to insulate the Nation's economy from price changes, maintaining secure supplies of petroleum can help discourage temporary supply disruptions or threats thereof, and consuming domestic supplies limits the amount of dollars sent overseas, reducing the balance of payments deficit.

[41] BOEM; http://www.gomr.boemre.gov/homepg/offshore/deepwatr/summary.asp

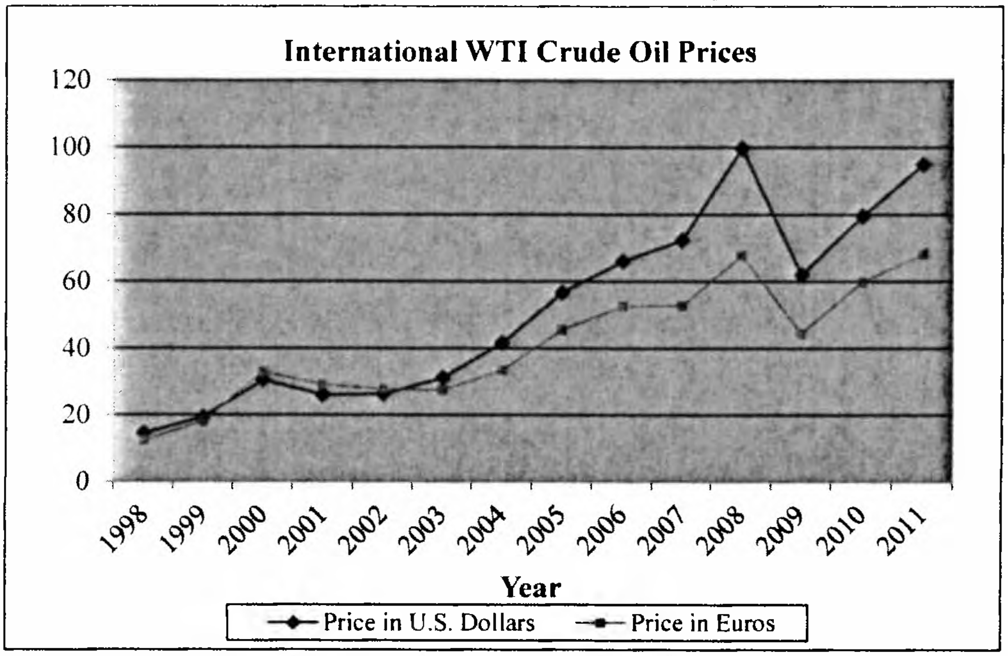
[42] BEA, 2012 (Table 2a); http://www.bea.gov/iTable/iTable.cfm?ReqID=6&step=1

[43] United States Census Bureau; http://www.census.gov/foreign-trade/statistics/graphs/PetroleumImports.html

[44] BEA, 2012 (Table 2a); http://www.bea.gov/iTable/iTable.cfm?ReqID=6&step=1

[45] As the dollar weakened, oil became relatively more expensive to U.S. consumers than to those with stronger currencies, resulting in less pressure to reduce demand abroad and greater pressure on available world supply than there otherwise would have been. This was another factor contributing to increased overall world prices.

Chart 1: International Crude Oil Prices



Source: EIA data at http://www.eia.gov/dnav/pet/pet_pri_spt_s1_a.htm and http://www.econstats.com/fx/fx_aa1.htm for exchange rates.

Not only did world oil prices increase rapidly through the summer of 2008, but the declining value of the dollar exerted additional upward pressure on overall U.S. import costs. The dollar amount spent on oil imports for the first 8 months of 2008 surpassed the amount spent in all of 2007. Although average prices dropped over 40 percent from 2008 to 2009, by 2011 world oil prices had risen sharply and EIA price projections over the next two decades estimate over $130 dollars per barrel of oil in 2010 dollars. Increased world oil prices, coupled with increases in crude oil consumption by economies such as those of China and India, and could have serious effects on the U.S. economy. Domestic production of oil, and to a lesser extent natural gas, from the OCS reduces the amount of oil that must be imported from abroad, thereby lessening the risk to the U.S. economy posed by supply disruptions.

Contribution of OCS Natural Gas

Natural gas consumption has risen significantly over the last decade as new gas-fired generation plants have been built and placed into service. The increase in domestic demand, as well as plans for LNG exports, raise concerns that the volumes of natural gas available from traditional sources —involving both domestic production and imports from Canada and Mexico—might not be able to keep pace with growing U.S. use. However, significant increases of domestic natural gas production from large shale gas plays and production areas with high concentrations of natural gas liquids and crude oil alleviate these concerns.[46] According to the *AEO 2012*, natural gas production in the

[46] The presence of oil and natural gas liquids, which can fetch higher prices in today's markets, provides incentive to pursue these plays even in the face of low natural gas prices.

United States from shale gas resources has increased considerably to meet growing demand and will continue to do so in the future. USGS estimates the United States has over 482 tcf of unproved technically recoverable resources of shale gas; leading EIA to project the United States will become a net exporter of natural gas by 2021.

In 2010, the Federal OCS supplied about 10 percent[47] of annual domestic natural gas production and EIA estimates 12 tcf in proven reserves of natural gas in the GOM. Over the projected time period, EIA forecasts offshore natural gas production in the GOM to fluctuate between 2.0 and 2.8 tcf per year as new large projects directed toward liquids development start and replace depletion of other offshore fields. By 2035, OCS production will still account for roughly 10 percent of total domestic dry natural gas production. While the OCS has large volumes of proven and undiscovered natural gas resources, most of the increased domestic natural gas production in the next decade will come from onshore areas.

Regional Energy Considerations

Table 8 shows proportional petroleum and natural gas production and consumption by region in the United States in 2010. The table also indicates each region's total energy consumption as a percentage of total U.S. energy consumption (2009 figures). One noticeable theme is that the East and West Coasts and Midwest consume 75 percent of the oil and natural gas used in the United States but supply only about 25 percent of domestic oil and natural gas production.

The Federal GOM region has by far the most resource potential of the four OCS regions, and it is located such that it can supply oil and gas to the Nation's top three consuming Petroleum Administration for Defense Districts (PADD),[48] the East Coast, the Gulf Coast, and the Midwest.

The production percentages provide a rough approximation of the distribution of known oil and gas resources among the country's PADDs. Of the six PADDs (with Alaska as a separate district), the East Coast has the highest consumption but by far the lowest production of oil. Its natural gas production, while not the lowest, is well below levels in the top three onshore PADDs and the Federal GOM. In BOEM's 2011 Assessment, the North Atlantic is the 9th highest-ranked planning area for overall resource potential and is 7th for natural gas potential. The Mid-Atlantic is in the top 7-8th overall and the top 5-6th for natural gas, depending on the price case. The South Atlantic is about 15th overall, but like the other Atlantic planning areas, higher for natural gas potential. Oil production in

[47] DOI, Office of Natural Resources, 2011; http://www.boemre.gov/stats/PDFs/AnnualPercentage1954-2010.pdf

[48] For this analysis, PADD V is split into the Lower 48 Pacific and Alaska, given how different Alaska's production-consumption relationship is from the remainder of PADD V. It also creates a one-to-one relationship between coastal PADDs and the four OCS regions. Hawaii does not have oil or gas production, and its energy consumption would not contribute appreciably to Table 8. For the composition of each PADD, see the Table 8 notes.

the Lower 48 Pacific coastal states represents about a third of its oil consumption, but its natural gas production is closer to a tenth of consumption. The three planning areas off California are among the top ten OCS areas for resource potential, with the Southern California Planning Area falling behind only the GOM and Arctic planning areas. All three are more oil prone but have important potential for natural gas as well.

Regional production–consumption gaps, proximity to production areas, and existing transportation constraints can affect regional prices for petroleum and natural gas products. For example, gasoline prices in the Rocky Mountain area were lower than the national average for much of 2011. This was due to relatively low crude oil input costs to refineries in a region that is fairly self-sufficient in meeting its demand for gasoline and other petroleum products. In contrast to the eastern half of the United States, refineries within the Rockies supply most of the regional demand. In terms of natural gas, geographic price differences for U.S. natural gas can reflect transportation and/or transmission constraints between regional markets. Sudden geographic price differences that manifest during regional demand disturbances can be indicative of transportation and/or transmission constraints in a given market.

Table 8: Petroleum and Natural Gas Production and Consumption by Region in 2010

Petroleum Admin for Defense District (PADD) or OCS Region*	Production (MMbbl:MMcf)		Consumption		Total Energy Consumption (MMBtu) % of U.S. Total***
	Crude Oil % of U.S. Total	Natural Gas % of U.S. Total	Crude Oil % of U.S. Total	Natural Gas % of U.S. Total	
East Coast	0.38%	4.74%	29.25%	27.67%	31.26%
Midwest	12.31%	11.38%	25.43%	25.95%	29.31%
Gulf Coast	29.46%	50.04%	26.70%	25.96%	20.57%
Federal OCS, GOM	27.69%	10.49%	0.00%	0.46%**	0.00%
Rocky Mountain	6.55%	19.59%	3.48%	4.29%	3.86%
Lower 48 Pacific	10.50%	1.14%	15.14%	14.27%	14.33%
Alaska	11.76%	1.64%	0.21%***	1.40%	0.67%
Federal OCS, Pacific	1.06%	0.19%	0.00%	0.00%	0.00%
Federal OCS, Alaska	0.30%	0.78%	0.00%	0.00%	0.00%

East Coast (PADD I): Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont, Delaware, District of Columbia, Maryland, New Jersey, New York, Pennsylvania, Florida, Georgia, North Carolina, South Carolina, Virginia, and West Virginia
Midwest (PADD II): Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, Oklahoma, South Dakota, Tennessee, Wisconsin
Gulf Coast (PADD III): Alabama, Arkansas, Louisiana, Mississippi, New Mexico, and Texas
Rocky Mountain (PADD IV): Colorado, Idaho, Montana, Utah, and Wyoming

Pacific (PADD V): Alaska, Arizona, California, Hawaii, Nevada, Oregon, and Washington

*Offshore production in state waters is included with onshore production for each PADD. Federal OCS production is not included in the PADDs.
** Natural gas is often used as a fuel in offshore production.
***2009 Data. 2010 State Energy Totals not available at time of document.

Sources:
Oil Production- http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm
OCS Oil Production - http://www.boemre.gov/stats/OCSproduction.htm
Gas Production - http://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGM_mmcf_a.htm
OCS Gas Production - http://www.boemre.gov/stats/OCSproduction.htm
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Gas Consumption - http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_m.htm
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OCS crude oil and natural gas production -
http://www.eoearth.org/files/156001_156100/156002/ocsproduction2010_doi.xls
Petroleum conversion factors -
http://www.eia.gov/kids/energy.cfm?page=about_energy_conversion_calculator-basics#oilcalc
2010, million Btu per barrel (5.8)
Natural gas conversion
factors: http://www.eia.gov/kids/energy.cfm?page=about_energy_conversion_calculator-basics#oilcalc
2010, Btu per cubic foot (1,025)

In the United States, almost half of the total inter-PADD petroleum product movements by pipeline, tanker, or barge in 2011 were from the Gulf Coast (PADD 3), an area with significant refining capacity, to the East Coast (PADD 1), a major population center. For crude oil, nearly two-thirds (341,576 Mbbl per year) of inter-PADD movements by pipeline, tanker, or barge were movements from Gulf Coast (PADD 3) to the Midwest (PADD 2). These volumes include crude oil produced in the GOM and imports to the Gulf Coast region that move inland to refineries in the Midwest. As pipeline receipts of Canadian oil sands crude oil and increased production from North Dakota's Bakken formation have bolstered Midwest crude oil supplies in recent years, the volume of crude oil moving by pipeline from the Gulf Coast to the Midwest has steadily declined. This increase in crude oil to the Midwest from sources other than the GOM has reduced its need for crude oil supplies from the Gulf Coast. Still, overall the vast majority of the inter-regional crude oil pipeline movements occur among the states of the Midwest, Gulf Coast and Rocky Mountain PADDS, with very little crude oil pipeline activity into or out of the East and West Coasts.

