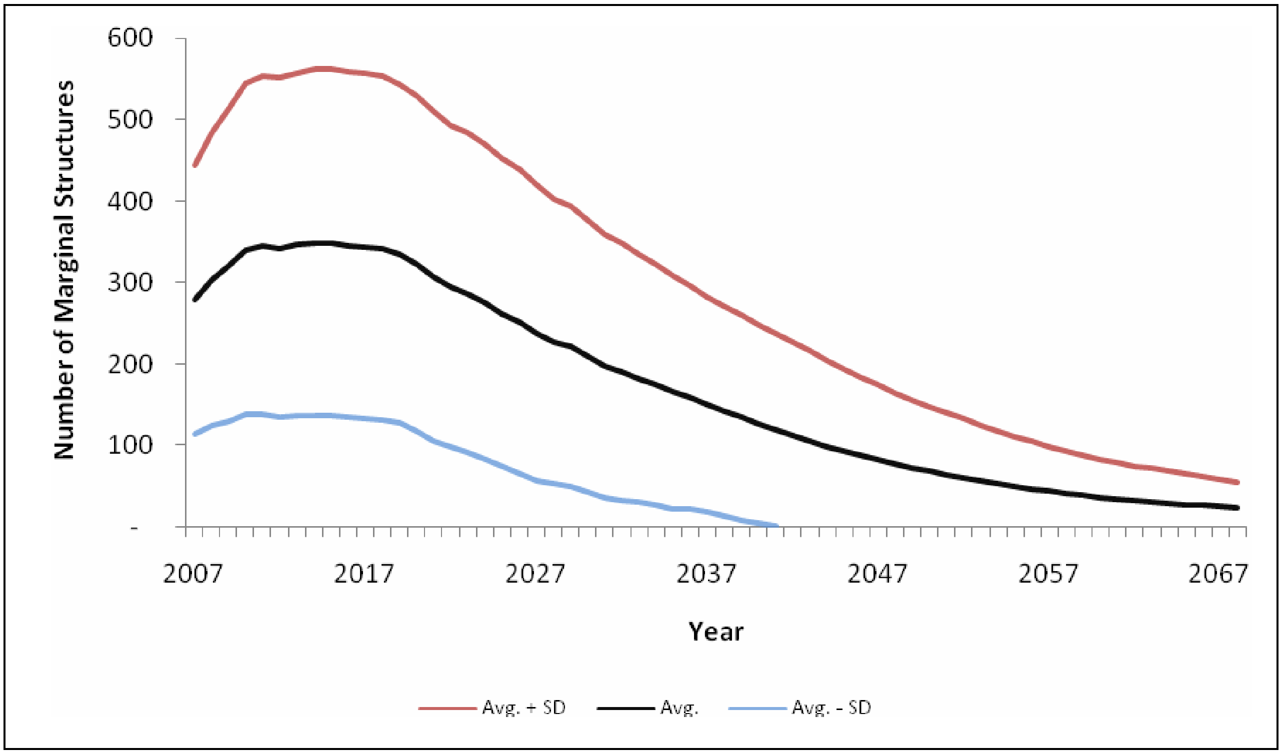
OCS Study
MMS 2010-007

Coastal Marine Institute

Assessment of Marginal Production in the Gulf of Mexico and Lost Production from Early Decommissioning



U.S. Department of the Interior
Minerals Management Service
Gulf of Mexico OCS Region

Cooperative Agreement
Coastal Marine Institute
Louisiana State University

OCS Study
MMS 2010-007

Coastal Marine Institute

Assessment of Marginal Production in the Gulf of Mexico and Lost Production from Early Decommissioning

Authors

Mark J. Kaiser
Yunke Yu
Allan G. Pulsipher

April 2010

Prepared under MMS Contract
1435-01-04-CA-32806-39902 (M08AC12864)
by
Louisiana State University
Center for Energy Studies
Baton Rouge, Louisiana 70803

Published by

U.S. Department of the Interior
Minerals Management Service
Gulf of Mexico OCS Region

Cooperative Agreement
Coastal Marine Institute
Louisiana State University

DISCLAIMER

This report was prepared under contract between the Minerals Management Service (MMS) and Louisiana State University's Center for Energy Studies. This report has been technically reviewed by the MMS, and it has been approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the MMS, nor does mention of trade names or commercial products constitute endorsement or recommendation for use. It is, however, exempt from review and compliance with the MMS editorial standards.

REPORT AVAILABILITY

This report is available only in compact disc format from the Minerals Management Service, Gulf of Mexico OCS Region, at a charge of $15.00, by referencing OCS Study MMS 2010-007. The report may be downloaded from the MMS website through the Environmental Studies Program Information System (ESPIS). You will be able to obtain this report also from the National Technical Information Service in the near future. Here are the addresses. You may also inspect copies at selected Federal Depository Libraries.

Minerals Management Service
Gulf of Mexico OCS Region
Public Information Office (MS 5034)
1201 Elmwood Park Boulevard
New Orleans, Louisiana 70123-2394
Telephone requests may be placed at
(504) 736-2519, 1-800-200-GULF, or
Rush Orders: 1-800-553-6847
Fax: (504) 736-2620

U.S. Department of Commerce
National Technical Information Service
5285 Port Royal Road
Springfield, Virginia 22161
Phone: (703) 605-6040
Fax: (703) 605-6900
Email: bookstore@ntis.gov

CITATION

Kaiser, M.J, Y. Yu, and A.G. Pulsipher. 2010. Assessment of marginal production in the Gulf of Mexico and lost production from early decommissioning. U.S. Dept. of the Interior, Minerals Management Service, Gulf of Mexico OCS Region, New Orleans, LA. OCS Study MMS 2010-007. 194 pp.

ABSTRACT

During the 2004 and 2005 hurricane seasons in the Gulf of Mexico, Hurricanes Ivan, Katrina, and Rita destroyed 120 structures. When a structure is destroyed, its revenue stream is either lost or temporarily deferred. If the field is redeveloped, reserves will be recaptured after redevelopment; otherwise, reserves will be left behind in-the-ground and considered lost. We estimate the quantity and value of lost production from structures destroyed in the 2004 and 2005 hurricane seasons and review operator redevelopment plans circa February 2009. A screening tool is developed to assess redevelopment potential and we estimate that about 70 percent of the reserves impacted by the hurricanes and associated with destroyed structures will be recovered. A review of redevelopment plans indicate that gas producing assets appear to have more favorable economics with 11 of the 14 redevelopment plans thus far submitted for gas structures.

As of June 2008, there were 3,847 structures in the Outer Continental Shelf of the Gulf of Mexico associated with the production of oil and gas. About 65 percent of the inventory, or 2,514 structures, were producing with the remaining structures either serving in an auxiliary role or no longer in production. Structures in water depth less than 1,000 ft constitute the vast majority of the producing assets and contribute about 70 percent of the gas and 30 percent of annual oil production in the Gulf. A large portion of the shallow water assets are operating on the lower edge of profitability.

We provide a historical analysis of marginal production in the Gulf and estimate the number of shallow water committed assets that are economic and marginal throughout a 60-year time horizon. Oil and gas reserves from the inventory of shallow water assets are estimated at 1,056 MMbbl oil and 13.3 Tcf gas, and marginal production is expected to constitute 4.1 percent of the future oil and 5.4 percent of the total gas production. Marginal production is estimated to be valued at about 1 percent of the $149 billion shallow water production expected in the future.

TABLE OF CONTENTS

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

TABLE OF CONTENTS
(continued)

TABLE OF CONTENTS
(continued)

Page

LIST OF FIGURES

Page

LIST OF FIGURES
(continued)

Page

LIST OF FIGURES
(continued)

Page

LIST OF FIGURES

(continued)

LIST OF FIGURES
(continued)

Page

LIST OF FIGURES

(continued)

Page

LIST OF TABLES

LIST OF TABLES
(continued)

LIST OF TABLES
(continued)

Page

EXECUTIVE SUMMARY

The oil and gas industry in the Gulf of Mexico has the greatest weather exposure in the world and is vulnerable to a range of losses that include physical damage and destruction, business interruption, and pollution liability. Operating offshore is more complex and risky, and more capital intensive, than onshore environments where fixed costs are smaller and production profiles tend to decline at more predictable rates. The application of secondary and enhanced oil recovery techniques is more complex and subject to constraints not found onshore, and only a few offshore fields are economic to recover in secondary or tertiary mode. Marginal fields have different economics than large fields, require different recovery techniques, and are produced by smaller companies.

During the 2004 and 2005 hurricane seasons, a number of offshore facilities, drilling rigs, and pipelines were destroyed and extensively damaged. In total, 120 structures were destroyed by Hurricanes Ivan, Katrina, and Rita. The question we first address is to estimate the amount of reserves likely to be recovered in the future. Recovered reserves are a useful indicator to gauge the impact of extreme events on offshore operations and the economic criteria employed in redevelopment decisionmaking.

In the first part of this report, we examine the destroyed infrastructure from the 2004 and 2005 hurricane seasons and the post-hurricane recovery efforts of operators. After a summary overview of the hurricane impacts (Chapter 1), the model framework is described (Chapter 2), and the value of lost production is estimated using a revenue model and scenario parameters assuming that all destroyed structures will be abandoned (Chapter 3). The value of lost production is estimated to range between $1.3 billion to $4.5 billion if no redevelopment of the asset occurs. Sensitivity analysis is performed and we describe the maximum redevelopment cost per structure that will yield a specific rate of return.

In Chapter 4, we review pre- and post-hurricane production and revenue characteristics for the collection of destroyed structures that have been redeveloped circa February 2009 and compare these structures against structures that have not submitted redevelopment plans. A screening tool is presented that describes the redevelopment potential and percentage of remaining reserves that will likely be recaptured during recovery. We estimate that 60 percent of the 63 MMBOE of reserves impacted by the hurricanes will be recovered by redevelopment. The screening tool is a generalized instrument that can be used with future hurricane events to assess what structures will likely be redeveloped and the amount of reserves that will be lost to future hurricanes.

After a structure has produced for several years, it will eventually transition to marginal status and operate on the lower edge of profitability. When a structure turns marginal, the conditions under which profit is generated tend to be more restricted, and the lease on which a marginal structure is producing may no longer generate a profit. We investigate the role of marginal production in the Gulf relative to the 2006 inventory of shallow water assets and forecast its expected contribution to future production. Marginal production deserves careful consideration from a regulatory point of view since production may not be commercial. This will put the lease at risk and should warrant a greater level of regulatory scrutiny. Because marginal structures are on the verge of decommissioning, they represent a useful indicator of future removal activity. The collection of marginal assets also provides useful insight into general production characteristics of the shelf.

In the second part of this report, the number of marginal producers and the amount of marginal production is quantified and its expected contribution to future production is examined. Oil, gas, and BOE production from the shallow water committed assets in the Gulf in 2006 are estimated at 1,056 MMbbl oil, 13.3 Tcf gas, and 3,279 MMBOE. Marginal production is expected to contribute 4.1 percent of the total oil production and 5.4 percent of the total gas production from the collection of committed assets. The expected present value of production from the committed asset inventory is calculated as $149.4 billion and marginal structures are estimated to contribute 1.2 percent of this value.

We begin in Chapter 5 by counting wells and structures across different categorizations, identifying the inventory of producing and non-producing wells and structures, and classifying production according to type and class. In Chapter 6, a generalized methodology is developed to forecast oil and gas production from shallow water assets. We categorize committed assets according to their age of production and the nature of their production profile and forecast production within each asset category. The methodology is illustrated with examples and a summary of results.

In Chapter 7, we identify when a structure is expected to turn marginal using the production models developed in Chapter 6. A forecast of the level of marginal production from the inventory of shallow water assets is presented. The results of our modeling include average trajectories of economic and marginal structure counts over a 60-year horizon, average production profiles across each structure category, and expected cumulative production and valuation functions.

PART 1. MODELING LOST PRODUCTION AND POST-HURRICANE RECOVERY IN THE GULF OF MEXICO

Chapter 1. Redevelopment Economics and Impact Assessment

In this chapter, we describe the weather risk that operators encounter and review the factors that are involved in redevelopment decisions. The impact of the 2004 and 2005 hurricane seasons on the infrastructure and production statistics in the Gulf of Mexico are summarized.

1.1. Introduction

Powered by heat from the sea, a hurricane acts as a gigantic heat engine transforming warm ocean water into powerful wind fields. Hurricanes are typically about 300-350 mile wide and have extreme horizontal pressure gradients that generate powerful winds. Wind speed and the intensity of precipitation both increase toward the center of the system (eye) and generate waves and current which interact with the offshore built environment increasing the stress on structural components, which in some cases, leads to catastrophic failure and destruction.

Winds in excess of 74 mph usually extend 25-50 miles on each side of the storm path and represent the boundaries of hurricane strength winds and the zone where structures are the most vulnerable. In the hurricane force wind swath, old structures are especially vulnerable because older vintage facilities are designed to lower environmental criteria. Typically, 2-4 percent of all structures exposed to hurricane force winds are destroyed and 5-7 percent are damaged. The destruction rates of old structures are usually higher than these ranges when examined as a group. No general correlation exists between the eye path and distance to the destroyed platform because destruction is primarily based upon deck elevation and platform strength, which is site-specific and varies with vintage and design codes.

Structures fail in different modes and any wells underneath the deck and substructure are usually bent at the mudline and require complex and expensive intervention to cleanup and abandon. Hurricane destroyed structures may be completely toppled (Figure A.1) or only the jacket structure may remain standing (Figure A.2). Structures may lean and be declared destroyed (Figure A.3) or be so severely damaged that it can no longer carry out its function. In all cases, destroyed platforms can be a hazard to navigation and need to be immediately identified as navigation hazards.

Hurricane Ivan entered the GOM on September 14, 2004 as a Category[1] 4 storm and passed through the Mississippi River delta, the area most susceptible to underwater mudslides (Figure

[1] The Saffir-Simpson scale classifies hurricanes into five categories based on the highest 1-minute average wind speeds: Category 1 (74-95 mph), Category 2 (96-110 mph), Category 3 (111-130 mph), Category 4 (131-155 mph), and Category 5 (156+ mph).

A.4). Seven platforms were destroyed and significant damage[2] to 24 other platforms were reported (USDOI, MMS, 2004). One structure was toppled by a mudslide, while the other six failures are thought to be attributed to environmental loads (i.e., wind, wave, current) exceeding the capacity of the structure. Three additional platforms were later considered destroyed and decommissioned (Energo, 2006).

Hurricane Katrina entered the GOM in late September 2005 as a Category 4 storm and destroyed 44 platforms (Figure A.5). Hurricane Rita followed in mid-October as a Category 4 storm destroying 69 platforms (Figure A.6). Normally, most destroyed platforms occur to the east of the storm path, since this is the area where the winds and waves are highest. For Katrina, the majority of the destruction lie to the west of the eye path and has been attributed to the reduced fatigue life of structures, since previously, Hurricanes Ivan and Andrew (1992) also passed through this region (Energo, 2007).

Property owners of damaged and destroyed infrastructure are faced with a decision: Should the asset be abandoned along with its potential cash flow or should the property be redeveloped? Decisions are made relative to other opportunities in a company's portfolio based on a comparison of the cost and risk of redevelopment against the benefits of future production. Fields early in their lifecycle are likely to support the production rates and reserves necessary for redevelopment. Mature assets and small producers are the least likely to meet the economic thresholds, and in most cases, will be abandoned.

1.2. Data Source

1.2.1. Notice to Lessees and Operators

Following every major hurricane, the Minerals Management Service (MMS) issues Notices to Lessees and Operators (NTLs) that require platform owners to perform above and below water inspections of infrastructure that were exposed to hurricane force winds. For platforms exposed to hurricane force winds, operators are required by the MMS in accordance with the API Recommended Practice 2A-WSD to conduct a Level I survey (above water visual inspection) before manning[3]. Platform owners report the progress or results of the inspections to the MMS, and indicate if platforms had no damage, incurred minor or major damage, or were destroyed.

The MMS coordinates with the operators and reports on the assessment on a periodic basis, and in a "final" official list, report the total number of damaged and destroyed platforms by category. The data source used in this analysis is the inventory of destroyed platforms reported

---

[2] The MMS defines significant damage as exhibiting some evidence of severe structural overload which caused damage to the primary load bearing members.

[3] A Level II survey (underwater visual inspection by divers or remotely operated vehicle) is required when a Level I survey indicates that underwater damage may have occurred. If any underwater damage is located, or if there are indications of wave loading on the topsides, then additional Level III inspections (close visual inspection of areas of known or suspected damage) is required. A Level IV survey (underwater nondestructive testing of areas of known or suspected damages) is based on the results of a Level III survey.

by the MMS after Hurricanes Ivan (USDOI, MMS, 2004), Katrina, and Rita (USDOI, MMS, 2006).

After a major hurricane, the number of platforms that are declared destroyed usually increases in the weeks following the event, but when the official list is finally released – typically 8-12 weeks after the event - operators have mostly finished their damage assessments and the inventory of destroyed structures has stabilized. The data set may still not be complete at the time the official list is released, however, because an owner of a damaged platform may require additional time to determine if it is economic to replace. If the damage was not found in the initial inspection, the owner may elect to remove the platform at a later date. A structure may also be removed if a pipeline or platform that was part of their operation scheme is no longer in service or removed from service at a later time. Structures not on the official list are not considered in this analysis although they may be significant[4].

1.2.2. Plans for Exploration and Development

All exploration, development, and production activities on the Outer Continental Shelf (OCS) and certain preliminary or ancillary activities (geological/geophysical)[5] are conducted in accord with an Exploration Plan (EP), a Development and Production Plan (DPP), or a Development Operations Coordination Document (DOCD), approved by the MMS Regional Supervisor.

The submission of plans for approval allows MMS to determine whether plans comply with all applicable Federal laws and regulations while permitting for environmental review under National Environmental Policy Act (NEPA) guidelines so to ensure environmental policy, and safety. Submission of plans for approval also allows MMS to determine whether the proposed activities will unreasonably interfere with other uses of the area; interferes with or endangers operations on other leases; or result in pollution or create hazardous conditions.

An EP and its supporting information must be submitted for approval to the MMS before an operator may begin exploratory drilling on a lease. As plans evolve and change, supplemental, amended and revised plans are formed. A supplemental plan is a revision to an approved plan that proposes the addition of an activity that requires a permit.

After the MMS receives an EP, drilling cannot begin until the lessee submits and receives the approval of an Application for Permit to Drill (APD) for each proposed well. An APD provides the MMS data that uniquely identifies a wellbore under an approved plan and allows the MMS to address the technical adequacy and regulatory compliance of the proposed drilling activity. If a well is productive, the operator may submit additional APDs to further develop the lease or may submit an Application for Permit to Modify (APM) to perform completion or workover operations.

---

[4] For Katrina and Rita, it has been reported that an additional 150-200 platforms will be removed or have been removed as a result of the storms (Energo, 2007). Independent verification of this statistic was not confirmed.

[5] See Notice to Lessees and Operators (NTL) Number 2006-G12 for details on which ancillary activities require submittal of a plan.

If the results of exploratory or appraisal operations justify the development of one or more reservoirs, a company will prepare a development plan to commence the development of the area. DPPs and DOCDs describe the schedule of development activities, platforms, or other facilities, including environmental monitoring features and other relevant information. All platforms and pipelines, including their associated components, require the operator to submit an application and receive MMS approval for their installation, modification, and ultimate decommissioning.

1.3. Redevelopment Economics and Uncertainty

1.3.1. Destroyed Structures

Offshore structures are designed for the environmental conditions in which they operate, and for day-to-day operations, platforms are extremely safe and historically have performed at an acceptable rate of failure. With the appearance of a tropical storm or hurricane, however, the risks of damage and destruction increase dramatically because structures must sustain wind speeds, wave forces, and potential mudslides that in extreme circumstances may equal or exceed their design capacity. Older platforms generally have lower strength characteristics (e.g., weaker joints, less robust bracing patterns, etc.) and lower topside deck height which make them significantly more susceptible to wave-in-deck conditions (Laurendine, 2008; Puskar et al., 2007; Versowski, 2006). A wave crest hitting a platform deck creates a very large load that will likely result in significant platform damage and in some cases collapse. A key ingredient in surviving hurricanes is to have a deck elevation above the largest hurricane waves.

1.3.2. Cleanup Cost

Destroyed structures must be decommissioned for removal. The nature of the work involved and the working environment are particularly challenging to ensure that operations are undertaken in a way that ensures that there is no harm to people, property, or the environment (Beck et al., 2008; Wisch et al., 2004).

Structures fail in different modes and cleaning up the sites of destroyed platforms is a complicated and time consuming process (McCutcheon and Payne, 1986; Mailey, 2008). Debris over and around the wells must first be cleared and a vertical section of pipe must be accessed before the wells can be plugged and abandoned. This may require a section of the platform to be cut and removal of soil from around the wellbores. Depending on the lease area and water depth, there may be limited and at times zero visibility. Divers do the work with limited access and the tasks are often complex and require the design of new tools. To gain vertical access to wellbores, conductors could be cut by divers, specially-equipped remotely-operated vehicles (ROVs), and/or explosive-severance charges. Diver cuts are more hazardous and expensive than mechanical or explosive cutting, and because of limited access and poor visibility, progress is often slow and personnel are exposed to more risk than under normal conditions. If the well is under pressure, it will be necessary to snub in to gain access; if the well is "dead" the re-entry process is only marginally simplified. In extreme cases, an operator may have to drill a new well to access the old well to plug.

The intervention vessels required to cut, remove, or relocate downed platforms are often different than those used in conventional operations and their associated activities always require longer times to perform. Unique procedures and new technologies are commonly required to match the complexity of the decommissioning of a downed structure. If the integrity of the platform is sufficient, the platform can be lifted and transported to shore or a reef site (Kaiser and Kasprzak, 2008); otherwise, the toppled structure will be cut and removed in pieces, or dismantled in a manner that satisfies site clearance requirements.

The risk and cost involved in decommissioning destroyed structures often range between 5-25 times more expensive than conventional abandonment. The resources necessary to initiate inspections, conduct repairs, and procure materials and equipment are usually stretched thin during recovery efforts. Day-tripping (working during the day and traveling back to shore at the end of the day) is common. Time constraints associated with cleanup and increased activity levels (the so-called "demand surge") put upward pressure on prices which contribute to higher decommissioning cost.

1.3.3. Decisionmaking Economics

If the value of remaining reserves at a structure is estimated to exceed the expected cleanup and redevelopment cost, the field will likely be redeveloped. There is little or no exploration risk, and it is possible that a young field can be brought back on-line at higher rates of production to help offset the capital expenditures. Assets capable of producing at high rates or those associated with significant levels of remaining reserves are more likely to achieve the economic criteria than assets with low production rates and/or less reserves. Structures that form a complex[6] or are close to other infrastructure where processing equipment or pipelines can be utilized will reduce redevelopment cost and may present new drilling opportunities.

If the estimated value of future production from a destroyed asset is less than the expected cleanup and redevelopment cost, then the decision will likely be to postpone redevelopment or to decommission the asset. The MMS will typically issue an NTL to grant lease extension when operators cannot complete the necessary assessment work prior to lease expiration (USDOI, MMS, 2009a). Operators may need to apply for a Suspension of Operations (SOO) or Suspension of Production (SOP) to maintain lease operations. Between 1996 and 2004, the MMS granted a total of 553 lease suspensions, or 59 applicants on average per year. From 2005-2008, there has been a six-fold increase in the number of lease suspensions requested by operators with the MMS granting 1,304 lease suspensions, or 326 applications on average per year. The MMS may issue suspensions for up to five years and may grant successive suspension periods depending on each case, but usually an SOP is for one year or less.

Cleanup is a sunk cost, and once service vessels are on location, an operator may choose to decommission if the field is near the end of its life. For mature fields, reservoir pressures have been reduced from years of production and production rates are often low and not likely to support the expenditures and payback required by investors. If the operator chooses not to

---

[6] Structures that are physically connected by a bridge (or walkway) are referred to as a complex.

redevelop, it may seek a buyer for the asset contingent upon the federal government allowing the lease transfer. A rational operator would not spend more than the estimated value of remaining reserves to replace a destroyed structure or repair a damaged structure.

1.3.4. Revenue and Cost Uncertainty

The decision to repair, replace, or decommission damaged and destroyed infrastructure is often difficult because of the uncertainty involved in estimation. The return on investment that an owner would expect to receive depends upon future production rates and hydrocarbon prices, as well as the cost to cleanup and redevelop the site. Cleanup costs vary widely. Development cost are similar to normal operations and include the cost to fabricate/install a new platform, subsea assembly and/or pipeline interconnection/tieback, and the cost to re-enter or drill new wells. Under normal circumstances, redevelopment decisions are no different than an initial development decision, but in the case of destroyed or severely damaged assets, there are additional complications and uncertainties regarding the procedures and costs that need to be taken into account. Costs are weighed against the potential revenue generating capability expressed through the expected remaining reserves, production levels, and future prices. If expected benefits exceed costs, redevelopment may occur; if costs exceed benefits, deferral or decommissioning is likely.

1.3.5. Redevelopment Strategies

Redevelopment strategies available to operators are site-specific and depend on field configuration. To an outside observer, factors such as the geologic condition of the reservoir, drilling opportunities, cleanup and redevelopment cost are difficult (or impossible) to assemble. Fortunately, public data can be utilized to provide insight into decisionmaking. Production and drilling profiles, for example, and inventories of lease infrastructure can be computed with a high degree of accuracy. Reserves and their potential value can also be estimated.

When a producing structure is destroyed, most wells require abandonment. Depending on the lease infrastructure and processing/transportation options available, the operator may seek to replace the structure and drill new wells. A structure may be replaced at the original site or elsewhere on the lease or an adjacent lease. New wells may be drilled or the original wells may offer recompletion or sidetrack[7] opportunities. All of these cases involve additional capital expenditure. If infrastructure is installed to replace destroyed structures, or if new wells are drilled, operators are required to submit and receive approval for activity plans.

[7] A sidetrack well is a well planned and drilled from the bore of a previous well in order to achieve a geologic objective. Sidetracks are usually used to confirm the lateral extent and thickness of the reservoir. Savings in drilling cost may be achieved by using existing wellbores, but problems or unexpected conditions during re-entry may occur negating the anticipated savings.

1.4. Structure and Production Classification

Offshore structures can be classified in a number of ways, but the two most common approaches are based on the physical nature of the infrastructure and the characteristics of the production stream.

1.4.1. Structure Type

Offshore structures are designed for a particular field, and are built according to specific design criteria at a specific location and time. Caissons, well protectors, and fixed platforms are the primary configurations employed in shallow water. In the simplest configuration, a platform will simply protect the well(s) with minimal production handling equipment. A caisson is a cylindrical or tapered large diameter steel pipe enclosing a well, while a well protector employs a jacket structure to provide support to one or more wells. Caissons and well protectors are considered minimal structures, and their production is usually sent to processing facilities on production platforms prior to being transported to shore. Equipment on minimal structures may include test separators for measurement, pressure production and test headers, gas lift systems, sump tanks for skid drains, and fixed cranes.

Fixed platforms resemble the jacket structure of well protectors, but are larger, more robust structures, that include facilities for drilling, production, and workover operations. Production platforms include all the equipment and facilities required to gather, separate, process, and sell sales quality natural gas and crude oil. Drilling platforms include the rig and all equipment to drill and workover wells. Platforms that combine the two functions are referred to as drilling and production rigs. In water depth greater than 1,500 ft, various floater technologies replace fixed platforms, and include spars, semisubmersibles, and tension-leg platforms.

1.4.2. Production Status

A structure is classified as active or idle depending on its production status. Oil production is expressed in barrels (bbl) and includes condensate (natural gas liquids); gas production is expressed in thousand cubic feet (Mcf) and includes associated gas (oil well gas, or casinghead gas). A barrel of oil equivalent (BOE) combines the oil and gas streams on a heat content basis (1 bbl = 6 Mcf). A structure is said to be active in year *t* if it produces any amount of oil or gas during the year, while a structure is said to be idle if it once produced hydrocarbons but has not been productive for at least one year prior to the time of observation[8]. Structures which serve in a support role as a storage, compression, or metering facility have never produced and are called auxiliary structures.

---

[8] A structure that is inactive for several years is unlikely to return to active status. According to federal regulations, all structures need to be removed from a lease within one year after production on the lease ceases, unless the lease has received an authorized suspension or is part of a unitization agreement. If an idle structure resides on a producing lease, the structure can remain on the lease for as long as the lease is in production.

1.4.3. Production Type

The producing gas-oil ratio (GOR) is a common means to classify reservoir fluids and field production and we use this measure to classify structures as primarily "oil" or "gas" producers. The GOR is based on observed producing characteristics and is a surface measurement, expressed in volume of produced gas (measured in cubic feet) per unit of produced oil (measured in barrels). A structure with GOR < 5,000 cf/bbl is labeled an oil structure and a structure with GOR > 5,000 cf/bbl corresponds to a gas structure.

1.5. Aggregate Assessment

1.5.1. Energy Losses

In the final list released by MMS, 120 structures were reported destroyed from Hurricanes Ivan (7), Katrina (44), and Rita (69). One hundred eleven of the 120 structures produced hydrocarbons at some point during their lifetime, while 81 structures were producing at the time of the hurricane passage. A total of nine (=120-111) structures served in an auxiliary[9] (non-producing) role and 30 (=111-81) structures were idle at the time of the hurricane passage. Idle structures are unlikely to ever return to producing status, and through February 2009, about half (13) of the 32 structures that have been decommissioned were idle.

Losses incurred in a hurricane are a combination of physical damage and time element losses. When production operations are disrupted, either by damage on site or elsewhere, cash flow is impacted. Insurance claims on time element coverage are typically categorized as business interruption from damage to assets (e.g., platforms, pipelines, etc.), and contingent business interruption, associated with damage to upstream facilities such as processing plants, trunk lines and refineries, owned by third-parties, which prevent production from being received.

Hurricane Ivan caused energy losses of $2.5-3 billion, while Katrina and Rita were responsible for a record $15 billion in losses (Willis Group, 2006). In Ivan, about two-thirds of the total losses were attributed to business interruption and contingent business interruption, while for Katrina and Rita, physical damage was the major cause of losses. Two-thirds of the energy-related losses due to Katrina and Rita have been attributed to physical damage (Willis Group, 2006).

1.5.2. Shut-In Production Profiles

Shut-in production statistics are reported on a daily basis by operators when hurricanes enter the GOM and in the weeks and months after the event. In a typical hurricane, anywhere between 50-100 percent of all the oil and gas that is being produced in the GOM at the time will be shut in 1, 2, or 3 days depending on the strength and location (path) of the storm. Obviously, the more central the storm path is relative to production fields, the greater the

[9] Auxiliary structures do not represent lost production, at least not directly, since they are not producers. However, if an auxiliary structure was integral to the production at a producing platform or field, its destruction may tie-up production upstream, similar to what would occur if an export pipeline was disabled.

amount of oil and gas will be shut in. Shut-in production is usually not “lost,” since after the storms pass and operators assess the integrity of their wells, pipelines, and structures, chokes and valves will be reopened and production resumed. After Hurricane Ivan, damage to subsea pipelines, production platforms, and onshore processing facilities required six weeks to restore 80 percent of shut-in oil production and 10 weeks to restore 90 percent of shut-in gas production. The paths of Hurricanes Katrina and Rita crossed higher-density infrastructure regions and caused more damage to the natural gas systems and processing facilities (USDOE, 2006).

In Figures A.7 and A.8 we plot the shut-in production profiles for oil and gas for major storms over the past two decades. Many factors impact the shape of these curves. The MMS requires operators to shut down facilities and evacuate personnel with the approach of extreme weather, and thus the storm path, speed, strength, and operator response impact the rate at which production is shut in and the peak value of the curves. The duration of the storm and its impact on production facilities and pipeline infrastructure will determine the plateau and slope of the shut-in curve after peak. Many factors may complicate and delay efforts to get production back to pre-storm levels, including damage to onshore support facilities and staging areas, the availability of service vessels and helicopters, and the effects of personnel dislocation and property loss. If onshore gas processing plants are inoperable for any length of time, for example, the loss could delay a recovery of natural gas production – even if platforms and pipelines are unaffected – because gas needs to be processed before flowing to market. Production levels will return to pre-storm levels if no wells, structures, or pipelines are damaged or destroyed. Production associated with destroyed wells and structures that are not redeveloped is classified as lost.

1.5.3. Damage Rates

The amount of damage incurred by a hurricane would be expected to be roughly correlated with the strength of the storm and the number of structures in the storm path. In Table A.1, we tabulate exposure levels and physical damage estimates. Damage rates are stochastic and we observe that the number of structures destroyed are only weakly correlated with damage estimates; e.g., the number of structures destroyed by Katrina was about half that of Rita, but Katrina’s losses were nearly double. The number of offshore structures that are destroyed or damaged depend not only upon the path and strength of the storm, but also the physical characteristics of the wind and wave fields and their interaction with the offshore facilities, the location of the structure relative to the storm path, design characteristics, and various other factors. The complexity of analysis requires sophisticated meteorological, met-ocean and structural modeling to normalize exposed entities to wind speed, structure type, and design specifications (Kaiser et al., 2007a and 2007b).

1.5.4. Destroyed Structures

Most of the structures destroyed by Hurricanes Ivan, Katrina and Rita (Table A.2) were older than ten years, but some were in the prime of their production life cycle (Table A.3). Chevron, Apache, BP America, Forest Oil, and Energy XXI owned more than half of the destroyed structures and a majority of the destroyed wells (Table A.4). In total, over 850 wells throughout the Gulf were destroyed by the storms.

1.5.5. Aggregate Production

Gas, oil, and water production from the collection of hurricane destroyed structures as a percentage of total GOM production is shown in Table A.5. Hurricane destroyed structures represented about 1.2 percent of the total gas and 1.5 percent of the total oil production in the Gulf in 2005, and about 3.4 percent of the total produced water.

1.5.6. Structure Classification

In Table A.6, structures are classified according to their primary output and level of production, in terms of barrels of oil per day (BOPD) for oil producers, thousand cubic feet per day (MCFPD) for gas producers, and in total barrels of oil equivalent per day (BOEPD) for all structures.

A marginal producer would likely be producing less than 50 BOPD oil or 300 MCFPD gas, depending upon structure type, water cut, oil and gas price, operating expense, and other factors, but it may vary at somewhat higher or lower levels. Production greater than 200 BOPD oil or 1,200 MCFPD gas will be commercial under most circumstances.

Chapter 2. Model Framework

In this chapter, we develop a model framework to forecast the production and revenue streams associated with the collection of destroyed assets. The general framework of analysis is outlined along with the assumptions employed in modeling.

2.1. Model Framework

To estimate the amount and value of production that a structure would have generated if it was not destroyed, a five-step procedure is applied:

- Step 1. Model the structure's historic oil and gas production data.
- Step 2. Forecast future production based on model curves assuming stable reservoir and investment conditions.
- Step 3. Forecast future revenue based on a given hydrocarbon price deck.
- Step 4. Terminate production when revenue from the structure falls below its estimated cost of operation.
- Step 5. Output cumulative production and present value of the revenue stream.

2.2. Model Production Profiles (STEP 1)

2.2.1. Notation

Structure s is the basic unit of analysis. Define $q_t^i(s)$ as the amount of hydrocarbon type i (i =oil, gas, BOE) produced by structure s in year t. Oil production is expressed in barrels (bbl) and includes condensate (natural gas liquids); gas production is expressed in thousand cubic feet (Mcf) and includes associated gas (oil well gas, or casinghead gas). The production stream for an asset is described by its oil, gas, and BOE vectors, denoted as: $q^o(s) = (q_1^{\mathrm{o}}, q_2^{\mathrm{o}}, \cdots)$, $q^{\mathrm{g}}(s) = (q_1^{\mathrm{g}}, q_2^{\mathrm{g}}, \cdots)$ and $q^{\mathrm{BOE}}(s)=$ $(q_1^{\mathrm{BOE}}, q_2^{\mathrm{BOE}}, \cdots)$, where the ith element of each vector denotes the ith year of production.

2.2.2. Decline Curves

Production levels exhibit a wide variety of shapes due to factors and events that are unobservable, unpredictable, or both, related to reservoir characteristics, aggregation levels, investment strategies, weather events, technical intervention, and various other conditions. Multiple production peaks after plateau are common. Pre-plateau peaks may also occur if development occurred in stages or unforeseen events arose during development. The purpose of decline curves is to characterize production outside the influence of exogenous factors.

Three types of decline curves are commonly used in reservoir engineering to describe the production of a well or group of wells after plateau: exponential decline, hyperbolic decline, and harmonic decline:

$$q_t(s) = q_0 e^{-dt}$$

$$q_t(s) = \frac{q_0}{1 + Ct}$$

$$q_t(s) = \frac{q_0}{(1 + \frac{C}{n} q_0^{1/n} t)^n}$$

where $q_t(s)$ denotes the production rate of structure s in year t, q_o represents the initial (or peak) production rate, and d, C, n are parameters determined from historical data.

The exponential model is probably the most frequently used method to model production profiles because of its ease of application and ability to capture basic reservoir dynamics. Hyperbolic decline models the production drop as a fractional power of the production rate and is usually applied during the later stages of the life cycle of a well. Harmonic decline is often used to model gravity drainage or water drive mechanisms. For some fields, the production rate may not be adequately modeled using any of these function types.

2.2.3. Production Classification

For each structure, we fit each fluid stream (oil, gas) to each of the three model forms (exponential, harmonic, hyperbolic) using regression techniques and select the best-fit curve using the maximum R^2-value. The input to the procedure is the structure's historic production of oil and gas, and the output is the model parameters for the best-fit decline curve for each hydrocarbon stream. If the model fit for $q_t^i(s)$ has an R^2-value that exceeds 0.75 the model is considered an acceptable fit and a reasonable predictor of future production. We refer to structures that satisfy this criterion as "Normal" producers.

A small number of structures have production profiles that do not yield an acceptable best-fit curve. If $R^2 < 0.75$ for the oil or gas stream, the model fit is deemed unacceptable and simplified techniques are applied to generate the forecast curve. In this case, we repeat the curve fitting procedure from the second-half of the production profile. In other words, if a structure is T years old at the time of observation, then we model the second-half of the production history using data beginning in year $T/2$. If the reduced time horizon model does not satisfy $R^2 > 0.75$, then we assume an exponential model based on the structure's historic decline rate. Structure profiles with initial $R^2 < 0.75$ are referred to as "Chaotic" producers.

Structures that are early in their life cycle present a special problem, since production has probably not peaked and remains largely unknown. Forecasting lost production from early producers, say within 7 years of first production, are subject to a large amount of uncertainty. For this subset of producers, we make a conservative estimate that production has peaked over the time horizon observed and declines following the exponential model according to a specified decline rate that is held fixed across time. Structures that are within 7 years of first production are classified as "Young" producers.

“Idle” structures refer to structures that were not producing at the time of their destruction. Idle structures are unlikely to re-start production or to be re-developed at a later time. We consider any structure inactive prior to 2003 incapable of future production.

“Uneconomic” structures are producing structures with revenue streams in 2006 that have already fallen below their estimated economic threshold. When the revenue stream generated by production falls below a structure’s economic threshold, the operator will stop producing.

2.3. Forecast Future Production (STEP 2)

The model curves determined in Step 1 are used to forecast future oil and gas production for the three classes of assets identified:

- Normal producers: structures that yield best-fit oil and gas production profiles with $R^2 \geq 0.75$.
- Chaotic producers: structures that have initial best-fit production profiles with $R^2 < 0.75$.
- Young producers: structures with less than 7 years production history.

Structures that do not exhibit a reasonable model fit or are early in their life cycle are subject to a greater amount of forecasting uncertainty. These structures are considered separately. For all three asset classes, the production curves $q^i(s)$ determined in Step 1 are used as the forecast model. Time is initialized to the year 2006 (t = 1), and for the model form and decline curve parameters determined, we step ahead year-by-year in the production forecast, yielding $q^i(s) = (q_1^i, q_2^i, \ldots)$.

The forecast is performed under the assumption of “stable reservoir and investment conditions.” This is a strong assumption. A structure that was producing prior to the appearance of a hurricane is assumed to produce according to its historic rates after the event. We assume that the modeled production will not be altered in the future due to reservoir/production problems or additional investment (to enhance production, recover additional reserves, etc.). We control for the impact of the stability assumption on our model results by performing sensitivity analysis.

2.4. Forecast Future Revenue (STEP 3)

Revenue is estimated by multiplying the oil and gas production forecast by the average market hub prices in the year received. The hydrocarbon quality (API gravity, sulfur content, etc.) and transportation expense to deliver production to market is not considered. Company oil and gas sales are primarily made in the spot market or pursuant to contracts based on spot market prices. In an attempt to reduce price risk, a company may enter into hedging transactions with respect to a portion of future production. The impact of hedging or other price risk management strategies that the owner may have employed are not considered.

Revenue in year t for structure s is computed as follows:

$$r_t(s) = q_t^{o} P_t^{o} + q_t^{g} P_t^{g}$$

where P_t^{o} and P_t^{g} represent the average oil and gas price in year t, respectively. We assume a price deck that is constant throughout the life cycle of the structure: $P_t^{o} = P^{o}$ and $P_t^{g} = P^{g}$.

The revenue forecast vector starts in the year 2006 and is denoted as: $r(s) = (r_1, r_2, r_3, \cdots)$. Five commodity price scenarios are employed: P(I) = {P^{o} = \$40/bbl, P^{g} = \$4/Mcf}; P(II) = {P^{o} = \$60/bbl, P^{g} = \$6/Mcf}; P(III) = {P^{o} = \$80/bbl, P^{g} = \$8/Mcf}; P(IV) = {P^{o} = \$100/bbl, P^{g} = \$10/Mcf}; and P(V) = {P^{o} = \$120/bbl, P^{g} = \$12/Mcf}. For each scenario, the oil and gas price is assumed constant over the life cycle of the structure.

2.5. Estimate Abandonment Time (STEP 4)

When the production revenue generated by the asset falls below its current costs, the asset is considered uneconomic and production at the structure will cease. The time at which a structure is no longer commercial is determined by comparing the revenue in year t, $r_t(s)$, to the economic limit of the structure, $\tau_a(s)$, yielding $T_a(s)$:

$$T_a(s) = \min\{t \mid r_t(s) < \tau_a(s)\}$$

The value of the revenue threshold $\tau_a(s)$ is derived from empirical relations using historical data and is correlated with structure characteristics such as development type (caisson, well protector, fixed platform), primary production (oil, gas), and site characteristics (water depth). The values of the economic limit represent category averages based on statistical analysis of over 1,500 structures removed in the GOM over the past two decades. $T_a(s)$ determines the time - for a given production forecast, price deck, and revenue threshold - that a structure will no longer be commercial (economic). At $t = T_a(s)$, a rational operator will stop producing, which will terminate the cash flow vector: $r(s) = (r_1, r_2, \cdots, r_{T_a(s)})$.

2.6. Cumulative Production and Discounted Cash Flow (STEP 5)

The cumulative production $Q(s)$ and discounted cash flow $V(s)$ associated with each structure is computed from 2006 (t = 1) through the time of abandonment ($t = T_a(s)$) as shown:

$$Q = Q(s) = \sum_{t=1}^{T_a(s)} q_t(s)$$

$$V = V(s) = \sum_{t=1}^{T_a(s)} \frac{r_t}{(1+D)^t}$$

The choice of D has a significant impact on the value of lost production and the redevelopment decisions of operators. Each company uses its own rate to guide decisions, which may be the cost of capital, the borrowed cost of money plus the cost of dividends, the return from the least profitable investment, etc. For our purposes, since we are evaluating the aggregate value of lost production, a common discount rate is applied.

2.7. Aggregation

The final step is to aggregate the production profiles and discounted cash flow across all structures in the sample set. The model output for structure *s* is the forecast production profile, $q^i(s)$, cumulative production, $Q^i(s)$, and discounted cash flow, $V(s)$. If the set of hurricane destroyed structures is denoted Γ, aggregating across this collection yields:

$$q^i(\Gamma) = \sum_s q^i(s)$$

$$Q^i(\Gamma) = \sum_s Q^i(s)$$

$$V(\Gamma) = \sum_s V(s)$$

The cumulative oil and gas production, $Q^o(\Gamma)$ and $Q^g(\Gamma)$, and the value of production, $V(\Gamma)$, represent the primary model output.

2.8. Economic Limit and Estimation Techniques

2.8.1. Economic Limit

When marginal costs exceed marginal revenues and the net cash flow for a structure is negative, the operator is unlikely to continue production. Operations may be shut down temporarily or permanently, depending upon the producing status of the lease, whether oil or gas is being produced, etc. The economic limit is defined as the time when the direct operating cost of the structure is equal to the income under production (Harrel and Cronquist, 2007).

The economic limit criteria is reasonable given profit-maximizing decision makers. In practice, an operator may shut-in wells *before* the economic limit is reached if the return on the investment does not satisfy a given threshold or the operator decides for strategic reasons to exit the region. An operator may also produce for a period of time *after* the economic limit is reached if they intend to perform additional drilling on the property or believe prices will increase to return the operations to profitability. Because many structures in the GOM are operated in units either on a field- or lease-basis, the cash flow position of an individual structure is often reviewed in terms of its incremental impact to the overhead position of the production unit. An operator may continue to produce at marginal levels at a loss simply to delay the cost of abandonment. The decision criteria an operator employs for a specific asset is ultimately unobservable to analysts outside the company, but this does not negate the use of the economic limit as a proxy for these criteria.

2.8.2. Estimation Techniques

The economic limit of a structure can be estimated based on its operating cost or by using historical data to assess the revenue position of structures at the time they stopped producing. Both approaches have advantages and disadvantages. With expert opinion, estimates can be performed quickly and updated relatively easily. The main advantage of historic data is that we are measuring actual outcomes that incorporate a broad set of random events. Ultimately, the two approaches are roughly similar in their level of uncertainty.

Expert Opinion

The EIA provides oil and gas lease equipment and operating costs on an annual basis for domestic oil and gas production operations (USDOE, EIA, 2007). EIA personnel track equipment, labor, and maintenance cost, and categorize operating costs on a location and production basis. For the GOM, operating costs are estimated for 12- and 18-well slot platforms with dual-completions assumed to be 50, 100, and 125 miles from shore (corresponding to water depths of 100, 300, and 600 feet, respectively). Maximum crude oil production is assumed to total 11,000 BOPD and maximum associated gas production is assumed to be 40 MMCFPD. Meals, maintenance, helicopter and boat transportation, communication, insurance, and administration are included in expenses; water disposal costs are not included. Table B.1 provides operating cost estimates for offshore wells displayed by platform size and water depth. On a per-well basis, operating costs range from $621,000/well to $802,000/well.

Historical Data

In the threshold level approach, the revenue of structures at the time of their abandonment is quantified relative to a set of attributes. Structures are grouped according to type (caisson, well protector, fixed platform), primary production (oil, gas), and site characteristics (water depth). Inflation-adjusted averages are computed across each categorization based on structure removals in the GOM over the past two decades (Kaiser, 2008a). We associate the economic limit of a producing structure with its category average (Table B.2). Near abandonment, most structures will be producing from a small set of wells. When normalized on a per well basis, there is general agreement between the expert opinion values in Table B.1 and the historic data presented in Table B.2.

2.9. Descriptive Statistics

Three decline models were fit to each structure's oil and gas production profile and the best-fit model parameters are shown in Table B.3 in terms of structure type, model function, and frequency of occurrence. The average value of the model coefficients, average model fit, and coefficient of variation are also depicted. All producing structures were modeled, including idle and uneconomic producers. The exponential decline was the most frequently applied model specification.

The number of model curves classified as idle, uneconomic, normal, young, and chaotic are shown in Table B.4. Idle and uneconomic structures form the largest subset of the collection.

Nearly half the destroyed structures were no longer producing or were producing at levels below their economic limit in 2006. Of the remaining structures, 39 of the 67 producers yielded reasonable model fits; 19 producers were classified as young producers; and 9 did not yield an acceptable best-fit curve.

Chapter 3. Model Results and Limitations

In this chapter we estimate the value of lost production assuming that all destroyed structures will be abandoned and that no redevelopment will occur. In Chapter 4, we will review the redevelopment status of destroyed structures. The value of lost production is estimated to range between $1.3 billion to $4.5 billion depending upon the scenario assumptions employed. For a future average oil and gas price of $100/bbl and $10/Mcf, the total lost production is estimated to be $3.7 billion. We perform sensitivity analysis, describe the maximum redevelopment cost per structure that will yield a specific rate of return, and discuss the limitations of modeling.

3.1. Value of Lost Production

For each destroyed structure, we forecast future production and abandonment according to the model specification described in Chapter 2. Production is valued at a constant oil and gas price across the life cycle of each asset under five scenarios. We break out the production forecast and valuation for structures that yielded an acceptable initial model fit – normal producers (Table C.1); structures with less than 7 years production history – young producers (Table C.2); and structures that required additional processing to yield an acceptable decline model – chaotic producers (Table C.3). Model results for all three categories are subject to uncertainty, but the later two asset classes – and especially young producers – are considerably more uncertain than normal producers. The aggregate forecast and valuation is summarized in Table C.4.

For the normal producer class, the amount of lost production is reasonably sensitive to the price deck (Table C.1), while for the early and chaotic producers, the variation in production output is less sensitive (Tables C.2 and C.3). The likely explanation for this is due to the nature of the models employed in Table C.1 (which includes exponential, harmonic, and hyperbolic curves), relative to the assumed (exponential) decline forms employed in Tables C.2 and C.3. Most of the value of future production is contained with the early producers, both by virtue of their higher production rates and longer anticipated production cycles. It is interesting to note that across all producing structures, the amount of lost production is only slightly sensitive to the price deck, while the valuation estimates are highly sensitive. This is primarily due to the mature nature of the producing properties – a high price deck may delay the economic limit, but does not play a significant role in contributing to additional quantities of production because of the high fixed cost associated with offshore operations. In Table C.2, as decline rates increase, production drops more quickly, decreasing the reserves estimates.

3.2. Rate of Return Calculation

The aggregate present value of each structure's cash flow stream for each price deck is shown in Table C.5 under variable discount rates, extending the valuation estimates provided in Tables C.1-C.4. The values represent the maximum capital investment that owners would be able to spend to provide a specified return. For a given price deck, as the rate of return increases, the allowable capital expenditures will necessarily decrease. As the price deck increases, the revenue from production will increase, and with it the total expenditures that can be spent to achieve a given return. Thus, as we proceed down a given column, the maximum allowed investments increase, and as we proceed across a given row, the maximum allowable investment decreases. The redevelopment cost per structure that yields a specific rate of return is shown in Table C.6.

3.3. Average Redevelopment Costs

Average redevelopment costs provide insight into the cost equation facing operators. Consider an operator with price deck P(III) = {P^o = \$80/bbl, P^g = \$8/Mcf} and a desired internal rate of return (IRR) of 15 percent. An "average" GOM operator could spend between \$11.4 to 24.3 million to achieve a 15 percent return, while an operator with a young producer could spend as much as \$93.1 million on redevelopment and clean-up. An operator that required a 25 percent return would have a more constrained capital budget, ranging between \$8.2-18.3 million (for normal/chaotic producers) to \$66.5 million (for young producers). Structures early in their production cycle, by virtue of their reserves potential and expected number of years of remaining production, can spend significantly more capital for redevelopment. The results in Table C.6 represent average cost but can be specialized to individual assets.

3.4. Sensitivity Analysis

There are many factors in production and valuation estimation that are not directly amenable to analysis. Commodity price level was considered explicitly by using price deck scenarios, and for early producers, we illustrated the impact of changes in the assumed decline rate (Table C.2). Additional parameters that impact the cumulative production and valuation estimate is the threshold used to determine when production will no longer be commercial and the discount factor used in the cash flow analysis. We vary the economic limit and the discount rate across all structures to determine the degree to which changes in these factors impact the model output.

The change in cumulative oil, gas, and BOE production across five price scenarios as a function of changes in the threshold level are depicted in Figure C.1 and Figure C.2. In these figures, the economic limit $\tau_a(s)$ is multiplied by the factor k, $k \geq 0$, and as the value of k increases, $k \cdot \tau_a$ will increase, causing the economic limit to occur at an earlier time, reducing cumulative production and valuation estimates. The greatest change in cumulative production occurs at low price decks.

The sensitivity of the present value to changes in the discount rate is shown in Figure C.3 for the price deck P(I) and in Figure C.4 for the price deck P(III). As k and D increase, present value decreases. Similar figures can be broken out for each price deck and producer class category.

3.5. Limitations of the Analysis

3.5.1. Public Data Sources Have Limited Information Content

Production data is extracted from public domain sources, and so it is not possible to fully identify those factors which make each property unique. We are thus limited in our ability to understand why structures produce in a particular way without detailed, site-specific information. Our ability to infer production trends from curve fitting exercises is similarly limited, and hence our results are only indicative of general trends, and should only be interpreted in this manner.

