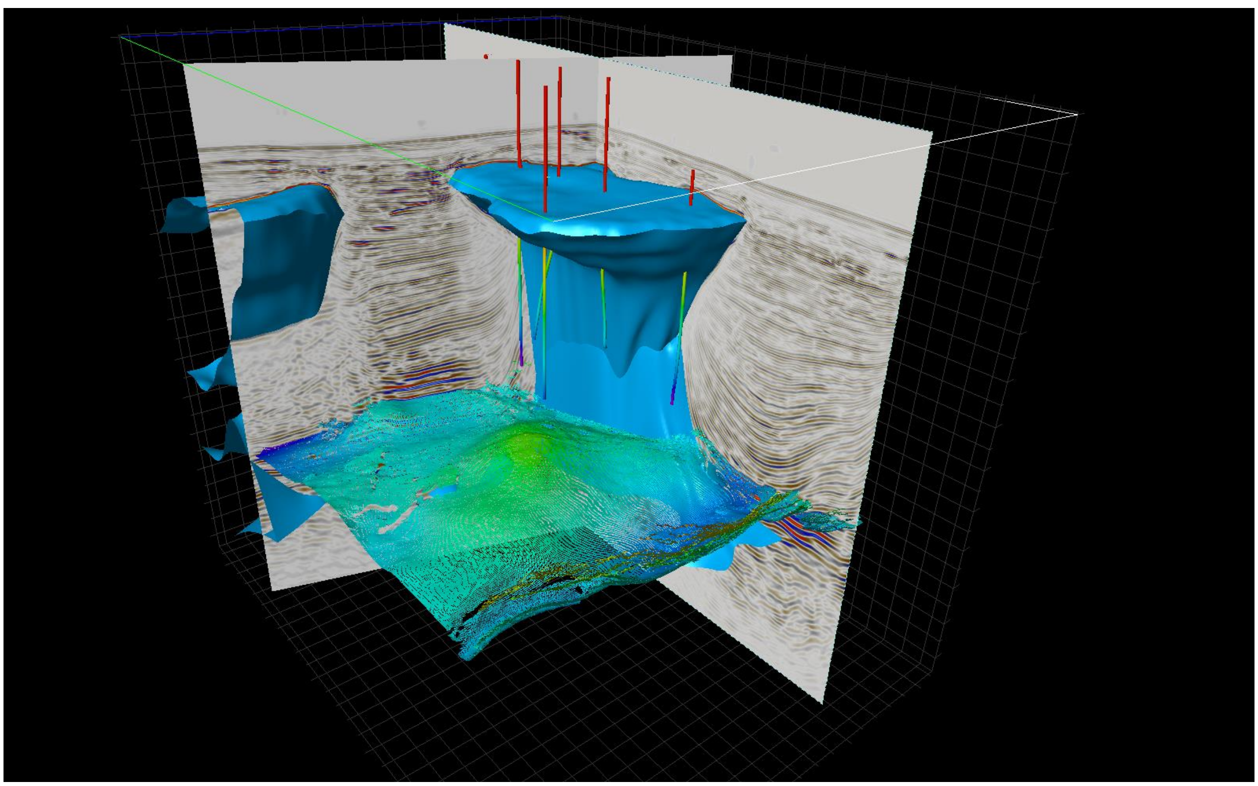
Report to Congress:
The Comprehensive Inventory of U.S. Outer Continental Shelf Oil and Natural Gas Resources: 2013 Update

Energy Policy Act of 2005 – Section 357



U.S. Department of the Interior
Bureau of Ocean Energy Management

Cover illustration is a three-dimensional representation of subsurface geology and a possible oil and gas well development scenario.

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Prepared by
Bureau of Ocean Energy Management

For the
U.S. Congress

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Preface

Section 357 of the Energy Policy Act of 2005 directs the Secretary of the Interior to provide a report to Congress within six months of the date of enactment (i.e., August 8, 2005) with updates of at least every five years. The *Comprehensive Inventory of Outer Continental Shelf (OCS) Oil and Natural Gas Resources: 2013 Update* report is an update to the February 2006 report. The statute mandates that the inventory and report:

1) incorporate available data on oil and natural gas resources in areas offshore of Mexico and Canada that are relevant to estimating the resource potential of the OCS;
2) use any available technology except drilling to obtain accurate resource estimates;
3) analyze how OCS resource estimates have changed over time in relation to available data and exploration and development activities;
4) estimate the effect of understated oil and natural gas resource estimates on domestic energy investments; and,
5) identify and explain how legislative, regulatory and administrative programs or processes restrict or impede resource development and affect domestic supply.

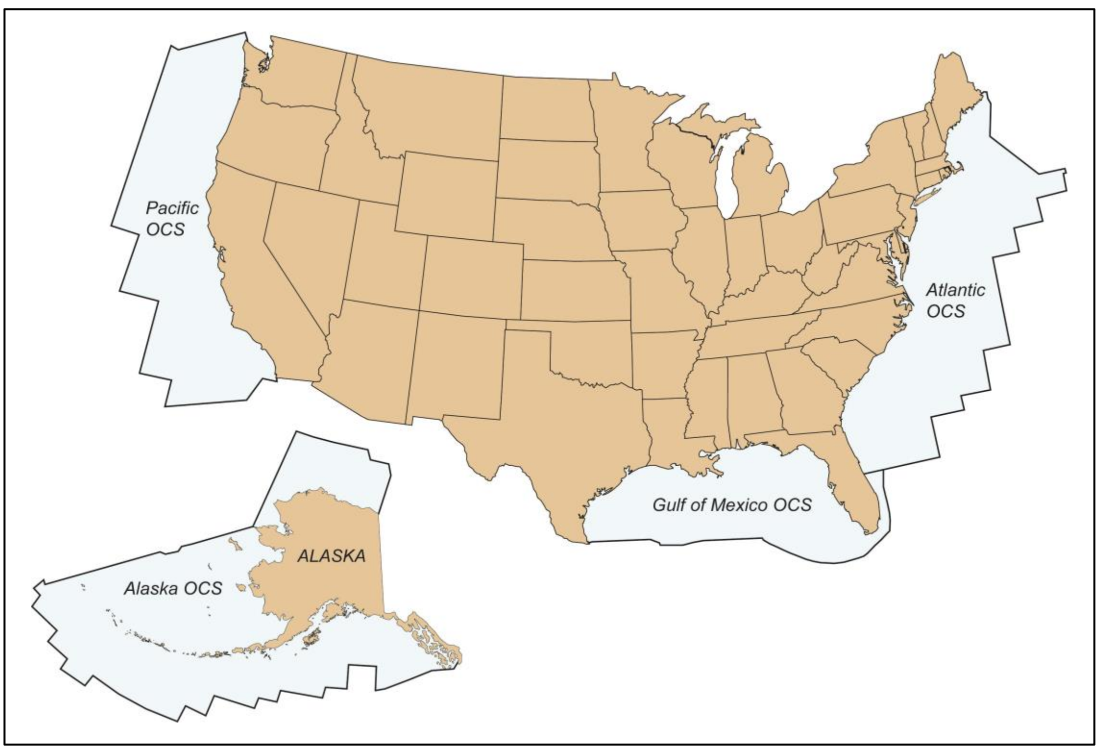
This report was authored by the U.S. Department of the Interior's Bureau of Ocean Energy Management.

Executive Summary

Oil and natural gas resources will likely remain a critical component of our nation's energy portfolio in the coming decades. Petroleum resources are considered finite since they do not renew at a rate remotely approaching their rate of consumption. Since petroleum is an important driver of the Nation's economy, there is considerable interest in the magnitude of the domestic resource base from which future discoveries and production will occur. Resource assessments are a critical component of energy policy analysis and provide important information about the relative potential of U.S. offshore areas as sources of oil and natural gas.

This report represents an update of the initial 2006 Comprehensive Inventory Report and reflects information consistent with the Bureau of Ocean Energy Management's (BOEM) latest 2011 National Assessment of Undiscovered Technically Recoverable Oil and Gas Resources on the Outer Continental Shelf (OCS) and the 2014 Atlantic Assessment Update. Technically recoverable resources are hydrocarbons potentially recoverable by conventional production methods regardless of the size, accessibility, and economics of the accumulations assessed. The OCS comprises the portion of the submerged seabed whose mineral estate is subject to Federal jurisdiction (see Figure 1). BOEM and its predecessors have previously completed several assessments of OCS oil and gas resources. The 2011 assessment is a comprehensive appraisal that considered relevant data and information available as of January 1, 2009. The Atlantic assessment update considered data as of December 2013.

Figure 1: Map Showing the Outer Continental Shelf of the United States



The commodities assessed are crude oil, natural gas liquids (condensates), and natural gas that exist in conventional reservoirs and are producible with conventional recovery techniques. The terms natural gas and gas are used interchangeably in this report. The estimates of oil resources reported represent combined volumes of crude oil and condensate. It is necessary to make fundamental assumptions regarding future technology and economic conditions when developing these estimates. The necessity to predict the future magnitude and directional impact of these factors introduces considerable uncertainty to the resource assessment. The continued expansion of technological frontiers can be reasonably assumed to partially mitigate the impacts of a maturing resource base (smaller and less concentrated accumulations in more remote locations) as exploration and development moves into areas with less favorable economic conditions.

Resource estimates are just that — *estimates*. All methods of assessing potential quantities of technically recoverable resources are efforts to quantify a value not reliably known until the resource is nearly depleted. Thus, there is considerable uncertainty intrinsic to any estimate. The estimates incorporate uncertainty, but they cannot account for serendipity or the unforeseen. As such, resource estimates should be used as general indicators and not predictors of absolute volumes. All resource estimates are subject to continuing revision as undiscovered resources are converted to reserves and reserves to production and as improvements in data and assessment methods occur. The assessment results do not imply a rate of discovery or a likelihood of discovery and production within a specific time frame. However, uncertainty surrounding the estimates decreases as the asset progresses through this cycle. Resource estimates should be viewed from the perspective of the point in time the assessment was performed—based on the data, information, and methodology available at that time.

In general, risk and uncertainty in estimates of undiscovered oil and natural gas are greatest for frontier areas that have little or no past exploratory effort. For areas that have been extensively explored and are in a mature development stage, many of the geologic and economic risks have been reduced or eliminated and the degree of uncertainty in possible outcomes narrowed considerably. As a result, resource potential can be evaluated with much more confidence. However, even in some mature producing areas such as the Gulf of Mexico (GOM) shelf, considerable uncertainty remains about the petroleum potential at greater drilling depths. In spite of these inherent uncertainties, resource assessments are valuable input to developing energy policy and planning.

The results of the 2011 resource assessment are presented in Table 1 (below) and Table 3 in Section III of this report. The total endowment of technically recoverable oil and gas on the OCS is comprised of known resources—i.e., cumulative production, and estimates of remaining proved and unproved reserves and reserves appreciation—plus estimates of undiscovered resources. This endowment is estimated to equal 129.5 billion barrels of oil (Bbo) and 661.1 trillion cubic feet of gas (Tcfg). On a barrel of oil-equivalent (BOE) basis, approximately two-thirds of the total hydrocarbon endowment is projected to be in the GOM region (for a definition of the term “barrel of oil-equivalent” refer to appendix A). No government-sponsored geological or geophysical data acquisition was undertaken for this inventory.

Table 1: Total Endowment of Technically Recoverable Oil and Gas on the OCS, 2011

Region	Known Resources			Undiscovered Resources (mean Estimate)	Total Endowment (mean Estimate)
	Cumulative Production	Reserves	Reserves Appreciation		
OIL (Billion Barrels)					
Alaska OCS	0.03	0.03	0.00	26.61	26.65
Atlantic OCS**	0.00	0.00	0.00	4.72	4.72
Gulf of Mexico OCS	17.11	10.00	9.52	48.40	85.03
Pacific OCS	1.3	1.62	0.00	10.20	13.12
Total OCS	**18.44**	**11.65**	**9.52**	**89.93**	**129.54**
GAS (Trillion Cubic Feet)					
Alaska OCS	0.00	0.00	0.00	131.45	131.45
Atlantic OCS**	0.00	0.00	0.00	37.51	37.51
Gulf of Mexico OCS	179.3	25.52	48.47	219.46	472.75
Pacific OCS	1.77	1.53	0.00	16.10	19.40
Total OCS*	**181.07**	**27.05**	**48.47**	**404.52**	**661.11**

* Summation of total OCS resources and endowment may not equal sums of components due to individual computer modeling runs and rounding.
** The Atlantic OCS undiscovered resource estimates reflect the 2014 Atlantic Assessment Update

Discovered Resources: Of the total endowment, about 39.6 Bbo and 256.6 Tcfg (approximately 34 percent on a BOE basis) is represented by discovered resources in known fields — the total of cumulative production, remaining proved and unproved reserves, and reserves appreciation.

As of January 1, 2011 (2013 for the Alaska and Pacific), cumulative production on the OCS was approximately 18.44 Bbo and 181.07 Tcfg, 96 percent of which was produced in the GOM. The production represents 21 percent of the estimated total endowment.

Estimates of the discovered resources remaining to be produced (reserves and reserves appreciation) total 21.2 Bbo and 75.5 Tcfg and are located in approximately 1,300 OCS fields. Reserves growth or appreciation accounts for 9.5 Bbo and 48.5 Tcfg of this total and represents the projected increase in current estimates of reserves within existing fields based on historical trends. This growth occurs primarily from the discovery of new reservoirs and an increase in the estimate of the recoverable portion of in-place hydrocarbons within known fields, due to future advances in technology, an increased understanding of reservoir performance and improved economic viability.

Undiscovered Resources: The mean estimate for undiscovered technically recoverable resources (UTRR) totals 89.9 Bbo and 404.5 Tcfg. (The full range of estimates corresponding to different probabilities of occurrence can be found in Section III). On a BOE basis, more than half of the UTRR are projected to exist in the GOM region.

Section III of this report also includes a discussion on changes in assessment results between the 2006 and 2011 assessments. Figures 2a and 2b show the comparison for the total endowment of both oil and natural gas between the 2006 and 2011 assessments. For the entire OCS, estimates of the total endowment of oil and gas increased by 12 percent and 4 percent respectively.

Figure 2a: Comparison of Estimates of Total Endowment Oil Resources on the OCS—2006 and 2011 Assessments

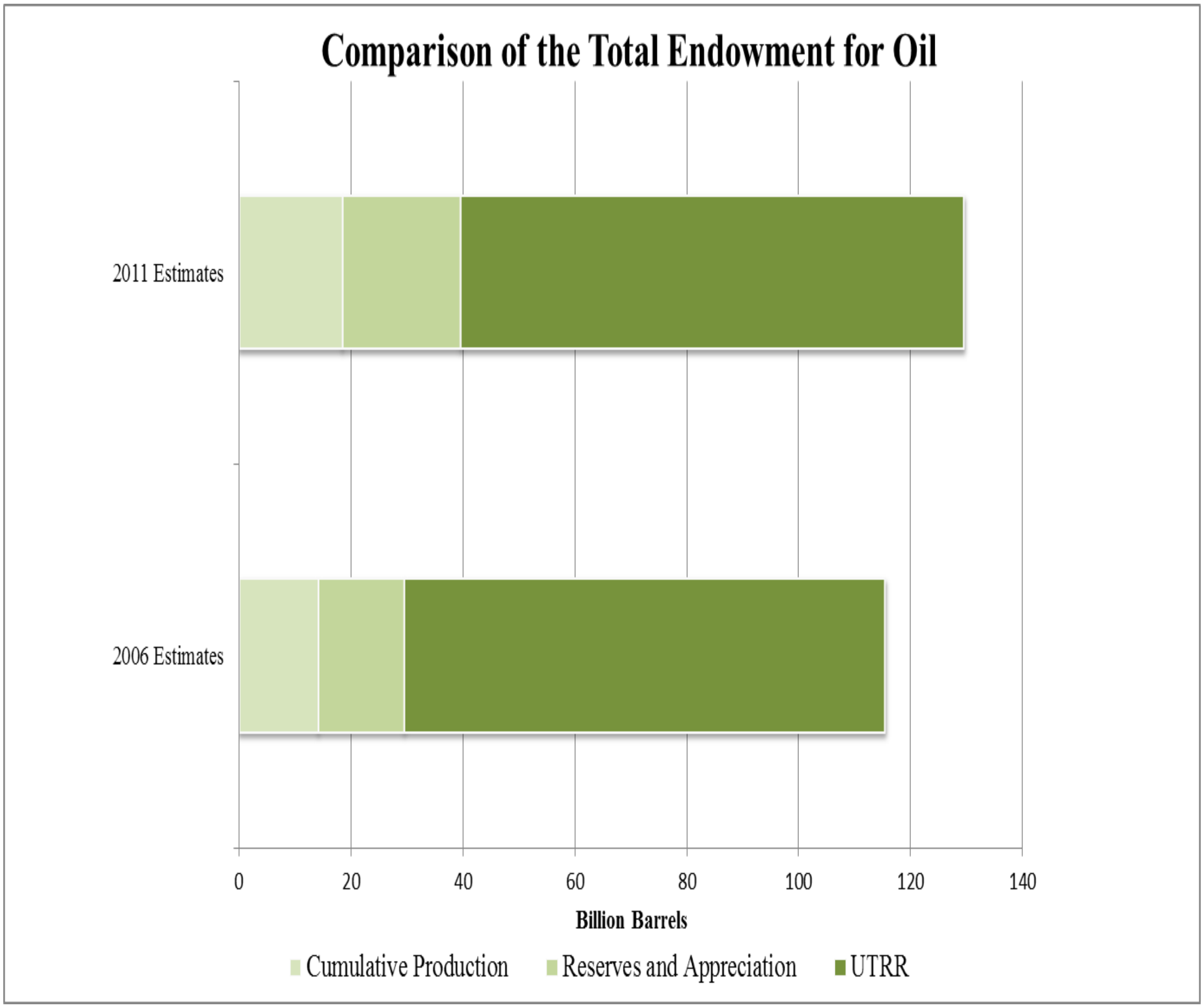
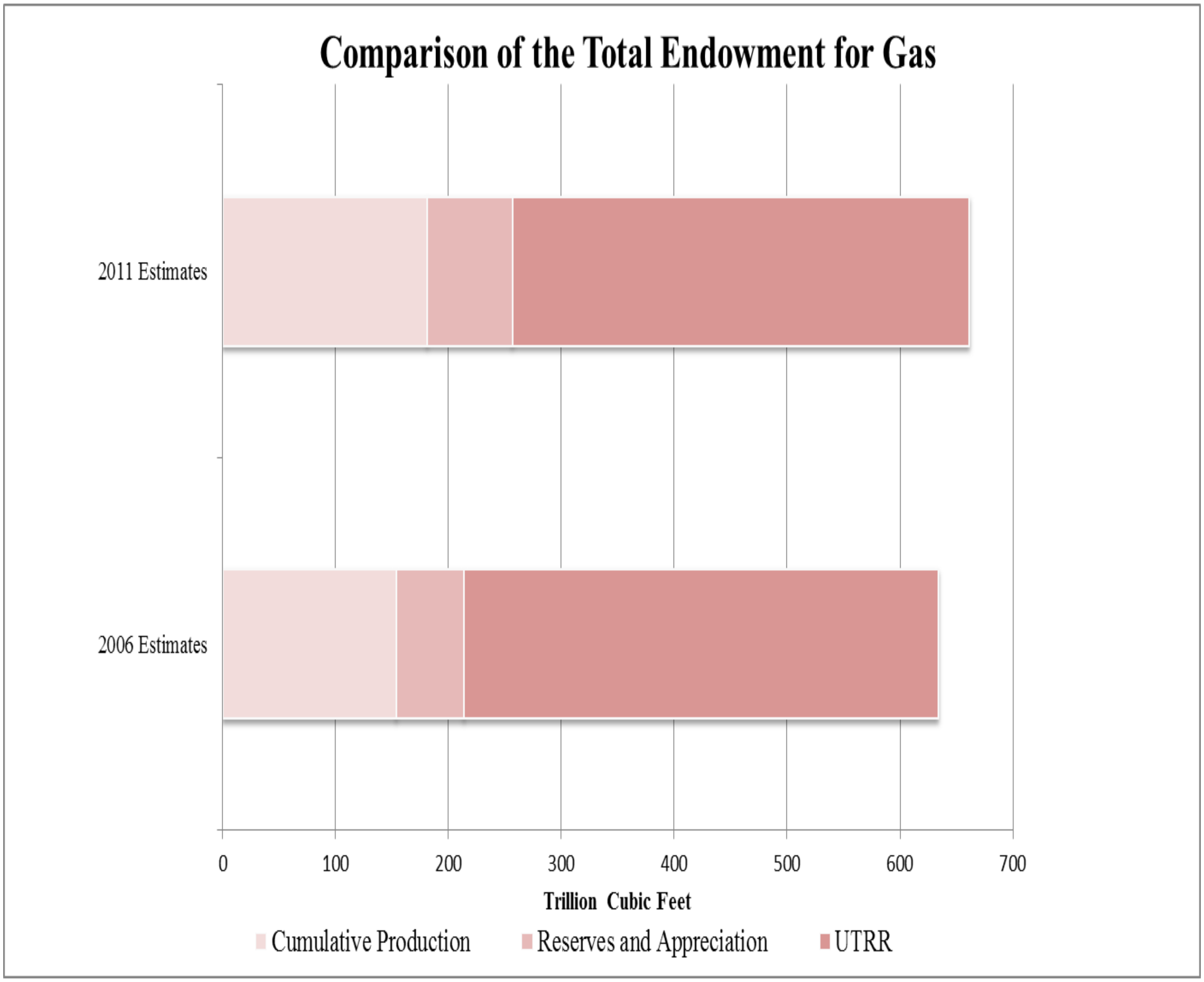


Figure 2b: Comparison of Estimates of Total Endowment Gas Resources on the OCS—2006 and 2011 Assessments



Note: The 2011 UTRR estimates above reflect the 2014 Atlantic Assessment Update.

Since the 2006 assessment, about 4.3 Bbo and 27.5 Tcfg were produced from the OCS, with 94 percent of the oil and 98 percent of the gas from the GOM. Despite this significant volume of oil production, the estimate of oil reserves (including reserves appreciation) grew during this period, increasing by about 5.74 Bbo. This means that industry was successful in replacing considerably more than all the OCS oil reserves produced during this period through new oil prone discoveries. This is not the case for natural gas on the OCS. The estimate for GOM gas reserves (including appreciation) increased by 15.4 Tcfg, yet GOM gas production during this time period totaled 27.05 Tcfg, meaning that discoveries of new sources of OCS gas are currently not keeping pace with OCS production. As the Nation's demand for natural gas increases, new domestic sources such as shale gas onshore continue to offset the decline in OCS gas production that is attributed in part to relatively low gas prices.

The BOEM estimate for undiscovered technically recoverable oil resources on the OCS has increased by 5 percent; and the volume of undiscovered technically recoverable gas resources decreased 4 percent between the 2006 and 2011 assessments. These changes in estimates of UTRR volumes are primarily attributable to the GOM region where the estimate of oil UTRR increased by 3.5 Bbo and gas decreased by 13.1 Tcfg. If these volumes of estimated undiscovered oil and gas resources are in fact discovered, the resulting new reserves will provide significant new sources of domestic production in the years to come.

Since 1975, the Department of the Interior (DOI) has completed nine comprehensive OCS resource assessments. To be used effectively, knowledge of the terminology, commodities, regions assessed, methodology, and statistical reporting conventions are essential. Much of the confusion regarding the use of petroleum resource and reserve estimates results from misunderstanding or inappropriately interpreting the data and terminology. One must exercise caution when comparing assessments due to changes in methodology and the underlying data and assumptions over time.

Section IV of this report addresses in detail the historical change in assessments over time. During this period, the geological and geophysical (G&G) information available to government assessors has increased dramatically. These data have increased the BOEM's knowledge regarding the resource potential of the OCS. However, the majority of these data exist in the more mature areas of the central and western GOM and southern California.

Early DOI resource assessments focused on reporting estimates of undiscovered economically recoverable resources (UERR). UERR refer to the portion of the undiscovered conventionally recoverable resources that is economically recoverable under imposed economic and technologic conditions. Oil and natural gas prices have experienced considerable volatility since the initial assessment was completed. As a result, assessments reporting UERR typically utilized different prices and sets of economic conditions making comparisons difficult. The frequency of developing new resource estimates could not keep pace with changes in oil and gas prices. Beginning with the 1996 assessment, the resource assessments focus primarily on estimates of UTRR instead of UERR to remove the effect of economic volatility on resource estimates. In an attempt to present a more complete picture of the total hydrocarbon endowment, assessment reports also include estimates of cumulative production, reserves, and reserves appreciation.

The period covered by the assessments is also one in which the oil and gas industry's technology capabilities expanded considerably. Today the oil and gas industry possesses the ability to drill exploratory wells in water depths exceeding 10,000 feet and to produce hydrocarbons in water depths of over 9,000 feet. The use of three-dimensional (3-D) and other advanced seismic data and interpretation techniques has served as a catalyst to transform the geosciences and the petroleum industry by providing more accurate subsurface imaging. Resource assessment techniques have also become more sophisticated during this period.

Given the changes that have occurred over the past 30 years, it is difficult to determine to what degree changes in the assessments are attributable to specific changes in G&G data and information or any other particular individual technological advance. The differences in assessments do point to different perceptions concerning the overall depth of knowledge utilized in estimating the UTRR and UERR on the OCS. Due to sparse data in the Alaska, Atlantic and part of the Pacific OCS Regions, assessors must seek out geologic and geophysical information from both domestic and worldwide oil and gas discoveries to develop information analogous to the plays being assessed on the OCS. This analog information is then used in a more subjective manner within the Geologic Resource Assessment Program (GRASP) to cover a wider range of uncertainties typical to frontier OCS areas. For mature areas with significant amounts of data, such as the Gulf of Mexico and southern California, a subjective methodology using geologic parameters from historical trends was combined with a discovery based approach to account for what is known in existing discovered pools.

Section V of this report addresses how the government's resource assessment results are used and the extent to which they affect domestic investment decisions. The premise of the request contained in section 357(a)(4) of the Energy Policy Act of 2005—to estimate the effects of understated resource inventories suggests that government assessments are often conservative when viewed over time given the benefit of hindsight following actual discoveries. It is important to note that each assessment reflects a snapshot in time that should not be viewed as either understated or overstated, when compared to later assessments which will reflect changed circumstances and knowledge. The actual volume of oil and natural gas resources that can be recovered from the OCS are not definitively known until the resources are nearly depleted. Evolving technological capabilities, better seismic data and exploratory drilling, can lead to higher or lower estimates when the assessments are updated in later years. True knowledge of the actual volume of oil and natural gas resources can only come through the drilling of wells and production of the fields.

The BOEM resource assessment is one of a number of sources of information that is used by policy-makers when considering energy policy options. Industry and private investors take into account other sources of information when considering alternative investment opportunities, and often conduct independent assessments. This includes employing their own models and techniques. The same factors that can serve to moderate the government's assessment of the resource potential of certain OCS areas (e.g., lack of data, uncertainty) also influence industry's assessments and conclusions, and ultimately influence their willingness to invest in those areas.

Some frontier areas offer potential for larger field-size discoveries, but drilling and seismic data are limited, so estimates of potential resources must account for the higher risk and uncertainty associated with the geologic model. As such, the resulting risk-based estimates of oil and natural gas in frontier areas will ordinarily be seen as too conservative if later exploration demonstrates that the area does indeed contain hydrocarbon accumulations.

The actual discovery, development, and production of oil and natural gas results not from the inventory and data compiled by the government, but from efforts by a diverse set of companies working to identify oil and natural gas prospects that warrant investment. When examining alternative investment opportunities, companies will consider not only the oil and gas potential of an area, but also the expected costs of development, as compared to alternative investments. The expected profitability of specific projects will be affected by a company's determination of geologic and economic risk which will be lower in politically stable areas with proven resource potential, as well as its perception of local opinions towards oil and gas development in the area. Many in the industry believe that the resource potential may be larger than reflected by present evaluations. The more an area is successfully explored, the more its resource estimates tend to grow. However, industry will only invest in domestic oil and gas exploration and development when they have reasonable certainty of realizing a sufficient return on that investment. Companies usually will not expend capital or time attempting to evaluate the hydrocarbon potential of areas that are off-limits to leasing. In the face of uncertain rights to lease and develop, industry will tend to invest elsewhere.

Only those areas included in an approved Five Year Oil and Gas Leasing Program are available for leasing consideration. Portions of the OCS are currently not available for leasing as they have not been included in the current 2012-2017 Five Year Oil and Gas Leasing Program. Section VI of this report addresses such impediments and restrictions on OCS oil and gas development.

At the time of this report, part or all of six OCS planning areas, which include waters off six coastal States, have been made available for leasing in the current Five Year Program. The BOEM estimates that nearly 68 Bbo and 307 Tcfg of the OCS UTRR will be made available as a result of this program, which represents approximately 76 percent of the UTRR on a BOE basis. Areas unavailable for leasing in the 2012-2017 Program also contain significant amounts of technically recoverable oil and natural gas resources. The BOEM estimate of UTRR in OCS areas unavailable for leasing in the 2012-2017 Program totals nearly 22 Bbo and 98 Tcfg.

There remains considerable uncertainty concerning the resource potential of many of these OCS areas currently or previously off limits. The availability of additional modern G&G data (seismic) could serve to reduce this uncertainty. In OCS areas experiencing robust levels of exploration and production, BOEM's perceptions concerning the resource potential have continued to evolve over the years. Critical to this changing perception is the fact that BOEM has acquired approximately 2.6 million line-miles of two-dimensional (2-D) common depth point (CDP) seismic data and nearly 2.0 million square miles of 3-D seismic data. However, it's important to note that additional G&G data and information that may become available to assessors between assessments is frequently mixed in terms of having a positive or negative effect on the resource estimates and the perception of the overall hydrocarbon potential of the OCS.

Currently, legislative moratoria precludes about 65 million acres in the GOM from being offered for oil and gas leasing, exploration, and development as described in Section 104 of the Gulf of Mexico Energy Security Act of 2006. However, access can also be restricted to otherwise available areas of the OCS for a variety of reasons, including administrative restrictions for other purposes—such as for national defense or for protection of archaeological, cultural or environmentally-sensitive marine resources. New uses of the OCS could also affect the oil and gas industry's use of the seabed on existing leases, as well as restrict potential development on future areas offered for lease. Many of these constraints on activity represent important and necessary regulatory or administrative requirements to protect the environment and ensure safe and effective multiple uses of ocean resources.

Much of the OCS's oil and gas resources exist in environmentally sensitive areas, and the development of those resources must be balanced with potential environmental impacts. Proposed OCS oil and gas activities must comply with a variety of Federal and state statutes, regulations, and administrative orders that are designed to provide for safe and responsible resource development with appropriate environmental protection. Reviews and analyses under these laws can sometimes add time to the leasing and permitting processes. Multiple governmental review processes under varying statutory requirements can lead to conflicting requirements and uncertain deadlines. Such uncertainties and delays can prevent or impede development.

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I. Introduction

The U.S. Outer Continental Shelf (OCS) contains significant quantities of oil and natural gas resources. Section 357 of the Energy Policy Act of 2005 directed the Secretary of the Interior to prepare and submit to Congress within six months of the date of enactment a comprehensive inventory of OCS oil and natural gas resources with a report. This report is an update of the initial 2006 Comprehensive Inventory Report and reflects information consistent with the Bureau of Ocean Energy Management's (BOEM's) latest 2011 National Assessment of Undiscovered Technically Recoverable Oil and Gas Resources on the OCS and the 2014 Atlantic Assessment Update.

The following sections of this report address each statutory requirement and frame the discussion with background information about the OCS program:

- Section II provides background discussion on the OCS oil and gas leasing program and the current energy situation.

- Section III presents the OCS oil and natural gas inventory (Sec. 357(a)(1) and (a)(2)).

- Section IV discusses the historical changes in resource estimates (Sec. 357(a)(3)).

- Section V discusses possible effects of understated resource estimates on domestic investments (Sec. 357(a)(4)).

- Section VI describes the various types of impediments and restrictions affecting OCS oil and gas activities (Sec. 357(a)(5)).

    - Section VI (A) describes generally how legislative, regulatory, and administrative programs or processes can restrict or impede OCS oil and gas development and domestic supplies.

- Appendix A presents the glossary that defines relevant terms used in this Report.

- Appendix B presents a list of relevant abbreviations, acronyms, and symbols used throughout this Report.

- Appendix C lists the references consulted for this Report.