Alternatives to the Contribution of OCS Oil and Natural Gas

In the Five Year EIS, the term No Action Alternative (NAA)[49] refers to the No Sale Option for all program areas. In the NAA, no new OCS leasing would take place for at least 5 years and domestic oil and natural gas production would be reduced appreciably since replacements for depleting offshore fields would be delayed for at least that long. If no OCS oil and gas lease sales were held during the period covered by the new Five Year Program, energy markets would find substitutes to satisfy most of the demand that would

[49] See additional discussion in Net Economic Value section, below.

have been met by production resulting from the oil and natural gas resources made available by the additional lease sales to be held under the program. In an environment of strong worldwide demand for oil and natural gas, a domestic supply cut equivalent to the production anticipated to result from a new Five Year Program would lead to a slight increase in world oil prices and a relatively larger increase in U.S. natural gas prices. All other things being equal, this would lead to a market response providing increases in imported oil and natural gas and greater production of domestic onshore oil and natural gas, coal, and other energy substitutes. It would lead to a small reduction in the total amount of natural gas consumed in the United States, with oil consumption rising slightly.[50] Most of the foregone production would be replaced by other sources. The net result in the United States would be a slight reduction in oil and natural gas consumed, a substantial increase in oil imports, and added supplies provided by onshore hydrocarbon resources.

BOEM uses its *Market Simulation Model* (*MarketSim*) to estimate the amount and percentage of substitutes the economy would adopt should a particular program area not be offered for lease. *MarketSim* is based on authoritative and publicly available estimates of price elasticities of supply and demand and substitution effects. Elasticity measures the sensitivity of consumers or producers to changes in product price.

Table 9 demonstrates how energy markets would compensate in the event the NAA were implemented. Under the mid-price scenario of $110 per barrel and $7.38 per mcf, 68 percent of the oil and natural gas production foregone from this program would be replaced by greater imports, 16 percent by increased onshore production, 5 percent by a switch to coal, 3 percent by increased electricity from other sources, 2 percent by a switch to other energy sources, and 6 percent by a reduction in consumption.[51] Without the expected production from the Five Year Program, 10 billion BOE (BBOE) over 40 to 50 years would be deferred and offset by increased supplies from other energy sources. These energy sources would increase as follows: oil and natural gas imports by 6.8 BBOE (equal to current U.S. imports for almost 1.5 years), onshore oil and natural gas production by 1.6 BBOE (equal to almost half a year of current onshore production), and other energy sources by 1.0 BBOE. Consumption of oil and natural gas would be expected to decline by 0.6 BBOE (equal to less than 2 months of current U.S. oil and gas consumption) spread over the next 40 to 50 years.

[50] This increase in oil consumption reflects the fact that oil and gas are substitutes within the industrial sector and, to a lesser extent, the residential and commercial sectors. The loss of a given amount of OCS production is likely to result in greater increases in natural gas prices than in oil prices, because the price of oil is largely decided in the world market while the price of natural gas is largely set in smaller regional markets. Therefore, as natural gas prices increase under the No Action Alternative compared to the E&D scenarios due to reduced OCS production, consumption of substitutes, including oil, increases. The increase in oil prices under the No Action Alternative may cause some offsetting substitution in the opposite direction, from oil to gas, but the impact of increased gas prices is the more dominant of the two effects.

[51] Total does not sum to 100 percent due to independent rounding and conversion to equivalent units of energy (e.g., Btu to BOE)

Table 9: Results of No Action Alternative (No New Program)

Energy Sector	Quantity (BBOE) over 40 years	Percent of OCS Production Replaced
Onshore Production	**1.6**	**16**
Onshore Oil	0.1	1
Onshore Natural Gas	1.5	15
Imports	**6.8**	**68**
Oil Imports	5.9	60
Natural Gas Imports	0.9	9
Coal	**0.5**	**5**
Electricity from sources other than Coal, Oil, and Natural Gas	**0.3**	**3**
Other Energy Sources	**0.2**	**2**
Reduced Demand	**0.6**	**6**

Given its relative ease of transport, oil prices are set on the world market. Natural gas is not as easily transported, thus its prices are influenced much more by regional supply. Therefore, in the absence of production from a new Five Year Program, U.S. natural gas prices would increase proportionally more than oil prices. Based on *Marketsim* results, this would result in substitution away from natural gas and toward oil and other energy sources.

The distribution of reduced consumption and switching to alternative sources by sector depends largely on the amount of consumption and relative price elasticities of demand across the sectors. The transportation and industrial sectors accounted for almost 95 percent of U.S. oil consumption (approximately 72 and 23 percent of oil respectively) in 2010. Residential and commercial consumption accounted for the residual 5 percent. Other forms of energy cannot readily substitute for most of the oil and natural gas consumed in the transportation and industrial sectors in the near term. In the U.S. transportation sector, a decline in oil consumption would likely be the result of a reduction in miles traveled and/or the purchase of more fuel efficient vehicles. In addition to the modest price increase associated with these scenarios, the cost of developing an alternative fuel infrastructure hinders efforts to extend the use of alternative transportation fuels, although automobile companies have unveiled and/or announced plans for new gasoline-electric hybrid, plug–in hybrid, and electric vehicles.

A detailed discussion of the model and alternative sources of energy in the context of the PFP for 2012-2017 appears in *Energy Alternatives and the Environment* (BOEM 2012-021), which can be found with other program documents at http://www.boem.gov.

Replacement Energy Sources

Many renewable energy sources will contribute to the future U.S. with an increasing emphasis on sources with reduced CO_2 emissions-reducing sources. In February 2009, with the passage of the American Recovery and Reinvestment Act (ARRA), the President pledged over $90 billion to support a wide range of clean energy programs. For example, ARRA has funded $2.4 billion for battery and electric drive component manufacturing, and for electric drive demonstration and infrastructure. These investments already are transforming the advanced vehicle batteries industry in the United States.[52] In the long run, the electrification of the transportation sector will enable the use of electricity generated from renewable energy sources in place of petroleum fuels. Investments in the grid included $4.5 billion for Smart Grid investments, demonstration projects, and capacity building. The Section 1603 renewable energy grant program[53], another example of an ARRA investment, has been an essential tool in deploying renewable energy resources in the United States over the past 2 years, successfully increasing U.S. manufacturing and redirecting investments into renewable energy projects. As of the first three months of 2012, over $12 billion had been paid to eligible participants.[54] This and other investments are intended to ensure that electricity generation from non-hydro renewable sources doubles by 2012 from 2008 levels of 126 billion kilowatt hours (74 MBOE). Moreover, ARRA built on significant Federal investment in solar, geothermal, and marine and hydrokinetic renewable energy technologies under the Energy Independence and Security Act of 2007.

On a national scale, non-hydro renewable sources supplied about 7 percent of all the energy consumed domestically in 2010. This share is expected to reach 10 percent in the mid-2020s and grow to 13 percent by the mid-2030s, according to *AEO 2012* (Early Release). In 2010 and 2011, DOI approved 27 renewable energy projects on public lands, including 16 commercial-scale solar energy initiatives, 4 wind projects, and 7 geothermal plants. On a national scale, renewable sources supplied about 8 percent of all the energy consumed domestically in 2010. On the OCS, DOI and BOEM have responsibilities for renewable energy projects and other alternative uses of Federal lands under the Energy Policy Act of 2005. BOEM has the authority to (1) grant leases, easements or rights-of-way for renewable energy-related uses on the OCS and (2) monitor and regulate those facilities used for renewable energy production and energy support services. The first OCS renewable energy commercial lease was issued in October 2010 for the Cape Wind project, offshore Massachusetts. The construction and operation plan to develop the 468-megawatt project was approved in April 2011 and marks a milestone in the development of OCS renewable energy resources. Secretary Salazar's "Smart from the Start" offshore wind program is intended to identify high-

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[52] http://www1.eere.energy.gov/vehiclesandfuels/pdfs/merit_review_2011/electrochemical_storage/es098_johnson_2011_o.pdf

[53] U.S. Department of the Treasury, 2011; http://www.treasury.gov/initiatives/recovery/Pages/1603.aspx The 1603 program offers renewable energy project developers cash payments in lieu of investment tax credits (ITC). The value of the awards is equivalent to 30% of the project's total eligible cost basis in most cases.

[54] U.S. Department of the Treasury, 2011; http://www.treasury.gov/initiatives/recovery/Pages/1603.aspx

potential, low-conflict areas on the Atlantic OCS, near large population centers, where BOEM will consider offshore wind leasing as early as the end of 2012.

The alternative energy technologies expected to be deployed on the OCS should continue to mature over the next decade and beyond. Environmental and meteorological data collection has begun in the Mid-Atlantic OCS for potential wind energy production zones. BOEM is actively working with coastal states to share information on potential wind energy leasing sites. Federal or state governments might use taxes, subsidies, or other tools to incentivize a different mix of energy substitutes. These efforts could help offset the failure of the market to reflect all the externalities associated with the use of fossil fuels. These policies also could promote investments in renewable energy technologies that may not be cost-competitive at current historically low natural gas prices, but show promise for future competitiveness under longer-term energy price forecasts. Such policies could include renewable energy portfolio standards for electricity generation portfolios.

Despite the increased contributions from alternative and renewable energy sources that can be expected over the coming decades, it is important to note three points in relation to the decisions at hand. First, natural gas and oil will remain important contributors to the energy mix throughout the foreseeable future. Despite advances in alternative-fuel vehicles, transportation remains predominately dependent on petroleum, with most of the remaining fuel supplied by natural gas, and it accounts for about 72 percent of demand for liquid fuels. According to the *AEO* reference case, these shares and consumption levels are unlikely to change appreciably by 2035, although the forecast does indicate that dependence on petroleum would fall by about 5 percentage points, in favor of increased consumption of other liquid fuels. Until renewable energy sources can supply a much larger share of the Nation's energy, clean-burning natural gas likely will continue to be a favored fuel, especially for electricity generation, where it can be used to respond to the rapid fluctuations in demand that are inherent in electricity markets. Second, the focus of this document is the decision process for the next Five Year Program, as specified by section 18 of the Act. Therefore, the analyses that follow are focused on providing information that may help the Secretary decide among the options available to him through the section 18 process. Third, given the importance of increasing the share of renewable energy in fueling the Nation's economy, most realistic alternatives available to build renewable energy production will be advanced regardless of any Five Year Program decisions, as evidenced by Secretary Salazar's energy-related decisions to date. For example, he has not delayed or denied any renewable energy projects under his authority because of the availability of fossil fuels that could be used instead. Further, even if renewable fuels advance much faster than anticipated, OCS oil and natural gas production foregone because of a Five Year Program decision would be replaced by fuels that would most easily substitute for the same uses in the same geographic areas, and in many cases conversion to renewable fuels would require major changes and investments in alternate energy infrastructure.

Conclusion

Despite the promise of new sources of energy, America's reliance on oil and natural gas is likely to change only gradually in the near future. Additional reductions in oil dependence should come from increases in efficiency, which include Corporate Average Fuel Economy ("CAFÉ") Standards intended to improve the fuel economy of cars and light trucks with the goal of doubling efficiency by Model Year 2025. However, even increased vehicle fuel efficiency is predicted only to prevent an increase in consumption of petroleum products for transportation. Achieving the goal of ample secure, clean, and affordable energy will require diligent, concerted efforts on both the supply and demand sides of the energy equation. Notwithstanding a national energy policy focus on increasing conservation and efficiency to help reduce demand for fossil fuels (i.e., oil, natural gas, and coal), production of oil and natural gas, as well as eventually renewable energy from the OCS, are key components of a national energy strategy to diversify energy sources. Renewable energy sources are attractive for environmental reasons and potentially to avoid price volatility. Worldwide, government policies and incentives will increase the use of renewable energy sources.

In the interim, to help bridge the existing energy gap as the Nation moves towards a more sustainable energy future, obtaining sufficient supplies of traditional fuels at reasonable prices and continued responsible oil and natural gas development is crucial to the economy and energy security. The OCS leasing program helps supply a share of the Nation's energy requirements while reducing the dependence on imported energy by identifying key offshore Federal oil and natural gas bearing regions that best meet the Nation's energy needs. The OCS, and in particular the GOM and the Alaskan Arctic, offer ample oil and natural gas resources for the future. Over the next 25 years, offshore production is expected to account for roughly 32 percent of total domestic crude oil production and 10 percent of total domestic natural gas production. Without the program, significant increases in imported oil and onshore production of oil and natural gas would be needed to sustain the Nation's growing energy requirements because renewable energy sources and conservation will not achieve the scale necessary to materially dent import reliance.