3.5.2. Inventory of Destroyed Structures May Change in the Future

We only considered those structures that were destroyed in the 2004 and 2005 hurricane seasons. Several dozen structures were severely damaged, and some of these may not return to producing status. Conversely, early producers and those structures with a sufficient amount of remaining reserves may be redeveloped in the future, which would subsequently reduce the quantity and value of "lost" production reported. We assumed that idle structures will not return to producing status, and this is believed to be a reasonably good assumption. The impact of damaged or destroyed infrastructure that served as an active conduit, link, or hub for other producing structures was not assessed.

3.5.3. Decline Curves Are Subject to Significant Uncertainty

Decline curve analysis is an empirical technique that relates production data with one or more attributes, such as time, cumulative production, reservoir pressure, etc. Empirical equations fit data to assumed model forms, and do not include most of the factors that affect past, present, or future performance. Extrapolating the results of an empirically-derived equation to the future assumes that all the factors affecting performance in the past have exactly the same cumulative effect in the future. This is a strong, and certainly, questionable assumption. The use of decline curves necessitates assumptions regarding operating policy, field investment, mechanical problems, marketing issues, and the occurrence of exogenous events. The collective set of all these conditions are assumed constant for all future time and are referred to as "stable reservoir and investment conditions." Changes to any of the above-named factors have the potential to dramatically change both the production rate and reserves, which will impact the forecast results.

3.5.4. Decline Curves May Not Be a Reliable Predictor

The production rate of a well, group of wells, structure, lease, field, or other aggregation unit can be fit to any functional form or curve type. The function may fit the observed data so well that the user may consider it to be an accurate and reliable predictor of the future. Such a conclusion would, of course, be a serious mistake, since many other factors that we cannot control or directly account for will impact production levels. The ability to forecast is severely restricted by conditions that are both unobservable and unpredictable.

3.5.5. Stage of Production May Not Help to Reduce Forecast Error

The stage of production of an asset is often used as a rough indication of the amount of uncertainty that can be expected in forecast models, but such indicators are often ambiguous and should be used with caution. Early in the life of a field, little is known about the extent, quality, and drive mechanisms of the reservoir, and at this time, reserves estimates and production forecasting are the most uncertain. As a field is developed and production performance accumulates, the range of error often decreases, assuming no change in investment strategy. For mature assets, forecasting is considered less uncertain because a smaller number of factors influence production and dwindling remaining reserves are likely to be irreversible.

"Less uncertain" is not certainty, however, and there is still a large degree of unpredictability that can occur near the end of the life cycle of production. Offshore production has different economic characteristics than onshore production, where fixed costs are smaller and production profiles tend to decline at smoother rates. In offshore operations, production levels tend to be chaotic throughout the life of the field, and smoothly declining profiles near the end of production are not common, exacerbating the difficulty associated with forecasting abandonment timing.

Chapter 4. Evaluation of Post-Hurricane Recovery of Destroyed Platforms

In this chapter we examine the post-hurricane recovery efforts of structures destroyed in the 2004-2005 hurricane seasons and infer operational information on redevelopment decision-making. We review the production and revenue characteristics of structures that restarted production through redevelopment and summarize the plans that have been reported through February 2009. Our objectives are twofold: (1) to compare the pre- and post-hurricane production and revenue characteristics of structures that have been redeveloped with those structures that have not yet been redeveloped; and (2) to estimate the redevelopment rates of destroyed oil and gas platforms. An evaluation technique is presented to assess the redevelopment potential of destroyed structures to help predict the percent of reserves likely to be recaptured in future hurricane events.

4.1. Composite Production

Most destroyed structures were fixed platforms, with gas producers slightly exceeding the number of oil producers (Table D.1). One deepwater floating structure, Chevron's mini tension-leg platform (MTLP), was also destroyed. At the time of the analysis (January - February 2009), production profiles were only available through August 2008, but by mid-March, production data through December 2008 was reported[10]. We include as much of the recent data as possible, but the reader should be cautioned that this data may be subject to reporting error and other integrity issues. Twenty-one of the 81 producing structures restarted production via redevelopment, roughly evenly split between oil and gas producers (12 gas, 9 oil), but by August 2008, only ten of these structures (8 gas, 2 oil) were still producing. By December 2008, only two of the original 21 structures were still producing (1 gas, 1 oil).

Composite oil and gas production profiles pre- and post-hurricane for all structures destroyed by Ivan, Katrina, and Rita are shown in Figure D.1. Time is initialized at 1 with the occurrence of each hurricane and is reported through December 2008 on a monthly basis. The contribution of Chevron's deepwater MTLP Typhoon field is broken out separately since these reserves are expected to be recovered after new[11] infrastructure is installed and commissioned in 2009-2010. A longer-term view of production and recovery efforts to date is shown in Figure D.2.

4.2. Recovered Production

A list of the destroyed structures that restarted production as of August 2008 is presented in Table D.2. In Table D.3, average pre- and post-hurricane daily production is reported for oil and gas in terms of barrels of oil per day (BOPD) and thousand cubic feet per day (MCFPD). A

---

[10] There is usually a 3-6 month time delay in production reporting.

[11] The Typhoon field has new owners and a new name. Energy Resource Technology, a wholly owned subsidiary of Helix Energy Solutions, acquired a 100% working interest in the Typhoon field (GC 236, 237) from Chevron (50%) and BHP Billiton (50%), the Boris field (GC 282), the Little Burn field (GC 238), and farm-in rights on five nearby blocks for an undisclosed amount. The new field will be called Phoenix and developed using a floating production system featuring a dynamic positioning system and a disconnectable transfer system. The cost of redevelopment is estimated at $140 million.

composite stream is reported on a barrel of oil equivalent (BOE) basis. Pre-hurricane production levels were computed 1-year prior to the appearance of each hurricane and normalized on a daily basis, while post-hurricane production was averaged over producing months through August 2008. A post/pre daily production ratio is also depicted. The production profiles were generated by aggregating well production associated with each structure, and because not all wells have a structure identifier, some profiles might include well production belonging to other structures, which could bias the results.

Stuctures 1479 and 21599 were not producing at the time of the hurricanes. Structure 1479 began operating in August 2005 but did not produce any hydrocarbons prior to being destroyed. Structure 21599 was idle when Rita passed through and last produced in 2001. Structure 1479 has subsequently been decommissioned. Post-hurricane production totals in Table D.3 do not include the production from these two structures.

In Figure D.3, the pre- and post-hurricane production profiles are compared for those structures that restarted production through December 2008 through new wells and structures. The aggregate daily pre-hurricane production was 8,460 BOEPD and post-hurricane production was 9,433 BOEPD. In total, post-hurricane oil production was about 75 percent pre-hurricane levels, while gas production exceeded pre-hurricane levels.

Gas structures appear more successful in redevelopment operations. As of August 2008, eight of the 12 gas structures and only two of the ten oil structures were still producing. We do not know if any of the structures that stopped production will resume at a later date. Curiously, structure 1207 which had the largest recovery (7.31 post/pre production ratio), stopped producing in June 2008. Until a lease expires and a structure is decommissioned, we do not know if the cessation of production is permanent or temporary. Three gas structures increased their post-hurricane production above pre-storm levels (798, 1529, 32033). Oil structure 20981 also achieved higher post-production levels.

4.3. Revenue Comparison

In Table D.4, the average pre- and post-hurricane daily and annual revenues are presented. Revenue levels are estimated based on monthly average oil and gas prices reported by the Energy Information Administration (EIA) and is CPI-adjusted through August 2008. We do not adjust prices for quality differences in gravity and sulfur content, or apply a location differential for net-back prices. These may be important factors for specific platforms, but can reasonably be ignored in first-order estimates. Because of increasing commodity prices in the months following the hurricane events, the post-hurricane revenue streams are nearly identical to pre-hurricane levels despite a decline in overall production. Significant differences in pre- and post-hurricane daily revenue exist on an individual structure basis.

In Figure D.4, the aggregate monthly revenue streams for all destroyed structures are depicted. Collectively, destroyed structures were producing hydrocarbons at an average monthly revenue of \$60 million (including the MTLP, \$104 million) one year before the hurricanes, and thereafter, average monthly revenues dropped to about \$14 million. For the collection of structures that restarted production, post-hurricane daily revenues exceeded pre-hurricane levels at \$360,462/d and \$491,015/d (Table D.4). Pre- and post-hurricane monthly revenue are approximately \$11 million and \$15 million. See Figure D.5.

In Table D.5, the post/pre-hurricane production and revenue ratio distribution is depicted for structures that restarted production. We observe that gas structures produced at almost twice pre-hurricane levels, while oil structures produced at about 20 percent pre-hurricane levels. The majority of structures had smaller post-hurricane production and revenue levels. The average post/pre-hurricane revenue ratios for gas and oil structures are 2.2 and 0.22, respectively.

The post/pre-hurricane revenue ratios for structures categorized according to pre-hurricane production rates is shown in Table D.6. There is no apparent pattern or trend within the production groups. Oil structures that restarted production appear less successful than gas restarts, perhaps indicating more complex reservoir characteristics and/or difficult producing conditions. We would not expect significant differences in success rates to exist between oil and gas producers in full redevelopment.

4.4. Redevelopment Rates

The decision to redevelop is based on many factors, including expected production rates and remaining reserves, probability of success, cleanup and redevelopment cost, and expected future prices. We use pre-hurricane production as a proxy for post-hurricane production potential under the assumption that new reserves are not being targeted. Pre-hurricane production rates are known with a high degree of certainty. Remaining reserves can be estimated with a reasonable degree of certainty, while probability of success and cleanup and redevelopment cost are unknown and are not considered.

Pre-hurricane production rates are used as a proxy of post-hurricane rates that would be expected after redevelopment. In this sense, pre-hurricane rates provide a rough indication of minimum thresholds that are likely required to be considered for redevelopment. Daily production levels for structures that restarted production ranged from 79 – 1,004 BOEPD for gas structures and 71 – 4,904 BOEPD for oil structures (Table D.3). Our working assumption is that structures with greater pre-hurricane production rates are more likely to be redeveloped. This tendency is true although a more complex picture emerges.

In Table D.7, redevelopment rates are computed for structures according to pre-hurricane production levels and production type. Rates are based on production statistics through August 2008. Gas structures with pre-hurricane production levels less than 600 MCFEPD restarted at a 3 percent rate, increasing to 11 percent for production levels less than 1,500 MCFEPD. Above 1,500 MCFEPD, restart rates vary between 20-40 percent. Oil structures with pre-hurricane production levels less than 100 BOEPD restarted 14 percent of the time and elsewhere varied widely. Overall restart rates for destroyed oil and gas structures are roughly similar, with about one-in-four structures restarting production. On an aggregate BOE basis, structures producing less than 100 BOEPD have a 7 percent restart rate, while above 100 BOEPD, there is about a one-in-four chance of restarting production.

In Tables D.8 and D.9, the restart rates of destroyed structures according to the number of pre-hurricane producing wells and expected remaining reserves are depicted. Structures without any producing wells (i.e. idle structures) are highly unlikely to be redeveloped as shown in Table D.8. As the number of producing wells increase, the likelihood the structure will resume production also increases. We expect that structures with greater remaining reserves will be redeveloped at a greater rate, and this is generally supported by the empirical data. Table D.9 results are subject to a higher degree of uncertainty than the statistics presented in Tables D.7 and D.8 because pre-hurricane production rates and the number of producing wells are known quantities, while remaining reserves are estimated quantities.

4.5. Exploration and Development Plans

Operators that submitted EPs and DOCDs on leases that contained destroyed structures and restarted production is shown in Table D.10. We list the number of plans submitted, plan date and type, and activity description from August 2005 to February 2009. Hurricane damage is not always explicitly mentioned in the plans, indicating that the development may not be related to the destroyed structure. If plans are submitted on a lease and hurricane destruction is not mentioned explicitly, it is possible that the plans are not in support of redevelopment. Conversely, if no plans are submitted and the post-hurricane production profiles are positive, it is possible that model error is present.

Any activity in which new infrastructure is installed or new wells are drilled require that the operator submit an EP or DOCD. Plans for redevelopment at five locations were submitted by operators where hurricane destruction was mentioned explicitly; four plans were submitted on leases that contained destroyed infrastructure without explicit reference to hurricane destruction. If a well was re-entered for a workover or sidetrack operation, only an Application for Permit to Drill (APD) would be required, and we have not compiled these statistics.

In Figures D.6-D.8, we plot the expected remaining reserves and pre-hurricane production for all destroyed structures by production type according to those structures that have restarted production (through August 2008), structures that have submitted DOCD plans (through February 2009), structures that have not restarted production (through August 2008) and structures that have been decommissioned (through February 2009). In Figure D.6, the point at the far upper right is the deepwater Phoenix (formerly Typhoon) development.

Structures with no pre-hurricane production reside on the vertical axis and 13 of the 30 idle structures on the *y*-axis have been decommissioned. Structures on the horizontal axis also deserve comment since it does not seem logical that structures with positive pre-hurricane production can have zero expected remaining reserves. This is the result of modeling across a structure's entire life-cycle as opposed to curve fitting an exponential decline, say, from the structure's last producing year[12]. Structures along the *x*-axis are often uneconomic but may provide opportunities for redevelopment.

---

[12] If an exponential curve is fit to the last production year of a structure, then reserves would be positive and the coordinate would move upward off the x-axis. The forecast models were based on best-fit life cycle curves referenced to peak or truncated profiles over the structure's production history.

4.6. Redevelopment Opportunity Matrix

We delineate three regions in Figure D.8 and label them as “Unlikely Redevelopment”, “Possible Redevelopment” and “Probable Redevelopment” based on the data presented (Figure D.9).

Structures in the “Unlikely Redevelopment” quadrant with production rates less than 100-200 BOEPD are unlikely to be redeveloped because they will suffer from low cash flows and low valuations. Redevelopment in this region are estimated at 20 percent and considered unlikely. Structures in the “Possible Redevelopment” and “Probable Redevelopment” regions have a greater likelihood to be redeveloped. In the Possible Redevelopment quadrant, where pre-hurricane production rates range from 200 - 1,000 BOEPD and expected remaining reserves generally range from 10,000 - 3 million BOE, there is a 40 percent chance of redevelopment. In the Probable Redevelopment quadrant where production exceeds 1,000 BOEPD, redevelopment rates are estimated at 80 percent. Structures with high pre-hurricane production and reserves are good candidates for re-investment because the reserves estimates are sufficiently strong and the long-term value of production is expected to exceed expenditures.

4.7. Redevelopment Success

Profitability measures are difficult to compute without accurate cost data, but some basic inferences may be useful to attempt. Readers are cautioned that conclusions may change as better information becomes available.

In Table D.11, post-hurricane cumulative production, drilling activity, and percentage of remaining reserves is depicted for each structure that restarted production. The percentage of remaining reserves that have been captured provides an indicator of progress to date. None of the structures listed have been decommissioned, and an asterisk denotes if the structure was still producing in August 2008. Post-hurricane cumulative production to August 2008 is depicted. A cross denotes a structure producing in December 2008. Structures that are still producing are expected to capture additional reserves. The reason percent values are in some instances greater than 100 percent is provided by clues given in the last two columns of the table. The production forecast models and reserves estimates are based upon the assumption that no additional capital investment in drilling activity is made beyond the original field plan, so operators who drill additional wells are more likely to recover reserves beyond the model-estimated values.

4.8. Recovery Time

The time in which a destroyed structure resumes production depends on factors such as the complexity of the cleanup operations, access to service vessels, and the strategic interests of the owner group. In Table D.12, the time after which destroyed structures resumed production, the duration of post-hurricane production, and the status of production in August 2008 is depicted. Structures that did not file a DOCD plan were offline an average of 9.6 months for gas structures and 12.0 months for oil structures compared to 15.3 months (gas) and 11.2 months (oil) for structures that filed plans. Twelve of the 20 structures that restarted production were offline less than 1 year; 4 structures were offline greater than 2 years. Several of the structures producing in August 2008 did not file a lease DOCD plan, which indicates that the production data may be erroneous. If a structure stopped producing before August 2008 but has a plan date falling after this time, it will likely resume production in the future.

4.9. Remaining Reserves

Estimated remaining reserves and discounted gross revenue under constant future price scenarios and a discount rate of 10 percent is computed for each structure. Remaining reserves were estimated using production models specific to each structure, and for each production model, revenue streams were discounted using a 10 percent discount rate assuming first revenue would occur either one year (Table D.13) or two years (Table D.14) after initial investment.

Reserves are presented as a range based upon future prices assumed to vary from $60/bbl to $140/bbl. Estimates of remaining reserves show varying degrees of sensitivity to changes in price depending upon the age of the asset and nature of the production curve. In aggregate, total reserves were not sensitive to price variation demonstrating the lack of feedback mechanisms[13] in the forecast model. This is not considered a serious drawback, but reflects the limitations of the model. For two assets (structures 20981 and 21599), initial revenue fell below the structure's economic limit, and so future production is considered uneconomic. The fact that 20981 was producing in August 2008 is also problematic, although it is possible that new reserves were targeted. For mature assets low on the production curve, reserves exhibit a smaller variation to price than younger assets, which is consistent with expectations.

Discounted revenues increase significantly with changes in future prices and also with the timing of the revenue stream. Cash flow received sooner will have a greater present value for constant future prices. Estimates of remaining reserves and discounted gross revenue range from 7.9 MMBOE and $209 million ($60/bbl) to 8.5 MMBOE and $514 million ($140/bbl). See Table D.13. Delaying initial investment by two years will yield smaller discounted revenues, ranging from $190 million ($60/bbl) to $468 million ($140/bbl). Refer to Table D.14.

4.10. Production at Risk

The number of producing wells is a simple indicator of production risk. Mature structures low on the production curve often produce from one or two wells and are especially vulnerable to disruptions, since if a well stops producing it may not be economic to rework and/or re-enter, causing a sudden disruption in cash flow. Structures in the early/mid-life cycle of production usually produce from 5-10 wells and undergo frequent workovers and repair to maintain production.

In Table D.15, the pre- and post-hurricane number of producing wells is depicted for each redeveloped structure. The number of producing wells post-hurricane is often small, indicating

---

[13] Price enters the production forecast through the economic limit at the end of the life of the structure and not through additional capital investment.

risky production. In several cases, the number of pre- and post-hurricane wells is identical, indicating minimal well damage or congruent redevelopment strategies.

A graphical presentation of the total number of wells drilled and the number of wells plugged and abandoned (P&A) for those structures that restarted production is presented on an annual basis (Figure D.10) and in cumulative form (Figure D.11). Since all wells will eventually need to be P&A'd, the difference between the cumulative number of wells drilled and those P&A'd for these structures provides a rough indication of future expenditures.

4.11. Redevelopment Potential

Most destroyed structures have not been redeveloped and are unlikely to be redeveloped unless they fall within the middle or right quadrants of Figure D.9. In Table D.16, a list of structures with at least 250 BOEPD are shown along with pre-hurricane daily production and revenue levels and if an EP or DOCD plan has been submitted on the area block where the structure is located. The total pre-hurricane production from all 61 structures is 30.9 MBOEPD and structures with at least 250 BOEPD comprise 90 percent of the total daily production. Structures on leases with DOCD plans indicate where production will resume in the future if DOCD plans are executed successfully. A total of 14 redevelopment plans have been submitted as of February 2009.

The pre-hurricane daily revenue distribution for structures that have not been redeveloped as of August 2008 is depicted in Table D.17. Structures with less than $10,000 daily revenue are unlikely to be redeveloped. In the $10,000/d - $50,000/d range, there is a greater chance of redevelopment, and structures with more than $50,000/d are likely to be redeveloped. DOCD plan submissions broken out according to pre-hurricane daily revenue provides reasonable confirmation of this statement. Gas structures appear to present better economics and redevelopment potential than oil structures.

4.12. Remaining Reserves and Discounted Revenue

Estimated remaining reserves and associated gross revenue is computed for each structure assuming five price scenarios, a 10 percent discount rate, and a one-year (Table D.18) or two-year (Table D.19) investment timing. Reserves are decomposed according to structures that have been decommissioned and those leases that have filed an EP or DOCD. About 35 MMBOE out of 48 MMBOE (= 56 - 7.6 MMBOE) recoverable reserves are accounted for in redevelopment plans, nearly 75 percent of the total, which we expect to be recovered. Discounted gross revenue estimates range from $988 million ($60/bbl) to $2.32 billion ($140/bbl). See Table D.18. For a two year investment plan, the aggregate discounted revenue ranges from $899 million to $2.11 billion (Table D.19).

4.13. Redevelopment Potential Drilling Profiles

The number of producing wells pre-hurricane along with the cumulative number of drilled wells and plugged and abandoned wells is presented graphically in Figures D.12 and D.13. A large uptick occurred in the number of P&A wells in 2005-2007, but a large inventory still remains. Structures that restart production will attempt to use available wells when redeveloping a field, either as producers or possible injectors, but technical complications will limit the extent of the practice.

4.14. Redevelopment Potential Production Forecast

Gas, oil, and BOE production forecasts for structures that have restarted production, the MTLP, and structures with a submitted DOCD plan are depicted in Figures D.14-D.16. Profiles were computed on an individual basis and then aggregated. The MTLP and structures with submitted DOCD plans are assumed to begin production in 2010.

PART 2. MARGINAL PRODUCTION IN THE GULF OF MEXICO

Chapter 5. Wellbore and Structure Categorization

The purpose of this chapter is to categorize production in the GOM to gain insight into the nature and extent marginal production has contributed to total production. We take a historical view and consider both wells and structures. We begin with an overview of the life cycle stages of production followed by basic definitions. Well inventory and production is considered first, followed by structure inventory and production.

5.1. Introduction

Experts may disagree on when world oil production will peak, but there is general agreement that in the future marginal fields will contribute a greater percentage of world supply. Marginal production in the United States is already an important source of onshore supply. One of every five barrels of crude oil produced in the lower 48 states and about 8 percent of natural gas is produced from a marginal or stripper well (IOGCC, 1999; IOGCC, 2005), defined as a well whose production rate falls below 15 barrels of oil per day (BOPD) or 60 thousand cubic feet of gas per day (MCFPD). There are nearly 500,000 marginal wells and 230,000 stripper wells in the United States (IOGCC, 2005).

Simple definitions of production rates do not adequately capture the characteristics of marginal producers, but is often the standard approach in state and federal regulations. The best way to define a marginal well is with respect to the economics of its operation, but the economics of production is proprietary and is generally unobservable. When the operating cost of a well, structure, or field begins to approach the revenue from production, the unit (well/structure/field) can be considered to be marginal. Operating cost can vary considerably across operators, depending on size, complexity and age of operations, scale economies, accounting units employed, and other factors.

Marginal fields have different economics than large fields, require different recovery techniques, and are produced by smaller companies – proprietorships, partnerships, and limited liability companies – rather than the corporate structure of independents and majors. Marginal wells operate on the lower edge of profitability and the conditions under which profit is generated tend to be more restricted than “normal” commercial operations.

When an onshore field is shut in, wells are plugged and abandoned, the surface infrastructure – the pumps, piping, storage vessels, and other processing equipment – is removed, and the site is returned to its greenfield condition. After infrastructure and production equipment is removed, any hydrocarbons left behind in the ground are usually considered “lost” because prices would have to remain high for a sustained period of time to bring the field back into production. In a high price environment, operators have a strong incentive to maintain marginal wells in production, and if the economics make sense, perhaps even return to abandoned and orphaned wells to re-enter and re-develop. The value of all producing properties will eventually approach zero and turn negative because of decommissioning obligations.

Operating in the Outer Continental Shelf[14] (OCS) is more complex and risky, and more capital intensive, than onshore environments. Mature assets tend to produce from a small number of wells, and if a problem arises, it may not be economic to perform a workover (NRC, 1996; USDOE, NETL, 2001). In offshore operations, production levels also tend to be chaotic throughout the life of the field, and smoothly declining profiles near the end of production are not common, exacerbating the difficulty associated with forecasting abandonment timing. Production near the end of the life of an asset is at significantly greater risk than in the early years of production.

5.2. Life Cycle Stages

All producing properties pass through the same life cycle stages from discovery to depletion, but each stage is uniquely characterized in terms of its length, risk, cost, recovery, and value (Haag, 2005). Production characteristics and profitability change during the life cycle of every structure. The capital intensive expenditures associated with drilling wells, fabricating and installing infrastructure and topsides equipment, and producing during the early years of a structure's life cycle are gradually replaced by a decreasing revenue stream, high operating costs, fewer upside opportunities, and eventually, production that is worth less than the cost to operate and maintain the structure.

5.2.1. Exploration and Delineation

After a lease is acquired and a discovery made, the field will be delineated and the company will assign probable values to the expected reserves, costs, and economic measures, and place the property in a priority list of development plans. Investments are selected in descending order of rank by top management during the capital budgeting process until either the total available funds are exhausted or the minimum acceptable yard stick value reached.

5.2.2. Development

Projects that reach the development stage are subject to a number of complex tradeoffs. Development schemes vary widely across the world, depending upon the size, shape, depth, heterogeneity, and productivity of the reservoir; the time of development and proximity to infrastructure; logistical considerations in moving the production to market; economic considerations and technical constraints; strategic decisions such as an interest in establishing a production hub for the area; and the lead time required to acquire or design and construct structures, rigs, facilities, pipelines, and other downstream facilities.

If a reservoir is small or isolated, it will normally be completed with a "minimal" structure – a caisson, well protector, or subsea completion – with flow lines tied back to shore or an accompanying fixed platform. Fixed platforms can support both drilling and production operations, and tend to be large, self-contained structures built to robust design standards.

---

[14] The OCS of each coastal state generally begins three nautical miles from shore for all but two states – Texas and west Florida – which are three marine leagues (nine nautical miles), and extends at least 200 miles through the Exclusive Economic Zone.

After a structure has produced for several years, the drive mechanisms and cost structure of the field are better understood. Properties usually remain highly profitable and continue to have upside potential. As fields pass into the later stages of profitability, production declines, and the operating cost begins to rise. The value of the structure will still exceed abandonment cost and have positive value, but usually only limited or risky drilling upside remains. The number of inactive wells of a structure during mid-life will typically outnumber producing wells.

5.2.3. Redevelopment

A field may be revitalized during its mid-life period. Production and performance data may indicate the need for additional wells to increase or accelerate recovery, or new seismic data may be obtained to exploit undrilled areas of the reservoir. The infrastructure to support new production is in place, but most often, the reserves target per well is not as large as the original development. An economic comparison of the expected incremental production versus cost is used in decisionmaking.

The natural energy of the reservoir is usually exhausted near the end of the mid-life period, and secondary recovery techniques that use injectants to re-pressurize the reservoir and to displace oil to producer wells may be considered. Water flooding is the main injectant in secondary recovery and gas re-injection for pressure maintenance is also employed. Enhanced oil recovery (EOR) refers to reservoir processes that recover oil not produced by secondary processes. The primary economic driver for secondary and tertiary recovery is project profitability. In some cases, development of a reliable production stream, reserves additions, or employment related to project longevity might also be considerations.

A number of offshore fields in the GOM are under secondary recovery, primarily water flooding and gas re-injection for pressure maintenance. There are no EOR projects in the GOM, and only a few offshore EOR projects worldwide (Bondor et al., 2005; Brashaer et al., 1982). The application of EOR methods is more complex in the offshore environment and subject to a number of constraints that challenge the economics. Space and weight restrictions, subsurface constraints, high capital costs and technical risk, and the need for high reliability impose constraints not present in onshore environments which significantly restrict its application.

5.2.4. Sunset Production

Fields that have reached the advanced stages of depletion are referred to as “sunset”, “marginal”, “brownfield”, or “mature” properties. Structures that produce from sunset properties are nearing abandonment and the value of production is approaching the cost of decommissioning. Owners must decide whether an asset should be divested and offered to the market or produced to depletion. Owners that decide to sell need to maintain sufficient residual value that qualified buyers would be interested in acquiring the property. Some companies prefer not to perform decommissioning activities, especially offshore, where costs are significantly higher and more uncertain than onshore. Marginal structures usually produce from one or two wells and carry a large risk if one of the wells goes off production. Workovers may not be economical in mature wells. Fields that are marginal are often sold as part of a large package that includes better fields to attract a buyer.

5.3. Wellbore Definitions

5.3.1. Aggregation Unit

The wellbore is the most fundamental unit in petroleum studies since all hydrocarbons are extracted from one or more formation horizons[15] in a well. Typically, a well is produced from one horizon and is then recompleted from another (higher) formation at a later period. It is possible to produce from more than one formation at the same time as long as the production streams are not commingled.

5.3.2. Exploration and Development Wells

Exploratory (wildcat) wells are drilled in an area with no known hydrocarbon reserves, while delineation and development wells are used to delineate a known deposit and then produce it. A successful development well will produce hydrocarbons, while "success" for an exploratory well may not actually result in production. Onshore, discovery wells are usually turned into producers, while offshore, successful exploration wells may be plugged and abandoned because the location is not optimal for field development. Successful exploratory wells may be protected with a caisson or well protector, and as delineation wells are drilled, additional infrastructure such as fixed platforms, subsea tiebacks, and flowlines will be installed. Today, many development wells are deviated or drilled horizontally to enhance production rates and reduce pressure drawdown in the wellbore region.

5.3.3. Production Status

At any point in time, a well may be producing or inactive. An inactive well is classified as shut-in, temporarily abandoned, or idle. Shut-in and temporarily abandoned wells are transitory[16] states and may be brought back on-line at a later time. A well that is shut-in or temporarily abandoned for longer than one or two years is referred to as idle or non-producing. A well may transition between producing and non-producing status several times during its life cycle because of workover operations, technical problems, hurricane damage, etc. Idle wells may come back into production at a later time, but the probability of returning to producing status generally decreases with the time of inactivity.

5.3.4. Fluid Classification

Wellbore production contains various liquid and gas products, with oil, natural gas, condensate, and water the primary components. Hydrocarbon reservoirs contain complex mixtures of liquid and gaseous compounds, specific to the site and manner in which the deposits were laid down and transformed over time. Hydrocarbons also change as they are released from a high-pressure high-temperature environment to ambient conditions and are processed at the surface.

---

[15] An individual sealed reservoir is referred to as a block, and one or more blocks having comparable depth, origin, and characteristics is referred to as a horizon. Multi-block horizons are generally created by faulting.

[16] MMS regulations govern the manner in which well production is suspended and the frequency of inspection.

Producing wells contain a mixture of oil and gas, and often, a significant amount of water, especially as a well ages. Oil wells produce gas and gas wells produce condensate, and we will distinguish between the two output streams. Gas production associated with "oil" wells is typically referred to as associated gas, while liquid production associated with "gas" wells is called condensate or natural gas liquids (NGL's).

5.3.5. Gas-Oil Ratio

The producing gas-oil ratio (GOR) is the standard way to classify wells as either "oil" or "gas" producers. The GOR of a well is defined as the ratio of gas output (expressed in cubic feet) to oil output (expressed in barrels) computed on either an annual or cumulative basis. The solution gas-oil ratio describes the reservoir conditions of the fluid, and frequently, a value of 5,000 or less indicates a black oil with minimal gas production, while a GOR value between 5,000 to 10,000 indicates a volatile oil with gas production. A solution gas-oil ratio of 50,000 or more indicates a gas reservoir.

The producing gas-oil ratio is not equivalent to the solution gas-oil ratio since it is measured at the surface and after processing, but since public data only report produced hydrocarbon streams, we necessarily apply the producing GOR in our assessment. We choose to compute the producing GOR on a cumulative basis since cumulative metrics take into account the entire history of the well (through the time of observation), and is more representative[17] than a one-year snapshot. We apply a threshold value of 10,000 to distinguish between oil and gas wells: "oil" wells having a cumulative GOR $< 10,000$ and "gas" wells having a cumulative GOR $\geq 10,000$. Sensitivity analysis on this value will be performed.

5.4. Wellbore Counting Statistics

5.4.1. Exploration and Development Wells

The number of exploration and development wells drilled in the GOM is shown in Figure E.1. Drilling activity dropped off significantly in 2007 due in large part to the intense recovery efforts of the 2005 hurricane season. The last time drilling activity in the GOM fell below 600 wells drilled was in 1992, the year of Hurricane Andrew. The ten-year (1995-2005) average number of wells drilled in the GOM is 1,094; while in 2006 and 2007, a total of 780 and 600 wells were drilled.

From 1947-2007, 47,270 wells have been drilled in the GOM: 16,707 exploratory wells and 30,563 development wells (Figure E.2). The number of exploratory and development wells drilled by water depth is depicted in Figures E.3 and E.4. Since the mid-1990s, deepwater exploratory wells have played an increasingly important contribution to the total number of wells drilled. The total number of exploration and development wells by water depth category is shown in Table E.1.

[17] GORs change over time with changes that occur in the reservoir, reservoir fluids, and production techniques. Trends in GOR are useful to distinguish the drive mechanism of the reservoir and can also be beneficial in forecasting.

5.4.2. Producing Wells

The number of producing wells in the GOM changes over time, increasing when a successful exploration or development well goes online, or when a shut-in well returns to producing status, and decreasing when a well is shut-in, temporarily abandoned, or permanently abandoned. The total number of producing wells in the GOM has never exceeded 8,000, and in 2006, 5,546 wells were producing (Figure E.5).

In Figure E.5, the producing well count is disaggregated in terms of oil and gas producers using a GOR threshold GOR = 10,000. Prior to 1980, the number of oil wells dominated gas wells, but in recent years, the well types have converged (Figure E.6). The 2006 well count realized a significant reduction from 2004 (6,825) and 2005 (6,490) levels. At the end of 2006, there were 2,807 oil wells and 2,739 gas wells.

Oil and gas well count will vary with the level of the GOR threshold, and so we examine the manner in which well count varies as a function of GOR. The default threshold we apply is GOR = 10,000, and for any value of GOR < 10,000, the number of wells identified as "oil" will decrease as the number of "gas" wells increase. Conversely, for a GOR > 10,000, the number of oil wells will increase with a comparable reduction in the number of wells identified as gas. The greater the difference between the threshold values selected, the greater the difference in the well counts across category.

In Figures E.7 and E.8, the number of producing oil and gas wells for three GOR levels (5,000; 10,000; and 15,000) are depicted. Changing the GOR threshold from 10,000 to 5,000 decreases the average annual number of oil wells by 6.8 percent, and in aggregate across the entire time horizon, by 8.6 percent. The gas well count increases on average by 11.0 percent, and in aggregate, by 9.7 percent. The percentage values are not equivalent because the number of oil and gas wells vary each year, and thus, the percentage contribution. The percentage ratio of oil wells as a function of GOR is shown in Figure E.9.

5.5. Wellbore Production Statistics

5.5.1. Aggregate Production

Oil wells produce gas and gas wells produce oil, and as one would suspect, gas production from "oil" wells and liquid production from "gas" wells do not represent a significant percent of category production. On an individual well basis, however, residual production can be significant, depending on the level of the primary output stream; e.g., if the level of oil production is sufficiently high (and thus with it, associated gas) gas production will also be high. Liquid (oil and condensate) production from gas wells are a smaller percentage of the total production levels (Figure E.10) than gas production from oil wells (Figure E.11). Cumulative liquid and gas production from oil and gas wells is depicted in Figures E.12 and E.13.

5.5.2. Oil Producers

Oil wells are categorized by production level in terms of daily output, as producing less than 15 barrels oil per day (BOPD), between 15-200 BOPD, and greater than 200 BOPD. Oil well gas production is categorized[18] in terms of daily output as producing less than 90 thousand cubic feet per day (MCFPD), between 90-1,208 MCFPD, and greater than 1,208 MCFPD.

Oil wells are classified in terms of daily output for each year the wells are active and we also count and categorize gas output. Oil well oil production by category (number of each oil well division categorized according to daily oil production) is shown in Figures E.14 and E.15. About 500 oil wells currently populate the < 15 BOPD category, another 1,600 or so wells fall within the 15-200 BOPD category, and around 600 wells reside within the > 200 BOPD class. If a marginal oil well is considered as producing less than 15 BOPD, then as a percentage of the total number of producing wells, we see that the number of marginal wells has been relatively constant over the past 3 decades, comprising roughly 10 percent of the total number of oil wells in any given year (Figure E.16). The number of oil wells categorized according to daily gas production is shown in Figures E.17 and E.18.

Oil well oil production is shown in Figure E.19, and in Figure E.20, the relative contributions of each category are depicted. Oil well oil production is primarily due to large producers. Marginal producers contribute a relatively insignificant amount of liquid production. Medium wells contribute larger quantities of liquid and gas production, but relative to the larger producers, the values are relatively small on an annual basis. Oil well gas production is depicted in Figure E.21.

5.5.3. Gas Producers

Gas producers are classified according to marginal, medium, and large producer groups similar to oil producing wells. Gas wells categorized according to daily oil production is shown in Figures E.22 and E.23; gas wells categorized according to daily gas production is shown in Figures E.24 and E.25. In 2006, there were 531 wells with a daily gas production less than 90 MCFPD; 1,179 wells with daily production between 90 MCFPD to 1,208 MCFPD; and 1,029 wells producing greater than 1,208 MCFPD. Our focus is on gas well gas production. The population ratio of marginal gas producers is similar to marginal oil producers, but the trend toward greater marginal production and smaller large producers is clear as current gas fields deplete and new fields remain undiscovered (Figure E.26).

Gas well condensate production is shown in Figure E.27. Gas well gas production is shown in Figure E.28. Although large producers constitute less than half of the total number of gas wells, they contribute more than 95 percent of gas well gas production. Between 1947 and 2006, gas well oil production contributed approximately 11 percent of cumulative oil production in the GOM.

---

[18] The oil and gas categories are equivalent under the standard heat-conversion ratio: 6 MCF = 1 BOE.

The relative contribution of gas well gas production according to daily production levels is shown in Figure E.29. Similar to oil producers, marginal gas producers contribute an insignificant amount of total gas production, and even if the 90-1,208 MCFPD producer category is included, we see that the levels are reasonably constant around 10 percent. The most significant portion of gas in the GOM has always come from large gas producers.

5.6. Structure Definitions

5.6.1. Aggregation Unit

Wellbores access formations and are tied into structures via flowlines and pipelines for processing. Each well is associated with a unique structure, and the composite wellbore production streams yield the production profile of a structure.

Structures that are in close physical proximity and connected by a walkway, bridge, or similar infrastructure is referred to as a complex. The MMS assigns each site where platforms are installed a complex identification number, and within a complex of structures, individual structures are identified by a structure number. All structures in the OCS are uniquely identified by a complex identification number and structure number.

Leases, fields, and basins represent higher levels of aggregation. A field is an organizational unit that groups together production from similar blocks, horizons, or prospects, while a lease is an artificial (man-made) geographic construct. Lease and field units are not considered further.

5.6.2. Structure Type

Offshore structures are designed for a particular field, and are built according to a specific design criteria at a specific location and time. Shallow water structures, defined as development in water depths less than 1,000 ft, primarily employ caissons, well protectors, and fixed platforms.

5.6.3. Production Status

A structure is said to be active in the year of observation if it produces hydrocarbons during the year, while a structure is said to be idle if it once produced hydrocarbons but has not been productive for at least one year prior to the year of observation.

An auxiliary structure is a structure that has never produced hydrocarbons but serves in an auxiliary and supporting role, say as a quarters facility, flare tower, or storage platform. Auxiliary structures may exist on a producing or non-producing lease, and may or may not serve a useful economic function. Because auxiliary structures are not directly associated with a production stream, it is not easy to identify the structure as active or inactive.

Structure classification depends on the time of observation and structures may transition between active and idle status one or more times during their lifetime. A structure that is inactive for several years, however, is unlikely to return to active status.[19] Idle structures may or may not serve a useful economic function, and because we do not break-out the historic records of auxiliary structures over time, we prefer use of the category descriptor "non-producers" when referring to structures that are not in production rather than "idle" structures.

5.6.4. Production Type

Analogous to the wellbore classification adopted previously, a structure with cumulative GOR < 10,000 cf/bbl is defined as an oil structure, while if cumulative GOR > 10,000 cf/bbl, the structure is identified as a gas structure.

5.7. Structure Counting Statistics

5.7.1. Active Structures

The number of structures installed in the GOM by structure type is depicted in Figure E.30. The "other structures" category shown in Figure E.30 refers to deepwater structures, such as spars and tension leg platforms, and although they only represent a few dozen structures (Table E.2), they are currently responsible for about 72 percent of the total oil production in the GOM. Over the past decade, the number of structures installed per year has range between 73 and 161 (with average 119, standard derivation 27). To date, nearly 7,000 structures have been installed, with about one-third of the installations being caissons (Figure E.31).

When lease production ceases, all oil and gas infrastructure on the lease will be removed. The first offshore structures in the GOM were removed in the early 1970s, and by 1990, the number of structure removals in a typical year began to exceed 100 (Figure E.32). Over the past decade, the number of structures removed has ranged from 76 to 194 (with average 136, standard deviation 36). In total, nearly 3,000 structures have been removed in the GOM, almost half of which are caissons (Figure E.33). In Table E.3, the number of removals by structure type and water depth is depicted. About half of the installed unmanned fixed platforms have been removed, compared to only 10 percent of the manned installations.

The number of active (existing) structures in the GOM is shown in Figure E.34. There are currently 3,838 active structures: 2,324 fixed platforms, 380 well protectors, 1,091 caissons, and 43 other structures. The number of removals began to equal or exceed the number of installations in the early 1990s (Figure E.35), and so during this time, the inventory of active structures quit growing and began to stabilize. The average number of structure removals now slightly exceeds the number of installations, which we anticipate will continue in the future, as fewer, larger structures in the deepwater are installed, and a larger number of smaller structures supporting marginal fields, are abandoned. The cumulative number of installed, removed, and active structures is shown in Figure E.36.

---

[19] According to federal regulations, all structures need to be removed from a lease within one year after production stops. However, if idle structures reside on a producing lease, the structures can remain on the lease for as long as the lease is in production.

5.7.2. Producing Structures

The number of structures producing hydrocarbons in the GOM each year is shown in Figures E.37 and E.38. The number of producing structures is dynamic, similar to a "pool", where new (producing) installations or idle structures that re-enter production add to the inventory, and decommissioned producing structures deplete the inventory. A producing structure may also stop production for a period of time, perhaps due to hurricane damage or reservoir problems, temporarily reducing the producing structure count, only to re-enter the inventory at a later time.

Producing structures are classified according to their primary production using the gas-oil ratio threshold GOR = 10,000 (Figure E.37). Gas structures began to outnumber oil structures in 1978, and currently represent about 65 percent of the total inventory of producing structures in the GOM (Figure E.38). The sharp decline in the number of producing structures in 2006 is due to the impact of the 2005 hurricane season: producing structures declined from 2,328 in 2005 to 2,017 in 2006. At the end of 2006, there were 813 oil structures and 1,204 gas structures in the GOM.

5.7.3. Non-producing Structures

The number of non-producing (idle) structures in the GOM is computed as the difference between the number of active structures in a given year and the number of producing structures. The count of non-producers includes auxiliary structures, and as mentioned previously, at an aggregate level it is not possible to distinguish between those structures that serve a useful function and those structures that do not. The number of non-producing structures in the GOM on a historical basis is recreated in aggregate (Figure E.39) and as a percentage[20] of the total number of active structures (Figure F.40). Over the past several decades, the percentage of the total infrastructure in the GOM that is non-producing has remained relatively constant.

5.8. Structure Production Statistics

5.8.1. Aggregate Production

Annual oil (and condensate) and gas (including associated gas) production from GOM structures is shown in Figures E.41 and E.42. Oil structures produce the majority of oil production with relatively small amounts of condensate contributed by gas structures. Oil structures produce a significant amount of associated gas, currently about a third of total gas production. Gas production from "oil" wells and condensate production from "gas" wells will correlate with primary output stream. Cumulative oil and gas production from oil and gas structures is shown in Figures E.43 and E.44.

---

[20] The percentage values before 1960 appear quite high, and may be due to reporting problems and/or other data integrity issues, or may simply be reflective of the immature state of the industry at the time.

5.8.2. Oil Producers

The contribution to total oil production from low (marginal), medium, and high producer groups is shown in Figure E.45. Marginal producers contribute less than 0.1 percent total production on both an annual and cumulative basis (Figure E.46). Gas production from oil structures is shown in Figure E.47.

The number of oil structures that produce less than 15 BPD, between 15-200 BPD, and more than 200 BPD as shown in Figures E.48 and E.49. The number of oil structures categorized as marginal producers has remained relatively stable for the past 25 years, similar to the number of structures in the medium and high producer category. Gas production from oil structures is depicted in Figures E.50 and E.51.

5.8.3. Gas Producers

The contribution to total gas production from the low (marginal), medium, and high producer groups is shown in Figures E.52 and E.53. Liquid production from gas structures is shown in Figure E.54.

The number of gas structures categorized according to daily gas production is shown in Figures E.55 and E.56. High producer groups constitute the majority of active gas structures and contribute more than 95 percent of total annual production and cumulative production. While marginal producers account for about 4.6 percent of total active structures, their gas production is less than 0.1 percent on both an annual and cumulative basis.

Oil production from gas structures is shown in Figures E.57 and E.58. Marginal producers contribute a significant amount of liquid production, due to the changing nature of the gas reservoir near the end of their life.

Chapter 6. Shallow Water Committed Assets Production Forecast

The purpose of this chapter is to forecast oil and gas production from shallow water committed assets in the GOM. Shallow water is defined as water depth less than 1,000 ft and committed assets refer to the collection of all existing structures circa December 2006. We present a general overview of the factors that impact production and describe the units of our analysis. The basic model framework is introduced, followed by a description of the forecast methodology with worked examples. Model results are summarized.

6.1. Historical Production

About 25 percent of the United States domestic oil and gas supply comes from the OCS, and in 2007, OCS lands averaged daily production of about 1.3 million barrels (MMbbl) of oil and 7.6 billion cubic feet (Bcf) of natural gas. More than 96 percent of offshore production takes place in the GOM, and currently accounts for more than 25 percent of domestic oil production and 14 percent of domestic natural gas. Historical trends in oil and gas production on a BOE basis is shown in Figure F.1.

Oil production in the GOM rose rapidly in the 1960's, peaked in 1971, and has undergone cycles of increase and decline. From 1991 through 2001, oil production increased, leveling off through 2003, and then declined in 2004-2005, due in large part to hurricane activity. Since 1997, shallow water production has steadily declined, while deepwater production does not yet appear to have peaked (Figure F.2). Gas production in the Gulf has fallen steadily from 2001. Shallow water gas production has dropped beginning from 1996, with deepwater production unable to prevent an overall decline in total production levels (Figure F.3).

6.2. Factors that Impact Production

Oil and gas fields are developed in accord with the drive mechanisms of the reservoir, fluid characteristics, the investment decisions of operators, geologic constraints, the technology available at the time of development, infrastructure and market requirements, and many other factors. Production is the direct result of development and operational decisions, as well as events driven by factors which cannot be predicted – such as the price of oil and gas, and regulatory requirements – and events that interrupt production – such as extreme weather, equipment failure and problem wells. Additional factors such as the level of data aggregation will also impact the measurement of production volatility. A combination of design factors and exogenous conditions determine the production profiles that are observed in practice.

6.2.1. Drilling Schedule

The production rate of a structure will fluctuate as the number of producing wells change. During the development period, as the number of wells increase, the production rate of the structure will increase. As wells mature and the formation is depleted, structure production will decline. Not all wells will reach their economic limit at the same time, however, and as wells are shut-in or temporarily abandoned, the decline rate will accelerate. Well production begins and ends at different periods of time, and so depending on the drilling schedule, production profiles will exhibit various shapes. Near the end of the life of a structure, there may only be one or two wells producing, as opposed to a dozen or more wells at the start of development. Problems with wells at the end of the field life will have a more significant impact on production than earlier in the life cycle of the field.

6.2.2. Level of Aggregation

There are many choices when selecting the level of aggregation, grouped broadly across fluid type, spatial categories, and time dimension. The level of aggregation and time dimension selected will impact the appearance and statistical characteristics of production profiles. A well produces from one or more formation zones and each well is associated with a unique structure. A field will require one or more structures for development, which may be contained within one lease or overlap two or more leases. A field is a geologic structure while a lease is an artificial (man-made) geographic construct. Production is reported on a monthly basis and may be aggregated at any higher time dimension (semiannual, annual, etc.).

6.2.3. Reservoir Drive Mechanism

There are several sources of energy available to move reservoir fluids to the wellbore, and the type of drive mechanism and the geometry (depth, areal extent, shape) of the reservoir will affect decisions on the location and number of wells and the manner in which a field is developed. The primary drive mechanisms that provide the energy for oil production include: solution gas drive, water drive, and gas-cap drive. For gas production, gas expansion and water drives are common. Reservoirs are usually subject to more than one drive mechanism over the life of the asset and can be used to explain the general shape of production profiles, the producing gas-oil ratio, and extent of water cut.

6.2.4. Enhanced Recovery

A producing reservoir is a depleting resource that will exhibit declining production at some point during its life cycle. After or during primary recovery, secondary recovery techniques such as waterflooding may be initiated. Other enhanced recovery techniques such as CO_2 flooding, chemical injection, heat treatment, etc. may also be implemented if the economics are favorable. The primary economic driver for secondary and tertiary recovery is project profitability. A number of offshore fields in the GOM are under secondary recovery, primarily water flooding and gas re-injection for pressure maintenance, but there are no enhanced oil recovery projects in the GOM.

6.2.5. Fluid Classification

Each reservoir contains a unique blend of hydrocarbon compounds and exists under conditions specific to the site and nature of deposition, and so no two reservoirs are developed or behave the same when produced. Produced water is often a major output stream. Processing facilities separate the various phases and treat each stream before transportation to shore. The basic system collects production from each well or zone through an individual flowline. The flowlines are manifolded together and production from the combined well streams goes to the bulk separator. Liquid hydrocarbons are collected and sent to an oil treater, where it is sometimes necessary to heat the oil to facilitate the removal of latent gas and water. Produced water is treated to remove the latent oil and gas and is then injected back into the reservoir or deposited into the ocean. Declines in productivity generally coincide with changes in reservoir pressure which affects the physical chemistry of reservoir fluids and the cost of treatment.

6.2.6. Development Plan

A development plan will normally include the structure type, equipment capacity, and the number, location, and timing of development wells. Engineers design the production rate to maximize field profitability within the constraints of the optimal production rate – the maximum rate at which a well or field can be produced – without wasting reservoir energy or leaving oil in the reservoir. The maximum efficient production rate is usually designed to range between 3 – 8 percent of the recoverable reserves. To obtain a high ratio, the operator will need to have a large number of producing wells and adequate production equipment to handle the volumes of oil and gas produced. A low ratio provides an indication that an operator has chosen to drill less wells and produce longer. Fewer wells require smaller production, processing, and transportation facilities; less operating personnel; reduced financing cost, and presumably, lower operating expenditures. Fields generally deplete faster than operating costs decline, so as production falls, the cost per barrel will typically increase unless the asset is divested or farmed-out to a lower cost operator.

Production is generally considered to follow three phases: ramp-up, plateau, and decline. In practice, there is no one general model that can be used to describe production. Following the installation, hookup, and certification of the platform, development drilling is carried out and production started after a few wells are completed. The plateau period represents the maximum rate of production the facilities were designed to handle, pipeline capacity, or contractual constraints. The duration of the plateau is based upon the productivity of the reservoir and the economies of the project. After peak production, fields will decline due to the geology and pressure loss at a rate determined by the reservoir drive, investment, and economic conditions.

6.2.7. Reservoir Pressure

In order to be produced, reservoir fluids have to flow through the pore space of the rock, into the wellbore, and up through tubing to the surface facilities. After a well is drilled, a pressure sink is created at the wellbore, which allows oil and gas to flow because of the pressure differential. As the reservoir pressure depletes, the friction across the formation and through the tubing drops the pressure further, and the production rate declines. Changes in reservoir pressure affect the physical chemistry of reservoir fluids, and at some point in time, artificial lift methods will be required to continue production. How long a well flows before artificial lift is required depends on initial pressure and maintenance programs, water cut, fluid viscosity, and many other factors. Gas fields flow until the reservoir pressure approaches separator pressure conditions.

6.2.8. Workover Schedule

Several times during the life of a producing well, the well will be shut in and remedial work performed to maintain, restore, or improve production. This is called a workover. A workover may involve solving mechanical problems (such as collapsed casing, casing holes, collapsed tubing), cleaning out the well (from scale, waxes, and sand), stimulation, or replacing downhole equipment (such as leaking tubing, malfunctioning gas-lift valves, or leaking packers). A well can be recompleted to plug and abandon a zone on the bottom of a well and completed in a higher zone, to drill deeper, or to sidetract in a lateral direction. Workover activity will take production streams off line temporarily, and when the well re-starts production, the flow rates and decline parameters may be subject to a step change.