II. Background on the OCS Oil and Gas Leasing Program

The passage of the Outer Continental Shelf Lands Act (OCSLA) in 1953 established Federal jurisdiction over the mineral resources of the OCS and authorized the Secretary of the Interior to manage oil and natural gas and other marine minerals activity seaward of state submerged lands. The Federal OCS generally extends from 3 to 200 miles offshore and covers an area of about 1.7 billion acres. Of this total area, some 34 million acres (2.0 percent) as of April 1, 2014 are currently under lease for oil and natural gas exploration and development, and 15 percent of the leased acreage is in production[1].

The OCSLA, as amended, establishes a comprehensive framework for oil and gas resource management. It provides for development of Five Year OCS oil and gas leasing programs and supporting environmental documents that are used to establish the size, timing and location of OCS leasing over a 5 year time frame. The intensive planning process is designed to consider the laws and policies of affected coastal States and balance multiple objectives among geographic areas in terms of hydrocarbon potential, environmental sensitivity, and other factors. It involves extensive consultation and public commenting in the development of the programs and in planning for individual lease sales. Resulting sales offer industry access to OCS acreage for leasing by competitive bid, providing for potential future exploration and development of oil and gas resources.

As the DOI OCS resource management agency, BOEM manages the exploration and development of the nation's offshore resources. It seeks to appropriately balance economic development, energy independence, and environmental protection through oil and gas leases, renewable energy development and environmental reviews and studies. As of April 1, 2014, the bureau manages 6,251 active oil and gas leases of which 1,055 are considered producing[2].

As of April 2014, the Gulf of Mexico (GOM) OCS had over 2,500 platforms on nearly 5,600 active leases of which 1,009 were currently producing oil and gas. Oil production averaged 1.2 million barrels per day and gas production averaged 3.6 billion cubic feet per day for 2013.

On the Pacific OCS, there were 43 active leases with all of these leases producing oil and gas from 23 platforms (as of 2013). The cumulative number of oil and gas wells drilled on the Pacific OCS as of July 2013 was 1,146 of which 336 were exploration wells and 1,080 were development wells. Oil production averaged 51 thousand barrels per day and gas production averaged 69 million cubic feet per day for 2013.

The Alaska OCS had 607 active leases of which 3 are currently producing oil and gas as of April 2014. The Federal share of the oil production averaged 1.8 thousand barrels per day and gas production averaged 82 million cubic feet for 2013.

The total Federal OCS oil and gas production from 1954 to 2013 is about 20 billion barrels of oil and about 186 trillion cubic feet of gas. The total U.S production (including onshore) from 1954 to 2013 is about 160.6 billion barrels of oil and about 1,114 trillion cubic feet of gas. Over this nearly 60

[1] Source: http://www.boem.gov/Oil-and-Gas-Energy-Program/Leasing/Combined-Leasing-Status-Report/Index.aspx. Refer to April 2014 Report.
[2] Ibid

year period, the Federal OCS contribution to the total U.S. production is approximately 12 percent for oil and 16.7 percent for gas. However, in calendar year 2013, total Federal OCS production was about 476 million barrels of oil and about 1.4 trillion cubic feet of gas. This translates to a 17 percent contribution of OCS oil production to the total U.S. oil production; and a 5 percent contribution for gas in 2013.

Oil and gas activities on the OCS—leasing, exploration, and production—are subject to a number of environmental reviews by Federal, state and local agencies. The OCSLA and other applicable statutes like the National Environmental Policy Act (NEPA), the Coastal Zone Management Act (CZMA), the Endangered Species Act (ESA), the Marine Mammal Protection Act (MMPA), the Clean Air Act (CAA), and the Clean Water Act (CWA), as well as authorities of other agencies and Departments, govern the conduct of the OCS program. The bureau now has over three decades of experience working with coastal states on coastal zone and other issues related to offshore development.

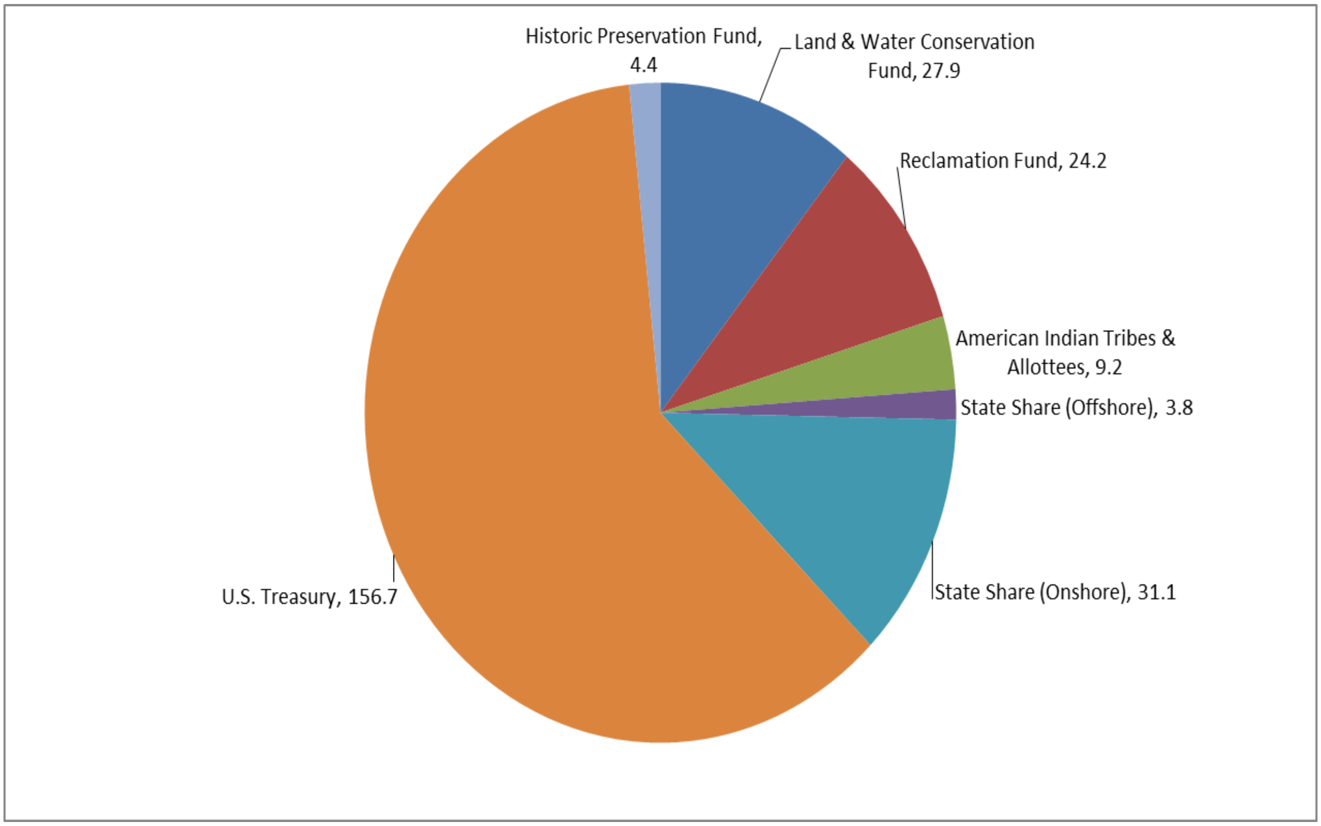
The OCS oil and gas program provides significant benefits to the Nation as a whole by providing secure domestic supplies of oil and gas, helping to meet our growing energy needs and helping to lessen the U.S. reliance on foreign sources of energy. The offshore oil and gas industry is estimated to support 314, 000 jobs[3]. Note, that this figure includes jobs sustained by direct industry spending and does not include jobs created from government spending or those created from domestic spending from profits.

The billions of dollars in revenue collected by the Office of Natural Resources Revenue (ONRR) annually from energy companies for offshore and onshore oil and gas leasing and production is one of the largest sources of non-tax revenue to the Federal Government. The disbursement of mineral revenues to various beneficiaries is shown in Figure 3. The Land and Water Conservation Fund (LWCF) administered by the National Park Service, the National Historical Preservation Fund and the Reclamation Fund have received $56.5 billion in ONRR collected mineral revenues since 1982[4].

The OCS receipts are the main funding source of the LWCF. Each year as directed by Congress, a portion of OCS receipts are distributed to the LWCF along with $150 million deposited annually into the Historic Preservation Fund. For both funds, accounting procedures require payments to be made from OCS rents and bonuses, and then any further needed payments to be made from OCS royalties.

[3] Source: The Department of the Interior's Economic Contributions: Fiscal Year 2013. http://www.doi.gov/ppa/economic_analysis/upload/FY2013-Econ-Report-FINAL.pdf
[4] Source: Office of Natural Resources Revenue.

Figure 3: Cumulative Mineral Lease Revenue Disbursements (1982 – 2013): $ billions



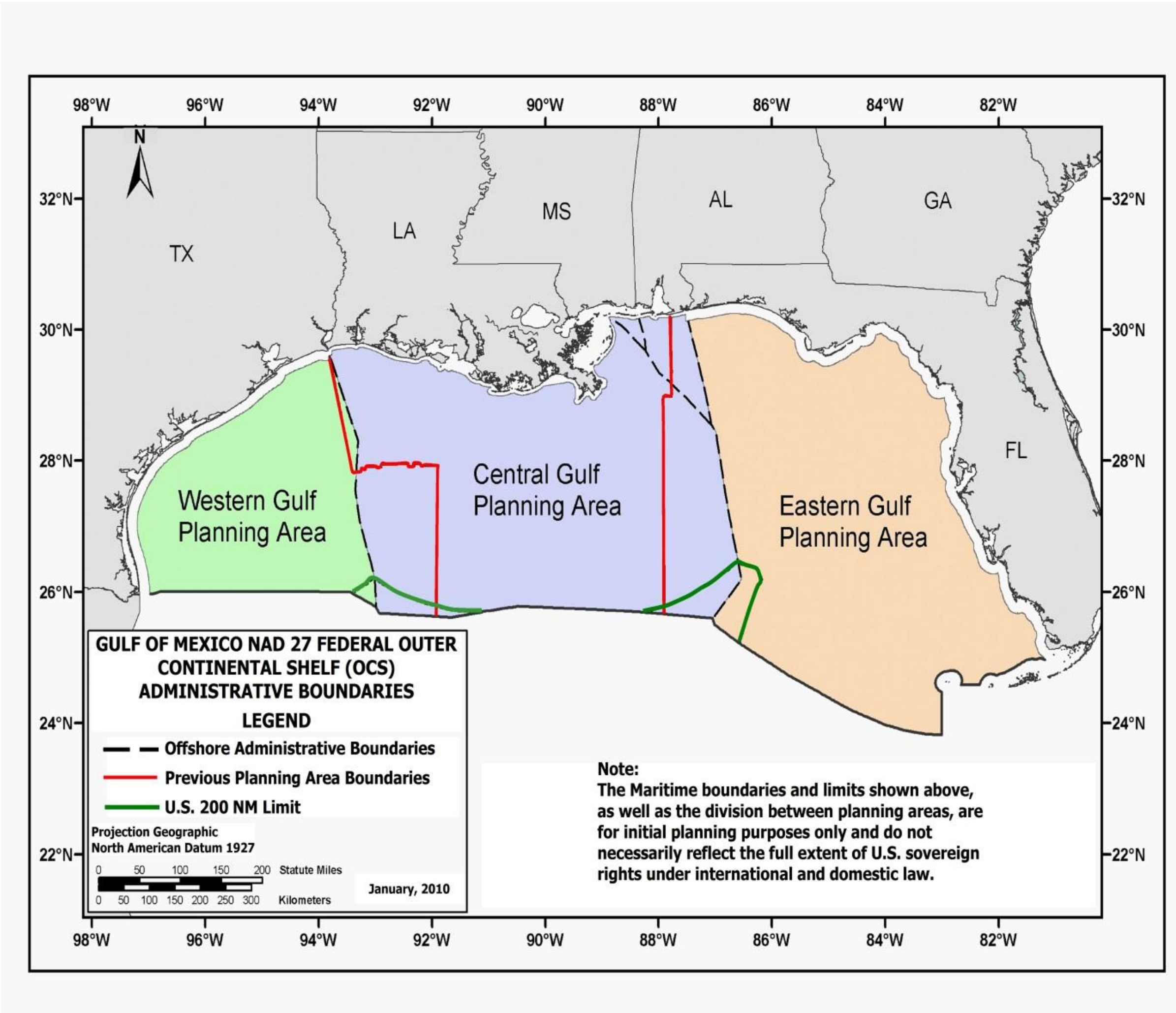
GOMESA

The Gulf of Mexico Energy Security Act of 2006 (GOMESA) (P.L. 109-432) opened additional areas of the Gulf of Mexico OCS to offshore oil and gas leasing, exploration, and development activities. The Act provided that 50 percent of revenues from these newly opened areas (termed "qualified OCS revenues") be disbursed to Gulf Producing States and to the LWCF with specific provisions for allocation during FY 2007- 2016. Beginning in 2017, the Act would share additional revenue from any new leases signed after enactment in the current program areas of the Gulf. The revenue would also be shared in the same percentages (37.5 percent to Gulf Producing States and their eligible Coastal Political Subdivisions (CPS) and 12.5 percent to LWCF) in newly opened areas. However, this additional revenue sharing is subject to a cap of $500 million per year (through 2055); revenues in excess of this cap would be deposited in the Treasury.

In 2006, BOEM implemented the planning area boundary realignments for the Gulf of Mexico as initially described in the Draft Proposed Program for the Outer Continental Shelf Oil and Gas Leasing Program 2007 – 2012 (Revised December 2010). BOEM had developed offshore administrative lines from each adjoining coastal state and undertook this task in light of the increasing number and type of both conventional and unconventional oil and gas energy activities, alternative energy projects and other activities on the OCS.

As a result of the realignment of the planning areas to follow the new administrative lines, certain areas formerly included in the Eastern and Western Gulf Planning Areas are now part of the Central Gulf Planning Area. The current planning area boundaries are highlighted in the Figure below.

Figure 4: Gulf of Mexico Outer Continental Shelf Administrative and Planning Area Boundaries



Energy Policy Act of 2005 (EPACT)

The EPACT of 2005 amended Section 31 of the OCSLA (43 U.S.C. 1356 et seq.); and, authorized the Secretary of the Interior to distribute to producing States and Coastal Political Subdivisions (CPSs), $250 million for each of the fiscal years 2007 through 2010. This funding was shared among six producing States (Alabama, Alaska, California, Louisiana, Mississippi, and Texas) and 67 eligible CPSs within those States, based upon allocation formulas prescribed by the Act. Funding for the administration of this program was provided through appropriations, with 3 percent of the annual program allocation provided in Fiscal Years 2007-2009, and 4 percent in 2010. While appropriation of new funds has ended, activities, such as grant awards and monitoring, will continue for several years.

Funds are awarded as grants for approved coastal impact assistance plans for the following purposes:

- Conservation, protection or restoration of coastal areas, including wetlands;
- Mitigation of damage to fish, wildlife or natural resources;
- Planning assistance and administrative costs;
- Implementation of a marine, coastal or comprehensive conservation management plan; and,
- Mitigation of the impact of OCS activities through funding of onshore infrastructure projects and public service needs.

The distribution formula under the Energy Policy Act of 2005 was based on the amount of qualified OCS revenues generated offshore each producing state related to the total OCS revenues. Of each state's allocable share, 35 percent was distributed to CPSs based on population, coastline, and distance to applicable OCS leases.

Section 8(g)

Under Section 8(g) of the OCSLA, 27 percent of receipts generated from 8(g) leases are shared with the coastal States. These leases are located in Federal waters within 3 miles of the seaward boundary of coastal States. For fiscal year 2013 the actual payments totaled $40,616,218. Table 2 shows the distributions to the various States.

Table 2: Distribution of Payments to Coastal States under OCSLA Section 8(g) for 2013

Payments to Coastal States under OCSLA Section 8(g)	FY 2013 Actual (Thousands Dollars)
Alabama	3,703
Alaska	2,941
California	8,455
Louisiana	24,533
Mississippi	114
Texas	869
Source: Office of Natural Resources Revenue. http://statistics.onrr.gov/ReportTool.aspx	

Access Restrictions

GOMESA included a moratorium that restricts a portion of the Central Gulf of Mexico Planning Area (CPA) and most of the Eastern Gulf of Mexico Planning Area (EPA) from OCS leasing until 2022. The area restricted is that portion of the EPA within 125 miles of Florida, all areas in the Gulf of Mexico east of the Military Mission Line (86° 41' west longitude), and a small area in the CPA that is within 100 miles of Florida that was formerly part of the EPA.

Oil and gas activities in marine sanctuaries are restricted through sanctuary regulations, Federal legislation, and Presidential order. Congress has prohibited oil and gas activities in Cordell Bank, Olympic Coast, Monterey Bay, and Florida Keys national marine sanctuaries. By Presidential order to the Secretary of the Interior, issuance of new leases for oil and gas drilling activities in sanctuaries is prohibited but does not affect leases that were in effect as of July 14, 2008 and only applies to existing sanctuaries. Generally, sanctuary regulations prohibit exploring for, producing, or developing hydrocarbons in sanctuaries. One exception is in the Flower Garden Banks National Marine Sanctuary where oil and gas activities are allowed outside of designated No Activity Zones.

On March 31, 2010, President Obama issued a memorandum for the Secretary of the Interior to withdraw from disposition by leasing through June 30, 2017, the Bristol Bay area of the North Aleutian Basin in Alaska. This withdrawal, which was set to expire in 2017, prevented any oil and gas leasing in the Bristol Bay area. However, on December 16, 2014, the President extended that withdrawal indefinitely by designating the North Aleutian Basin, which includes waters of Bristol Bay as off limits to consideration for oil and gas leasing.

On January 27, 2015 President Obama issued a memorandum for the Secretary of the Interior to withdraw certain areas of the OCS offshore Alaska from future leasing disposition. The areas include the Barrow and Kaktovik whaling areas in the Beaufort Sea, and a 25-mile coastal buffer and a subsistence area in the Chukchi Sea. The withdrawal also includes the biologically rich Hanna Shoal area in the Chukchi Sea.

Beginning in the 1980s the planning areas along the Atlantic and Pacific coasts were subject to annual Congressional moratoria for over 20 years. Congress imposed this moratorium through language included in the Bureau's annual appropriations language which prohibited any spending on pre-lease activities for these areas. This moratorium language was not included in the appropriations legislation for fiscal year 2009 and has not yet been included since and thus expired at the end of fiscal year 2008.

III. OCS Oil and Natural Gas Inventory

A. Background

Oil and natural gas resources are the major contributor to the world energy supply and this reliance on petroleum is likely to continue for decades. However, as mentioned earlier, petroleum resources are considered as finite since they do not renew at a rate remotely approaching their rate of consumption. Therefore there is considerable interest in the magnitude of the resource base, from which future domestic discoveries and production will occur.

Geologists, statisticians, and economists have been performing resource assessments for decades in an attempt to provide insights into the future petroleum supply. The demands of and uses for these assessments have led to the evolution of increasingly complex quantitative techniques and procedures to meet the challenge. Generally, the evolution has been from deterministic to stochastic methods, incorporating uncertainty and risk analyses. Scientific disciplines involved in the assessment process have evolved in parallel with the methodology, from primarily geology in the early assessments to a complex multi-disciplinary array of geology, geophysics, petroleum engineering, economics, and statistics.

1. Purposes of Resource Assessments: Resource assessments are performed by BOEM at various scales and for many purposes. Regional assessments may be prepared to develop an inventory of potential oil and natural gas resources as part of an evaluation of future supply options. Assessments may be undertaken to analyze the relative merits of oil and gas development proposals and alternatives versus other competing uses. Resource estimates provide critical input to decision makers regarding the virtues of various policy alternatives. Detailed site-specific assessments provide data essential for valuing Federal lands prior to leasing or analyzing industry exploration or development proposals.

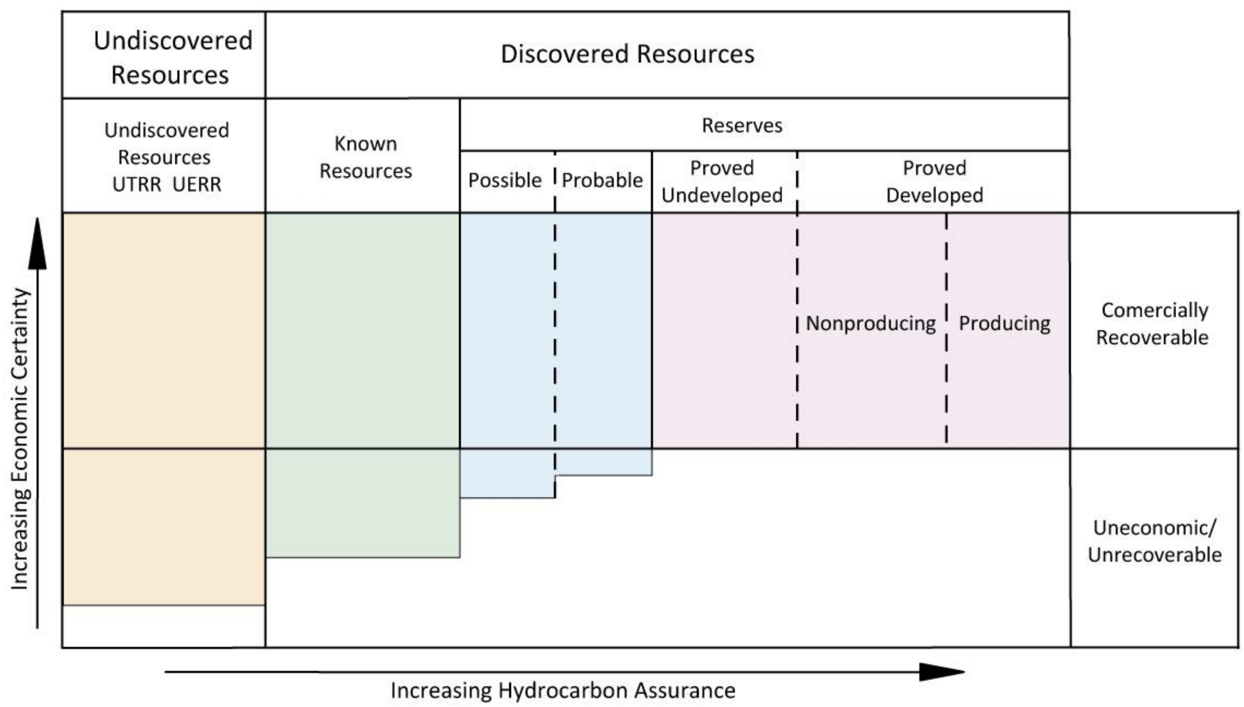
Corporations and financial institutions use resource estimates for long-term planning, the analysis of investment options and as a guide in analyzing the future health of the oil and gas industry. Exploration companies use resource assessments to design exploration strategies and target expenditures. Increasingly, resource estimates are being used by the Administration, Congress, and the public to provide objective statements of how much oil and natural gas will be available for future domestic consumption.

This report presents the results of a regional, play-based assessment of the entire U.S. OCS. It represents the results of a thorough investigation of the petroleum geology of each province and an identification of appropriate domestic and international analogs, coupled with a probabilistic methodology to estimate the remaining hydrocarbon potential.

2. Terminology and Classification Schema: At the time of this report, BOEM definitions and classification schema concerning resources and reserves reflect those approved by the Board of Directors, Society of Petroleum Engineers (SPE), Inc., and the Executive Board, World Petroleum Congresses (WPC), March 1997. BOEM definitions and classification schema concerning resources are modified as referenced by the DOI (USGS-MMS, 1989). Future BOEM definitions and classification schema concerning resources and reserves and Gas Reserves reports will be based upon the 2007 update of reserves definitions currently being adopted world-wide under the Petroleum Resource Management System. Terms related to this resource assessment are included in a glossary located in appendix A.

The bureau's scheme of classifying conventionally recoverable hydrocarbons (see Figure 5) is modified from the well-known McKelvey diagram (U.S. Bureau of Mines and U.S. Geological Survey (USGS) 1980). The scheme is dynamic with hydrocarbon resources migrating from one category to another over time. Resource availability is expressed in terms of the degree of certainty about the existence of the resource and the feasibility of its economic recovery. With increasing geologic assurance, hydrocarbon accumulations advance from undiscovered resources to discovered resources to reserves.

Figure 5: BOEM Resource Classification Schema



Reserves can be classified as proved when sufficient economic and geologic knowledge exists to confirm the likely commercial production of a specific volume of hydrocarbons. Proved reserves must at the time of the estimate either have facilities that are operational to process and transport those reserves to market, or a commitment or reasonable expectation to install such facilities in the future (Society of Petroleum Engineers, 1997).

The overall movement of petroleum resources within the schema is upward and to the right as development and production ensue. The degree of uncertainty as to the existence of resources decreases to the right in the diagram. The degree of economic viability decreases downward and also implies a decreasing certainty of technologic recoverability.

Another key concept is that of "technically recoverable resources." Resource assessments that are intended for more than scientific interest are generally limited to accumulations that are believed to be amenable to discovery and production employing conventional techniques under reasonably foreseeable technological and economic conditions. The assessments discussed in this report exclude oil and natural gas that are producible only through the use of more exotic and expensive "unconventional technologies." This distinction eliminates from consideration significant portions of the resource base, some portion of which may be developable in the future.

3. Commodities Assessed: The petroleum commodities assessed in this inventory are crude oil, natural gas liquids (condensate), and natural gas that exist in conventional reservoirs and are producible with conventional recovery techniques. Crude oil exists in a liquid state in the subsurface and at the surface; it may be described on the basis of its American Petroleum Industry (API) gravity as "light" (i.e., approximately 20^{o} to 50^{o} API) or "heavy" (i.e., generally less than 20^{o} API). Condensate is a very high-gravity (i.e., generally greater than 50^{o} API) liquid; it may exist in a dissolved gaseous state in the subsurface but liquefy at the surface. Crude oil with oil gravity greater than 10^{o} API and condensate removed from the subsurface with conventional extraction techniques have been assessed for this effort. Natural gas is a gaseous hydrocarbon resource, which may consist of associated and/or nonassociated gas; the terms natural gas and gas are used interchangeably in this report. Associated gas exists in spatial association with crude oil; it may exist in the subsurface as undissolved gas within a gas cap or as gas that is dissolved in crude oil (solution gas). Nonassociated gas does not exist in association with crude oil. Gas resources that can be removed from the subsurface with conventional extraction techniques have been assessed for this inventory. Crude oil and condensate are reported jointly as oil; associated and nonassociated gases are reported as gas. Oil volumes are reported as stock tank barrels and gas as standard cubic feet. Oil-equivalent gas is a volume of gas (associated and/or nonassociated) expressed in terms of its energy equivalence to oil (i.e., 5,620 cubic feet of gas per barrel of oil) and is reported in barrels. The combined volume of oil and oil-equivalent gas resources is referred to as barrel of oil-equivalent (BOE) and is reported in barrels.

This report encompasses only a portion of all the oil and natural gas resources believed to exist on the U.S. OCS. This assessment does not include potentially large quantities of hydrocarbon resources that could be recovered from known and future fields by enhanced recovery techniques, gas in geopressured brines, natural gas hydrates, or oil and natural gas that may be present in insufficient quantities or quality (low permeability "tight" reservoirs) to be produced by conventional recovery techniques. In some instances the boundary between these resources is somewhat indistinct; however, not included in this assessment is any significant volume of unconventional resources. These unconventional resources have yet to be produced from the OCS; still, with improved extraction technologies and economic conditions, they may become important future sources of domestic oil and gas production.

Estimates of the quantities of historical production, reserves, and future reserves appreciation are presented to provide a frame of reference for analyzing the estimates of the UTRR. Furthermore, reserves appreciation and the UTRR comprise the resource base from which the midterm future oil and gas supplies will emerge.

4. Data Sources: This assessment of the hydrocarbon potential of the OCS required the compilation and analysis of published information and vast amounts of proprietary geologic, geophysical, and engineering data obtained by industry from operations performed under permits or mineral leases and furnished to the BOEM. As of January 2014, BOEM held 138 OCS lease sales awarding 30,043 leases to industry for the exploration, development, and production of oil and natural gas since 1954. As a condition of these permits and leases, BOEM acquired approximately 2.6 million line-miles of 2-D CDP seismic data and nearly 2.0 million square miles of 3-D CDP seismic data. Moreover, BOEM has accumulated geologic and reservoir engineering information from over 42,400 wells drilled on the U.S. continental margin. These exploration activities have resulted in the discovery of over 1,300 fields. Additionally, the Bureau has reprocessed much of the seismic and well data from offshore the Canadian Arctic, Bahamas, and Cuba. BOEM evaluated and considered publicly available information from the onshore portions of the OCS basins, as well as international geologic analogs including the North Sea, North Africa, Angola, Australia, Brazil, Norway, Canada and Mexico. This database, in its entirety, was the information source for the play delineation process, as well as the basis for determining key parameters of geologic variables and pool size distributions for the OCS.

5. Limitations of Resource Assessments: It is important to recognize that estimates of undiscovered oil and natural gas resources are just that — *estimates*. Resource assessments are an attempt to quantify something that cannot be accurately known until the resource has been essentially depleted. In spite of this inherent uncertainty, resource assessments are a valuable input to developing energy policy and for corporate planning—e.g., for ranking exploration opportunities, as a basis for economic analyses, and assessments of technology and capital needs. The assessment results do not imply a rate of discovery or a likelihood of discovery and production within a specific time frame. In other words, resource assessments cannot be used directly to draw conclusions concerning the rate of conversion of these undiscovered resources to reserves and ultimately production. However, all else being equal, to the extent that industry relies on its own assessment results for a given area, or, less likely, those of the Federal Government, increases in resource estimates could change their perceptions of expected returns on capital and ultimately result in increased exploration activity.

Imperfect knowledge is associated with almost every facet of the assessment process. Dreyfus and Ashby (1989) noted that resource assessments are performed at widely varying levels of detail and precision. At one end of the spectrum lie estimates of proved reserves. These assessments rely primarily upon detailed investigations incorporating relatively abundant subsurface G&G data, as well as actual reservoir performance information associated with the particular reservoir. At the other end of the spectrum is the appraisal of undiscovered resources that might exist in areas of regional, national or even global scope. While dealing with the same type of data as reserve estimates the scope is extended to a generalized inference of the probable quantities of undiscovered hydrocarbon resources that may exist in broad areas. All resource estimates are subject to continuing revision as undiscovered resources are converted to reserves and reserves to production and as improvements in data and assessment methods occur. Uncertainty surrounding the estimates also decreases as the asset progresses through this cycle.

The various estimates presented in this report should be considered general indicators and not predictors of the absolute volumes of petroleum potential of the areas. It is also important to realize that the UTRR volumes estimated may not be found or, in fact, produced. It is, however, implied that these resources have some chance of existing, being discovered, and possibly produced. Finally, serendipitous plays, those found as complete surprises, are not considered in this assessment. These unknown plays do not have a geologic model that can be logically assessed at this time. In sum, resource estimates should be viewed from the perspective of the point in time the assessment was performed—based on the data, information, and methodology available at that time.

6. Role of Risk and Uncertainty in Resource Assessments: Exploration for hydrocarbons is a high risk proposition. Risk and uncertainty are integral parts of every resource assessment, with nearly every component of the assessment process incorporating a consideration of risk and uncertainty. The accumulation of petroleum in significant quantities requires the juxtaposition of many complex geologic events: the accumulation of organic matter in a source rock; the maturation of this organic matter into petroleum; the presence of a reservoir rock with sufficient thickness, porosity, and permeability; the migration of the petroleum into a trap with adequate size and seals; and the preservation of the petroleum in the trap. Prior to drilling, the actual existence of these geologic conditions is unknown. Not only must all of these conditions coexist they must also converge at a particular location, an unlikely event that results in a high probability of failure often described as dry hole or geologic risk. Even if all of these conditions coexist at a particular location, there remains considerable uncertainty regarding the effectiveness of a seal, the size of a trap, the quality and thickness of the reservoir, and the volume and type of hydrocarbons that not only migrated into the trap, but were preserved and still remain to be recovered.

In general, risk and uncertainty in estimates of undiscovered oil and natural gas are greatest for frontier areas that have had little or no past exploratory effort. For areas that have been extensively explored and are in a mature development stage, many of the risks have been reduced or eliminated and the degree of uncertainty in possible outcomes narrowed considerably. As a result, resource potential can be evaluated with much more confidence. However, even in some mature producing areas, such as the GOM shelf, considerable uncertainty remains about the petroleum potential at greater drilling depths. Uncertainty also pervades projections of whether potential reservoirs have been unrecognized or bypassed in past drilling. Similarly, in frontier areas where resource estimates are largely based on analog comparisons between maturely explored areas and unexplored areas, uncertainty is introduced because each area or basin has unique characteristics.