The size, timing, and location of lease sales in the PFP have been selected to help meet the needs described above in an efficient and practical manner in light of existing legal constraints, local conditions, and other uses of particular parts of the OCS. In the short term, the PFP is designed to maximize the potential of the Central and Western GOM, which have both the highest economically recoverable resource potential of available areas and by far the most developed infrastructure. In the intermediate term, the PFP sets in motion further exploration and potential development of undiscovered resources offshore Alaska.

B. Analysis of Environmental Concerns

Introduction

The Act, as amended, requires consideration of environmental protection in managing the Nation's offshore oil and natural gas resources. The Act's amendments point to the importance of applying safeguards to help limit the risks of environmental damage and to protecting the human, marine, and coastal environments. Section 18 of the Act mandates that decisions on managing the mineral resources of the OCS strike a proper balance between the potential for environmental damage, the potential for discovery of oil and natural gas, and the potential for adverse impact on the coastal zone. It is therefore important in developing a five year program to solicit comments relating to environmental concerns, to consider and analyze carefully the comments received, and to make use of that information in the development of the EIS prepared for the program, and, ultimately in the development of the program itself.

Environmental Analyses

The Final EIS for the Five Year Program for 2012-2017 has been prepared for the Secretary's consideration and to accompany this document. Preparation of the EIS began with publication of an NOI to Prepare an EIS published in the *Federal Register* (74 FR 3631) on January 21, 2009. That notice was intended to start the formal scoping process by calling for comments and information to be used to determine the scope of the planned EIS for the 12 areas in the 2009 DPP. However, scoping was postponed when the comment period for the 2009 DPP was extended by 180 days. A second notice was published in the *Federal Register* on April 2, 2010, (75 FR 1628) announcing scoping in eight areas as part of the OCS Strategy announced by the President and the Secretary on March 31, 2010. In the aftermath of the *Deepwater Horizon* event on April 20, 2010, scoping meetings again were postponed. Following the December 1, 2010, announcement of a revised OCS Strategy, a third notice was published in the *Federal Register* on January 4, 2011, (76 FR 376) setting out the schedule for scoping meetings and another comment period. The Draft EIS was published with a 60-day comment period on November 10, 2011, (76 FR 70156) and analyzed six areas proposed for leasing along with seven alternatives. The Final EIS accompanies this document for the Secretary's consideration. See part III of this decision document and Chapter 2 of the EIS for descriptions of the proposed action and alternatives. The potential environmental impacts that correspond to proposed and alternative lease sale options are summarized following each set of options presented in part III of this document.

There is additional information relating to environmental concerns in the analyses of social costs, environmental sensitivity and marine productivity, and other uses of the OCS presented in part IV.C below. Also, much pertinent information is available in other documents cited and incorporated by reference, listed in part II of this document.

C. Comparative Analysis of OCS Planning Areas

This section presents the analyses that compare the volume, size and social value of anticipated production from the various program areas included in the PFP decision. The analyses address the section 18 criteria that can be quantified as well as some that cannot. The domestic benefits and costs of proposed OCS activities are enumerated, as well as the costs of providing energy substitutes avoided by implementing the program. Other factors such as environmental sensitivity and marine productivity of the areas proposed for leasing consideration are addressed more qualitatively. The comparative analysis also takes into account comments received, other considerations pursuant to the Act and NEPA, and applicable judicial opinions. The Final EIS, published concurrently with this document, contains a more extensive description of potential environmental impacts from the Five Year Program.

1. Net Benefits Analysis

At the draft proposed, proposed, and proposed final program stages in the five year program preparation process, BOEM conducts a benefit-cost analysis of the social value from anticipated production of oil and natural gas resources expected in each program area as a result of the program. The analysis examines the benefits to society from the production of oil and natural gas as well as the environmental and social costs associated with the anticipated exploration, development, and production activities. The analysis also includes estimates of the environmental and social costs associated with those activities that would occur when obtaining replacement energy from other sources should the No Sale Option be selected in any program area.

While society continues to receive the benefits from previously leased OCS resources, policies relating to their treatment are not subject to this PFP decision. Accordingly, this analysis only considers the net benefits from proposed new leasing. Further, the net benefits analysis includes information designed to help with decisions about the size, timing and location of future Federal lease sales on the OCS, so this analysis only covers energy activities under BOEM's jurisdiction.

The 2009 DPP decision document provided a comparative analysis of all unleased, undiscovered oil and natural gas resources in all 26 OCS planning areas, resulting in the "relative ranking" of those planning areas. Consideration of this analysis and of the various other factors outlined in part II of the 2009 DPP document, led to the selection of the six program areas and the timing of OCS lease sales in the PP.

The 2011 PP document moved from the relative ranking of all unleased, undiscovered economically recoverable resources in the 26 planning areas to the value of anticipated production from each program area for the program proposal and for each of the broad program alternatives described in the EIS. (See Valuation of Program Alternatives in this section.) This analysis is expanded and updated here to provide valuation for the Secretary, with estimated net benefits by planning area from anticipated production under each of the three resource price cases listed in Table 10. The PFP was updated significantly from the PP analysis.[55] Note that for the purpose of this analysis, each of the price cases is conceptually germane beginning only when new production commences from the six-area program. Prior to that time, stipulated prices of oil and natural gas have no effect on the calculations. Both the PP and this analysis add to the 2009 DPP analysis by including the net domestic consumer surplus[56] that arises with new leasing. Summing the production value and the difference between environmental, social and net domestic consumer surplus benefits and losses from exploring each program area instead of the most likely energy substitute provides the net benefits shown in Table 16.

Figure 2 summarizes the components of BOEM's net benefits analysis. Additional information on the methodology and economic assumptions can be found in the *Economic Analysis Methodology for the Five Year OCS Oil and Gas Leasing Program for 2012-2017,* (BOEM 2012-022).

Figure 2: Components of Net Benefits Analysis

Anticipated Production from the Program Area	x	Assumed Price Level	=	Gross Revenue
Gross Revenue		Private Costs	=	Net Economic Value (NEV)
NEV		Environmental and Social Costs of Program Proposal *less* Environmental and Social Costs of Energy Substitutes (Resulting from the No Sale Option)	=	Net Social Value (NSV)
NSV		Consumer Surplus Benefits *less* Lost Domestic Producer Surplus Benefits	=	Net Benefits

The net benefits analysis reflects several values derived from economic activity as well as the various costs associated with generating that economic value. The net economic value (NEV) calculation described below looks at changes in economic activity that can

[55] See *Economic Analysis Methodology* (BOEM 2012-022) for more information on changes since the PP.

[56] Consumer surplus, a standard term in economics, represents the difference between the amount that consumers would be willing to pay and the actual price of goods and services they purchase. In this context, an action or event that lowers the price of oil and natural gas will increase consumer surplus by the change in price summed over the quantity purchased at the original price, plus an increment reflecting the sum of consumer surplus benefits from purchasing additional quantity at the lower price. Typically, the gains from the added consumer surplus would be substantially reduced by the losses from a decrease in producer surplus, i.e., the decrease in economic value to producers receiving a lower product price, leaving a relatively small residual net societal benefit. However, since this is focused on net benefits to domestic consumers and producers, the producer surplus offset affects only the portion of domestic consumption that is produced domestically. Hence, there is no producer surplus decline to offset that portion of consumer surplus gain on the aggregate amount of imported oil and natural gas. The result is that in this case the net consumer benefits, primarily representing pecuniary gains from reduced market price of imported oil and gas, are substantial for the program as a whole.

be measured in several forms, e.g. net value reflected as the sum of commercial income, tax receipts, royalties, and other government revenues. Net social value (NSV) is measured as NEV less the difference between the social costs of the program option and of the No Sale Option.

Another perspective on social value involves comparison of the benefits of incremental employment, labor income, and other such factors with the potential range of costs imposed by each EIS alternative. That approach is more appropriate when considering impacts from the local or regional perspective and is used in the equitable sharing of developmental benefits and environmental risks analysis in section C.4 below. The net benefits analysis in this section is approached from the national perspective, which provides the Secretary with a clearer picture of the overall balance of benefits and costs tied to the program-area-by-program-area decision as to whether to offer the area for leasing.

Gross Revenue

The net benefits analysis begins with the calculation of the gross revenue from the production of OCS oil and natural gas anticipated as a result of the Five Year Program. Gross revenue equals the anticipated production of each resource multiplied by the assumed price level.

Price Level Assumptions

Leasing from the 2012-2017 Program is expected to stimulate exploration, development, and production activity for approximately 40 years,[57] over which time oil prices could fluctuate dramatically. Historical oil price volatility has shown that unanticipated market and political events, new technologies, weather, geopolitical unrest, or economic changes can cause energy price paths to deviate considerably from even the most respected forecasts.[58] Moreover, use of a trend forecast or fluctuating prices in the analysis would make it difficult to separate out the effects of assumed price changes and their timing from the resource and cost differences in program areas on the measures of net benefits. For these reasons, the PFP analysis includes resource and net benefit estimates evaluated at each of the three level sets of real price scenarios shown in Table 10. These price scenarios are consistent with the ones analyzed in BOEM's 2011 Assessment.[59] Having three different sets of flat price cases also allows the decision maker to more clearly identify the extent to which net benefits vary under a wide range of general price levels, independent of other input assumptions such as the timing of activities. A real discount

[57] Some Alaska exploration and development (E&D) scenarios extend to about 50 years because the pace of development historically has been slow. However, most of the activity takes place within 40 years of the start of activity.
[58] The widespread application of technology to extract abundant tight natural gas has recently reduced domestic natural gas prices, causing at least a temporary decoupling of oil and natural gas prices.
[59] U.S. Department of the Interior. Bureau of Ocean Energy Management. 2011. Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's Outer Continental Shelf, 2011. November. RED-2011-01a.

rate of 3 percent is used in the PFP analysis to aggregate 40 to 50 years of effects at a society-wide rate of time preference.

Table 10: Price Scenarios

	Oil (per bbl)	Natural Gas (per mcf)
Low	$60	$4.27
Mid	$110	$7.38
High	$160	$11.39

BOEM has chosen to retain the same price scenarios used previously in the PP decision document. Given the major changes in energy-equivalent prices for natural gas and oil in recent years, the ratio of the price of natural gas to oil for the same heat content (Btu) equivalency factor was reduced for the PP decision document that was used previously and in the 2009 DPP decision document. That factor, which was 0.90 in 2005, was decreased to 0.60 for the 2009 DPP decision document, and has been further reduced to 0.40 for the 2011 Assessment and the PP and PFP analyses. For example, an oil price of $60 per bbl in the 2009 DPP decision document was associated with a gas price of $6.41 per mcf, while the same oil price is associated with a natural gas price of $4.27 per mcf in the 2011 and 2012 program documents.

Since these oil and gas prices were determined for the 2011 Assessment and for the Five Year Program net benefits analyses, the natural gas price has fallen below the 0.40 ratio, but BOEM has chosen to retain the 0.40 ratio between oil and natural gas prices. Low natural gas prices primarily are due to new technology which has increased shale gas production and to the continued drilling in shale plays with high concentrations of natural gas liquids and crude oil, which have higher energy content than dry natural gas.[60] The low prices are likely unsustainable over the 40-year period covered by the net benefits analysis as market forces cause prices to increase back to equilibrium. On the supply side, producers will switch their attention to more oil-prone prospects which will create a future upward pressure on natural gas prices via reduced supply. Similarly, environmental concerns about hydraulic fracturing (fracking) fluids may put pressure on the industry to scale back or even cease the use of fracking technologies to unlock natural gas from shale. Because natural gas is relatively less expensive, demand will go up over time, gradually causing the price to rise as infrastructure develops to allow for the use of natural gas in electricity, transportation, etc., and as capacity develops to export natural gas via LNG. Therefore, BOEM has retained the same price scenarios used in the PP analysis for this decision.

Estimates of Hydrocarbon Resources and Anticipated Production

Resource estimates from the 2011 Assessment provide the foundation for this evaluation of program areas.[61] The 2011 Assessment considers recent geophysical, geological, technological, and economic information and utilizes a probabilistic, geologic-play-based

[60] 2012 AEO Early Release, http://www.eia.gov/forecasts/aeo/er/early_production.cfm
[61] U.S. Department of the Interior. RED-2011-01a.

approach to estimate the undiscovered technically recoverable resources of oil and natural gas for individual plays. This methodology is suitable for both conceptual plays where there is little or no specific information available, and for developed plays where there are discovered oil and natural gas fields and considerable information is available.