6.2.9. Problem Wells

A well may go off production due to mechanical reasons (e.g., equipment failure if pumping), wellbore damage (e.g., from unconsolidated sands), extraneous water production (e.g., due to a casing leak or bad cement job), or other issues such as flow assurance. One of the primary reasons to maintain a periodic workover schedule is to reduce and/or minimize the occurrence of problem wells and subsequent production interruption.

6.2.10. Cost Structure

Onshore, decline curves are often characterized by relatively smooth decreasing functions, while offshore, the additional uncertainty and risk of the operating environment contributes to a more volatile production profile. The cost of operating and maintaining offshore infrastructure is more expensive and uncertain than onshore, which will also negatively impact an operator’s ability to sustain commercial production late in its life. Structures are abandoned as high operating costs set an economic limit that typically range from 3 – 7 times higher than for comparable onshore operations (Brashaer et al., 1982).

6.2.11. Weather Events

There are many exogenous events that contribute to production volatility and weather is a primary factor. Offshore production occurs in an uncertain and hostile environment, where weather, supply vessel delays, and other events may temporarily disrupt or significantly impair production. The occurrence of extreme weather forces operators to shut down facilities and evacuate personnel. Hurricanes will suspend production for at least several days, and sometimes, weeks or months at a time, and the magnitude of the disruption relative to the time scale of aggregation will determine the impact observed. In physical terms, shutting-in a well will usually not cause a loss of the hydrocarbon resource, but in financial terms, the impact of deferred production can have a significant economic effect. Operators attempt to recover deferred production by increasing production “at the margins,” but because operators usually produce at the maximum design rate allowed by the reservoir dynamics or equipment capacity, the ability to increase production is often limited without additional capital investment.

6.2.12. System Reconfiguration

Reconfiguration, restaging, and optimization of surface facilities and subsea architecture are commonly applied to maximize production and increase recovery when bottlenecks arise or production levels reach threshold levels. Production will be offline during some or all of a redevelopment period.

6.2.13. Price Effects

Operators control the production rate of oil and gas and generally produce at capacity to maximize return on investment, but differences may arise in how oil and gas is produced. Oil is a global commodity while gas is often produced to satisfy local demand. Changes in the local demand and supply balance of gas will impact prices, which will impact production decisions to varying degree. Associated gas is produced in conjunction with crude production, and since crude is almost always produced at capacity, the quantity of associated gas is a byproduct of oil production and outside the operator's control. Non-associated gas is expected to be more sensitive to price fluctuations to maximize profitability; i.e., gas production from non-associated reservoirs may be reduced in the summer season in anticipation of higher gas prices during the winter season. This sort of operational flexibility is generally not present with associated gas production.

6.2.14. Regulations and Operating Policy

The occurrence of extreme weather in the GOM requires operators to decide what facilities to shut-down and when. Decisions are operator, facility, and event specific, guided by the level of risk tolerance of the operator and knowledge regarding the expected storm path. MMS regulations require operators to evacuate all personnel before the latest safe departure time and shutdown all production activity affected. During the early years of GOM production, gas was allocated, and so output was constrained by government regulation rather than market forces, but today, this is no longer an issue.

6.3. Production Classification

Offshore structures come in many different types and sizes and can be characterized in a number of ways, similar to well characterization. Structures are classified into four subcategories denoted as: (I) Young, (II) Normal, (III) Chaotic, and (IV) Latecomer. A fifth subcategory is used to identify structures with missing identification: (V) Unknown. Recall that young structures are defined to be any structure with less than 7 years production. Normal structures have production profiles that are best-fit by decline curves with $R^2 \geq 0.75$, while chaotic structures have best-fit decline curves with $R^2 < 0.75$. Latecomers have a production history 7 years or more, and a peak occurring within the past 7 years. Unknown structures have missing identifiers on structure type, water depth, or similar attribute that prevent their classification. The number of active structures classified by primary production and structure type are shown in Table F.1.

6.4. Forecast Methodology

The methodology used to forecast production across each structure class is now described. For young structures, a production forecast is achieved through a history match, using the statistical characteristics of structures that have been previously removed as the matching set. Normal and chaotic structures have produced to a condition of pseudo steady-state flow which allows curve fitting with standard regression techniques. Latecomers exhibit unusual profiles, usually late peaks, that do not permit standard curve fitting techniques to be employed. For latecomer structures, various heuristic techniques are applied to generate forecast curves. In the next section, examples with step-by-step calculations are used to illustrate the manner in which forecasting is achieved.

6.4.1. Young Structures – History Matching

Structures with a short production history pose difficulties in forecasting because the structure is unlikely to have achieved its peak production and the limited sample population cannot support regression analysis. What constitutes a "young" (or new) structure is, of course, somewhat subjective, and we select 7 years as the threshold[21] to denote young structures. All structures with less than 7 years production are classified within the young class category.

To forecast the future production of a young structure, we match the cumulative production of the structure with "similar" structures that have been previously removed in the GOM. Similarity is defined according to structure type, water depth, and primary production. The production history of an average structure removed within each categorization that most closely resembles the cumulative production of the structure at the time of observation is used as the forecast curve. The details of how this is accomplished follows.

Young structures are classified according to structure type (ST), water depth (WD) and primary production (OIL/GAS). Three structure types (caisson, well protector, fixed platform), three water depth categories (<60ft, 60-200ft, >200ft), and two production groups (oil, gas) are employed for a total of 3*3*2 = 18 categories, denoted by Γ_{ijk}, i, j = 1, 2, 3; k = 1, 2, or alternatively, Γ (ST, WD, OIL/GAS). Within each category Γ_{ijk}, a number of subcategories γ_{ijk} are created based upon the size of the sample set.

From 1973-2006, a total of 1,867 gas structures and 477 oil structures were removed in the GOM. These structures were categorized according to structure type, water depth, and primary production, and then depending on the number of structures N within the category Γ_{ijk}, average production profiles $\bar{q}(\gamma_{ijk}, t)$ for each subcategory γ_{ijk} was computed. The number of profiles computed (i.e., the number of subcategories) increases with the number of elements N in the sample. If $N \le 25$, 3 average production profiles are computed. For $25 < N < 50$, 5 average profiles were computed, and for $N \ge 50$, 10 average profiles were used. Hence, there are either

[21] We recognize that our age cut off is arbitrary, but the selection is robust in the sense that neither the size of our sample set nor the results of our modeling differ dramatically with small changes in the cut-off point.

3, 5, or 10 average profiles $\bar{q}(\gamma_{ijk},t)$ within each main category Γ_{ijk}. The distribution of subcategories that result is shown in Table F.3.

Average production profiles are computed for each category and used as reference (comparison) profiles. We illustrate 3 of 18 categories that were employed in Figures F.4 – F.6. In Figure F.4, the five average BOE production profiles in the fixed platform, 0 – 60 ft water depth, oil production, subcategory is depicted. In Figure F.5, the average BOE profiles for the caisson, 60 - 200 ft, gas production, subcategories are depicted. In Figure F.6, the average BOE profiles for the well protector, 60-200 ft water depth, oil production, subcategories are shown. Profiles may not be smooth or yield strictly decreasing trends because they represent sample averages. Trends are reasonably consistent, however, with production increasing, on average, according to structure type and water depth category.

The cumulative production of structure s of age T, $Q(s,T)$, is compared with the cumulative production from each subcategory profile at the same age T, $\bar{Q}(\gamma_{ijk},T) = \sum_{t=1}^{T}\bar{q}(\gamma_{ijk},t)$, and the profile with the smallest absolute difference is selected as the best match:

$$\bar{Q}^*(\gamma_{ijk},T) = \min_{\gamma} \left| Q(s,T) - \bar{Q}(\gamma_{ijk},T) \right|.$$

The annual production curve corresponding to $\bar{Q}^*(\gamma_{ijk},T)$ is $\bar{q}^*(\gamma_{ijk},t)$ and is used as the structure match. $Q(s,T)$ will either be greater or less than the category cumulative production, $\bar{Q}^*(\gamma_{ijk},T)$, and so we adjust the profile using the multiplier α,

$$\alpha = \frac{Q(s,T)}{\bar{Q}(\gamma_{ijk},T)}.$$

Note that if $Q(s,T) < \bar{Q}(\gamma_{ijk},T)$, $\alpha < 1$, and if $Q(s,T) > \bar{Q}(\gamma_{ijk},T)$, $\alpha > 1$. The final step is the identification of the structure production with the category average:

$$q(s,t) = \alpha\,\bar{q}^*(\gamma_{ijk},t),\ t > T.$$

A summary of the history matching procedure for young structures is presented in Table F.4.

6.4.2. Normal and Chaotic Structures – Regression Techniques

Decline curve analysis is a common method used for analyzing reserves in areas with established performance trends and was previously described in Chapter 2. The decline curve method extrapolates an established trend into the future, assuming that the wells have been produced to a steady-state flow and that whatever conditions that influenced the behavior of the well in the past will continue to influence it in the same way in the future. A summary of the best-fit curve parameters for normal and chaotic structures are shown in Table F.5. For each structure class and production type, the best fit curves are depicted by frequency along with the average coefficients for the model parameters and average R^2-values.

6.4.3. Latecomer Structure - Heuristics

The production curves of some structures may yield multiple peaks during their lifetime, often due to changes in capital investments or production problems. Multiple production peaks after plateau are common. Pre-plateau peaks may also occur if development occurred in stages or unforeseen events arose during development. There are several ways to handle these profiles, and we choose to use heuristic techniques to generate the forecast. The most common heuristic method adopted was to truncate the production history and fit a decline curve from the most recent production peak of the structure. If an adequate number of observations to perform regression is not available, an assumed exponential model form and decline parameter was adopted.

6.5. Illustrative Examples

6.5.1. Young Structures – History Matching

Structure 587 is a caisson in 63 ft water depth with a GOR = 590,000. First production began in 2000, and by 2006, cumulative production was 2.08 MMBOE.

From the removed structure category Γ(CAIS, 60-200, GAS), we compare the cumulative BOE production of structure 587 with the cumulative production from each of the 10 subcategories in year six (Table F.6). The cumulative production of structure 587 is closest to subcategory 10, which is selected as the reference category for the structure (Figure F.5). The ratio of the structure's cumulative production to subcategory 10 cumulative production is α =2.08/2.36 = 0.88.

The forecast production of structure 587 in the seventh year is computed from the average BOE production of subcategory 10 in the seventh year multiplied by the adjustment factor α:

$$q^{BOE}(587,7) = 0.88 \times 169{,}353 = 149{,}312 \text{ BOE}.$$

The production stream is then decomposed into its oil and gas components assuming a constant GOR = 590,000:

$$q^{o}(587,7) = 149{,}312 \text{ BOE} \times \frac{1}{(1+\dfrac{590{,}000\text{cf}}{\text{bbl}}\times\dfrac{\text{bbl}}{6{,}000\text{cf}})} = 1{,}503 \text{ bbl}$$

$$q^{g}(587,7) = (149{,}312 \text{ BOE} - 1{,}503 \text{ bbl}) \times 6 \text{ Mcf/BOE} = 886{,}853 \text{ MMcf}$$

This process is repeated each year using the subcategory 10 profile as reference forecast and assuming a constant GOR throughout the life cycle of the structure. The forecasted production profile of structure 587 is shown in Figure F.7.

If oil and gas maintain an average price of \$80 per barrel and \$8 per Mcf over the production lifetime of the structure, 587 is forecast to cease production in the year 2014 when the structure's revenue (\$621,847) is equal to its economic limit.

6.5.2. Normal Structure – Regression Techniques

Structure 33 is a typical normal structure. First oil began in 1997 and production peaked a year later. The best fit regression was determined to be an exponential model with $R^2 = 0.99$ (Figure F.8):

$$q^{BOE}(33,t) = q^{BOE}(33,0) \times e^{-0.4821t}.$$

The peak year is set as time 0. In 2007, the BOE production is forecast to be:

$$q^{BOE}(33,9) = 1{,}156{,}791 \text{ BOE} \times e^{-9\times 0.4821} = 15{,}090 \text{ BOE},$$

which yields the expected future production profile shown in Figure F.9. The GOR is used to decompose the BOE production stream into oil and gas production:

$$q^{o}(33,t) = q^{BOE}(33,t) \times \frac{1}{1+\frac{GOR}{6000}}$$

$$q^{g}(33,t) = q^{BOE}(33,t) - q^{o}(33,t)$$

The cumulative GOR of structure 33 is 1,190. In 2007, the expected annual oil and gas production is 12,592 bbl and the expected annual gas production is 14,987 Mcf:

$$q^{o}(33,9) = 15{,}090 \text{ BOE} \times \frac{1}{1+\frac{1{,}190}{6{,}000}} = 12{,}592 \text{ bbl}$$

$$q^{g}(33,9) = (15{,}090 \text{ BOE} - 12{,}592 \text{ BOE}) \times 6 \text{ Mcf/BOE} = 14{,}987 \text{ Mcf}$$

Production is expected to stop when revenue falls below the operating threshold. Assuming oil and gas prices average \$120/bbl and \$12/Mcf over the forecast horizon, production will cease in 2011 when the structure revenue (\$245,776) equals its economic limit. Historical and projected oil and gas production is shown in Figure F.10.

6.5.3. Chaotic Structure – Regression Techniques

Structure 152 is a caisson in 18 ft water depth and a gas producer with a GOR = 231,642. Structure 152 has a 9-year production history, and because the best-fit curve is an exponential model with $R^2 = 0.69$, we classify the structure as a chaotic producer and apply regression modeling. The exponential curve has the form,

$$q^{BOE}(152,t) = 368{,}601 \times e^{-0.2794\,t},$$

and in 2007, the BOE production is $q^{BOE}(152,9) = 368{,}601e^{(-0.2794 \times 9)} = 29{,}803$ BOE, yielding an oil and gas production stream:

$$q^{o}(152,9) = q^{BOE}(152,9) \times \frac{1}{1+\dfrac{231{,}543}{6{,}000}} = 753 \text{ bbl}$$

$$q^{g}(152,9) = (29{,}803 \text{ BOE} - 753 \text{ BOE}) \times 6 \text{ Mcf/BOE} = 174.3 \text{ MMcf}$$

For \$120/bbl oil and \$12/Mcf gas, the expected revenue in 2007 is computed to be \$2,181,960. Under this price scenario, the structure is expected to stop producing in 2012 at its economic limit of \$539,520 (Figure F.11).

6.5.4. Latecomer Structure - Heuristic Method

Structure 23266 is a fixed platform in 219 ft water depth that is primarily a gas producer (GOR = 12,533). Multiple production peaks require care in modeling, and ultimately, forecasting from such structures remains subject to significant uncertainty. We truncate the first half of the production profile in Figure F.12 and determine the peak year of the second half (Figure F.13). Since there are 8 observations in the truncated history, the sample population is sufficient for regression analysis. The best-fit decline curve is a harmonic function with n = 1.876 and c = 0.00074.

Structure 10042 illustrates another variation of latecomer structures (Figure F.14). In this case, since there are only a few years of empirical data from peak production, we assume that production declines following an exponential curve at rate d:

$$q^{BOE}(10042,t) = q^{BOE}(10042,0) \times e^{-dt}$$

In 2006, structure 10042 has 255,053 BOE production. For d = 0.1, the expected BOE production of structure 10042 in 2007 is:

$$q^{BOE}(10042,1) = 255{,}053 \text{ BOE} \times e^{(-0.1 \times 1)} = 230{,}782 \text{ BOE}$$

The GOR of the structure is 125,967, yielding the oil and gas production streams $q^{o}(10042,1)$ = 10,493 and $q^{g}(10042,1)$ = 1.32 Bcf. At \$120/bbl oil and \$12/Mcf gas, the revenue in 2007 is computed to be \$17.1 million. Structure 10042 is expected to stop producing in 2041.

6.6. Model Results

6.6.1. Active Structure Forecast

The average number of committed shallow water structures is shown in Figure F.15 across a 40-year time horizon. In 2006, 380 of the 2364 shallow water producing structures fall below their economic threshold and were removed from analysis, reducing the inventory of committed assets as shown in Table F.7. Producing structures start out economic, but as production declines, operating expenditures increase and commercial structures will transition into marginal status, and eventually, stop production at their economic limit. The trajectory of active structures represents the average of multiple simulations that varied oil and gas prices, economic limits, and discount rates according to the distribution functions shown in Table F.8. A one standard deviation envelope is used to bound the average trajectory, and assuming normality conditions on the model parameters, the trajectory of the active structure count is expected to stay within the envelope about two-thirds of the time.

6.6.2. Production Forecast

The oil, gas, and BOE production forecast for committed shallow water structures are illustrated in Figures F.16 – F.18. Production profiles exhibit the same decreasing trend as the average count trajectory. One and two standard deviation envelopes bound the results.

In Figures F.19 and F.20, the annual and cumulative BOE production profile per structure class is depicted. In Figure F.20, we observe that young and normal structures are responsible for nearly two-thirds of cumulative production from the committed asset inventory. Latecomer structures are also a significant producing class. In Figures F.21 and F.22, the annual and cumulative gas production for each asset class is depicted; and in Figures F.23 and F.24, the annual and cumulative oil production is depicted.

6.6.3. Composite Statistics

The expected amount of hydrocarbon production from committed assets in the GOM is estimated to be 1,056 MMbbl oil and 13.3 Tcf gas assuming the range of the design space given in Table F.8. The present value of hydrocarbon production from this asset class is estimated to be $149.4 billion.

6.6.4. Cumulative Production Models

Cumulative oil, gas and BOE production in the GOM is given by regression models depicted in Table F.9 and summarized as follows:

$$Q^o(d, P^o, P^g, a) = -2.1\text{E}9d + 5.5\text{E}7P^o + 5.6\text{E}8P^g + 3.5\text{E}7a$$

$$Q^g(d, P^o, P^g, a) = -2.1\text{E}10d + 6.4\text{E}7P^o + 7.0\text{E}8P^g + 2.9\text{E}7a$$

$$Q^{BOE}(d, P^o, P^g, a) = -5.6\text{E}9d + 1.6\text{E}7P^o + 1.7\text{E}8P^g + 8.3\text{E}7a,$$

where d represents the decline rate of latecomer structures that do not have a sufficient time horizon for analysis, P^o is the expected oil price ($/bbl), P^g is the expected gas price ($/Mcf), and a is the multiplier of the economic threshold. Most of the coefficients of the regression model are of the expected sign and statistically significant.

Application of the regression functions provide a quick way to infer cumulative production for any value of (d, P^o, P^g, a) selected within the design space. For example, for (d, P^o, P^g, a) =

(0.10, 140, 10, 1), the total BOE production from the committed asset set is estimated to be $Q^{BOE}(0.10, 140, 10, 1) = -5.6E8 + 2.24E9 + 1.7E9 + 8.3E7 = 3.3$ billion BOE.

6.6.5. Present Value Models

The present value functionals of the oil, gas and BOE production is given by regression models depicted in Table F.10 and summarized as follows:

$$PV^{o}(d, P^{o}, P^{g}, a, D) = -9.3E7d + 7.0E5P^{o} + 1.3E6P^{g} + 8.3E5a - 1.5E8D$$
$$PV^{g}(d, P^{o}, P^{g}, a, D) = -9.3E7d + 1.2E5P^{o} + 8.7E6P^{g} - 4.5E6a - 1.6E8D$$
$$PV^{BOE}(d, P^{o}, P^{g}, a, D) = -1.9E8d + 8.1E5P^{o} + 10.0E6P^{g} - 3.66E6a - 3.1E8D$$

The present value functionals employ the same model variables as the cumulative production, but also require the discount rate D to discount the future cash flows. Again, most of the coefficients of the regression model are of the expected sign and statistically significant, and can be used to infer present values for any input variables within the design space. Present value functions provide a quick and simple way to estimate the production value of the committed assets for given model parameters; e.g., $PV^{BOE}(0.1, 100, 10, 1, 0.15) = \$112$ billion.

Chapter 7. Meta-Model Evaluation of Marginal Production

The purpose of this chapter is to forecast the level of marginal production from the existing inventory of shallow water assets in the GOM. The model framework is outlined and the model structure described. The results of our modeling include the trajectories of structure counts over a 60-year horizon, average production profiles, and expected cumulative production and valuation functions.

7.1. Model Framework

7.1.1. General Procedure

A meta model methodology is described to quantify the quantity and value of marginal and economic production. The approach is as follows.

Step 1. Sample the input parameters d, P^o, P^g, m, a, D from their respective distribution functions.

Step 2. (a) Forecast future oil and gas production, $q^o(s,t)$ and $q^g(s,t)$, and revenue, $r(s,t)$, based on the model specifications described in Step 1.

(b) Determine the time when each committed asset turns marginal and uneconomic based on the marginal threshold, $\tau_m(s)$, and economic limit, $\tau_a(s)$, respectively. Denote the time a structure turns marginal and uneconomic as $T_m(s)$ and $T_a(s)$.

(c) Decompose each structures production profile into "economic" and "marginal" components. The economic component of production $q_e^t(s)$ is defined for $t \le T_m(s)$, while the marginal component $q_m^t(s)$ is defined for $T_m(s) < t \le T_a(s)$.

(d) Compute the cumulative oil and gas production for each structure according to its economic and marginal status, $Q_e^i(s)$ and $Q_m^i(s)$, and the associated discounted cash flows, $V_e(s)$ and $V_m(s)$.

Step 3. Aggregate total oil and gas production for all structures in the shallow water Gulf of Mexico, $Q^o(\Gamma)$ and $Q^g(\Gamma)$, and compute the total value of production, $V(\Gamma)$.

Step 4. Repeat Step's 1-3, and regress the model output $\{Q^o(\Gamma), Q^g(\Gamma), V(\Gamma)\}$ against the input variables (d, P^o, P^g, m, a, D) to construct functional relations describing cumulative production and value.

7.1.2. Preprocessing (STEP 0)

Each producing structure in the Gulf of Mexico is classified into one of five categories based upon the age of the structure, the nature of its production profile, and the completeness of information available. The classes Young, Normal, Chaotic, Latecomer, and Unknown were defined previously in Chapters 2 and 6. The committed shallow water structures are classified according to class and primary production as follows: 525 young structures, 1,280 normal structures, 90 chaotic structures, 427 latecomers, and 42 unknown structures (Table G.1).

7.1.3. Initialization (STEP 1)

The user selects the model variables and quantifies the manner in which they vary. The input set is user-defined and varies with the objectives of the problem and the model formulation. The variables that we employ include: the price of oil and gas (P^o, P^g), the marginal and abandonment threshold multipliers (m, a), and the discount rate (D). A decline parameter is associated with those latecomer structures that do not have a sufficient production history to perform regression analysis. In this case, we assume an exponential model with decline rate d. The input parameters of the model are denoted by the vector (d, P^o, P^g, m, a, D).

Each system parameter is governed by a distribution function f_i, $i = 1,\ldots, 6$, that is assumed invariant[22] across time. The specification of each function is determined by empirical analysis or user preference. For example, if the historic price of oil is determined to follow a Lognormal distribution according to the parameters μ and σ^2, $P^o \sim \mathrm{LN}(\mu,\sigma^2)$, the user may model future prices according to this specification or may prefer to assume another distribution type, such as the Uniform distribution U(a,b) with endpoints (a,b).

The distribution functions of the model variables that we select in this analysis are shown in Table G.2. We refer to the set of all input variables and their distribution functions as the design space.

7.1.4. Forecasting (STEP 2)

(a). The model curves determined in preprocessing are used to forecast future oil and gas production under the assumption that production will not be altered in the future from reservoir/production problems or additional investment. The assumption of "stable reservoir and investment conditions" is required to eliminate additional sources of uncertainty that we are not prepared to model.

The production forecast for each structure for each hydrocarbon stream i (i = oil, gas, BOE) are initialized in the year 2006 ($t = 1$):

$$q^i(s) = (q^i(s, 1), q^i(s, 2), \ldots).$$

Revenue is estimated by multiplying the oil and gas production forecast by the average market hub prices in the year received. The hydrocarbon quality (API gravity, sulfur content, etc.) and transportation expense (netback cost) to deliver production to market is not considered. Revenue in year t for structure s is computed as

[22] It is possible to allow the system parameters to vary with time, but the additional complexity involved with this modification requires a significant investment in processing capability and modeling structure. It is for this reason that we do not allow input variables to vary across time within a given simulation run.

$$r(s, t) = q^{o}(s, t)\, P^{o}(t) + q^{g}(s, t)\, P^{g}(t),$$

where $P^{o}(t) = P^{o}$ and $P^{g}(t) = P^{g}$ represent the oil and gas price in the year t which is assumed constant throughout the life cycle of the structure. The revenue forecast vector is denoted as:

$$r(s) = (r(s, 1), r(s, 2), \ldots).$$

(b). The time at which a structure becomes marginal or economic is determined by comparing its revenue in year t, $r(s, t)$, to a marginal threshold, specific to the structure, $\tau_m(s)$:

$$T_m(s) = \min\{t \mid r(s,t) < m \cdot \tau_m(s)\},$$

where m is a user-defined multiplier that is used to capture the sensitivity of the model output to variation in parameter uncertainty.

The time at which a structure is no longer profitable is determined by comparing the revenue in year t, $r(s, t)$, to the economic limit of the structure, $\tau_a(s)$:

$$T_a(s) = \min\{t \mid r(s,t) < a \cdot \tau_a(s)\},$$

where a is user-defined multiplier that plays a role similar to m, but in this case, tests the model results against the sensitivity of the economic limit.

The values of $\tau_a(s)$ are determined by historic data as described in (Kaiser, 2008a) and applied previously in Chapter 6, while $\tau_m(s)$ is set as a multiple of $\tau_a(s)$. $T_m(s)$ denotes the time when structure production transitions from economic to marginal status. $T_a(s)$ denotes the time when production at the structure is no longer profitable and cash flow terminates:

$$r(s) = (r(s,1), r(s,2), \ldots., r(s,T_a(s))).$$

For convenience, we assume that once a structure reaches its economic limit it will be removed from the GOM. According to federal regulations, structures only need to be removed from a lease once lease production stops. A structure that reaches its economic limit can thus be "held" by lease production, and this can be built into the model (e.g., Kaiser, 2008b), but we have not pursued this development.

(c). At some point in time during the life of every structure, an asset will transition from economic to marginal status and continue to produce marginally until it becomes unprofitable. The production profile of each structure is decomposed into economic and marginal components:

$$q^{i}(s) = (q(s,1), \cdots, q(s,T_m - 1), q(s,T_m), \cdots, q(s,T_a)),$$

where the "economic" production components are defined by $q(s,t)$, $t = 1, \ldots, T_m-1$, and the "marginal" components are defined for $t = T_m, \ldots, T_a$. At any point in time, a structure is either "economic" or "marginal."

The revenue stream is similarly segmented into economic and marginal components corresponding to the economic and marginal components of production:

$$r(s) = (r(s,1),\cdots,r(s,T_m-1),r(s,T_m),\cdots,r(s,T_a)) = (r_e(s),r_m(s)),$$

where, $r_e(s) = (r(s,1),\cdots,r(s,T_m-1),0,\ldots,0)$ and $r_m(s) = (0,\ldots,0,r(s,T_m),\ldots,r(s,T_a))$.

(d). The cumulative production $Q(s)$ and discounted cash flow $V(s)$ associated with structure s is decomposed into its economic and marginal components for oil, gas, and BOE output streams, beginning from 2006 ($t = 1$) through the time the structure reaches marginal status ($t < T_m(s)$), and thereafter, until the structure is no longer economic ($T_m(s) \le t < T_a(s)$):

$$Q_e^i(s) = \sum_{t=1}^{T_m-1} q_t^i(s), \quad Q_m^i(s) = \sum_{t=T_m}^{T_a} q_t^i(s), \quad Q_T^i(s) = Q_e^i(s) + Q_m^i(s).$$

The discounted present value of the economic and marginal production streams are computed similarly:

$$V_e(s) = \sum_{t=1}^{T_m-1} \frac{r_t(s)}{(1+D)^t}, \quad V_m(s) = \sum_{t=T_m}^{T_a} \frac{r_t(s)}{(1+D)^t}, \quad V_T(s) = V_e(s) + V_m(s).$$

The value of D denotes an industry-wide discount rate.

7.1.5. Aggregation (STEP 3)

The model output for structure s is the forecast production profiles, $q_e^i(s)$ and $q_m^i(s)$; production status vectors, $\sigma_e(s)$ and $\sigma_m(s)$; cumulative production, $Q_e^i(s)$, $Q_m^i(s)$, $Q_T^i(s)$; and discounted cash flows, $V_e(s)$, $V_m(s)$, and $V_T(s)$. The collection of all shallow water structures in the GOM is denoted as Γ and the aggregation is presented as:

$$\sigma_e(\Gamma) = \sum_s \sigma_e(s), \quad \sigma_m(\Gamma) = \sum_s \sigma_m(s).$$

$$q_e^i(\Gamma) = \sum_s q_e^i(s), \quad q_m^i(\Gamma) = \sum_s q_m^i(s).$$

$$Q_e^i(\Gamma) = \sum_s Q_e^i(s), \quad Q_m^i(\Gamma) = \sum_s Q_m^i(s), \quad Q_T^i(\Gamma) = Q_e^i(\Gamma) + Q_m^i(\Gamma).$$

$$V_e(\Gamma) = \sum_s V_e(s),\ \ V_m(\Gamma) = \sum_s V_m(s),\ \ V_T(\Gamma) = V_e(\Gamma) + V_m(\Gamma).$$

7.1.6. Simulation and Regression Analysis (STEP 4)

The input parameters for each loop of the simulation include (d, P^o, P^g, m, a, D), and the output includes $\{\sigma_e(\Gamma), \sigma_m(\Gamma), Q_T^o(\Gamma), Q_T^g(\Gamma), V_e(\Gamma), V_m(\Gamma), V_T(\Gamma)\}$. The model curves used to forecast production is fixed, with the exception of structures in the latecomer class, where a subset of profiles are modeled with an assumed decline parameter. The values of (d, P^o, P^g, m, a, D) are sampled from distribution functions for each loop in the cycle, the output metrics are computed, and after a sufficient number of iterations have been performed, the model outputs are regressed against the input parameters.

7.2. Model Structure and Interpretation

7.2.1. Model Specification

A linear model is specified that relates the output measures to the input parameters, as follows:

$$f = \alpha_0 + \sum_{i=1}^{6} \alpha_i X_i\ ,$$

where f is selected from the set $\{Q_e^i,\ Q_m^i,\ Q_T^i,\ V_e,\ V_m,\ V_T\}$ and (X_1, X_2, X_3, X_4, X_5, X_6) = (d, P^o, P^g, m, a, D). A linear model is specified for simplicity and ease in interpretation, and if the model fits are unacceptable, it is straightforward to apply a general nonlinear specification. The model coefficients α_i, i = 0, …, 6 are unique to the selection of f and will vary with the size and shape of the design space of the input parameters.

7.2.2. Expected Signs

The signs of the model coefficients are expected to follow certain values, which can be motivated through economic theory and the mechanics of the model structure. A check on the signs of the model coefficients provides a first indication of the veracity of the model results.

The coefficient α_0 represents the fixed term (intercept) of the functional and its sign is indeterminate. The fixed term coefficient may be excluded from the formulation, depending upon user preference and model specification.

The coefficient α_1 is associated with d, which defines the rate of decline of production for a subset of latecomer structures. The magnitude of the coefficient α_1 relative to the other model coefficients depends upon the proportion of total production controlled by d. If d increases, holding all other model parameters fixed, structure production will decline faster and reach its economic limit sooner, and so the quantity of latecomer reserves and its value will decline. We would thus expect $\alpha_1 < 0$ for Q_e^i, Q_m^i, and Q_T^i and V_m, V_e, and V_T since increasing d will lead to declining cumulative production and value.

The coefficients α_2 and α_3 are associated with the price of oil and gas, respectively. As P^o and P^g increase, revenue streams for all assets will increase, delaying the onset of the economic limit. This will allow the production of additional reserves, and at an elevated price level, lead to a greater valuation. Thus, increases (decreases) in P^o and P^g will lead to increases (decreases) of α_2 and α_3, and so we would expect α_2, $\alpha_3 > 0$ across all the functional outputs Q_j^i and V_j^i (i = oil, gas; $j = m, e, T$). We expect differences to exist in the relative magnitude of oil and gas price for a particular asset (depending, say, if it is primarily an oil or gas producer) and on the stage of its lifecycle; e.g., if it is economic or marginal. Because the value of economic production is expected to be at least one or two orders-of-magnitude larger than a structure that is a marginal producer, oil and gas prices are expected to play a more significant role for economic production.

The coefficient α_4 is associated with the multiplier m, and the coefficient α_5 is associated with the multiplier a. These multipliers are used to vary the marginal and economic thresholds τ_m and τ_a. The impact of the multipliers will vary depending upon the functional under consideration.

The value of m ranges over a positive interval bounded below by a and above by twice the upper limit of the economic threshold interval. As m increases, $m \cdot \tau_m(s)$ will increase, and thus, production will become marginal at an earlier time, decreasing the amount of economic production (Q_e) and its value (V_e). Since marginal production occurs at an earlier time and at a higher rate, the amount of production that is classified as marginal (Q_m) will subsequently increase along with its value (V_m). The value of the coefficient α_4 is thus expected to be negative for the functionals Q_e and V_e, and positive for Q_m and V_m. For the composite production and valuation functionals Q_T and V_T, coefficient α_4 does not enter into the model formulation because there is no need to segment the production and revenue streams.

The variable a ranges over a positive interval, and as a increases, $a \cdot \tau_a(s)$ will increase, forcing production out of profitability at an earlier time. This will not have any impact on Q_e and V_e, but will reduce marginal production (Q_m) and its value (V_m). Thus, the coefficient α_5 will not enter into the economic production model but is expected to be negative for the functionals Q_m and V_m. By linearity, Q_T and V_T will also be negative. Coefficient α_5 will not enter into the Q_e and V_e functional since the amount and value of economic production is not influenced by what happens at the end of the life of the structure.

The coefficient α_6 is associated with the discount rate D used to compute present value, and thus, will only influence the valuation estimates V_m, V_e, and V_T. The behavior of discount rate with present value is obvious: as D increases, the value of future cash flow declines, and so, we expect the sign of coefficient α_6 to be negative for all three valuation functionals. Further, since changes in discount rate have a greater impact on early cash flows, we would expect that the magnitude of α_6 would be greater for V_e than V_m since it is defined earlier in the life of cycle of the asset. Coefficient α_6 is not included in the model specification for cumulative production since it is only a component of the valuation estimate.

7.2.3. Design Space

The model input parameters and assumed distribution functions are shown in Table G.2. The vector (d, P^o, P^g, m, a, D) represents our design (input) parameters and the collection of the variable intervals denote the design space:

$$\sum = \{(d, P^o, P^g, m, a, D) \mid 0.05 \leq d \leq 0.30, 80 \leq P^o \leq 160, 8 \leq P^g \leq 16, a \leq m \leq 6,$$
$$0.5 \leq a \leq 0.3, 0.08 \leq D \leq 0.14\}.$$

The Uniform distribution has well-defined endpoints, and for the Normal distribution, we truncate the endpoints at two standard deviations.

Model output includes a count of the number of economic and marginal structures over time; cumulative economic, marginal, and total production; and the valuation of each production stream and class. Cumulative production and present value are numeric quantities, while the count and annual production profile are vectors. Numeric quantities are easier to configure and compute, while vector quantities require somewhat more advanced modeling techniques to handle.

The influence of the design space on the model results is subtle but important. The design space represents the input variables of the model, and as such, all model results are related to the size and shape of ∑. If the distribution type or parameter values changes, the coefficients of the regression model will also change. Fortunately, small perturbations in ∑ along one or more directions - either in distribution type or parameter value - do not change the output significantly. Changes in the dimensionality of the design space, however, which would occur by adding or deleting variables, will have a more significant impact since the structural aspects of the model are no longer compatible. Model comparisons should be performed carefully across different dimensional design spaces.

7.3. Model Results

7.3.1. Producing Structure Count

The number of shallow water committed structures that are expected to produce over a 60-year horizon is depicted in Figure G.1 according to their marginal and economic status. The trajectories represent the result of several hundred simulations, and so the paths denote the average trajectory computed from all of the simulations runs. New installations that will occur in the future and deepwater structures are not considered; hence, our structure count and production forecast is tied to the inventory of shallow water structures circa 2006.

The total number of structures decline over time as production at individual assets decrease and transition from economic to marginal status, and eventually, to abandonment. As structures transition from economic to marginal status, and then to abandonment, the number of structures classified as economic and marginal will change.

All structures transition from economic to marginal status, and are removed from service at their economic limit, regardless of the production status of the lease on which they reside. The number of economic structures decrease over time, since once a structure leaves the economic category, it will not return. Economic structures transition to a marginal classification, and operate as marginal producers until their revenue falls below their economic limit. The size of the marginal subcategory can therefore increase or decrease over time, depending upon the relative difference between the number of structures entering the class (from economic production) and structures departing the class (to abandonment).

The economic and marginal structure categories are dynamic and change over time. In Figure G.1, we note that the absolute size of the marginal class is relatively constant over the first 20 years of the forecast, but on a percent basis, as the number of economic structures decline, the inventory of marginal structures will represent an increasing share of the committed asset inventory (Figure G.2).

7.3.2. Structure Count Envelopes

The number of committed assets for a given (d, P^o, P^g, m, a) is denoted $\sigma(d, P^o, P^g, m, a)$, while the counting function for economic and marginal structures is denoted $\sigma_e(d, P^o, P^g, m, a)$ and $\sigma_m(d, P^o, P^g, m, a)$. Counting functions represent a simple enumeration of the number of economic and marginal structures over a 60-year horizon.

In Figures G.3-G.5, the average number of economic, marginal, and total structures are depicted with a one standard deviation envelope. It is useful to think of the envelope as bounding the path trajectories that arise from selecting points (d, P^o, P^g, m, a) in the design space. Each point (d, P^o, P^g, m, a) is associated with one path trajectory, and as we sample points within $\sum$, the trajectories will change. The average path is computed from the collection of all the sample paths in the simulation. Under Normality assumptions on the input variables, the path trajectories would be expected to be bound within the envelope about two-thirds of the time.

In Figures G.3 and G.4, the structure counts are strictly decreasing functions, while the marginal structure count in Figure G.5 increases and plateaus for several years before declining. Because the number of economic structures initially dominates the total structure count, the behavior of the composite trajectory (Figure G.3) will mostly follow the economic count path (Figure G.4). The impact of the marginal trajectory plays a more important role later in the time horizon when the number of economic structures declines, but at this time, the shape of the two trajectories are similar.

7.3.3. Aggregate Production Profiles

The average annual BOE production from economic and marginal structures is shown in Figure G.6. The production profile parallels the general shape of the structure count and illustrates the relative contribution provided by economic and marginal assets for each year of the forecast. Marginal assets provide a mere fraction of the production from economic structures, although over time its relative contribution increases (Figure G.7). BOE production from marginal structures contributes less than 5 percent total production.

7.3.4. Production Envelopes

Average BOE production envelopes for economic and marginal structures are shown in Figures G.8-G.10. In Figure G.8, the average BOE production profile for all producing structures is bound by a two standard deviation interval. Near the beginning and end of the production forecast for the economic class, the envelope is tight, due in part to the relative insensitivity of the total production to parameter variation at these points in time (Figure G.9). As structures age and profiles become more diverse, the impact of changes in input variables becomes more pronounced. The production envelope of marginal structures maintains a wide interval at the start of the horizon, but shows a similar convergence near the end of production (Figure G.10).

7.3.5. Production by Asset Category

In Figure G.11, BOE production is decomposed according to the five structure subcategories. The cumulative production profiles in Figure G.12 depict the relative contribution of each asset class. Observe the large contribution played by young and normal producers. Young and normal assets contribute nearly two-thirds to cumulative production; with latecomer structures, the relative contribution exceeds 80 percent of the total production.

7.3.6. Summary Statistics

Composite statistics for oil, gas, and BOE production from all shallow water committed assets in the GOM in 2006 are summarized in Table G.3. Production quantity and value are decomposed in terms of economic, marginal, and the composite class. The expected amount of hydrocarbon production is estimated at 1,056.4 MMbbl oil and 13.3 Tcf gas, or 3,279 MMBOE. The expected present value of hydrocarbon production is calculated as $149.4 billion. Marginal production is expected to contribute 4.1 percent of the total oil production, 5.4 percent total gas production, and 1.2 percent of the total present value over the productive life of the committed asset inventory.

7.3.7. Cumulative Production Functions

The cumulative economic, marginal, and total BOE production functions in the GOM are expressed in terms of the model input variables and given by (Table G.4):

$$Q_e\,(d, P^o, P^g, m) = -5.3\text{E}9d + 1.5\text{E}7P^o + 1.7\text{E}8P^g + 2.9\text{E}7m$$

$$Q_m\,(d, P^o, P^g, m, a) = -1.8\text{E}8d + 4.2\text{E}5P^o + 1.1\text{E}6P^g + 7.7\text{E}7m - 9.1\text{E}7a$$

$$Q_T\,(d, P^o, P^g, a) = -5.6\text{E}9d + 1.6\text{E}7P^o + 1.7\text{E}8P^g + 8.3\text{E}7a$$

The coefficients of the regression models are of the expected sign and statistically significant for most of the variables, and the model fits are relatively high. For any input parameters selected within the design space, the output for cumulative BOE production will vary in accord with the regression models shown. In Tables G.5 and G.6, regression results for the individual gas and oil production streams are depicted with somewhat better model fits.

Cumulative production functionals are useful to estimate the total BOE production for any given input vector and to investigate parameter sensitivity. For example, for the collection of marginal assets and $(d, P^o, P^g, m, \alpha) = (0.10, 120, 10, 4, 1)$, cumulative production is computed as Q_m (0.10, 120, 10, 4, 1) = -1.8E7 + 5.04E7 + 1.1E7 + 3.08E8 – 9.1E7 = 2.60E8 BOE = 260 million BOE. Similarly, Q_e (0.10, 120, 10, 4) = 3.09 billion BOE, and Q_T (0.10, 120, 10, 1) = 3.14 billion BOE. Cumulative oil and gas production estimates are applied similarly using the results in Tables G.5 and G.6.

7.3.8. Valuation Functions

The present value of future oil and gas production is obtained by valuing the individual oil and gas production streams at assumed future prices, discount rates, and economic and marginal thresholds. The model results for total BOE, gas, and oil production for the economic, marginal, and combined asset classes are shown in Tables G.7-G.9 and summarized for the total hydrocarbon production stream (without a fixed term coefficient) as follows (in $1,000):

$$PV_e\,(d, P^o, P^g, m, D) = -1.9\text{E}8d + 8.1\text{E}5P^o + 9.6\text{E}6P^g - 2.6\text{E}5m - 3.2\text{E}8D$$

$$PV_m\,(d, P^o, P^g, m, \alpha, D) = 4.4\text{E}5d + 2.2\text{E}3P^o + 7.9\text{E}4P^g + 1.3\text{E}6m - 1.8\text{E}6a - 1.0\text{E}7D$$

$$PV_T\,(d, P^o, P^g, \alpha, D) = -1.9\text{E}8d + 8.1\text{E}5P^o + 10.0\text{E}6P^g - 3.66\text{E}6a - 3.1\text{E}8D$$

The use of a fixed-term coefficient is optional and we present model results with and without this term. The coefficients of the regression models are of the expected sign and statistically significant for most of the variables, and the model fits are again relatively high.

The most important components of marginal production are the values of *m, a, D*; the decline parameter and hydrocarbon price are less significant. This is not surprising considering the nature of the producing assets. The decline parameter only contributes to the portion of total production due to latecomer structures. For economic assets, the abandonment threshold does not play a role in determining value, and thus a term for *a* is not included in the model. The present value of economic production at a 10 percent decline rate, $100/bbl oil, $10/Mcf gas, and a 15 percent discount rate is computed to be PV_e (0.1, 100, 10, 4, 0.15) = $147 billion. The present value of marginal producing assets is computed to be PV_m (0.1, 100, 10, 4, 1, 0.15) = $3.0 billion.

REFERENCES

Beck, R.D., J.P. Davis, R. Lynch, T. Philips, M. Taylor, G. Openshaw, M. Buhrke, W. Tomaszkiewicz, R. Simpson, and R. Butcher. 2008. Imaging downed platforms. OTC 19650. Presented at the 2008 Offshore Technology Conference. Houston, TX, 5-8 May.

Bondor, P.L., J.R. Hite, and S.M. Avasthi. 2005. Planning EOR projects in offshore oil fields. Presented at the SPE Latin America and Caribbean Petroleum Engineering Conference, Rio de Janeiro, Brazil, June 20 – 23, 2005. SPE #94637.

Brashaer, J.P., F. Morra, M.R. Haas, and S. Payne. 1982. Enhanced oil recovery from offshore Gulf of Mexico reservoirs. Presented at the 1982 SPE/DOE Third Joint Symposium on Enhanced Oil Recovery, Tulsa, OK, April 4 – 7, 1982. SPE/DOE #10698.

Energo. 2006. Assessment of fixed offshore platform performance in Hurricanes Andrew, Lili and Ivan. Report to MMS by Energo Engineering, Inc. TAR No 549.

Energo. 2007. Assessment of fixed offshore platform performance in Hurricanes Katrina and Rita. Report to MMS by Energo Engineering, Inc. TAR No 578.

Haag, J. 2005. The acquisition and divestiture of petroleum property. Penn Well, Tulsa, OK.

Harrel, R. and C. Cronquist. 2007. "Estimation of primary reserves of crude oil, natural gas, and condensate." Ch. 16, 1480-1570, in Reservoir Engineering and Petrophysics, Vol V(B), Ed. E. Holstein, SPE, Richardson, TX.

Interstate Oil and Gas Compact Commission (IOGCC). 1999. Marginal oil and gas: Fuel for economic growth. Internet website: http://iogcc.publishpath.com/.

Interstate Oil and Gas Compact Commission (IOGCC). 2005. Marginal oil and natural gas: American energy for the American dream. Internet website: http://iogcc.publishpath.com/.

Kaiser, M.J. 2008a. "An empirical assessment of the economic limit of offshore structures in the Gulf of Mexico – Descriptive statistics." *Energy Sources, B: Economics, Planning, and Policy.* 3(2): 314-322.

Kaiser, M.J. 2008b. "Modeling regulatory policies associated with offshore structure removal requirements in the Gulf of Mexico." *Energy*. 33: 1038-1054.

Kaiser, M.J. and R. Kasprzak. 2008. The impact of the 2005 hurricane season on the Louisiana Artificial Reef Program. *Marine Policy*, 32: 956-967.

Kaiser, M.J., A.G. Pulsipher, A. Singhal, T. Foster, and R. Vojjala. 2007a. "Catastrophic event modeling – I. How coverage has evolved for offshore storm risks." *Oil and Gas Journal.* 105(48): 39-47, December 3.

Kaiser, M.J., A.G. Pulsipher, A. Singhal, T. Foster, and R. Vojjala. 2007b. "Catastrophic event modeling – II. Industry exposure and value at risk." *Oil and Gas Journal.* 105(49): 39-47, December 10.

Laurendine, T.T. 2008. Gulf of Mexico offshore platforms-risk engineering. OTC 19576, 2008 Offshore Technology Conference. Houston, TX, 5-8 May.

Mailey, J.F. 2008. Technology and innovations contribute to safety and efficiency in storm disaster recovery. SPE 111563. Presented at the 2008 SPE International Conference on Health, Safety, and Environment. Nice, France, 15-17 April.

McCutcheon, J.B. and M.L. Payne. 1986. Successful salvage and tie-back operations for a hurricane-damaged satellite well in the Gulf of Mexico. SPE 15450. Presented at the 61th Annual Technical Conference and Exhibition. New Orleans, LA, 5-8 October.

National Research Council (NRC). 1996. Maintaining oil production from marginal fields: A review of the department reservoir class program. National Academy Press, Washington, D.C.

Puskar, F.J., S.M. Verret, and C. Roberts. 2007. Fixed platform performance during recent hurricanes: comparison to design standards. OTC 18989. Presented at the 2007 Offshore Technology Conference. Houston, TX, April 30-May 3.

Twachtman Snyder and Byrd, Inc. 2008. Twachtman Snyder and Byrd, Inc.: Total decommissioning solutions. Internet website: http://www.tsboffshore.com/.

U.S. Department of Energy. 2006. Impact of the 2005 Hurricanes on the Natural Gas Industry in the Gulf of Mexico Region, Washington, D.C.

U.S. Department of Energy. Energy Information Administration (USDOE, EIA). 2007. Oil and gas lease equipment and operating costs 1988 through 2006. Internet website: http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/cost_indices/c_i.html.

U.S. Department of Energy. National Energy Technology Laboratory (USDOE, NETL). 2001. An evaluation of marginal production in the Gulf of Mexico. National Petroleum Technology Office, National Energy Technology Laboratory, U.S. Department of Energy, DOE/BC-01/5/SP.

U.S. Department of the Interior. Minerals Management Service (USDOI, MMS). 2004. MMS updates damage assessment from Hurricane Ivan. Release: #3164. October 8. Available at: www.mms.gov/ooc/press/2004/press1008a.htm.

U.S. Department of the Interior. Minerals Management Service (USDOI, MMS). 2006. MMS updates Hurricanes Katrina and Rita damage. Release: #3486. May 1. Available at: www.mms.gov/ooc/press/2006/press0501.htm.

U.S. Department of the Interior. Minerals Management Service (USDOI, MMS). 2007. Minerals Management Service. Gulf of Mexico Region. Production Information. Internet website: http://www.gomr.mms.gov/homepg/pd/index.html.

U.S. Department of the Interior. Minerals Management Service (USDOI, MMS). 2008. Minerals Management Service. Gulf of Mexico Region. Production Information. Internet website: http://www.gomr.mms.gov/homepg/pd/index.html.

U.S. Department of the Interior. Minerals Management Service (USDOI, MMS). 2009a. Lease Term Extensions Pursuant to 30 CFR 250.180(e) Due to Hurricane Damage. NTL No. 2008-G24. Internet website: http://www.ocsbbs.com/ntls/08-G24.pdf.

U.S. Department of the Interior. Minerals Management Service (USDOI, MMS). 2009b. Minerals Management Service. Gulf of Mexico Region. Production Information. Internet website: http://www.gomr.mms.gov/homepg/pd/index.html.

Versowski, P., G. Rodenbusch, P. O'Connor, and M. Prins. 2006. Hurricane impact reviewed through API. Offshore Technology Conference, OTC 18417. Houston, TX.

Willis Group. 2006. Willis energy market review. Internet website: www.willis.com.

Wisch, D.W., F.J. Puskar, T.T. Laurendine, P. O'Connor, P.E. Versowsky, and J. Bucknell. 2004. An update on API RP 2A Section 17 for the assessment of existing platforms, OTC 19454. Presented at the 2004 Offshore Technology Conference. Houston, TX, 2-5 May.

APPENDIX A.

CHAPTER 1 TABLES AND FIGURES

Table A.1.

Structure Damage Rate and Physical Damage Estimates

Hurricane	Year	Structures in Storm Path	Structures Destroyed and with Major Damage	Damage Rate[a] (%)	Physical Damage ($ billion)
Andrew	1992	700	87	12%	0.9
Lili	2002	800	10	1%	0.4
Ivan	2004	150	31	21%	1.5
Katrina	2005	2,068	66	3%	6.4
Rita	2005	793	101	13%	3.7

Source: USDOI, MMS, 2006.
Footnote: (a) Damage rate expressed as percent exposed, computed as the number of structures destroyed and with major damage divided by the number of structures in a 50-mile envelope centered on the storm path.

Table A.2.

Structure and Rig Damage Caused by Hurricanes Ivan, Katrina, and Rita

	Ivan	Katrina	Rita
Platforms destroyed	7	46	69
Platforms extensively damaged	24	20	32
Rigs adrift	5	6	13
Rigs destroyed	1	4	4
Rigs extensively damaged	4	9	10

Source: USDOI, MMS, 2006.

Table A.3.

Structures Destroyed by Hurricanes Ivan, Katrina, and Rita by Age Group

Age Group (yrs)	Number
< 10	24
11-20	9
21-30	17
31-40	49
> 40	23
Total	122

Source: USDOI, MMS, 2006.

Table A.4.

Operators with Three or More Destroyed Structures in the 2004-2005 Hurricane Seasons

Operator	Structures Destroyed	Total Wells	Active Wells (2005)
Chevron	15	179	38
Apache	11	131	39
BP America	11	109	24
Forest Oil	11	53	11
Energy XXI	9	17	6
Stone Energy	7	37	11
Energy Resources Technology	5	29	10
Newfield Exploration Company	5	21	10
Anglo-Suisse Offshore Partners	4	72	13
Noble	4	101	18
Mariner Energy	3	4	1
Maritech	3	28	2

Source: USDOI, MMS, 2006.

Table A.5.