Scientists can estimate the quantity of the UTRR based on the present state of geological and engineering knowledge, modified by a consideration of future technological advancement. However, the percentage of that quantity that may actually be discovered and produced is ultimately an economic question. Uncertainties about future crude oil and natural gas prices and the costs of exploration and development (including the impacts of technology advances on costs) adversely affect all economic resource estimates. In terms of the commercial viability of an accumulation there is substantial uncertainty concerning total costs and future market prices, resulting in additional economic risk and uncertainty for a project. In short, uncertainties embodied in economic assumptions lead to significant uncertainties in estimates of the UERR and account for some of the large differences among published estimates.

Finally, there are no foolproof, completely mechanical methods for estimating potential quantities of undiscovered hydrocarbon resources. Because all methods contain elements of subjective judgment or expert opinion, the risk analysis and degree of uncertainty reflected in an estimate is affected by the knowledge, experience and assessment expertise of the personnel performing the assessment. This expertise is continually refined as new information tests the validity of previous assumptions.

The BOEM stochastic resource assessment methodology incorporates geologic risk and uncertainty at the prospect, play and basin level. The level of uncertainty is reflected in the frequency distributions for uncertain variables affecting the volume of hydrocarbons that may exist in a prospect and the number of accumulations that may exist in a play if technically recoverable hydrocarbons are present. Resource volumes are estimated under the condition that the hydro carbons are present in a prospect and play. These conditional assessments are then weighted by the appropriate risk analysis which considers the probability that hydrocarbons may in fact not be present in a prospect, play or basin. Key factors in this analysis include the potential for the existence of reservoir quality rock, adequate trapping mechanisms, mature source rock, and the presence of effective migration pathways for moving the hydrocarbons from the source rock to the trap.

The question of how much oil and gas remains to be discovered and produced cannot be answered with certainty. The answer can only be estimated with a significant degree of uncertainty, so the assessment results are expressed as probability distributions showing the full range of possible outcomes. Despite all of this inherent risk and uncertainty a common problem surrounding resource assessments is that the way that they are frequently used and reported often underemphasizes the uncertainty inherent in the final estimates. Users of petroleum assessments tend to focus on only one number, the mean value, as providing a definitive answer to the question of how much undiscovered petroleum may exist on the OCS. The focus on the mean value is misleading. In reality, what an assessment offers is a broad range of possible values, i.e. 65.16 to 121.72 Bbo and 307.86 to 556.51 Tcfg range of UTRR's from the current BOEM assessment are based on the best knowledge available at the time.

The following example illustrates some of the problems inherent in reporting and interpreting resource estimates. In some cases when a discovery is made in a frontier area and a casual observer examines published resource estimates developed prior to the discovery with post discovery assessments for the prospect or play, the conclusion is made that the resource potential was seriously underestimated. This may, in fact, be true, but frequently it represents a failure to properly understand the role of geologic risk in the reporting of estimates of undiscovered recoverable resources.

At the play level (for a definition of the term "play" refer to the appendix B), geologic risk analysis is the process of subjectively estimating the chance that at least a single hydrocarbon accumulation exists somewhere in the play. This is referred to as the marginal probability of hydrocarbons for the play (MP_{hc}). Once a conceptual or frontier play has been geologically defined it is necessary to address the question of its probable existence. As part of the play description it is assumed that critical geologic factors, such as the existence of adequate hydrocarbon source rocks, thermal maturation, migration pathways and timing, and reservoir facies exist. However, in conceptual plays and at the earliest stages of exploration in immature plays, the assessment team cannot state with absolute confidence that all of these critical factors occur anywhere within the extent of the delineated play.

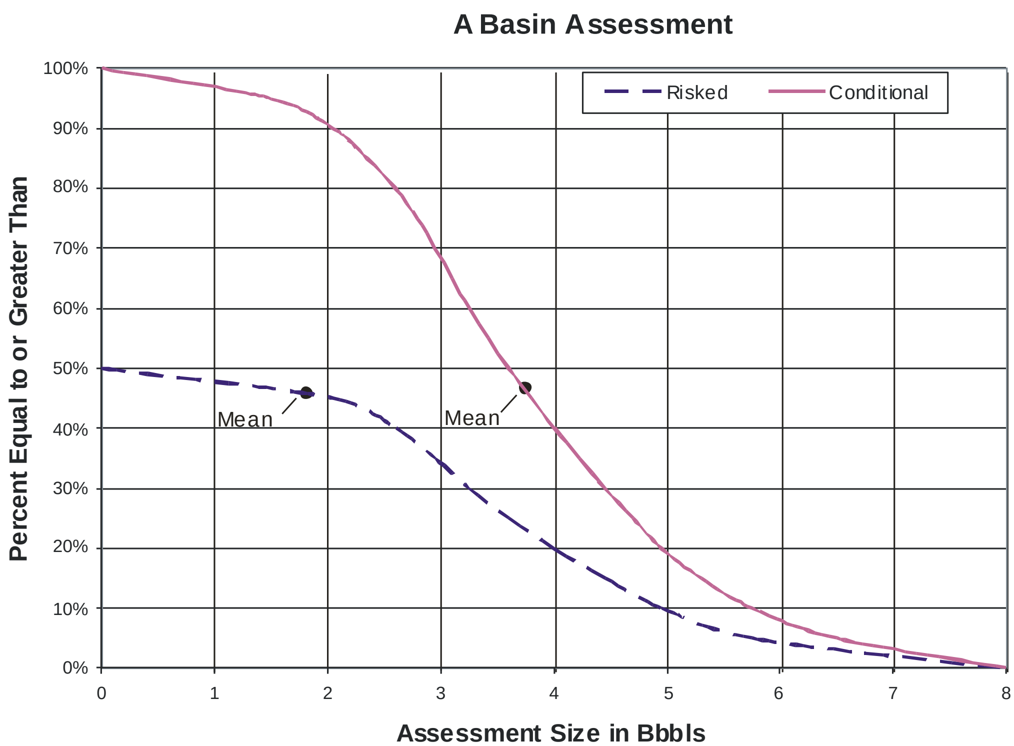
The play-level assessment of MP_{hc} is comprised of a subjective analysis performed on each of the critical components necessary for the existence of a productive play— the hydrocarbon source, reservoir, and trap components. The MP_{hc} or play chance (White, 1980) analysis assesses individually the probability of existence for each of the critical geologic factors. If a play contains more than a minimal show of hydrocarbons as in an established play, all critical geological factors are known to be present. If any of these essential factors are not present or favorable the play will not exist. The probability of the presence of each factor is subjectively estimated by the assessment team. Each component is considered to be geologically and thus statistically independent from the others. Therefore, the product of the marginal probabilities for each individual component represents the chance that all factors simultaneously exist within the play—that the play is, in fact, successful.

This play-level MP_{hc} is in addition to the prospect-level MP_{hc}, which relates the chance of all critical geologic factors being simultaneously present in an individual prospect given the play, in fact, exists. The play-level MP_{hc} reflects the regional play-level controls affecting all prospects within the play. The prospect-level MP_{hc} incorporates prospect-specific considerations. The realization that an individual prospect may be devoid of hydrocarbons does not mean that the play is nonproductive, nor does the existence of hydrocarbons in a play assure their existence in a particular prospect. However, if the play is devoid of hydrocarbons so are all of the prospects contained within that play.

The DOI reported volumes of oil and natural gas, unless stated otherwise, are discounted by the probability that the area assessed is devoid of technically recoverable hydrocarbons. Figure 6 illustrates the effect of this risking process on reported resource estimates.

Risked estimates reflect the long term expected outcome from repeated exploration in areas identical to the one being assessed. For example, an MP_{hc} of 0.5 means that 50 percent of the time the basin will not contain hydrocarbons and the other 50 percent of the time technically recoverable hydrocarbons will be present. In the 50 percent of the cases when exploration is successful, the volume discovered is represented by the solid curve labeled “conditional.” The assessment shows that there is a 95 percent chance that at least 1.5 Bbo will be found and a 5 percent chance that the amount found will be at least 6.5 Bbo. The average amount is assessed at 3.75 Bbo. The basin, however, is a frontier basin without a discovery, therefore if the basin is dry, the volume of resource expected is zero. The resource assessment results reported would reflect this risk of failure. This is shown in the dashed curve labeled “Risked.” Note on this curve there is a 50 percent chance that the volume of resources discovered will be greater than zero. The corresponding F_{95} and F_5 estimates are zero and 5.5 Bbo, respectively. The reported mean estimate is 1.88 Bbo.

Figure 6: Sample Cumulative Probability Distribution for a Basin Showing Risked and Conditional (unrisked) Results



Note: MP_{hc} at the basin level is 0.5

In the above example, if the drilling results indicate that the basin does not contain hydrocarbons then does the reported pre-drill assessment represent an over estimate? The assessor forecast that this result would occur half of the time. In fact, this represents the single most likely outcome of the assessment. On the other hand, if the published pre-drill estimate was 1.88 Bbo and 4.0 Bbo was reported, as the volume discovered after exploration was completed, does the assessment represent an underestimate? Post drilling, after the MP_{hc} has in this case been resolved and shown to be 1.0, the reviewer should use the conditional assessment curve to form a judgment concerning the quality of the assessment. In the case of an exploration failure a subjective assessment can be made as to the reasonableness of the forecast probability of failure.

The merits of the risk assessment can only realistically be judged by a comparison of the results from numerous ventures. In cases where details of the assessment are available, the judgment can be strengthened on the basis of a thorough review of individual details. For example, assume that the basin was dry because of the absence of a thermally mature source rock. Adequate traps and reservoir rocks were found to be present. Did the risk analysis correctly identify source as the major component of risk and the presence of trap and reservoir as highly probable? In the case of success, were the actual hydrocarbon type encountered, pay thickness, reservoir porosity, etc. within the assessed distributions? This information, if available, is rarely reviewed by assessment critics. It is, however, a part of the "look-back" self-assessment performed by most resource assessment teams.

In other words, resource assessments are complex. Presentation of the results in a readily meaningful format that adequately portrays this complexity and uncertainty has proven to be an elusive goal. At the risk of constantly changing perceptions regarding the hydrocarbon potential of the OCS, DOI performs periodic assessments that incorporate significant new data and information. In a forward looking sense these periodic reassessments somewhat mitigate this overstatement/understatement issue.

7. Role of Technology and Economics in Resource Assessment: This inventory assesses only technically recoverable hydrocarbon resources, both discovered and undiscovered. In developing these estimates it is necessary to make fundamental assumptions regarding future technology and economics. The inability to accurately predict the magnitude and effect of these factors introduces additional uncertainty to the resource assessment. Thus, the interplay of technological progress and changing economic conditions plays not only a crucial role in the assessment of discovered and undiscovered technically recoverable resources but it also determines the extent of the production possibility frontier of hydrocarbons resources. Newer, improved and emerging technologies used to enhance the efficiency of exploration programs, and those employed to increase the volume of hydrocarbons production are discussed below.

Scientists can estimate the quantity of technically recoverable resources (both discovered and undiscovered) on the basis of the present state of geologic and engineering knowledge, modified by a subjective consideration of future technologic advancement. However, the quantity of resources that may ever actually be produced is dependent in large part upon economics. Actual cost/price relationships are critical determinants. New capital intensive exploration and development technologies require higher product prices for implementation. Typically, as these high-cost technologies are more widely employed, costs decrease, resulting in even more widespread use of these techniques. On the other hand, new modest-cost exploitation technologies that increase recoveries or decrease finding, development, or operating costs can markedly increase estimates of technically recoverable resources without requiring an increase in product prices. A decrease in price as experienced in the late 1980's can be moderated or offset by the implementation of a technology that reduces unit costs or vice versa. Rogner (1997) concluded that "over the last century technology has probably had a more profound and lasting impact on prices than prices have had on technology."

Generally, the effects of price and technology can be considered interchangeable within the context of a resource assessment. There is a technologic and economic limit to the amount of in-place oil and natural gas resources that can be physically recovered from a reservoir. Within conventional reservoirs, approximately 30 to 45 percent of the in-place oil and 60 to 80 percent of the in-place natural gas resources are typically recovered through both primary and secondary recovery mechanisms. Three principal factors affect the amount of oil or gas that can be recovered from a known reservoir— rock properties, technology, and economics. While industry cannot change the properties of the rock it can develop new techniques to recover more oil from the rock, thus adding to the resource base. For instance, technological progress and innovation are the key factors that would enable development and production of oil and gas in new frontier regions located in deep water and in deeper reservoirs. Most notably, technologies adapted to the High Pressure High Temperature environment are the key drivers for the huge oil and gas resources hosted in the Lower Tertiary formations of the GOM. Subsea technology and extended architecture systems will boost production of offshore oil and gas in remote and challenging environments of the deep and ultra-deepwater areas which lack the basic infrastructure needed to produce and transport hydrocarbons to shore. Innovative seismic technologies that allow for better imaging of the sub salt horizons in the GOM are pivotal to the expansion of hydrocarbon resources via additional newer discoveries. Furthermore, recent technology advances, such as horizontal wells and multi-lateral completions, enable the recovery of a higher percentage of the in-place resources from a field.

These new technologies contribute to the reduction of exploration and development cost of previously uneconomical resources. The implementation of newer production platform technologies, such as Tension Leg Platforms, SPAR platforms, semi-submersible and floating production storage and offloading production (FPSO) systems allow for the development and production of hydrocarbon resources in smaller fields that would not have otherwise been economically feasible. The combination of a host platform and long distance tie-back approach, known in the industry as “Hub and Spoke” field arrangements has facilitated a lowering of development and production costs that ultimately lead to the development of marginal resources in smaller fields. The Independence Hub development in the GOM OCS is an example of this approach whereby these technologies contributed to the expansion of the economically recoverable hydrocarbon resources.

Another important aspect of the role of technology in a resource assessment is the ability to rethink fundamental approaches to developing exploration play concepts through the deployment of new technologies. Scientific advances aided by new technologies have affected the ability to identify previously unknown potential exploration plays. The introduction of new seismic data acquisition techniques, high end computing technology and new data processing algorithms have resulted in the ability for geoscientists to analyze areas below massive salt bodies underlying a large portion of the GOM OCS.

Improvements in exploration technology, notably 3D seismic have had a significant impact on discovering resources, reducing finding costs, improving exploration success rates, decreasing dry holes and optimizing development well locations. As exploration moved into more challenging areas, such as the deep water regions of the GOM, 3D seismic along with increased computing abilities and innovative drilling technologies were instrumental in increasing the resource base. It allowed for better imaging of more subtle traps and stratigraphic structures hidden beneath the canopy of salt.

Progress in drilling technology has allowed for the discovery of hydrocarbon fields located in water depth of up to 12,000 feet and 40,000 feet total depth. Techniques such as ultra-deep and extended reach drilling increase both the resource base and the amount of hydrocarbon production. One such milestone is BP's drilling of the Tiber well to 35,000 feet vertical depth in the GOM, and another is Exxon's extended reach drilling of over 40,000 feet at the Odoptu field off Sakhalin Island, Russia. These continually evolving drilling technologies allowed for the capture of resources that would have otherwise been left undiscovered and untapped. The introduction of drill ships and semi-submersibles capable of drilling in up to 12,000 feet of water, coupled with dual gradient drilling techniques, will likely expand the envelope of producible oil and gas resources in very challenging environments.

As the search for oil and gas leads to even more challenging environments, newer technologies are required for high temperature, high pressure wells that pose drilling and completion issues for casing, tubing, fluids, packers, perforating equipment, blow out preventers, safety valves, and intelligent well monitoring. The high pressure high temperature applications, currently applying to 10-15 thousand pounds per square inch (ksi) and 250-400 degrees Fahrenheit are being pushed out further to 20-30 ksi and 400-500 degrees Fahrenheit. This technological advance will open up further opportunities for the oil and gas industry in terms of increasing hydrocarbon resources.

Consideration of these new, improved and emerging technologies and their impacts on the exploration, development and production costs of oil and gas resources provide ample support to the notion that resource assessments based on a set of assumptions about future technologies and economics conditions are far from being static and devoid of uncertainty at varying levels. Constantly changing resource estimates due to increased knowledge of existing and yet to be discovered fields, and the impact of newer technologies on the economic viability of technically recoverable resources are rather the rules, not the exception, in the overall endeavor of resource assessment.

B. Inventory Results

Essential in performing the resource management mission responsibilities of the DOI is the development and maintenance of a thorough knowledge of the mineral resource base. This knowledge provides an understanding of the characteristics and distribution of the resource to better inform decision makers on issues related to resource management. With this as the primary objective, BOEM completed an assessment of the technically recoverable oil and natural gas resources of the OCS, which reflects data and information available on January 1, 2009 (December 2013 for the Atlantic OCS). This assessment was the culmination of a multi-year effort that included data and information not available at the time of the previous assessment (MMS, 2006), incorporated advances in petroleum exploration and development technologies, and employed new methods of resource assessment. The 2011 assessment of the U.S. OCS incorporated a comprehensive play-based approach toward the analysis of hydrocarbon potential. A major strength of this method is that it has a strong relationship between information derived from oil and gas exploration activities and the geologic model developed by the assessment team. An extensive effort involved developing play models, delineating the geographic limits of each play, and compiling data on critical geologic and reservoir engineering parameters. These parameters are crucial inputs to determining the total quantities of recoverable resources in each play.

1. Cumulative Production: Cumulative production is a measured quantity that can be accurately determined. The uncertainty associated with these estimates is less than with comparable estimates of volumes of reserves and considerably less than estimates of undiscovered resources.

As of January 1, 2011 (Figures for Pacific and Alaska are as of 2013), 18.4 Bbo and 181.1 Tcfg (50.6 BBOE) were produced from the Federal OCS (see Table 3). Over 95 percent of this production comes from the GOM OCS.

Table 3: Cumulative Oil and Gas Production on the OCS

Region	Cumulative Production	
	Oil (Billion Barrels)	Gas (Trillion Cubic Feet)
Alaska OCS	0.03	0.00
Atlantic OCS	0.00	0.00
Gulf of Mexico OCS	17.11	179.3
Pacific OCS	1.3	1.77
Total OCS	**18.44**	**181.07**

Note: The GOM cumulative production as of January 1, 2011. For the Pacific and Alaska the figures are as of 2013)

2. Reserves: Reserves are frequently estimated at different stages during the exploration and development cycle of a hydrocarbon accumulation, i.e., after exploration and delineation drilling, during development drilling, after initial production and, finally, after production has been well established. Different methods of estimating the volume of reserves are appropriate at each stage. Reserve estimating procedures generally progress from volumetric to performance-based techniques as the field matures. The relative uncertainty associated with these estimates decreases as more subsurface information and production history become available. Estimates of reserves are uncertain; however, traditional industry practice has been to calculate reserves through a deterministic process and present the results as single point estimates. Table 4 shows that the total proved and unproved reserves remaining in over 1,300 fields beneath the OCS are estimated to be 11.65 Bbo and 27.05 Tcfg (16.5 BBOE). Nearly 90 percent of the reserves are present within the GOM (see Figures 7a and 7b).

3. Reserves Appreciation: Cumulative production plus total estimated future production (from reserves) equals the estimate of the ultimate recovery (EUR) from a field. Predicting a field's true EUR requires an estimate of its future reserves growth or appreciation. The reserves appreciation phenomenon has been observed in onshore and offshore basins for years. During the initial years after discovery, reserve estimates typically increase rapidly. In later years the rate of growth tends to level off at a much smaller annual rate of increase. Appreciation is the result of numerous factors, which occur as a field is developed and produced. Most importantly:

- Standard industry practices for reporting initial proved reserves are often conservative in the early stages of development;
- Further drilling provides additional well log and drill stem test information to improve knowledge of the petrophysical properties and produceability of the

petroleum reservoir;

- Physical expansion of the field through the discovery of new reservoirs or the extension of existing reservoirs; and
- Improved recoveries gained through experience from actual field performance, the implementation of new technology, and/or changes in the cost-price relationships.

Reserves appreciation in the GOM routinely exceeds new field discoveries and contributes the bulk of annual additions to proven reserves. It is an important consideration in any analysis of future oil and natural gas supplies. Future reserves appreciation within the existing active fields in the GOM OCS is estimated at 9.5 Bbo and 48.5 Tcfg (18.2 BBOE) (see Table 4).

Reserves appreciation has not been estimated for the existing fields on the California and Alaska OCS. BOEM reserve estimates associated with fields offshore California are updated annually. At the time of this report, those fields have not exhibited significant growth in EUR that could be used to project future appreciation. As of 2013 the single producing field on the Alaska OCS is located primarily in state waters and has produced 27 MMbbls of oil on the Federal OCS.

4. Undiscovered Technically Recoverable Resources (UTRR): Estimates of UTRR (refer to Table 4) for the entire OCS range from 65.2 Bbo at the F_{95} fractile to 121.7 Bbo at the F_5 fractile with a mean of 89.9 Bbo. Similarly, natural gas estimates range from 307.9 to 556.5 Tcfg with a mean of 404.5 Tcfg. On a barrel of oil-equivalence basis 54 percent of the potential is located within the GOM. The Alaska OCS ranks second with 31 percent and the Pacific is third among the regions in terms of oil potential and fourth with respect to gas. The Atlantic region, on the other hand, ranks third when considering gas potential and fourth in terms of oil.

5. Total Endowment: Mean estimates of the OCS total hydrocarbon endowment are 129.5 Bbo and 661.1 Tcfg (247.2 BBOE). The total endowment distribution by resource category can be seen in Table 4 and Figure 7. Approximately 20 percent of the total endowment in terms of the mean estimate of the BOE has already been produced with an additional 14 percent contained within the various reserves categories, the source of near and midterm production.

After more than 60 years of exploration and development, 66 percent of the mean BOE total endowment remains represented by undiscovered resources on the OCS.

Figure 7a: A Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category

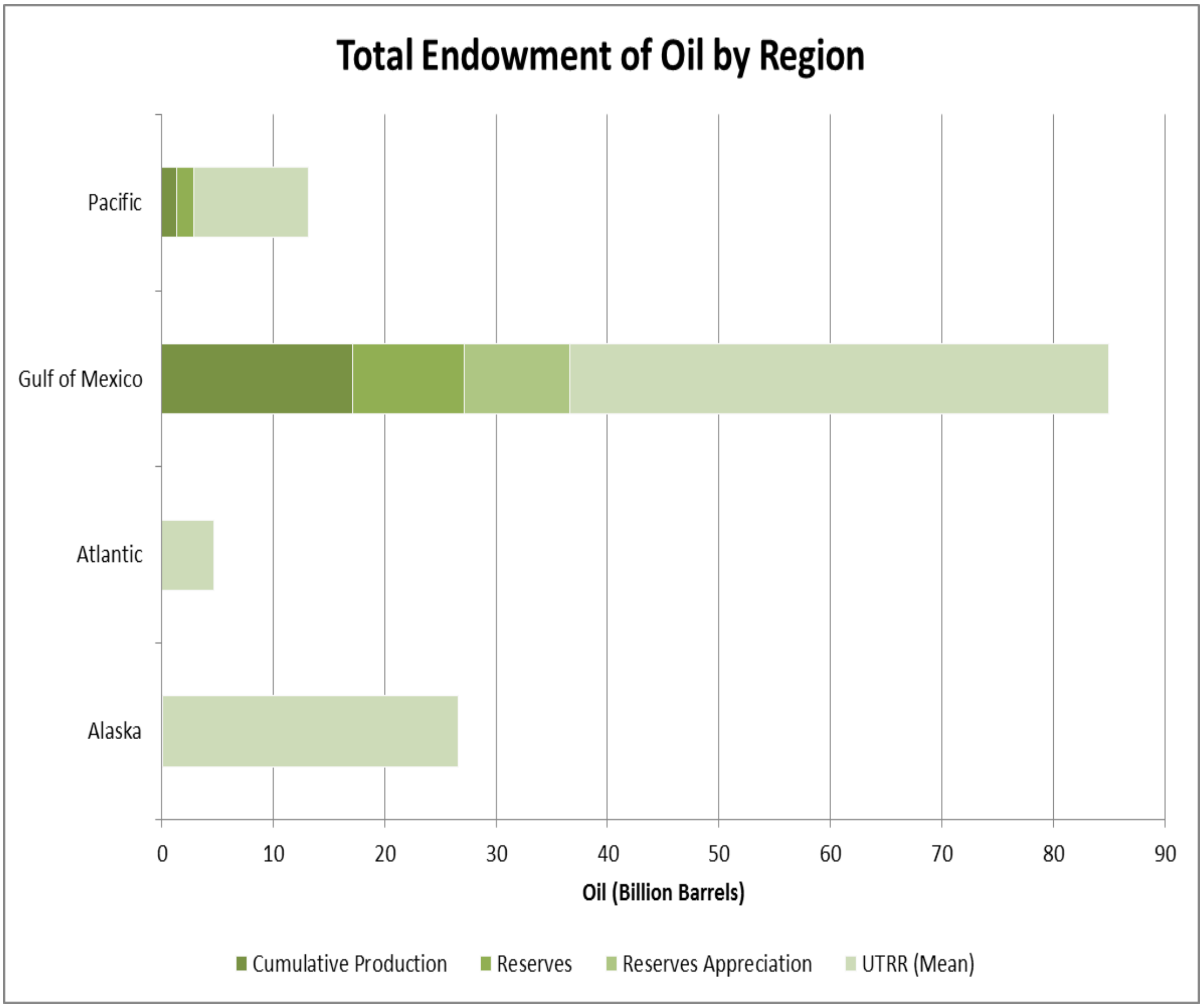
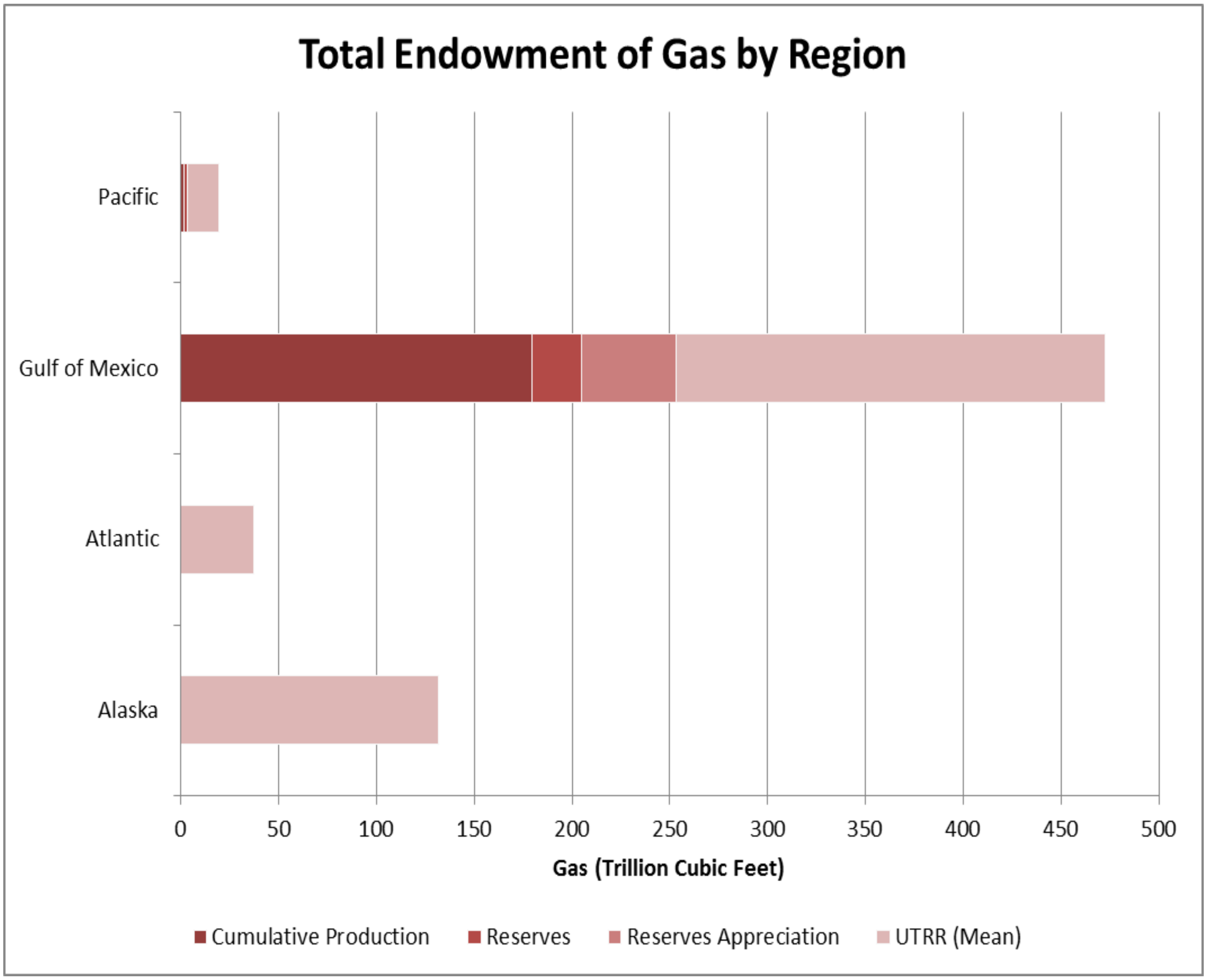


Figure 7b: A Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category



Note: The UTRR estimates above reflect the 2014 Atlantic Assessment Update.
http://www.boem.gov/Resource-Assessment-Atlantic-OCS-Region/

Table 4: Total Endowment of Technically Recoverable Oil and Gas on the OCS, 2011

Region	Cumulative Production		Reserves		Reserves Appreciation		Undiscovered Technically Recoverable Resources						Total Endowment (Mean)	
	Oil	Gas	Oil	Gas	Oil	Gas	Oil (Bbo)			Gas (Tcfg)			Oil	Gas
	(Bbo)	(Tcfg)	(Bbo)	(Tcfg)	(Bbo)	(Tcfg)	F_5	F_{95}	Mean	F_5	F_{95}	Mean	(Bbo)	(Tcfg)
Alaska OCS	0.03	0.00	0.03	0.00	0.00	0.00	55. 53	8. 81	26.61	271.04	47.43	131.45	26.65	131.45
Atlantic OCS	0.00	0.00	0.00	0.00	0.00	0.00	9.23	1.32	4.72	67.69	11.81	37.51	4.72	37.51
Gulf of Mexico OCS	17.11	179.3	10.00	25.52	9.52	48.47	59.18	38.86	48.40	245.25	193.99	219.46	85.03	472.75
Pacific OCS	1.3	1.77	1.62	1.53	0.00	0.00	14.30	6.73	10.20	23.75	10.11	16.10	13.12	19.40
Total OCS	**18.44**	**181.07**	**11.65**	**27.05**	**9.52**	**48.47**	**121.72**	**65.16**	**89.94**	**556.51**	**307.86**	**404.52**	**129.54**	**661.11**

Note: The Atlantic OCS figures reflect the 2014 Atlantic Assessment Update.
http://www.boem.gov/Resource-Assessment-Atlantic-OCS-Region/
The GOM cumulative production is as of January 1, 2011 (2013 for the Pacific and Alaska)

6. Comparison of the BOEM 2011 Assessment with the MMS 2006 Assessment: Since the 2006 assessment, 4.3 Bbo and 27.5 Tcfg were produced from the OCS, 94 and 98 percent respectively from the GOM. This production was primarily from the estimated volume of reserves and reserves appreciation reported in the 2006 resource assessment.

The sum of reserves and reserves appreciation reported in this assessment equals 21.2 Bbo and 75.5 Tcfg as compared to 15.4 Bbo and 60.2 Tcfg reported in the 2006 assessment. Despite producing 4.1 Bbo, the estimate of GOM oil reserves increased by 2.9 Bbo and the appreciation estimate increased by 2.6 Bbo resulting in a net increase of 5.6 Bbo. Industry replaced all of the oil reserves produced in the Gulf during this period. During the period between the assessments, estimates of natural gas reserves in the GOM decreased by 2.2 Tcfg while 27.1 Tcfg were produced. This decrease in natural gas reserves and incremental production between assessments is somewhat offset by a 17.6 Tcfg increase in forecasted volumes of reserves appreciation.