The 2011 Assessment incorporates significant updates from previous assessments for the economic assumptions used to assess the Undiscovered Economically Recoverable Resource (UERR) for developing the anticipated production expected from the program areas. The most influential change involved incorporating a relationship between oil price and development costs in the modeling methodology. Capturing observed variations in oil and natural gas exploration and development costs across a wide range of oil prices improved BOEM's confidence in estimating the UERRs from which the anticipated production volumes in Table 11 were derived. This fundamental relationship was not modeled in previous economic assessments. A cost-price "elasticity factor" was defined based on internal analyses that found that a statistically significant relationship exists between crude oil price and an index of upstream capital cost. These analyses were based in part on indices developed by IHS-CERA, Inc., and were applied to all cost components.

Furthermore, estimates of UERR expected to be available for lease as of the start of the Program were revised to incorporate recent leasing activity in those planning areas with OCS lease sales scheduled in the interim. A description of the methodology and results of the 2011 Assessment is available in the 2011 Assessment Fact Sheet at *www.boem.gov.*

Estimates of anticipated production are a subset of the total resource potential and provide a more realistic basis for valuation in the program and EIS analyses. Anticipated production differs from undiscovered technically and economically recoverable resource estimates in that anticipated production only includes oil and natural gas resources that are expected to be leased, discovered, developed, and produced as a result of a series of lease offerings in the PFP. The cumulative case in the Final EIS uses the full UERR for the collective effect of current and future activities resulting from all past, present, and future five year programs.

In the GOM, anticipated production expected to result from sales in this PFP was based on historical sale-specific field discovery volumes, production and drilling activity, leasing trends, and BOEM's most recent 10-year GOM production forecast.[62] UERR estimates from BOEM's 2011 Assessment provide the upper-limit constraint of the production estimates. 2011 Assessment data also was used to segregate anticipated production into water-depth categories by applying geologic play-specific resource estimates as well as a distribution of available acreage. A significant decline in leasing and drilling activity in the shallow water of the Western GOM since 2007 resulted in a sizeable reduction relative to past formulations of the anticipated production volumes in

[62] U.S. Department of Interior, Minerals Management Service, Gulf of Mexico Region. 2009. Gulf of Mexico Oil and Gas Production Forecast: 2009-2018. May, <http://www.gomr.boemre.gov/PDFs/2009/2009-012.pdf>.

this area. The anticipated production estimates for the Eastern GOM also incorporated new area-specific, subsurface geological and geophysical data interpretation.

In Alaska, many factors influence the development of exploration, development and anticipated production scenarios related to the program. In the Alaskan Arctic, oil is the priority commodity of interest due to its higher market value and the existing TAPS. Accordingly, the scenarios for the Beaufort and Chukchi Seas assume that large oil fields will be developed first. Natural gas production is likely to be delayed until oil pools are depleted and even then only if a new large-volume transportation system pipeline is built. Natural gas is assumed to be utilized as both fuel for facilities and for reservoir pressure maintenance through injection to extract more oil. An exception occurs in Cook Inlet which has established infrastructure and a nearby market for oil and natural gas production. With access to existing infrastructure and a local market, smaller oil or natural gas pools could become commercial projects, and natural gas could be produced more quickly in Cook Inlet.

In part due to the differences between mature areas and frontier areas in information and historical data, estimates for GOM areas are subject to a smaller range of uncertainty compared to those for Alaska OCS areas, especially for the Arctic areas. The estimates for the GOM are based on years of experience, while those for the Beaufort and Chukchi Seas must necessarily rely on key exploration and development assumptions. This is true even more for the high-price estimates than for the low-price and mid-price estimates.

Table 11 shows the anticipated production for each program area.

Table 11: Production Estimates at Different Prices*

	Oil (billion barrels)			Natural Gas (trillion cubic feet)			BBOE (billion barrels of oil equivalent)		
	Low Price	Mid-Price	High Price	Low Price	Mid-Price	High Price	Low Price	Mid-Price	High Price
Central GOM	2.24	3.77	4.34	9.47	16.41	19.07	3.92	6.69	7.73
Western GOM	0.56	0.86	0.97	2.63	4.07	4.59	1.03	1.58	1.79
Eastern GOM**	0.00	0.05	0.07	0.00	0.11	0.16	0.00	0.07	0.10
Chukchi Sea	0.50	1.00	2.15	0.00	2.50	8.00	0.50	1.44	3.57
Beaufort Sea	0.20	0.20	0.40	0.00	0.50	2.20	0.20	0.29	0.79
Cook Inlet	0.10	0.10	0.20	0.00	0.04	0.68	0.10	0.11	0.32

* After publication of the January 2009 DPP decision document, BOEM completed a subsequent resource assessment (2011 Assessment) resulting in revised estimates of unleased, undiscovered economically recoverable resources. The new estimates are reflected in the anticipated production numbers in this table. The low-price case represents a scenario under which inflation-adjusted prices are $60 per barrel for oil and

$4.27 per mcf for natural gas throughout the life of the program. Prices for the mid-price case are $110 per barrel and $7.38 per mcf. Prices for the high-price case are $160 per barrel and $11.39 per mcf.
** Current information does not indicate that the number of sales would affect anticipated production for the Eastern GOM. The two-sale option allows the Secretary to consider any new information that might arise from exploration on existing leases subsequent to his decision on the program, when deciding whether to hold a second sale.

Net Economic Value

Once the gross value of the resources is calculated, the second stage in the net benefits analysis calculates the NEV from resources expected to be leased and produced from sales in the 2012-2017 Program. NEV is the discounted gross revenue from the produced oil and natural gas less the discounted costs of exploring, developing, producing, and transporting the oil and natural gas to the market, or the costs required to realize the economic value of the resources. NEV estimates for each program area use the same schedules of exploration, development, and production activities that are used in the environmental and social cost analysis and in the Final EIS. The Federal government, as lessor, collects most of NEV as transfer payments in the form of cash bonuses, rentals, royalties, and taxes. The lessees, as private firms, retain the remainder of NEV as economic profits that may be distributed to shareholders around the country or reinvested in exploration and development projects. NEV can be equated to the sum of the present values of royalties, rents, bonuses, taxes, and after-tax profits. Based on the calculated government share and general estimates of foreign shareholder proportions in foreign companies, only 95 percent of the estimate of NEV is used to measure the domestic piece of NEV from a program area.[63] Table 12 shows the domestic NEV estimates.

In the low-price case, discovery of sufficient resources to justify production is not expected for the Eastern GOM. If companies bid successfully on blocks in the Eastern GOM, the government receives the bonus bid and rental revenue. This is a transfer payment that would not affect NEV. Successful exploration and production could lead to positive NEV, but the more likely result of exploration in the low-price case would seem to be dry holes. Without production, companies do not make profit and NEV for the Eastern GOM would be negative. In both the mid- and high-price scenarios, production and positive NEV are predicted. Because no sales can be added to an approved five year program, the two-sale option for the Eastern GOM ensures that sales can be held if prices remain at current levels or rise even higher. If prices were to fall drastically toward the level of the low-price case, the Secretary could reconsider holding both Eastern GOM sales.

[63] This adjustment is discussed in more detail in the *Economic Analysis Methodology* paper.

Table 12: Net Economic Value

	Net Economic Value* ($ billions)		
	Low Price	Mid-Price	High Price
Central GOM	36.66	153.59	287.16
Western GOM	10.31	38.73	69.56
Eastern GOM (2 Sales)	**	2.30	5.32
Chukchi Sea	5.02	31.06	135.37
Beaufort Sea	0.14	3.68	16.57
Cook Inlet	1.56	3.71	12.30

All values are discounted at a real discount rate of 3 percent.
*The low-price case represents a scenario under which inflation-adjusted prices are $60 per barrel for oil and $4.27 per mcf for natural gas throughout the life of the program. Prices for the mid-price case are $110 per barrel and $7.38 per mcf. Prices for the high-price case are $160 per barrel and $11.39 per mcf.
** Given current information, no production is expected from the Eastern GOM Program Area at the low-price case, whether from one or two sales; therefore NEV is assumed to be zero. If exploration occurs, NEV could be either negative if no production results or positive if successful exploration leads to production. The estimated value of Eastern GOM resources is highly sensitive to changes in information, so placing a second sale on the schedule would provide flexibility to adapt to such changes.

Net Social Value

The third stage in the net benefits analysis is the calculation of NSV from offering a program area. NSV equals the NEV less the present value of *net* environmental and social costs anticipated from the program area. Environmental and social costs arise from air emissions, oil spills, visual and ecological disturbance, and preemption of other land uses during the exploration, development, production, and transportation of OCS oil and natural gas resources. Such costs also would arise in the absence of the new OCS activity, with added production from replacement fuel sources that the economy will demand in any event. In order to calculate the *net* environmental and social costs, such costs are estimated under both the PFP and the No Sale Option and the difference assigned to each program area. Table 13 presents the estimates for the environmental and social costs associated with the development of resources in the OCS program areas from sales in this program and the environmental and social costs of the No Sale Option.[64]

Selection of the No Sale Option in all of the program areas is equivalent to the NAA that is analyzed in the Final EIS. Choice of the No Sale Option in any or all of the program

[64]Table 3 of the *Economic Analysis Methodology* paper shows the split of environmental costs and social costs for the Central GOM mid-price case. Environmental costs make up approximately 96 percent of total program costs and 99 percent total costs for the No Sale Option.

areas means no new leasing would take place in those areas for at least 5 years and domestic oil and natural gas supply would be reduced. This supply reduction would cause only a small change in hydrocarbon prices so there would be very little decrease in the quantity of oil and natural gas demanded.[65] Instead, increased imports and domestic onshore production as well as fuel switching would ensue to meet continuing domestic demand for oil and natural gas products.

BOEM uses its *MarketSim* to determine the substitutions for offshore oil and natural gas development if one or more areas are excluded from the program.[66] Overall, the model indicates that if the No Sale Option were selected in each program area, there would be a 23-percent reduction in OCS production of oil and natural gas over the next 40 to 50 years. Of this, 60 percent would be replaced by increased oil imports, 9 percent by increased gas imports; 1 percent by increased onshore oil production; 15 percent by increased onshore gas production; 5 percent by increased domestic coal production; 3 percent by increases in electricity from sources other than oil, coal, and natural gas; 2 percent by increases in other energy sources; and 6 percent by a reduction in domestic quantity demanded.[67] The replacements proportions may vary slightly depending on the relative amount of oil and natural gas.

BOEM uses an updated version of its Offshore Environmental Cost Model (OECM) to estimate both the environmental and social costs that would result from OCS activities and those costs that would result from selecting the No Sale Option in each program area.[68] This estimate uses the levels of OCS activity from the E&D scenarios employed in NEV and the Final EIS as well as the energy market substitutions from the *MarketSim* to calculate environmental and social costs.[69] OECM computes[70] environmental costs

[65] Though the change in oil and natural gas prices is small, since these pecuniary gains are derived from each unit of domestic consumption, consumer surplus is still quite large. For more information on the calculation of consumer surplus, see the *Economic Analysis Methodology* paper.
[66] Industrial Economics, Inc. 2012a. Consumer Surplus and Energy Substitutes for OCS Oil and Gas Production: The Revised Market Simulation Model. U.S. Department of the Interior, Bureau of Ocean Energy Management. OCS Study BOEM 2012-024.
[67] Total does not sum to 100 due to independent rounding and conversion to equivalent units of energy, e.g. Btu to BOE.
[68] Industrial Economics, Inc.; Applied Science Associates, Inc.; Northern Economics; and Dr. Nicholas Z. Muller. 2012b. Forecasting Environmental and Social Externalities Associated with OCS Oil and Gas Development: The Revised Offshore Environmental Cost Model (OECM). U.S. Department of the Interior, Bureau of Ocean Energy Management. OCS Study BOEM 2012-025.
[69] *MarketSim* does not include estimates of changes in production from existing OCS leases in response to the selection of the No Sale Option for one or more program areas. While this may be considered for future versions of the model, any such OCS response effect would depend on numerous factors, such as whether the decision was for one or multiple areas, the specific areas to which it applied, companies' beliefs as to whether the decision implied the direction for future programs, and changes in the relative attractiveness of opportunities elsewhere for investment as decisions were made. Industry could pursue strategies that create short-term and long-term effects with offsetting results. Therefore, it is not even certain that the OCS response effect would result in higher production over the period of analysis.
[70] OECM also provides a general estimate of greenhouse gas (GHG) emissions from OCS program activities and the activities necessary to provide the energy substitutes. Because any effects of GHG emissions on climate change would not be affected by location, BOEM hopes eventually to estimate emissions not only from domestic production but also from overseas production and from supertankers

(ecology and air quality) and social costs (recreation, property values, subsistence harvests, and commercial fishing, in addition to costs from activities associated with exploration, development, production, and transportation that might occur with new OCS production and its most likely replacement. OECM is designed to model the social and environmental impact of activities associated with OCS exploration, development, production, and transportation as well as typical oil spills that might occur on the OCS. Replacement energy sources generate such costs from the added risk of oil spills and additional air emissions with increased tanker imports as well as with additional air emissions resulting from increased onshore production of oil, natural gas, and other energy sources such as coal.