Gas, Oil, and Water Production from Hurricane Destroyed Structures as a Percentage of Total Gulf of Mexico Production (2000-2005)

Fluid Type	2000	2001	2002	2003	2004	2005
Gas	1.7	1.9	2.0	2.3	2.1	1.2
Oil	2.2	3.0	3.7	2.9	2.7	1.5
BOE[a]	1.7	2.3	2.7	2.6	2.4	1.3
Water	3.9	3.7	4.2	4.3	4.3	3.4

Source: USDOI, MMS, 2006.

Footnote: (a) BOE = barrels of oil equivalent, computed on a heat equivalent basis, where 6,040 cf of gas provides 1 barrel of oil equivalent. The BOE stream is the combined oil and gas production output.

Table A.6.

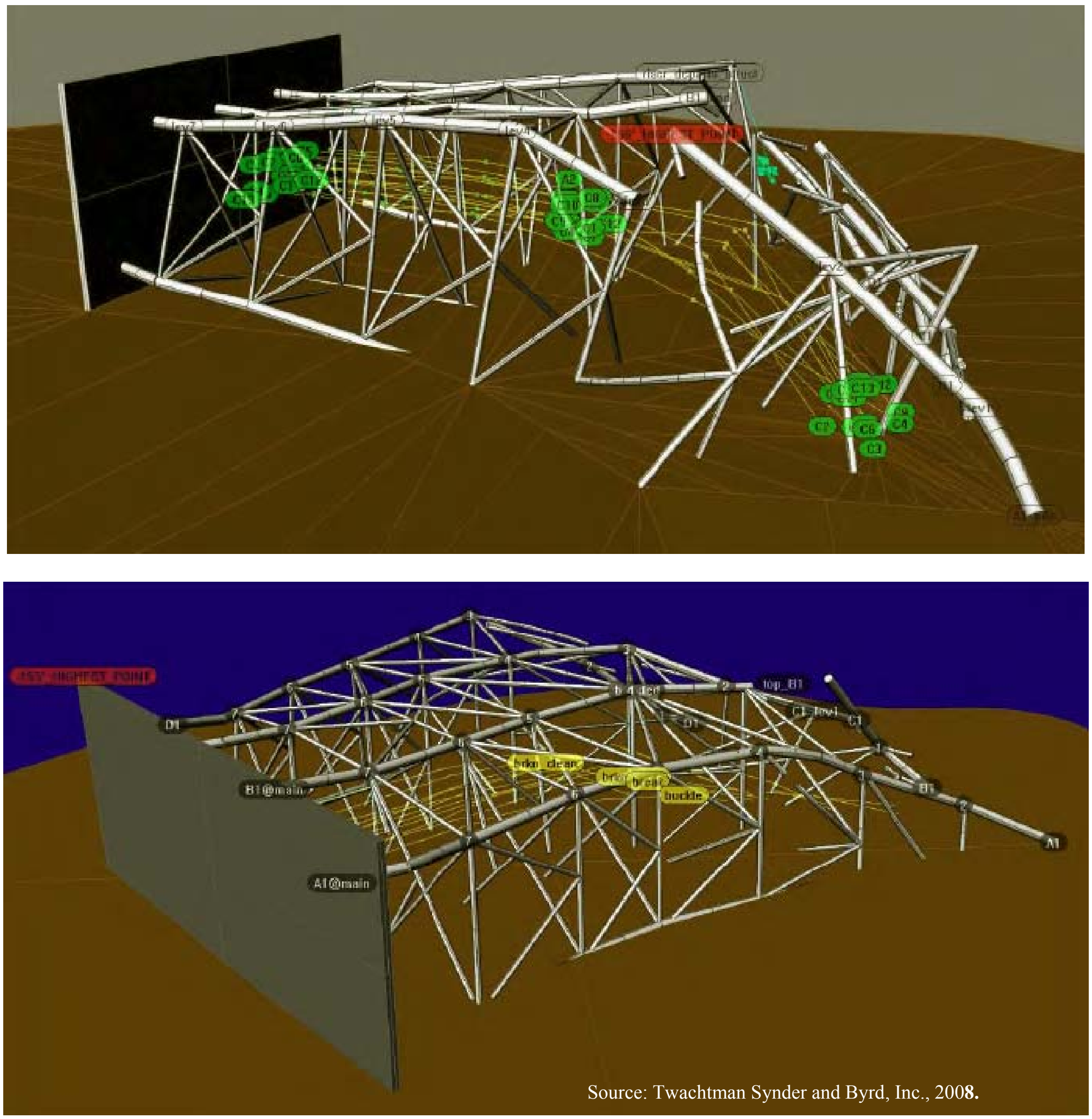
Structure Count by Production Category (2000-2005)

Structure Type[a]	Year	Production (BOPD)[b]				
		<100	100-500	500-1,000	> 1,000	Total
Oil	2000	8	18	7	5	38
	2001	8	18	6	7	39
	2002	9	15	8	6	38
	2003	6	17	7	5	35
	2004	7	16	9	3	35
	2005	13	15	1	3	32
Structure Type	Year	Production (MCFPD)				
		<600	600-3,000	3,000-6,000	> 6,000	Total
Gas	2000	12	19	9	8	48
	2001	13	14	9	11	47
	2002	14	17	7	7	45
	2003	15	18	7	7	47
	2004	18	17	6	9	50
	2005	14	21	9	2	46
Structure Type	Year	Production (BOEPD)				
		<100	100-500	500-1,000	> 1,000	Total
ALL	2000	14	37	17	18	86
	2001	26	18	14	28	86
	2002	12	34	21	16	83
	2003	14	28	23	17	82
	2004	18	35	15	17	85
	2005	21	35	16	6	78

Source: USDOI, MMS, 2006.

Footnote: (a) Structures are classified as oil or gas producers according to their cumulative gas-oil ratio (GOR) measured in cf/bbl. Structures with GOR $\leq$ 5,000 are classified as primarily oil producers; structures with GOR > 5,000 are primarily gas producers.

(b) BOPD = barrels of oil per day; MCFPD = thousand cubic feet per day; BOEPD = barrels of oil equivalent per day.



Source: Twachtman Synder and Byrd, Inc., 2008.

Figure A.1. Model Rendition of Hurricane Destroyed Structure Lying Horizontally on the Seafloor.

Figure A.2. Hurricane Destroyed Platform in the East Cameron Area.

Figure A.3. Hurricane Destroyed Platform Suspected to Be Due to a Foundation Failure.

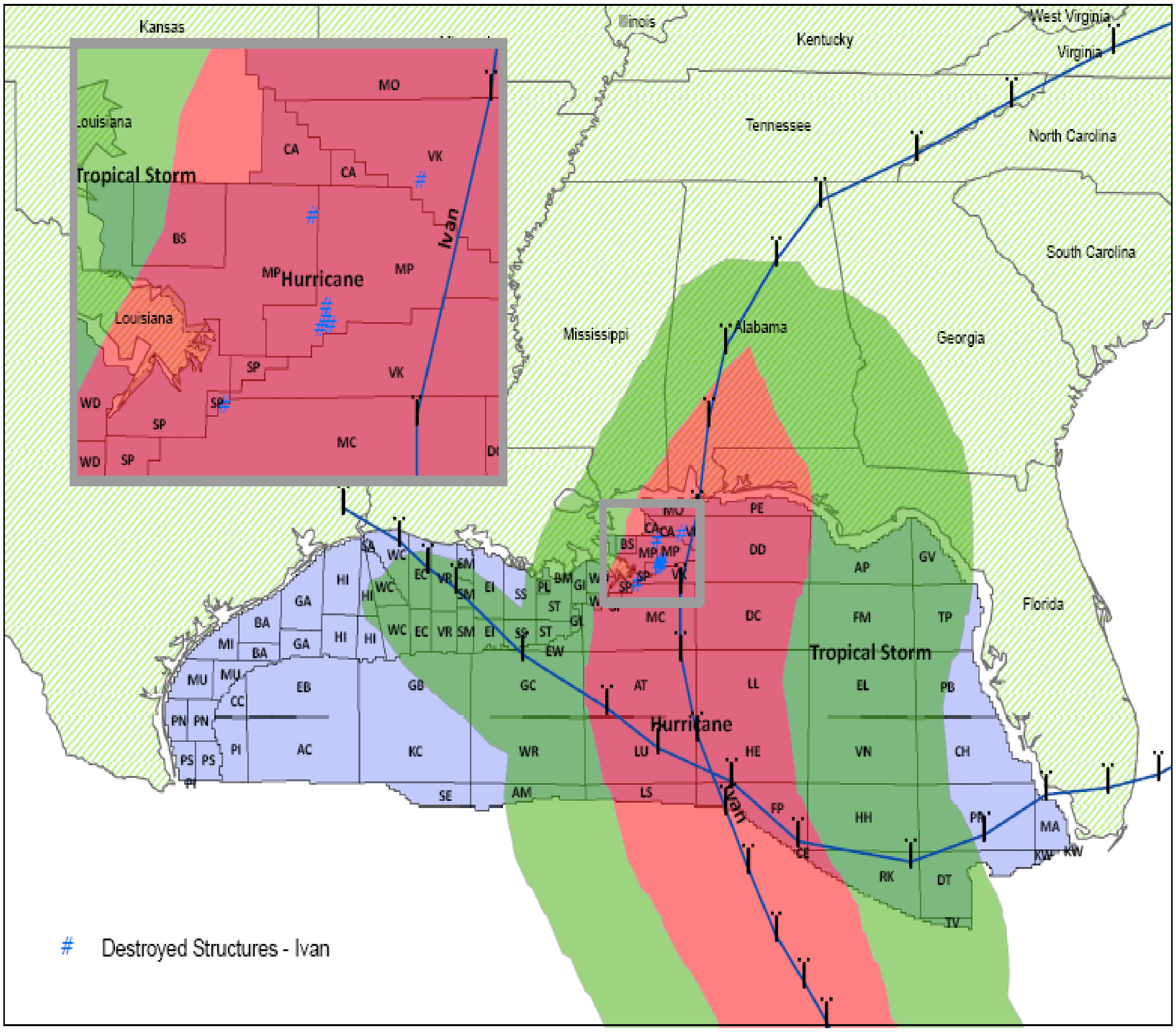


Figure A.4. Structures Destroyed by Hurricane Ivan and Hurricane Force Wind Swath.

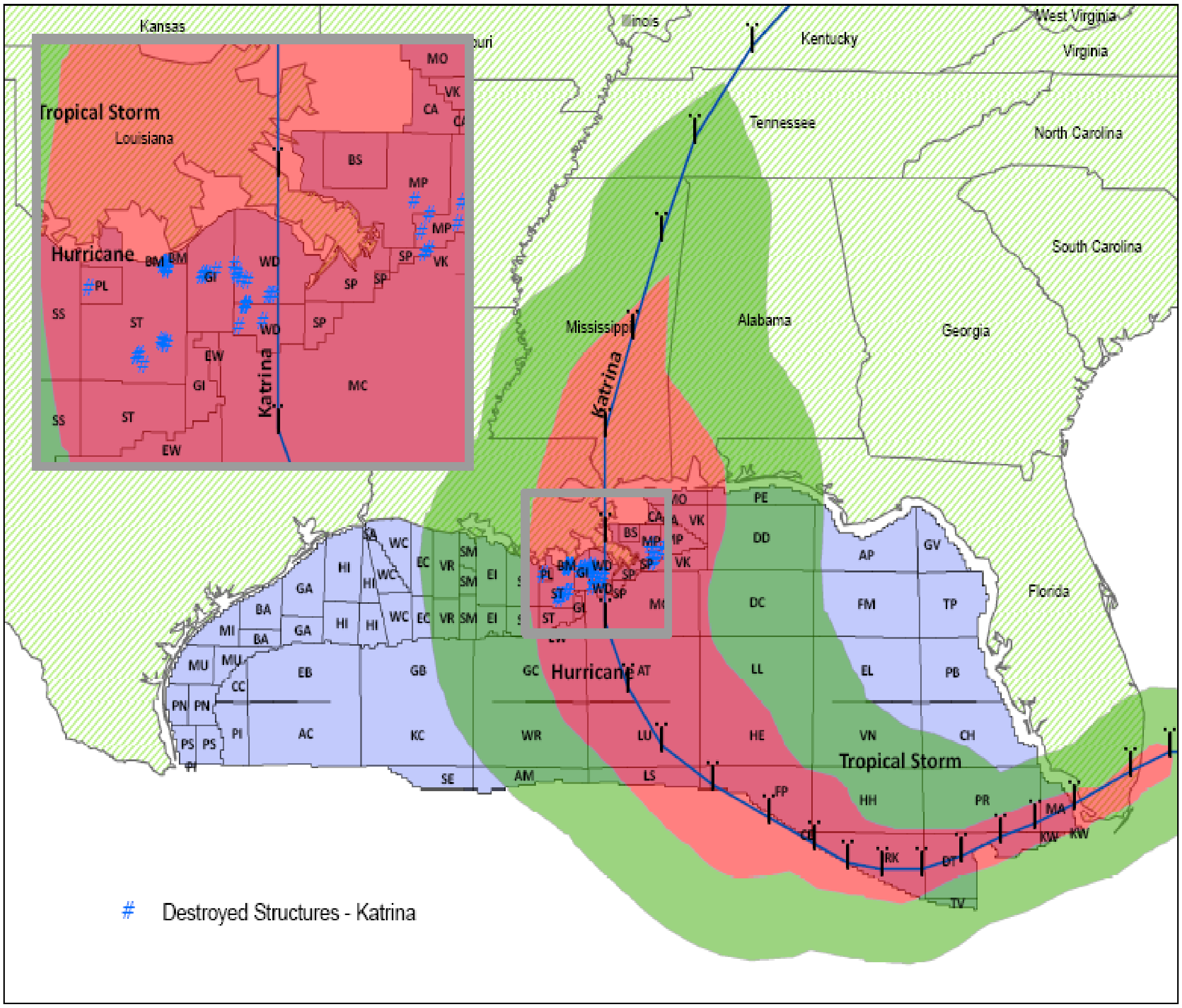


Figure A.5. Structures Destroyed by Hurricane Katrina and Hurricane Force Wind Swath.

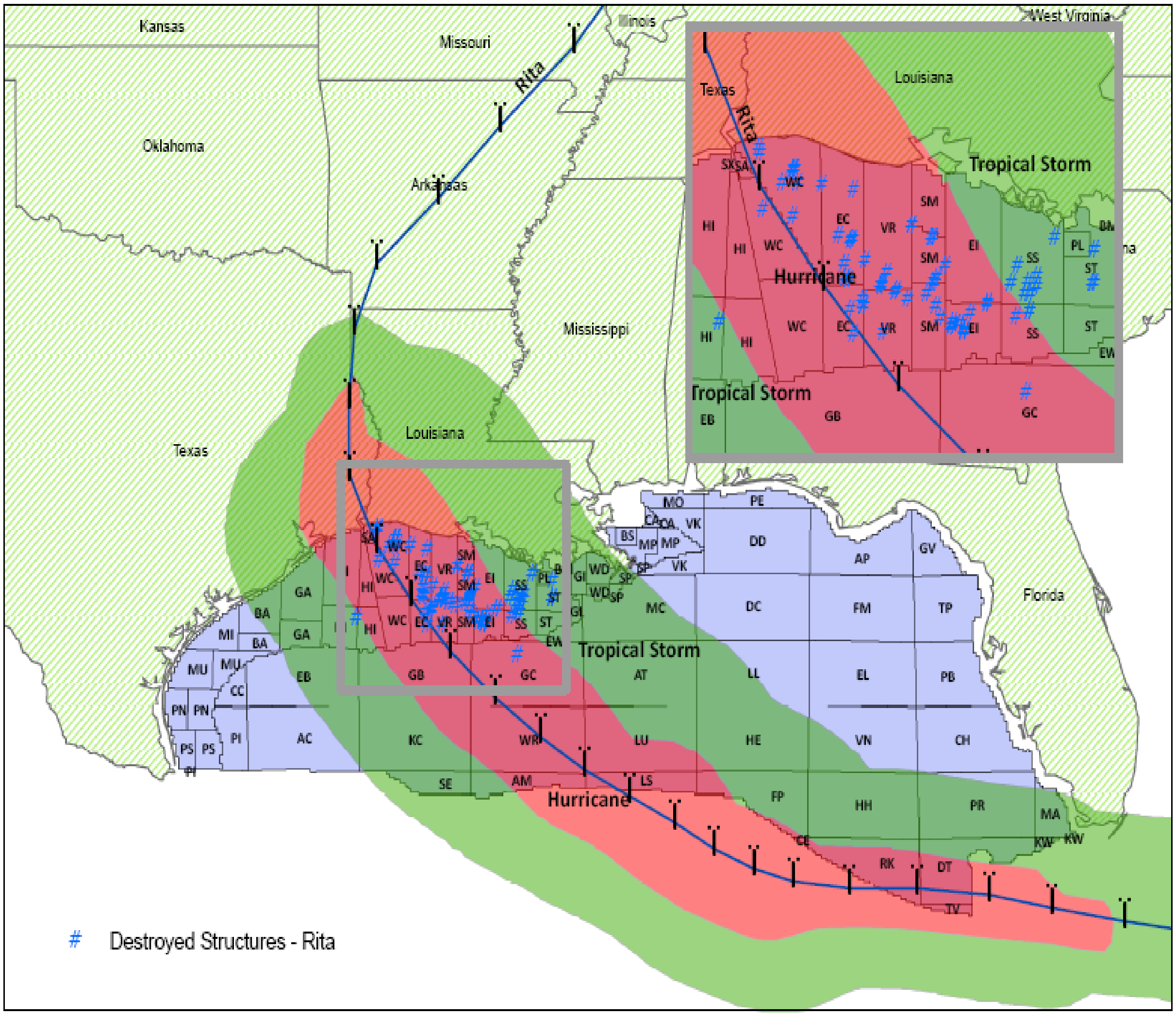


Figure A.6. Structures Destroyed by Hurricane Rita and Hurricane Force Wind Swath.

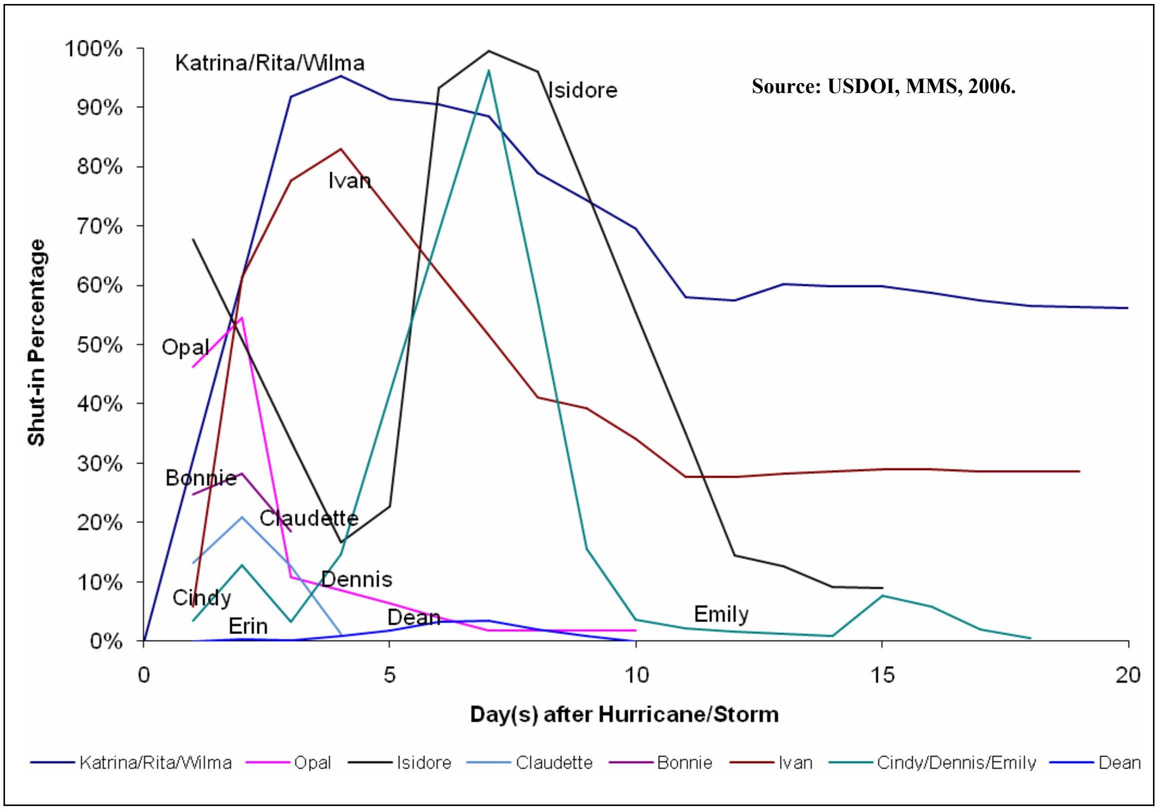


Figure A.7. Shut-In Oil Production in the Gulf of Mexico.

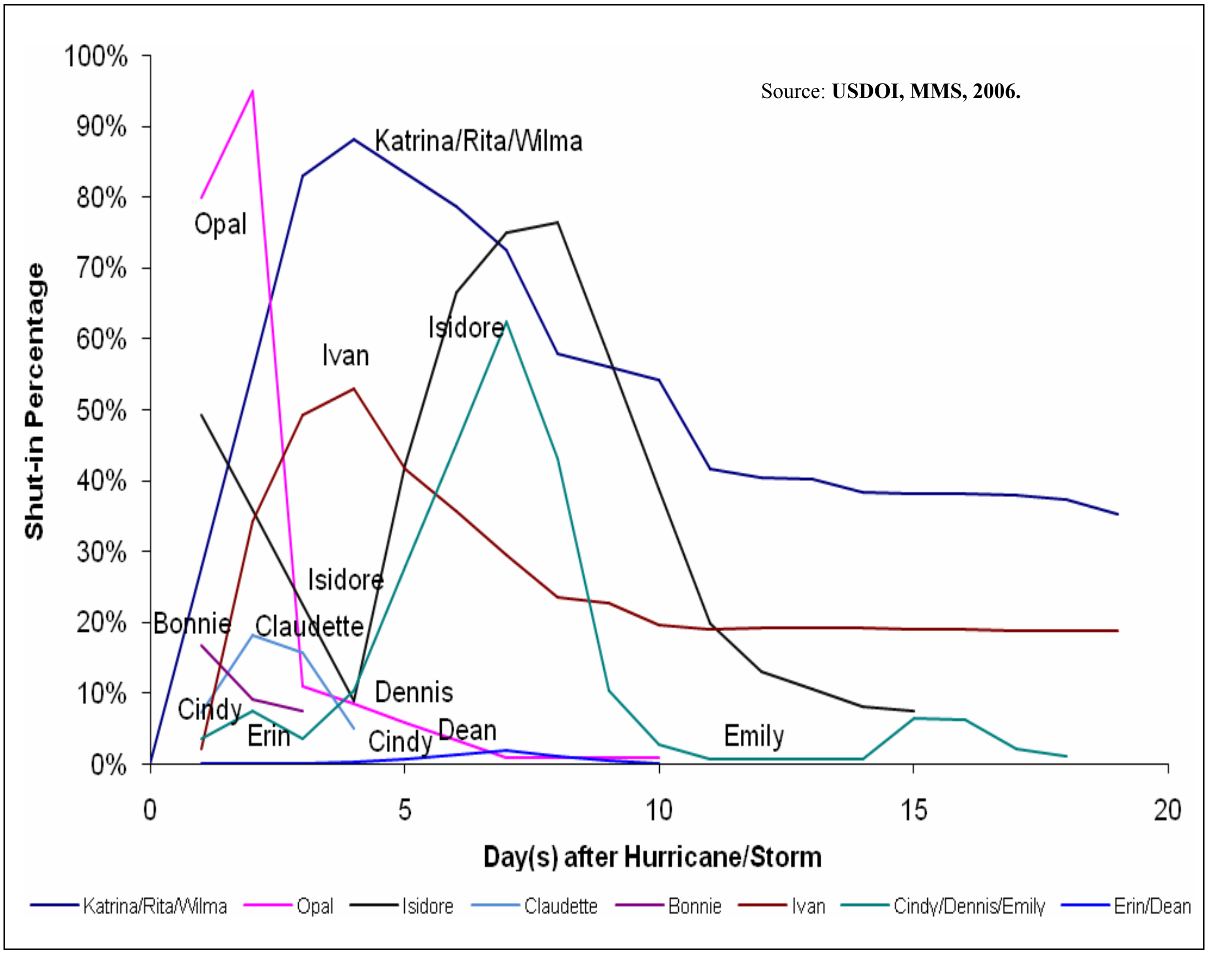


Figure A.8. Shut-In Gas Production in the Gulf of Mexico.

APPENDIX B.

CHAPTER 2 TABLES

Table B.1.

Annual Operating Cost for Gulf of Mexico Structures (2006 dollars)

Water Depth (ft)	12-Slot Platform ($ million)	18-Slot Platform ($ million)	Average ($ million)
100	9.34	11.18	10.26
300	9.62	11.52	10.57
600		12.15	12.15

Source: USDOE, EIA, 2007.

Table B.2.

Average Threshold Revenue for Gulf of Mexico Structures (2006 dollars)

Water Depth (ft)	Primary Production	Caisson ($1,000)	Well Protector ($1,000)	Fixed Platform ($1,000)
< 100	Oil	162	152	451
	Gas	525	446	491
101-200	Oil	345	398	715
	Gas	589	692	588
> 200	Oil			520
	Gas			935

Source: Kaiser, 2008a.

Table B.3.

Best Fit Curve Frequency and Average Model Parameters

Structure Type	Model Type	Frequency (%)	Coefficients		Curve Fit	
			a, *C*	*n*	R^2	CV
Gas	Exponential	62%	0.891		0.89	0.09
	Harmonic	18%	7.1E-07		0.79	0.41
	Hyperbolic	20%	0.049	3.6E5	0.90	0.11
Oil	Exponential	40%	0.875		0.88	0.15
	Harmonic	20%	1.7E-06		0.76	0.38
	Hyperbolic	40%	0.068	798	0.89	0.13

Table B.4.

Number of Structures According to Structure Type and Model Specification

Structure Type	Idle	Uneconomic	Normal	Young	Chaotic	Total
Oil	7	10	17	4	6	44
Gas	15	11	22	15	3	66
All	22	21	39	19	9	110

APPENDIX C.

CHAPTER 3 TABLES AND FIGURES

Table C.1.

Estimated Lost Production and Valuation (Normal Producers) – Best-Fit Curves with $R^2 \geq 0.75$, Hurricane Destroyed Structures with ≥ 7 Years Production

Price Deck[a]	Lost Production			Present Value[b] $ Million
	Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)	
I[a]	19.4	31.8	24.7	231
II	21.1	37.9	27.5	393
III	22.2	41.7	29.1	561
IV	22.9	44.0	30.2	732
V	23.4	45.6	31.0	905

Footnote: (a) P(I) = {P^o = \$40/bbl, P^g = \$4/Mcf}; P(II) = {P^o = \$60/bbl, P^g = \$6/Mcf}; P(III) = {P^o = \$80/bbl, P^g = \$8/Mcf}; P(IV) = {P^o = \$100/bbl, P^g = \$10/Mcf}; and P(V) = {P^o = \$120/bbl, P^g = \$12/Mcf}
(b) Discount rate = 10%

Table C.2.

Estimated Lost Production and Valuation (Young Producers) – Hurricane Destroyed Structures with < 7 Years Production, Exponential Decline Curves with Assumed Decline Rate

Decline Rate *a* (%)	Price Deck[a]	Lost Production			Present Value[b] $ Million
		Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)	
$a = 0.05$	I	78.4	279.8	141.7	1,493
	II	79.1	290.4	144.1	2,288
	III	79.4	396.5	145.5	3,086
	IV	79.6	400.0	146.3	3,885
	V	79.8	402.5	146.9	4,684
$a = 0.1$	I	38.1	184.2	68.8	1,061
	II	38.5	189.4	70.0	1,634
	III	38.6	192.5	70.7	2,209
	IV	38.7	194.1	71.1	2,796
	V	38.8	195.4	71.4	3,363
$a = 0.15$	I	24.7	118.7	44.5	811
	II	24.9	122.5	45.4	1,252
	III	25.1	124.6	45.8	1,696
	IV	25.1	125.6	46.1	2,141
	V	25.2	126.5	46.3	2,587

Footnote: (a) P(I) = {P^o = \$40/bbl, P^g = \$4/Mcf}; P(II) = {P^o = \$60/bbl, P^g = \$6/Mcf}; P(III) = {P^o = \$80/bbl, P^g = \$8/Mcf}; P(IV) = {P^o = \$100/bbl, P^g = \$10/Mcf}; and P(V) = {P^o = \$120/bbl, P^g = \$12/Mcf}
(b) Discount rate = 10%

Table C.3.

Estimated Lost Production and Valuation (Chaotic Producers) – Best-Fit Curves with Initial $R^2 < 0.75$, Half Cycle Time Horizons and Exponential Decline with Historic Decline Rate

	Cumulative Lost Production			Present Value[b]
Price Deck[a]	Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)	$ Million
I	2.4	21.6	6.0	50
II	2.7	23.2	6.5	85
III	2.8	24.1	6.8	121
IV	2.8	24.4	6.9	157
V	2.9	24.7	7.0	193

Footnote: (a) P(I) = {P^o = \$40/bbl, P^g = \$4/Mcf}; P(II) = {P^o = \$60/bbl, P^g = \$6/Mcf}; P(III) = {P^o = \$80/bbl, P^g = \$8/Mcf}; P(IV) = {P^o = \$100/bbl, P^g = \$10/Mcf}; and P(V) = {P^o = \$120/bbl, P^g = \$12/Mcf}
(b) Discount rate = 10%

Table C.4.

Estimated Total Lost Production and Valuation – Normal, Young, and Chaotic Producers (Sum of Tables C.1, C.2, C.3)

	Lost Production[b]			Present Value[c]
Price Deck[a]	Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)	$ Million
I	59.9	230.5	99.5	1,342
II	62.3	250.5	104	2,012
III	63.6	258.3	106.6	2,891
IV	64.4	262.5	108.2	3,684
V	65.1	265.7	109.4	4,460

Footnote: (a) P(I) = {P^o = \$40/bbl, P^g = \$4/Mcf}; P(II) = {P^o = \$60/bbl, P^g = \$6/Mcf}; P(III) = {P^o = \$80/bbl, P^g = \$8/Mcf}; P(IV) = {P^o = \$100/bbl, P^g = \$10/Mcf}; and P(V) = {P^o = \$120/bbl, P^g = \$12/Mcf}

(b) For young producers, we assume the model output for a = 0.1
(c) Discount rate = 10%

Table C.5.

Maximum Aggregate Investment that Yields a Specific Rate of Return ($ million)

Production Type	Price Deck[a]	IRR =10%	IRR = 15%	IRR = 20%	IRR = 25%
Normal	I	231	185	155	133
	II	393	313	261	225
	III	561	446	372	320
	IV	732	581	484	416
	V	905	717	598	513
Chaotic	I	50	98	84	74
	II	85	158	136	119
	III	121	218	188	164
	IV	157	280	240	210
	V	193	341	292	255
Young	I	1,342	853	712	611
	II	2,012	1,310	1,093	937
	III	2,891	1,769	1,474	1,263
	IV	3,684	2,228	1,856	1,590
	V	4,460	2,688	2,238	1,917

Footnote: (a) P(I) = {P^o = $40/bbl, P^g = $4/Mcf}; P(II) = {$P^o$ = $60/bbl, P^g = $6/Mcf}; P(III) = {$P^o$ = $80/bbl, P^g = $8/Mcf}; P(IV) = {$P^o$ = $100/bbl, P^g = $10/Mcf}; and P(V) = {$P^o$ = $120/bbl, P^g = $12/Mcf}

Table C.6.

Maximum Redevelopment Cost per Structure to Yield a Specific Rate of Return ($ million/structure)

Production Type	Price Deck[a]	IRR = 10%	IRR = 15%	IRR = 20%	IRR = 25%
Normal	I	7.4	6.2	5.2	4.4
	II	10.6	8.9	7.5	6.4
	III	13.8	11.4	9.5	8.2
	IV	17.5	14.5	12.1	10.4
	V	21.3	17.9	14.9	12.8
Chaotic	I	12.4	10.8	9.4	8.2
	II	20.3	17.5	15.1	13.2
	III	28.4	24.3	20.8	18.3
	IV	36.5	31.1	26.6	23.3
	V	44.7	37.9	32.4	28.3
Young	I	60.0	50.2	41.9	36.0
	II	92.6	77.1	64.3	55.1
	III	112.5	93.1	77.6	66.5
	IV	140.5	117.3	97.7	83.7
	V	171.3	141.5	117.8	100.9

Footnote: (a) P(I) = {P^o = $40/bbl, P^g = $4/Mcf}; P(II) = {$P^o$ = $60/bbl, P^g = $6/Mcf}; P(III) = {$P^o$ = $80/bbl, P^g = $8/Mcf}; P(IV) = {$P^o$ = $100/bbl, P^g = $10/Mcf}; and P(V) = {$P^o$ = $120/bbl, P^g = $12/Mcf}

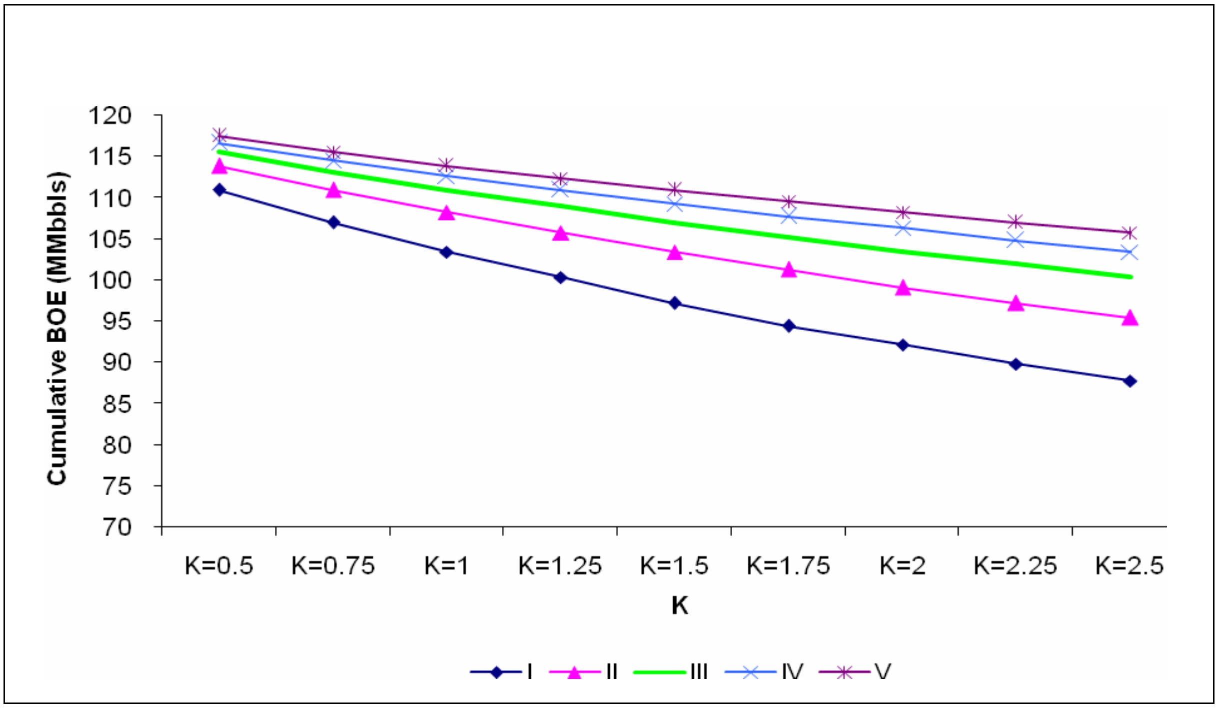


Figure C.1. Cumulative BOE Production as a Function of Threshold Level and Price Scenario.

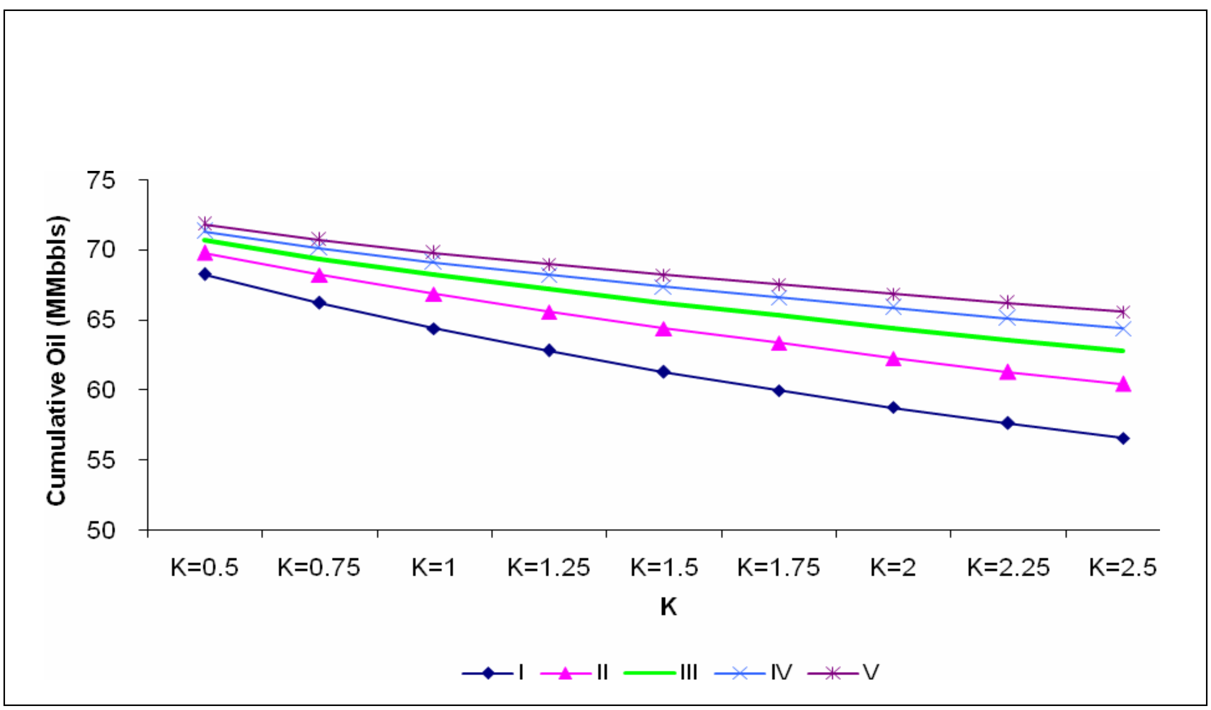


Figure C.2. Cumulative Oil Production as a Function of Threshold Level and Price Scenario.

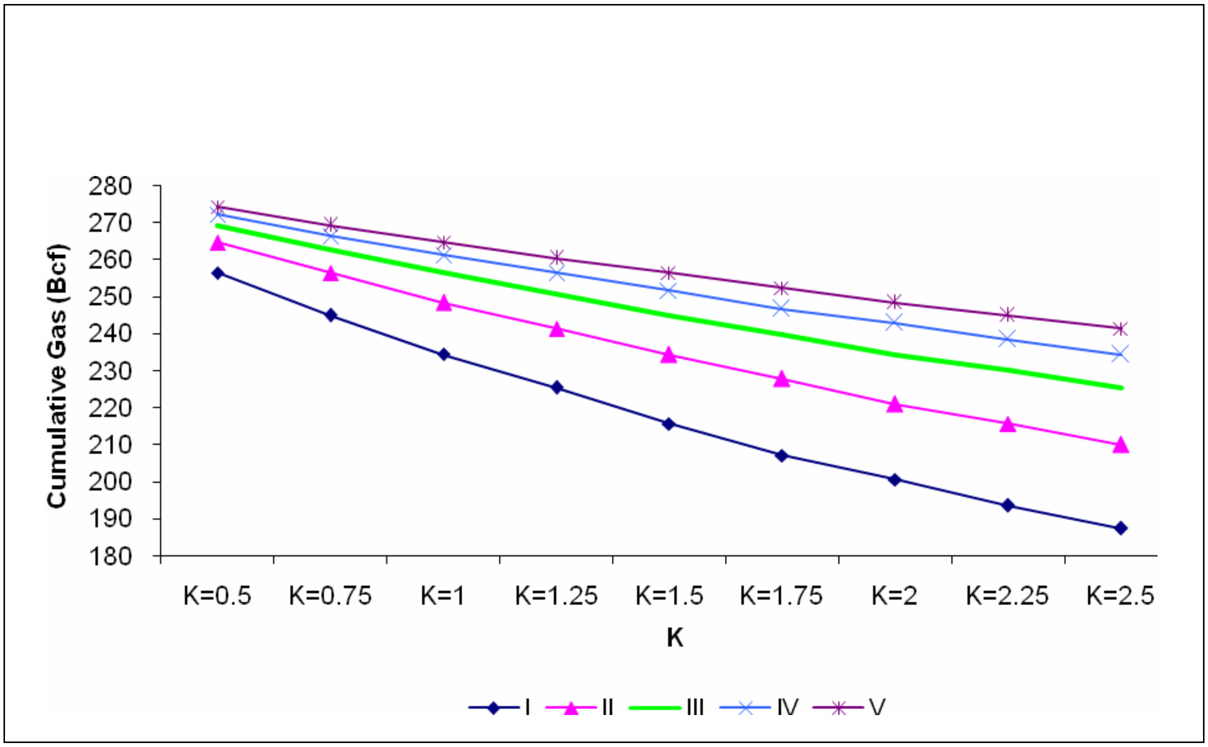


Figure C.3. Cumulative Gas Production as a Function of Threshold Level and Price Scenario.

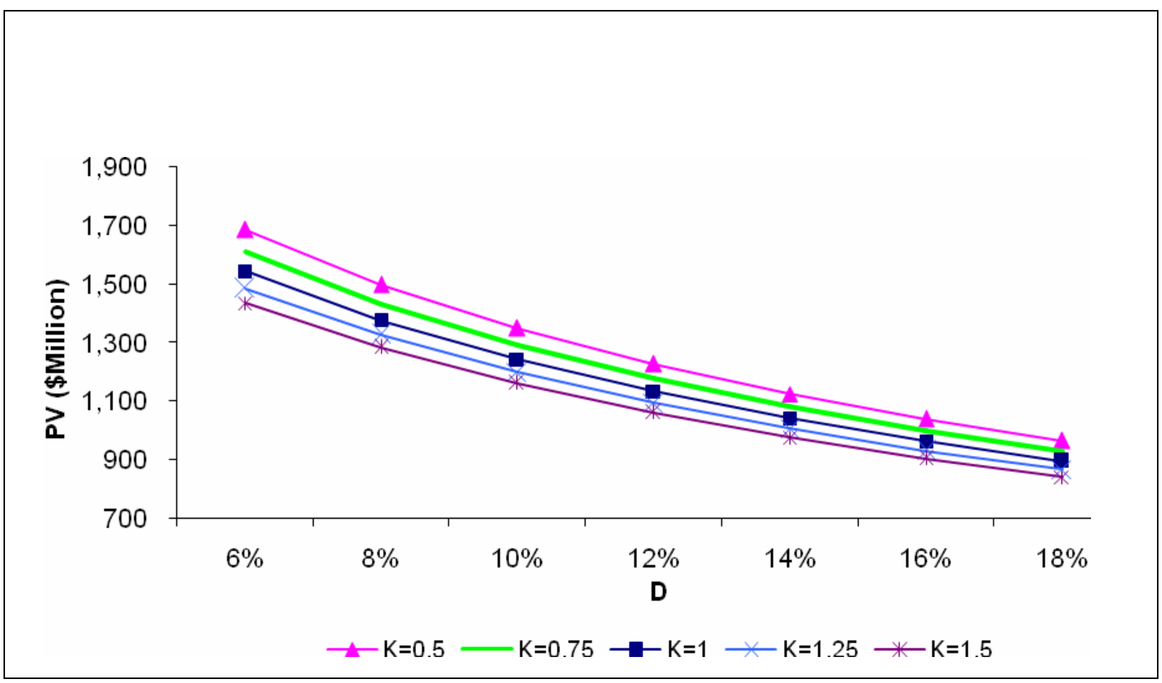


Figure C.4. Present Value as a Function of Threshold Level Multiplier and Discount Rate for Price Deck P(I).

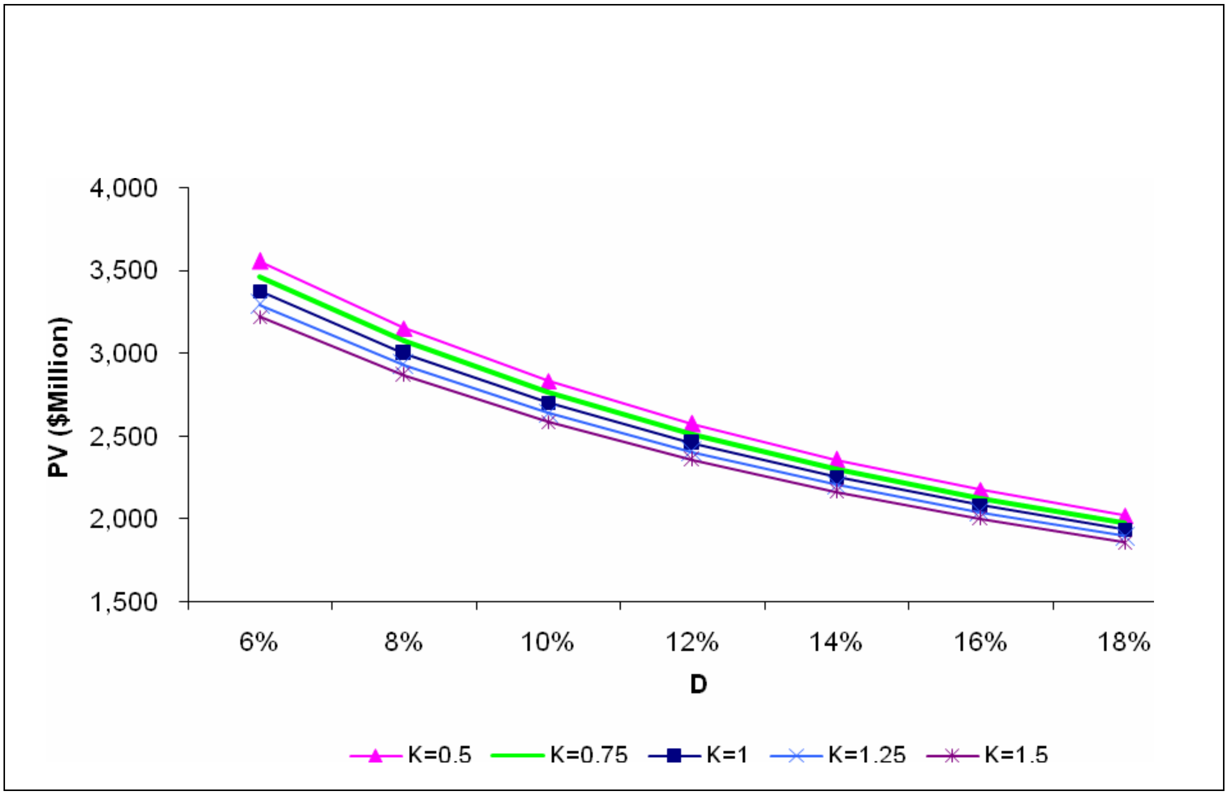


Figure C.5. Present Value as a Function of Threshold Level Multiplier and Discount Rate for Price Deck P(III).

APPENDIX D.

CHAPTER 4 TABLES AND FIGURES

Table D.1.

Number of Producing Structures Destroyed by Hurricanes Ivan, Katrina, and Rita

Structure Type	Oil	Gas
Caisson	4	12
Well Protector	6	7
Fixed Platform	32	49
Mini Tension Leg Platform	1	0
Total	43	68

Source: USDOI, MMS, 2006.

Table D.2.

Destroyed Structures that Restarted Production by August 2008

Complex	Operator	Area	Block	Hurricane	Production Type	Structure Type
397	Chevron U.S.A. Inc.	WC	172	Rita	Gas	CAIS
798	Energy Partners, Ltd.	EC	161	Rita	Gas	CAIS
1207	Dominion Exploration & Production, Inc.	MP	270	Katrina	Gas	FIXED
1479	Taylor Energy Company	SS	218	Rita	Gas	FIXED
1525	East Cameron Partners, LP	EC	71	Rita	Gas	CAIS
1529	Chevron U.S.A. Inc.	SS	181	Rita	Gas	CAIS
20677	Merit Energy Company	EC	254	Rita	Gas	FIXED
22438	BP Exploration & Production Inc.	WC	110	Rita	Gas	CAIS
22929	Energy Partners, Ltd.	EC	160	Rita	Gas	FIXED
32008	Gulf of Mexico Oil & Gas Properties LLC	SS	148	Rita	Gas	FIXED
32033	Chevron U.S.A. Inc.	SM	90	Rita	Gas	FIXED
80022	Newfield Exploration Company	SS	69	Rita	Gas	CAIS
20040	BP America Production Company	GI	47	Katrina	Oil	FIXED
20042	BP America Production Company	GI	40	Katrina	Oil	FIXED
20223	Anglo-Suisse Offshore Partners, LLC	WD	117	Katrina	Oil	FIXED
20224	Anglo-Suisse Offshore Partners, LLC	WD	117	Katrina	Oil	FIXED
20225	Anglo-Suisse Offshore Partners, LLC	WD	117	Katrina	Oil	FIXED
20981	Marlin Energy Offshore, LLC	ST	21	Katrina	Oil	WP
21599	Forest Oil Corporation	SM	11	Rita	Oil	WP
21802	Anglo-Suisse Offshore Partners, LLC	WD	117	Katrina	Oil	FIXED
23831	Newfield Exploration Company	MP	138	Katrina	Oil	FIXED

Source: USDOI, MMS, 2009b.

Table D.3.

Pre- and Post-Hurricane Daily Average Production Statistics for Destroyed Structures that Restarted Production by August 2008

Complex	Pre-Hurricane Daily Production[a]			Post-Hurricane Daily Production[b]			Post/Pre BOE Production Ratio
	Oil (BPD)	Gas (MCFPD)	BOE (BOEPD)	Oil (BPD)	Gas (MCFPD)	BOE (BOEPD)	
397	3.2	2,196.8	369.4	3.0	1,946.0	327.3	0.89
798	4.9	2,922.6	492.0	-	4,036.8	672.8	1.37
1207	62.4	2,364.1	456.5	445.6	17,357.8	3,338.6	7.31
1479[c]	-	-	-	143.7	13,185.0	2,341.2	N/A
1525[d]	34.4	4,689.3	816.0	13.1	2,202.5	380.2	0.47
1529[d]	249.4	4,526.3	1,003.8	578.8	13,612.7	2,847.5	2.84
20677	7.8	3,421.8	578.1	3.7	275.9	49.7	0.09
22438	2.3	3,360.5	562.4	252.2	40.1	258.9	0.46
22929	8.0	981.1	171.5	-	72.1	12.0	0.07
32008	7.0	1,736.9	296.5	2.3	739.8	125.6	0.42
32033	437.0	1,763.2	730.9	434.5	3,389.5	999.4	1.37
80022	53.7	149.7	78.7	43.6	143.7	67.6	0.86
20040	964.3	2,628.2	1,402.3	0.2	-	0.2	0.00
20042	45.0	156.4	71.1	3.1	-	3.1	0.04
20223	432.9	615.9	535.5	143.3	-	143.3	0.27
20224	104.8	212.4	140.2	6.2	-	6.2	0.04
20225	103.1	1,153.3	295.3	20.1	-	20.1	0.07
20981	131.4	99.4	148.0	127.5	175.6	156.8	1.06
21599[e]	-	-	-	0.0	19.8	3.3	N/A
21802	177.9	209.2	212.8	22.6	-	22.6	0.11
23831	55.6	261.9	99.2	1.2	-	1.2	0.01
Total[f]	2,885.3	33,449.1	8,460.2	2,101.0	43,992.6	9,433.1	1.10

Source: USDOI, MMS, 2009b.

a. Computed 1-year prior to each hurricane event and normalized on a daily basis.

b. Computed over the duration of post-hurricane production for producing months through August 2008.

c. Structure 1479 began operations in August 2005 but did not produce before being destroyed.

d. Structures 1525 and 1529 started producing 8 and 9 months before Hurricane Rita. Pre-hurricane daily production is averaged during this period.

e. Structure 21599 last produced in 2001 and was idle at the time Rita destroyed it. Production restarted in June 2006, and in August 2008, one of 6 wells were producing.

f. Post-hurricane production from 1479 and 21599 is not included in the aggregate production total.

Table D.4.