Figures 8a and 8b compare the mean estimates along with the 5th and 95th percentile of UTRR from the 2006 and 2011 resource assessments for oil and gas respectively. For the entire OCS, mean estimates for oil increased approximately 5 percent and decreased 4 percent for gas. The GOM region estimates for oil increased by 3.5 Bbo or about 8 percent while the estimates for gas decreased by 13.1 Tcfg or about 6 percent. Overall each of the other regions either had no change or a slight decrease in the estimates.

Figure 8a: A Comparison of Mean Estimates of Undiscovered Technically Recoverable Resources – 2006 and 2011 Assessments

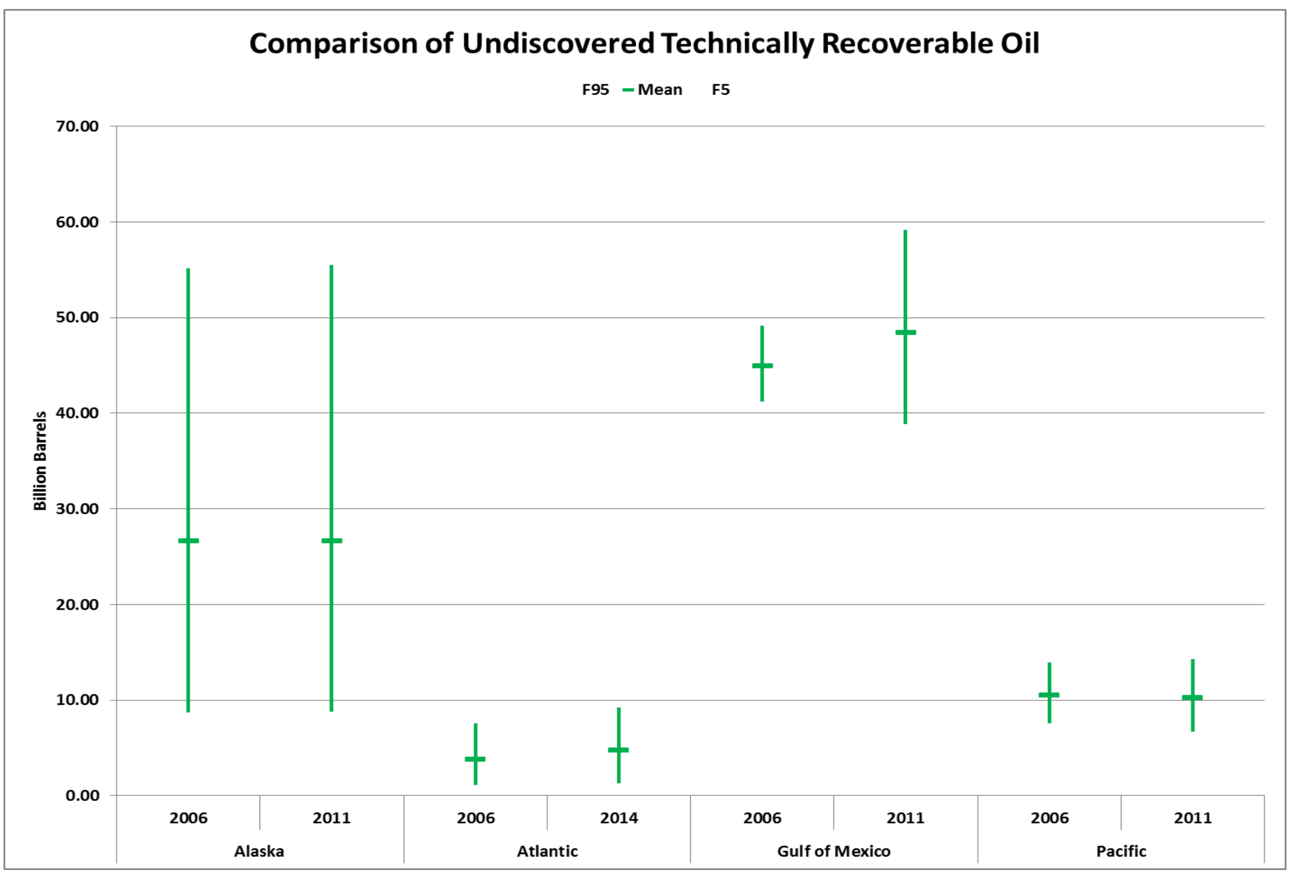
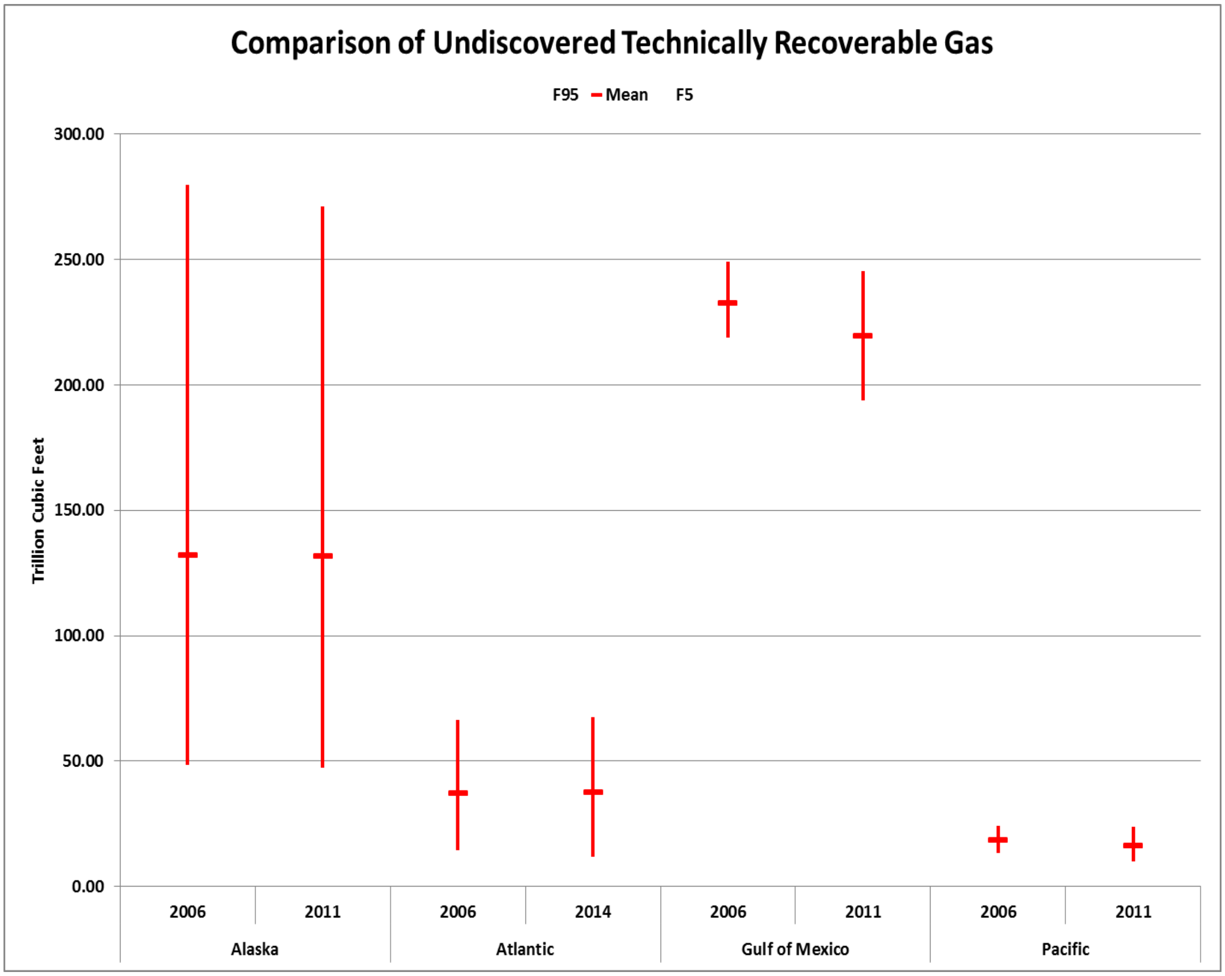


Figure 8b: A Comparison of Mean Estimates of Undiscovered Technically Recoverable Resources – 2006 and 2011 Assessments



Note: The Atlantic OCS figures reflect the 2014 Atlantic Assessment Update

IV. Historical Changes to Resource Estimates

As mentioned previously, in making judgments about what is essentially unknowable, uncertainty abounds. There is little in the way of scientific laws and hard-and-fast rules to guide an assessment. The art of resource assessment employs a multi-faceted analytical procedure. Results are not generally repeatable by different assessors, each using different methodologies, within what most observers would view as reasonable margins of error. There is plenty of room for differences of opinion and error. No single definitive assessment procedure appropriate to all situations exists that has been demonstrated to be "correct."

Assessment comparisons are difficult to do correctly in a meaningful manner. Assessments are comparable if each assessment's resource estimates attempt to measure the same commodities under similar conditions. For example, technically recoverable estimates should reflect the effect of reasonably foreseeable changes in technology, not economic conditions not caused by technology advances or policy changes.

To properly compare petroleum estimates, especially a series of estimates developed over time, it is first necessary to ascertain that the assessments cover the same things. The assessments should be identical in terms of:

- commodities assessed,
- categories of resources assessed,
- areas assessed,
- reporting of statistical data, e.g., ranges and probabilities; and,
- technological and economic conditions incorporated.

As discussed earlier, the last item may be the most troublesome to deal with since these conditions are rarely explicitly stated or easily measured. They are also precisely the conditions most apt to change between assessments. Irrespective of modifications in methodology, changes in basic geologic knowledge, economic conditions, and exploitation technologies make it difficult to compare estimates developed over time or to draw in-depth conclusions regarding the impact of these factors on individual assessments.

Since 1975, DOI has completed nine comprehensive, large-scale assessments of the undiscovered petroleum potential of the OCS. These estimates have been prepared by different bureaus, each using different assessment methods that in turn continued to evolve over time as more information becomes available and improvements in technology are realized. The techniques used vary from simple Delphi and volumetric yield approaches to geologic analogy, to statistical techniques, such as finding rates and discovery process models, to summation of prospects and play assessment approaches employing sophisticated discounted cash flow analysis. The estimates presented all appear to have no time limit regarding realization, although they assume discovery and recovery under the economic and technologic trends prevailing at the time of the assessment. The assessments also have covered different areas, measured different resources, e.g., UTRR versus UERR, and employed different assumptions developed from the perspective of different knowledge bases available at a particular point in time.

To effectively compare these estimates, one must develop an understanding of how they were prepared; the extent and reliability of the data upon which they were based; the expertise of the assessors; the implications and limitations of the methodology used; and the nature of any geographic, economic, technologic, or time limitations and assumptions that may apply. This analysis would be an exhaustive, time consuming effort. However, an attempt to compare the changes in the estimates can be made in light of the geologic knowledge base available to each assessment team, the state of exploration and production technology, choice of assessment methodologies, and the portion of the resource base assessed between successive assessments.

The degree to which variations among the reported assessments are attributable to different perceptions of the magnitude and distribution of the resource base is impossible to determine. It is certain that estimates have a time dimension that impacts the degree of basic geologic knowledge available to the assessors, as well as their technologic and economic perceptions. In the case of the GOM region, an example of the changing information base available to the assessor is the 28,671 wells drilled and additional 920 fields discovered during the period covered by the assessments between 1975 and 2002. The number of wells drilled on the OCS outside of the GOM increased from 362 to 1,427 during this period. All but one of the 362 wells at the time of the first assessment was located in the Pacific OCS. Millions of line-miles of 2-D seismic and more than 350,000 square miles of 3-D seismic were acquired on the OCS.

The first two assessments were performed by the USGS and the remainder by BOEM (formerly known as MMS). Table 5 summarizes the results from each assessment. The comments column highlights some of the key high level characteristics of each assessment in terms of area covered (defined primarily by water depth), key economic assumptions if applicable, assessment methodology, etc. Note that the principal estimates reported originally were of UERR. More recently the focus has shifted to estimates of UTRR which provides a more reliable resource comparison between assessments without having to consider differences in cost and price assumptions. BOEM has in recent assessments supplemented the primary UTRR estimates with price-supply curves that demonstrate the sensitivity of resources to changes in the cost-price relationship.

Table 5a: Summary of the Department of the Interior OCS Resource Assessments

Organization	Effective Date	Region	Risked Estimates of Undiscovered Resources									Reserves [2]			Cumulative Production			Total Endowment (Mean)			Comments
			Oil (Bbbl) [1]			Gas (Tcf)			BOE (Bbbl)			Oil	Gas	BOE	Oil	Gas	BOE	Oil	Gas	BOE	
			F_5	F_{95}	Mean	F_5	F_{95}	Mean	F_5	F_{95}	Mean	(Bbbl)	(Tcf)	(Bbbl)	(Bbbl)	(Tcf)	(Bbbl)	(Bbbl)	(Tcf)	(Bbbl)	
		Alaska OCS	33.00	3.20	16.10	80.00	8.00	44.00			23.93	0.16	0.15	0.19	0.46	0.42	0.53	16.72	44.57	24.65	1. 0-200m WD
		Atlantic OCS	6.55	0.00	3.25	22.00	0.00	10.00			5.03	0.00	0.00	0.00	0.00	0.00	0.00	3.25	10.00	5.03	2. Includes state waters
USGS	1/1/1975	Gulf of Mexico OCS	10.23	3.45	6.25	91.00	18.00	50.00			15.15	4.66	102.35	22.87	4.14	32.14	9.85	15.05	184.49	47.87	3. Florida Straits included in Atlantic OCS
(Miller et al. 1975)	UERR	Pacific OCS	5.00	2.00	3.00	6.00	2.00	3.00			3.53	1.31	0.86	1.47	1.50	1.42	1.75	5.81	5.28	6.75	4. Prevailing pre-1974 prices:$4.17/bbl and $0.22/mcf
		Total OCS	**53.53**	**11.05**	**28.60**	**181.00**	**42.00**	**107.00**			**47.64**	**6.13**	**103.36**	**24.52**	**6.09**	**33.98**	**12.14**	**40.82**	**244.33**	**84.30**	5. Delphi subjective judgment
		Alaska OCS	27.60	5.67	14.33	109.65	33.32	64.61			25.83	0.30	3.20	0.87	0.70	0.60	0.81	15.33	68.41	27.50	1. 0-2500m WD
		Atlantic OCS	14.17	1.37	5.51	42.82	9.17	23.66			9.72	0.00	0.00	0.00	0.00	0.00	0.00	5.51	23.66	9.72	2. Includes state waters
USGS	mid 1980	Gulf of Mexico OCS	16.20	5.01	8.09	114.15	41.66	71.84			20.87	2.70	73.90	15.85	5.60	55.30	15.44	16.39	201.04	52.16	3. Florida Straits included in Atlantic OCS
(Dolton et al. 1981)	UERR	Pacific OCS	8.33	1.83	4.04	13.55	3.73	6.89			5.27	1.70	2.30	2.11	1.90	1.50	2.17	7.64	10.69	9.54	4. Prevailing 1980 prices: $28.07/bbl and $1.59/mcf
		Total OCS	**51.68**	**21.03**	**31.97**	**230.65**	**117.42**	**167.00**			**61.69**	**4.70**	**79.40**	**18.83**	**8.20**	**57.40**	**18.41**	**44.87**	**303.80**	**98.93**	5. Delphi subjective judgment
		Alaska OCS			3.33			13.85			5.79	0.00	0.00	0.00	0.00	0.00	0.00	3.33	13.85	5.79	1. 0-2500m WD
		Atlantic OCS			0.68			12.31			2.87	0.00	0.00	0.00	0.00	0.00	0.00	0.68	12.31	2.87	2. Includes Federal OCS only
MMS	7/1/1984	Gulf of Mexico OCS			6.03			59.64			16.64	3.41	43.70	11.19	5.90	62.50	17.02	15.34	165.84	44.85	3. Florida Straits included in Atlantic OCS
Cooke, 1985	UERR	Pacific OCS			2.19			4.70			3.03	1.15	2.14	1.53	0.28	0.16	0.31	3.62	7.00	4.87	4. Starting: $29/bbl and $2.90/mcf escalated
		Total OCS			**12.23**			**90.50**			**28.33**	**4.56**	**45.84**	**12.72**	**6.18**	**62.66**	**17.33**	**22.97**	**199.00**	**58.38**	5. PRESTO I prospect summation
		Alaska OCS	11.21	0.59	3.84	39.42	4.67	16.75			6.82	0.00	0.00	0.00	0.00	0.00	0.00	3.84	16.75	6.82	1. 0-2500m WD
		Atlantic OCS	3.15	0.09	0.96	33.71	6.78	17.03			3.99	0.00	0.00	0.00	0.00	0.00	0.00	0.96	17.03	3.99	2. Includes Federal OCS only
	1/1/1987	Gulf of Mexico OCS	15.12	5.52	9.57	156.92	63.02	103.34			27.96	3.95	47.00	12.31	6.93	75.20	20.31	20.45	225.54	60.58	3. Florida Straits included in Atlantic OCS
	UTRR	Pacific OCS	8.92	0.81	3.51	15.07	3.50	8.01			4.94	1.30	2.14	1.68	0.37	0.33	0.43	5.18	10.48	7.04	
MMS		**Total OCS**	**25.60**	**9.20**	**17.88**	**204.80**	**97.80**	**145.13**			**43.70**	**5.25**	**49.14**	**13.99**	**7.30**	**75.53**	**20.74**	**30.43**	**269.80**	**78.44**	
Cooke et al, 1990																					
		Alaska OCS	4.76	0.00	0.92	0.00	0.00	0.00			0.92	0.00	0.00	0.00	0.00	0.00	0.00	0.92	0.00	0.92	4. Starting: $18/bbl and $1.80/mcf escalated
	1/1/1987	Atlantic OCS	1.01	0.00	0.25	9.77	0.00	4.51			1.05	0.00	0.00	0.00	0.00	0.00	0.00	0.25	4.51	1.05	5. PRESTO III & DIST
	UERR	Gulf of Mexico OCS	9.88	2.77	5.64	103.65	36.01	64.33			17.09	3.95	47.00	12.31	6.93	75.20	20.31	16.52	186.53	49.71	
	Primary Case	Pacific OCS	6.02	1.78	2.10	11.04	1.78	5.17			3.02	1.30	2.14	1.68	0.37	0.33	0.43	3.77	7.64	5.13	
		Total OCS	**14.30**	**4.00**	**8.91**	**113.84**	**44.30**	**74.01**			**22.08**	**5.25**	**49.14**	**13.99**	**7.30**	**75.53**	**20.74**	**21.46**	**198.68**	**56.81**	
		Alaska OCS	7.16	0.00	1.87	0.00	0.00	0.00			1.87	0.00	0.00	0.00	0.00	0.00	0.00	1.87	0.00	1.87	1. 0-2500m WD
		Atlantic OCS	1.01	0.00	0.25	9.77	0.00	4.51			1.05	0.00	0.00	0.00	0.00	0.00	0.00	0.25	4.51	1.05	2. Includes Federal OCS only
MMS	1/1/1990	Gulf of Mexico OCS	17.16	1.24	6.34	122.68	27.90	64.74			17.86	3.03	40.20	10.18	7.84	88.90	23.66	17.21	193.84	51.70	3. Florida Straits included in Atlantic OCS
Cooke, 1991	UERR	Pacific OCS	6.12	0.63	2.49	12.14	2.46	6.15			3.58	1.48	2.20	1.87	0.46	0.48	0.55	4.43	8.83	6.00	4. $18/bbl and $1.80/mcf flat
		Total OCS	**23.93**	**3.56**	**10.95**	**133.68**	**46.44**	**75.40**			**24.36**	**4.51**	**42.40**	**12.05**	**8.30**	**89.38**	**24.21**	**23.76**	**207.18**	**60.62**	5. PRESTO III

Table 5b: Summary of the Department of the Interior OCS Resource Assessments (Continued)

Organization	Effective Date	Region	Risked Estimates of Undiscovered Resources									Reserves [2]			Cumulative Production			Total Endowment (Mean)			Comments
			Oil (Bbbl)[1]			Gas (Tcf)			BOE (Bbbl)			Oil	Gas	BOE	Oil	Gas	BOE	Oil	Gas	BOE	
			F_5	F_{95}	Mean	F_5	F_{95}	Mean	F_5	F_{95}	Mean	(Bbbl)	(Tcf)	(Bbbl)	(Bbbl)	(Tcf)	(Bbbl)	(Bbbl)	(Tcf)	(Bbbl)	
MMS MMS, 1996	1/1/1995 UTRR	Alaska OCS	33.57	16.85	24.31	229.53	58.01	125.93	70.61	28.68	46.72	0.04	0.70	0.16	0.00	0.00	0.00	24.35	126.63	46.88	1. No WD limit
		Atlantic OCS	3.70	1.30	2.30	43.40	15.90	27.50	10.70	4.50	7.20	0.00	0.00	0.00	0.00	0.00	0.00	2.30	27.50	7.20	2. Includes Federal OCS only
		Gulf of Mexico OCS	11.10	6.00	8.30	110.30	82.30	95.70	30.00	21.20	25.40	8.60	65.60	20.27	9.34	112.60	29.38	26.24	273.90	75.05	3. Florida Straits included in Gulf of Mexico OCS
		Pacific OCS	12.60	9.00	10.70	23.20	15.20	18.90	16.60	11.80	14.10	1.23	2.03	1.59	0.68	0.65	0.79	12.61	21.58	16.48	
		Total OCS	**55.30**	**37.10**	**45.61**	**369.20**	**186.30**	**268.03**	**117.00**	**72.90**	**93.42**	**9.87**	**68.33**	**22.03**	**10.02**	**113.25**	**30.17**	**65.50**	**449.61**	**145.62**	
	1/1/1995 UERR	Alaska OCS	7.65	1.41	3.75	4.33	0.02	1.11	8.20	1.43	3.95	0.04	0.70	0.16	0.00	0.00	0.00	3.79	1.81	4.11	4. $18/bbl and $2.11/mcf flat
		Atlantic OCS			0.40			5.20			1.33	0.00	0.00	0.00	0.00	0.00	0.00	0.40	5.20	1.33	5. GRASP & PRESTO V
		Gulf of Mexico OCS			4.90			57.90			15.20	8.60	65.60	20.27	9.34	112.60	29.38	22.84	236.10	64.85	
		Pacific OCS			5.30			8.30			6.78	1.23	2.03	1.59	0.68	0.65	0.79	7.21	10.98	9.16	
		Total OCS			**14.35**			**72.51**			**27.25**	**9.87**	**68.33**	**22.03**	**10.02**	**113.25**	**30.17**	**34.24**	**254.09**	**79.45**	
MMS MMS, 2001	1/1/1999 UTRR	Alaska OCS	35.40	16.50	24.90	226.80	55.00	122.60	71.90	28.00	46.70	0.00	0.00	0.00	0.00	0.00	0.00	24.90	122.60	46.70	1. No WD limit
		Atlantic OCS	2.80	1.90	2.30	34.10	23.90	28.00	8.90	6.20	7.30	0.00	0.00	0.00	0.00	0.00	0.00	2.30	28.00	7.30	2. Includes Federal OCS only
		Gulf of Mexico OCS	44.90	33.40	37.10	207.20	180.40	192.70	81.80	65.50	71.40	12.09	103.23	30.46	10.91	132.70	34.52	60.10	428.63	136.38	3. Florida Straits included in Gulf of Mexico OCS
		Pacific OCS	12.60	9.00	10.70	23.20	15.20	18.90	16.60	11.80	14.10	1.58	1.85	1.91	0.92	1.02	1.10	13.20	21.77	17.11	4. GRASP & PRESTO V
		Total OCS	**88.30**	**63.70**	**75.00**	**468.60**	**292.10**	**362.20**	**166.90**	**117.80**	**139.50**	**13.67**	**105.08**	**32.37**	**11.83**	**133.72**	**35.62**	**100.50**	**601.00**	**207.49**	
MMS MMS, 2006	1/1/2003 UTRR	Alaska OCS	55.14	8.66	26.61	279.62	48.28	132.06	104.89	17.25	50.11	0.03	0.00	0.03	0.01	0.00	0.01	26.65	132.06	50.15	1. No WD limit
		Atlantic OCS	7.57	1.12	3.82	66.46	14.30	36.99	19.39	3.67	10.40	0.00	0.00	0.00	0.00	0.00	0.00	3.82	36.99	10.40	2. Includes Federal OCS only
		Gulf of Mexico OCS	49.11	41.21	44.92	249.08	218.83	232.54	93.43	80.15	86.30	13.94	58.61	24.37	13.05	152.25	40.14	71.91	443.40	150.81	3. Florida Straits included in Gulf of Mexico OCS
		Pacific OCS	13.94	7.55	10.53	24.12	13.29	18.29	18.24	9.91	13.79	1.46	1.56	1.74	1.06	1.32	1.29	13.05	21.17	16.82	4. GRASP II
		Total OCS	**115.13**	**66.60**	**85.88**	**565.87**	**326.40**	**419.88**	**215.82**	**124.68**	**160.60**	**15.43**	**60.17**	**26.14**	**14.12**	**153.57**	**41.45**	**115.43**	**633.62**	**228.18**	
BOEM BOEM, 2011 [4]	1/1/2009 UTRR	Alaska OCS	55.53	8.81	26.61	271.04	47.43	131.45	103.76	17.25	50.00	0.03	0.00	0.03	0.03	0.00	0.03	26.67	131.45	50.06	1. No WD limit
		Atlantic OCS	9.23	1.32	4.72	67.69	11.81	37.51	21.27	3.42	11.39	0.00	0.00	0.00	0.00	0.00	0.00	4.72	37.51	11.39	2. Includes Federal OCS only
		Gulf of Mexico OCS	59.18	38.86	48.40	245.25	193.99	219.46	102.82	73.38	87.45	19.52	73.99	32.69	17.11	179.30	49.01	85.03	472.75	169.15	3. Florida Straits included in Gulf of Mexico OCS
		Pacific OCS	14.30	6.73	10.20	23.75	10.11	16.10	18.53	8.53	13.06	1.62	1.53	1.89	1.30	1.77	1.61	13.12	19.40	16.57	4. GRASP II
		Total OCS	**121.72**	**65.16**	**89.93**	**556.51**	**307.86**	**404.52**	**220.74**	**119.94**	**161.91**	**21.17**	**75.52**	**34.61**	**18.44**	**181.07**	**50.66**	**129.54**	**661.11**	**247.17**	

[1] Includes oil and condensate (natural gas liquids)
[2] Includes reserves appreciation if assessed
[3] Only mean values additive
[4] The Atlantic OCS figures reflect those from the 2014 Atlantic Assessment Update

1. USGS 1975 Assessment (Miller et al., 1975): This assessment utilized a Delphi technique incorporating subjective judgment by a group of appraisers to directly estimate probabilities of occurrence and the undiscovered resource potential of an area. The assessors relied on various analyses to guide their judgments. These estimates were primarily analog based; e.g., volumetric yields, finding rates, etc., comparing more mature, geologically similar basins to the frontier OCS basins being assessed. The USGS relied on publicly available data to perform this assessment. Outside of the shelf portion of the central and western GOM and the Santa Barbara Channel there was little in the way of hard geological data available on the OCS for use in this assessment.

No wells had yet been drilled on the Atlantic OCS and only a single deep stratigraphic test well had been drilled on the Alaska OCS in the Gulf of Alaska. Twenty exploratory wells had been drilled off central and northern California and 12 off Oregon-Washington during the period 1963 through 1969. Three wells had been drilled in the current Florida Straits Planning Area, off the Marquessa Keys during 1960 and 1961. At least 17 other wells were drilled in state waters or onshore adjacent to this area. All of the wells mentioned above were considered at the time to be dry holes. Elsewhere in the Eastern GOM the initial four dry holes had recently been drilled on the eastern crest of the Destin Dome structure and two other dry holes were drilled on other prospects located within the planning area.

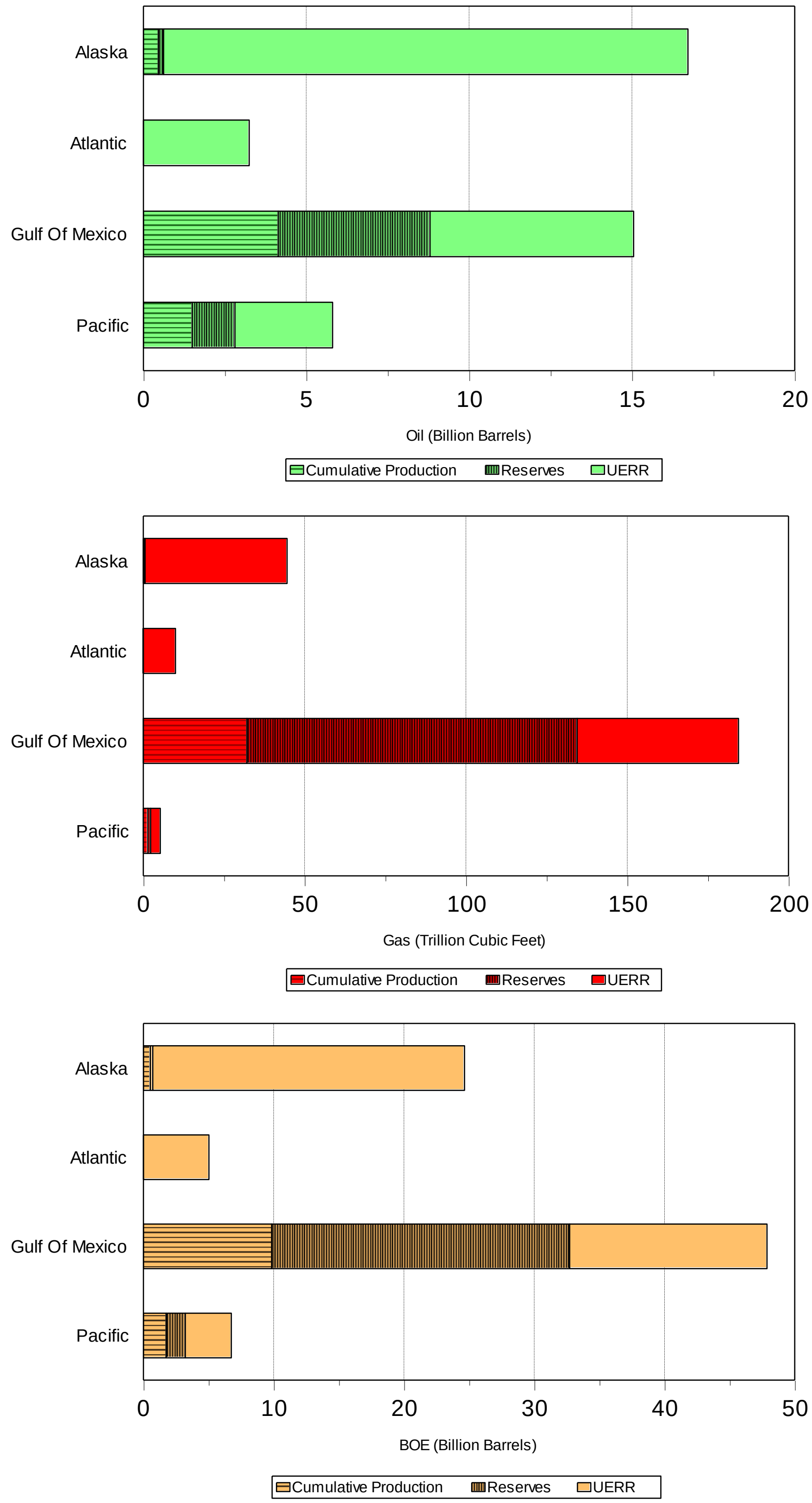
In the Central and Western GOM, industry was proceeding with its steady interest into deeper waters on the continental shelf (less than 200m water depths). Discoveries were primarily off Louisiana, but industry activity along the shelf edge was beginning to move westward off Texas. Eleven of the 12 discovered Pacific OCS oil and gas fields, including both producing fields, were in the Santa Barbara Channel. The other discovery was located to the south in the Los Angeles basin.

Industry proven technology capabilities were just beginning to expand beyond the shallow waters of the OCS. The first pipeline in water depths exceeding 1,000 feet had recently been laid. The Hondo platform soon to be installed in 850 feet of water in the Santa Barbara Channel was being fabricated at the time of the assessment. The introduction of dynamic positioning systems, used on drill ships and semi-submersible drilling rigs, was opening up deepwater exploration.