The model is not designed to represent impacts from catastrophic oil spill events or impacts on unique resources such as endangered species. The reasoning behind this omission of catastrophic oil spills is explained in the section in this document entitled Possibility of Catastrophic Well Blowout or Oil Spill. A discussion of the resources that could potentially be affected as a result of a catastrophic spill on the OCS is included in the supporting paper, *Inventory of Environmental and Social Resource Categories Along the U.S. Coast* (BOEM 2012-003). Note that OECM-based analysis also omits several factors that would disproportionately raise the environmental and social costs of the No Sale Option including the environmental and social costs resulting from the substitution of coal for natural gas in electricity generation and from a reduction in land and water conservation efforts from loss in OCS funding that would attend the No Sale Option.

As shown in Table 13, for every program area, the environmental and social costs of relying on the substitute sources of energy under the No Sale option are equal to or greater than these costs from producing area resources under the Five Year Program. Higher air emission-related costs account for almost all the difference between the environmental and social costs for the likely energy market substitutes and these costs under the program. When OCS natural gas is not available, replacements come from onshore production, which occurs nearer domestic population centers. When OCS oil is replaced, it is mostly replaced with added imports which increase air emissions and heighten the risk of nearshore tanker spills along U.S. coastal areas receiving the imported oil.[71] Both circumstances mean air emissions and oil spills have a greater impact on health and property values per unit of production than do air emissions and oil spills many miles offshore.

This analysis attributes environmental and social costs that would occur without new leasing to the subject program area.[72] Among other things, this approach allows for

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carrying oil from the exporting countries overseas to U.S. shores, as well as from tanker emissions in port. These emissions calculations are in Table 7 of the *Economic Analysis Methodology* paper.

[71] Note that in the net benefits analysis, half of the oil produced in Alaska is expected to be transported by tanker to the continental United States. The air emission and oil spill impacts of this tankering are included in the program costs of OECM.

[72] The primary purpose of this analysis is to help the Secretary select decision options for each program area. Tying benefits and costs to the source program area is a relatively transparent way to represent the domestic benefits and costs likely to result from approving each individual program area options rather than indivisible packages of options. To do otherwise would result in there being no clear link between the

consistent treatment of program area benefits and costs, and thereby provides a meaningful framework for the Secretary to make sound program area decisions. In practice, the resulting costs would actually be felt in areas that would receive the increased imports and host the extra domestic natural gas production. Instead, the costs of the energy substitutes are allocated in proportion to the amount of production expected from each area in the E&D scenarios.

A feature of this allocation choice merits comment. Increased onshore production replaces most of the gas lost under the No Sale Option while added imports replace most of the oil lost. Since environmental and social costs from development tend to be higher per unit with natural gas replacement sources than with oil replacement sources,[73] the No Sale Option in natural gas-prone program areas generates higher environmental and social costs than in more oil-prone areas.

Table 13 reports the program environmental and social costs, those costs of the energy market substitutes supplied as a result of No Sale Option selections, and the net costs for new OCS leasing and production. A more detailed explanation of BOEM's OECM and *MarketSim* methodology can be found in the *Economic Analysis Methodology* paper as well as the documentation for those models.[74]

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cause of the adverse effects (e.g., less OCS production in a specific program area) and the adverse effects themselves. For example, foregoing all proposed sales in all program areas would lead to additional environmental and social costs from increased tanker traffic along the Mid-Atlantic. However, in a simple table showing costs by locality, it would be impossible to demonstrate how size, timing, and location decisions for each program area could contribute to the reduction of costs that would otherwise accrue to the Mid-Atlantic coast.

[73] This is due primarily to differences in degradation of air quality, because of both the emission rates for different sources and the locations of those sources. Per-unit, emissions of unhealthy air pollutants are greater from onshore gas production than from offshore gas production. Dilution rates are lower because those emissions are on land, often near population centers, rather than on the open sea. While this is true also for onshore oil production, most foregone OCS oil would be replaced instead by imports, with *all* of the production activity and associated environmental and social costs occurring outside the United States and thus excluded from this national-perspective analysis. While supertankers bringing imported oil to the United States do emit significant levels of pollutants, most of this occurs in foreign ports or outside U.S. waters, so the related costs likewise are excluded from the analysis.

[74] Industrial Economics, Inc. 2012a. and Industrial Economics, Inc.; Applied Science Associates, Inc.; Northern Economics; and Dr. Nicholas Z. Muller. 2012b.

Table 13: Environmental and Social Costs*

Environmental and Social Costs									
	Program			**No Sale Option****			**Net**		
	($ billions)								
	Low Price	Mid-Price	High Price	Low Price	Mid-Price	High Price	Low Price	Mid-Price	High Price
Central GOM	3.47	5.94	6.94	10.08	17.43	20.26	-6.61	-11.49	-13.32
Western GOM	1.27	1.89	2.13	2.73	4.42	4.76	-1.45	-2.53	-2.63
Eastern GOM (2 Sale)	***	0.06	0.07	***	0.11	0.17	***	-0.05	-0.10
Chukchi Sea	0.04	0.08	0.15	0.24	0.43	1.03	-0.20	-0.36	-0.89
Beaufort Sea	0.02	0.02	0.03	0.05	0.58	2.30	-0.03	-0.56	-2.27
Cook Inlet	0.01	0.01	0.02	0.03	0.07	0.10	-0.02	-0.07	-0.09

All values are discounted at a real discount rate of 3 percent.

* The low-price case represents a scenario under which inflation-adjusted prices are $60 per barrel for oil and $4.27 per mcf for natural gas throughout the life of the program. Prices for the mid-price case are $110 per barrel and $7.38 per mcf. Prices for the high-price case are $160 per barrel and $11.39 per mcf.

** Selection of the No Sale option for any program area would result in greater reliance on other sources of energy ("energy substitutes") to meet the demand that would have been satisfied with OCS oil and natural gas production anticipated from the proposed sale(s) for that area. These energy market substitutes also would impose significant costs on society. See discussion above.

*** Given current information, no production is expected from the Eastern GOM Program Area at the low-price case. Therefore environmental and social costs, whether from one or two sales, are assumed to be zero, as are the costs of replacing foregone OCS production with substitute sources of energy. If exploration occurs without subsequent production, the costs attributed to the sale(s) would be positive.

Possibility of Catastrophic Well Blowout or Oil Spill

The net benefits analysis does not include estimates of every possible environmental and social cost or benefit. One cost not included in the analysis is the cost of a catastrophic oil spill.[75] Some risks are, by their nature, difficult or impossible to value in monetary terms while others could be monetized but for a lack of relevant information. Estimating the costs of a potential catastrophic discharge of oil into the marine and coastal environment presents difficulties with both information availability and monetization of adverse effects. The estimated impacts of a catastrophic spill are not included in the net benefits analysis but rather are discussed separately in the *Economic Analysis Methodology* paper.

A catastrophic spill has the potential to damage many categories of resources and the impact on these categories could vary greatly depending on the size, timing, and location of the a spill. Hence, any attempt to quantify a spill based on one set of assumptions may be more misleading than informative. The wide and unpredictable nature of the many factors that determine the severity of a large oil spill's impact make efforts to quantify expected costs far less reliable than other measures developed in the net benefits analysis. Any future large spill could have wildly different characteristics as to location, season, oil properties, etc., resulting in vastly different costs. The geographic, geologic, and climatological conditions under which an incident occurs could lead to widely different impacts. Due to the range of possible circumstances, the costs are not solely a function of the quantity of oil released. Therefore, relying on the very limited historical record of catastrophic discharges attributable to offshore oil and natural gas projects will not produce reliable cost estimates comparable to others in the net benefits analysis.[76]

In addition to the difficulty in calculating the cost of the potential impacts of a catastrophic spill, there are similar difficulties in calculating the risk of a spill. A catastrophic spill is possible but not expected from this program. Calculating its

[75] Because it is from a national perspective, the net benefits analysis does not consider the risks assumed by, or imposed on other countries, in the case of transit corridors, if the decision is to not to develop domestic energy resources. The risks and consequences of a catastrophic accident could be far worse in or near countries with looser regulations and/or a lower ability to respond after it occurs.

[76] Despite the absence of sufficient data needed to evaluate all aspects of the distribution of large spill sizes and frequencies, along with their likely economic consequences, there is no question that the presence of a catastrophic discharge of oil, whether resulting from OCS production or from the transportation of imported oil because of a decision not to lease, could greatly alter the net benefits of leasing. Hence, the Secretary will carefully consider the potential risks posed by each PFP option and by any of the No Sale Options, based on the available data and information. Proceeding with the proposed sales increases the risk of a catastrophic discharge of oil into the ocean by a smaller percentage, but a decision to restrict production of domestic offshore resources raises the risk of accidents in the production and transportation of the energy sources that would substitute for OCS production, such as increased imports of oil and increased production of onshore oil and natural gas, coal, and nuclear power. However, the Secretary, BOEM and BSEE, the agency that exists primarily to prevent such accidents and/or to minimize the effects of any accidents, do have the ability to promote safeguards through the intelligent design and rigorous enforcement of regulations intended to reduce accidents and prevent the succession of failures of response mechanisms necessary for a blowout or other event which may lead to loss of life and/or a major release of oil into the ocean.

probability is complicated by the fact that empirical evidence only provides a single useful data point with respect to Federal offshore activities. During the last 30 years, there has been only one such accident due to OCS oil and gas activities, the *Deepwater Horizon* event. While the *Exxon Valdez* accident in 1989 was not related to OCS activities, it provides the only other modern data point for events of national significance. Since the *Deepwater Horizon* event, DOI has initiated a major series of reforms aimed at preventing future oil spills. These reforms have further reduced the risk of a catastrophic spill, although the actual extent of this improvement is difficult to determine.[77] See the discussion in part I of this document and Section IV.A of the Final EIS.

The rarity and unpredictable nature of the many factors that determine the severity of a large oil spill's impact make efforts to quantify expected costs far less meaningful than the other measures developed by the OECM and *MarketSim* analyses. There is no question that a large extended discharge of oil resulting from OCS production could cause a catastrophic event which would greatly alter the estimate of the net benefits of leasing. Because of the extreme rarity of that event, there is only one data point over the last 30 years or 6 programs, leading to a miniscule statistical likelihood. Reducing such an effect to an expected value, as is done for the other more routine factors evaluated in the net benefits analysis, would obscure the consequence of a discrete event like a catastrophic spill, should it actually occur. Hence, the possible risks and impacts of a catastrophic spill are assessed outside the net benefits analysis. The risks and conditional estimates for such an event are dealt with in a separate assessment in the *Economic Analysis Methodology* paper.

In addition to the efforts in the *Economic Analysis Methodology* paper to provide some very rough quantitative estimates of the potential impacts that might result from a very unlikely, but possible, catastrophic release of oil, BOEM has provided the *Inventory* paper.[78] This paper describes the resources and activities that could be affected by a catastrophic spill event in or near each program area whether from OCS oil and natural gas activities resulting from the proposed sales or from tankering of imported oil to U.S. ports to replace foregone OCS production should the sales not be held. While it is unlikely that even a catastrophic spill would destroy all or even most of the value of the resources and activities described, the information in the *Inventory* paper provides

[77] Improvements in the various containment and response capabilities each independently reduce the likelihood of a catastrophic spill. For example, most well blowouts are contained very quickly after they occur. A properly-operating BOP can stop the flow almost immediately. One response of the oil and natural gas industry to the *Deepwater Horizon* event has been development of cap-and-contain systems that would control a blowout such as the one that occurred. Beyond that, improved response readiness lowers the risk that significant quantities of oil would reach vulnerable resources. The industry has made major strides, largely adopting the recommendations of the Presidential Commission appointed to investigate the causes of the *Deepwater Horizon* event. Included among recent improvements are enhanced training and auditing of procedures, reducing the human-factor risks that are a major causal factor in most accidents with catastrophic consequences.