Pre- and Post-Hurricane Daily and Annual Revenue Statistics for Destroyed Structures that Restarted Production by August 2008

Complex	Production Type	Pre-Hurricane[a]		Post-Hurricane[b]		Post/Pre Daily Revenue Ratio
		Daily Revenue ($)	Annual Revenue ($1,000)	Daily Revenue ($)	Annual Revenue ($1,000)	
397	Gas	14,568	5,317	14,312	5,224	0.98
798	Gas	18,951	6,917	33,517	12,234	1.77
1207	Gas	17,835	6,510	155,815	56,872	8.74
1479[c]	Gas	-	-	106,693	38,943	N/A
1525[d]	Gas	22,771	8,311	16,330	5,961	0.72
1529[d]	Gas	33,598	12,263	145,791	53,214	4.34
20677	Gas	22,300	8,140	2,090	763	0.09
22438	Gas	22,413	8,181	26,641	9,724	1.19
22929	Gas	6,947	2,536	707	258	0.10
32008	Gas	12,059	4,401	6,029	2,201	0.50
32033	Gas	36,251	13,232	59,573	21,744	1.64
80022	Gas	3,995	1,458	4,588	1,675	1.15
20040	Oil	71,478	26,089	11	4	0.00
20042	Oil	3,505	1,279	298	109	0.08
20223	Oil	29,187	10,653	9,706	3,543	0.33
20224	Oil	7,275	2,655	421	154	0.06
20225	Oil	13,460	4,913	1,361	497	0.10
20981	Oil	7,901	2,884	12,216	4,459	1.55
21599[e]	Oil	-	-	142	52	N/A
21802	Oil	11,417	4,167	1,528	558	0.13
23831	Oil	4,553	1,662	79	29	0.02
Total[f]		360,462	131,569	491,015	179,221	1.36

a. Computed 1-year prior to each hurricane event based on monthly average oil and gas prices adjusted using CPI.

b. Computed over the duration of post-hurricane production for producing months through August 2008 and based on monthly average oil and gas prices adjusted using CPI.

c. Structure 1479 began operations in August 2005 but did not produce before being destroyed.

d. Structures 1525 and 1529 started producing 8 and 9 months before Hurricane Rita. Pre-hurricane daily production is averaged during this period.

e. Structure 21599 last produced in 2001 and was idle at the time Rita destroyed it. Production restarted in June 2006, and in August 2008, one of 6 wells were producing.

f. Post-hurricane production from 1479 and 21599 is not included in the aggregate production total.

Table D.5.

Post/pre-Hurricane Production and Revenue Ratio Distribution for Destroyed Structures that Restarted Production

Ratio	Production			Revenue		
	Gas	Oil	All	Gas	Oil	All
0-0.5	5	7	13	3	7	11
0.5-1.0	2	0	2	2	0	2
1.0-1.5	2	1	3	2	0	2
1.5-2.0	0	0	0	2	1	3
2-4	1	0	1	0	0	0
4-6	0	0	0	1	0	1
6-8	1	0	1	0	0	0
8-10	0	0	0	1	0	1
All	11	8	20	11	8	20
Average (SD)[a]	1.63(2.09)	0.21(0.33)	0.79(1.66)	2.20(2.54)	0.20(0.49)	1.00(2.05)

a. SD = Standard deviation

Table D.6.

Post/Pre-Hurricane Revenue Ratios for Destroyed Structures that Restarted Production

Pre-Hurricane Production (BOEPD)	Gas Structures			Oil Structures			All Structures		
	Pre-Hurricane Aggregate Daily Revenue (US Dollar)	Post-Hurricane Aggregate Daily Revenue (US Dollar)	Ratio	Pre-Hurricane Aggregate Daily Revenue (US Dollar)	Post-Hurricane Aggregate Daily Revenue (US Dollar)	Ratio	Pre-Hurricane Aggregate Daily Revenue (US Dollar)	Post-Hurricane Aggregate Daily Revenue (US Dollar)	Ratio
<100	3,995	4,588	1.15	8,058	377	0.05	12,053	4,965	0.41
100 - 250	6,947	707	0.10	26,593	14,165	0.53	33,540	14,872	0.44
250 - 500	63,413	209,673	3.31	13,460	1,361	0.10	76,873	211,034	2.75
500 – 1,000	103,735	104,634	1.01	29,187	9,706	0.33	132,922	114,340	0.86
1,000 - 2,500	33,598	145,791	4.34	71,478	11	0.00	105,076	145,802	1.39
2,500 - 5,000	0	0	-	0	0	-	0	0	-
5,000 - 10,000	0	0	-	0	0	-	0	0	-
>10,000	0	0	-	0	0	-	0	0	-
All	211,688	465,393	2.20	148,776	25,620	0.17	360,464	491,013	1.36

Table D.7.

Hurricane Destroyed Structures Redevelopment Rate by Pre-Hurricane Production Rates

Gas Structures

Pre-Hurricane Production (MCFEPD)	Restarted	Not Restarted	Restart Rate[a] (%)
<600	1	28	3
600 – 1,500	1	8	11
1,500 – 3,000	4	6	40
3,000 – 6,000	4	9	31
6,000 - 15,000	1	4	20
15,000 - 30,000	0	1	0
30,000 - 60,000	0	0	-
>60,000	0	0	-
All	11	56	16

Oil Structures

Pre-Hurricane Production (BOEPD)	Restarted	Not Restarted	Restart Rate[a] (%)
<100	2	12	14
100 - 250	3	7	30
250 - 500	1	6	14
500 – 1,000	1	6	14
1,000 - 2,500	0	2	0
2,500 - 5,000	1	0	100
5,000 - 10,000	0	0	-
>10,000	0	1[b]	0
All	8	34	19

All Structures

Pre-Hurricane Production (BOEPD)	Restarted	Not Restarted	Restart Rate[a] (%)
<100	3	40	7
100 - 250	4	15	21
250 - 500	5	12	29
500 – 1,000	5	15	25
1,000 - 2,500	1	6	14
2,500 - 5,000	1	1	50
5,000 - 10,000	0	0	-
>10,000	0	1[b]	0
All	19	90	17

a. Restart rates are based on production statistics through August 2008.
b. The Typhoon field announced a plan to restart production in 2009-2010.

Table D.8.

Hurricane Destroyed Structures Restart Rate by the Number of Pre-Hurricane Producing Wells

Gas Structures

Pre-Hurricane Producing Wells	Restarted	Not Restarted	Restart Rate[a] (%)
0	0	23	0
1	3	13	19
2	4	8	33
3-4	4	9	31
>4	0	3	0
All	11	56	16

Oil Structures

Pre-Hurricane Producing Wells	Restarted	Not Restarted	Restart Rate[a] (%)
0	0	10	0
1	2	6	25
2	2	7	22
3-4	1	2	33
>4	3	9	25
All	8	34	19

All Structures

Pre-Hurricane Producing Wells	Restarted	Not Restarted	Restart Rate[a] (%)
0	0	33	0
1	5	19	21
2	6	15	29
3-4	5	11	31
>4	3	12	20
All	19	90	17

a. Restart rates are based on production statistics through August 2008.

Table D.9.

Hurricane Destroyed Structures Restart Rate by Expected Remaining Reserves

Gas Structures

Remaining Reserves[a] (MBOE)	Restarted	Not Restarted	Restart Rate[b] (%)
<100	4	27	13
100-250	2	5	29
250-500	1	7	13
500-1,000	2	9	18
1,000-2,500	2	4	33
2,500-5,000	0	3	0
5,000-20,000	0	1	0
All	11	56	16

Oil Structures

Remaining Reserves[a] (MBOE)	Restarted	Not Restarted	Restart Rate[b] (%)
<100	6	17	26
100-250	0	6	0
250-500	1	2	33
500-1,000	0	4	0
1,000-2,500	0	2	0
2,500-5,000	1	1	50
5,000-20,000	0	2	0
All	8	34	19

All Structures

Remaining Reserves[a] (MBOE)	Restarted	Not Restarted	Restart Rate[b] (%)
<100	10	44	19
100-250	2	11	15
250-500	2	9	18
500-1,000	2	13	13
1,000-2,500	2	6	25
2,500-5,000	1	4	20
5,000-20,000	0	3	0
All	19	90	17

a. Remaining reserves are estimated on a structure basis as depicted in Table D.13 (restarted) and Table D.18 (not restarted).

b. Restart rates are based on production statistics through August 2008.

Table D.10.

Exploration and Development Plans on Leases that Restarted Production as of February 2009

Block	Complex	Number of Plans 8/05-2/09	Plan Date	Plan Type[a]	Description
WC 712	397	0			
EC 161	798	0			
MP 270	1207	0			
SS 218	1525	0			
EC 71	1529	1	3/14/07	DOCD	
SS 181	20677	0			
EC 254	22438	1	8/13/07	DOCD	
WC 110	22929	2	9/11/06	DOCD	
			5/11/07	DOCD	
EC 160	32008	0			
SS 148	32033	0			
SM 90	80022	0			
SS 69	20040	0			
GI 47	20042	2	8/21/06	EP	Drill six wells (five wells on GI 47, One on GI 40) and install well protector
			10/24/06	DOCD	
GI 40[b]	20223	2			
WD 117	20224	1	12/16/05	DOCD	Drill six wells and install a 4-pile platform
WD 118	20225	0			
WD 119	20981	0			
ST 21	21599	8	1/23/06	EP	
			2/7/06	DOCD	
			2/16/06	DOCD	
			3/2/06	DOCD	
			3/22/06	DOCD	
			7/27/06	DOCD	Drill one well and install caisson
			12/19/06	DOCD	
			10/23/06	DOCD	
SM 11	21802	1	7/14/08	DOCD	
MP 138	23831	1	6/15/06	DOCD	Drill four wells and install fixed platform to replace two destroyed platforms

Source: USDOI, MMS, 2009b.
a. EP = Exploration Plan, DOCD = Development Operations Coordination Document.
b. Development plans for GI 47 and GI 40 are combined.

Table D.11.

Post-Hurricane Cumulative Production, Drilling Activity Levels, and Percentage of Reserves Remaining as of August 2008

Complex[a]	Daily Revenue ($)	Post-Hurricane Cumulative Production (BOE)	Post-Hurricane Cumulative Production (MMCFE)	Percentage of Remaining Reserves[b] ($60/bbl)	Percentage of Remaining Reserves[b] ($140/bbl)	Post-Hurricane Development Wells	Post-Hurricane Sidetrack[c] Wells
397*	14,312	284,739.8	1,708.4	24%	23%	0	0
798*	33,517	161,473.8	968.8	66%	64%	0	0
1207	155,815	2,904,544.3	17,427.3	307%	298%	1	0
1525†	16,330	273,718.5	1,642.3	450%	306%	0	0
1529*	145,791	2,904,487.2	17,426.9	6514%	5610%	2	0
20677	2,090	11,930.0	71.6	8%	7%	0	0
22438	26,641	23,301.8	139.8	2%	2%	0	0
22929	707	360.5	2.2	2%	1%	0	0
32008*	6,029	128,134.8	768.8	22%	20%	0	0
32033*	59,573	809,550.0	4,857.3	470%	427%	4	3
80022†	4,588	70,969.5	425.8	542%	130%	0	0
20040	11	32.0		0%	0%	0	0
20042	298	93.0		0%	0%	0	0
20223	9,706	8,599.0		N/A	81%	3	2
20224	421	373.0		1%	0%	0	0
20225	1,361	1,206.0		2%	1%	0	0
20981‡	12,216	122,291.7		N/A[d]	N/A[d]	0	0
21599	142	1,981		N/A[d]	N/A[d]	0	0
21802	1,528	1,354.0		4%	2%	0	0
23831	79	111.0		0%	0%	0	0
Total	491,157	7,709,251	45,439	43%	42%	10	5

a. Asterisk (*) denotes structure was producing August 2008. Cross (†) denotes structure producing in December 2008. Double cross (‡) denotes structure has been decommissioned.

b. Post-hurricane cumulative production divided by estimated remaining reserves computed in Table D.13.

c. A sidetrack well is a well planned and drilled from the bore of a previous well in order to achieve a geologic objective. Sidetracks do not represent a new well.

d. Structures 20981 and 21599 were evaluated as uneconomic and by default will have no remaining reserves (zero denominator term).

Table D.12.

Time Offline, Duration of Production, and Last Producing Month for Structures that Restarted Production

Complex	Hurricane	Production Type	Time offline (mo)	Duration of Production (mo)	Last Producing Month	DOCD Plan on Lease	Last Plan Date
397	Rita	Gas	6	29	2008 Aug.	No	
798	Rita	Gas	27	8	2008 Aug.	No	
1207	Katrina	Gas	4	29	2008 June	No	
1479	Rita	Gas	8	27	2008 Aug.	No	
1525	Rita	Gas	11	24	2008 Aug.	Yes	3/14/07
1529	Rita	Gas	1	34	2008 Aug.	No	
20677	Rita	Gas	7	8	2006 Dec.	Yes	8/13/07
22438	Rita	Gas	28	3	2008 Apr.	Yes	5/11/07
22929	Rita	Gas	31	1	2008 May	No	
32008	Rita	Gas	1	34	2008 Aug.	No	
32033	Rita	Gas	8	27	2008 Aug.	No	
80022	Rita	Gas	0	35	2008 Aug.	No	
20040	Katrina	Oil	9	7	2007 Jan.	No	
20042	Katrina	Oil	27	1	2008 Jan.	Yes	10/24/06
20223	Katrina	Oil	4	2	2006 Mar.	Yes	10/24/06
20224	Katrina	Oil	4	2	2006 Mar.	Yes	12/16/05
20225	Katrina	Oil	4	2	2006 Mar.	No	
20981	Katrina	Oil	9	26	2008 Aug.	No	
21599	Rita	Oil	11	20	2008 Apr.	Yes	10/23/06
21802	Katrina	Oil	4	2	2006 Mar.	Yes	7/14/08
23831	Katrina	Oil	17	3	2007 May	Yes	6/15/06

Source: USDOI, MMS, 2008.

Table D.13.

Estimated Remaining Reserves and Discounted Gross Revenue for Redeveloped Structures[a] – I. One Year Time Shift

Complex	Remaining Reserves[b] (MBOE)	Discounted Revenue at 10%[c] ($1,000)				
		$60/bbl	$80/bbl	$100/bbl	$120/bbl	$140/bbl
397	1,191 – 1,233	29,951	40,339	50,424	60,627	70,731
798	245 - 254	6,686	8,915	11,430	13,716	16,002
1207	945 - 975	26,159	34,879	43,979	53,116	61,968
1525	61 - 89	1,996	3,667	4,584	5,501	6,418
1529	45 - 52	1,645	2,193	2,741	3,740	4,363
20040	2,843 – 2,887	77,361	103,177	129,005	154,823	180,634
20042	39 - 83	1,694	2,876	4,310	5,364	6,592
20223	0 - 11	0	723	904	1,085	1,265
20224	36 - 75	1,649	3,006	4,389	5,531	6,697
20225	80 - 92	3,504	5,039	6,299	7,559	9,153
20677	144 - 165	4,450	6,322	7,903	9,844	11,484
20981[d]	0 - 0	0	0	0	0	0
21599[d]	0 - 0	0	0	0	0	0
21802	33 - 87	1,579	3,366	5,152	6,565	8,005
22438	1,201 – 1,290	23,487	31,508	39,482	47,457	55,429
22929	21 - 39	711	1,430	1,788	2,145	2,933
23831	227 - 305	8,174	11,697	15,027	18,362	21,682
32008	579 - 643	13,517	18,202	22,959	27,652	32,304
32033	172 - 190	5,848	7,798	10,151	12,489	14,570
80022	13 - 55	515	1,204	2,763	3,316	4,167
Subtotal[e]	5,569 - 6,009	148,768	204,023	258,238	311,851	365,842
Subtotal[f]	2,306 – 2,516	60,158	82,318	105,052	127,041	148,555
Total	7,875 – 8,525	208,926	286,341	363,290	438,892	514,397

a. Structure 1479 is excluded from analysis.
b. Remaining reserves are presented as a range corresponding to oil prices from $60/bbl - $140/bbl.
c. Computed based on the assumption that first revenue occurred one year after destruction.
d. Structure was evaluated as uneconomic.
e. Computed based on structures not producing as of August 2008.
f. Computed based on structures producing as of August 2008.

Table D.14.

Estimated Remaining Reserves and Discounted Revenue for Redeveloped Structures[a] – II. Two Year Time Shift

Complex	Remaining Reserves[b] (MBOE)	Discounted Revenue at 10%[c] ($1,000)				
		$60/bbl	$80/bbl	$100/bbl	$120/bbl	$140/bbl
397	1,191 - 1,233	27,229	36,672	45,840	55,115	64,301
798	245 - 254	6,078	8,104	10,391	12,469	14,547
1207	945 - 975	23,781	31,708	39,981	48,287	56,335
1525	61 - 89	1,815	3,334	4,167	5,001	5,834
1529	45 - 52	1,495	1,993	2,492	3,400	3,967
20040	2,843 - 2,887	70,328	93,797	117,278	140,748	164,213
20042	39 - 83	1,540	2,614	3,918	4,876	5,993
20223	0 - 11	0	657	822	986	1,150
20224	36 - 75	1,499	2,733	3,990	5,028	6,089
20225	80 - 92	3,185	4,581	5,726	6,871	8,321
20677	144 - 165	4,046	5,747	7,184	8,949	10,440
20981[d]	0 - 0	0	0	0	0	0
21599[d]	0 - 0	0	0	0	0	0
21802	33 - 87	1,435	3,060	4,684	5,968	7,277
22438	1,201 - 1,290	21,352	28,643	35,892	43,143	50,390
22929	21 - 39	646	1,300	1,625	1,950	2,666
23831	227 - 305	7,431	10,634	13,661	16,692	19,711
32008	579 - 643	12,288	16,547	20,872	25,138	29,367
32033	172 - 190	5,317	7,089	9,229	11,353	13,246
80022	13 - 55	468	1,095	2,512	3,015	3,788
Subtotal[e]	5,569 – 6,009	135,243	185,474	234,761	283,498	332,585
Subtotal[f]	2,306 – 2,516	54,690	74,834	95,503	115,491	135,050
Total	7,875 – 8,525	189,933	260,308	330,264	398,989	467,635

a. Structure 1479 is excluded from analysis.
b. Remaining reserves are presented as a range corresponding to oil prices from $60/bbl - $140/bbl.
c. Computed based on the assumption that first revenue occurred two years after destruction.
d. Structure was evaluated as uneconomic.
e. Computed for structures not producing as of August 2008.
f. Computed for structures producing as of August 2008.

Table D.15.

Producing Wells, Drilled Wells, and Plugged and Abandoned (P&A) Wells for Redeveloped Structures

Complex	Production Type	Number of Producing Wells		Cumulative Number of Drilled Wells	Cumulative Number of P&A Wells
		Pre-Hurricane	Post-Hurricane		
397	Gas	2	2	3	0
798	Gas	3	0[a]	4	1
1207	Gas	3	3	4	0
1479	Gas	0	3	4	1
1525	Gas	1	1	3	2
1529	Gas	3	3	3	0
20677	Gas	3	1	17	13
22438	Gas	1	0	1	0
22929	Gas	2	0	3	0
32008	Gas	2	1	2	0
32033	Gas	2	2	8	0
80022	Gas	1	1	1	0
20040	Oil	8	1	24	3
20042	Oil	1	0	16	3
20223	Oil	6	6	21	6
20224	Oil	2	2	14	4
20225	Oil	3	2	23	8
20981	Oil	1	1	2	0
21599	Oil	0	1	6	0
21802	Oil	2	2	32	10
23831	Oil	5	1	12	0
Total		54	33	203	51

Source: USDOI, MMS, 2008.

a. Producing structures with no post-hurricane producing wells may be due to clerical error, late reporting, or a failure to update records. An incorrect well assignment may also lead to erroneous results.

Table D.16.

Structures with ≥ 250 BOEPD Pre-Hurricane Production Not Redeveloped, August 2008

Complex	Production Type	Area Block	Hurricane	Structure Type	Plan Filed	Pre-Hurricane Daily Production			Pre-Hurricane Daily Revenue (US Dollar)
						Oil (BPD)	Gas (MCFPD)	BOE (BOEPD)	
20901	Gas	SM11	Rita	WP	Yes	197	333	252	13,258
21602	Gas	SM49	Rita	FIXED	No	8	1,496	257	10,291
23257	Gas	MP98	Ivan	FIXED	No	1	1,842	307	10,672
20606	Gas	ST135	Katrina	FIXED	No	41	1,770	336	13,627
20123	Gas	WC176	Rita	WP	Yes	198	1,424	435	20,498
669	Gas	WD137	Katrina	FIXED	No	44	2,470	456	18,662
20958	Gas	ST161	Rita	FIXED	No	2	3,028	506	19,922
20940	Gas	EC272	Rita	FIXED	Yes	151	2,352	543	23,936
20025	Gas	WD70	Katrina	FIXED	No	437	838	577	29,797
20527	Gas	VR255	Rita	FIXED	No	337	1,711	622	30,886
21573	Gas	EI276	Rita	FIXED	Yes	554	888	702	37,221
20524	Gas	VR217	Rita	FIXED	Yes	48	4,125	735	31,687
20708	Gas	SM108	Rita	FIXED	Yes	2	4,998	835	34,053
20959	Gas	ST161	Katrina	FIXED	No	6	5,217	876	34,918
20031	Gas	GI32	Katrina	FIXED	Yes	746	1,090	928	48,674
21581	Gas	EI333	Rita	FIXED	No	46	6,165	1,073	43,359
20655	Gas	SM76	Rita	FIXED	Yes	14	8,205	1,381	54,500
96	Gas	MP312	Katrina	FIXED	Yes	838	6,584	1,935	90,419
21994	Gas	ST51	Rita	FIXED	Yes	443	12,055	2,452	109,041
80011	Gas	SS193	Rita	FIXED	Yes	211	19,068	3,389	135,460
20618	Oil	ST151	Katrina	FIXED	No	209	334	264	13,941
20045	Oil	GI40	Katrina	FIXED	No	314	197	346	18,904
20228	Oil	WD103	Katrina	FIXED	No	338	307	389	20,999
20450	Oil	MP293	Ivan	FIXED	No	384	237	423	16,957
21571	Oil	EI276	Rita	FIXED	Yes	366	367	427	22,951
20982	Oil	ST21	Katrina	WP	No	439	232	478	26,043
20229	Oil	WD103	Katrina	FIXED	No	489	511	575	30,747
20446	Oil	MP305	Ivan	FIXED	No	488	1,057	664	27,563
21582	Oil	EI338	Rita	FIXED	Yes	582	1,133	770	39,615
20449	Oil	MP306	Ivan	FIXED	No	740	674	852	35,512
21763	Oil	EC322	Rita	FIXED	No	701	1,068	879	46,378
20612	Oil	ST151	Katrina	FIXED	No	791	1,194	990	52,723
20615	Oil	ST151	Katrina	FIXED	No	1,835	2,192	2,200	117,085
735	Oil	GC237	Rita	MTLP	Yes	21,492	34,763	27,285	1,413,483
Subtotal						11,999	95,161	27,859	1,280,299
Total						13,479	104,724	30,933	1,427,205

Table D.17.

Pre-Hurricane Daily Revenue Distribution and Redevelopment Rates for Structures that Have Not Restarted Production as of August 2008

Pre-Hurricane Daily Revenue ($1,000/d)	Structures			DOCD Plans Submitted			Redevelopment Rates[a]		
	Gas	Oil	All	Gas	Oil	All	Gas (%)	Oil (%)	All (%)
<10	35	16	51	0	0	0	0	0	0
10-25	9	8	17	3	1	4	33	13	24
25-50	8	6	14	4	1	5	50	17	36
50-100	2	1	3	2	0	2	100	0	67
100-200	2	1	3	2	0	2	100	0	67
>200	0	1	1	0	1	1	N/A	100	100
All	56	33	89	11	3	14	20	9	16

a. Computed as the ratio of DOCD plans submitted to the total number of structures in each category.

Table D.18.

Estimated Remaining Reserves and Discounted Revenue for Top 25 Structures that Have Not Been Redeveloped as of February 2009 – I. One Year Time Shift

Complex	Remaining Reserves (MBOE)	Discounted Revenue at 10%[a] ($1,000)				
		$60/bbl	$80/bbl	$100/bbl	$120/bbl	$140/bbl
735	17,073 - 17,073	570,013	760,017	950,021	1,140,026	1,330,030
21994	4,908 - 4,952	122,202	163,064	203,882	244,704	285,529
20615	4,313 - 4,393	117,153	156,279	195,386	234,494	273,600
80011	5,162 - 5,232	112,023	149,404	186,782	224,146	261,516
20606	2,897 - 2,965	68,955	92,019	115,064	138,109	161,141
20524	3,166 - 3,248	61,351	81,887	102,402	122,918	143,419
669	1,684 - 1,708	44,886	59,848	74,810	90,093	105,384
20655	2,212 - 2,299	42,293	56,520	70,715	84,911	99,086
20450	1,624 - 1,691	40,812	54,477	68,127	81,769	95,410
96	1,256 - 1,293	35,050	47,249	59,061	70,874	82,686
20045	1,389 - 1,458	31,524	42,085	52,634	63,181	73,722
20982	943 - 958	26,104	34,819	43,531	52,243	60,953
20447	817 - 873	24,526	32,856	41,180	49,471	57,740
20123	926 - 980	23,983	32,109	40,203	48,298	56,390
21763	601 - 620	23,213	31,131	39,071	46,886	54,853
20723	918 - 996	22,787	30,617	38,391	46,166	53,937
20026	496 - 579	15,089	20,570	25,946	31,328	36,704
20025	513 - 578	14,303	19,399	24,417	29,437	34,403
20612	290 - 305	12,893	17,191	21,920	26,303	31,051
23257	387 - 432	9,723	13,337	16,824	20,327	23,838
21573	244 - 263	9,253	12,728	15,910	19,438	22,678
20449	250 - 295	9,073	12,574	15,948	19,238	22,538
20527	245 - 261	8,993	11,991	15,353	18,699	21,815
12	274 - 297	7,405	9,873	12,737	15,285	18,142
20708	229 - 275	6,361	9,151	11,692	14,030	16,625
Subtotal[b]	2,179 - 2,504	62,561	86,261	110,545	134,258	157,745
Subtotal[c]	35,321 - 35,799	988,853	1,321,080	1,652,393	1,984,366	2,315,901
Total[d]	54,080 - 56,025	1,506,105	2,023,937	2,541,878	3,058,498	3,574,357

a. Computed based on the assumption that first revenue occurred one year after initial redevelopment investment.
b. Computed based on structures that have been decommissioned by February 2009.
c. Computed based on structures/leases that filed an EP or DOCD by February 2009.
d. For all 61 structures that have not restarted production.

Table D.19.

Estimated Remaining Reserves and Discounted Revenue for Top 25 Structures that Have Not Been Redeveloped as of February 2009 – II. Two Year Time Shift

Complex	Remaining Reserves (MBOE)	Discounted Revenue at 10%[a] ($1,000)				
		$60/bbl	$80/bbl	$100/bbl	$120/bbl	$140/bbl
735	17,073 - 17,073	518,193	690,925	863,656	1,036,387	1,209,118
21994	4,908 - 4,952	111,093	148,240	185,347	222,458	259,571
20615	4,313 - 4,393	106,503	142,071	177,624	213,176	248,728
80011	5,162 - 5,232	101,839	135,821	169,802	203,769	237,742
20606	2,897 - 2,965	62,686	83,653	104,603	125,553	146,492
20524	3,166 - 3,248	55,774	74,443	93,093	111,743	130,381
669	1,684 - 1,708	40,806	54,408	68,010	81,903	95,804
20655	2,212 - 2,299	38,448	51,382	64,286	77,192	90,078
20450	1,624 - 1,691	37,102	49,525	61,934	74,335	86,737
96	1,256 - 1,293	31,864	42,954	53,692	64,431	75,169
20045	1,389 - 1,458	28,659	38,260	47,849	57,438	67,020
20982	943 - 958	23,731	31,654	39,574	47,494	55,412
20447	817 - 873	22,296	29,869	37,437	44,974	52,491
20123	926 - 980	21,802	29,190	36,548	43,907	51,264
21763	601 - 620	21,103	28,301	35,519	42,623	49,867
20723	918 - 996	20,716	27,834	34,901	41,969	49,034
20026	496 - 579	13,717	18,700	23,588	28,480	33,367
20025	513 - 578	13,003	17,636	22,197	26,761	31,275
20612	290 - 305	11,721	15,628	19,927	23,912	28,229
23257	387 - 432	8,840	12,125	15,294	18,479	21,671
21573	244 - 263	8,412	11,571	14,464	17,671	20,617
20449	250 - 295	8,248	11,431	14,498	17,489	20,489
20527	245 - 261	8,176	10,901	13,958	16,999	19,832
12	274 - 297	6,732	8,976	11,579	13,895	16,493
20708	229 - 275	5,783	8,319	10,629	12,755	15,113
Subtotal[b]	2,179 - 2,504	56,873	78,419	100,496	122,053	143,405
Subtotal[c]	35,321 - 35,799	898,957	1,200,982	1,502,175	1,803,969	2,105,365
Total[d]	54,080 - 56,025	1,369,186	1,839,943	2,310,798	2,780,453	3,249,415

a. Computed based on the assumption that first revenue occurred one year after initial redevelopment investment.
b. Computed based on structures that have been decommissioned by February 2009.
c. Computed based on structures/leases that filed an EP or DOCD by February 2009.
d. For all 61 structures that have not restarted production.

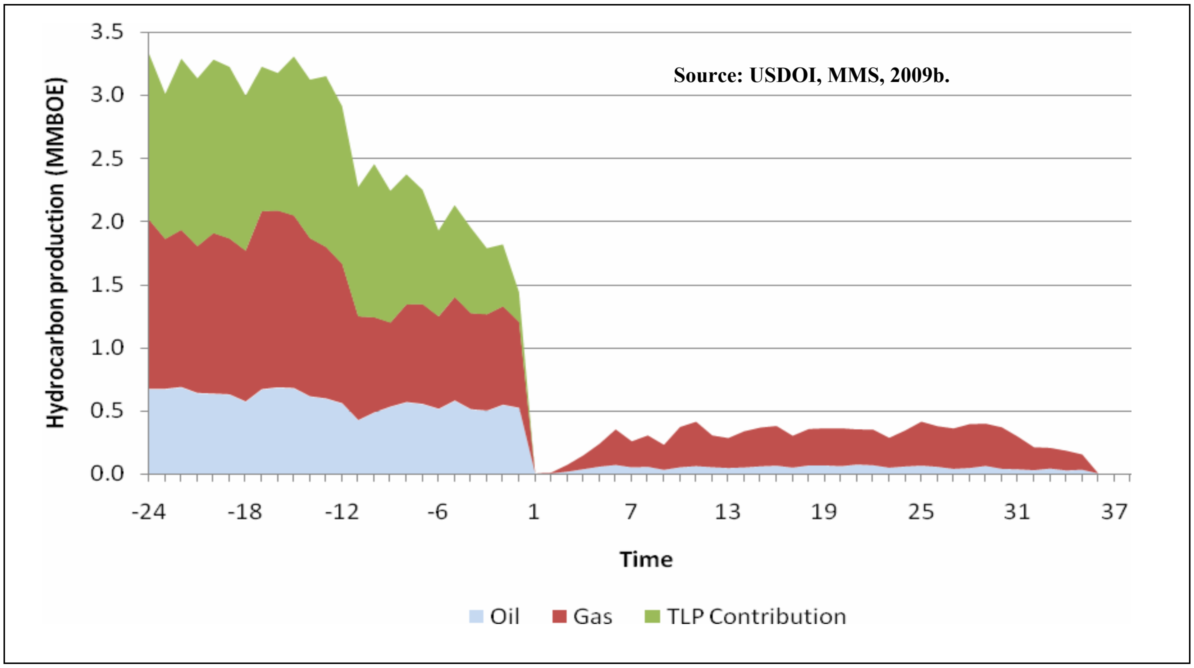


Figure D.1 Pre- and Post-Hurricane Production from All Structures Destroyed by Ivan, Katrina, and Rita. (Time unit is month and is set at 1 for the first month after each hurricane event and ends in December 2008.)

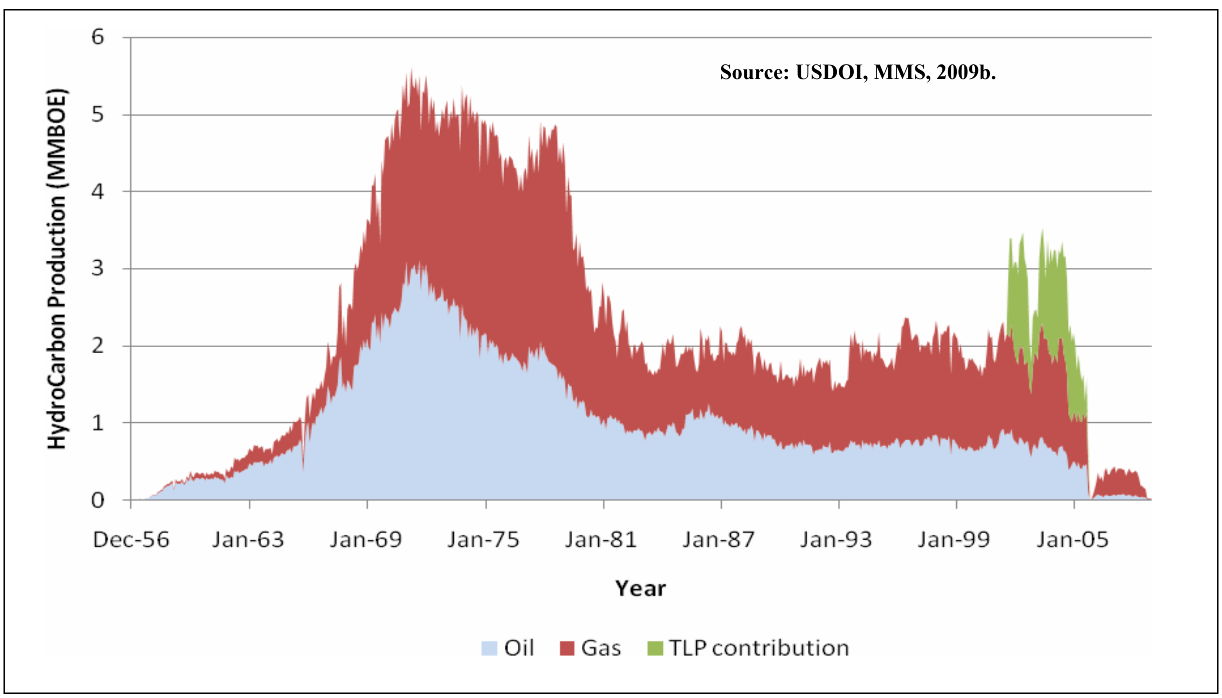


Figure D.2. Longer Term View of Production from All Structures Destroyed by Ivan, Katrina, and Rita through December 2008.

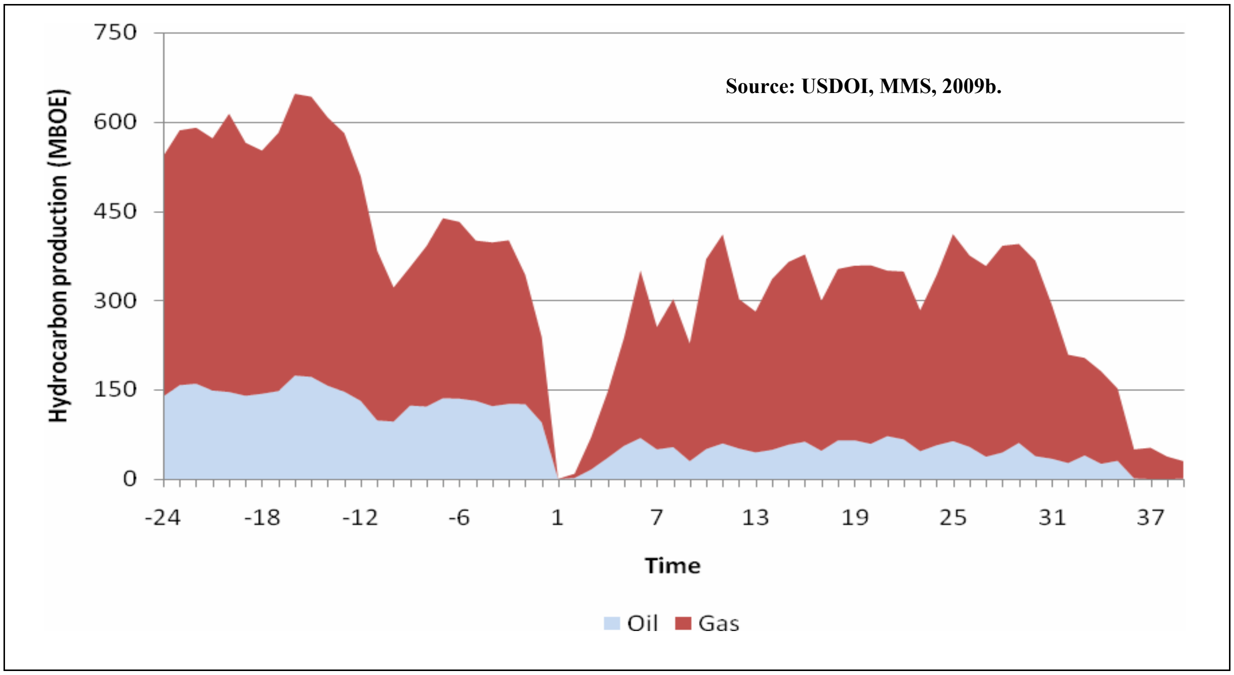


Figure D.3. Pre- and Post-Hurricane Production from Destroyed Structures that Restarted Production. (Time unit is month and is set at 1 for the first month after each hurricane event through December 2008.)

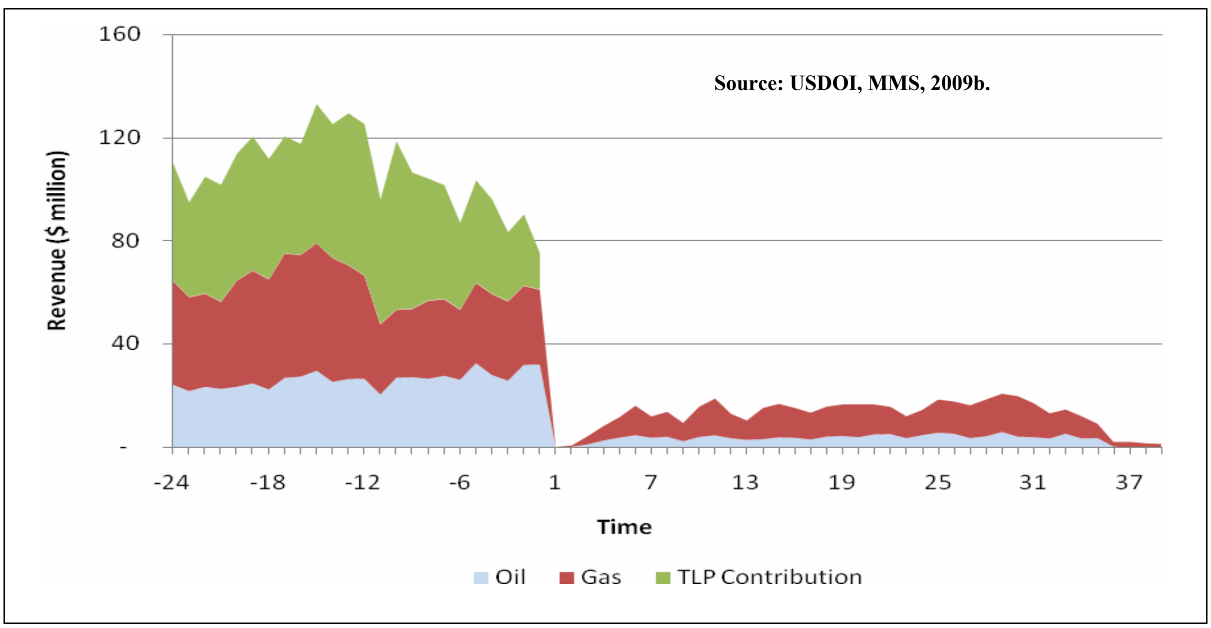


Figure D.4. Pre- and Post-Hurricane Aggregate Monthly Gross Revenue from All Structures Destroyed by Ivan, Katrina, and Rita. (Time unit is month and is set at 1 for the first month after each hurricane through December 2008.)

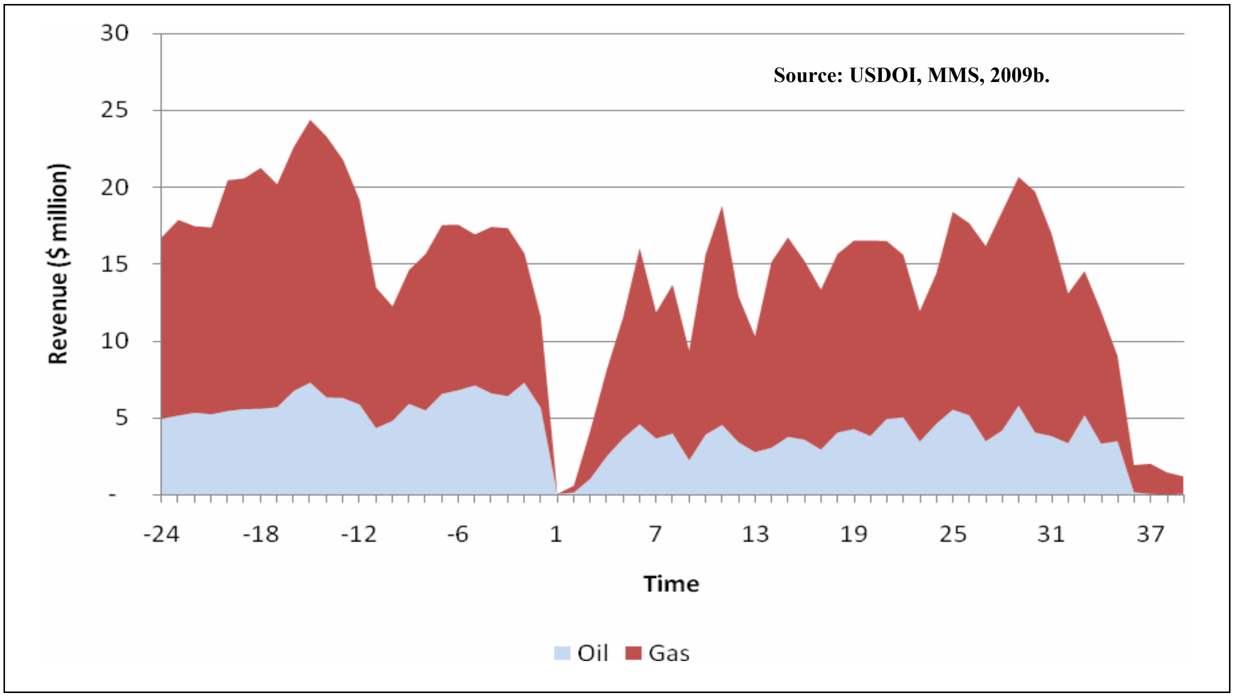


Figure D.5. Pre- and Post-Hurricane Aggregate Monthly Gross Revenue from Destroyed Structures that Restarted Production through December 2008. (Time unit is month and is set at 1 for the first month after each hurricane event.)

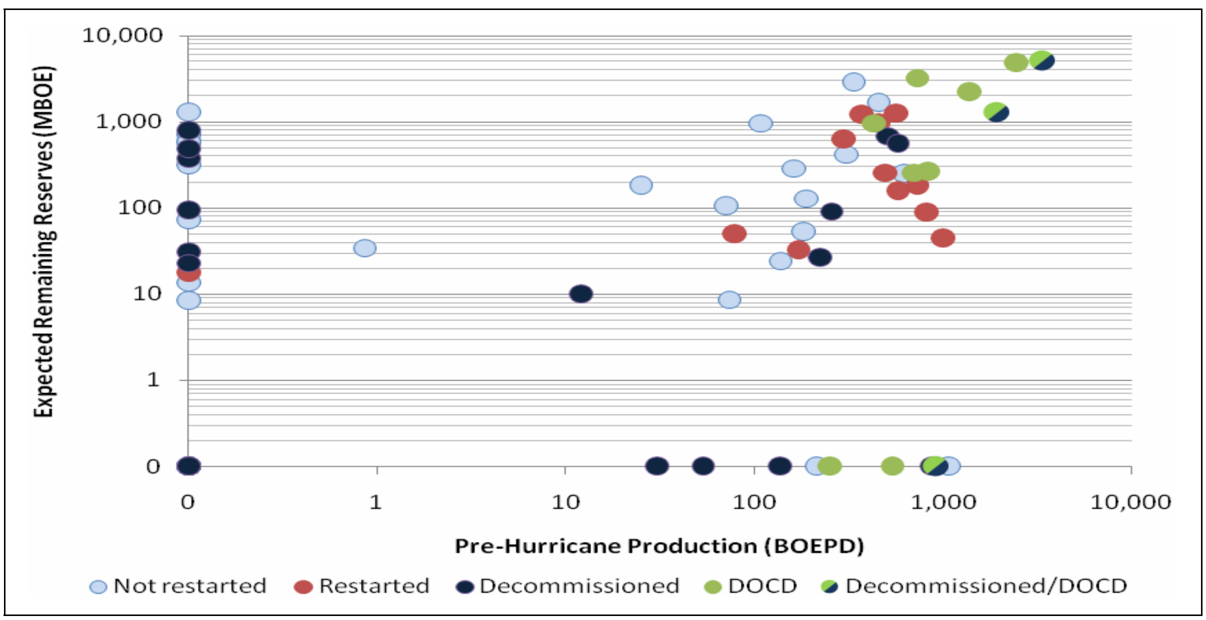


Figure D.6. Gas Structures that Restarted Production, Leases that Have Submitted DOCD Plans, Structures that Have Been Decommissioned, and Those Structures that Have Not Restarted Production.

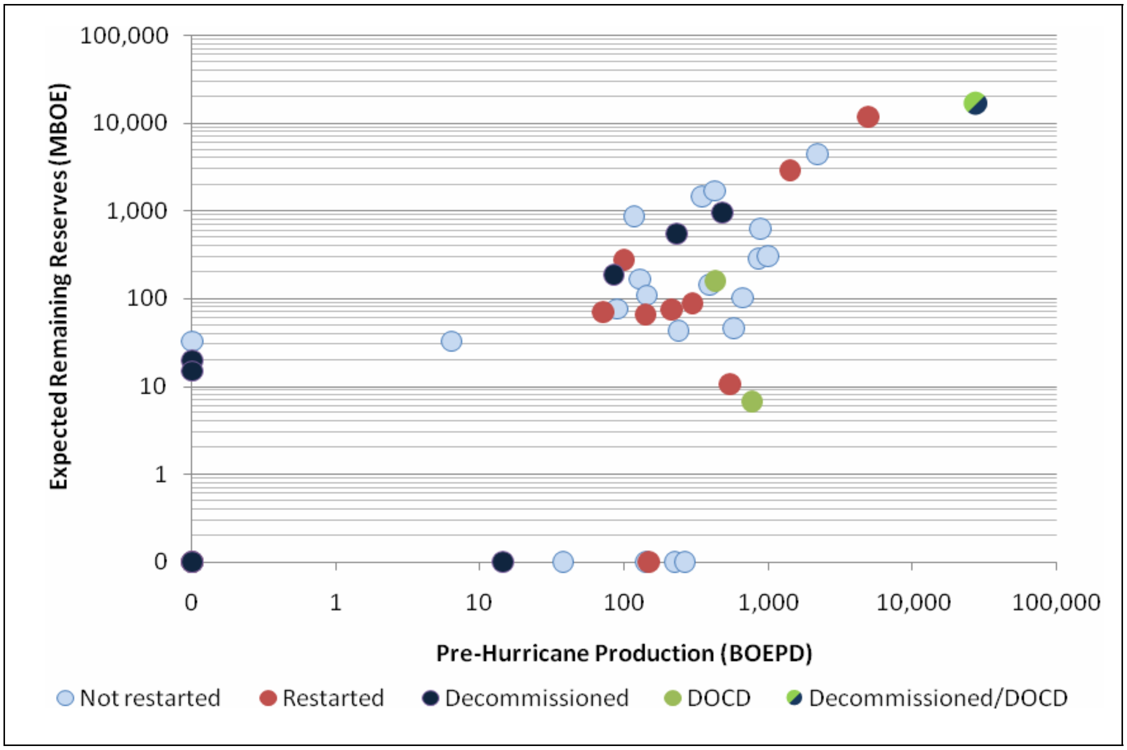


Figure D.7. Oil Structures that Restarted Production, Leases that Have Submitted DOCD Plans, Structures that Have Been Decommissioned, and Those Structures that Have Not Restarted Production.

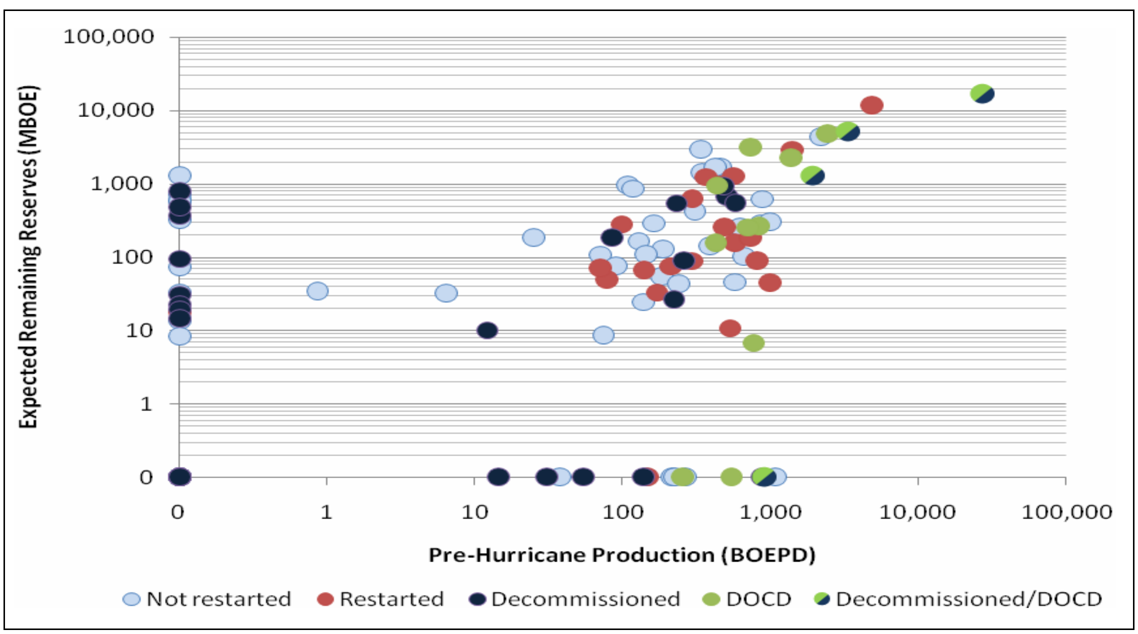


Figure D.8. All Structures that Restarted Production, Leases that Have Submitted DOCD Plans, Structures that Have Been Decommissioned, and Those Structures that Have Not Restarted Production.

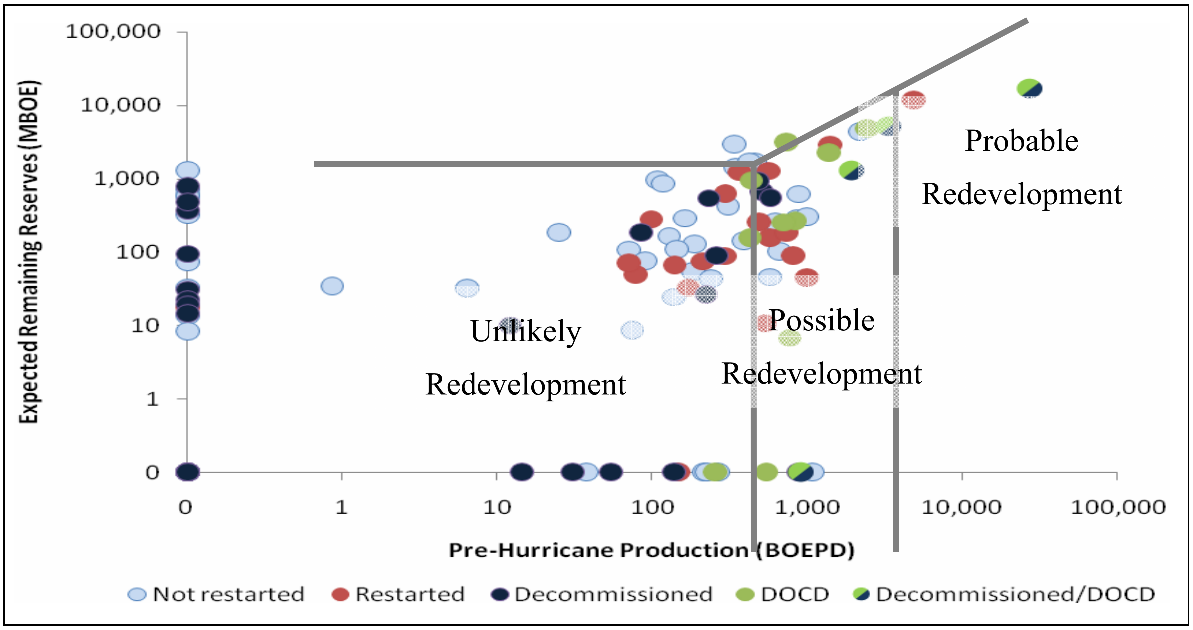


Figure D.9. Redevelopment Opportunities Outlined by Regions: (I) Unlikely Redevelopment, (II) Possible Redevelopment, and (III) Probable Redevelopment.