The assessment included only those portions of the OCS located in water depths of less than 200 meters. The offshore portion of the assessment also included state waters. Estimates of UERR were reported. The UERR were defined as "economically recoverable under price-cost relationships and technological trends prevailing at the time of the assessment." The assessment assumed that prevailing pre-1974 costs and prices relationships would continue. The 1973 average refiner's acquisition cost for crude oil was $4.17 per barrel and the average wellhead price for gas was $0.22 per million cubic feet (Mcf). The price, cost and technology considerations were not a quantitative part of the assessment procedure, but rather considered subjectively by each assessor in formulating their judgments.

Estimates of UERR (see Table 5a) ranged from 11.1 to 53.5 Bbo and 42.0 to 181.0 Tcfg, with a mean estimate of 28.6 Bbo and 107.0 Tcfg. The GOM was forecast to contain 22 percent of the oil and offshore Alaska 45 percent, with the remainder nearly evenly split between the East and West Coasts (see Figure 9). The assessment forecast that 47 percent of the undiscovered economically recoverable gas was located in the GOM. Offshore Alaska followed with 41 percent of the total. The mean estimate of total endowment was projected at 40.8 Bbo and 244.3 Tcfg (84.3 BBOE).

Figure 9: Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category, USGS (1975)



2. USGS 1981 Assessment (Dolton et al., 1981): The USGS completed its second national resource assessment in 1981, employing an updated version of its Delphi assessment technique. This time there was information available in many frontier basins from industry's early seismic and exploratory drilling activities. During the period since the previous assessment eight additional deep stratigraphic test wells (one in St. George, six in Kodiak, and one in the lower Cook Inlet) were drilled in Alaska basins. The results from follow-on industry exploration drilling in each of these basins were discouraging. The initial industry interest was in the Gulf of Alaska where 11 dry exploratory wells were drilled between 1976 and 1978. Industry next moved on to the lower Cook Inlet where an additional nine dry holes were drilled in the first cycle of exploration for this basin. In the south Atlantic one deep stratigraphic test well was followed up by six dry holes within the southeast Georgia embayment. Two deep stratigraphic tests were drilled in the North Atlantic providing direct geologic control for this assessment. During this period, industry's primary interest was in the Baltimore Canyon trough offshore New Jersey where two deep stratigraphic tests (one with an announced hydrocarbon show) and 23 exploratory wells were drilled. Tests on the "Great Stone Dome" structure were dry. Five wells, drilled by Tenneco and Texaco on a single separate structure, also in the Baltimore Canyon trough flowed significant quantities of natural gas and some oil on tests.

In the Santa Barbara Channel industry was in the midst of a string of new field discoveries. Four of the five producing OCS fields were in the Santa Barbara Channel. Exxon installed Platform Hondo in 1976 in 842 feet of water, a world record water depth at the time. Two deep stratigraphic tests were drilled off southern California, one on the Cortes Bank about 90 miles southwest of Los Angeles, and the other in the Point Conception area of the Santa Maria Basin. A hydrocarbon show was encountered in the Point Conception test. Based on favorable stratigraphy in the Cortes Bank test a series of nine exploratory wells were drilled on the southern California borderland. All of these wells were dry holes. The first OCS discovery in the Santa Maria Basin, the Point Arguello Field, was made in late 1980. The northernmost block of this field was leased after the field discovery in 1981 for a bonus bid of $333,596,200. This is the all-time OCS record high bid.

Industry continued to drill additional dry holes on and around the Destin Dome structure and elsewhere in the Eastern GOM. By October 1975, drilling in the area had halted after a total of 15 dry holes. However, the penetration of the Norphlet Formation revealed the presence of massive reservoir quality sandstone. This dry hole became even more important to industry with the 1979 discovery of the Mary Ann Field in state waters offshore Alabama, which generated interest in the probable extension of the prolific Norphlet trend into adjacent Federal waters. In the Central and Western GOM, industry interest was focused on the Flexure trend, located at the outer edge of the continental shelf offshore Louisiana and Texas and the Corsair trend on the Texas shelf.

The offshore portion of the assessment again included state waters. Industry exploration and production activity in the Flexure trend in the GOM, the Santa Barbara Channel, and elsewhere had exceeded the 200 meter water depth technology limit used in the previous assessment.

The first OCS deepwater production facility, Shell's Cognac fixed leg platform, was installed in the GOM in 1979 in 1,023 feet of water. Acknowledging this advancement in deepwater exploration and production technology, the USGS expanded the extent of the offshore area included in this assessment to include all areas in water depths less than 2,500 meters. The water depth limit of 2,500 meters in conjunction with a consideration of only those sediments shallower than 30,000 feet represented two high level technology limits imposed in this assessment. Estimates of UERR were again reported. The assessment assumed that prevailing 1980 costs and price relationships would continue. During 1980 prices averaged $28/bbl and $1.60/Mcf, more than seven times the 1974 averages assumed in the prior report. The USGS introduced the concept of a "minimum economic field size" (MEFS) for the various OCS regions. This MEFS incorporated quantitatively a consideration of local costs, prevailing prices and foreseeable technologies. The USGS applied individual threshold sizes across a broad range of locations, geologic conditions and water depths. Resources in accumulations below the appropriate MEFS were excluded from consideration in the assessment. The MEFS were subjectively considered by each individual assessor.

Estimates of UERR ranged from 21.0 to 51.7 Bbo and 117.4 to 230.7 Tcfg, with a mean estimate of 32.0 Bbo and 167.0 Tcfg (Table 5a). Despite the exploration results from drilling in the frontier basins in the Gulf of Alaska, southern California borderland and the southeast Georgia embayment, mean estimates of overall UERR increased by 14 percent for oil and 56 percent for gas. Table 6 shows a more detailed breakdown of the two assessments by offshore region and the shelf and slope areas.

Table 6: Comparison of the Department of the Interior 1975 and 1981 OCS Resource Assessments by Water Depth

Organization	Effective Date	Region	Risked Estimates of Undiscovered Resources									Reserves [2]			Cumulative Production			Total Endowment (Mean)		
			Oil (Bbbl) [1]			Gas (Tcf)			BOE (Bbbl)			Oil	Gas	BOE	Oil	Gas	BOE	Oil	Gas	BOE
			F_5	F_{95}	Mean	F_5	F_{95}	Mean	F_5	F_{95}	Mean	(Bbbl)	(Tcf)	(Bbbl)	(Bbbl)	(Tcf)	(Bbbl)	(Bbbl)	(Tcf)	(Bbbl)
USGS (Miller et al., 1975)	1/1/1975 UERR	Alaska shelf	33.00	3.20	16.10	80.00	8.00	44.00			23.93	0.16	0.15	0.19	0.46	0.42	0.53	16.72	44.57	24.65
		Atlantic shelf	6.55	0.00	3.25	22.00	0.00	10.00			5.03	0.00	0.00	0.00	0.00	0.00	0.00	3.25	10.00	5.03
		Gulf of Mexico shelf	10.23	3.45	6.25	91.00	18.00	50.00			15.15	4.66	102.35	22.87	4.14	32.14	9.85	15.05	184.49	47.87
		Pacific shelf	5.00	2.00	3.00	6.00	2.00	3.00			3.53	1.31	0.86	1.47	1.50	1.42	1.75	5.81	5.28	6.75
		Total shelf	**53.53**	**11.05**	**28.60**	**181.00**	**42.00**	**107.00**			**47.64**	**6.13**	**103.36**	**24.52**	**6.09**	**33.98**	**12.14**	**40.82**	**244.33**	**84.30**
		Alaska slope																		
		Atlantic slope																		
		Gulf of Mexico slope																		
		Pacific slope																		
		Total slope																		
		Total OCS	**53.53**	**11.05**	**28.60**	**181.00**	**42.00**	**107.00**			**47.64**	**6.13**	**103.36**	**24.52**	**6.09**	**33.98**	**12.14**	**40.82**	**244.33**	**84.30**
USGS (Dolton et al.,1981)	mid 1980 UERR	Alaska shelf	25.22	4.73	12.67	99.00	28.50	57.40			22.88	0.30	3.20	0.87	0.70	0.60	0.81	13.67	61.20	24.56
		Atlantic shelf	4.51	0.07	1.58	17.90	2.20	8.20			3.04	0.00	0.00	0.00	0.00	0.00	0.00	1.58	8.20	3.04
		Gulf of Mexico shelf	9.67	1.79	5.01	79.20	22.00	45.10			13.03	2.70	73.90	15.85	5.60	55.30	15.44	13.31	174.30	44.32
		Pacific shelf	3.15	0.63	1.57	5.20	0.90	2.50			2.02	1.70	2.30	2.11	1.90	1.50	2.17	5.17	6.30	6.29
		Total shelf	**30.20**	**9.20**	**20.82**	**166.80**	**72.00**	**113.40**			**41.00**	**4.70**	**79.40**	**18.83**	**8.20**	**57.40**	**18.41**	**33.72**	**250.00**	**78.20**
		Alaska slope	5.86	0.00	1.63	20.20	0.00	7.20			2.92	0.00	0.00	0.00	0.00	0.00	0.00	1.63	7.20	2.92
		Atlantic slope	11.87	0.17	4.62	34.50	5.10	15.40			7.36	0.00	0.00	0.00	0.00	0.00	0.00	4.62	15.40	7.36
		Gulf of Mexico slope	6.36	1.15	3.09	51.80	11.10	26.50			7.81	0.00	0.00	0.00	0.00	0.00	0.00	3.09	26.50	7.81
		Pacific slope	6.30	0.66	2.53	10.20	1.90	4.40			3.31	0.00	0.00	0.00	0.00	0.00	0.00	2.53	4.40	3.31
		Total slope	**19.20**	**4.20**	**11.87**	**87.10**	**28.60**	**53.60**		**21.41**	**21.39**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**11.87**	**53.50**	**21.39**
		Alaska OCS	27.60	5.67	14.33	109.65	33.32	64.61			25.83	0.30	3.20	0.87	0.70	0.60	0.81	15.33	68.41	27.50
		Atlantic OCS	14.17	1.37	5.51	42.82	9.17	23.66			9.72	0.00	0.00	0.00	0.00	0.00	0.00	5.51	23.66	9.72
		Gulf of Mexico OCS	16.20	5.01	8.09	114.15	41.66	71.84			20.87	2.70	73.90	15.85	5.60	55.30	15.44	16.39	201.04	52.16
		Pacific OCS	8.33	1.83	4.04	13.55	3.73	6.89			5.27	1.70	2.30	2.11	1.90	1.50	2.17	7.64	10.69	9.54
		Total OCS	**51.68**	**21.03**	**31.97**	**230.65**	**117.42**	**167.00**			**61.69**	**4.70**	**79.40**	**18.83**	**8.20**	**57.40**	**18.41**	**44.87**	**303.80**	**98.93**

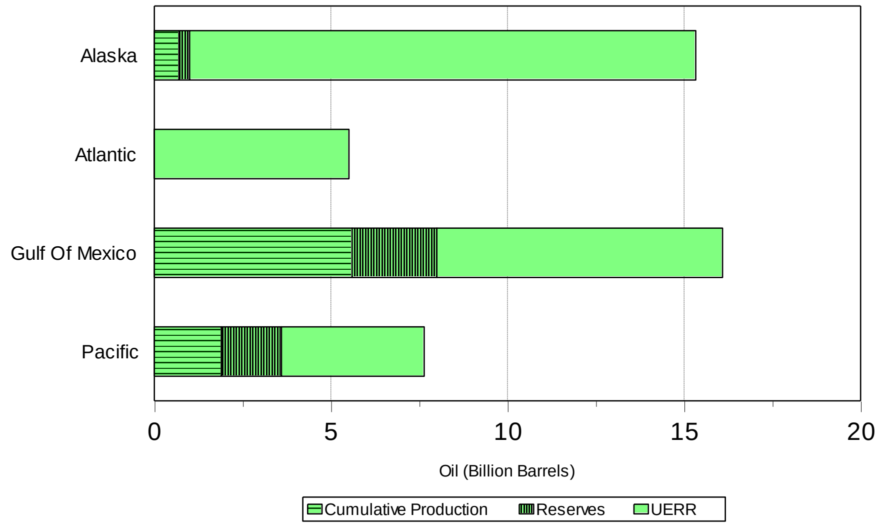
[1] Includes oil and condensate (natural gas liquids)
[2] Includes reserves appreciation if assessed
[3] Only mean values additive

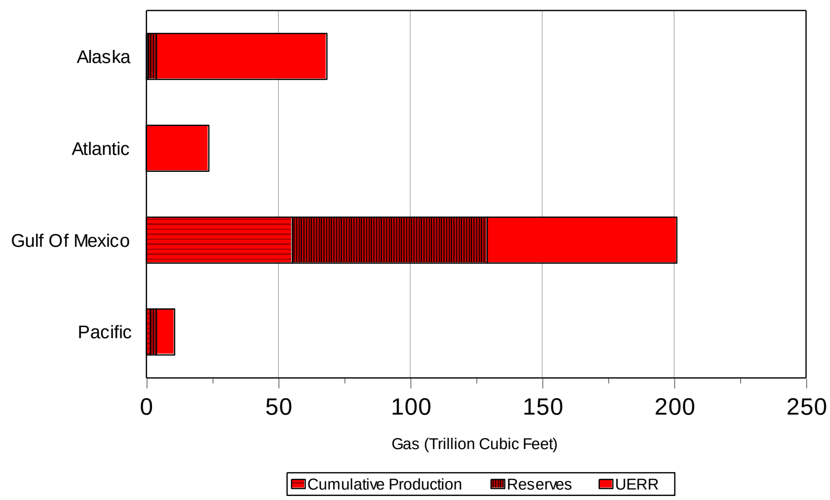
The mean oil and gas estimates for UERR located on the shelf (0 – 200 meters water depth) in this assessment were 20.8 Bbo and 113.4 Tcfg (41.0 BBOE) versus 28.6 Bbo and 107.0 Tcfg (47.6 BBOE) in the prior assessment, a decrease of 38 and 14 percent for oil and BOE, respectively. The total mean estimate for gas increased slightly in this assessment. A closer look shows that UERR estimates for oil were down in every region, as was gas with the exception of offshore Alaska where the estimates increased by 13 Tcfg or almost 30 percent. The increase in the estimate of potential quantities of gas in the shallow waters offshore Alaska is probably the result of a combination of factors. The drilling results off Alaska, while generally unsuccessful, indicated that the Bering Sea basins were probably more gas prone than previously assumed. The considerably higher gas prices incorporated in this assessment and the lower economic risk and MEFS thresholds associated with gas discoveries more than offset any increase in geologic risk imposed. The remainder of the increase in UERR is attributable to the inclusion of the continental slope in this assessment. Approximately one third of the total UERR estimate was for the deeper water portion of the OCS. Of particular note at the time of this assessment was the announcement by the USGS scientists of the existence of a buried Mesozoic shelf-edge reef complex that extended intermittently along much of the Atlantic continental margin. Comparisons were made with similar features in prolific producing trends in Mexico and the onshore U.S. gulf coast.

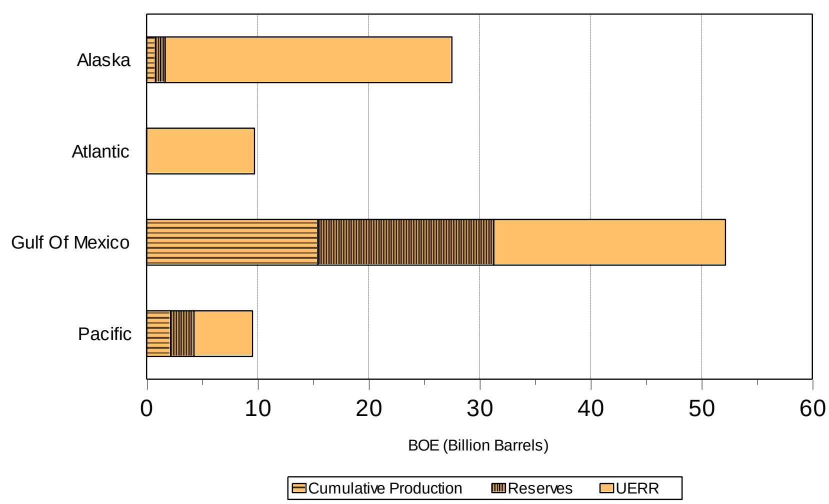
Mean estimates of the total hydrocarbon endowment of the OCS developed from this assessment were 44.9 Bbo and 303.8 Tcfg (98.9 BBOE), corresponding to an increase of 11 percent for oil and 24 percent for gas (18 percent for BOE) since the 1975 assessment. The mean value for oil UERR was 71 percent of the mean estimate for the total oil endowment. Corresponding estimates for gas and BOE are 55 and 63 percent.

The GOM was forecast to contain nearly one quarter of the UERR oil and offshore Alaska 44 percent (see Figure 10). The assessment forecast that 43 percent of the UERR gas was located in the GOM. Offshore Alaska followed with 39 percent of the total.

Figure 10: Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category, USGS, (1981)







3. MMS 1985 Assessment (Cooke, 1985): This assessment was performed as the initial phase in the development of a new proposed five year oil and gas leasing program. It was the first systematic assessment of the entire OCS performed by the newly created MMS. The resource assessment was completed primarily by a portion of the organization that was within the former Conservation Division of the USGS. Prior to this effort, staff assessment experience was confined to assessing the potential of smaller portions of the OCS for the analysis of environmental and policy concerns related to individual lease sales and for determining the adequacy of industry bids for leases. The MMS assessment methodologies at the time were, in comparison to the broad regional analysis employed by the USGS, very data intensive, requiring extensive site-specific geological and geophysical (G&G) information. USGS's assessments relied almost exclusively on data and information within the public domain, while the MMS assessment relied extensively on proprietary G&G data acquired on the OCS by the oil and gas industry. The analysis also incorporated as part of the methodology a more quantitative consideration of economic and cost information.

MMS initially considered continuing the use of the classic Delphi approach to regional resource assessment that was employed by the USGS. Because of its leasing responsibilities and a desire to employ an internally consistent and repeatable assessment technique for all analyses that supported leasing decisions, the MMS ultimately chose to pursue another direction. Previous resource assessments presented risked resource estimates which incorporate the probability that the area under consideration may be devoid of hydrocarbons. MMS program analyses typically require the use of conditional resource estimates in association with their corresponding marginal probability. To support these analyses the assessment focused on developing and presenting conditional resource estimates. Because of this focus a complete risked resource distribution was not included as part of the assessment products, only the mean values were reported. A more complete discussion of the differences between conditional and risked estimates is presented in Section V of this report.

The assessment technique employed by MMS was a summation of prospects approach incorporated in a Monte Carlo simulation model called PRESTO (Probabilistic Resource Estimates Offshore). This mathematical model enabled assessors to make judgments concerning each of the variables affecting the assessment. These individual judgments were then subjected to the model simulation to derive a resource estimate. Unlike the Delphi subjective assessment approach, this model allowed for the incorporation of new information in a quantifiable and repeatable way. This assessment approach as implemented did, however, require that individual exploration targets be identified by existing G&G information.

Instead of a consideration of flat prevailing product prices, MMS incorporated in its economic analyses long term price forecasts that incorporated inflation and real price changes. Starting prices used in this assessment were $29/barrel and $2.90/Mcf. Project economics and technology were largely considered through the use of the MEFS (see appendix A) cut-offs that were rigorously applied within the simulation model. In this assessment the use of the MEFS was fine-tuned for much smaller portions of planning areas than previous assessments. These areas and the MEFS were defined primarily in terms of production characteristics, water depths, and distance from shore. For the first time, only the portion of the offshore under Federal jurisdiction was included in the assessment. The area assessed in both the Chukchi and Beaufort Seas was limited to water depths of less than 200 meters, which was considered to be the foreseeable limit on exploitation technology. The assessed area in the Atlantic OCS was also reduced from that considered in the prior assessment by the World Court decision establishing the U.S. – Canada maritime boundary. Estimates of UERR were again reported.

The effective date of this assessment in terms of G&G data and information considered was July 1, 1984. Since the previous assessment, five additional deep stratigraphic test wells had been drilled in three Alaskan frontier basins (two wells in the Norton Basin, one well in the St. George Basin and one well in the Navarin Basin). An additional six exploratory wells were drilled in the Beaufort Sea and a final dry hole in the Gulf of Alaska. During 1983, industry drilled a single unsuccessful $140 million exploratory well on the "Mukluk" prospect in the Beaufort Sea where it had previously invested $1.5 billion to acquire leases. With the exception of the Beaufort and Chukchi Seas and a final well in the lower Cook Inlet this period marked the end of exploration interest in these frontier basins.

All eight exploratory wells drilled in the north Atlantic were dry holes. In the mid-Atlantic an additional 15 exploratory wells were drilled since the previous assessment was completed. Three of these wells were drilled on the "Tenneco-Texaco" discovery. The last, drilled on the structural crest was a dry hole. A 3-D seismic survey was acquired over the structure in an attempt to resolve structural and stratigraphic complexities and determine if additional effort was merited. The leases were subsequently relinquished in April 1984. During this period Shell undertook an ambitious, multi-well, deepwater drilling program that set several world water depth records. The target was the buried Mesozoic shelf-edge reef complex and associated features. Unfortunately all of these wells were also deemed dry holes. Industry acquisition of seismic data in the Atlantic virtually ceased after the 1984 acquisition season.

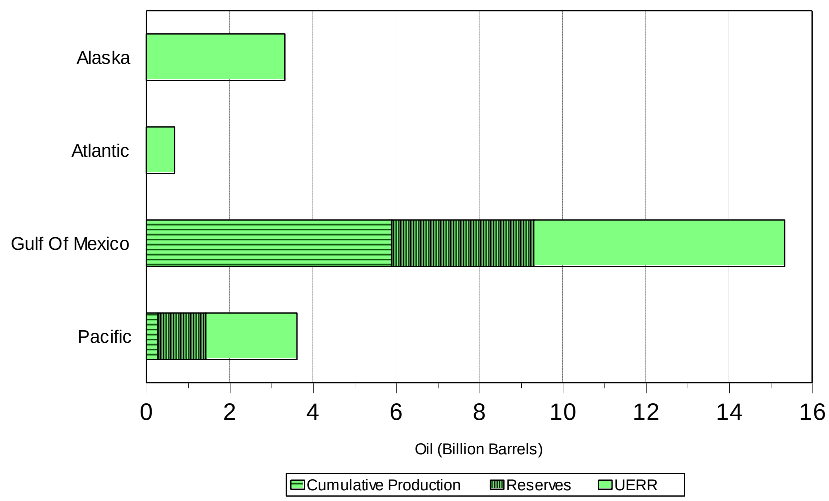
The Santa Maria Basin underwent extensive exploration from 1980 through 1986. More than 40 exploration and delineation wells were drilled in the Santa Maria Basin during this time. By mid-1984 seven oil and gas fields had been discovered.

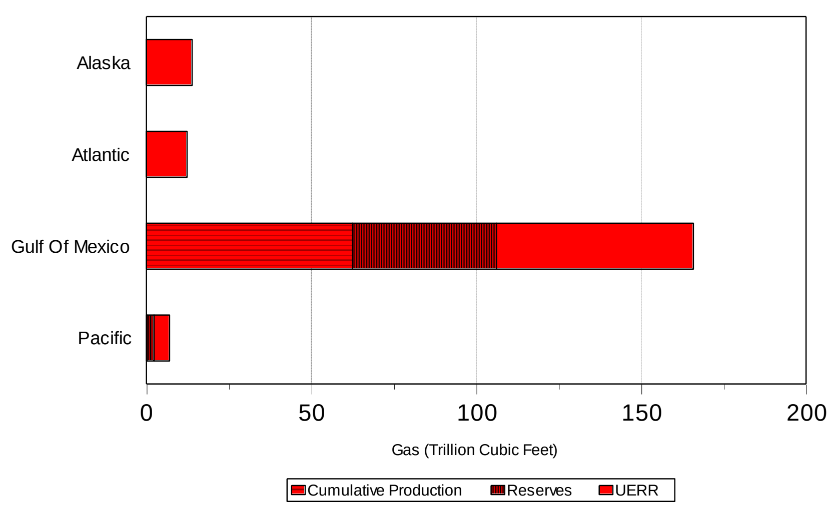
Exploration in the Eastern GOM continued to yield generally limited results. Eleven exploratory wells were drilled (six within the Charlotte Harbor area) without a commercial discovery. However, there was a discovery in 1983 of the Mobile 823 Field, which extended the Norphlet trend eastward into the Eastern GOM.

On the technology front, the first artificial drilling island was constructed in Alaska in 1981 and was used to drill two exploratory wells in 18 feet of water. During 1983 the Lena platform, a compliant tower, was installed in the GOM in 1,017 feet water. While this structure did not set a water depth record it did prove a technology that could be extended to water depths of as much as 3,000 feet, well beyond the capabilities of bottom founded fixed leg platforms which had approached their water depth limit. On the drilling front, Tenneco had recently drilled the first exploration well in the GOM to exceed 25,000 feet, subsea in depth. The Bullwinkle Field was discovered in 1983 in 1,331 feet of water. The Bullwinkle platform was designed as one of the first deepwater production hubs. The Amberjack Field was also discovered in 1983 in 1,049 feet of water.

As explained previously, in this assessment region-level estimates of UERR were reported only at the mean value. The GOM was forecast to contain nearly 50 percent of the UERR oil while offshore Alaska contained 27 percent (see Figure 11). Two-thirds of the natural gas UERR was located in the GOM, whereas offshore Alaska and Atlantic each contained about 15 percent of the total. Estimates of the undiscovered resource potential of the OCS decreased dramatically to 12.2 Bbo and 90.5 Tcfg (28.3 BBOE).

Figure 11: Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category, (MMS, 1985)





Direct comparisons with the previous assessment are especially tenuous in this case. There were major differences in the methodologies employed, information base available, technology and economic assumptions, and areas assessed. Estimates of the undiscovered resource potential of the OCS represented a decrease of 62 percent for oil and 46 percent for natural gas (55 percent for BOE) from the earlier assessment. Cooke (1985) adjusted the previous assessment results in the lower 48 to remove the effect of excluding state waters. After this adjustment the overall differences are slightly smaller, 55 percent for oil and 44 percent for natural gas. The decreases were greatest in the Alaska (about 75 percent for both oil and gas) and Atlantic (87 percent for oil and 48 percent for natural gas) OCS. Decreases in the Pacific estimates were more modest at 31 percent for oil and 24 percent for gas. The GOM estimates of UERR decreased slightly for oil and gas, 3 and 13 percent respectively.

Certainly a significant portion of the difference can be attributable to different methodologies and objectives. MMS was highly dependent upon the existing proprietary information base and near term decision-making considerations related to the OCS leasing program that must reflect current market realities. In hindsight, this assessment displayed a conservative, short term view of potential exploration opportunities. The large decreases in the estimates for Alaska reflected the very unsuccessful drilling results on the OCS. The only exploration successes offshore at the time of the assessment were in state waters in the upper Cook Inlet and Beaufort Sea. MMS risk analysis reflected low probabilities of encountering commercial quantities of hydrocarbons outside the Beaufort Sea. Even in the Beaufort Sea the probability of encountering commercial quantities of hydrocarbons was only 0.70. The area with the next highest probability, 0.27, was the Navarin Basin, which had yet to have an exploratory well drilled. As discussed earlier, an increase in risk greatly lowers the reported estimates.

The story for the Atlantic is similar—unsuccessful exploration results reflected in increases in the perceived levels of risk dramatically lower reported resource expectations. In both the Pacific and GOM regions estimates of the total hydrocarbon endowment, which consider the volumes of hydrocarbons discovered and produced during the period between assessments, also decreased, though less markedly. These decreases probably reflect primarily the removal of state waters from consideration. Secondary factors contributing to the reduction were the heavy focus on prospects in combination with a more rigorous consideration of economic factors.

Mean estimates of total hydrocarbon endowment of the OCS developed from this assessment were 23 Bbo and 199 Tcfg (58.4 BBOE), corresponding to a decrease of 50 percent for oil and 35 percent for natural gas (42 percent for BOE) from the prior assessment. The impact of considering or excluding areas within state waters on this assessment is apparent in Table 2. Despite the discoveries made in the intervening years estimates for oil reserves were down slightly; reported gas reserves decreased by a whopping 34 Tcfg. Cumulative production reported was significantly lower for oil, but higher for gas.

4. MMS 1990 Assessment (Cooke et al., 1990): After MMS completed its first OCS-wide resource assessment it requested that the National Research Council of the National Academy of Sciences (NAS) review the methodology that was employed. The NAS review (National Research Council, 1986) was generally favorable, but it did offer a number of suggestions for improving future assessments. These included: (1) pursuing a grouped-prospect play assessment methodology compatible with existing MMS models; (2) reporting the undiscovered resource base in addition to the economically attainable potential; and (3) developing a systematic process for including the resource potential from unmapped or unidentified prospects. MMS incorporated each of these recommendations in this assessment.

This assessment was the first attempt by DOI to assess the underlying conventionally recoverable resource base instead of just that portion that was perceived to be economically recoverable given a certain set of assumptions regarding future economic conditions. This assessment continued to rely on the MMS prospect oriented analyses and databases, but was supplemented by an additional consideration of unmapped prospects that could be anticipated to exist. This methodology used an updated version of the PRESTO model and an additional model to account for the resource potential of any unmapped prospects. Cooke and Dellagiarino, 1990, and Lore and Peccora, 1988, further describe this technique. The PRESTO model was modified to incorporate economic considerations beyond the field level. In frontier areas, in particular, discoveries may be large enough to cover prospect-specific costs, but because of a lack of existing infrastructure be abandoned as uneconomic. Additional economic screens were incorporated to more rigorously test to assure that resources discovered could support the necessary costs to bring the product to market. This additional consideration tended to raise the economic risk associated with frontier portions of the OCS.

The effective date for the information base used in this assessment was January 1, 1987. There was a dramatic decrease in oil and gas prices during 1986 which served to heighten interest in price volatility and its effects on resource assessments. In this assessment, MMS reported three different categories of resource estimates: (1) the undiscovered "resource base," synonymous with undiscovered conventionally recoverable resources (and UTRR), (2) a primary economic case based on prevailing conditions, and (3) an alternative economic case based on significantly higher oil and gas prices. The primary economic case again incorporated a price forecast. The starting prices for this assessment were $18/barrel and $1.80/Mcf. The first two cases are presented in Table 5a.

Exploration activity peaked on the Alaska OCS during the mid-1980s. Industry interest was now focused on the Arctic areas. Eleven exploratory wells were drilled in the Beaufort Sea since the previous assessment. Industry had by now made several noncommercial discoveries in this area. Since the prior assessment, there was an initial period of exploration in the three basins in the Bering Sea. The most promising prospects were drilled first and the results were extremely disappointing. Twenty-four exploratory wells were drilled during the period between assessments in the Norton Sound (six wells), Navarin basin (eight wells), and the St. George Basin (ten wells). None encountered commercial quantities of hydrocarbons. The final two dry holes were drilled in the lower Cook Inlet as part of the second industry exploration campaign in the area.

Industry interest in much of the Alaska OCS was waning. This lower level of interest was reflected in the sharp drop in 1986 in the annual number of geophysical exploration permits issued. The results of the initial Alaska exploration rounds condemned many very large prospects and some play concepts. For other plays and prospects geologic risk was significantly increased. In some plays previously thought to be oil-prone, analysis of the drilling results indicated that if hydrocarbons were present they were more likely to be gas-prone. The limited activity in the Cook Inlet primarily confirmed previous the MMS geologic models. A final deepwater dry hole was drilled in the mid-Atlantic. Since subsequent efforts to drill the large "Manteo" structure located in the Carolina trough off North Carolina were unsuccessful, this period essentially marked the end of all industry exploration activity on the U.S. Atlantic continental margin.

The exploration drilling program in the Santa Maria Basin concluded in 1986, resulting in the discovery of 14 oil and gas fields with reserves of over 1 Bbbls of mostly heavy oil. The Point Pedernales Field was the first of these discoveries to produce, beginning in the first quarter of 1987.

In the GOM, industry was actively extending the deepwater Flexure trend westward into the western GOM and aggressively pursuing additional opportunities associated with the Corsair trend off the Texas coast. The Ram-Powell Field was discovered in 1985 in 3,239 feet of water and the Allegheny Field was discovered in 3,254 feet of water. It took ten years to achieve first production from Ram Powell. Mensa, one of the largest natural gas accumulations in the deepwater Gulf, was discovered in December 1986 in 5,280 feet of water.