[78] This paper is an expansion of what appeared in the PP document as Appendix B, which contained information for the Central GOM only. This *Inventory* paper provides information for the resources and activities in and near all six PFP areas.

information on the different kinds of effects that might occur in or near one program area rather than in another.

Net Benefits

Total net benefits equal NSV plus the net domestic consumer surplus generated by each of the program areas. In economic theory, consumer surplus is the difference between the maximum amount consumers would be willing to pay for a service or product and the amount they actually have to pay in the market. Similarly, producer surplus is the difference between the actual amount that producers receive in the market and the minimum amount they would be willing to accept. New OCS oil and natural gas production increases the supply of oil and natural gas which slightly lowers the price consumers pay and the price producers receive. The domestic portion of the change in both of these surpluses is accounted for in this analysis.

MarketSim calculates the change in domestic consumer surplus occurring due to the increase in OCS oil and natural gas production under this program. This model also determines the domestic loss in producer surplus, conceptually equal to lost producer profits, on the remaining amount of domestic production and on energy sources that are displaced by the new OCS production of oil and natural gas. The difference between the gains in consumer surplus and the losses in domestic producer surplus represents the change in net consumer surplus. In the case of oil, the change in net consumer surplus derives mostly from the lower price of imported oil and natural gas attributable to the added OCS production.[79]

Though most of the natural gas sold in the United States is produced domestically, the net domestic consumer surplus gain from new OCS gas production still is significant because of the substantial equilibrium price reduction it imposes on the import share of total domestic natural gas consumption, given that the price for natural gas is based on a national rather than a world price. In contrast, new OCS oil leads to a modestly lower price spread over the large volume of imported oil that is consumed domestically. Taken together, these changes result in a substantial gain for the domestic consumer that far exceeds the losses to domestic producers. Additional information on consumer surplus can be found in the *Economic Analysis Methodology* paper.

The sum of NSV and net domestic consumer surplus benefits constitutes the total measurable net benefits associated with the program area resources. These net benefits for each program area provide a comprehensive and consistent basis for comparing OCS program areas and program options. Table 14 shows the estimates for the components of the net benefit analysis for each of the program areas for each of the three price cases.

[79] The traditional "welfare gain" portion of consumer surplus, i.e., the non-pecuniary portion, is much less than 1 percent of the entire change in consumer surplus. For more detailed information on the calculation of consumer surplus, see the *Economic Analysis Methodology* paper.

Table 14: Net Benefits*

	Net Social Value			Net Domestic Consumer Surplus			Net Benefits		
	($ billions)								
	Low Price	Mid-Price	High Price	Low Price	Mid-Price	High Price	Low Price	Mid-Price	High Price
Central GOM	43.27	165.08	300.48	19.37	35.14	44.52	62.64	200.23	344.99
Western GOM	11.77	41.26	72.19	5.08	8.32	10.28	16.85	49.59	82.47
Eastern GOM (2 Sale)	**	2.35	5.42	**	0.37	0.58	**	2.73	6.00
Chukchi Sea	5.22	31.41	136.25	2.66	7.54	25.00	7.88	38.95	161.26
Beaufort Sea	0.18	4.25	18.84	1.03	1.51	5.54	1.20	5.75	24.38
Cook Inlet	1.58	3.77	12.39	0.57	0.59	1.39	2.15	4.37	13.78

All values are discounted at a real discount rate of 3 percent.

* The low-price case represents a scenario under which inflation-adjusted prices are $60 per barrel for oil and $4.27 per mcf for natural gas throughout the life of the program. Prices for the mid-price case are $110 per barrel and $7.38 per mcf. Prices for the high-price case are $160 per barrel and $11.39 per mcf.

** Given current information, no production is expected from the Eastern GOM Program Area at the low-price case, whether from one or two sales; therefore net benefits are assumed to be zero. If exploration occurs, net benefits could be either negative—if no production results—or positive—if successful exploration leads to production. The estimated value of Eastern GOM resources is highly sensitive to changes in information, so placing a second sale on the schedule would provide flexibility to adapt to such changes.

Summary Valuation of Program Options Benefits and Costs

Table 15 combines the anticipated production and the various net benefit components in one place, arranged from the highest valued to the lowest valued area, by OCS region, under the mid-price case. The low- and high-price cases yield the same ranking, with one exception. Under the low-price case, the net benefits for the Beaufort Sea are lower than those for Cook Inlet.

Leasing any of the program areas is estimated to result in meaningful additional domestic production and net economic and societal benefits, with the exception of the Eastern GOM in the low-price case. NEV accounts for the bulk of the net social benefits from about 60 percent in the low-price case to over 80 percent in the high-price case. The net domestic consumer surplus gains represent almost 15 percent of the net social benefits in the high-price case and more than 30 percent in the low-price case.

Given the relatively small proportional increase in worldwide energy production associated with the Five Year Program, i.e., an increase of about 0.4 percent over the next 40 years, it is somewhat surprising that the magnitude of net consumer surplus gains to the Nation is so meaningful. However, it can be demonstrated that in the case of oil, which generates almost 70 percent of the net consumer surplus gains, the required proportional oil price change needed to support these gains, also is about 0.4 percent. These findings imply an underlying oil price elasticity of demand of about unity, which is both plausible over the long run and consistent with the range of oil price elasticities of demand reported in *MarketSim* documentation.[80]

Another result worth noting is the significant contribution of natural gas production to net consumer surplus gains. The added natural gas is responsible for generating about 30 percent of the net consumer surplus gains from the Five Year Program, even though only 15 percent of natural gas is assumed to be represented by imports. Unlike the case of oil, the added OCS production of natural gas is projected to have a much more robust effect on domestic natural gas prices, i.e., around 5 percent, much larger proportionally than the 0.4 percent effect on the world price of oil from the added OCS oil production.

A small but important component of the net benefits, especially in GOM areas, is the environmental and social costs avoided by producing from the OCS, rather than from the energy substitutes. These societal costs of *not* approving one or more proposed lease sales are largely due to the environmental and social costs associated with the most likely substitutes. These include increased oil imports and onshore oil and gas production, which generate additional air emissions in port and onshore, often in Clean Air Act non-attainment areas, and raise the risk of oil spills from tankers.

There is one option in the PFP that relates to the number of sales in a specific program area. That option is to hold only one sale in the Eastern GOM rather than two sales.

[80] Industrial Economics, Inc. 2012a.

Anticipated production is the same between the two options, but there is slightly more activity and exploration in the two-sale option. The two-sale option provides flexibility within the next 5 years if prices remain at current levels or rise even higher, or if new technologies emerge or new discoveries are made in the area. Since there is less activity in the one-sale case, environmental and social costs of the program are expected to be slightly lower. The net benefits results in Table 15 reflect the two-sale Eastern GOM option.

Table 15: Summary of Net Benefits Analysis*

		Oil (BBO)	Gas (Tcf)	BBOE	NEV	Environmental and Social Costs			NSV	Net Domestic Consumer Surplus	Net Benefits
						Program	Energy Alter-natives	Net			
					$ billions						
Central GOM	Low	2.24	9.47	3.92	36.66	3.47	10.08	-6.61	43.27	19.37	62.64
	Mid	3.77	16.41	6.69	153.59	5.94	17.43	-11.49	165.08	35.14	200.23
	High	4.34	19.07	7.73	287.16	6.94	20.26	-13.32	300.48	44.52	344.99
Western GOM	Low	0.56	2.63	1.03	10.31	1.27	2.73	-1.45	11.77	5.08	16.85
	Mid	0.86	4.07	1.58	38.73	1.89	4.42	-2.53	41.26	8.32	49.59
	High	0.97	4.59	1.79	69.56	2.13	4.76	-2.63	72.19	10.28	82.47
Eastern GOM	Low	0.00	0.00	0.00	*	*	*	*	*	*	*
	Mid	0.05	0.11	0.07	2.30	0.06	0.11	-0.05	2.35	0.37	2.73
	High	0.07	0.16	0.10	5.32	0.07	0.17	-0.10	5.42	0.58	6.00
Chukchi Sea	Low	0.50	0.00	0.50	5.02	0.04	0.24	-0.20	5.22	2.66	7.99
	Mid	1.00	2.50	1.44	31.06	0.08	0.43	-0.36	31.41	7.54	38.95
	High	2.15	8.00	3.57	135.37	0.15	1.03	-0.89	136.25	25.00	161.26
Beaufort Sea	Low	0.20	0.00	0.20	0.14	0.02	0.05	-0.03	0.18	1.03	1.20
	Mid	0.20	0.50	0.29	3.68	0.02	0.58	-0.56	4.25	1.51	5.75
	High	0.40	2.20	0.79	16.57	0.03	2.30	-2.27	18.84	5.54	24.38
Cook Inlet	Low	0.10	0.00	0.10	1.56	0.01	0.03	-0.02	1.58	0.57	2.15
	Mid	0.10	0.04	0.11	3.71	0.01	0.07	-0.07	3.77	0.59	4.37
	High	0.20	0.68	0.32	12.30	0.02	0.10	-0.09	12.39	1.39	1.78

All values are discounted at a real discount rate of 3 percent.

* Note: The low-price case represents a scenario under which inflation-adjusted prices are $60 per barrel for oil and $4.27 per mcf for natural gas throughout the life of the program. Prices for the mid-price case are $110 per barrel and $7.38 per mcf. Prices for the high-price case are $160 per barrel and $11.39 per mcf.

Valuation of Program Alternatives

While Table 15 shows the estimates of the components of the net benefit analysis for each program area in the PFP, Table 16 compares the total estimated net benefits for the same options as those that comprise the alternatives analyzed in the Final EIS. The net benefits shown for each alternative excludes one of the six program areas and assumes that all of the other areas remain in the program. Given that program options reflect gains relative to the NAA, the net benefits of the NAA in the Final EIS are the negative of those for the program and are not displayed here. See "Relationship of Proposed Final Program Options to the Final EIS Alternatives" in part III of this document for a fuller description of the program options included in each alternative.

With the exception noted with Table 15 of the Beaufort Sea and Cook Inlet swapping places in the low-price case, the ranking of program options is unaffected by the oil and natural gas prices considered. At the beginning of 2012, the market price of oil was close to the assumed oil price in the mid-price case, while the market price of natural gas was close to the gas price in the low-price case. Thus, alternating between either the absolute or the relative current product market prices and those sets assumed in the analysis should have little if any effect on the relative importance of the options being considered.

Table 16: Valuation (Net Benefits) of Program Alternatives*
[All figures in the table are discounted at a real rate of 3 percent and in billions of 2012 dollars]

EIS Alternative	Price Case*	Net Economic Value	Environmental and Social Costs	Net Social Value	Net Consumer Surplus	Net Benefits
		$ billions				
1: Proposed Action	Low	53.70	-8.31	62.01	28.72	90.73
	Mid	233.08	-15.06	248.13	53.48	301.61
	High	526.27	-19.29	545.57	87.30	632.87
2: Exclude Eastern GOM	Low	53.70	-8.31	62.01	28.72	90.73
	Mid	230.78	-15.00	245.78	53.11	299.32
	High	520.95	-19.20	540.15	86.73	626.88
3: Exclude Western GOM	Low	43.39	-6.86	50.24	23.63	73.88
	Mid	194.34	-12.53	206.87	45.16	252.03
	High	456.72	-16.66	473.38	77.03	550.41
4: Exclude Central GOM	Low	17.04	-1.70	18.74	9.34	28.09
	Mid	79.48	-3.57	83.05	18.34	101.39
	High	239.12	-5.97	245.09	42.79	287.88
5: Exclude Beaufort Sea	Low	53.56	-8.28	61.84	27.69	89.52
	Mid	229.39	-14.50	243.89	51.97	295.86
	High	509.71	-17.02	526.73	81.77	608.50
6: Exclude Chukchi Sea	Low	48.68	-8.11	56.79	26.06	82.84
	Mid	202.02	-14.70	216.72	45.94	262.66
	High	390.91	-18.40	409.31	62.30	471.61
7: Exclude Cook Inlet	Low	52.14	-8.29	60.43	28.15	88.58
	Mid	229.37	-14.99	244.36	52.89	297.25
	High	513.97	-19.21	533.18	85.91	619.09

* Note: The low-price case represents a scenario under which inflation-adjusted prices are $60 per barrel for oil and $4.27 per mcf for natural gas throughout the life of the program. Prices for the mid-price case are $110 per barrel and $7.38 per mcf. Prices for the high-price case are $160 per barrel and $11.39 per mcf.