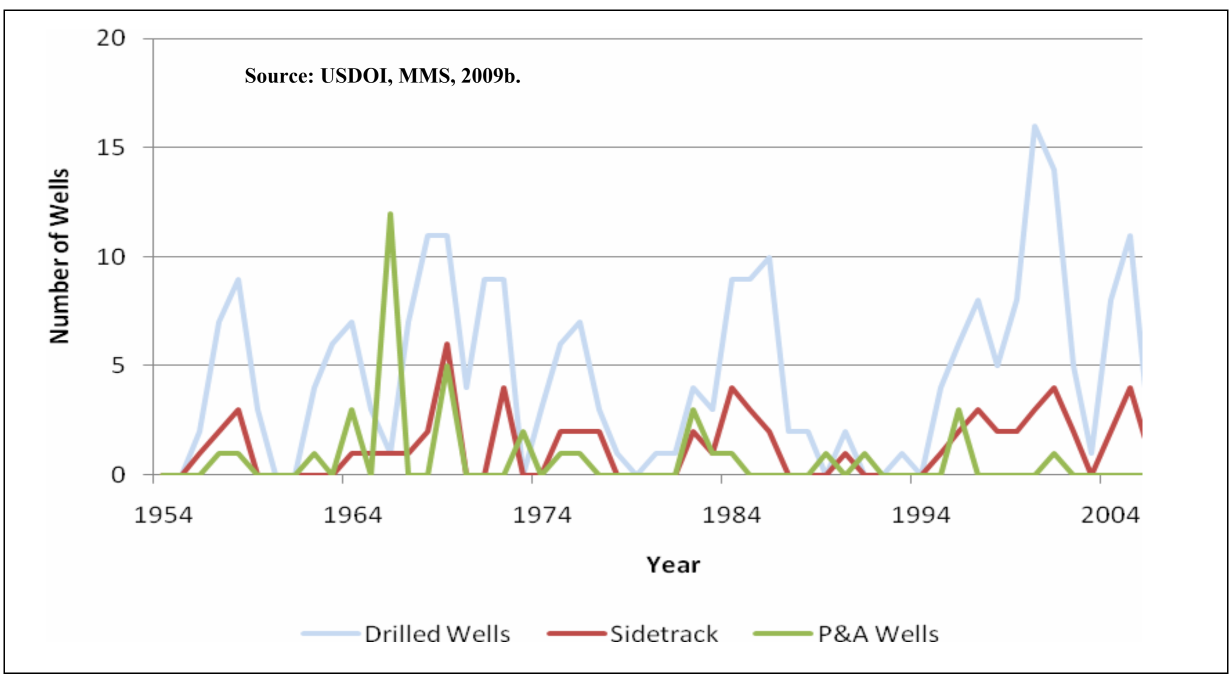


Figure D.10. Aggregate Annual Drilled Wellbores, Sidetrack Wells, and Plugged and Abandoned Wells for the Collection of Structures that Restarted Production by August 2008.

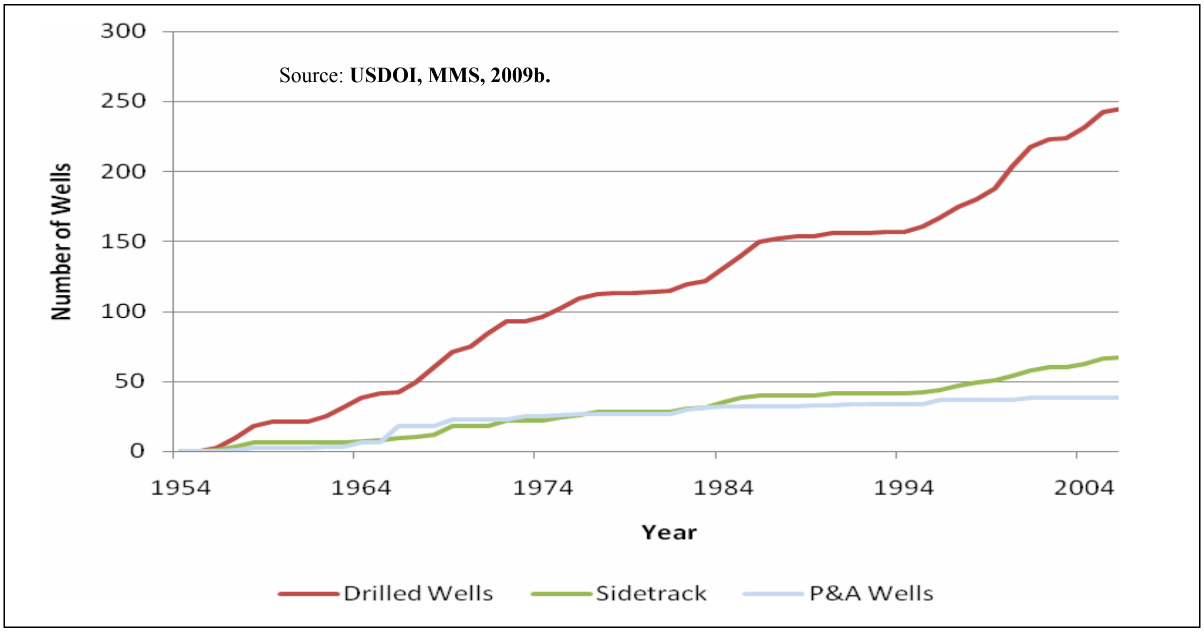


Figure D.11. Cumulative Annual Drilled Wellbores, Sidetrack Wells, and Plugged and Abandoned Wells for the Collection of Structures that Restarted Production.

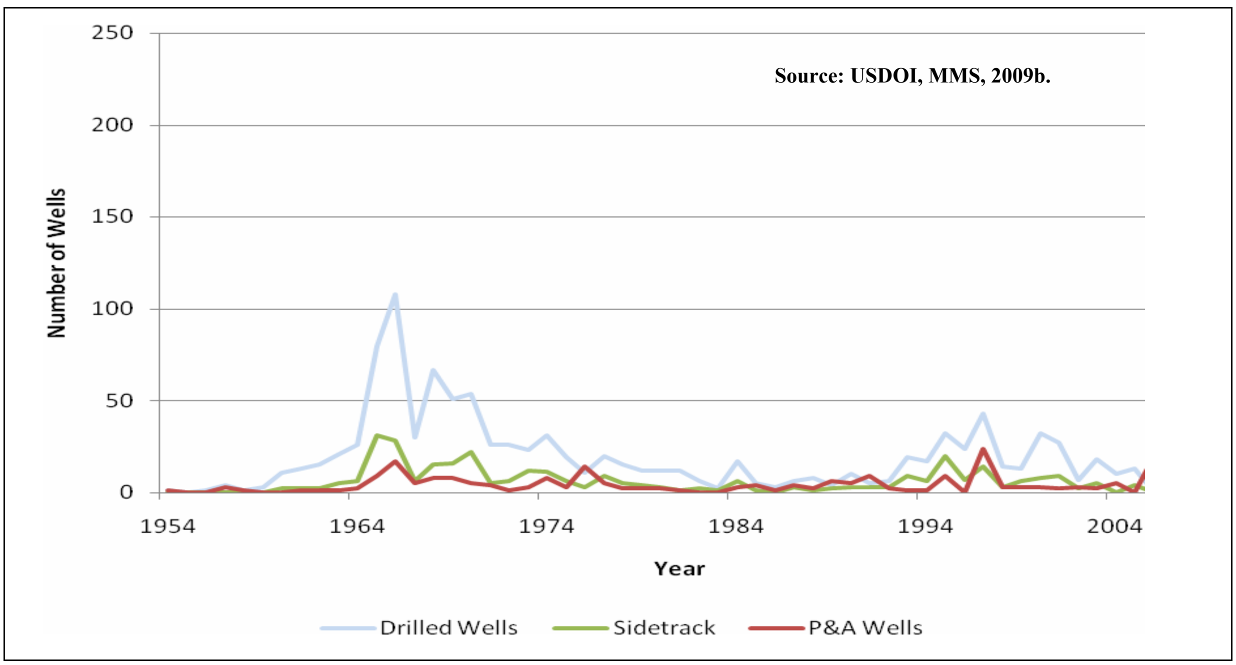


Figure D.12. Aggregate Annual Drilled Wellbores, Sidetrack Wells, and Plugged and Abandoned Wells for Structures that Have Not Been Redeveloped Wells by August 2008 (ex-structure 735).

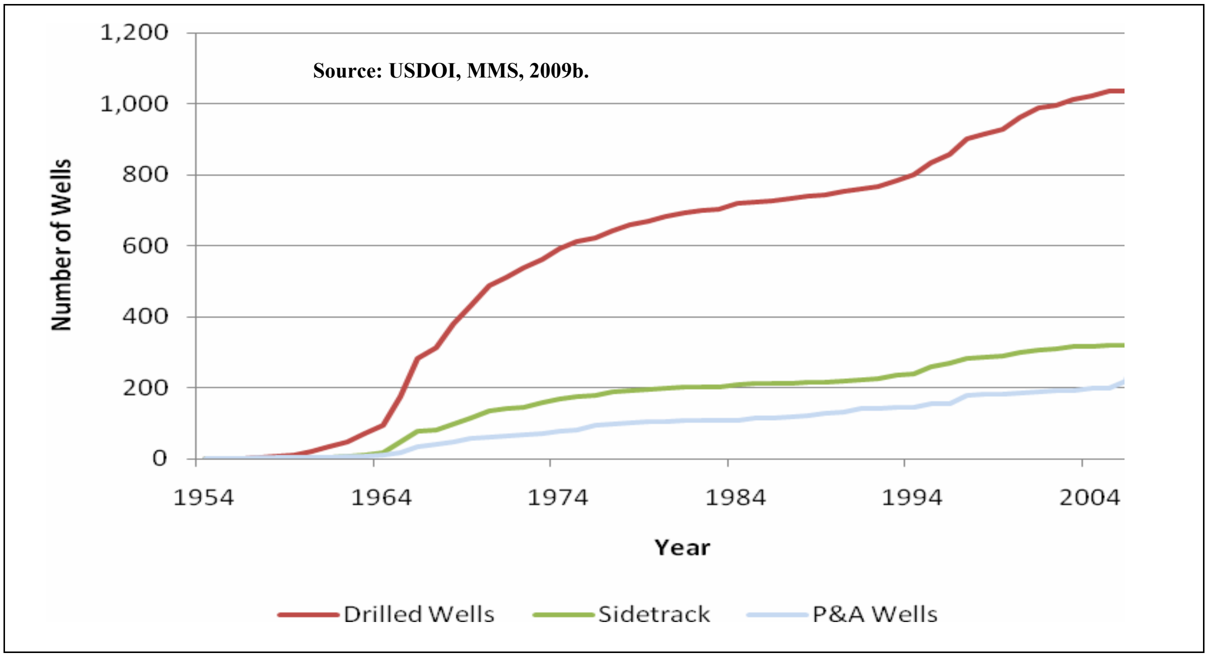


Figure D.13. Cumulative Annual Drilled Wellbores, Sidetrack Wells, and Plugged and Abandoned Wells for Structures that Have Not Been Redeveloped by August 2008 (ex-structure 735).

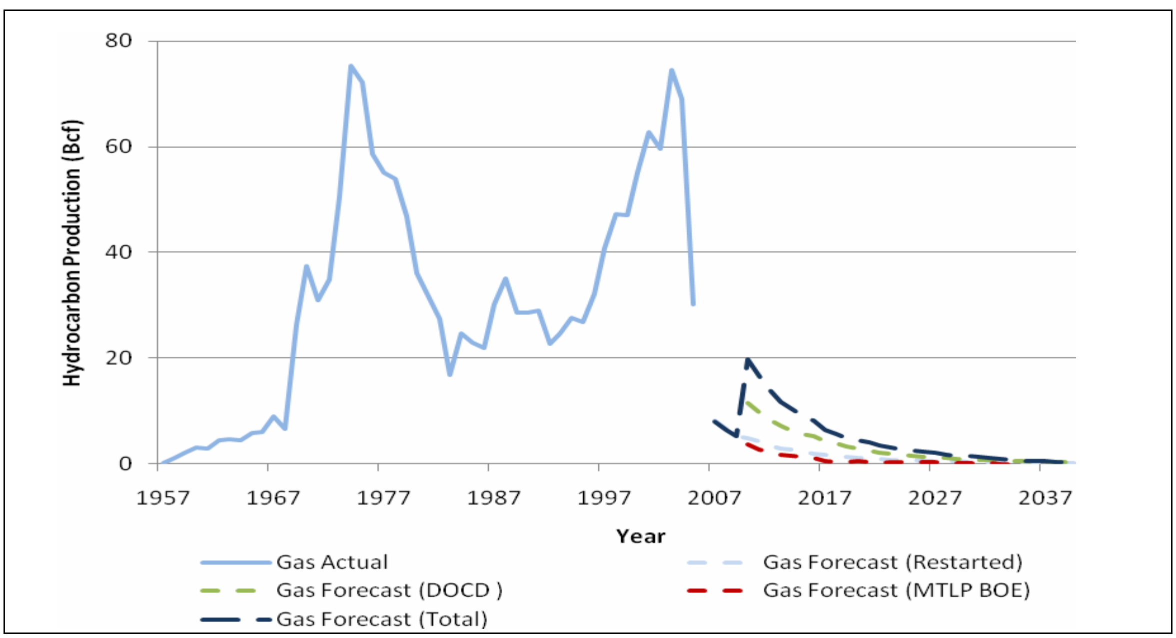


Figure D.14. Forecast Gas Production for Structures that Have Restarted Production, the MTLP, and Structures with a Submitted DOCD Plan.

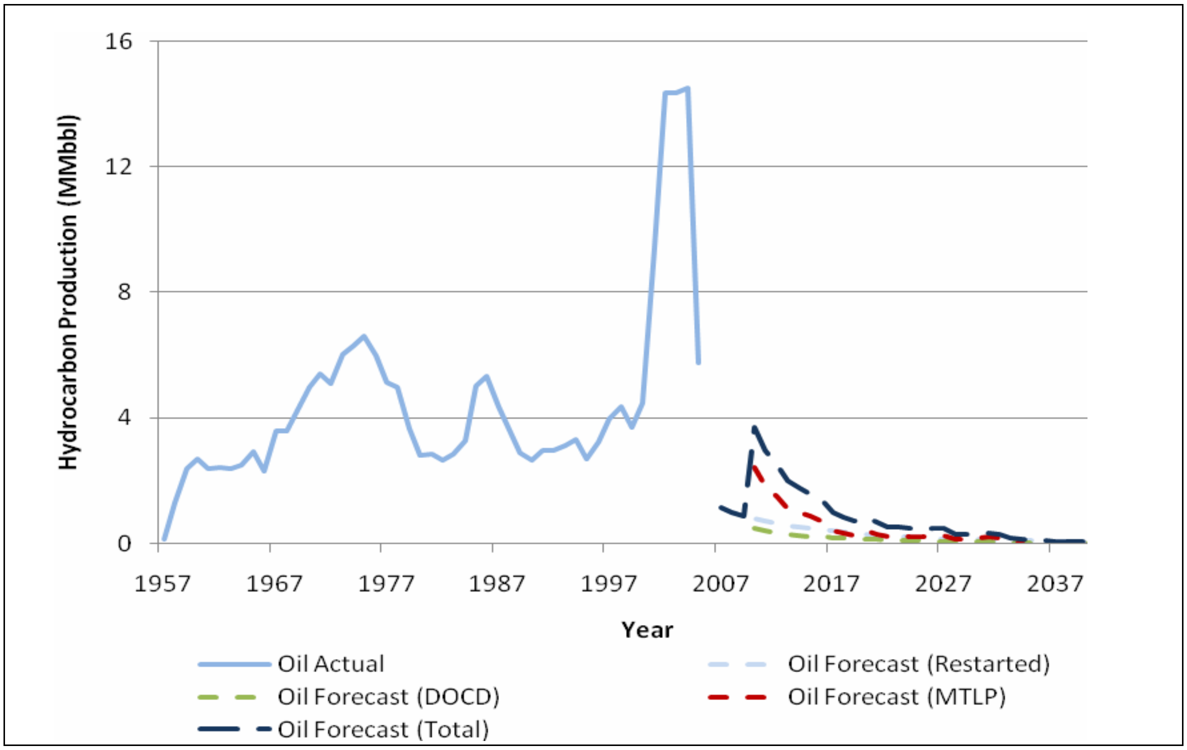


Figure D.15. Forecast Oil Production for Structures that Have Restarted Production, the MTLP, and Structures with a Submitted DOCD Plan.

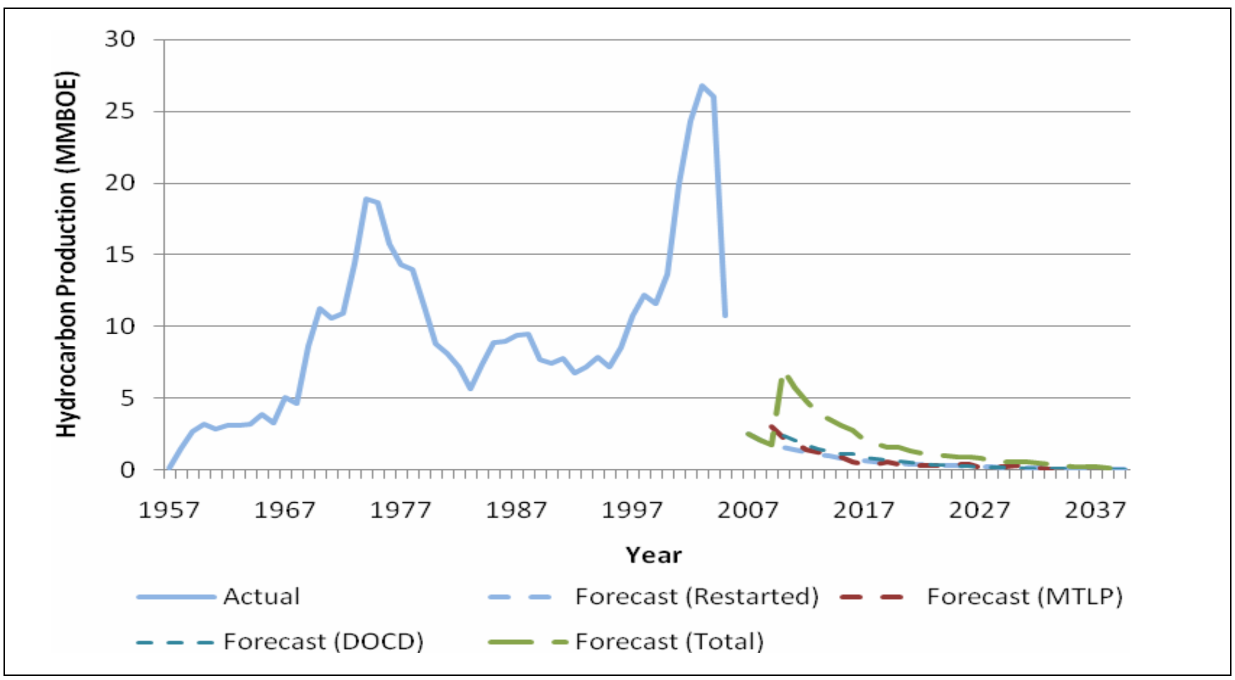


Figure D.16. Forecast BOE Production for Structures that Have Restarted Production, the MTLP, and Structures with a Submitted DOCD Plan.

APPENDIX E.

CHAPTER 5 TABLES AND FIGURES

Table E.1.

Exploration and Development Wells Drilled in the Gulf of Mexico (1947-2007)

Water Depth (ft)	Exploration Wells	Development Wells
0-60	4,257	8,651
61-200	6,337	12,229
201-600	3,894	7,836
601-1,000	414	487
> 1,000	2,005	1,360
Total	16,907	30,563

Source: USDOI, MMS, 2008.

Table E.2.

Structure Installations by Structure Type and Water Depth (1947-2007)

	Water Depth					
Structure Type[a]	0-60 ft	61-200 ft	201-600 ft	601-1,000 ft	> 1,000 ft	Total
CAIS	1,970	488	4	0	0	2,462
FP/Manned	384	501	301	18	6	1,210
/Unmanned	860	1,135	301	3	0	2,299
/Total	1,244	1,366	602	21	6	3,509
CT	0	0	0	1	2	3
MOPU	2	2	0	0	0	4
SEMI	0	0	0	0	6	6
SPAR	0	0	0	0	14	14
SSMNF	0	1	0	0	0	1
SSTMP	0	1	1	0	1	3
TLP	0	0	0	0	10	10
WP	450	310	39	0	0	799
TOTAL	3,666	2,438	646	22	39	6,811

Source: USDOI, MMS, 2008.

Footnote: (a) CAIS = caisson, FP = fixed platform, CT = compliant tower, MOPU = mobile offshore production unit, SEMI= semisubmersible, SPAR = deep draft floating caisson, TLP = tension leg platform, WP = well protector.

Table E.3.

Structure Removals by Structure Type and Water Depth (1973-2007)

Structure Type[a]	Water Depth					
	0-60 ft	61-200 ft	201-600 ft	601-1,000 ft	> 1,000 ft	Total
CAIS	1,084	283	2	0	0	1,369
FP/Manned	39	68	30	1	0	138
/Unmanned	393	523	127	0	0	1,043
/Total	432	591	157	1	0	1,181
CT	0	0	0	0	0	0
MOPU	0	2	0	0	0	2
SEMI	0	0	0	0	1	1
SPAR	0	0	0	0	14	14
SSMNF	0	0	0	0	0	0
SSTMP	0	2	0	0	1	3
TLP	0	0	0	0	0	0
WP	211	187	21	0	0	419
TOTAL	1,727	1,065	180	1	16	2,989

Source: USDOI, MMS, 2008.

Footnote: (a) CAIS = caisson, FP = fixed platform, CT = compliant tower, MOPU = mobile offshore production unit, SEMI= semisubmersible, SPAR = deep draft floating caisson, TLP = tension leg platform, WP = well protector.

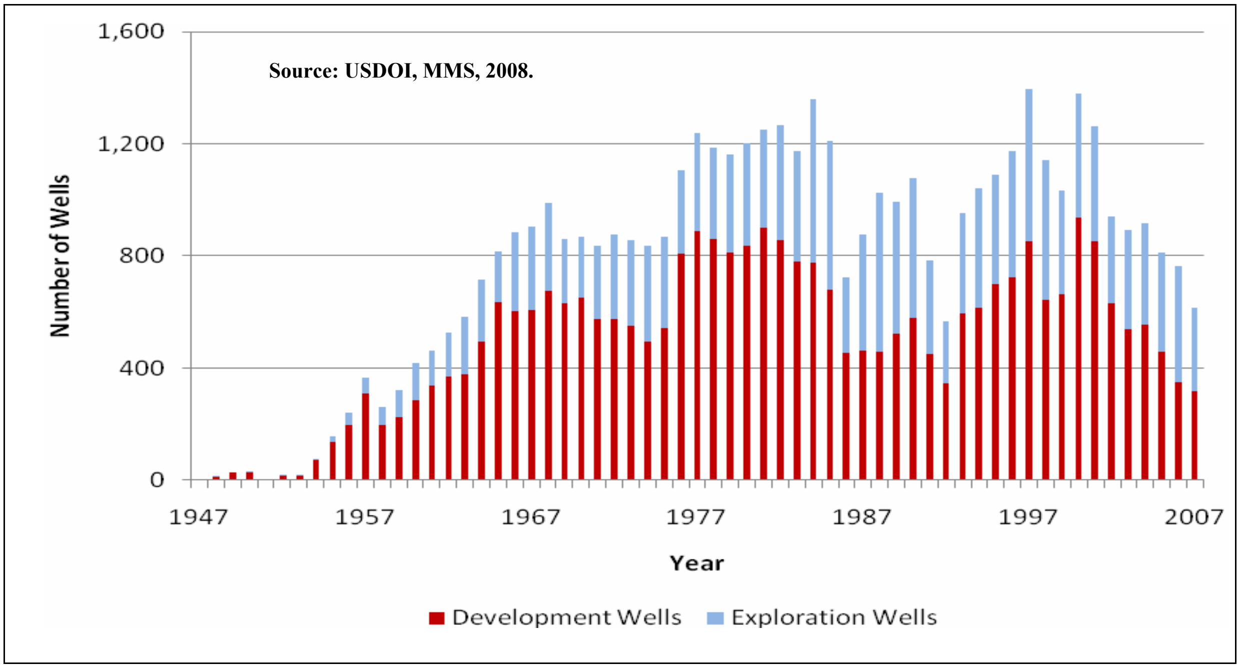


Figure E.1. Number of Exploration and Development Wells Drilled Annually in the Gulf of Mexico (1947-2007).

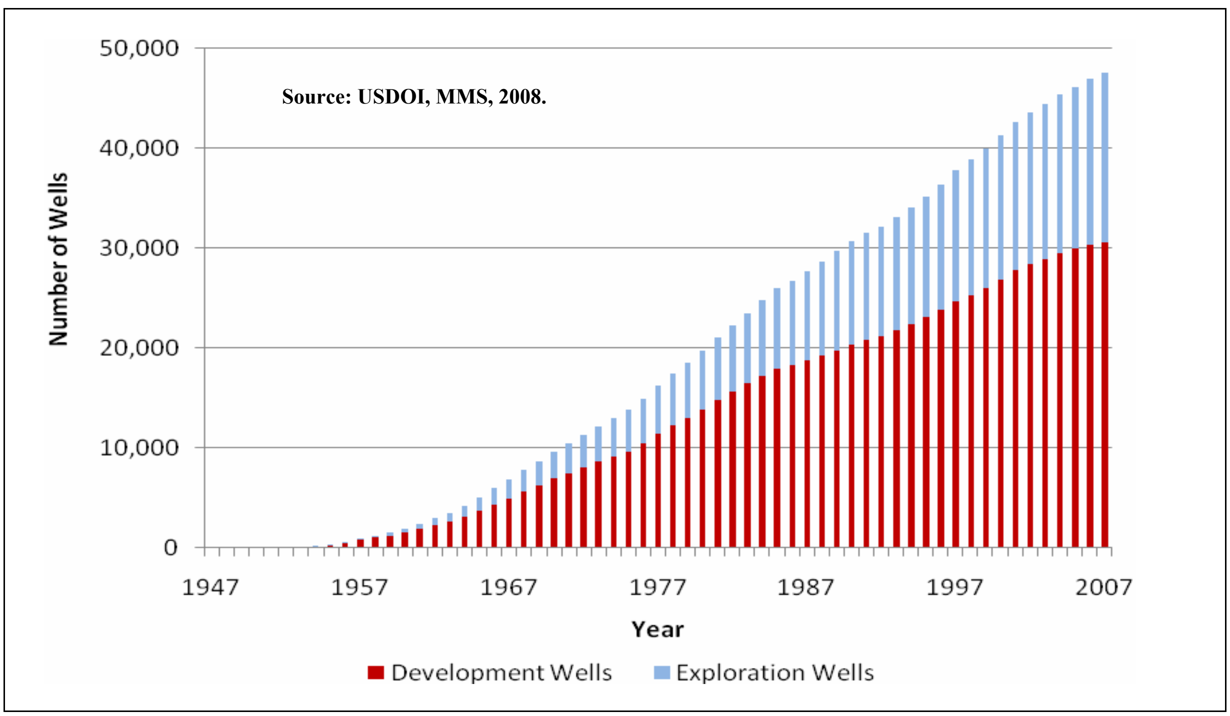


Figure E.2. Cumulative Number of Exploration and Development Wells Drilled in the Gulf of Mexico (1947-2007).

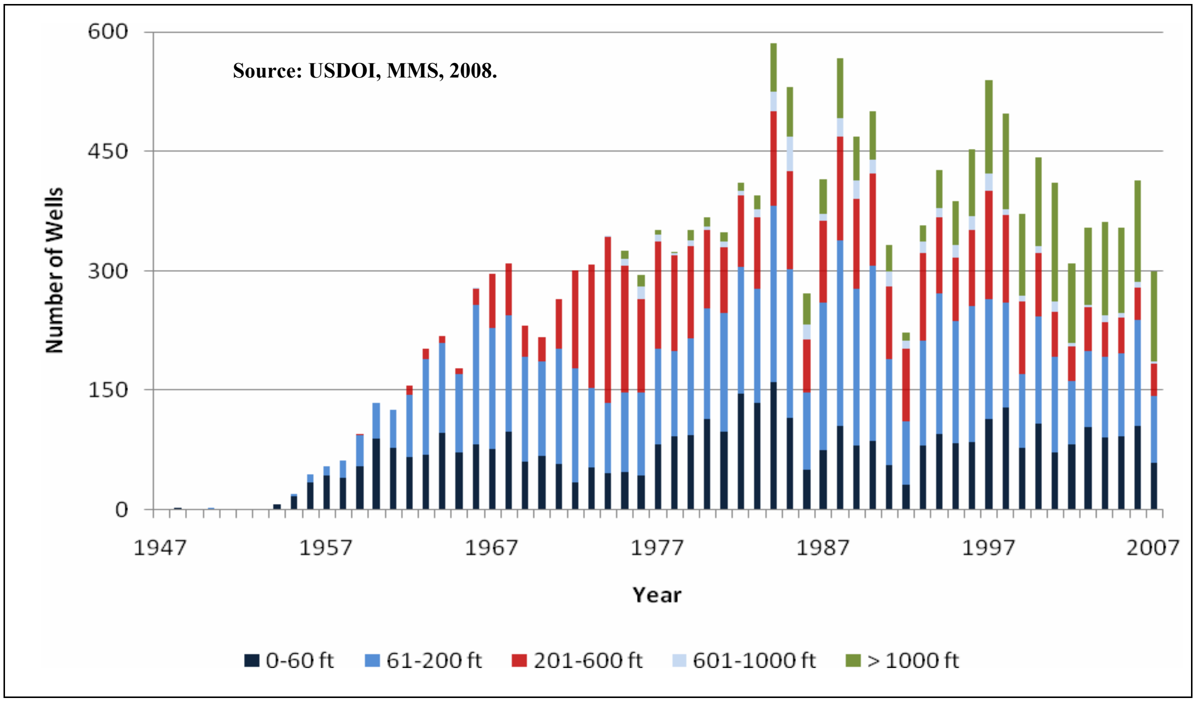


Figure E.3. Number of Exploration Wells Drilled by Water Depth Category (1947-2007).

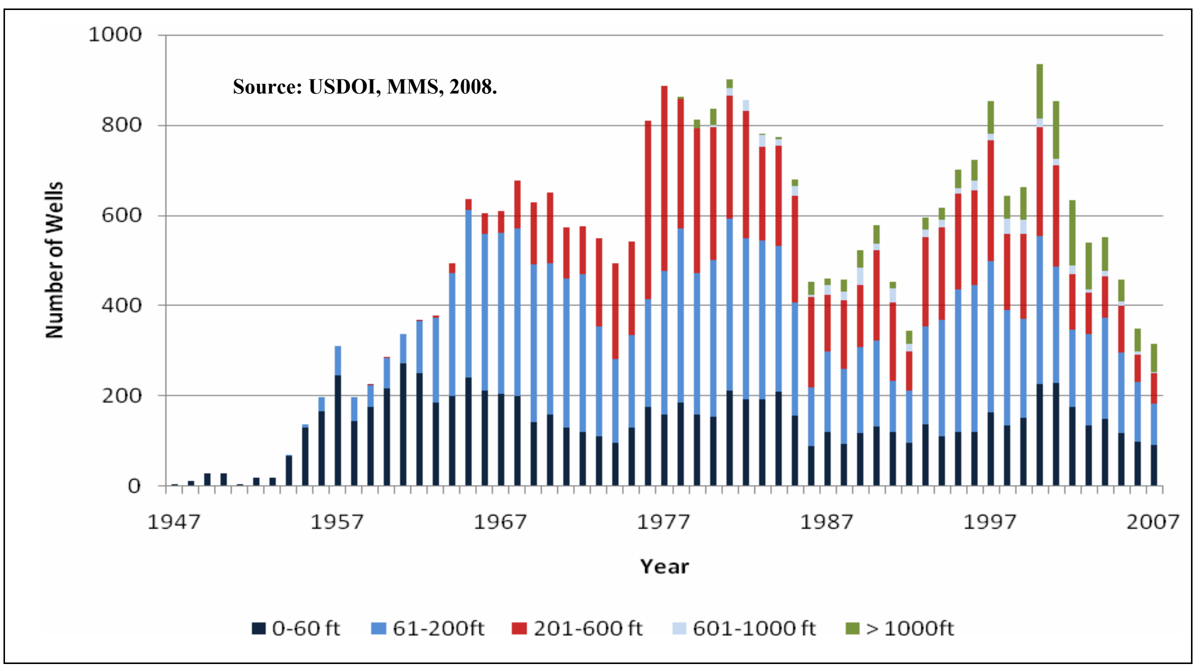


Figure E.4. Number of Development Wells Drilled by Water Depth Category (1947-2007).

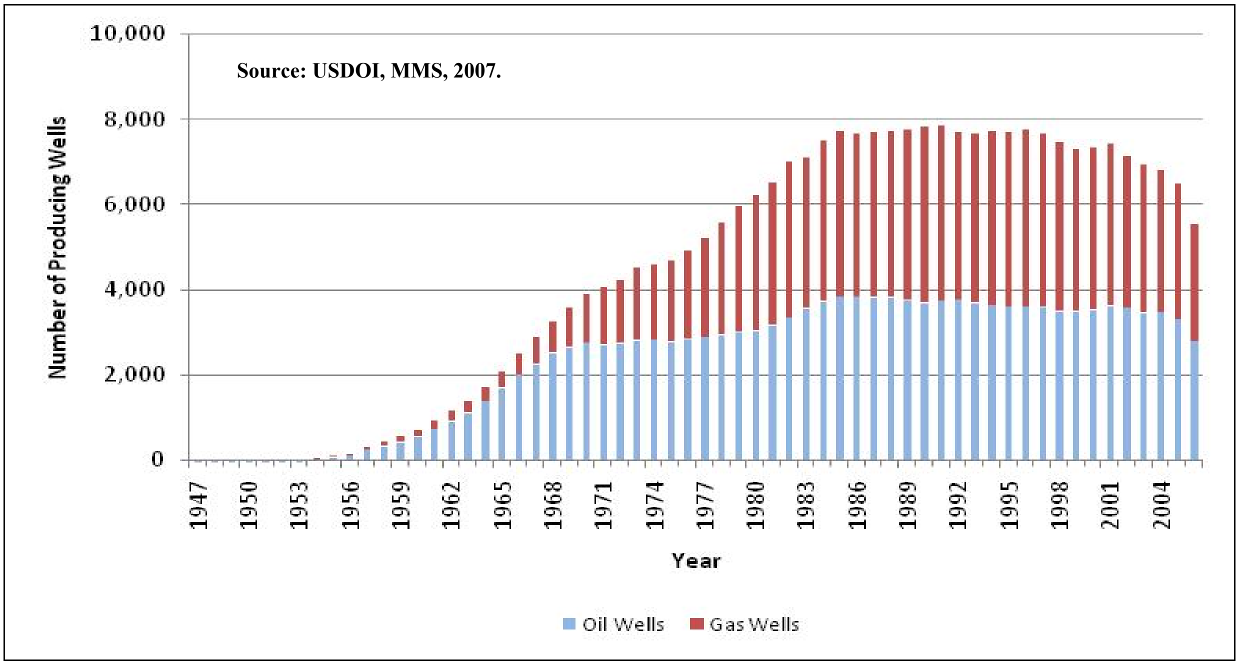


Figure E.5. Stacked Area Graph of the Number of Producing Oil and Gas Wells in the GOM for GOR=10,000 (1947-2006).

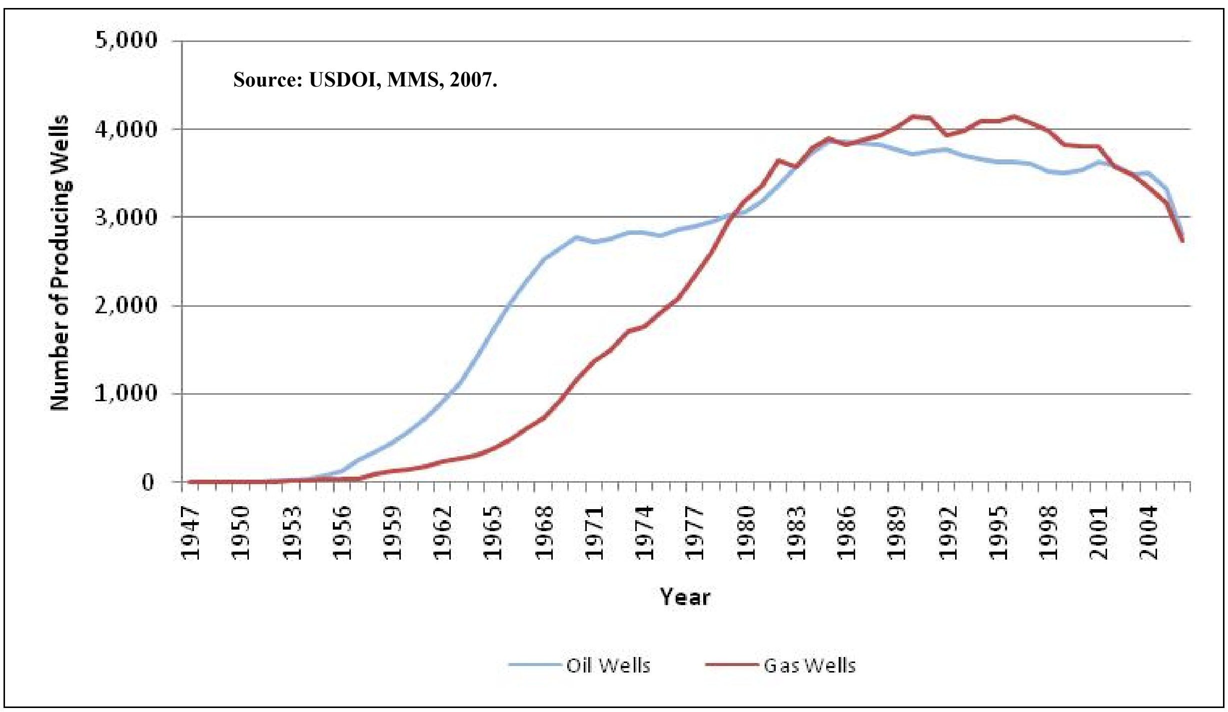


Figure E.6. Number of Producing Oil and Gas Wells in the GOM for GOR=10,000 (1947-2006).

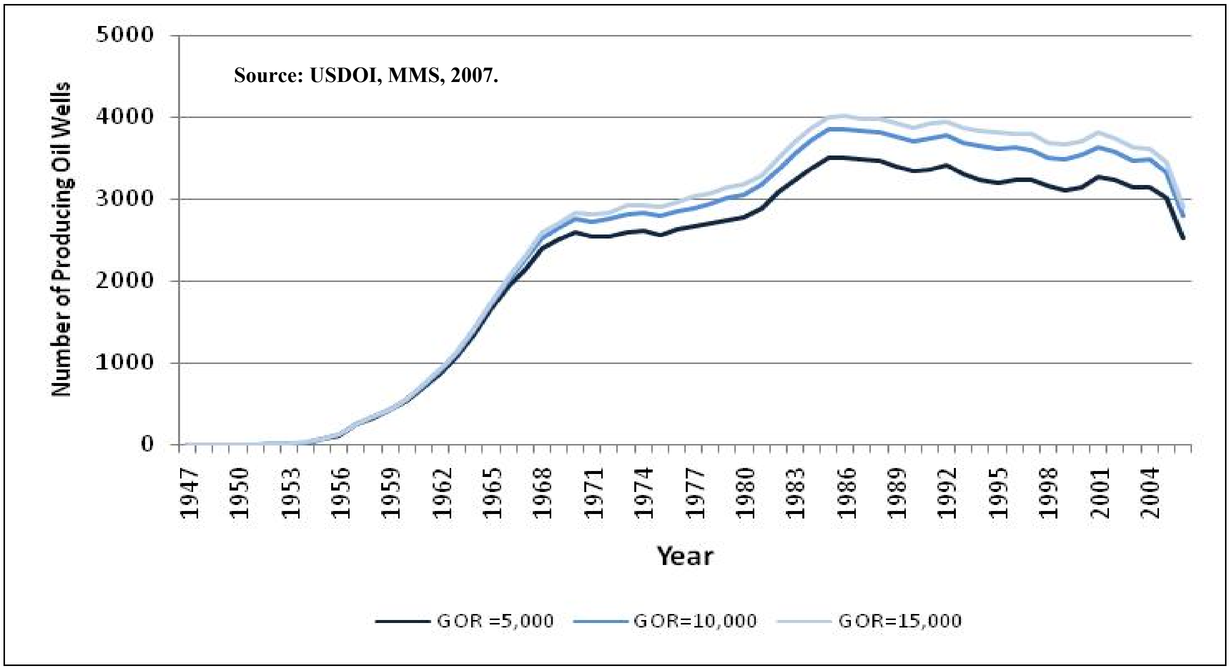


Figure E.7. Number of Producing Wells in the GOM Identified as Oil Wells as a Function of GOR Thresholds (1947-2006).

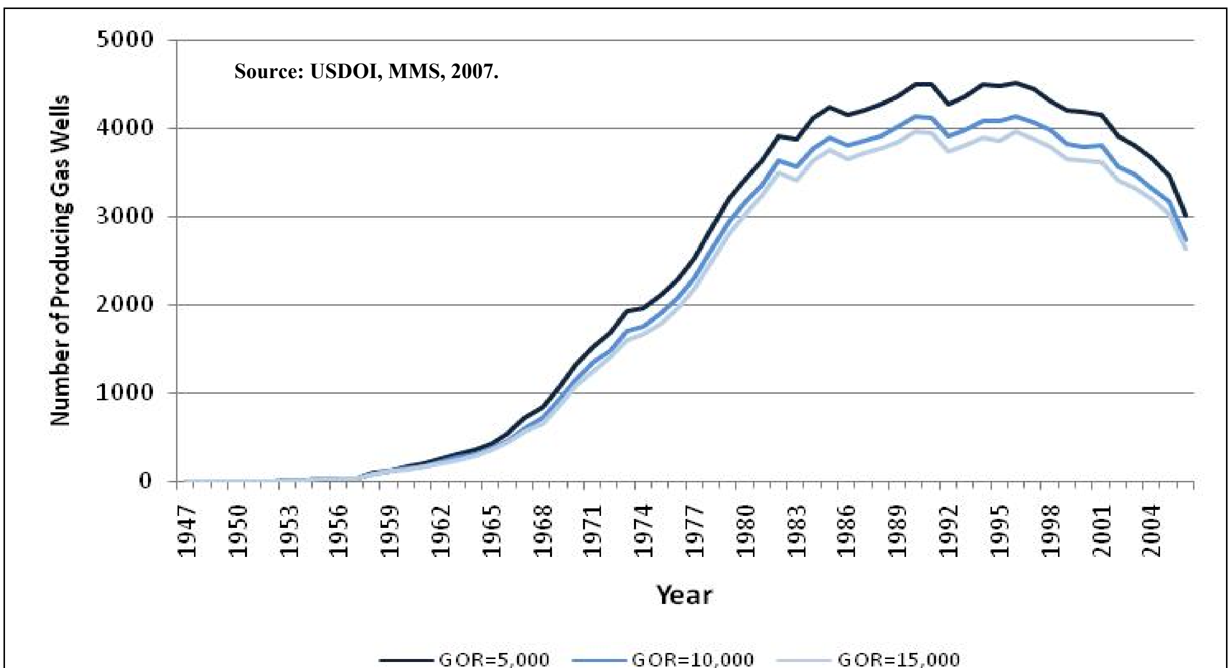


Figure E.8. Number of Producing Wells in the GOM Identified as Gas Wells as a Function of GOR Thresholds (1947-2006).

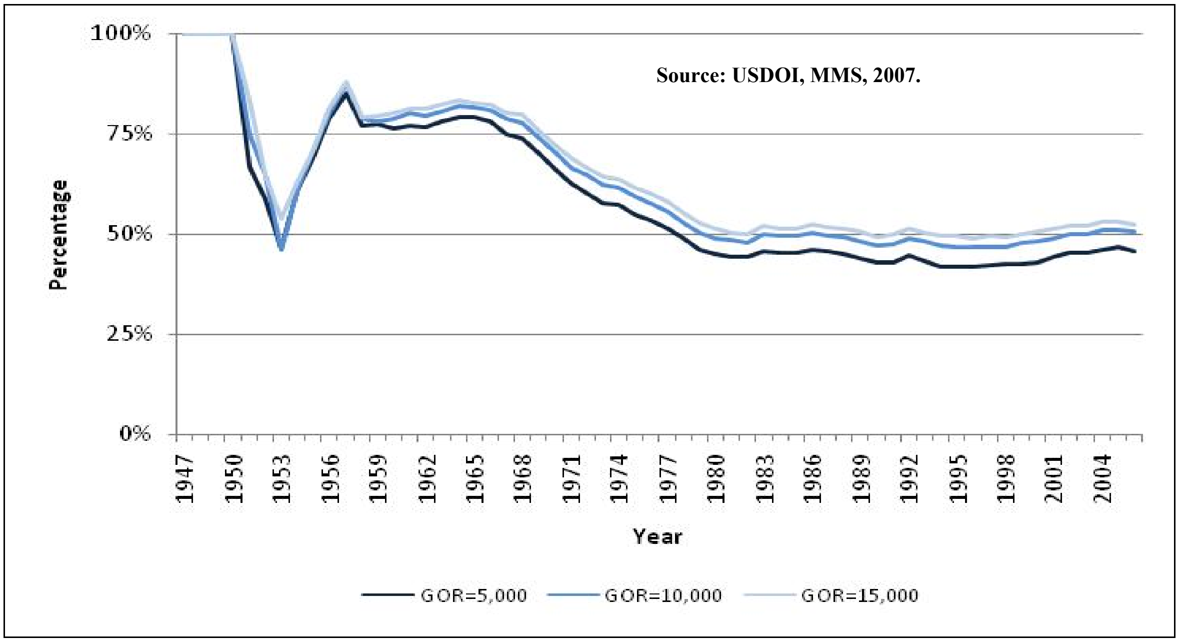


Figure E.9. Oil Well Population Ratio in the GOM as a Function of GOR Thresholds (1947-2006).

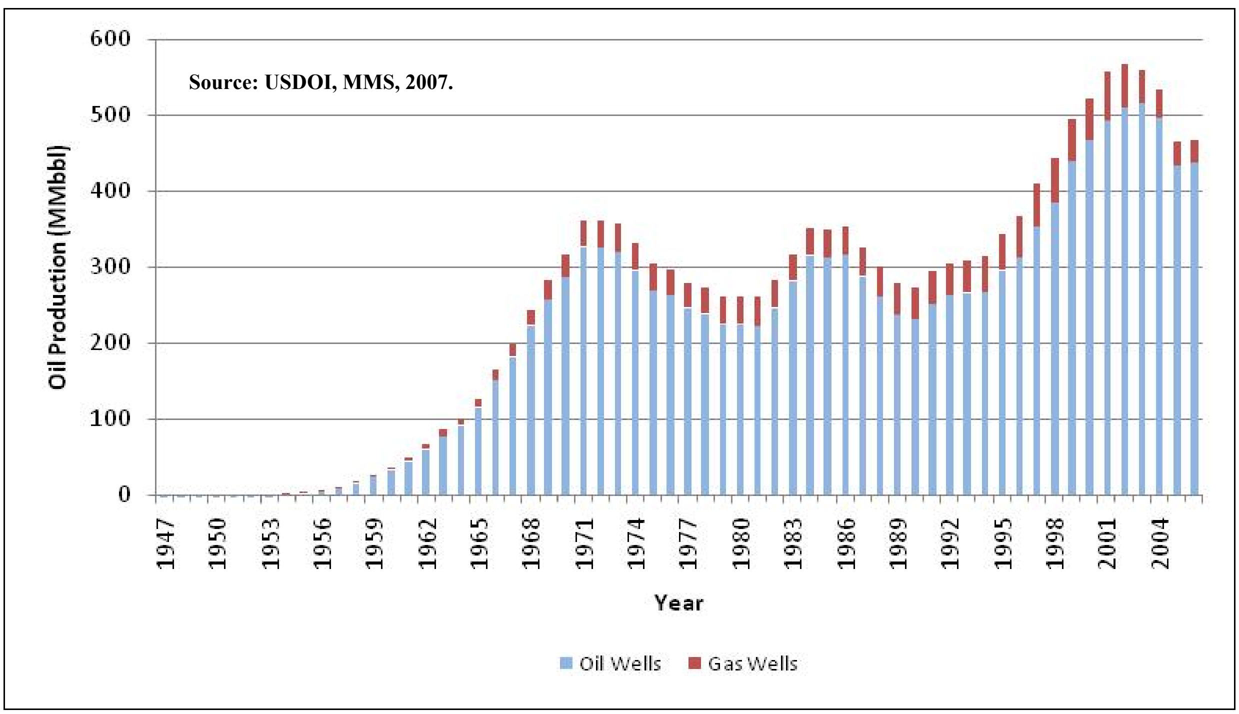


Figure E.10. Liquid Production from Oil and Gas Wells in the GOM (1947-2006).

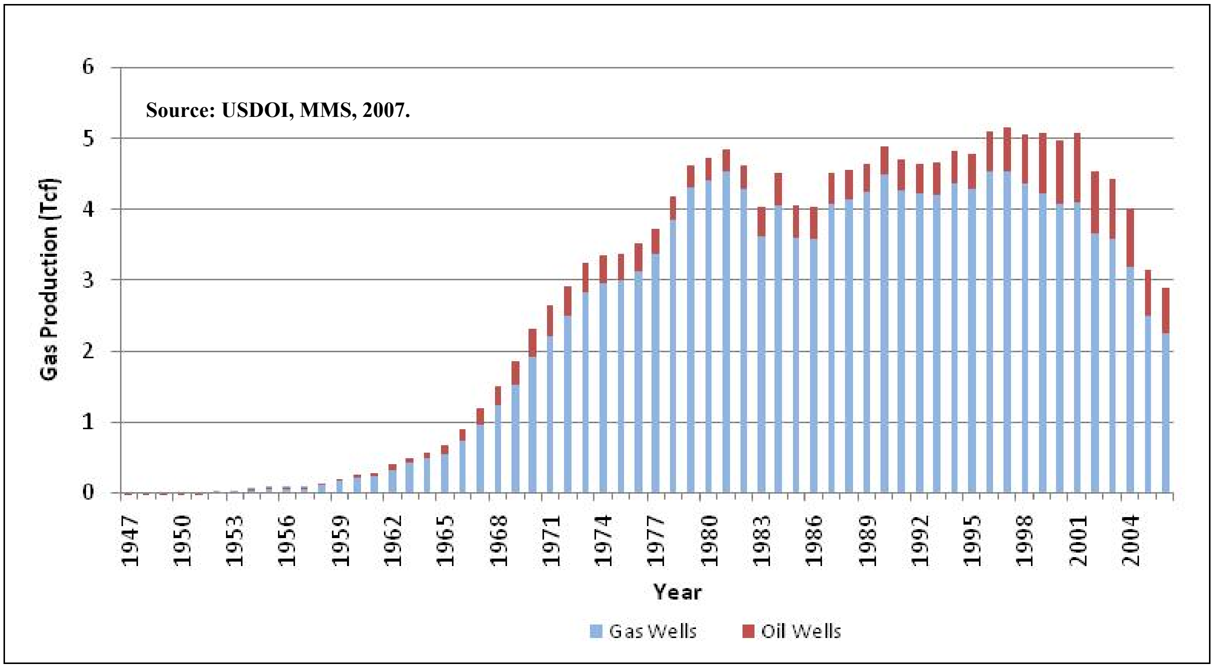


Figure E.11. Gas Production from Oil and Gas Wells in the GOM (1947-2006).