Estimates of UERR for oil ranged between 4.0 and 14.3 Bbo with a mean value of 8.9 Bbo. Natural gas estimates ranged from 44.3 to 113.8 Tcfg, with a mean of 74.0 Tcfg. Approximately 63 percent of the UERR was projected to be present in the GOM. Nearly a quarter of the estimate was in the Pacific region. Nearly 87 percent of the undiscovered gas estimated to be economically recoverable was in the GOM. Nowhere in the Alaskan OCS was natural gas considered to be economic under the imposed economic conditions. The re-evaluation of many areas as being gas-prone when considered in conjunction with lower prices and the large volume of stranded gas on the North Slope condemned Alaska's OCS gas prospects. Poor exploration results coupled with the economics of gas led to another round of increases in risk assessments associated with Alaskan basins.

At the mean level, the estimates of UERR represent a decrease compared to the previous assessment of 27 percent for oil and 18 percent for gas. Despite the significant decrease in price expectations oil estimates decreased only slightly for those areas outside of Alaska. The decreases in the Pacific and GOM estimates were offset by new discoveries during the intervening period. Dismal exploration results in the frontier areas of Alaska and the Atlantic combined with the recent oil price collapse resulted in a lowered assessment of UERR potential. Notwithstanding the decrease in the estimates of UERR for oil and natural gas in this assessment, mean estimates of the total hydrocarbon endowment remained virtually unchanged between assessments.

Estimates of UTRR ("undiscovered resource base" in this assessment) were presented for the first time. Estimates ranged from 9.2 to 25.6 Bbo, with a mean of 17.9 Bbo and 97.8 to 204.8 Tcfg, with a mean value of 145.1 Tcfg. More than half of the undiscovered oil and two-thirds of the gas estimate were in the GOM. Alaska was next with 21 percent of the oil and 11 percent of the gas.

In the mean primary case economic analysis 50 percent of the OCS total UTRR is economic (see figure12). In the GOM 60 percent of the oil and gas UTRR was economically recoverable. In Alaska less than a quarter of the 3.8 Bbo and none of the 16.8 Tcfg were considered to be economically recoverable. The Pacific and Atlantic OCS fell in between.

5. ***MMS 1991 Assessment (Cooke, 1991*****)**: In response to industry concerns expressed about the prior assessment, the MMS asked the Association of American State Geologists (AASG) to review the geologic information that formed the foundation for the assessment. The review concluded that "The assessment of undiscovered, conventionally recoverable oil and gas resources on the OCS is supported by an adequate data base, personnel with suitable expertise and training, and a disciplined, structured process that produced results that inspire confidence." (AASG, 1988, p. 2). DOI also requested that the NAS review the assumptions and procedures employed by both MMS and USGS in recent assessments. The findings from this review were not available at the time this assessment was performed.

In preparation for the 1992 to 1997 five year oil and gas leasing program, MMS reviewed the existing resource estimates to determine if they were still adequate. It was determined that the estimates should be updated in five planning areas where significant new data had become available since 1987. The planning areas updated were the Beaufort Sea, Chukchi Sea, Hope Basin, northern California and Eastern GOM. The amount of seismic data available in the Chukchi Sea more than doubled since the previous assessment was completed. As a result, more prospects were identified, and the existence of some of the larger prospects was confirmed by the new data. There were also three new exploratory wells drilled in the basin since the prior assessment. In the Beaufort Sea, three additional wells had been drilled and a number of changes were incorporated in the geologic model, the most significant of which was an increase in the probability of success.

Activities from this time onward in the Pacific OCS consisted mainly of establishing and maximizing production of previously discovered oil and gas fields. The last Pacific OCS lease sale was held in 1984. Also, the last exploration well in the Pacific OCS was drilled in 1990. By 1995 there were 11 producing fields in Pacific region, located in the Santa Barbara Channel, Santa Maria Basin and Los Angeles Basin.

In preparation for an upcoming lease sale in the Eastern GOM a significant amount of new seismic data were acquired and interpreted by MMS. In 1987, Amoco drilled the first discovery (noncommercial) well in the Norphlet formation in the Eastern GOM. In 1987 and 1989, Chevron drilled two discovery wells in the Eastern GOM in Destin Dome Block 56 located approximately 25 miles south of Pensacola. Both wells found significant quantities of natural gas in the Norphlet Formation below 22,000 feet. This discovery was part of the same play that was found productive in the Mobile Bay and adjacent state and Federal waters. Several discoveries were also made in the eastern extension of the shallow Miocene "bright spot" play. These discoveries increased the marginal probability of success for the Eastern GOM area to 1.00.

MMS only reported estimates of UERR. The largest change in estimates occurred in the Chukchi Sea portion of the Alaskan OCS. Resource estimates for the Beaufort Sea increased modestly, while Hope Basin estimates decreased by about 25 percent. Overall, mean estimates of the UERR for Alaska more than doubled compared to the earlier assessment (see Figures 12 and 13).

Figure 12: Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category, (MMS, 1990)

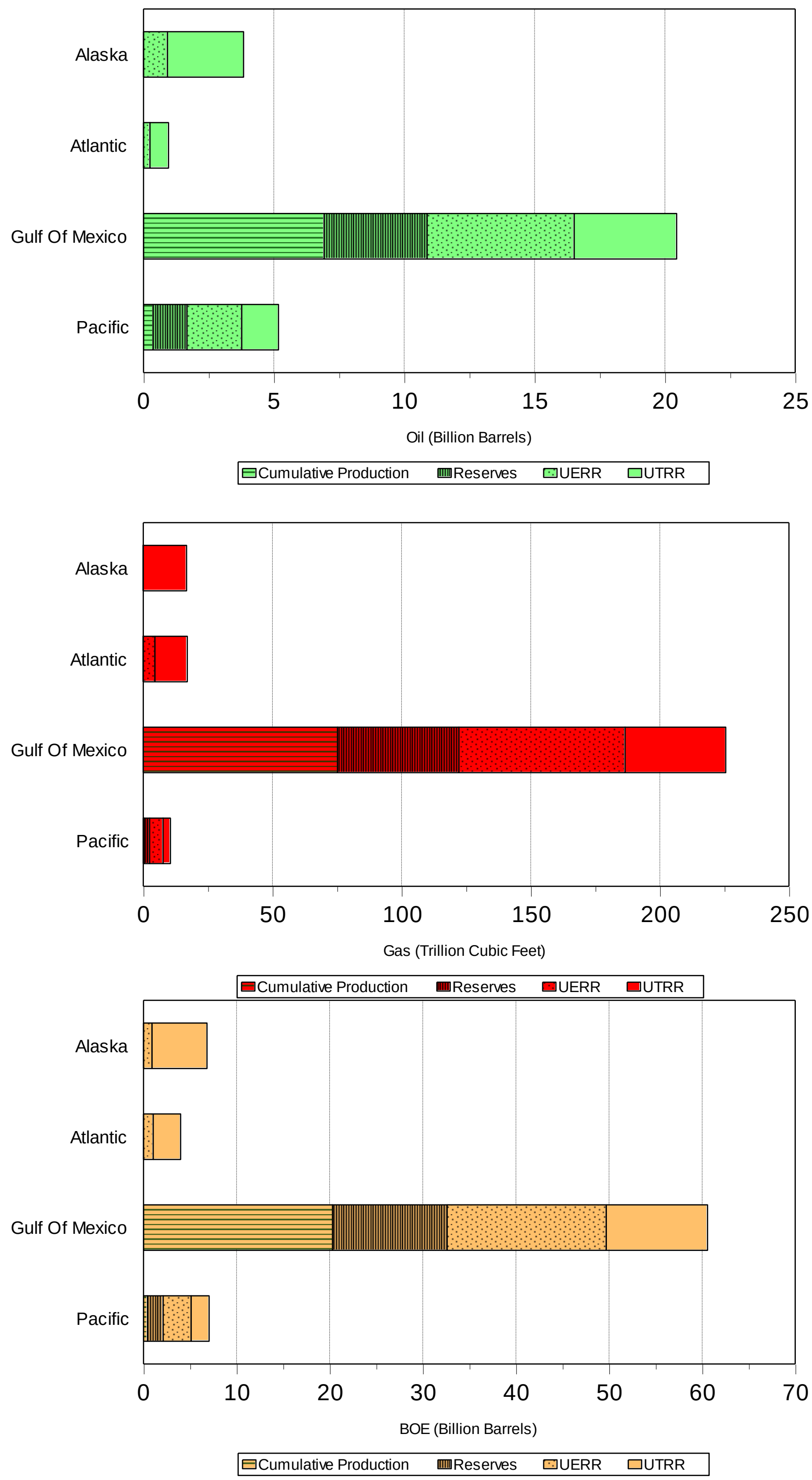
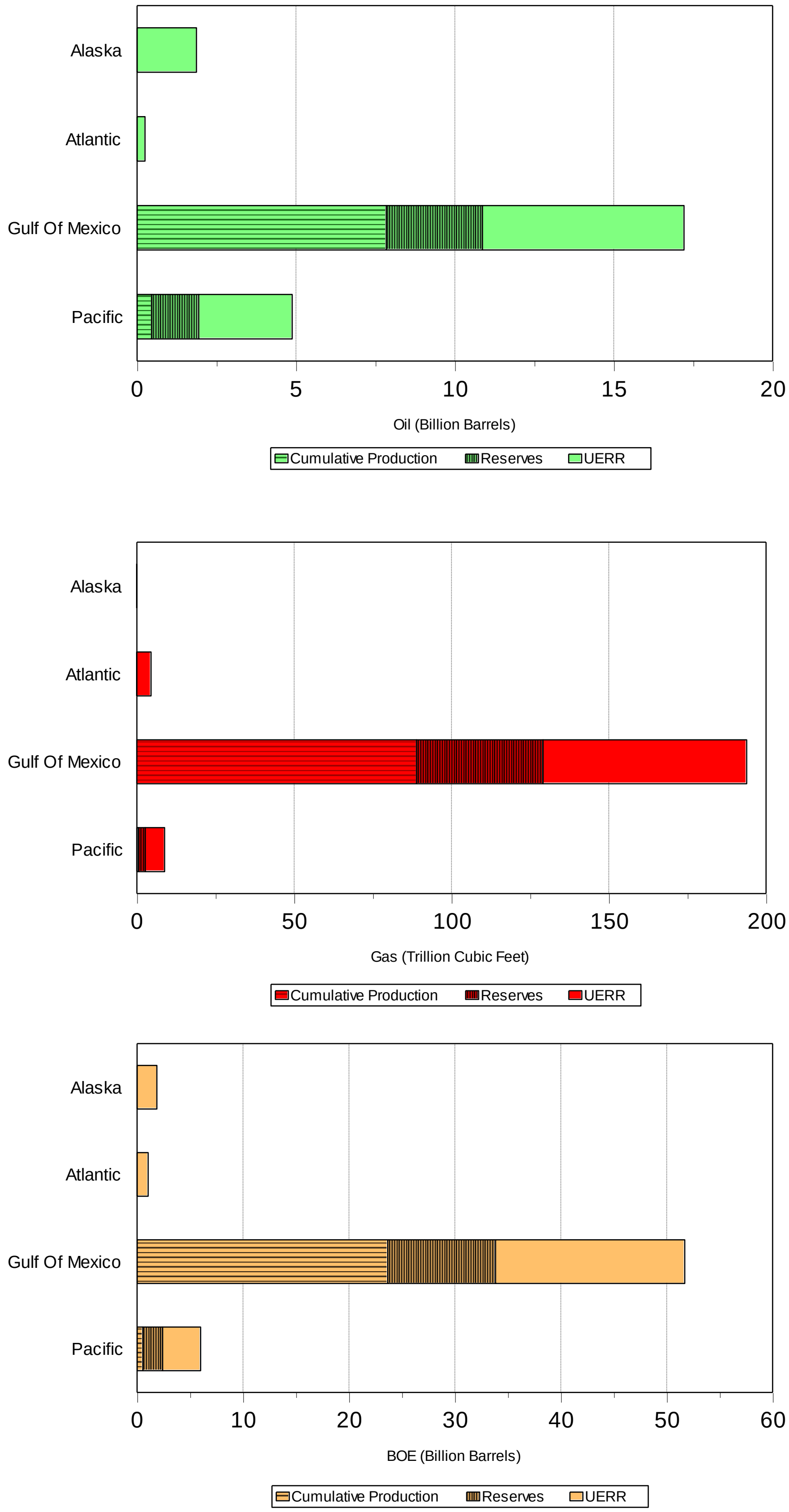


Figure 13: Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category, (MMS, 1991)



Mean estimates of UERR for the Eastern GOM more than tripled to 1.25 BBOE. In the entire GOM the oil estimate increased 12 percent and gas estimate remained unchanged. The northern California estimates of UERR also increased substantially primarily due to changes in the geologic model for the Point Arena Basin. Mean estimates for both oil and gas UERR in the Pacific estimate increased by about 18 percent.

For the OCS as a whole, mean estimates of UERR increased modestly from 8.9 to 10.9 Bbo, 74.0 to 75.4 Tcfg and 22.1 to 24.4 BBOE.

6. MMS 1996 Assessment (MMS, 1996): This assessment represented a watershed event in the MMS resource assessments. It incorporated major changes in the basic underlying approach to resource assessment and shifted the principal focus from assessing UERR to undiscovered conventionally (or technically) recoverable resources. The recommendations of the 1991 NAS review were available for consideration in this assessment. In contrast to the AASG, the NAS stated "…that there may have been a systematic bias toward overly conservative estimates. Eliminating the probable sources of this bias will improve the accuracy and credibility of future assessments." (National Research Council, 1991, p. 4). The primary concerns identified by the NAS included (1) concerns regarding play definition, (2) use of conceptual plays, (3) treatment of dependencies among variables, and (4) unintended imposition of economic constraints on estimates of UTRR.

The recommendations of the 1991 NAS study were fully incorporated in this assessment. Previous MMS resource assessments employed play concepts, but the focus was on groupings of prospects within the context of a play. The analysis was still prospect-oriented. The modeling emphasis for this assessment was reversed. It was the first time MMS geoscientists applied an assessment method called "play analysis" on a national scale. This method evaluates the resource potential of "plays"—families of prospective and/or discovered petroleum accumulations that share a common history of oil or gas generation, migration, reservoir development, and trap configuration (White, 1980). In play analysis, statistical methods are used to translate the judgments of geologists into a set of probabilities that given petroleum volumes will exist within the plays. Databases were constructed and subsequent analyses were performed from this viewpoint. A new play-based computer model, Geologic Resource Assessment Program (GRASP), derived from the Canadian Geological Survey's Petroleum Resources Information Management and Evaluation System (PETRIMES) suite of programs was used for the first time.

The NAS recommendations adopted by the MMS generally provided for a more expansive interpretation of the UTRR potential of the OCS, resulting in significant increases in the estimates. For example, comparing this assessment with the 1990 UTRR, in Alaska the mean estimates for oil increased from 3.8 Bbo to 24.3 Bbo. Similarly, the mean gas estimates increased from 16.8 to 125.9 Tcfg. The majority of this increase occurred in the estimates for the Beaufort and Chukchi Seas. All exploratory drilling on the Alaskan OCS since the previous assessment occurred in these two areas, seven new wells were drilled in the Beaufort and four wells in the Chukchi Sea. Although none of the wells were deemed to be commercial successes, the results confirmed play concepts and reduced geologic risks. A detailed discussion of the impacts of these methodological changes on MMS estimates is contained in MMS (1996) and Sherwood *et al.* (1998).

In the GOM, some individual companies continued to expand their deepwater portfolios and invest in the development of technology. In 1987, Shell made a world record deepwater field discovery at the Coulomb Field in 7,558 feet of water. Furthermore, Shell found another deepwater discovery called Auger, a field with reserves of approximately 220 million BOE. The discovery of the Auger Field and other promising finds gave rise to the view that the deepwater GOM had unrealized resource potential. What was particularly striking was not only the size of the fields, but also the high flow rates of individual wells.

Several new production technologies were introduced in the GOM since the effective date of the last assessment. A floating production system was installed in 2,172 feet of water and a semi-submersible in 1,554 feet of water. The first U.S. tension leg platform (TLP) was installed at the Joliet Field in 1,722 feet of water. Shell pushed the limit of fixed leg platforms with the massive Bullwinkle platform which was installed in 1,330 feet of water. Subsea production technology continued to evolve during this period. Prior to 1988 the deepest subsea completion was in 350 feet of water. This jumped to 2,243 feet of water with Oryx' GC 75 Field development.

Elsewhere, the level of drilling in the GOM had dropped to levels not seen in 30 years. This was not the case with geophysical exploration. The impact on this assessment of 3-D seismic imaging technology and new computerized mapping, modeling, and interpretation programs was significant. Marine 3-D seismic data had been in use since the early 1980's, primarily acquired as an exclusive proprietary survey by an operator to improve field development after a discovery is made. The proprietary 3-D surveys are more expensive than older 2-D seismic surveys. By the mid-1980's there was a noticeable industry-wide trend in increased success rates for field development wells drilled on the basis of 3-D seismic data. This realization, coupled with the initial availability of low cost speculative 3-D seismic data and the emerging workstation technologies combined to fuel an explosion in speculative 3-D data acquisition. The technology was viewed by industry as a primary way to control costs and risks in an era of price uncertainty and quickly became a standard tool for exploration.

The continued evolution of the computational and graphical power of workstation technology coupled with decreasing CPU costs placed a powerful interpretation tool that could handle the vast amounts of data necessary to build 3-D models within the grasp of most geoscientists. This capability in turn created additional demands for 3-D seismic data as both an exploitation and exploration tool. Sophisticated workstations allowed geologists, geophysicists, and petroleum engineers for the first time to fully integrate data previously exclusive to their individual disciplines into a composite 3-D geologic and petrophysical model of a prospect or field. This new capability created opportunities to more fully exploit existing discoveries, identify new targets in old fields, and re-evaluate prospects that were previously drilled unsuccessfully on the basis of 2-D seismic data and less than full integration of available geologic data. This focus was clearly in evidence in terms of actual drilling activity.

Industry, as a whole, was retrenching and backing off risky investments during this period, but a few companies continued to pursue high-risk, high-cost exploration opportunities. Following closely on the heels of advances in 3-D seismic data acquisition, interpretation tools and computational power of computers was the emergence of the “subsalt play” as the next hot exploration play in the GOM. The play extended across the outer portion of the central GOM shelf and onto the upper slope encompassing an area of approximately 36,000 square miles. This area is characterized by relatively shallow water depths (300 to 2,000 feet) within areas of extensive existing infrastructure related to the Flexure trend activity, as well as recent deepwater discoveries. This proximity made for attractive project economics. In spite of the extensive publicity, this play was not a totally new phenomenon in terms of geologic targets.

The subsalt play is actually a technology-driven play. It is defined principally by the presence of tabular salt bodies, commonly referred to as salt sheets, sills, lenses, canopies, or tongues. Unlike traditional salt domes, which had been exploration targets since the earliest OCS wells were drilled, these salt bodies do not appear to be deep rooted to a mother salt layer. Typical mid-1980's vintage 2-D time-migrated seismic geophysical processing techniques frustrated explorationists for years. It could not properly image the base of the salt body, strata below the salt or correctly portray salt and sediment geometries. It also created problems in the conversion to depth from seismic travel time. As a result, wells could not be precisely located, greatly increasing operator risk. It was only through the use of advanced 3-D seismic acquisition and the raw processing power of massively parallel processor (MPP) supercomputers that explorationists were able to reprocess seismic to accurately see through these salt bodies.

At least 20 wells were drilled to subsalt objectives between 1979 and the first discovery in 1990 at Exxon and Conoco's Mickey (since renamed Mica) prospect. Despite a modest number of wells drilled every year, it was not until 1986, that the first substantial reservoir quality sands were encountered by Diamond Shamrock after drilling through 1,000 feet of salt. Hydrocarbons were present, but the discovery of thick reservoir quality sands encouraged additional drilling. At Mickey, Exxon drilled through nearly 3,300 feet of salt before encountering hydrocarbons. This was seen as a significant breakthrough in the history of exploration and exploitation of the GOM since it opened a huge volume of sediment to prudent, reasonable risk exploration for the first time. The discovery, however, was in 4,350 feet of water making commercial exploitation uncertain.

The major technological breakthrough that put this play within reach of larger independents occurred during 1992 and 1993 when the first MPP supercomputers became available outside of the government and defense industries. These computers made practical for the first time, pre-stack depth migration processing of 3-D data sets on a non-proprietary basis. An indication of the raw computing power of the new supercomputers was the ability to process in about three weeks what a 1980 vintage mainframe would take about five years to accomplish.

In 1993, Phillips, Anadarko and Amoco drilled the Mahogany prospect. They drilled through 3,500 feet of salt before encountering significant oil and natural gas pays. This discovery touched off a frenzy of subsalt leasing and drilling activity. Despite the high levels of risk and uncertainty associated with prospect definition, high exploratory well costs, use of cutting edge drilling and processing technologies, and the larger than usual upfront data processing costs, the play was of significant interest. It offered the potential for huge world class reserves in a mature producing area located in proximity to existing infrastructure. The relatively shallow water depths greatly reduced the MEFS and increased the profitability of otherwise commercial finds.

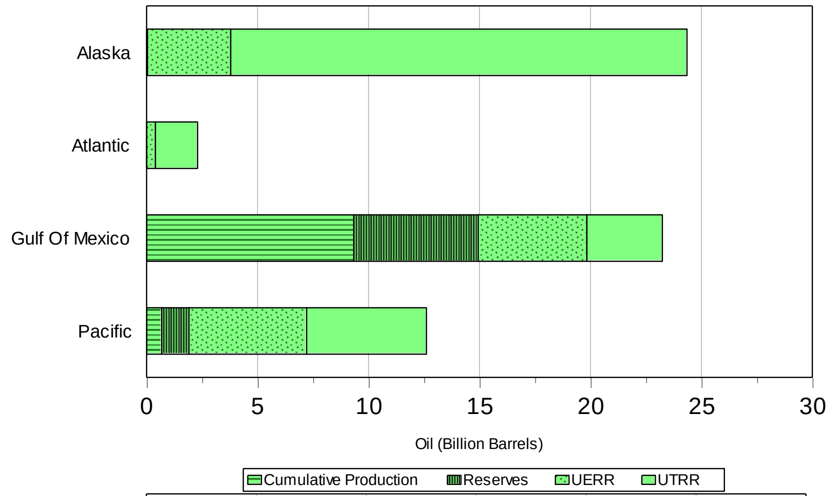
Following this initial strong interest, subsequent subsalt exploration yielded mixed results. The immediate follow-up drilling at the Mattaponi, Mesquite and Ship Shoal 250 prospects were announced as dry holes. The only announced discovery in the immediate flurry of drilling was the Teak prospect. The results from the first round of drilling activity led to a re-evaluation of the geologic complexities, seismic uncertainties, and drilling difficulties associated with subsalt exploration.

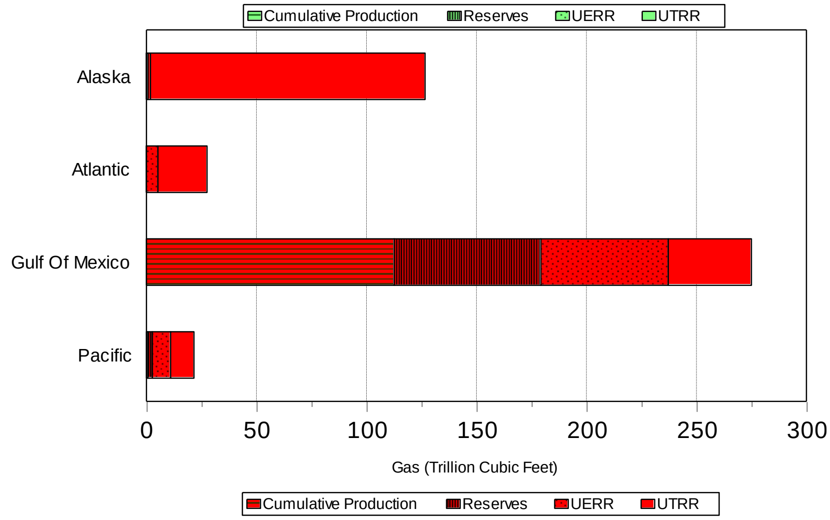
On other technology fronts, industry continued to push the envelope on deepwater production technology. The Auger TLP was installed in 2,864 feet of water. The use of subsea production systems in deepwater was becoming more common including remote wells with tie-backs to host systems. A subsea completion was installed at Mars in 2,956 feet of water, in 1996 and at Mensa in 1997, in 5,295 feet of water. The distance from subsea completion to host facility was increasing during this period, achieving a record of 68 miles with the Mensa development.

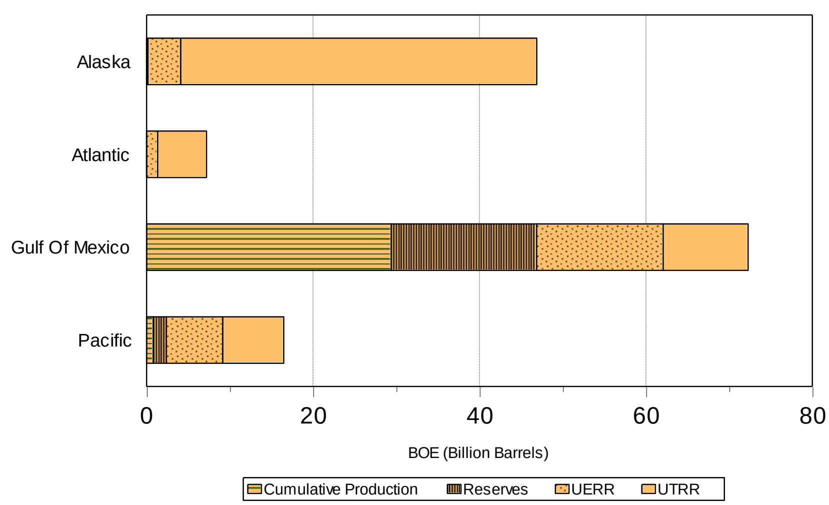
The first horizontal well had been drilled in the GOM offshore. This technology initially allowed the exploitation of marginal accumulations on the shelf, but soon became a part of many deepwater developments.

For the entire OCS, estimates of UTRR for oil ranged between 37.1 and 55.3 Bbo with a mean value of 45.6 Bbo. Gas estimates ranged from 186.3 to 369.2 Tcfg, with a mean of 268 Tcfg. Comparable estimates for BOE were 72.9 to 117.0 BBOE with a mean of 93.4 BBOE. Fifty percent of the mean estimate of UTRR on a BOE basis was projected to be present in the Alaska OCS (see Figure 14). The GOM, Pacific and Atlantic OCS comprise 27, 15 and 8 percent, respectively of the total UTRR.

Figure 14: Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category, (MMS, 1996)







At the mean level, the estimates of UTRR for the OCS represent an increase compared to the previous assessment of 155 percent for oil and 85 percent for gas. The vast majority of this increase occurred in the Alaska estimates where oil increased by 20.5 Bbo and natural gas by 109.2 Tcfg. The increase in the estimates for the Alaska OCS was primarily the result of a concerted effort in response to the NAS recommendations to further remove any consideration of economic constraints from the estimates. Ninety percent of the Alaska endowment was located in the Beaufort and Chukchi Seas. Mean estimates of UTRR in the Atlantic OCS increased by 1.4 Bbo and 10.8 Tcfg (3.32 BBOE), a 158 and 65 percent increase respectively, for oil and gas. There were no new G&G data acquired in the area. The increase was primarily the result of a fundamental reassessment of the area's prospectiveness and the use of the new assessment approach. The reassessment included acquiring G&G data and information from Canada's Scotian shelf and from a consideration of additional analog basins for the Atlantic margin.

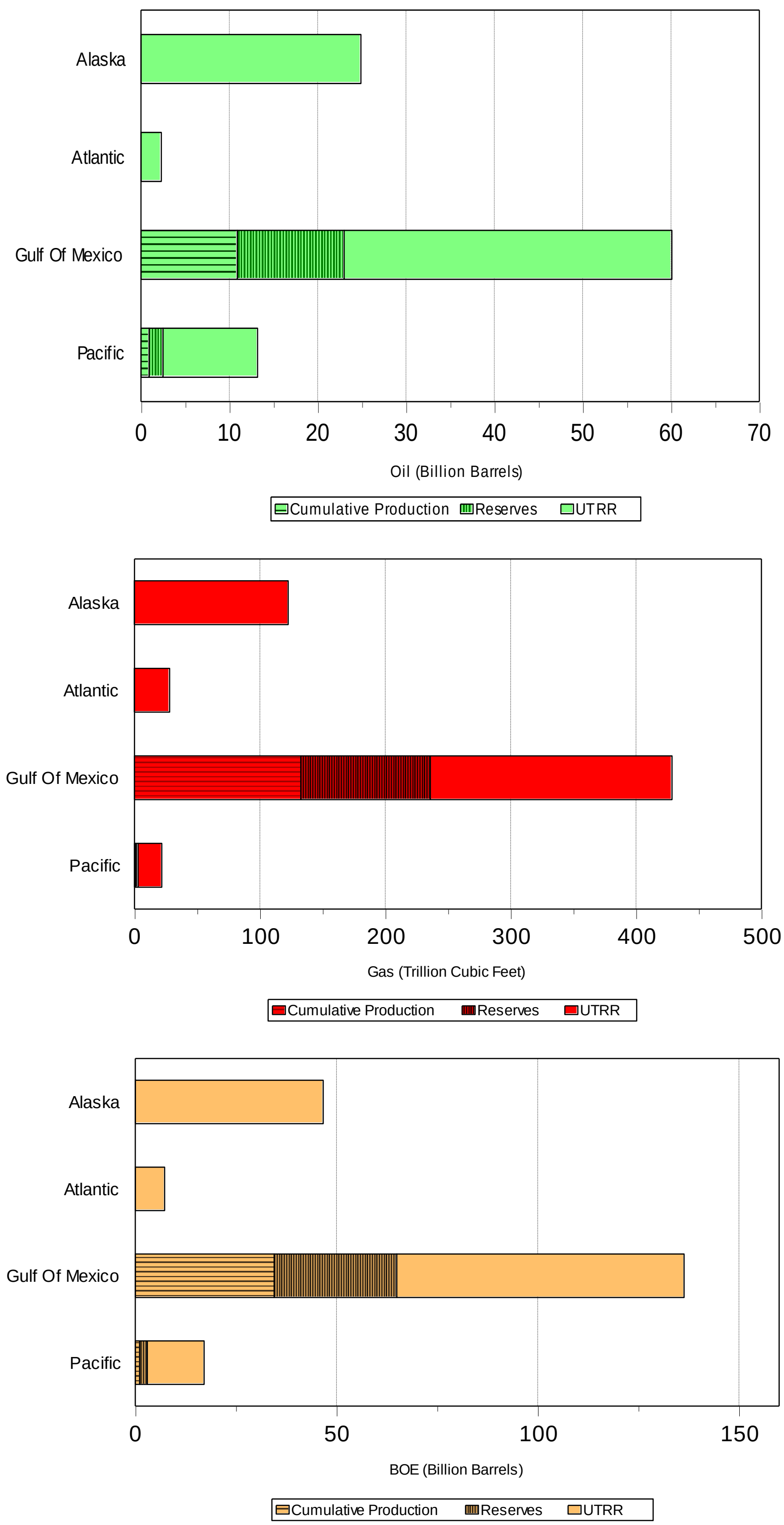
The mean estimate for UTRR in the Pacific region increased by 7.1 Bbo, an approximate tripling from the prior assessment, and 8.08 Tcfg, almost double the prior estimate. A portion of this increase was attributable to a new analysis of the Monterey formation that indicated a potentially much larger volume of reservoir rock than previously considered. The major cause of the increase, however, was probably due to the new assessment approach employed by MMS for this assessment.

In the GOM region the mean estimates of UTRR decreased by 1.3 Bbo and 8.1 Tcfg (2.7 BBOE) when compared to the 1990 assessment. If the intervening discoveries and production are considered, as in the estimates of total endowment, the assessment of the GOM resource potential actually increased by 9 Bbo and 80 Tcfg (23.4 BBOE)

7. MMS 2001 Assessment (MMS, 2001): Leading up to this assessment, deepwater GOM areas increasingly became the focus on the OCS for leasing, seismic acquisition, drilling and production activity. The major oil companies forged the way until 1996 when independents joined in. This interest was spurred by a number of large deepwater field discoveries and technological advances in drilling and development systems. Many of these discoveries were among the largest in the GOM in decades. The total number of deepwater discoveries with an EUR of more than 100 million BOE (e.g., Neptune, Nansen, Holstein, Mad Dog, Medusa, and Thunder Horse) more than doubled in the period since January 1, 1995. During the nine year period between 1989 and 1997, 175 fields containing total resources of 1.2 BBOE were discovered in the shallower waters of the GOM. The mean size of these discoveries was 6.9 million BOE. During this same period 44 fields containing resources of over 2.4 BBOE, a mean field size of 55.5 million BOE, were discovered in deepwater— double the total resource volume discovered in the shallow water fields in only 25 percent of the number of fields.