2. Environmental Sensitivity and Marine Productivity

a. Relative Environmental Sensitivity

1. Introduction

An assessment of "relative environmental sensitivity" is required by section 18 (a)(2)(A) of the Act. However, "sensitivity" is not a well-defined term in ecology or environmental science. Sensitivity can be considered from at least two perspectives: 1) the vulnerability of ecological components (such as species) to potential impacts (such as harm to individual animals) and 2) the resilience of an ecosystem or an ecosystem's ability to resist fundamental change and recover from an impact. The former vulnerability approach is a component response approach and provides a relatively straightforward and quantifiable measure of potential impacts. This approach could be augmented with consideration of the impacts on an ecosystem's ability to resist fundamental, or "state," change, a characteristic known as "resilience," which is a "system response."

Historically, BOEM has focused on the vulnerability or component response approach. This approach provides the analysis and information required by §18(a)(2)(G), but with the advent of new technology and new scientific research. BOEM is evaluating adding a resilience component to the relative sensitivity analysis. While either of the approaches used alone provide valid and adequate information on relative environmental sensitivity, developing and implementing an analysis of relative environmental sensitivity that combines both of these components could provide an improved assessment of the relative sensitivity of areas considered for leasing. BOEM continues to support the ongoing research to consider options and potential new approaches to defining and measuring environmental sensitivity and will look for ways to incorporate these different types of analyses in an effort to continually improve the science used for OCS decision-making. This may include components of ecosystem resilience, biodiversity, marine productivity and other potential considerations. The results of BOEM's research will be made available to DOI and public stakeholders as soon as it is available. Comments and concerns submitted on the analysis in the PP are being considered in the ongoing research for the new study and are not addressed in this document.

Therefore, as used in this PFP, the term "sensitivity" refers to "sensitivity, as measured by indicators of vulnerability to impact." Accordingly, "sensitivity, as measured by indicators of vulnerability to impact" will be indicated by use of the term "sensitivity."

As in the PP, the analysis in this document largely mirrors that found in the 2007-2012 Revised Program (December 2010) and considers vulnerability of the various components of biological marine environment to multiple impact-producing factors, such as oil spills, sound and physical disturbance, and increased vulnerability due to climate change and ocean acidification. The results are summarized in Table 17 below. Because relatively small differences in total scores are not meaningful, this table presents the OCS program areas grouped into three categories of relative vulnerability ranging from "most" to "less" vulnerable to OCS oil and natural gas activities. Categorization of an OCS program area as "less" vulnerable does not mean that environmental resources of that OCS program area are not sensitive, but as a collection are found to be relatively less sensitive than other OCS program areas to the types of impacts anticipated from OCS oil and natural gas activities. See section 5 below for a detailed explanation of how these vulnerability groups were determined. This analysis only considers the PFP areas which are being considered for leasing.

Table 17: Grouping of OCS Program Areas by Relative Environmental Sensitivity to Impact as a Measure of Environmental Sensitivity[1]

Most Sensitive to Impact	
	Central GOM
	Eastern GOM
More Sensitive to Impact	
	Beaufort Sea
	Western GOM
Less Sensitive to Impact	
	Chukchi Sea
	Cook Inlet

[1] OCS program areas are listed in alphabetical order within each grouping.

2. Methodology

Definitions

The Act and court opinions do not define relative environmental sensitivity, but defer to the Secretary's methodology "so long as it is not irrational."[81] For the purposes of this analysis, relative environmental sensitivity is defined as the vulnerability of an OCS area's ecological components (i.e., coastal habitats, marine habitats, marine fauna, and marine productivity) to the potential impacts of OCS oil and natural gas activities in comparison to the same ecological components in other OCS program areas. This analysis also provides a discussion of the increased vulnerability of certain areas due to anticipated effects of global climate change.

Coastal and marine environmental resources in and adjacent to the six OCS program areas were evaluated in this analysis. "Coastal" is defined as the coastline and boundaries of estuarine waters. "Marine" is defined as seaward of the shoreline, and includes both state and Federal waters.

OCS Impact Factors Analyzed for Sensitivity

This environmental analysis is based, in large part, on an evaluation of the sensitivity of various coastal and marine habitats and biota to accidentally spilled crude oil. Other relevant factors, such as sound generated by and physical disturbance from routine OCS oil and natural gas activities, were analyzed where appropriate or applicable. This analysis assumes these routine activities would be mitigated, to the extent possible, by measures in the form of lease stipulations, regulations, and laws to minimize impacts and protect marine resources. Monitoring and mitigation measures would be developed through consultation and coordination with the NMFS and the USFWS as required by the

[81] 43 U.S.C. §1344(a)(2)(G); *Watt I*, 668 F.2d 1290, 1320 (D.C. Cir. 1981); *Watt II*, 712 F.2d 584, 596 (D.C. Cir. 1983); *Center for Biological Diversity v. U.S. Department of the Interior*, 563 F.3d 466, 488 (D.C. Cir. 2009).

ESA, Magnuson-Stevens Fishery Conservation and Management Act (MSFCMA), and MMPA. Biological opinions arising from these consultations identify Reasonable and Prudent Measures, Terms and Conditions, and/or Conservation Recommendations that can then be applied as lease stipulations.[82]

Oil Spills

One measure of relative environmental sensitivity is the sensitivity of the various ecological components to spilled crude oil. Unlike some assessments in the programmatic and sale-specific EIS's designed to estimate potential risks from proposed oil and natural gas leasing activities, this relative environmental sensitivity analysis does not consider risk, nor do the rankings for environmental sensitivity reflect potential risk. Analysis of the effects of oil and natural gas activities is left to programmatic, sale-specific, and site-specific reviews conducted pursuant to NEPA. The Five Year Final EIS, prepared in conjunction with this decision document, describes the biological environments of the OCS regions in Chapter III and discusses the potential environmental consequences of OCS program activities in Chapter IV.

Sound

Another measure of relative environmental sensitivity is the sensitivity of marine fauna to sound. Seismic surveys, drilling and production activities at OCS facilities, and support vessel traffic generate sound that could affect marine resources. This analysis assumes that monitoring and mitigation measures, such as the use of independently contracted protected species observers to monitor exclusion zones around the source vessels and shut down procedures when protected species are within the exclusion zone, would continue to be included as lease stipulations to minimize impacts from sound on marine resources. Such monitoring and mitigation measures would be developed through consultation and coordination with NMFS and USFWS as required by ESA, MSFCMA, and MMPA.

Physical Disturbance

Another measure of relative environmental sensitivity is the sensitivity of various ecological components to physical disturbance. Physical disturbance includes bottom disturbances from OCS platform and pipeline emplacements, as well as from anchors. This analysis assumes that BOEM will continue to require site-specific surveys to assist in avoiding direct contact with marine habitats. However, unavoidable or accidental disturbances could result in physical destruction and burial of organisms and habitat.

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[82] In *Center for Biological Diversity v. U.S. Department of the Interior*, 563 F3d 466 (D.C. Cir. 2009), the U.S. Court of Appeals for the District of Columbia Circuit upheld "graduated compliance with environmental and endangered life standards, [thereby making] ESA requirements more likely to be satisfied both in an ultimate and a proximate sense."

Habitats and Biota Analyzed

Distribution, abundance, and environmental sensitivities of four ecological components within and on the adjacent coast of each OCS program area are first evaluated based on their present condition. Thereafter, climate change effects projected to occur over the life of the program are considered in order to adjust for increased sensitivity to oil and natural gas activities. While this analysis continues to use NOAA's ESI data to analyze the sensitivity of shoreline or coastal habitats, it does not use those data as a proxy for overall marine sensitivity, but separately considers the sensitivity of offshore marine resources. BOEM has identified three relevant components of the various areas of the OCS biological marine environment that may be affected by oil and natural gas activities: marine habitats, marine productivity, and marine fauna (i.e., birds, fish, marine mammals and sea turtles).

This analysis is directed at the environmental sensitivity requirement under section 18)(2)(a)(D) of the Act rather than considering the social value of these habitats and biota. The social value, such as subsistence or cultural use, is the analysis under section 18(2)(a)(D), which is in part IV.C of this document. As an affecting factor, subsistence harvests include birds, fish and marine mammals in all coastal areas of Alaska. However, marine mammal harvests are managed by NMFS and USFWS within the potential biological removal of each stock and U.S. law prohibits any harvesting of sea turtles. Commercial fishing and recreational or subsistence harvests of fish and birds are managed within sustainable limits under existing laws and are reflected in the abundance levels of these resources in each OCS program area. Subsistence harvests, in particular, represent a very small amount of the total annual harvest. Therefore, subsistence harvest and other uses of the OCS are properly addressed as social values under section 18(a)(2)(D).

Reports, Studies and Data Used

Section 18 (a)(2)(A) of the Act specifies that required analyses, including the relative environmental sensitivity analysis, shall be based on a consideration of existing information. Earlier relative environmental sensitivity and marine productivity analysis relied on only two studies (CSA, 1990 and 1991) and one dataset (http://response.restoration.noaa.gov). In contrast, this analysis relies on almost 50 reports, studies, and datasets (see section 6).

Qualifications

To facilitate the evaluation of scheduling and preparing for sales in a Five Year Program, the OCS is divided into 26 administrative geographical units called planning areas. See Maps 1 and 2 in part III of this document. The program areas analyzed in this document encompass all or parts of the six relevant planning areas. These are areas, rather than ecoregions, for which decisions on the size, timing and location of lease sales will be made. They do not necessarily correspond to ecosystem boundaries, and sometimes do not correspond to geographic areas with which the public is familiar. BOEM expects that its future analyses of the relative environmental sensitivity on the OCS, including the ongoing research noted in the introduction to this section, are most likely to take ecosystem boundaries into consideration.

In this analysis, relative environmental sensitivity is defined as the vulnerability of an OCS area's ecological components, i.e., coastal habitats, marine habitats, marine fauna, and marine productivity, to the potential impacts of OCS oil and natural gas activities in comparison to the same ecological components in other OCS program areas. Risk, likelihood of adverse impact, and amount or size of disturbance is considered in the Five Year Final EIS.

3. Ecological Components

The relative environmental sensitivity ranking of OCS program areas by various ecological components is presented in Table 18 from most sensitive to less sensitive to impact from OCS oil and natural gas activities. The rankings below are based on scoring of the OCS program areas as described later in this section.

This analysis continues to use NOAA's ESI data to analyze the sensitivity of coastal habitats, thus indirectly including coastal fauna and productivity (see section 3.1). This analysis also separately considers marine resources. However, there is not an equivalent dataset available for the biological marine environment, so this analysis has identified three components to the biological marine environment that may be affected by OCS oil and natural gas activities: marine habitats, marine productivity, and marine fauna (i.e., birds, fish, marine mammals and sea turtles).

The potential response of these four ecological components were considered and scored separately from the potential effects of oil and natural gas development. This analysis does not try to account for the interaction of these components in relation to each other, as this would involve a complex, ecosystem-level study, which is beyond the scope of this review.

Table 18: Ranking of OCS Program Areas by Relative Environmental Sensitivity from Most to Less Sensitive to Impact[1]

Coastal Habitats	Marine Habitats	Marine Fauna	Marine Productivity
Eastern GOM	Eastern GOM	Central GOM	Cook Inlet
Central GOM	Beaufort Sea	Eastern GOM	Eastern GOM
Western GOM	Central GOM	Western GOM	Central GOM
Beaufort Sea	Western GOM	Cook Inlet	Western GOM
Cook Inlet	Chukchi Sea	Chukchi Sea	Chukchi Sea
Chukchi Sea	Cook Inlet	Beaufort Sea	Beaufort Sea

[1] Most sensitive areas are at the top of the columns, less at the bottom.
In the case of ties, OCS program areas were listed in alphabetical order.