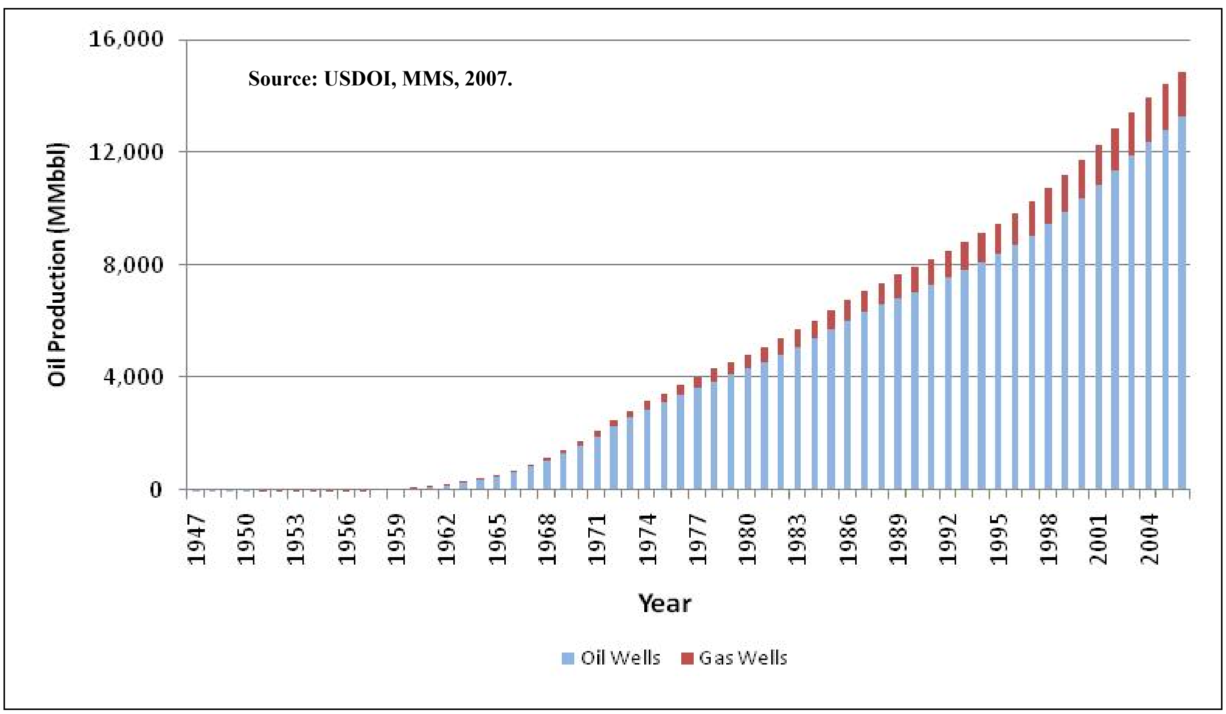


Figure E.12. Cumulative Oil Production from Oil and Gas Wells in the GOM (1947-2006).

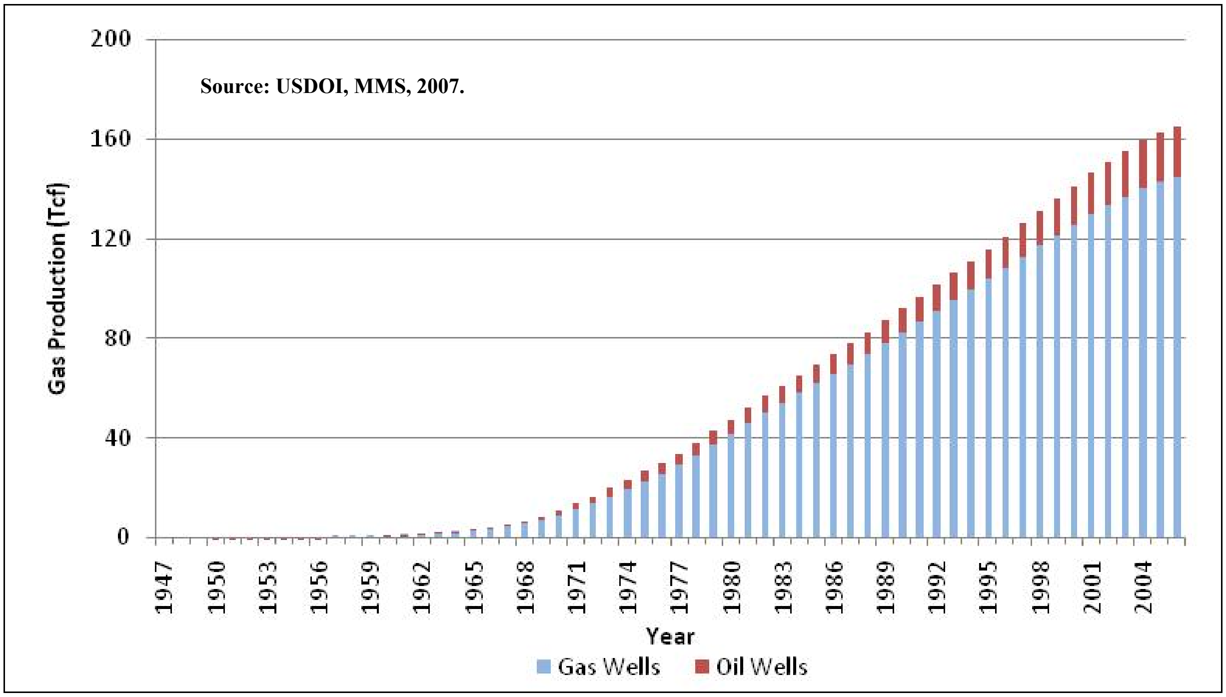


Figure E.13. Cumulative Gas Production from Oil and Gas Wells in the GOM (1947-2006).

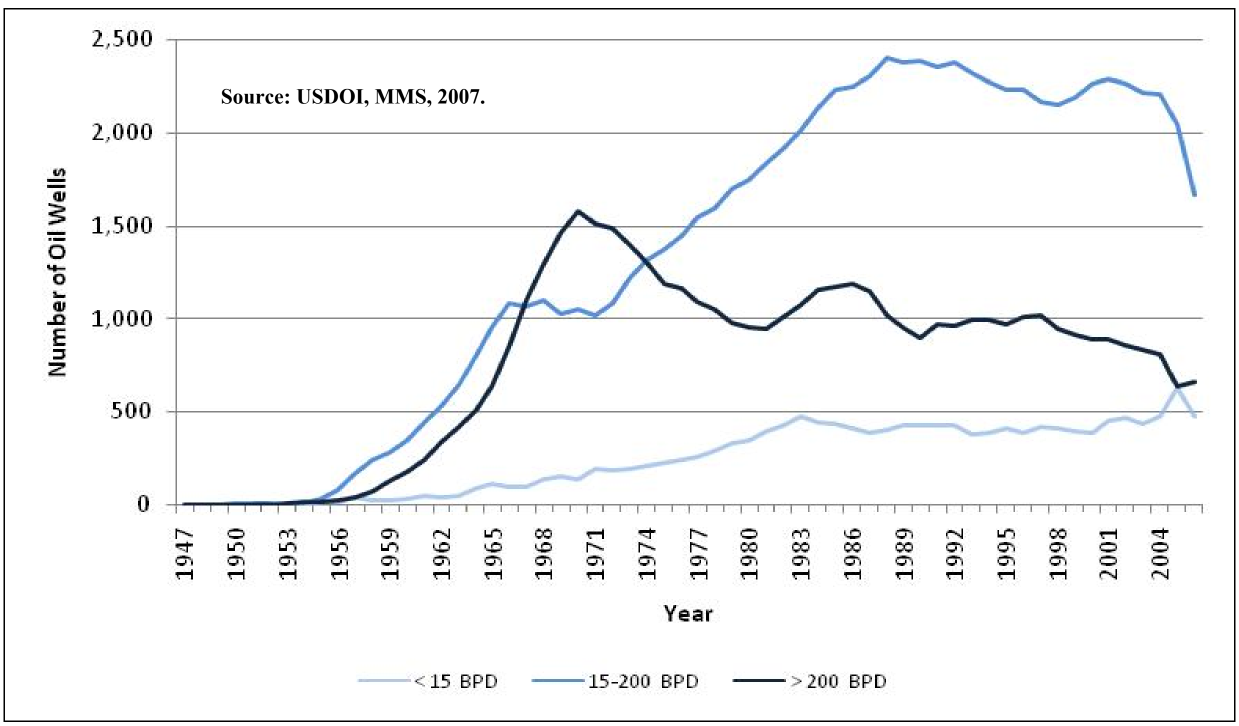


Figure E.14. Oil Wells Categorized According to Daily Oil Production Levels (1947-2006).

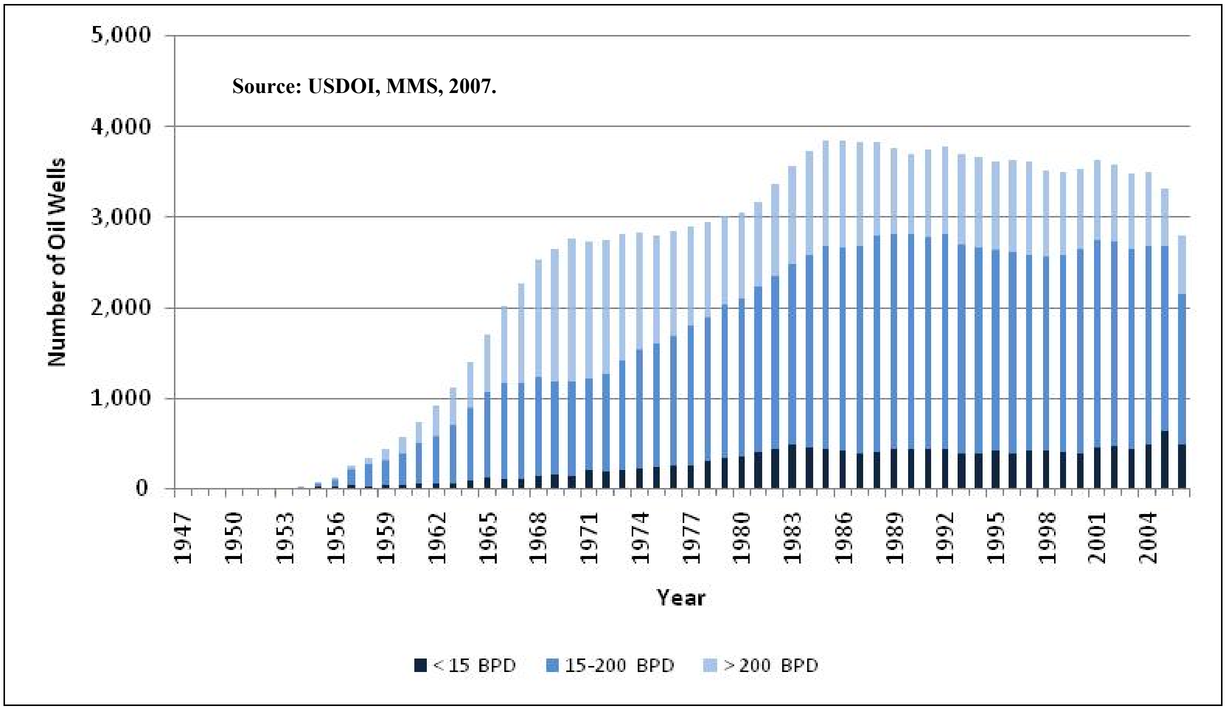


Figure E.15. Stacked Area Graph of Oil Wells Categorized According to Daily Oil Production Levels (1947-2006).

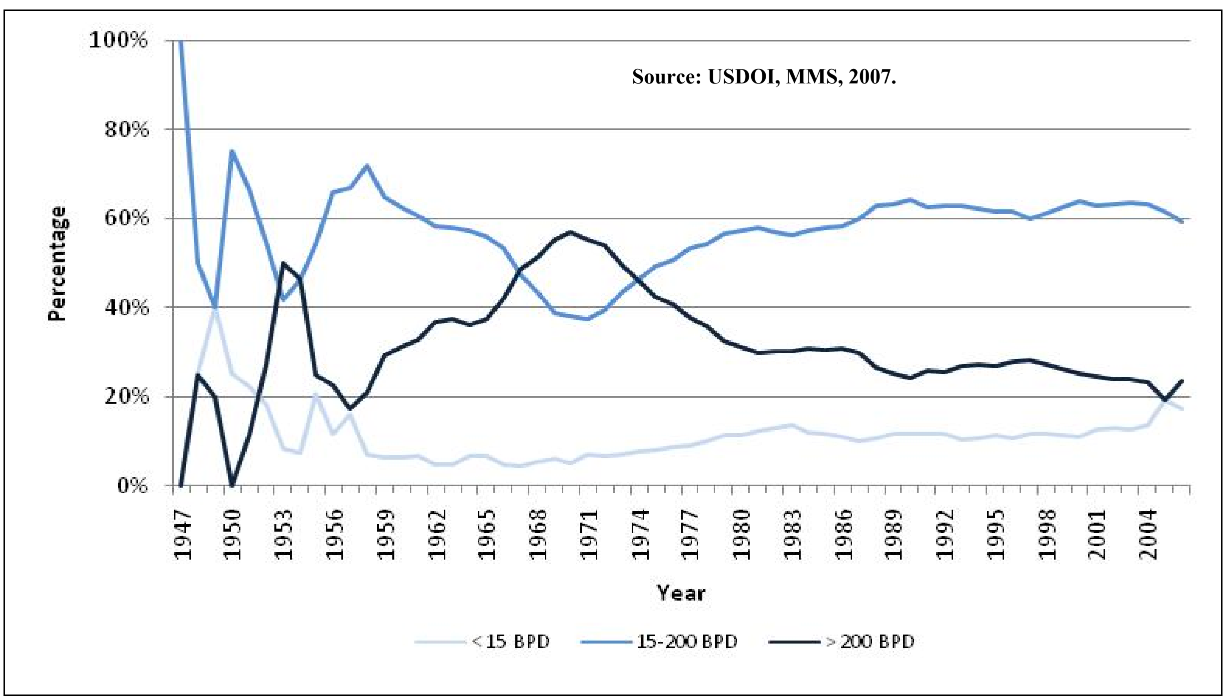


Figure E.16. Population Ratio of Oil Wells Categorized According to Daily Oil Production Levels (1947-2006).

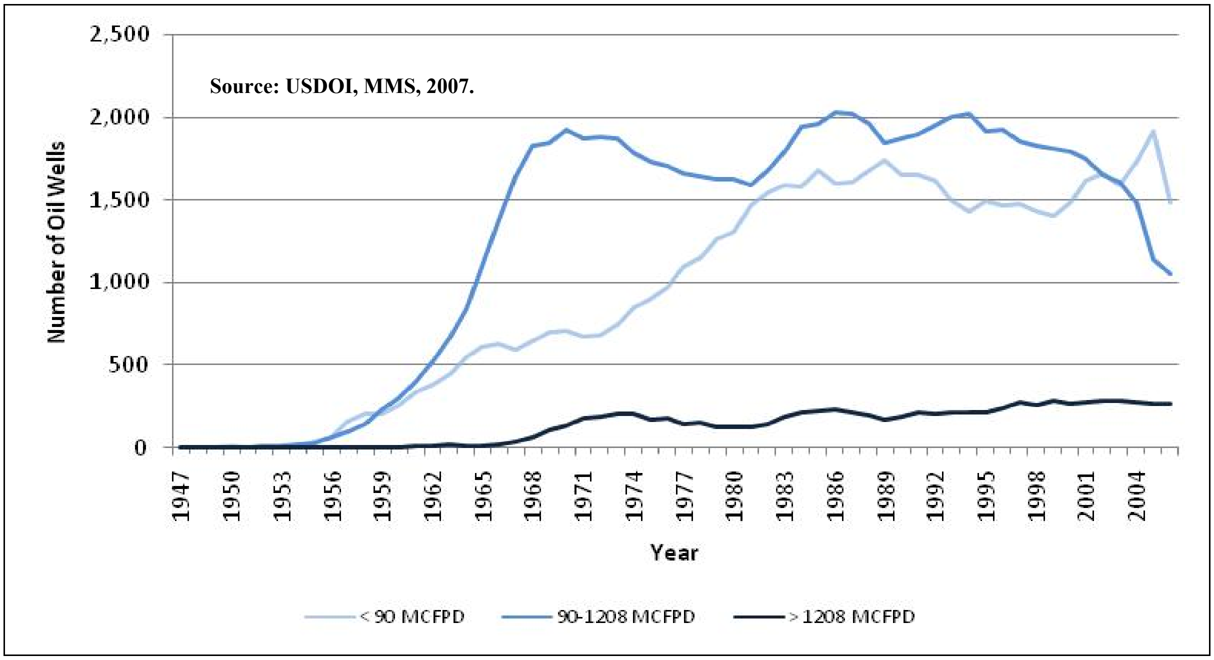


Figure E.17. Oil Wells Categorized According to Daily Gas Production (1947-2006).

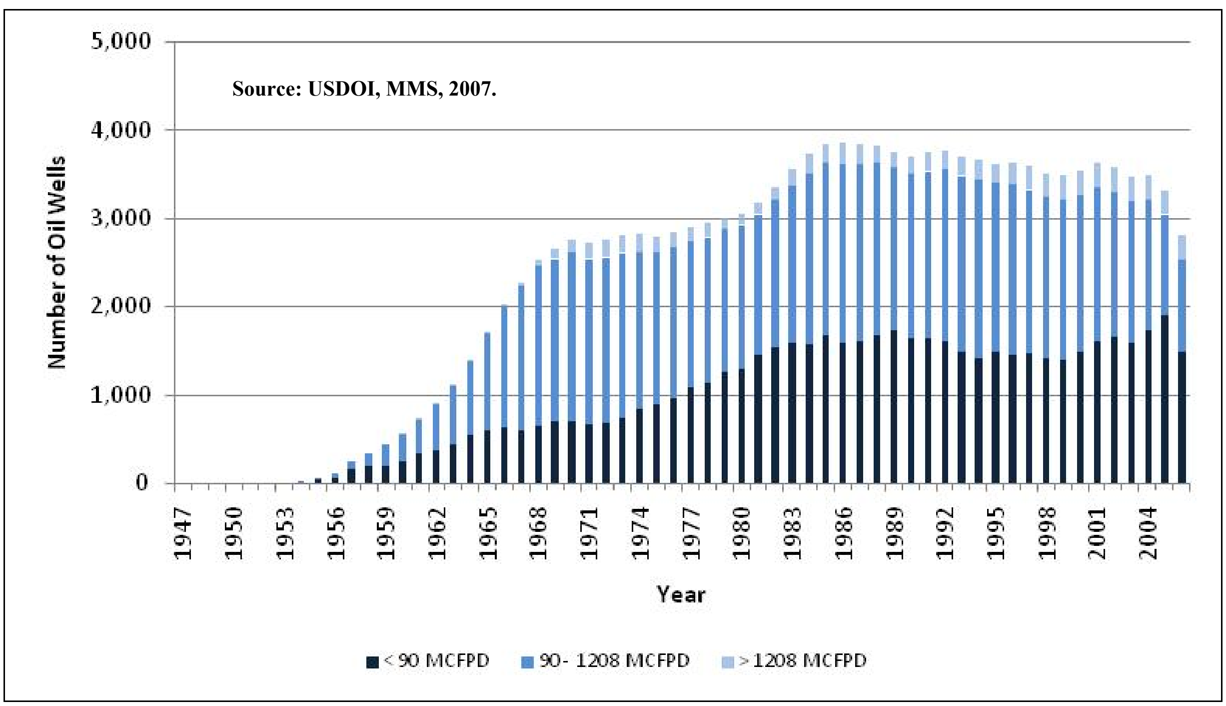


Figure E.18. Stacked Area Graph of Oil Wells Categorized According to Daily Gas Production (1947-2006).

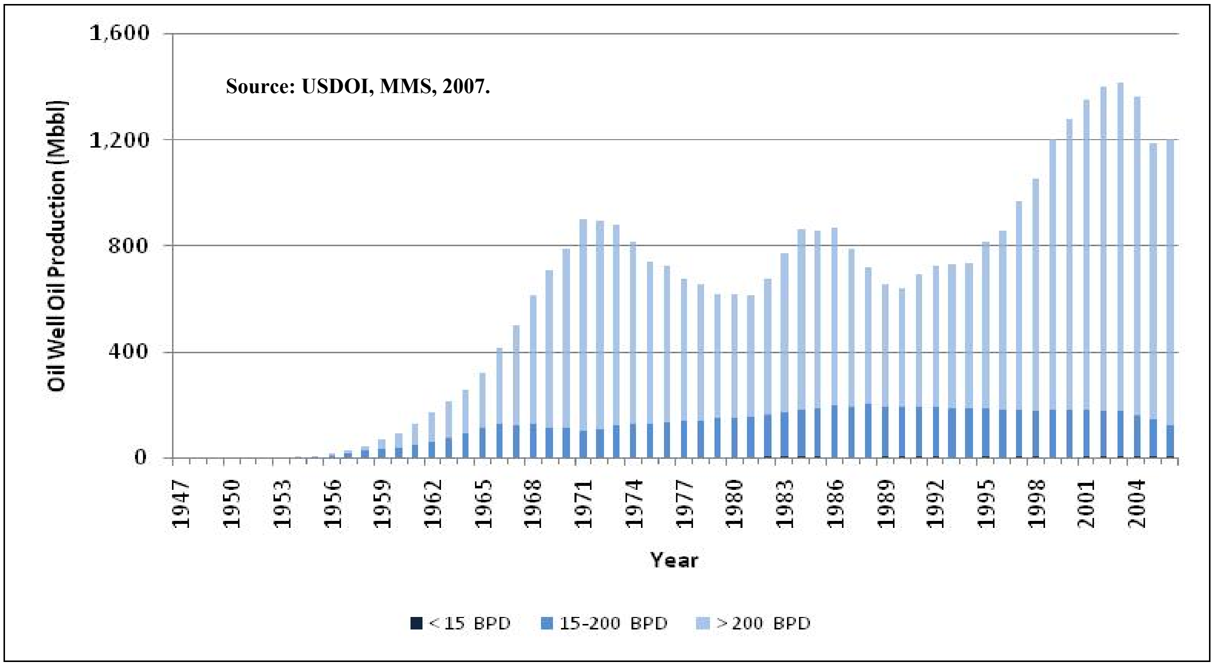


Figure E.19. Oil Well Oil Production per Category (1947-2006).

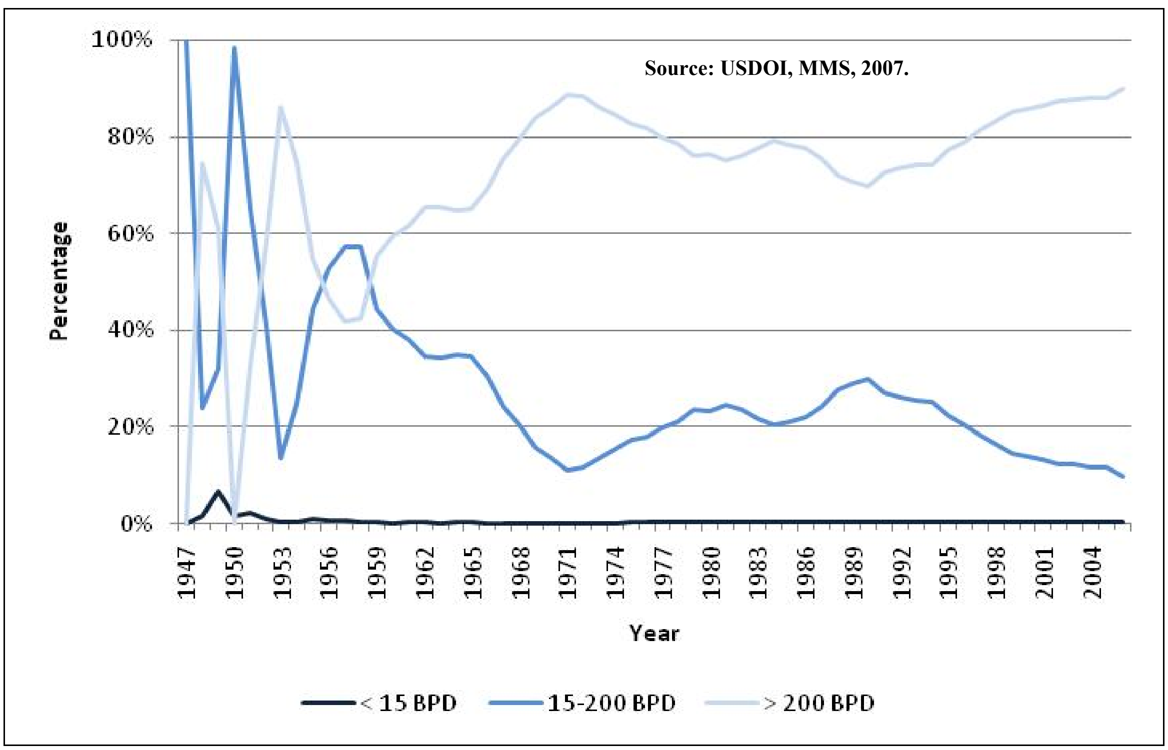


Figure E.20. Oil Production Ratio per Category According to Daily Oil Production (1947-2006).

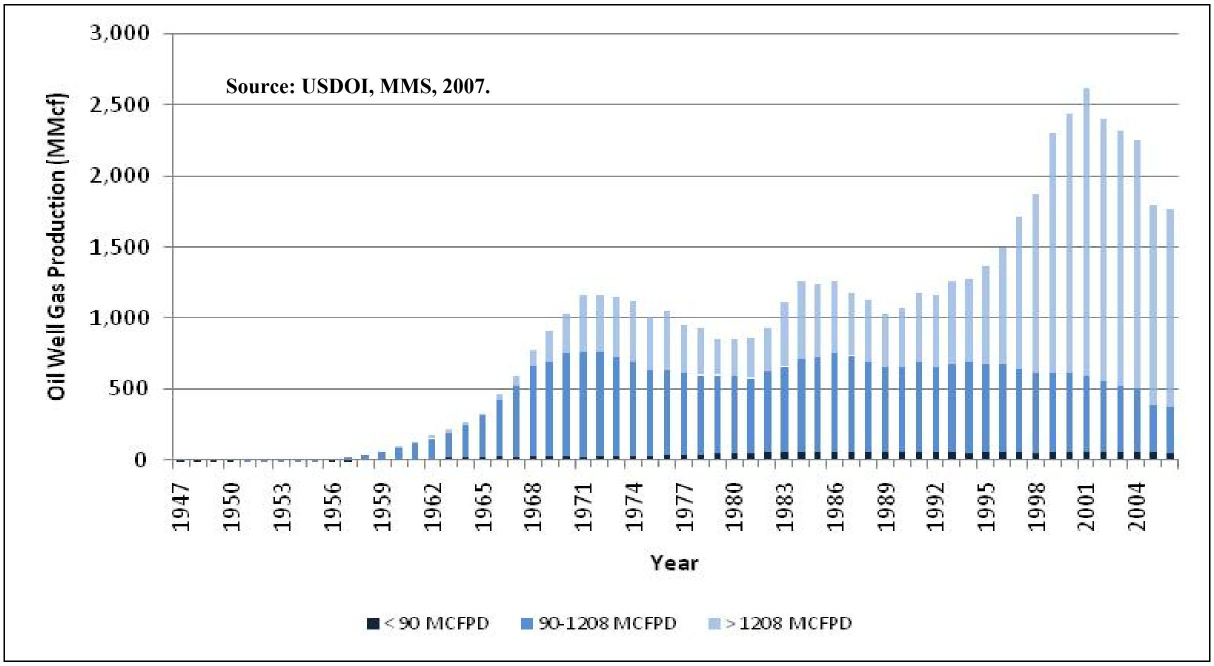


Figure E.21. Oil Well Gas Production per Category (1947-2006).

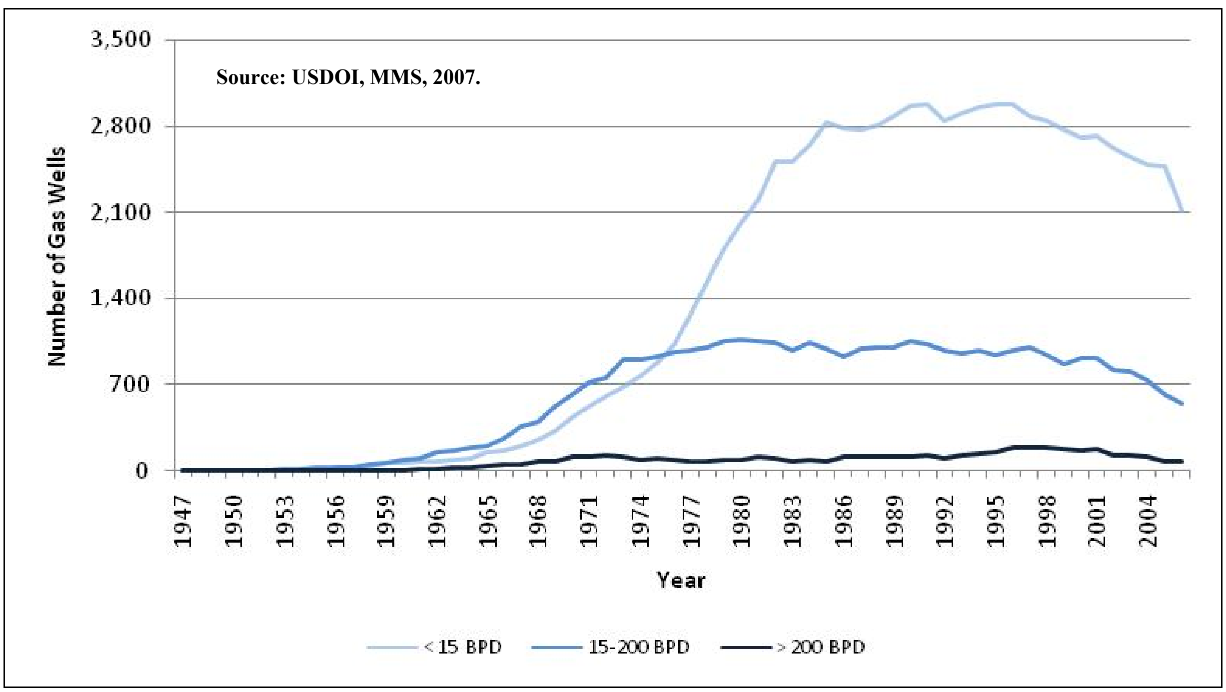


Figure E.22. Gas Wells Categorized According to Daily Oil Production Levels (1947-2006).

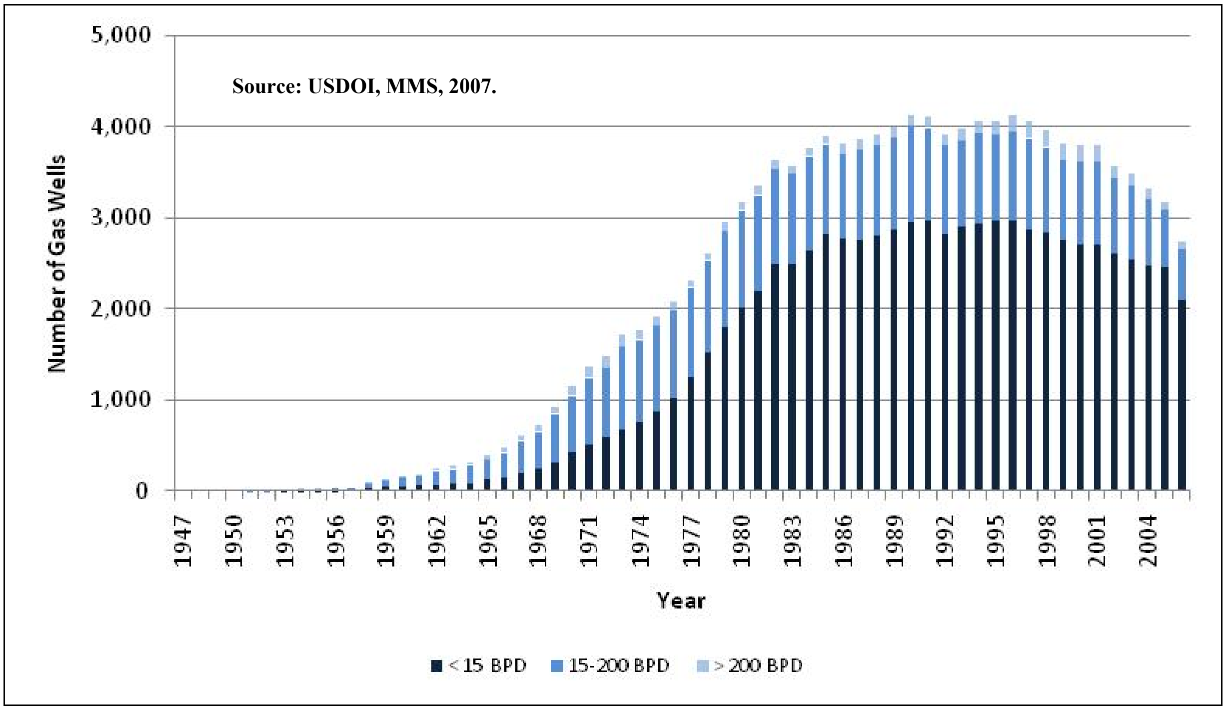


Figure E.23. Stacked Area Graph of Gas Wells Categorized According to Daily Oil Production Levels (1947-2006).

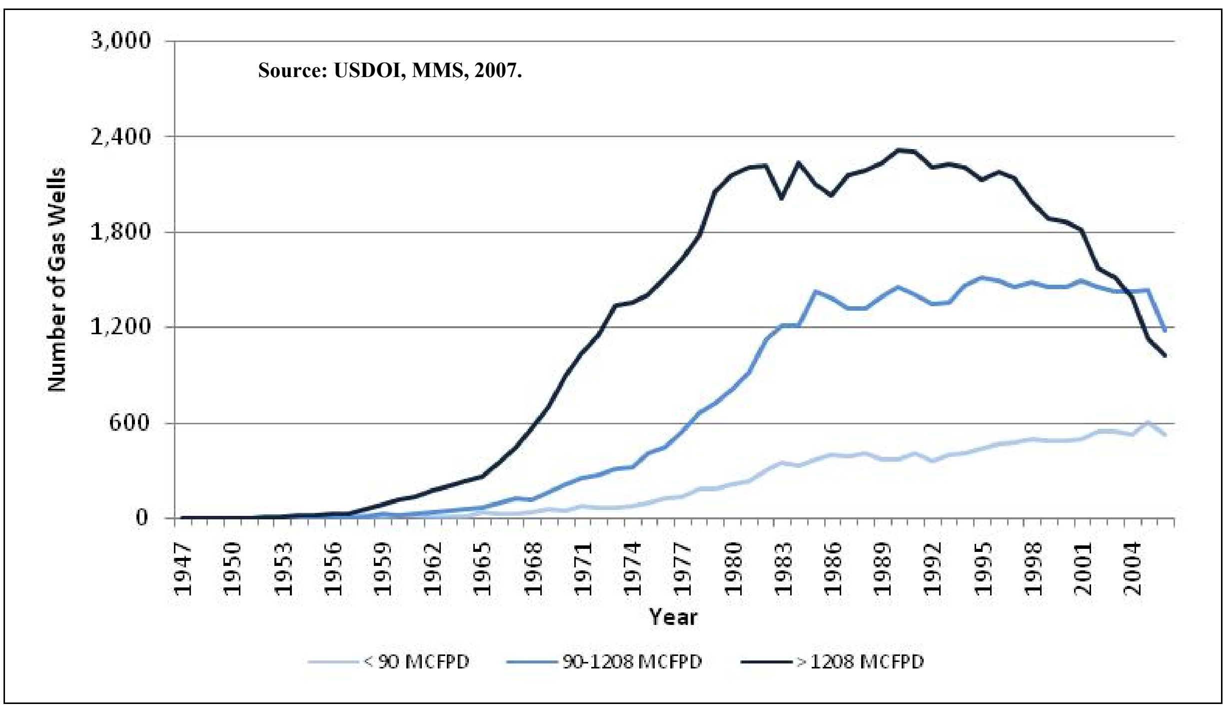


Figure E.24. Gas Wells Categorized According to Daily Gas Production Levels (1947-2006).

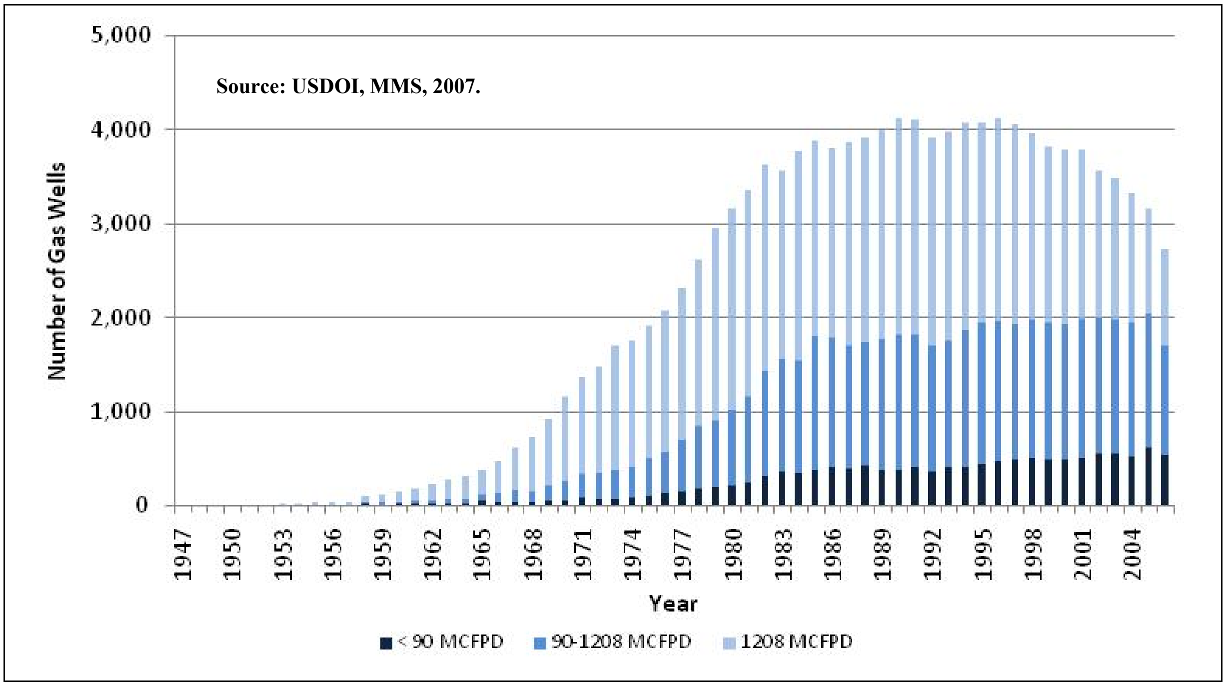


Figure E.25. Stacked Area Graph of Gas Wells Categorized According to Daily Gas Production Levels (1947-2006).

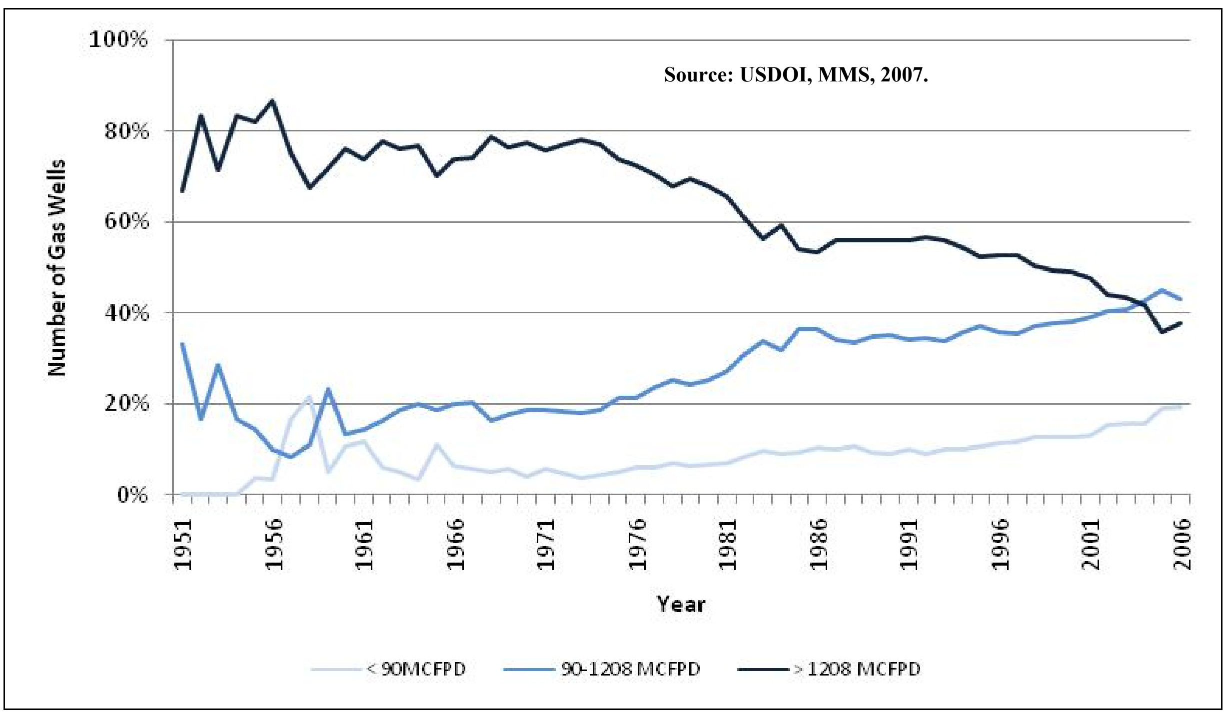


Figure E.26. Population Ratio of Gas Wells Categorized According to Daily Gas Production Levels (1951-2006).

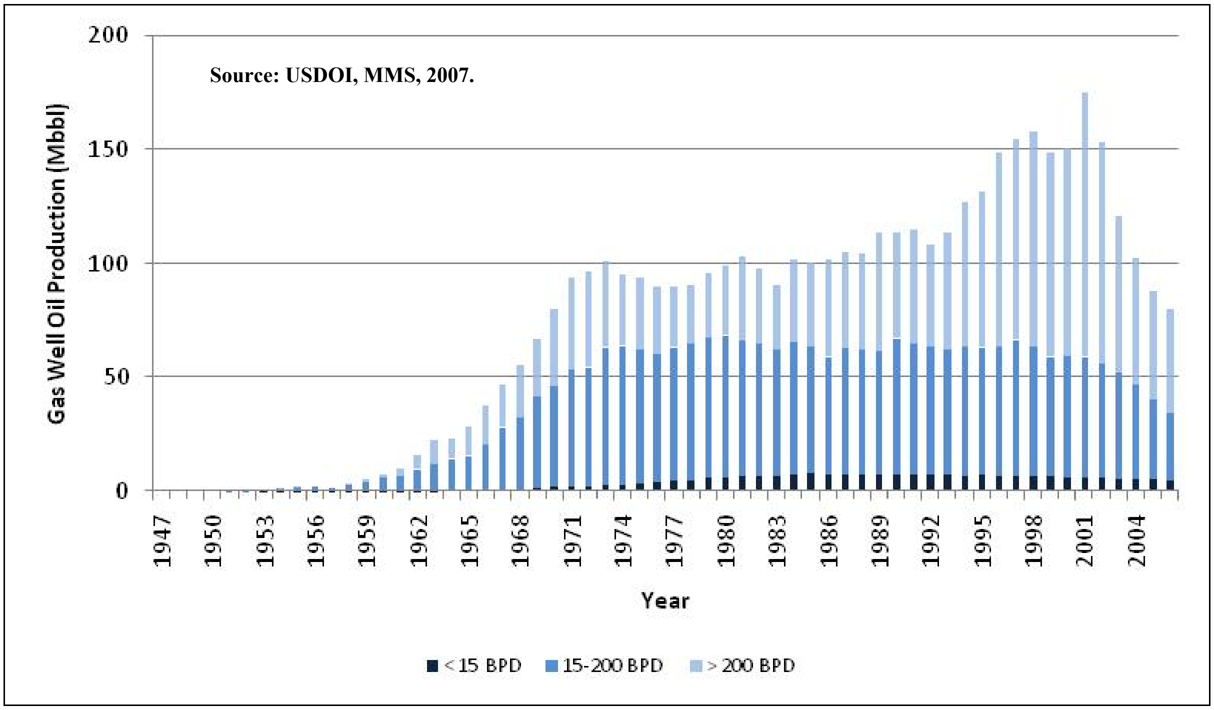


Figure E.27. Gas Well Oil Production per Category (1947-2006).

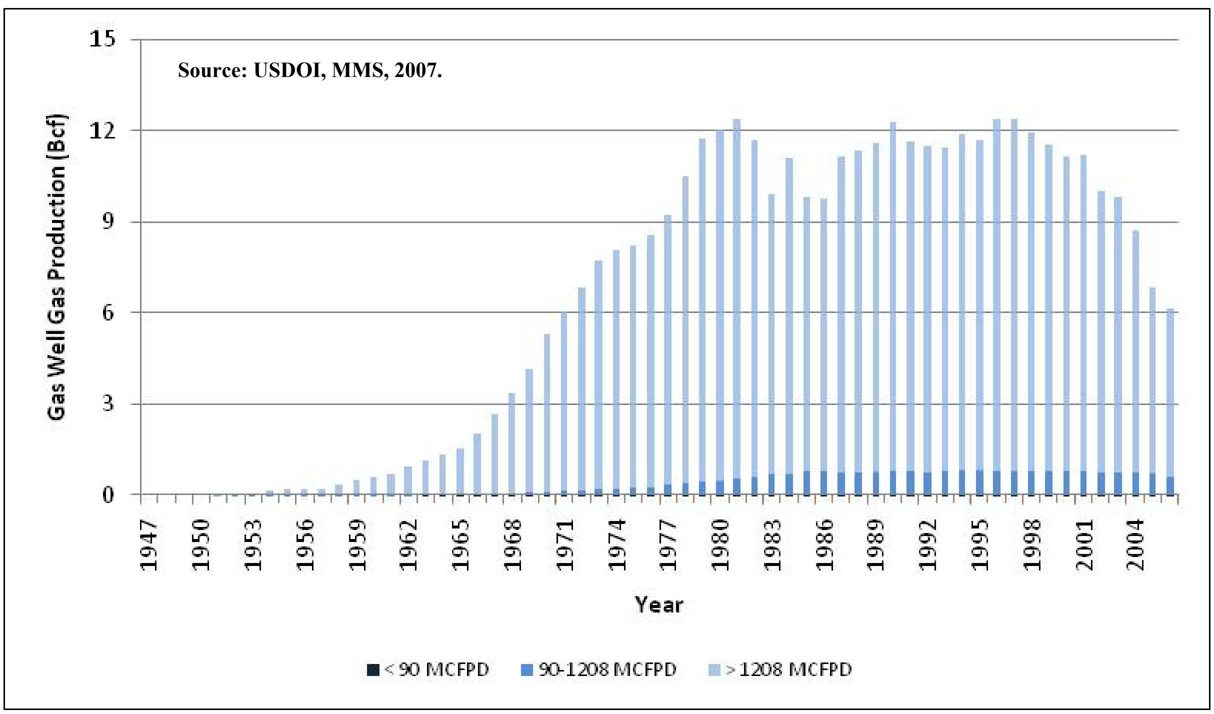


Figure E.28. Gas Well Gas Production per Category (1947-2006).

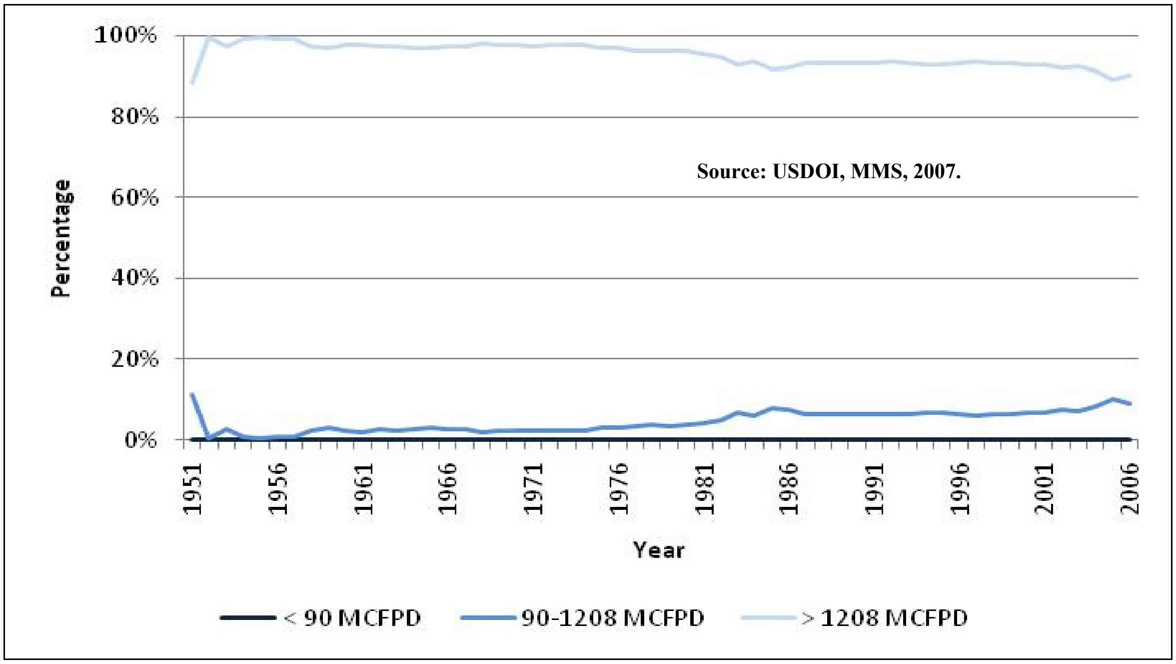


Figure E.29. Gas Production Ratio per Category According to Daily Gas Production (1951-2006).

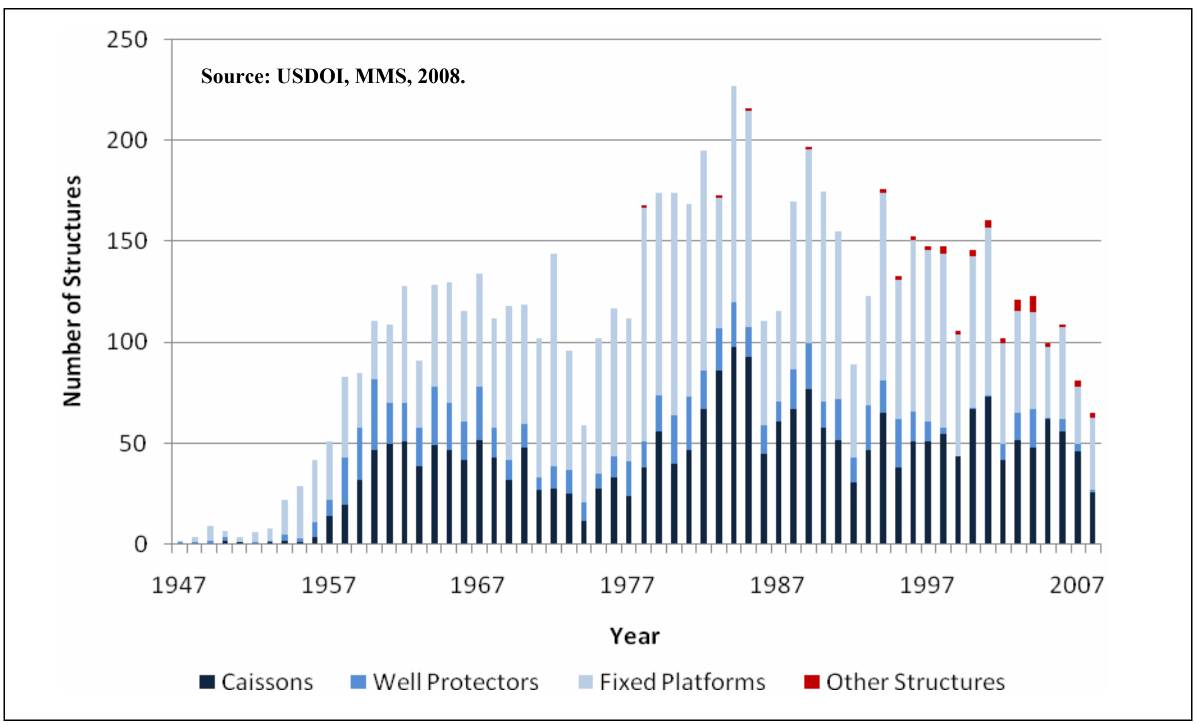


Figure E.30. Structure Installations in the Gulf of Mexico (1947-2007).