Estimates of UTRR ranged from 63.7 to 88.3 Bbo and 292.1 to 468.6 Tcfg, with a mean estimate of 75.0 Bbo and 362.2 Tcfg (see Table 5a). The GOM OCS was forecast to contain one-half of the mean estimates of oil UTRR and offshore Alaska one-third (see Figure 15). The assessment forecast that 53 percent of the mean UTRR gas was located in the GOM. Offshore Alaska followed with 34 percent of the total. This assessment resulted in an increase of the mean values by 29.4 Bbo and 94.2 Tcfg over the earlier 1996 assessment.

Figure 15: Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category, (MMS, 2001)



The increase occurred almost entirely in the deepwater GOM. In the 1996 assessment the mean estimates of UTRR for the deepwater portions of the Gulf (water depths greater than 900m) were 3.6 Bbo and 36.5 Tcfg (10.1 BBOE). In this assessment the comparable deepwater (water depths greater than 800m) estimates increased to 28.0 Bbo and 115.2 Tcfg (48.5 BBOE).

Mean estimates of total hydrocarbon endowment of the OCS developed from this assessment were 100.5 Bbo and 600.1 Tcfg (207.5 BBOE), corresponding to an increase of 53 percent for oil and 34 percent for natural gas (42 percent for BOE) since the prior assessment. The mean value for oil UTRR represented 75 percent of the mean estimate for the total oil endowment. Corresponding estimates for the increases in gas and BOE are 60 and 67 percent. More than 65 percent of the total endowment is projected in the GOM. Only 38 percent of the total oil endowment and 55 of the natural gas endowment in the GOM were represented by discovered resources.

8. MMS 2006 Assessment (MMS, 2006): The first Alaskan OCS production occurred in 2001 from the joint state/Federal Northstar unit in the Beaufort Sea. Several new play concepts were introduced in the GOM since the previous assessment and others continued to evolve. Play concepts were being refined in the ultra-deep sediments on the shelf (>20,000 feet) where discoveries such as JB Mountain and Mounds Point had recently been announced (MMS, 2001(b), 2003). In the deepwater areas there were several new discoveries. Drilling for the first time encountered Paleogene reservoirs at several locations. In the western GOM several discoveries were made in the Perdido foldbelt. These discoveries included Trident and Great White. Discoveries such as St. Malo and Cascade also continued to be made in the Mississippi fan foldbelt.

Deepwater exploratory drilling capabilities continued to increase. A new short-lived water depth record of 7,718 feet for an exploratory well was set by Chevron in August 1998, eclipsing the previous record of 7,620 feet set in 1996 at the BAHA prospect. Kerr McGee established a new water depth record at its Merganser discovery in 7,950 of water. This record would also be quickly surpassed as the first well to be drilled in water depths exceeding 10,000 feet was permitted.

The technical limits of deepwater production technology also continued to expand. Since the previous assessment numerous water depth production records were surpassed. Shell and British Petroleum (BP) established the water depth record for production from a platform at 2,940 feet with its Mars TLP in 1996. Ram-Powell TLP soon surpassed this in 1997 with a platform installed in 3,214 feet of water. This in turn was quickly surpassed by Shell's Mensa subsea development in MC Block 731, which set two world records in July 1997— a world water depth record for production at 5,300 feet and a world record of 68 miles for tieback distance to its host platform. This water depth record was also soon surpassed in 2002 at Camden Hills when a subsea tree was installed in 7,209 feet of water.

In March 1999, Shell (and partners Exxon, BP, and Conoco) began production from another TLP for the Ursa project in 3,885 feet of water. New production concepts were also introduced since the previous assessment. The world's first production SPAR, Oryx/CNG's "Neptune" platform, was installed in 1997 in 1,930 feet of water. A second SPAR system, Genesis, was brought on production in 1998 in 2,597 feet of water. Diana-Hoover, a drilling and production SPAR, was installed in 4,800 feet of water in 2000. This same technology has the potential for use in water depths up to 10,000 feet. British-Borneo Exploration installed Morpeth, the world's first mini-TLP, in 1,700 feet of water in 1998. This effort was followed in 1999 with another mini-TLP at its Allegheny project in 3,186 feet of water. This technology has potential applications in water depths approaching 3,500 feet. Another new development technology was introduced to the Gulf when Amerada Hess installed a compliant tower in 1998 on its Baldpate project in 1,619 feet of water. This was quickly followed by Petronius in 1,754 feet of water.

The advances in 3-D seismic data acquisition and processing technologies driven by the special requirements in the subsalt play and in areas proximal to steeply dipping salt bodies fueled a resurgence in the acquisition of modern data in areas previously shot with older data acquisition techniques. As a result, whole new families of previously unidentified or poorly defined exploration prospects were targeted. The new data and interpretation techniques reduced risk and uncertainty to levels that permitted companies to pursue these prospects.

On the information technology front, impacts were felt throughout the industry. The speed, volume, and scale of access to geotechnical data and information continued to expand within the exploration and production (E&P) industry with the enormous advances in computational power. Geoscientists and engineers experienced a fundamental revolution in the applied earth sciences that radically altered their ability to integrate, adapt, and analyze a broad spectrum of G&G data. The petroleum industry saw the value of these new technologies as a tool to drive down cost, risk, and uncertainty, as well as increase productivity. The technology was focused on data acquisition and manipulation, analysis applications, visualization, and integration.

For the entire OCS, estimates of UTRR for oil ranged from 66.6 to 115.3 Bbo with a mean value of 85.9 Bbo (refer to Table 5a). Natural gas estimates ranged from 326.4 to 565.9 Tcfg, with a mean of 419.9 Tcfg. Comparable estimates for BOE were 125.7 to 215.9 BBOE with a mean of 160.6 BBOE. Fifty-four percent of the mean estimate of UTRR on a BOE basis was projected to be present in the GOM OCS. The Alaska, Pacific, and Atlantic OCS comprise 31, 9 and 6 percent respectively of the total UTRR.

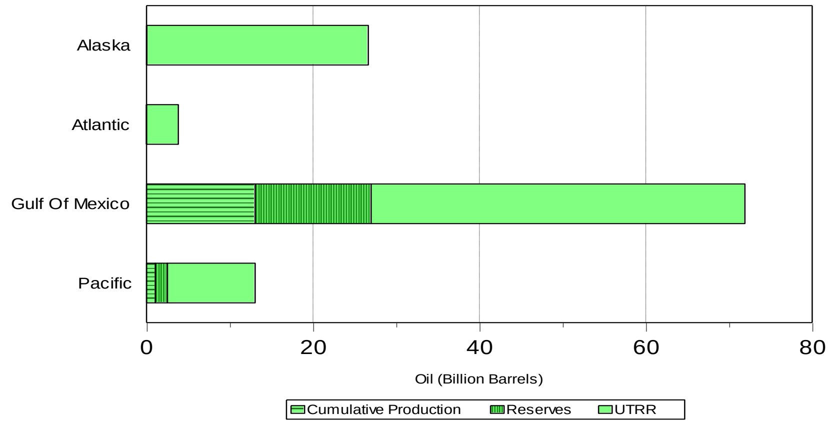
At the mean level, the estimates of UTRR for the OCS represent an increase compared to the previous assessment of 10.9 Bbo and 57.7 Tcfg or about 15 percent for oil and 16 percent for gas. The vast majority of this increase occurred in the GOM where estimates of UTRR range from 41.2 to 49.1 Bbo and 218.8 to 249.1 Tcfg with a mean of 44.9 Bbo and 232.5 Tcfg. This represents a 21 percent increase in oil resources and a slightly greater percent increase in natural gas resources since the previous assessment. Again significant increases in the estimates for the deepwater areas were the major contributor to the overall growth in the estimates of UTRR. The mean estimates of UTRR in the deepwater were 38.8 Bbo and 125.2 Tcfg (61.1 BBOE), which represents an increase over the previous assessment of 10.8 Bbo and 10.0 Tcfg (12.6 BBOE). This increase in UTRR was also accompanied by approximately 4.5 Bbo and 14 Tcfg that were discovered in fields, such as Thunder Horse and Holstein whose resources were moved to the reserve category during this time period.

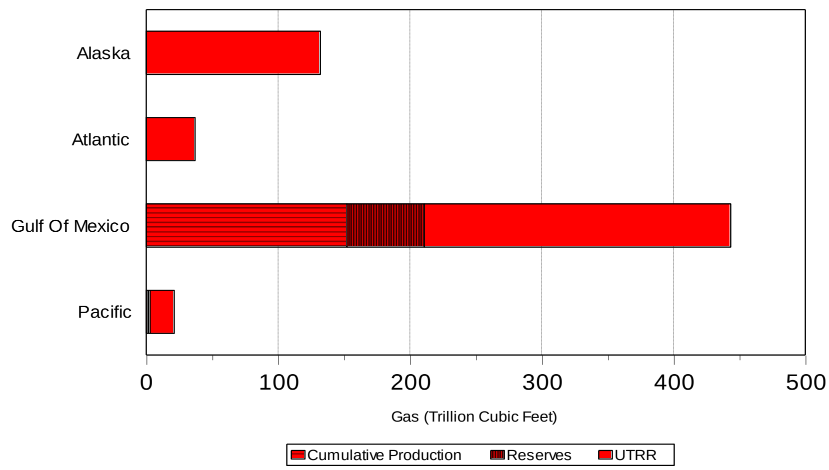
In the Pacific Region, the mean estimate for UTRR of 10.5 Bbo and 18.3 Tcfg represented a slight decrease for both oil and natural gas. The Atlantic estimate of UTRR ranges from 1.1 to 7.6 Bbo and 14.3 to 66.5 Tcfg with a mean of 3.8 Bbo and 37.0 Tcfg. The estimates represent a 66 percent increase in oil resources and a 33 percent increase in gas resources in the Atlantic OCS, when compared with the MMS 2001 assessment. The last remaining leases in the Atlantic OCS, on the Manteo prospect, expired in 2002 without a well being drilled. However, significant new analog information was available as the result of recent exploration in the Scotian shelf offshore Canada and the West African continental slope offshore Mauritania. Applying these new exploration ideas to the older Atlantic play models led to adjustments to risks in previously defined plays and the identification of additional new plays.

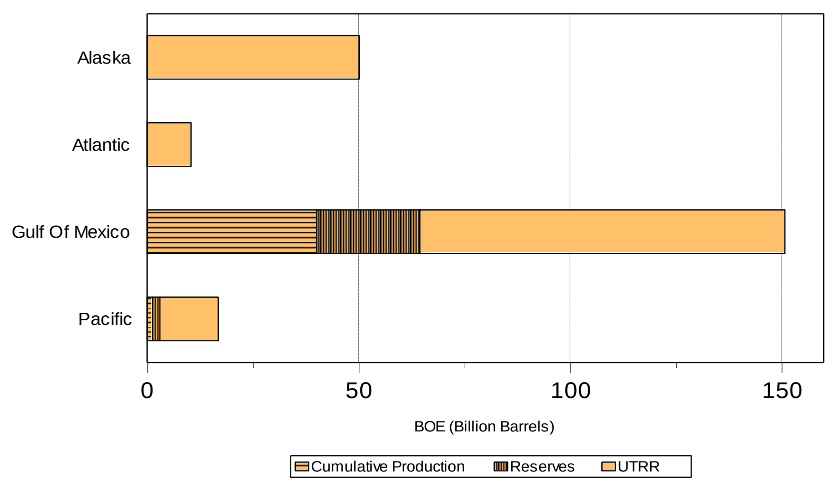
Estimates of UTRR on the Alaska OCS changed only slightly compared to the previous assessment. The mean oil estimates increased at mean level by 1.7 Bbo, while the natural gas estimate declined by 6.7 Tcfg.

Mean estimates of total hydrocarbon endowment of the OCS developed from this assessment were 115.4 Bbo and 633.7 Tcfg (228.2 BBOE), corresponding to an increase of 15 percent for oil and 5 percent for gas (10 percent for BOE) since the prior assessment. The mean value for oil UTRR represented 74 percent of the mean estimate for the total oil endowment (see Figure 16). Corresponding estimates for gas and BOE are 66 and 70 percent. More than two-thirds of the total endowment is projected in the GOM. Only 37 percent of the total oil endowment and 48 percent of the natural gas endowment in the GOM is represented by discovered resources.

Figure 16: Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category, (MMS, 2006)







9. BOEM 2011 Assessment (BOEM, 2011):

Leading up to BOEM's 2011 Assessment, the American Association of Petroleum Geologist (AAPG) Committee on Resource Evaluation (CORE) reviewed BOEM's 2011 Resource Assessment Methodology. This followed an initial review conducted by the CORE in 2003 for the 2006 OCS Assessment. Since then, BOEM, following the suggestions made by CORE at that time, substantially revised the methodology which was subsequently endorsed by the CORE. The CORE noted that the current BOEM assessment methodology is more driven by geology compared to the 2006 assessment, brings the proposed methodology closer to that applied by the USGS, which the CORE had endorsed earlier, and abandons purely statistical methods to estimate the distribution of numbers and sizes of undiscovered fields in mature geologic plays.

However, the CORE commented on a few areas of concern related to incorporating a wider range of possibilities for the number of undiscovered fields and their respective sizes in BOEM's proposed assessment methodology. These concerns were separated into categories of "conceptual and frontier plays" and "discovered plays."

The CORE used the U.S. Atlantic Shelf as an example of a "conceptual and frontier play" as it currently has no established production, very limited well control and lacks modern seismic data and thus relies on seismic data acquired more than 20 years ago. The CORE commented that BOEM had done an excellent job of synthesizing the stratigraphy, tectonic and basin evolution through use of reprocessed legacy seismic data and integrating with existing well information. Furthermore, in order to evaluate the play chance factors, the CORE noted that BOEM assessors used analogues in Canada or in the North African conjugate margin, as well as in other similar regions. The CORE felt that that the geologic analysis was excellent and on par with similar work done by the USGS on conceptual and frontier plays worldwide. However, some notable concerns related to frontier play assessment in the GOM and Atlantic were that BOEM should consider reducing the lower limit risk factors for which a specific play component are to be evaluated (reservoir, source, seal, or timing etc.) and BOEM should explain its use of analogues and risk of oil-vs-gas in some of the conceptual plays more precisely.

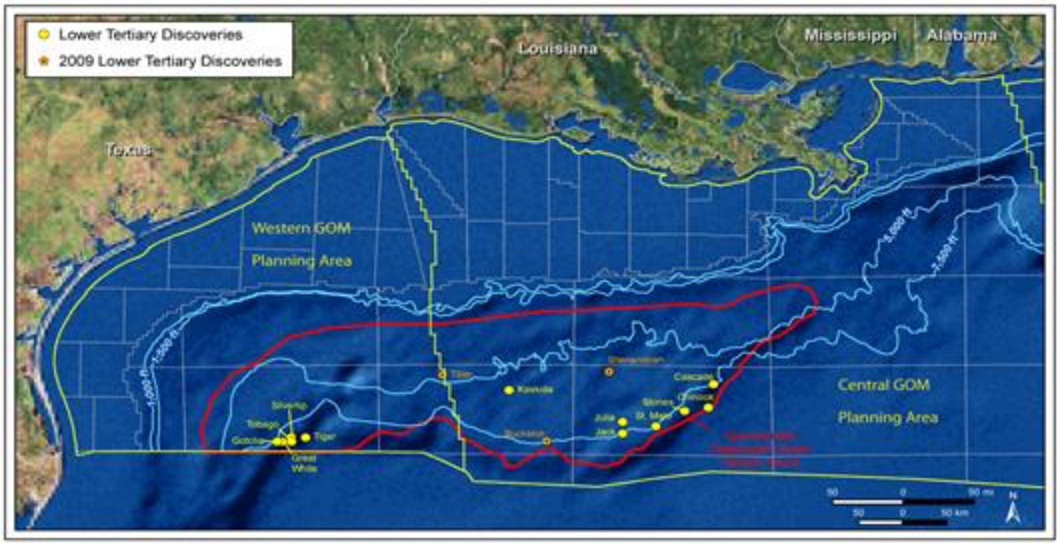
In discovered plays in the GOM, the following concerns were noted: BOEM scientists stated that their 2011 Assessment will now "roll-up" paleo-facies play information up to the sequence boundary to form the basis of their analysis. Previous assessments used a more "finely divided" facies approach and each of these facies independently formed the basis of their analysis. Some on the committee questioned this methodology, while the others felt that because these are shallow plays with minor discovery potential, combining these packages may not affect the final results. Following the suggestion of the CORE, the BOEM tested this concept by carrying out a test assessment on individual packages and combining them for a play and also assessed that play without subdividing it further. The effect of "lumping" the sub-plays was considered inconsequential to the overall assessment results. Another concern dealt with the possibility that "lumping" sub-play characteristics may effectively ignore some key aspects of a play. Specifically, field sizes, recoveries and success rates may vary within different parts of the sequence yet these data might be "smoothed" by lumping. The BOEM was encouraged to test this concern further in their work. The CORE felt that the logic and approach to reserve growth was not clearly explained and encouraged consultation with the USGS on this matter. The CORE recommended that the BOEM should describe the process by which success rate is ascribed to a given discovered play. A range might be used for recovery rates in a single play. This would allow for a wide range of outcomes rather than a concentration toward a narrow mean, independent of how many times a distribution of individual wells or prospects to be sampled. Additionally, the Bureau needs to explicitly state the methodology by which they address dependency among recognized plays.

In summary, the CORE felt that significant progress was made on the 2011 methodology since the 2006 assessment. The overall 2011 Assessment methodology review was endorsed by the AAPG Executive Committee in May 2011. However, some technical and statistical questions remain as summarized above. BOEM did address many of these concerns in response to the CORE recommendations and will continue to improve their assessment methodology through consideration of the valuable insight provided by the members of the committee.

For the 2011 assessment, the estimate of UTRR for the total OCS ranged from 65.2 to 121.7 with a mean of 89.9 billion barrels of oil and from 307.9 to 556.5 with a mean of 404.5 trillion cubic feet of gas. For the total OCS, the mean values of the undiscovered technically recoverable oil increased by approximately 5 percent, while the gas decreased by 4 percent compared to the 2006 assessment. Based on the BBOE mean values of the UTRR, the GOM has about 54 percent followed by Alaska with 31 percent, Pacific with 8 percent and Atlantic with 7 percent. The total endowment for the OCS is 129.5 Bbo for the oil and 661.1Tcfg for the gas, which is an increase of about 12 percent for the oil and 4 percent for the gas when compared to the previous assessment of 2006.

The GOM region continues to be the leader in developing new reserves for the entire OCS. From 2004 to 2009 over 75 new deep water discoveries were made in the GOM OCS. The Lower Tertiary geologic trend (see Figure 17) accounts for most of these new discoveries, namely: Gotcha, Tobago, Silvertip, Great White, Tiger, and Tiber in the western GOM planning area; Kaskida, Buckskin, Jack, Julia, St. Malo, Stones, Chinook, Cascade, and Shenandoah in the central GOM planning area. The Lower Tertiary geologic trend (also referred to as the Wilcox play) stretches from west to east over 450 miles and reaches over 100 miles from north to south. The trend may cover over 30,000 square miles at an average depth of 27,500 feet subsea (See Figure 17 map below of Lower Tertiary in the GOM). Wells that have been drilled on this trend have targeted reservoir rocks of Paleocene to Eocene age and have confirmed the presence of a regionally continuous Lower Tertiary sediment system. The deepwater GOM is estimated to provide 70 percent of the oil and 36 percent of the gas in the GOM. For the Cenozoic plays the majority of the undiscovered resources are believed to be located on the slope, while nearly three fourths of the existing reserves occur on the shelf because of the long period of extensive exploration efforts.

Figure 17: Lower Tertiary Trend in the Gulf of Mexico



In fact, it is expected that the bulk of the increase in U.S. offshore oil and gas production is likely to come from those new discoveries in deep and ultra deepwater regions of the GOM. According to Petroleum Economist (June 10th 2010 edition), "Lower Tertiary trend continues to reveal big discoveries. Significant finds have been made both in the trend's shallow and deep waters, which could hold as much as 15 billion barrels of oil, in high-pressure, high-temperature sub-salt formations at least 25,000 feet below the sea floor." The Lower Tertiary is recognized as a huge resource with the potential for long life projects of up to 30 to 40 years and the opportunity to enhance recoveries through technology (George Kirkland, vice chairman Chevron Corporation- "Chevron sanctions Jack/St. Malo project in the Gulf of Mexico", in Rigzone October 2010). The growing number of Lower Tertiary developments in the GOM has demonstrated that the technical challenges associated with high pressure, high temperature environments are being overcome and are paving the way for a significant increase in oil and gas production.

The robust Lease Sale 193 in the Chukchi Sea planning area offshore Alaska is evidence of the interest the oil and gas industry has shown in the region. Sale 193 held in 2008 generated approximately 2.7 billion dollars in high bonus bids for a total amount exposed of around 3.4 billion dollars. Roughly 2.8 million acres on 487 tracts were leased out of the 29.4 million acres offered for the lease sale. The 2011 assessment of the Atlantic Region incorporated and applied modern exploration concepts and key new learnings from NE-adjacent offshore Nova Scotia, conjugate NW Africa, and the African Transform Margin. Existing BOEM Atlantic region data sets were enhanced and new gravity and magnetic data were acquired, processed and interpreted. Also, the methodology used by BOEM for the Atlantic Region was updated and modified from those previously used (Lore et al., 2001). Previously used play and prospect level risk were replaced in the new methodology. The new methodology retained the major strengths of a comprehensive play-based approach. Conceptual plays were developed based on geophysical data, regional geologic data and knowledge of the region, consideration of productive analogs in similar tectonic/structural location, the style of analog oil and gas traps, reservoir depositional environment and lithology, reservoir age, and petroleum system analysis of existing drilling in the analog. Thus, within the Atlantic OCS, nine conceptual plays and one established high-risk play were identified and their resources inventoried.

The 2014 Atlantic Assessment update incorporates important new information from recent oil and gas discoveries considered analogous to selected geologic plays in the Atlantic OCS. Since the 2011 assessment, the number of analogous discoveries that are appropriate for use in developing the field size distributions for two of the conceptual plays in the Atlantic OCS has increased nearly three-fold. All of the analogous new field discoveries are located offshore East Africa and West Africa. They display similar geologic settings and petroleum system elements to what is observed in the Atlantic OCS.

Progress in drilling technology has enabled the exploration for hydrocarbons located in water depth of up to 12,000 feet and 40,000 feet total depth. Recent technological advancements, such as horizontal wells and multi-lateral completions, enable the recovery of a higher percentage of the in-place resources from a field. Also, the introduction of drill ships and semi-submersibles capable of drilling in up to 12,000 feet of water depth, coupled with dual gradient drilling techniques, will likely expand the envelope of producible oil and gas resources in very challenging environments.

10. Summary: DOI has completed nine comprehensive resource assessments since 1976. Resource estimates are very much a product of the knowledge base existing at the point in time during which they are developed. As such, they reflect the results from a complex interaction of many factors—available G&G data and information, working geologic models and play concepts, exploration and production technology and activities, cost-price relationships, and assessment techniques—which make clear attribution of a change in estimates to a single factor difficult.

It is difficult to draw broad general conclusions concerning the impact of new G&G data and information on the DOI resource assessments. The additional G&G data and information that become available to assessors between assessments are frequently mixed in terms of having a positive or negative effect on the perception of the overall hydrocarbon potential of the OCS. Since 1976 the G&G information available to assessors changed dramatically. For example, industry drilled more than 37,000[5] wells and collected 2.6 million line-miles of 2-D and nearly 2.0 million square miles of 3-D seismic data. At the time of the initial assessment there was only a single deep stratigraphic test well drilled anywhere on the Atlantic and Alaska OCS. More than 900 fields have been discovered in the interim. These data have increased knowledge regarding the resource potential of the OCS. However, much of these data exist in the central and western GOM and southern California. The information that was acquired in most of the other areas is now 20 to 40 years old. There remains today considerable uncertainty concerning the resource potential of many of these frontier areas. The availability of additional modern G&G data could reduce this uncertainty.

Oil and natural gas prices have experienced considerable volatility since the initial assessment. Assessments reporting UERR utilized different prices and sets of economic conditions.

[5] Source: BOEM and BSEE Technical Information Management System database

Technological advances have expanded exploratory drilling capabilities from a little over 1,000 feet of water to 10,000 feet. The oil and gas industry's ability to exploit discoveries has advanced from about 650 feet of water to over 9,000 feet. The ability to drill horizontal and extended reach wells or use multi-lateral completions was nonexistent 30 years ago and subsea completion technology was in its infancy. Marine 2-D seismic data were primitive by today's standards and there were no 3-D seismic data available. In 1975 the information technology revolution had not yet occurred, but by the 1990's information technology had exploded, which served as the catalyst to transform the geosciences and the petroleum industry.

Not only did each successive oil and natural gas resource assessment strive to incorporate the rapidly changing resource base, economic climate and advances in industry's exploration and production capabilities, it also advanced the science of resource assessment by continuously updating and revising assessment techniques, models, and approaches.

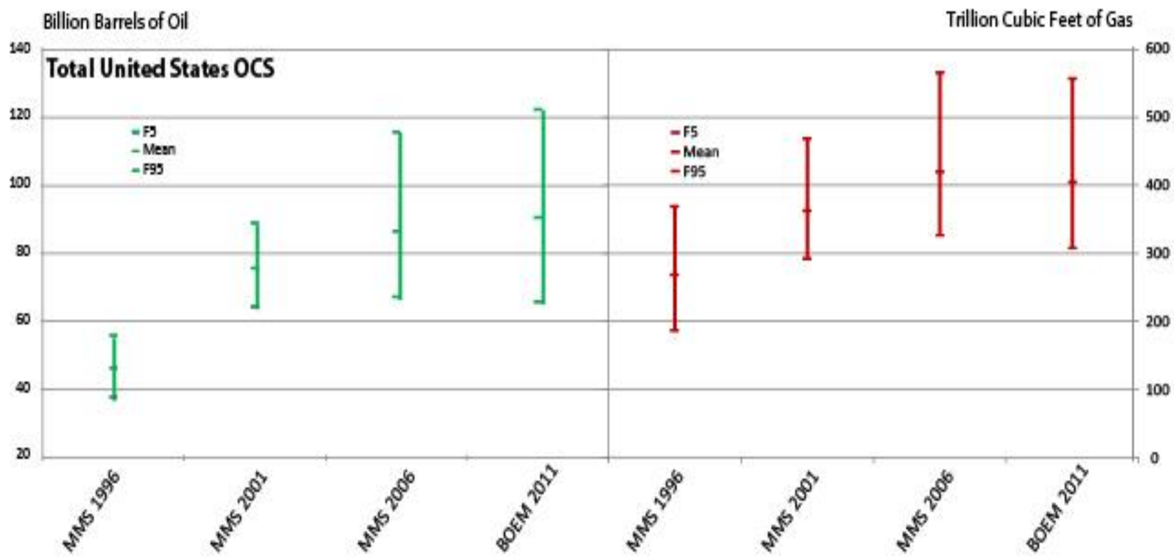
Early DOI resource assessments focused on reporting estimates of UERR. The period covered by these assessments (1975-1995) was characterized by volatile oil and gas prices. It was also a period during which the oil and gas industry's technology capabilities expanded immensely. During this period, exploration in frontier OCS basins in the Atlantic, the Bering Sea, southern Alaska and portions of the southern California borderland was disappointing. At the same time, production in the Central and Western GOM and the Santa Barbara Channel expanded greatly and production was established in the Santa Maria Basin off California. Assessment techniques became more sophisticated during this period, evolving from Delphi subjective judgment approaches to detailed stochastic hydrocarbon play evaluations (PRESTO III and GRASP).

Beginning with the fourth resource assessment in 1990, estimates of the UTRR were introduced. The UTRR is defined as oil and gas resources, primarily located outside of known fields that may be produced as a consequence of natural pressure, artificial lift, pressure maintenance, or secondary recovery methods, but without any consideration of economic viability. As the UTRR estimates are not sensitive to price volatility, they allow for a more meaningful comparison among different vintages of resource assessments as they do capture the effects of technological progress, the increased and/or improved geoscientific information base, and the expansion of the resource base. Estimates of the UERR along with estimates of the UTRR provide a better insight of the dynamic effects of oil and gas price volatilities, as they also capture the relative heat-content values of the two commodities.

The 1996 assessment represented a watershed event in the agency resource assessments. It incorporated major changes in the basic underlying approach to resource assessment and shifted the principal focus from assessing UERR to UTRR. This transition implemented the recommendations of the National Academy of Sciences (NAS) upon their review of the preceding resource assessment methodologies and results. The recommendations of the NAS fully incorporated in the assessment included (1) concerns regarding play definition, (2) use of conceptual plays, (3) treatment of dependencies among variables, and (4) unintended imposition of economic constraints on estimates of UTRR. Full adaptation of the NAS recommendations by the agency provided for a more expansive interpretation of the UTRR potential of the OCS, resulting in significant increases of the estimates.

Figure 18 compares the results from the 1996 through the 2011 DOI assessments. Overall, between the 1996 and 2011 assessments the mean UTRR of oil increased by about 97 percent (45.6 to 89.9 Bbbl); the mean UTRR of gas grew by about 51 percent (268.0 to 404.5 Tcfg). In likewise fashion, the mean total endowment of oil and gas increased by 98 percent and 47 percent respectively. This represents an increase in total endowment from 65.5 to 129.5 Bbbl of oil and 449.6 to 661.1 Tcfg of gas.

Figure 18: Comparison of 1996-2011 Undiscovered Technically Recoverable Resource Estimates



Note: The BOEM 2011 figures reflect the 2014 Atlantic Assessment Update

V. Interpreting Resource Estimates and Possible Effects of Understated Inventories on Domestic Investment

A. Background

The Energy Policy Act 2005, section 357(a)(4) directed the Secretary of the Interior to, "...estimate the effect that understated oil and gas resource inventories have on domestic energy investments."

Some confusion may surround terms like "inventories" when describing oil and natural gas. For example, the general public might think of inventories of oil and natural gas as physical stockpiles of the resources or to the investment community, these inventories might represent estimated quantities of already discovered reserves reflected on the books of individual oil and gas companies. In an effort to estimate the effects of understated inventories—the use of the term, "inventories" is meant to describe the quantities of oil and natural gas yet to be discovered.

The premise of this request—to estimate the effects of "understated" resource inventories—suggests that government assessments are too conservative, when viewed over time and in hindsight following actual discoveries in some OCS areas. However, note too that each assessment reflects a snapshot in time that should not be viewed as either understated or overstated when compared to later assessments, which reflect changed circumstances and knowledge. True knowledge of the extent of oil and natural gas resources can only come through the actual drilling of wells. Estimating undiscovered resources, no matter how sophisticated the models and statistical techniques employed, is an inherently uncertain exercise that is based on hypotheses and assumptions, with the results limited by the quality of the underlying geologic data. Results incorporate perceived levels of risk and are expressed in ranges of estimates to reflect the uncertainty. Nevertheless, resource assessments are a critical component of energy policy analysis, and provide the industry and public with important information about the relative potential of U.S. offshore areas as sources of oil and natural gas to supply the Nation's future energy needs.

The main objective of the government's assessment of undiscovered resources is to develop a set of scientifically-based hypotheses concerning the potential quantities of oil and natural gas that may exist on the OCS. The estimates are used primarily for internal planning and policy purposes. BOEM assessments of OCS resources typically provide aggregate oil and gas resource estimates for all of the OCS planning areas in the GOM, and offshore the Atlantic, Pacific, and Alaska coasts. These assessments represent the government scientists' best estimate of what quantities of oil and natural gas remain undiscovered given the current state of geologic knowledge and reasonably foreseeable technology. Both BOEM and the Department of Energy (DOE) use these assessments for planning, forecasting, and policy analyses. The oil and gas industry and private investors will use this information generally to guide investment decisions and their search for new resources.