3.1 Coastal Habitats

Spilled oil is a major environmental risk from OCS oil and natural gas activities. Coastal environmental resources face the most significant environmental consequences from contact with spilled oil. Although the occurrence of an OCS oil spill that contacts the shoreline would be a rare event, its unlikely occurrence could result in widespread effects on biological resources over a large area. Direct contact to coastal biota and habitats could result in mortality, weakened populations and habitat degradation. Cleanup and restoration activities could result in further disruptions to fauna. Oil that persists in the environment after cleanup operations would continue to be re-released into the environment, causing effects over an extended period of time. Examples of the potential magnitude and duration of these effects have been documented in studies of major marine spills, such as *Exxon Valdez* (Peterson *et al.* (2003)), and are being re-evaluated in the wake of the 2010 *Deepwater Horizon* event.

Concerns about oil spill impacts are reflected in the scoping information and public comments collected by BOEM during the preparation of EISs. Because oil spill effects are the major environmental concern when addressing coastal environments, this analysis uses the ESI database developed by NOAA to measure coastal relative environmental sensitivity. The ESI shoreline database provides a systematic method for compiling standardized data to map shoreline sensitivity to spilled oil. Coastal states and Federal agencies, including BOEM, assisted in ESI development efforts and use ESI products. The ESI scoring approach has a strong scientific basis, and has been used for oil spill response planning for over three decades in the United States and overseas. The ESI shoreline database is complete for all coastal states with the exception of Washington, Oregon, and Maine. However, not all of this data is needed for this analysis.

The ESI shoreline type classification uses standardized definitions of shoreline characteristics to assign the sensitivity rankings. The shoreline type classification is based on factors that include:

- Relative exposure to waves and tidal energy;
- Biological productivity and sensitivity of shoreline material;
- Substrate type (grain size, permeability, trafficability, and mobility);
- Shoreline slope;
- Ease of cleanup; and,
- Ease of restoration.

These factors determine how long the oil will persist in the shoreline environment and continue to cause potential environmental damage, how much damage may occur to the biologic properties of the shoreline substrate, and how much environmental damage may result from cleanup and restoration efforts. The sensitivity of many coastal biologic and socioeconomic resources to oil spills is determined to a large degree by these factors. Each shoreline segment is assigned an ESI score between 1 and 10 in order of increasing sensitivity to oil spill. Table 19 provides descriptive information about the types of shorelines associated with each score. Comparison of the standardized data over large areas reveals patterns in the distribution of the relative environmental sensitivity of coastal areas to oil spills. More information on the ESI shoreline can be found at http://response.restoration.noaa.gov.

Table 19: ESI Scoring and Respective Descriptions

ESI Score	Description
1	Exposed rocky shores; Exposed, solid man-made structures
2	Exposed wave-cut platforms in bedrock, mud, or clay; Exposed scarps and steep slopes in clay
3	Fine to medium-grained sand beaches; Scarps and steep slopes in sand
4	Coarse-grained sand beaches
5	Mixed sand and gravel beaches
6	Gravel beaches; Riprap
7	Exposed tidal flats
8	Sheltered rocky shores and sheltered scarps in bedrock, mud, or clay
9	Sheltered tidal flats; Vegetated low banks
10	Salt/brackish-water marshes; Freshwater marshes/swamps; Scrub-shrub wetlands; Inundated tundra

The shoreline analysis that follows is based on all the available digital ESI shoreline data from NOAA for the six program areas. These ESI line data sets were aggregated or disaggregated as appropriate to represent respective program areas. Each ESI value was weighted by the length of its line segment. An average rating for the OCS program area was calculated based on the weighted average of the ESI for the coastal areas adjacent to the OCS program area.

The results of this analysis are shown in Table 20, which lists the average ESI shoreline scoring by OCS program area in order of decreasing average ESI shoreline sensitivity rank. The table ranks OCS program areas with the greatest amounts of sensitive shorelines, as reflected in high average ESI shoreline sensitivity rank, as being the most sensitive.[83]

High scores at or near a score of 9.0 occur adjacent to the full Eastern and Central GOM Planning Areas, where extensive coastal lowlands made up of wetlands, swamps and other sensitive shorelines occur. The program areas considered in this analysis in the Eastern GOM and Chukchi Sea are not adjacent to the shoreline. However, their planning area ESI values are included in the analysis below. The variation in ESI shoreline sensitivity rank used as a measure of coastal environmental sensitivity is the result of geographic variations in coastal geologic, biologic, and oceanographic characteristics that affect the degree to which oil accumulates and persists in coastal areas. The actual presence or occurrence of specific biologic environmental resources is indirectly considered in the calculations, because accumulation and persistence of spilled oil would be the primary factors for determining impacts to these resources. A program area bordered by a rocky coastline would have a lower sensitivity to oil spills because less oil would typically accumulate and the oil's presence in the environment would be relatively short-term. As a result the impacts on the affected environmental resources would be less severe than in a more sensitive area.

Table 20: Relative Environmental Sensitivity to Impact of the OCS Program Areas for Coastal Habitats

OCS Program Area	Average ESI Score[1]
Eastern GOM	9.1
Central GOM	8.9
Western GOM	7.6
Beaufort Sea	7.4
Cook Inlet	5.9
Chukchi Sea	4.9

[1] Higher scores indicate greater sensitivity to spilled oil.

3.2 Marine Habitats

Marine habitats are the arrangements of geologic, oceanographic, and biologic features of the ocean that combine in characteristic ways to create environments favorable for the establishment, flourishing, and continued survival of the flora and fauna of marine and ecologically connected coastal areas.

[83] This method does not give extra weight to areas with smaller amounts of sensitive shoreline based upon a sensitive shoreline's rarity. While that kind of comparative analysis would be possible, it would require much more subjectivity and could undermine the agency's best efforts to create as objective an analysis as possible in comparing these greatly disparate areas. In addition, because persistence of oil, its penetration into shoreline substrate and the difficulty of cleanup are by far the most important factors in determining effects to shorelines and their inhabitants, the average sensitivity of an area's shoreline is the best comparative tool for conducting the difficult analysis required.

Marine habitats, seaward of the shoreline, are divided into benthic or pelagic categories as shown in Table 21. Benthic marine habitats are attached to the seafloor. Some benthic features, such as kelp forest, can extend vertically from the seafloor upward to near the ocean surface, and downward, in the case of submarine canyons, over a thousand meters deep. Pelagic habitats occur within or at the surface of the ocean independent of the seafloor. Examples include drifting surface Sargassum vegetation that provides habitat for fish and marine reptiles, areas where dynamic ocean circulation processes result in high biological productivity, and sea ice. The analysis also includes the presence of officially designated Federal marine critical habitats (U.S. Department of Commerce (USDOC), NOAA Fisheries, Office of Protected Resources, (2009a); and USFWS, (2009b)) and marine sanctuaries (USDOC, NOAA (2009)) as a factor in marine habitat scores.

Table 21: Examples of Marine Habitat Components*

Benthic		
Marine Habitat Type	**Example**	**OCS Area**
Vegetated	Big Bend seagrass	Eastern GOM
Bottom Relief Features	Pinnacle trend	Central GOM
Coral Reef	Florida Keys	Straits of Florida
Deep/Cold Water Coral	Aleutian Islands Coral Gardens	Aleutian Arc
Seeps	Chemosynthetic communities	Western GOM
Canyons	Baltimore Canyon	Mid-Atlantic
Pelagic		
Marine Habitat Type	**Example**	**OCS Area**
Ice	Polynyas	Chukchi Sea
Vegetated	Floating Sargassum	South Atlantic
Oceanic Process	Ocean upwelling	Central California
Designated Habitat/Sanctuary		
Marine Habitat Type	**Example**	**OCS Area**
Critical Habitat	Polar Bear	Beaufort and Chukchi Seas
Marine Sanctuary	Cordell Bank	Central California

*Some of component examples are areas that are not included in this PFP, but are included as illustrative of the breadth of the analysis only.

The analysis identified the relative abundance of benthic habitats, pelagic habitats, and designated habitat/sanctuary areas in each of the six OCS program areas. A relative abundance value (i.e., high = 3, moderate = 2, and low = 1) was determined for each habitat type by the amount and kind of habitat that occurs within each OCS program area. See Table 22. No abundance value was applied if the habitat was absent from the OCS program area. Information sources used to estimate abundance values include published reports and publications (for example, Navy (2005, 2006, 2007a, 2007b, 2008a, 2008b and 2008c); GeoHab (2008); McGee *et al.* (2006); Lumsden *et al.* (2007); and SEAMAP (2001)), and internal agency information from environmental documents and data.

Table 22: Marine Habitat Abundance Values

Marine Habitat Type	Abundance Value Criteria		
	High (3)	**Moderate (2)**	**Low (1)**
Benthic			
Vegetated	Widespread occurrence of seagrasses extending beyond the coastal fringe	Some occurrence of seagrasses beyond coastal fringe	Scattered occurrences limited to coastal fringes
Relief Features	Abundant features with relief of 100 meters or more	Some high relief features	Low relief features only or scattered occurrence of features
Chemosynthetic Communities	Likely abundant occurrence of features	Likely occurrence of features	Unlikely occurrence of features
Cold/Deep Coral	Extensive occurrence of coral and communities with reef building coral	Abundant coral organisms but no reef building	Occurrence of coral organisms
Tropical Coral	Extensive development of coral communities and reefs	Coral communities occur	Coral organisms occur
Canyons	Abundant canyon habitat with high relief	Common occurrence of canyon habitat, some with high relief	Some canyon habitat
Pelagic			
Ice	Substantial sea and landfast ice existing for > 6 months/year	Substantial sea and landfast ice for < 6 months/year	Discontinuous or scattered ice for < 4 months/year
Vegetated	Widespread occurrence of coalesced vegetative mats	Some occurrence of floating mats	Scattered occurrences
High Productivity Resulting from Oceanic Processes	Widespread occurrence in area for much of the year	Some occurrence for much of the year; or widespread for part of the year	Scattered and short-term occurrences

Benthic habitats are considered predominantly sensitive to bottom disturbances associated with anchoring, structure installation and removal, and pipeline installation activities. While marine oil spills are unlikely to contact benthic habitats, spills of synthetic drilling muds from a platform could settle on benthic habitats (Boland *et al.* (2004)). Physical disruption, destruction, and smothering of benthic habitat from these activities could result in long term or permanent impacts because of slow recovery rates from physical disturbances.

Pelagic habitats are assumed to be most sensitive to oil spills, as these habitats would be exposed at or near the sea surface to open contact from marine spills. Pelagic habitats typically are seasonal as their occurrences are related to seasonal properties of the global ocean circulation and temperature of the atmosphere. As a result, while the habitat could be degraded to the extent of being unavailable or dangerous to the habitat users for the remainder of the season, the habitat could return in the next cycle of its occurrence with no remnant evidence of the spill. Pelagic habitats also could be sensitive to disturbance from nearby normal OCS operations, such as service vessel and helicopter traffic, regulated discharges, and sound.

Impact coefficients were developed based on the expected sensitivity of marine habitats to oil and natural gas activities. The analysis applies the same degree of sensitivity to both the short-term but potentially dramatic impacts to pelagic habitats from oil spills and the potentially long-term impacts from bottom disturbances. The highest impact coefficient of 4 was used in habitats that span both pelagic and benthic environments, such as seagrasses and coral reefs that occur in relatively shallow water and could be exposed to impacts from both oil spills and bottom disturbances. The highest impact coefficient of 4 also was applied to sea ice habitat, which, by its physical presence during much of the year, would keep the oil more confined and concentrated than what would occur in an open-ocean habitat. A slightly lower impact coefficient of 3 was applied to floating vegetation, whose habitat value could become degraded through absorption of oil, but not bottom disturbance. The lowest coefficient of 2 was applied to the remaining habitats.

The presence of marine sanctuaries, critical habitat, and other officially designated and protected marine habitat areas in an OCS program area is used as an additional indicator of marine habitat sensitivity. Each federally designated area was given a value of 1. Examples include designation of critical habitat for the spectacled eider in the Chukchi Sea Program Area (USFWS (2009a)), and designation of polar bear critical habitat in Alaska in 2010 (USFWS (2010)).

The relative sensitivity scores and rankings of each of the six OCS program areas are presented in Table 23 below. The scores were calculated by summing the product of each benthic and pelagic marine habitat type's abundance value by each habitat's sensitivity coefficient. An additional value was added to this sum based on the number of federally designated areas present in an OCS program area.