BOEM resource assessments also provide detailed information about specific geologic plays associated with the aggregate estimates for OCS planning areas. Although this play information can provide industry with some new perspectives on an area, it is unlikely that this information alone or the aggregate resource assessments for OCS planning areas, have any direct material effect on the oil and gas industry's domestic investment in exploration and development as a whole. The BOEM resource assessment is one of a number of sources of information used by industry and the public, when making investment decisions. Industry and private investors, when considering alternative investment opportunities, often conduct independent assessments, employing their own models and techniques for evaluating and interpreting the data. The same factors that serve to moderate the government's assessment of certain areas (e.g., lack of data, uncertainty) may also tend to influence industry's own assessments and conclusions, and ultimately their willingness or ability to invest in those areas.

The OCSLA requires the Secretary of the Interior to develop OCS oil and gas leasing programs that set out the schedule and location of lease sales based on consideration and balancing of a number of factors, one of which is the geologic characteristics of the oil- and natural gas-bearing physiographic regions of the OCS. BOEM conducts comprehensive national assessments of the undiscovered oil and gas resources on the OCS at least every five years. The potential quantities of oil and gas resources are evaluated on the basis of the interpretation of the geology of the petroleum provinces within all OCS planning areas. For the development of a Five Year oil and gas leasing program, the assessments serve to indicate the relative potential of various petroleum provinces and planning areas, and provide BOEM with the basis for considering possible effects of future oil and gas related activities from the OCS. BOEM resource assessments are also used by Congress and other agencies to support energy policy analyses and decision making.

Areas included in the Five Year oil and gas leasing program are the only areas available for leasing unless the Secretary changes the program or due to congressional action. Industry and others are afforded a number of opportunities to provide input on those areas of interest to them, and to comment on the proposed schedule.

B. Will the Inventories of Undiscovered Resources Decline Over Time?

Each assessment is at best a snapshot in time that reflects the most timely data, current exploration and development technologies, and existing knowledge about the resource potential for each OCS area. The analytical search process continually adds prospects to the inventory as they are identified, drops them as they are leased or eliminated by further seismic evaluation or drilling, and re-characterizes their resource potential and costs. Thus, the actual knowledge of oil and natural gas resources on which leasing and planning decisions are based is never final or definitive. Changes occur with time in technology, the G&G data base available to assessors, and geologic interpretations and models which can lead to higher or lower estimates when the assessments are updated in later years. For this reason, specific assessments of undiscovered oil and gas resources need not decline systematically over relatively short time periods.

BOEM routinely updates and revises its resource estimates to reflect changing conditions and knowledge. For the 2011 assessment, mean estimates have increased 3.16 percent from the 2006 assessment for oil and decreased 5.12 percent for natural gas. Advances in seismic and drilling technology have enabled industry to drill exploration wells more efficiently and with a higher commercial rate of success than could reasonably have been anticipated. New drilling technology for exploration and development enabled industry to step out into deeper waters resulting in the discovery of significant new trends and plays. The more recent assessments reflect this new information.

C. Utility of Resource Assessments

The importance of having credible estimates of potential volumes of undiscovered oil and natural gas resources will differ from the perspective of the government as resource owner versus private industry as business investors, oil and gas producers, and portfolio managers. Government resource assessments are used for programmatic planning, like development of the Five Year OCS Oil and Gas Leasing Program, analyses of proposed legislation, or estimating effects on investment and revenues from various leasing and regulatory policies. Clearly, the government cannot rely solely on known reserves of oil and gas for planning purposes as these assessments would grossly underestimate resource potential for many areas and give misleading or unreliable analytical results. Therefore, to ensure meaningful policy analyses, government decision makers need to consider projections of potential undiscovered accumulations of oil and natural gas from comprehensive assessments of resource potential.

The government's resource assessments typically focus on large areas, examining the interplay of prospective geologic plays to estimate the potential sizes of yet-to-be discovered accumulations of oil and gas. These assessments do not attempt to locate, identify or delineate specific potential fields or prospects.

Industry's investment decisions include a variety of considerations and are based largely on comparative evaluations of the profitability of specific investment alternatives, including overseas opportunities. Their decisions on where to drill for oil and natural gas rely on a number of factors related to expected financial returns, market position, and perceived risk. These investment decisions occur in a staged manner over time. On the OCS, exploration and development costs are relatively high—seismic surveys, drilling, platform, and decommissioning costs can be substantial, especially in frontier areas. Based on their assessments, many companies will acquire (by competitive bidding) an inventory of promising acreage before undertaking very costly seismic acquisition or exploratory drilling programs. The expected profitability of specific projects will be affected by a company's perception of risk—geologic, and economic—which are lower in areas with proven resource potential and where oil and gas development is more-broadly accepted. Industry will only invest in domestic oil and gas exploration and development when they have reasonable certainty of realizing a sufficient return on that investment—e.g., on the OCS, in those areas with open access and predictable lease sale schedules, where there's a reasonable certainty that lease rights will be honored, appropriate plans would be approved on a timely basis, and that any discovered resources could ultimately be produced. In those OCS areas that are off-limits or unscheduled for leasing, companies will be disinclined to expend capital or time attempting to evaluate the hydrocarbon potential of those areas. In the face of uncertain rights to lease and develop, industry will tend to invest elsewhere in exploration.

D. Effects of Risk on Resource Assessments

There is considerable uncertainty and risk intrinsic to any estimate and resource estimates should be used as general indicators and not predictors of absolute volumes. In order to quantify these risks, seismic surveys are utilized to reveal possible oil and gas accumulations that serve to focus exploration drilling efforts. Actual deposits can only be discovered through drilling costly exploratory wells. Exploration investment more often than not fails to yield discoveries of oil and gas, and when prospects are identified, on closer evaluation, some do not warrant further investment with exploratory drilling. Many prospects that are drilled turn out to contain no oil and gas; others are found to contain oil or gas, but are not economically producible because of the size and character of the deposit. Estimating resource potential is not an exact science, and different technical experts and companies could have widely different views on appropriate methodologies and the interpretation of data. While the government has much of the same basic G&G data on unleased OCS oil and natural gas prospects, as do private companies, interpretations of those data and perceptions of an area's hydrocarbon potential will vary. Both groups, however, will evaluate the resource potential by explicitly incorporating risk and uncertainty into the resource assessments to account for the absence of a strong relationship between the geologic variables and the presence of specific amounts of hydrocarbon resources, as well as the lack of geologic information for many of the OCS areas.

The government assessments of oil and gas resource potential rely on risk-based methodologies to statistically reflect different chances for drilling success for different areas. As described previously in section III, the resource assessment models explicitly account for differences in geologic risk among oil and gas provinces and planning areas. As a result, the risk-based estimates in frontier areas ordinarily will have been seen as far too conservative if later exploration demonstrates that the area is hydrocarbon-prone (and will have overstated resources in those areas that ultimately prove unsuccessful). BOEM attempts to mitigate this problem by conducting periodic assessments that incorporate new data from drilling and new seismic surveys.

E. Improving Resource Estimates with More Data

The Nation and the energy debate would benefit from a better understanding of the resource potential, including the gas or oil "proneness" of areas, and the ability of the OCS to contribute significantly toward meeting future domestic demand. There is much uncertainty in the resource estimates due to a lack of data, especially in those OCS areas unavailable for exploration and development for many years.

Due to a lack of drilling activity in frontier planning areas, there can be limited availability of well bore data. However, industry has made huge advancements in the technology of seismic data acquisition and processing, which allows for use of these data to create high resolution images of the subsurface to great depths. With this and other technical advances, the industry has become increasingly successful in finding oil and natural gas resources. Additionally, worldwide, there has been an enormous amount of exploration and production activity in frontier offshore basins that can provide new geologic analogs and exploration and production insights to exploring within frontier U.S. offshore basins.

Although our fundamental knowledge of the origin, migration, and entrapment of oil and gas has advanced markedly during the past 40 years, the fact that incremental scientific advances are still being made leads to additional uncertainty in resource estimation. In other words, new knowledge may lead to increases or decreases in estimates of undiscovered resources, but generally leads to a reduction of uncertainty.

VI. Impediments and Restrictions Affecting OCS Oil and Gas Activities

A. How Legislative, Regulatory, and Administrative Programs or Processes Restrict or Impede OCS Oil and Gas Development

Producing more of the Nation's energy domestically will contribute to economic and national security. However, impediments to leasing and development, ranging from restrictions on access to certain Federal lands by the legislative and executive branches to legal, regulatory and administrative requirements on leasing and development, can restrict or delay development activities. Restrictions on exploration and development, or delays in governmental review and approval processes, can raise project costs and risks, affecting if and when resources can be developed relative to alternative industry investment opportunities.

There are long lead times needed for exploration and development of OCS oil and gas resources, especially in frontier areas where risks and costs are especially high. Preparing to offer oil and gas leases entails years of planning and consultation under sections 18 and 19 of the OCSLA. Once a lease sale is held, it could take five to ten years for drilling to commence. Production could take another five years or more after a discovery.

Under Section 18 of OCSLA, BOEM makes OCS acreage available for competitive bidding through a lease sale process. Subsections 18(c) and (d) prescribe a detailed process of consultation and analysis for preparing a Five Year Program. As administered by BOEM, the process takes two and a half to three years. This includes robust public involvement and compliance with OCSLA Section 18 requirements and NEPA. Even if conditions change, once the program is finalized it cannot be significantly revised without undertaking the full preparation process again.

The Five Year OCS Oil and Gas Leasing Program for 2012-2017 includes fifteen potential sales in six OCS planning areas – the Western and Central GOM, the portion of the Eastern GOM not currently under Congressional moratorium, and the Chukchi Sea, Beaufort Sea, and Cook Inlet Planning Areas offshore Alaska. The Central and Western GOM Planning Areas include five annual area-wide lease sales each. A total of two sales are scheduled in areas of the Eastern GOM not currently under congressional moratorium. For offshore Alaska, the Proposed Final Program schedules three potential sales – one each in the Chukchi Sea and Beaufort Sea Planning Areas and one special interest sale in the Cook Inlet Planning Area off of south-central Alaska. The 2012-2017 Five Year Program makes available areas with more than 75 percent of the undiscovered technically recoverable oil and gas resources offshore.

Areas not included in the 2012-2017 Five Year Program are not open for oil and natural gas exploration and development. Access can also be restricted to otherwise available areas for a variety of reasons, including administrative withdrawals for other uses, such as for national defense or for protection of archaeological, cultural or environmentally-sensitive marine resources.

The OCS leasing program currently covers the central and western GOM, a small portion of the Eastern GOM not under congressional moratorium, existing leases offshore California, and certain areas offshore Alaska. The central and western portions of the GOM account for almost all current domestic offshore oil and natural gas production.

With the increasing activity in the deep and ultra-deep waters of the GOM, contribution to domestic energy production from Federal offshore areas will remain significant in the upcoming years. The potential contribution from other frontier OCS areas is less certain. It is important to note that recent technological advances onshore have spawned economic development of shale oil and gas plays that were once considered non-viable. This has enabled significant increases in the onshore contribution to domestic energy production at a cost lower than that needed to spur production in certain OCS frontier areas.

Opposition to offshore development still exists in certain coastal communities. Such opposition stems from longstanding concerns about potential environmental and economic damage from development in environmentally sensitive marine and coastal areas, and on the socioeconomics of coastal areas. Legal challenges associated with these environmental concerns can lead to delays in the implementation of the OCS oil and gas leasing program.

On April 20, 2010, a loss of well control occurred and resulted in an explosion, fire, and the eventual sinking of the Deepwater Horizon drilling rig, an event that killed 11 workers and created the largest oil spill ever in American waters.

In response, DOI launched the most aggressive and comprehensive reforms in U.S. history to strengthen oversight and regulation of offshore oil and gas operations in order to reduce the risk of a similar disaster in the future. Multiple investigations and analyses were set in motion, including those conducted by the DOI Safety Oversight Board, the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, and the National Academy of Engineering.

In September 2013, the Bureau of Safety and Environmental Enforcement (BSEE) issued a proposed rule to revamp regulatory requirements for production safety systems. BSEE will publish the final rule in 2015. BSSE also published a proposed rule in 2015 to strengthen requirements for well control systems, and blowout prevention practices. These rules will improve workplace safety by reducing the risk of human error on drilling rigs and platforms. BSEE and BOEM also issued a joint proposed rule for offshore exploration in the Arctic. This proposed rule detailed the requirements necessary for safe and environmentally responsible operations in the challenging Arctic region.

The timing of oil and gas development can also be affected by the leasing and permitting process, or from various stipulations in the terms of the lease or permit that affect (permanently or seasonally) surface occupancy, use, and timing of development for safety reasons or to protect sensitive environmental resources. All OCS leases contain various terms, conditions, and stipulations that govern development of the oil and natural gas resources on the lease. These conditions are meant to protect the environment and ensure safety of operations, and ensure that resources are properly developed and provide a fair return to the public. BOEM does not consider existing lease stipulations and approval conditions to be an undue impediment to OCS oil and gas development. Many of the requirements are derived from implementing laws or from the consultation process, and so have facilitated development because they were critical to obtaining Federal, state and local approvals. None are considered so onerous that they would constitute an impediment to development.

The OCS oil and gas activity must comply with a variety of Federal and state statutes, regulations, and administrative orders under various laws such as NEPA, CZMA, ESA, MMMPA, CAA, and CWA, which are designed to provide for safe and responsible resource development and environmental protection. Many of the ocean's energy resources are in environmentally sensitive areas and the development of those resources must be balanced against potential environmental impacts.

BOEM and the BSEE are the primary regulatory and permitting agencies for OCS oil and gas activities. However, other agencies, such as the USCG, EPA, Department of Transportation (Office of Pipeline Safety), U.S. Army Corps of Engineers, U.S. Fish and Wildlife Service, and the National Marine Fisheries Service, have independent regulatory authority and processes for certain aspects of these activities. Additionally, coastal States potentially affected by any proposed OCS leasing or development activity are afforded numerous opportunities to have their concerns addressed through the consultative processes outlined in the OCSLA, NEPA and CZMA. Any unnecessary delays and uncertainties associated with approval processes can impede proper energy exploration and development.

BOEM conducts environmental analysis and prepares environmental impact statements and assessments to address the impacts of proposed leasing actions and exploration and development activities on the OCS. BOEM requires all operator plans for exploration and development have associated environmental documentation under NEPA, and plans are also subject to CZMA provisions that allow review by coastal States.

Under the CZMA, affected States review certain proposed OCS activities for consistency with their coastal zone management plans. If a state finds the activity to be inconsistent, the activity cannot proceed unless the Secretary of Commerce overrules the state after a company appeal. This process can stop or delay OCS activities. The effectiveness of some of the governmental review processes can become problematic if there are conflicting or unclear requirements and uncertain deadlines.

BOEM and the BSEE have taken a number of actions to find efficiencies and improve coordination within the two bureaus, among government agencies and with industry for permitting and administrative processes to avoid unnecessary delays to OCS activities. These steps will help create efficiencies for OCS oil and gas programs.

Appendices

Appendix A: Glossary

The glossary defines relevant terms in a general rather than in a strictly technical way.

API gravity: An arbitrary scale expressing the gravity or density of liquid petroleum products. The measuring scale is calibrated in terms of degrees API. The higher the API gravity, the lighter the fluid.

Appreciation: Analogous to reserves appreciation. See "reserves."

Assessment: The estimation of potential amounts of technically recoverable hydrocarbon resources.

Associated gas: See "gas, natural."

Barrel: A volumetric unit of measure for crude oil equivalent to 42 U.S. gallons.

Barrel of oil-equivalent (BOE): The sum of gas resources, expressed in terms of their energy equivalence to oil, plus the oil volume. The conversion factor of 5,620 standard cubic feet of gas equals 1 BOE is based on the average heating values of domestic hydrocarbons.

Chance: See "probability" or "risk."

Condensate: Hydrocarbons, associated with saturated gas that are present in the gaseous state at reservoir conditions, but produced as liquid hydrocarbons at the surface.

Conditional estimates: Sizes, numbers, or volumes of oil or natural gas accumulations that are estimated to exist in an area, assuming that they are present. Conditional estimates, therefore, do not incorporate the risk that the area may be devoid of oil or natural gas.

Continental margin: The composite continental rise, continental slope, and continental shelf as a single entity. The term, as used in this report, applies only to the portion of the margin whose mineral estate is under Federal jurisdiction; geographically synonymous with Outer Continental Shelf (OCS).

Continental shelf: The shallow, gradually sloping zone extending from the shoreline to a depth at which there is a marked steep descent to the ocean bottom.

Continental slope: The portion of the continental margin extending seaward from the continental shelf to the continental rise or ocean floor.

Conventionally recoverable: Producible by natural pressure, pumping, or secondary recovery methods, such as gas or water injection.

Cumulative probability distributions: A distribution showing the probability of a given amount or more occurring. These distributions include the values for the resource estimates presented throughout this report: a low estimate having a 95-percent probability (19 in 20 chance) of at least that amount (F_{95}), a high estimate having a 5-percent probability (1 in 20 chance) of at least that amount (F_5), and a mean estimate representing the average of all possible values. These distributions are often referred to as S-curves.

Cumulative production: The sum of all produced volumes of hydrocarbons prior to a specified point in time.

Deterministic: A process in which future states can be forecast exactly from knowledge of the present state and rules governing the process. It contains no random or uncertain components.

Development: Activities following exploration, including the installation of production facilities and the drilling and completion of wells for production.

Development systems: Basic options used in constructing OCS permanent production facilities.

Compliant tower: An offshore facility consisting of a narrow, flexible tower and a piled foundation that can support a conventional deck for drilling and production operations. Unlike the fixed platform, the compliant tower withstands large lateral forces by sustaining significant lateral deflections and is usually used in water depths between 1,500 and 3,000 feet.

Fixed platform: An offshore facility consisting of a jacket (a tall vertical section made of tubular steel members supported by piles driven into the seabed) with a deck placed on top, providing space for crew quarters, drilling rigs, and production facilities. The fixed platform is economically feasible for installation in water depths up to about 1,650 feet.

Floating production system (FPS): An offshore facility consisting of a semi-submersible which is equipped with drilling and production equipment. It is anchored in place with wire rope and chain or can be dynamically positioned using rotating thrusters. Wellheads are located on the ocean floor and are connected to the surface deck with production risers designed to accommodate platform motion. Floating production systems can be used in water depths ranging from 600 to 6,000 feet.

Mini-tension leg platform (mini-TLP): An offshore facility consisting of a floating mini-tension leg platform of relatively low cost developed for production of smaller deepwater reserves which would be uneconomic to produce using more conventional deepwater production systems. It can also be used as a utility, satellite, or early production platform for larger deepwater discoveries. Mini-TLPs can be used in water depths ranging from 600 to 3,500 feet.

SPAR: An offshore facility consisting of a large diameter vertical cylinder supporting a deck. It has a typical fixed platform topside (surface deck with drilling and production equipment), three types of risers (drilling, production, and export), and a hull, which is moored using a taut catenary system of 6 to 20 lines anchored into the sea floor. SPARs are presently used in water depths up to 3,000 feet, although existing technology can extend this to about 10,000 feet.

Subsea system (SS): An offshore facility ranging from single subsea wells producing to a nearby platform, floating production system, or tension leg platform to multiple wells producing through a manifold and pipeline system to a distant production facility. These systems are now used in water depths up to 7,000 feet, although existing technology can extend this to about 10,000 feet.

Tension leg platform (TLP): An offshore facility consisting of a floating structure held in place by vertical, tensioned tendons connected to the sea floor by pile-secured templates. Tensioned tendons provide for use of the tension leg platform in a broad water depth range and for limited vertical motion. Tension leg platforms can be used in water depths up to about 6,000 feet.

Dissolved gas: See "gas, natural."

Economic analysis: An assessment performed in order to estimate the portion of the undiscovered conventionally recoverable resources in an area that is expected to be commercially viable in the long term under a specific set of economic conditions.

Economic risk: See "risk."

Economically recoverable resources: See "resources."

Exploration: The process of searching for minerals prior to development. Exploration activities include geophysical surveys, drilling to locate hydrocarbon reservoirs, and the drilling of delineation wells to determine the extent and quality of an existing discovery prior to a development decision.

Field: A producible accumulation of hydrocarbons consisting of a single pool or multiple pools related to the same geologic structure and/or stratigraphic condition. In general usage this term refers to a commercial accumulation.

Fixed platform: See "development systems."

Floating production system: See "development systems."

Frequency: The number of times an indicated event occurs within a specified interval.

Gas, natural: A mixture of gaseous hydrocarbons (typically methane with lesser amounts of ethane, propane, butane, pentane, and possibly some nonhydrocarbon gases).
Associated gas: Natural gas that occurs in crude oil reservoirs as free gas (gas cap).

Dissolved gas: Natural gas that occurs as gas in solution within crude oil reservoirs.
Nonassociated gas: Natural gas that occurs in reservoirs not in contact with significant quantities of crude oil.

Geologic risk: See "risk."

Growth factor: A function used to calculate an estimate of a field's size at a future date. Growth factors reflect technology, market, and economic conditions existing over the period spanned by the estimates.

Annual growth factor: The function representing the ratio of the size of a field of a specific age as estimated in a subsequent year.

Cumulative growth factor: The function representing the ratio of the size of a field a specific number of years after discovery to the initial estimate of its size in the year of discovery.

Hydrocarbon maturation: The process by which organic material trapped in source rocks is transformed naturally by heat and pressure through time and depth of burial into oil and/or gas.

Hydrocarbons: Any of a large class of organic compounds containing primarily carbon and hydrogen. Hydrocarbons include crude oil and natural gas. As used in this report the term is synonymous with petroleum.

Marginal probability of hydrocarbons (MPhc): An estimate, expressed as a decimal fraction, of the chance that an oil or natural gas accumulation containing technically recoverable quantities of hydrocarbons exists in the area under consideration. The area under consideration is typically a geologic entity, such as a reservoir, prospect, play, basin, or province; or a large geographic area such as a planning area or region. All estimates presented in this report reflect the probability that an area may be devoid of technically recoverable hydrocarbons.

Mean: A statistical measure of central tendency; the arithmetic average or expected value, calculated by summing all values and dividing by the number of values

Model: A geologic hypothesis expressed in mathematical form.

Minimum economic field size (MEFS): The smallest field size that will generate income sufficient to cover expenses and yield a prescribed minimum rate-of-return.

Monte Carlo simulation: A method of approximating solutions of problems by iterative sampling from simulated random or pseudo-random processes.

Nonassociated gas: See "gas, natural."

Oil, crude: A mixture of hydrocarbons that exists naturally in the liquid phase in subsurface reservoirs.

Outer Continental Shelf (OCS): The continental margin, including the shelf, slope, and rise, beyond the line that marks the boundary of state ownership; that part of the seabed under Federal jurisdiction.

Petroleum: A collective term for oil, gas, and condensate.

Planning area: A subdivision of an offshore area used as the initial basis for considering blocks to be offered for lease in the Department of the Interior's OCS oil and gas leasing program.

Play: A group of known and/or postulated pools that share common geologic, geographic, and temporal properties, such as history of hydrocarbon generation, migration, reservoir development, and entrapment.

Probability: A means of expressing an outcome on a numerical scale that ranges from impossibility to absolute certainty; the chance that a specified event will occur.

Prospect: A geologic feature having the potential for trapping and accumulating hydrocarbons; a pool or potential field.

Proved reserves: See "reserves."

Recoverable resources: See "resources."

Region: A very large expanse of acreage usually characterized or set apart by some aspect such as a political division or area of similar geography. In this report, the regions are groupings of planning areas.

Reserves: The quantities of hydrocarbon resources anticipated to be recovered from known accumulations from a given date forward. All reserve estimates involve some degree of uncertainty.

Proved reserves: The quantities of hydrocarbons estimated with reasonable certainty to be commercially recoverable from known accumulations and under current economic conditions, operating methods, and government regulations. Current economic conditions include prices and costs prevailing at the time of the estimate. Estimates of proved reserves do not include reserves appreciation.

Proved Undeveloped reserves: Proved Undeveloped Reserves are those Proved Reserves that are expected to be recovered from future wells and facilities, including future improved recovery projects which are anticipated with a high degree of certainty in reservoirs which have previously shown favorable response to improved recovery projects. (see Undeveloped)

Proved Developed reserves: Proved Developed Reserves are those Proved Reserves that can be expected to be recovered through existing wells and facilities and by existing operating methods. Improved recovery reserves can be considered as Proved Developed Reserves only after an improved recovery project has been installed and favorable response has occurred or is expected with a reasonable degree of certainty.

Proved Developed Producing reserves: Proved Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation. (see Developed Producing Reserves)

Proved Developed Nonproducing reserves: Reserves subcategorized as non-producing include shut-in and behind-pipe reserves. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate, but which have not started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons.

Remaining Proved reserves: Are the quantities of proved reserves currently estimated to be recoverable. Estimates of remaining proved reserves equal proved reserves minus cumulative production.

Reserves appreciation: The observed incremental increase through time in the estimates of reserves of an oil and/or gas field. It is that part of the known resources over and above proved and unproved reserves that will be added to existing fields through extension, revision, improved recovery, and the addition of new reservoirs. Also referred to as reserves growth or field growth.

Unproved reserves: Quantities of hydrocarbon reserves that are assessed based on geologic and engineering information similar to that used in developing estimates of proved reserves, but technical, contractual, economic, or regulatory uncertainty precludes such reserves being classified as proved.

Unproved Possible reserves: Are unproved reserves that analysis of geological and engineering data suggests are less likely to be commercially recoverable than probable reserves. After a well on a lease qualifies, the reserves associated with the lease are initially classified as unproved possible because the only direct evidence of economic accumulations is a production test or electric log analysis.

Unproved Probable reserves: Are unproved reserves that analysis of geological and engineering data suggests are more likely than not to be commercially recoverable. Fields that have a Development Operations Coordination Document (DOCD) on file with the BOEM would be classified as unproved probable.

Estimated ultimate recovery (EUR): All hydrocarbon resources within known fields that can be profitably produced using current technology under existing economic conditions. Estimates of ultimate recovery equal the sum of cumulative production, proved reserves, unproved reserves and reserves appreciation.

Reservoir: A subsurface, porous, permeable rock body in which an isolated accumulation of oil and/or gas is stored.

Resource assessment: The estimation of potential amounts of recoverable resources. The focus is normally on conventionally or technically recoverable hydrocarbons.

Resources: Concentrations in the earth's crust of naturally occurring liquid or gaseous hydrocarbons that can conceivably be discovered and recovered. Normal use encompasses both discovered and undiscovered resources.

Recoverable resources: The volume of hydrocarbons that is potentially recoverable, regardless of the size, accessibility, recovery technique, or economics of the postulated accumulations.

Technically recoverable resources: The volume of hydrocarbons that may be produced from a wellbore as a consequence of natural pressure, artificial lift, pressure maintenance (gas or water injection), or other secondary recovery methods. They do not include quantities of hydrocarbon resources that could be recovered by enhanced recovery techniques, gas in geopressured brines, natural gas hydrates, or oil and gas that may be present in insufficient quantities or quality (low permeability "tight" reservoirs) to be produced via conventional recovery techniques.

Economically recoverable resources: The volume of technically recoverable resources that is potentially recoverable at a profit after considering the costs of production and the product prices.

Discovered resources: Hydrocarbons whose location and quantity are known or estimated from specific geologic evidence are discovered resources. Discovered resources include known resources, unproved reserves, and proved reserves depending upon economic, technical, contractual, or regulatory criteria.

Known resources: Hydrocarbons associated with reservoirs penetrated by one or more wells that are not currently qualified under the MMS regulations as capable of producing in paying quantities pursuant to 30 CFR 250.116 are known resources. Known resources can exist on active, relinquished, or expired leases and fields. Superseded by the definition Contingent Resources.

Undiscovered resources: Resources postulated, on the basis of geologic knowledge and theory, to exist outside of known fields or accumulations. Included also are resources from undiscovered pools within known fields to the extent that they occur within separate plays.

Undiscovered technically recoverable resources UTRR: Resources in undiscovered accumulations analogous to those in existing fields producible with current recovery technology and efficiency, but without any consideration of economic viability. These accumulations are of sufficient size and quality to be amenable to conventional primary and secondary recovery techniques. Undiscovered conventionally recoverable resources are primarily located outside of known fields.

Undiscovered economically recoverable resources UERR: The portion of the undiscovered conventionally recoverable resources that is economically recoverable under imposed economic and technologic conditions.

Risk: The chance or probability that a particular event will not occur; the complement (1.00 - MP_{hc}) of marginal probability or success.

Economic risk: The chance that no commercial accumulation of hydrocarbons will exist in the area under consideration (e.g., prospect, play, or area). The chance that an area may not contain hydrocarbons or the volume present may be noncommercial is incorporated in the economic risk.

Geologic risk: The chance that technically recoverable volumes of hydrocarbons will not exist in the area under consideration (e.g., prospect, play, basin or area). The commercial viability of an accumulation is not a consideration.

Risked (unconditional) estimates: Resource volumes that are estimated to exist, incorporating the possibility that the area may be devoid of technically recoverable volumes of oil or natural gas. Statistically, the risked mean value may be determined through multiplication of the mean of a conditional distribution by the related marginal probability of occurrence.

Seal: Impervious rocks that form a barrier to migrating hydrocarbons above, below, and/or lateral to the reservoir rock.

Source rock: A sedimentary rock, commonly a shale or carbonate, whose organic matter has been transformed naturally by heat and pressure through time and depth of burial into oil and/or gas. This transformation is referred to as generation or maturation.

SPAR: See "development systems."

Stochastic: A process in which each observation possesses a random variable.

Subjective judgment: A technique utilized to assign probabilities of occurrence to possible events when all of the possible outcomes of an event are not known and when the frequency of recognized outcomes cannot be estimated with certainty; often referred as expert opinion.

Subsea system: See "development systems."

Tension leg platform: See "development systems."

Total endowment: All conventionally recoverable hydrocarbon resources of an area. Estimates of total endowment equal the sum of undiscovered technically recoverable resources, cumulative production, proved reserves, unproved reserves and reserves appreciation.

Trap: A barrier to hydrocarbon migration that allows oil and gas to accumulate in a reservoir.

Stratigraphic trap: A trap that results from changes in the lithologic character of a rock.

Structural trap: A trap that results from folding, faulting, or other deformation of a rock.

Uncertainty: Imprecision in estimating the value (or range of values) for a variable.

Undiscovered economically recoverable resources (UERR): See “resources.”

Undiscovered resources: See “resources.”

Undiscovered technically recoverable resources (UTRR): See “resources.”

Unproved reserves: See “reserves.”

Appendix B: Abbreviations, Acronyms, and Symbols

AAPG	American Association of Petroleum Geologists
AASG	Association of American State Geologists
AGA	American Gas Association
API	American Petroleum Institute
Bbls	billion barrels
Bbo	billion barrels of oil
Bcfgpd	billion cubic feet per day
BBOE	billion barrels of oil-equivalent
BOE	barrels of oil-equivalent
BOEM	Bureau of Ocean Energy Management
BOEMRE	Bureau of Ocean Energy Management, Regulation, and Enforcement
BSEE	Bureau of Safety and Environmental Enforcement
CAA	Clean Air Act
CDP	common depth point
CWA	Clean Water Act
CZMA	Coastal Zone Management Act
DOE	Department of Energy
DOI	Department of the Interior
E&P	exploration and production
EIA	Energy Information Administration
ESA	Endangered Species Act
F_5	5^{th} percentile, a 5-percent probability (a 1 in 20 chance) of there being more than that amount
F_{95}	95^{th} percentile, a 95-percent probability (a 19 in 20 chance) of there being more than that amount
FY	Fiscal Year
G&G	geological and geophysical
GOM	Gulf of Mexico
GRASP	Geologic Resource Assessment Program
HPF	Historic Preservation Fund
LNG	liquefied natural gas
LWCF	Land and Water Conservation Fund

Mcf	thousand cubic feet
MEFS	minimum economic field size
MMbo	million barrels of oil
MMBOE	million barrels of oil-equivalent
MMbopd	million barrels of oil per day
MMPA	Marine Mammal Protection Act
MMS	Minerals Management Service
MP_{hc}	marginal probability of hydrocarbons
MPP	massively parallel processor
NAS	National Academy of Sciences
NEP	National Energy Plan
NEPA	National Environmental Policy Act
NOAA	National Oceanic and Atmospheric Administration
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act
PETRIMES	Petroleum Resources Information Management and Evaluation System
PRESTO	Probabilistic Resource Estimates Offshore
RFI	Request for Information
SPE	Society of Petroleum Engineers
SPR	Strategic Petroleum Reserve
Tcfg	trillion cubic feet of gas
UERR	undiscovered economically recoverable resources
UTRR	undiscovered technically recoverable resources
U.S.	United States
USCG	U.S. Coast Guard
USGS	U.S. Geological Survey

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