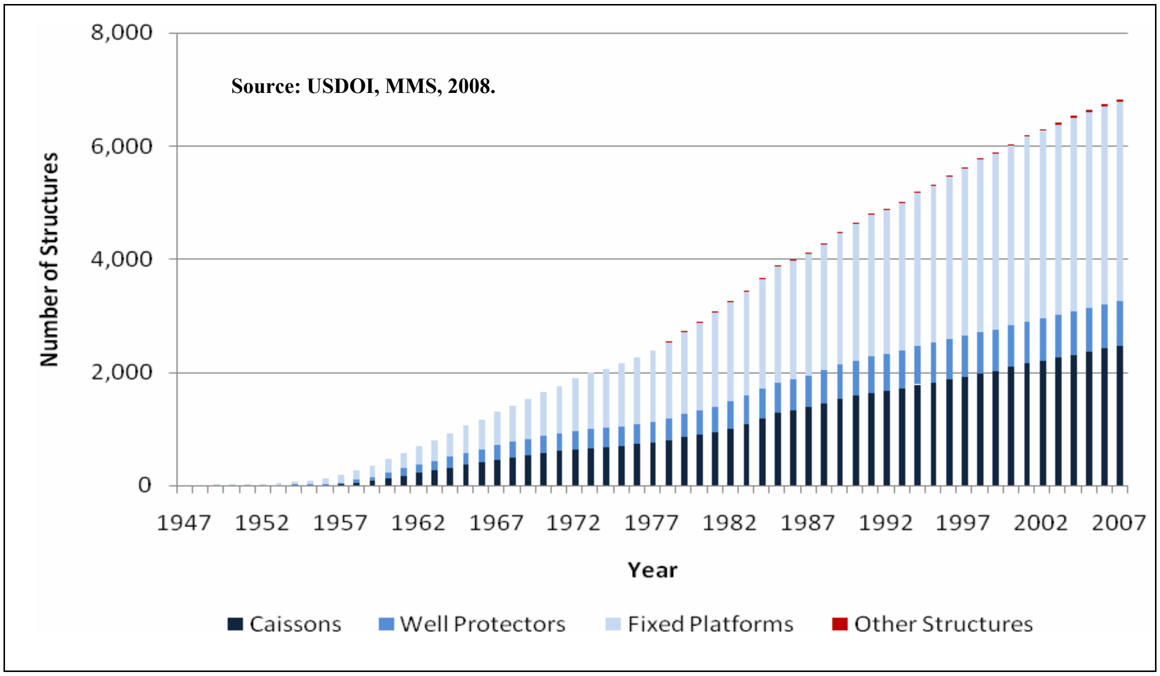


Figure E.31. Cumulative Number of Structure Installations in the Gulf of Mexico (1947-2007).

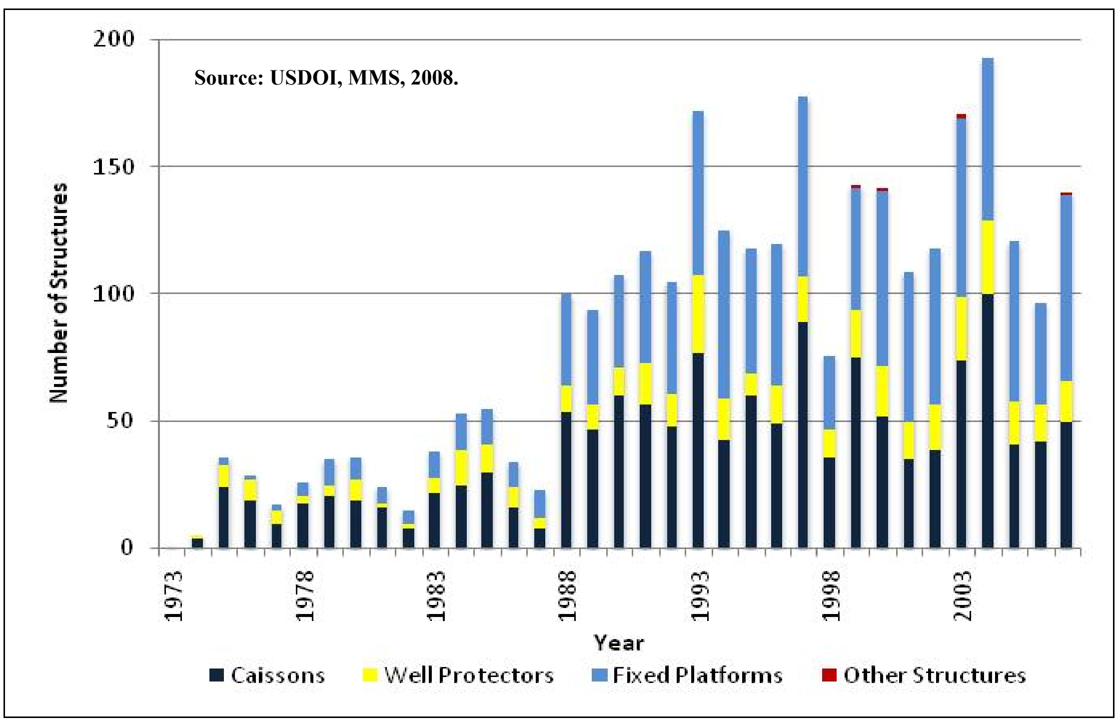


Figure E.32. Structure Removals in the Gulf of Mexico (1973-2007).

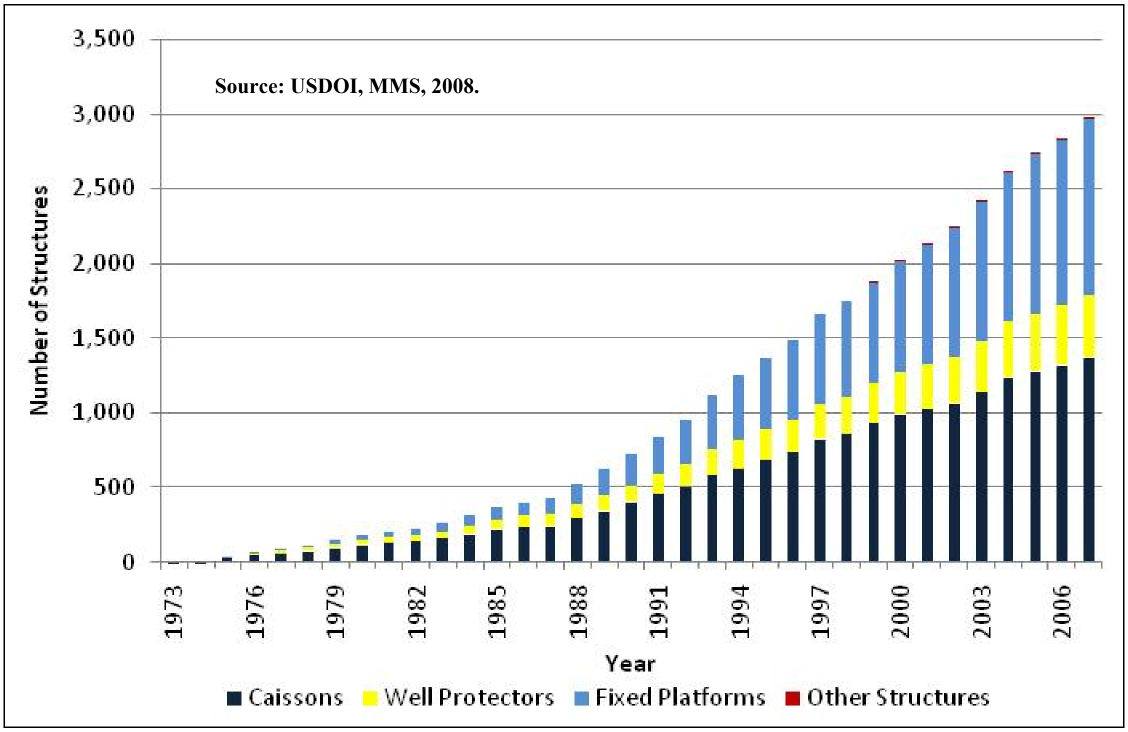


Figure E.33. Cumulative Number of Structure Removals in the Gulf of Mexico (1973-2007).

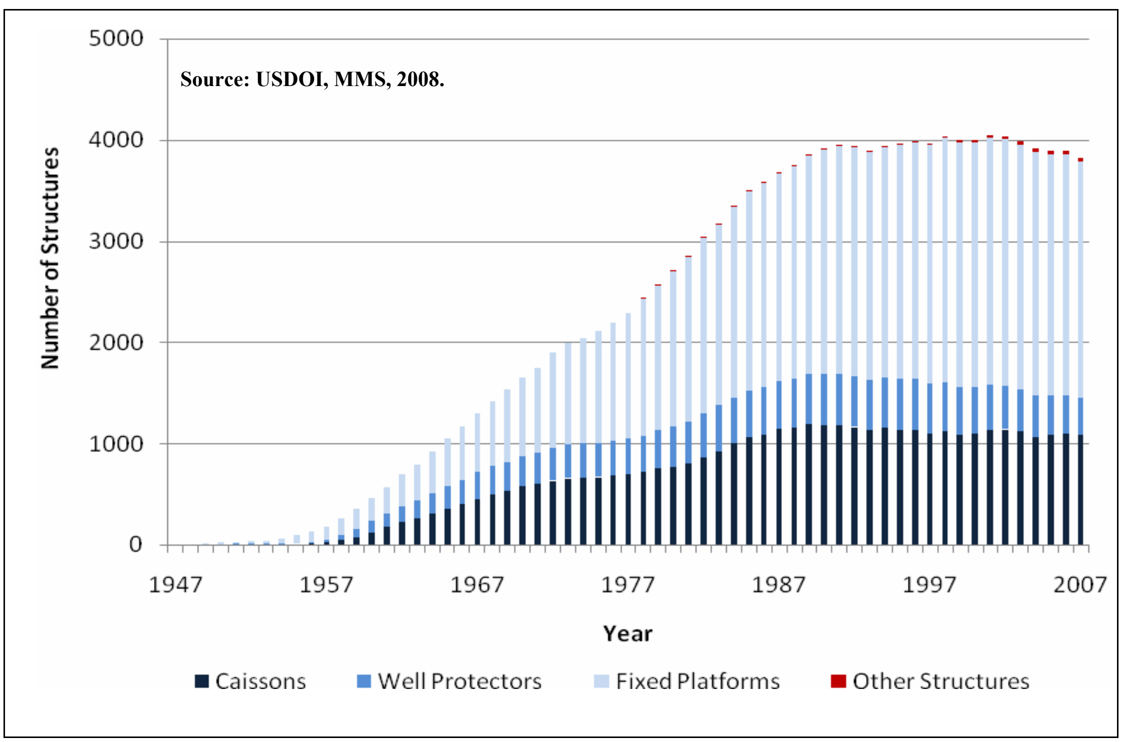


Figure E.34. Active Structures in the Gulf of Mexico (1947-2007).

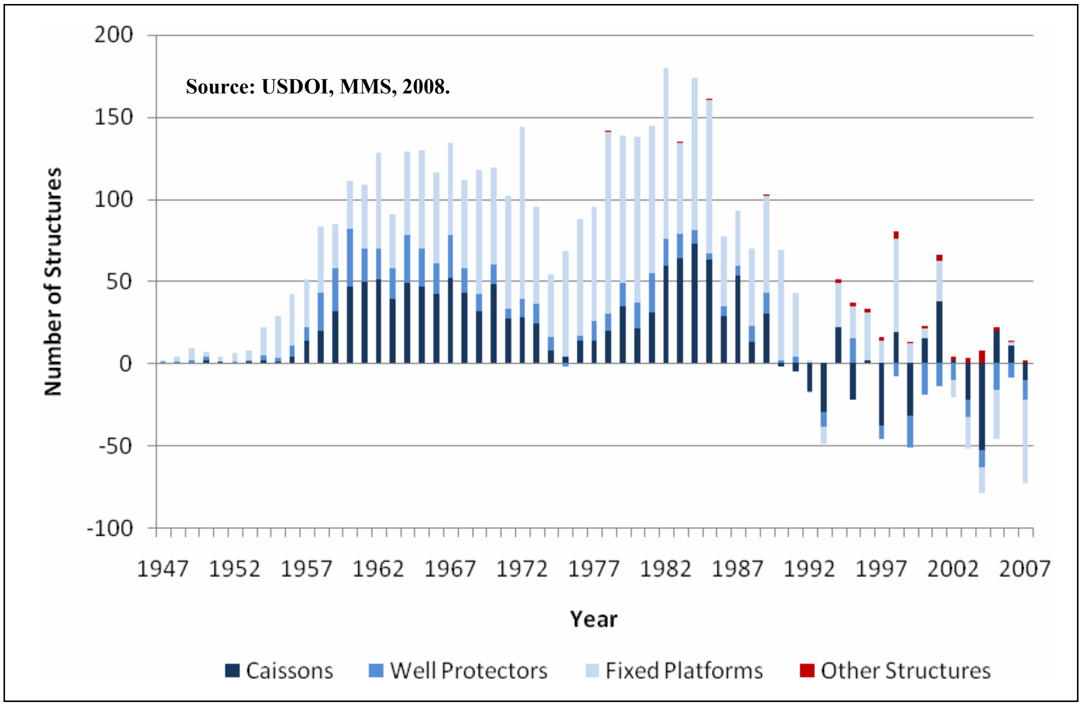


Figure E.35. Change in the Number of Active Structures in the Gulf of Mexico (1947-2007).

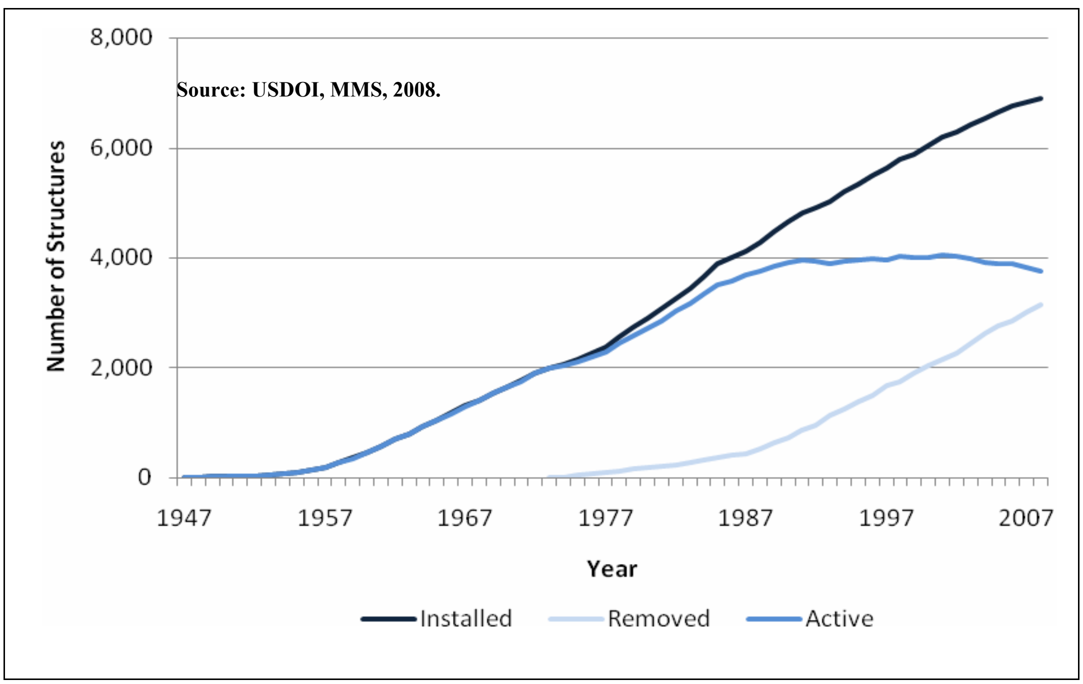


Figure E.36. Cumulative Number of Installed, Removed, and Active Structures in the Gulf of Mexico (1947-2007).

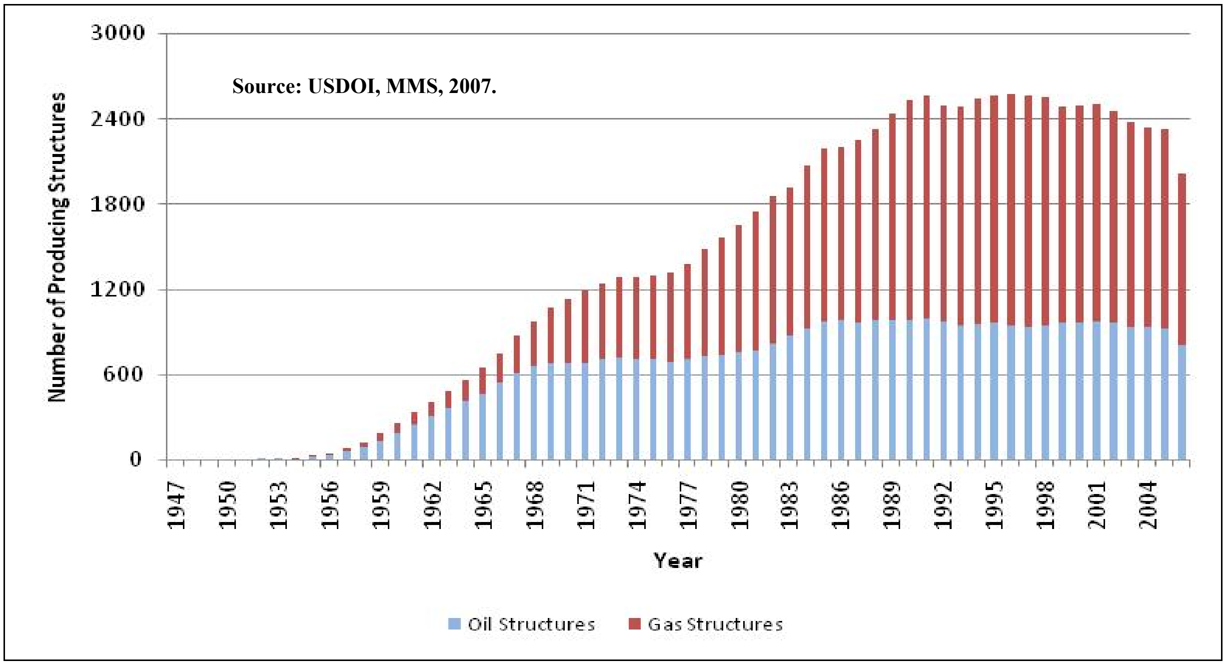


Figure E.37. Stacked Area Graph of Number of Producing Oil and Gas Structures in the GOM (1947-2006).

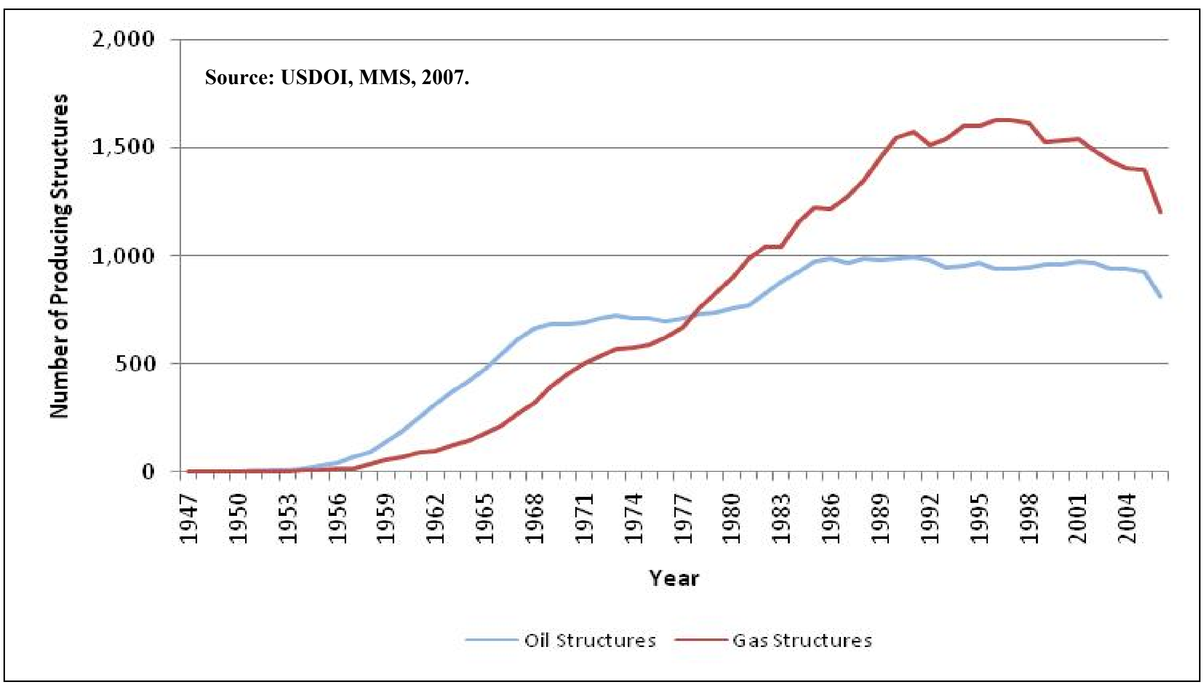


Figure E.38. Number of Producing Oil and Gas Structures in the GOM (1947-2006).

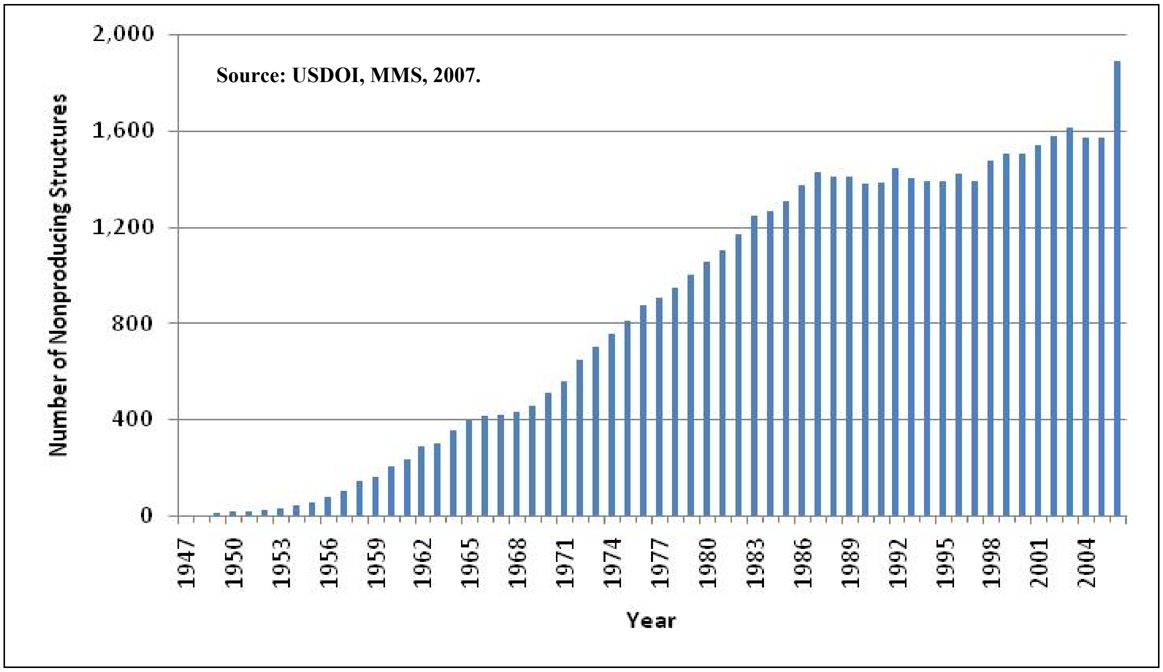


Figure E.39. Number of Non-Producing Structures in the GOM (1947-2006).

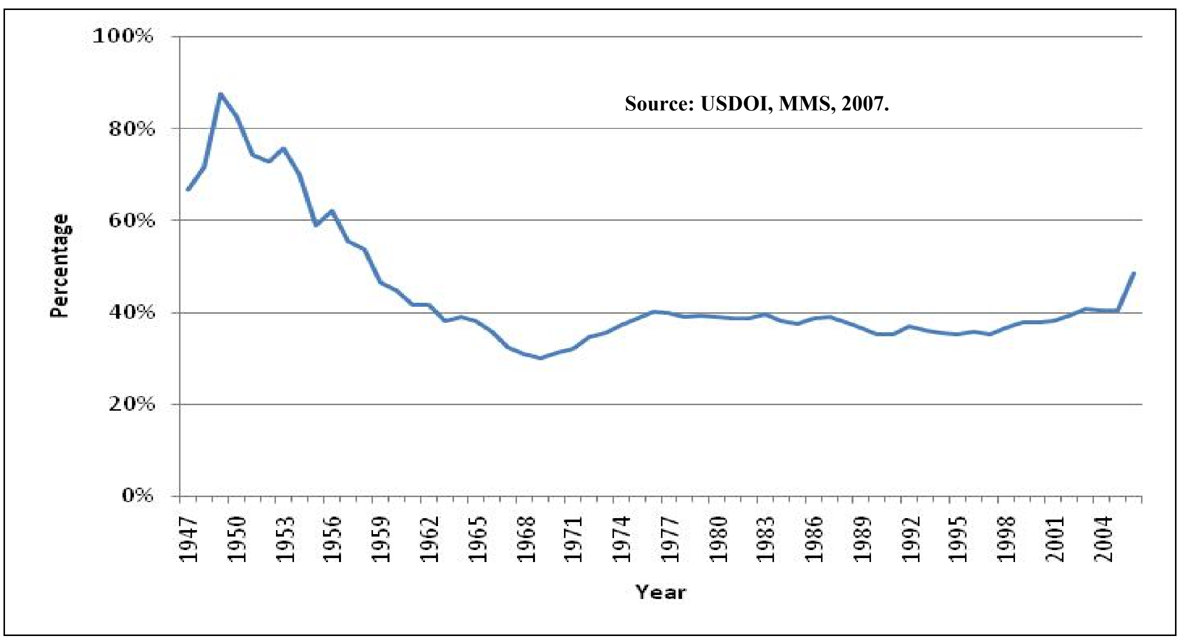


Figure E.40. Population Ratio of Non-Producing Structures in the GOM (1947-2006).

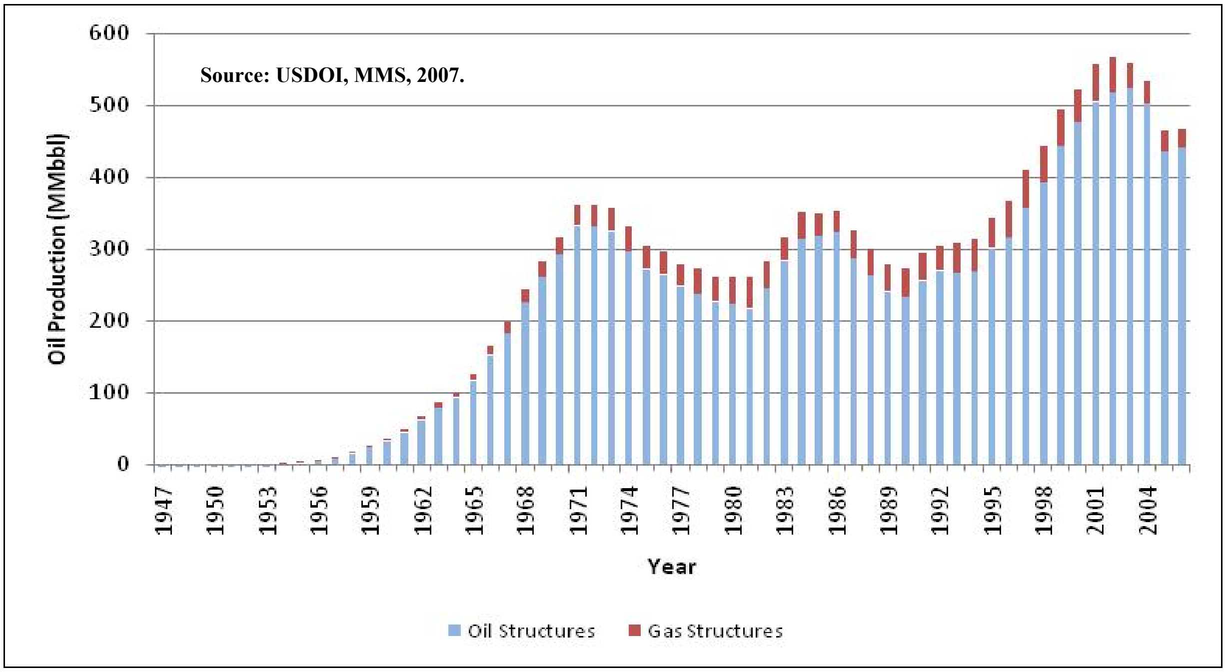


Figure E.41. Annual Oil Production from Oil and Gas Structures in the GOM (1947-2006).

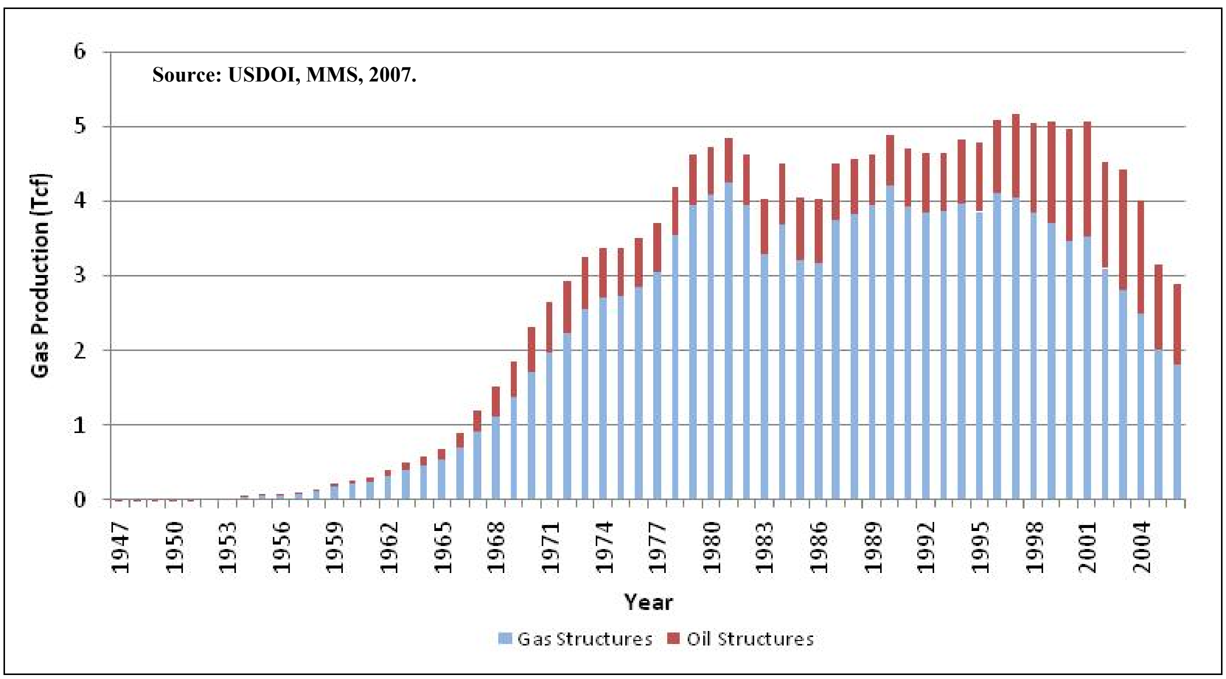


Figure E.42. Annual Gas Production from Oil and Gas Structures in the GOM (1947-2006).

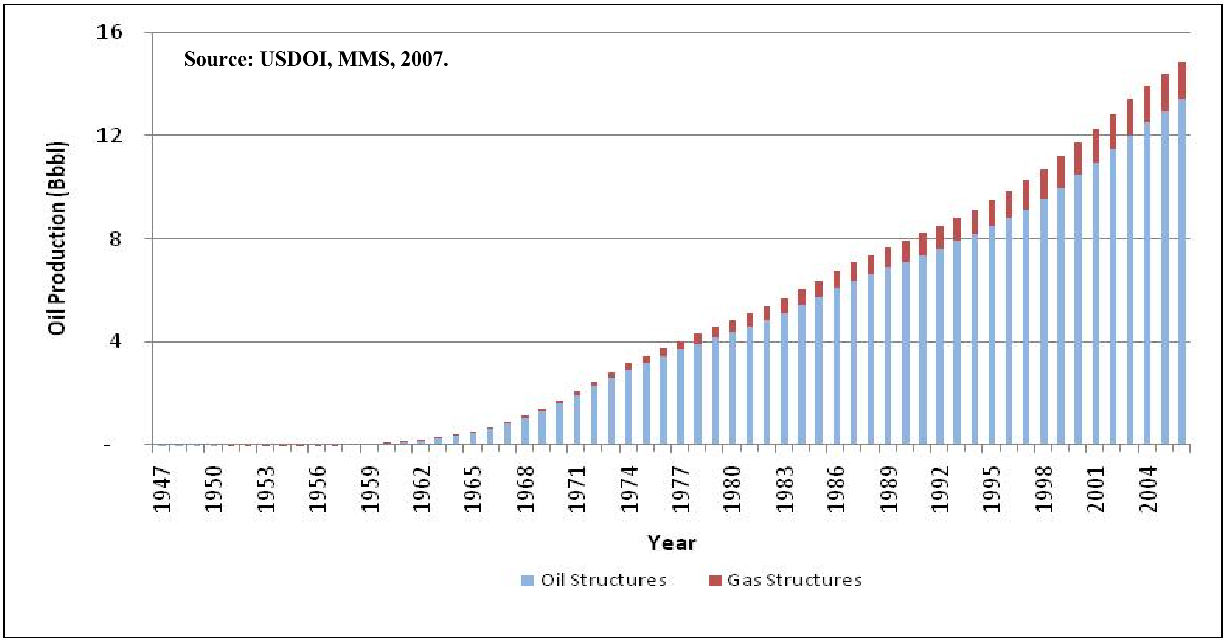


Figure E.43. Cumulative Oil Production from Oil and Gas Structures in the GOM (1947-2006).

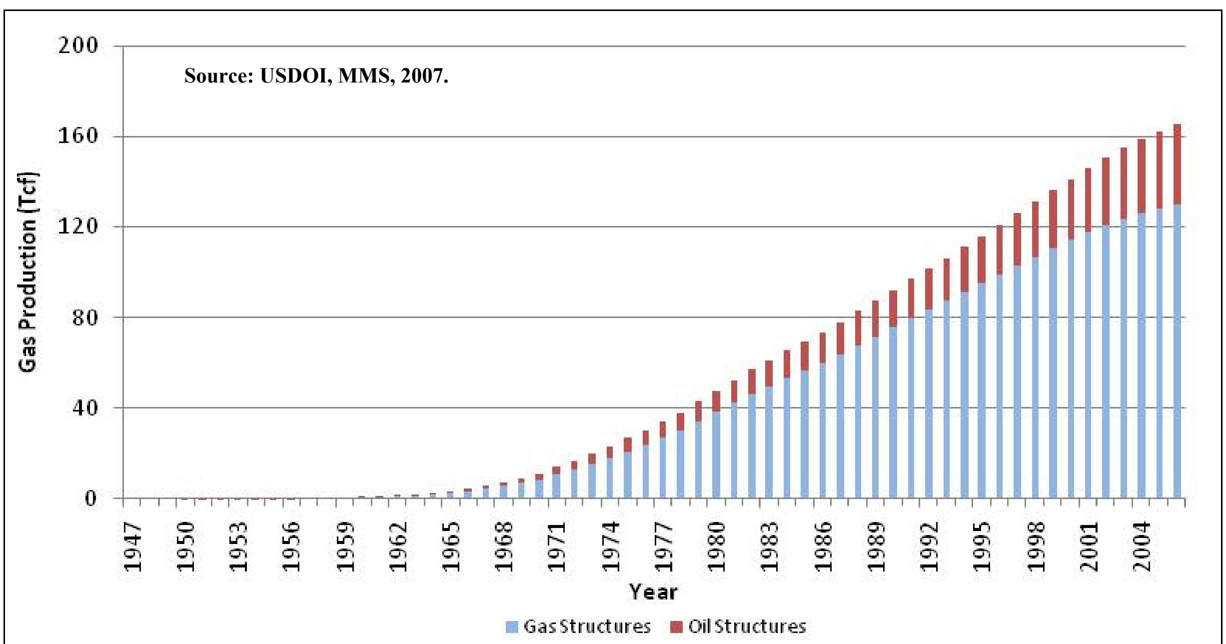


Figure E.44. Cumulative Gas Production from Oil and Gas Structures in the GOM (1947-2006).

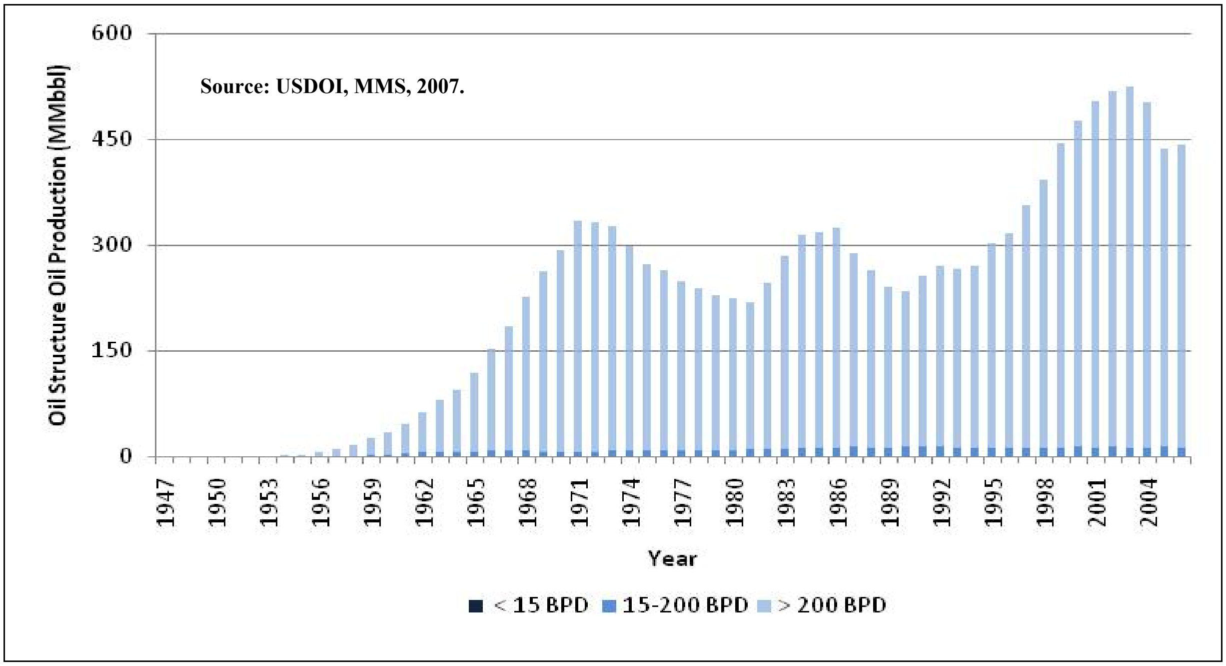


Figure E.45. Oil Structure Oil Production Decomposed According to Production Category (1947-2006).

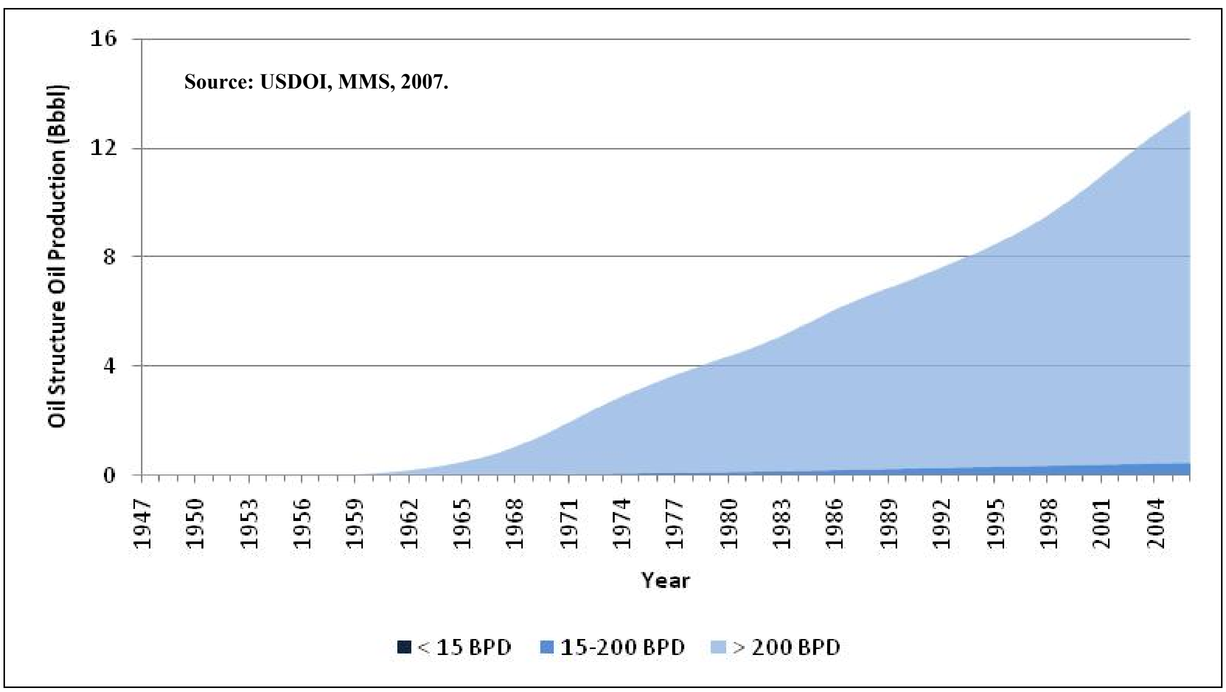


Figure E.46. Cumulative Oil Structure Oil Production Decomposed According to Production Category (1947-2006).

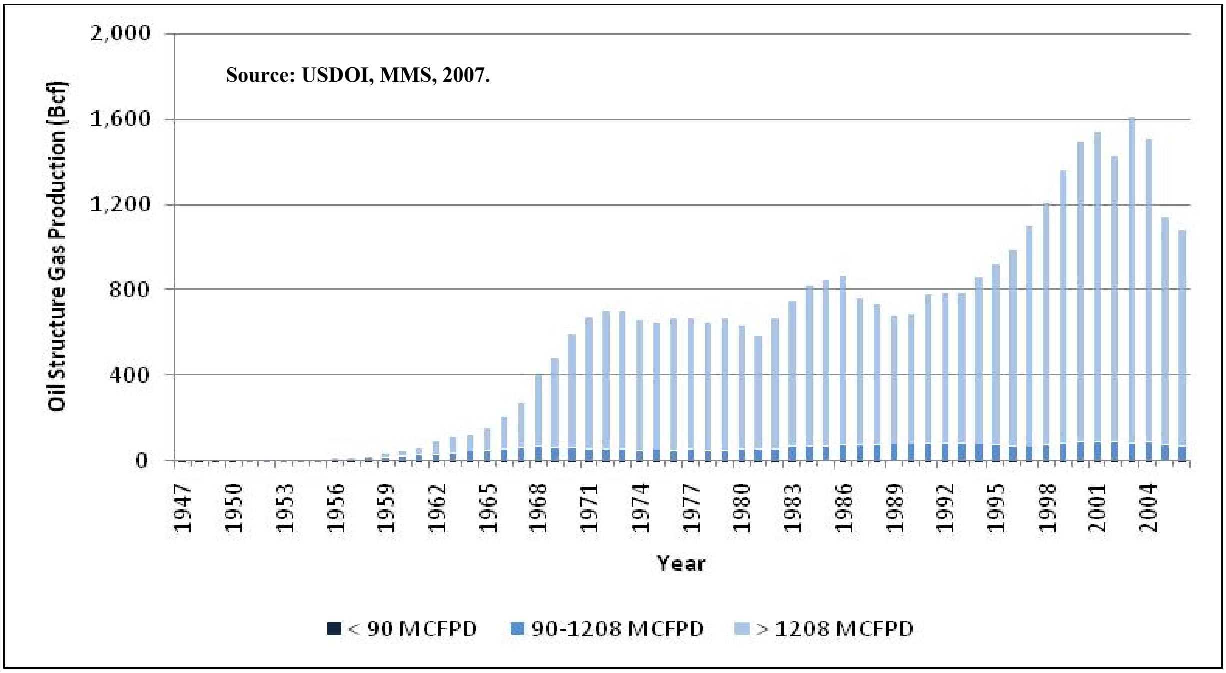


Figure E.47. Oil Structure Gas Production Decomposed According to Production Category (1947-2006).

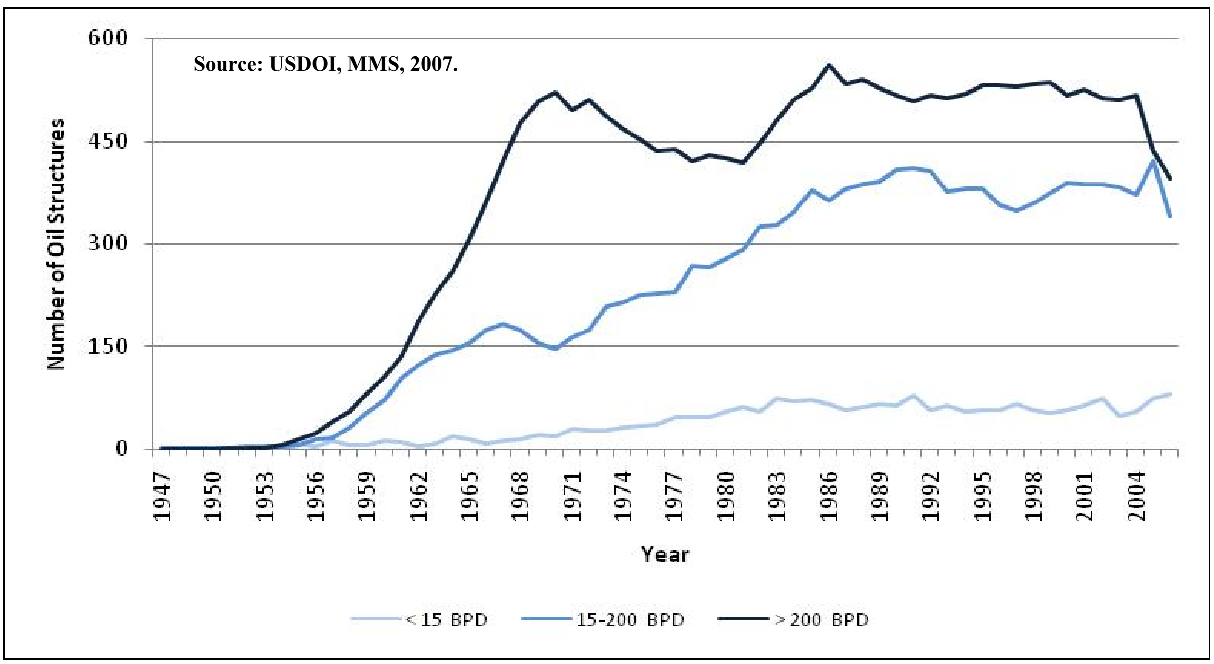


Figure E.48. Oil Structures Categorized According to Daily Oil Production (1947-2006).

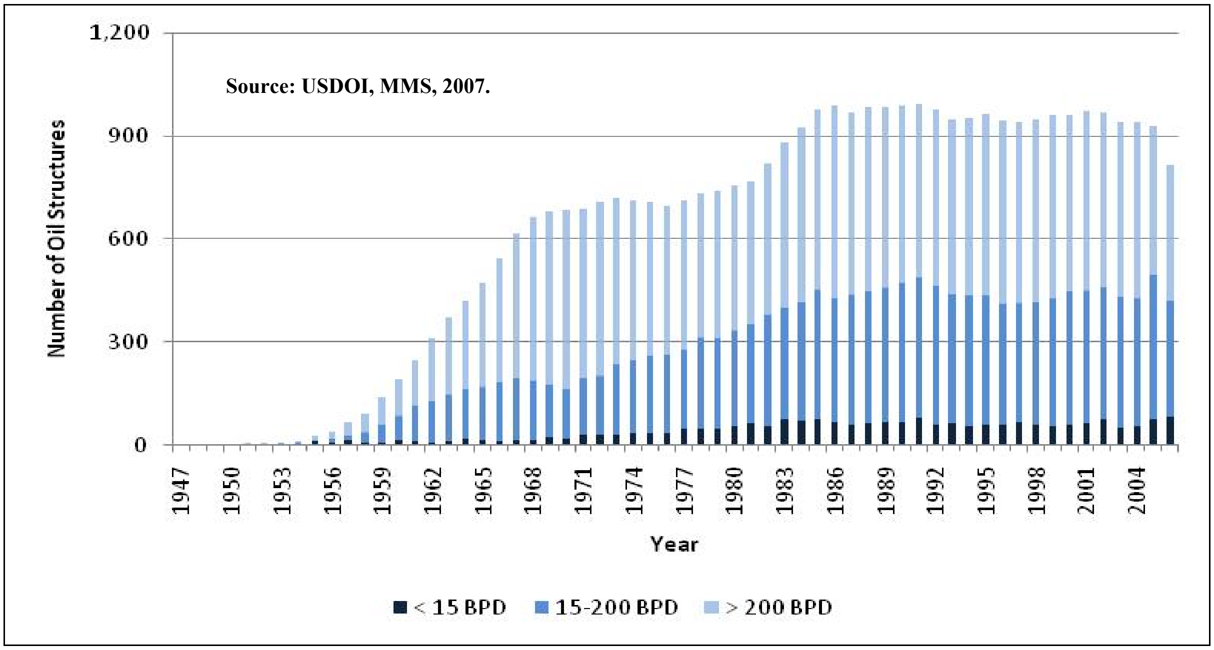


Figure E.49. Stacked Area Graph of Oil Structures Categorized According to Daily Oil Production (1947-2006).

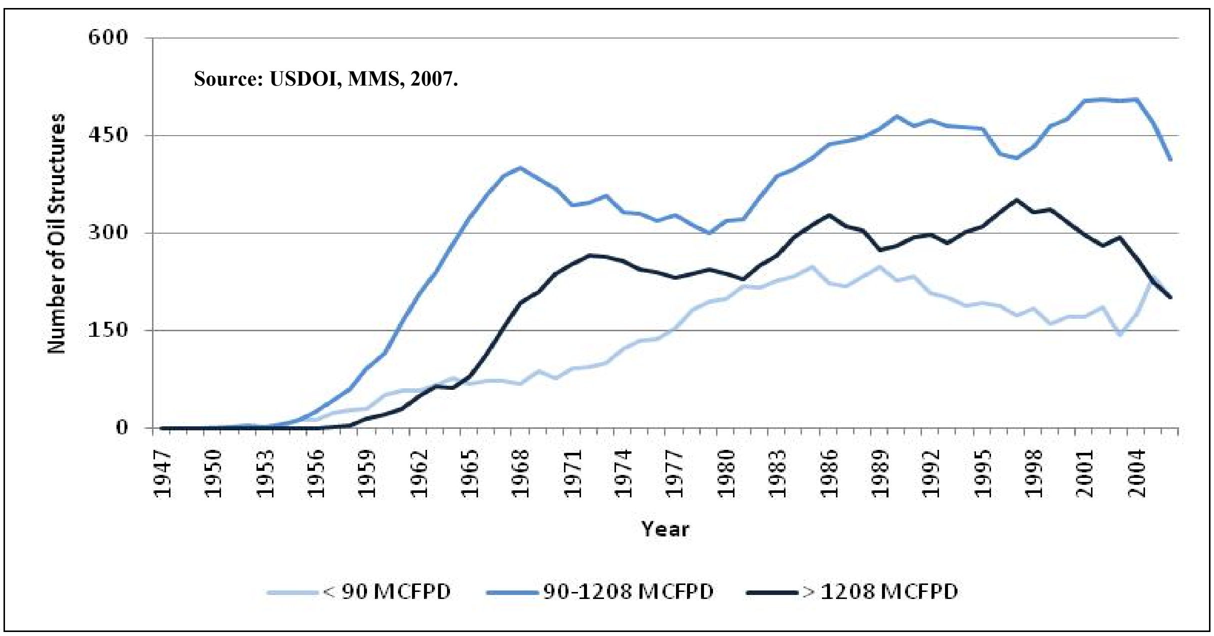


Figure E.50. Oil Structures Categorized According to Daily Gas Production (1947-2006).

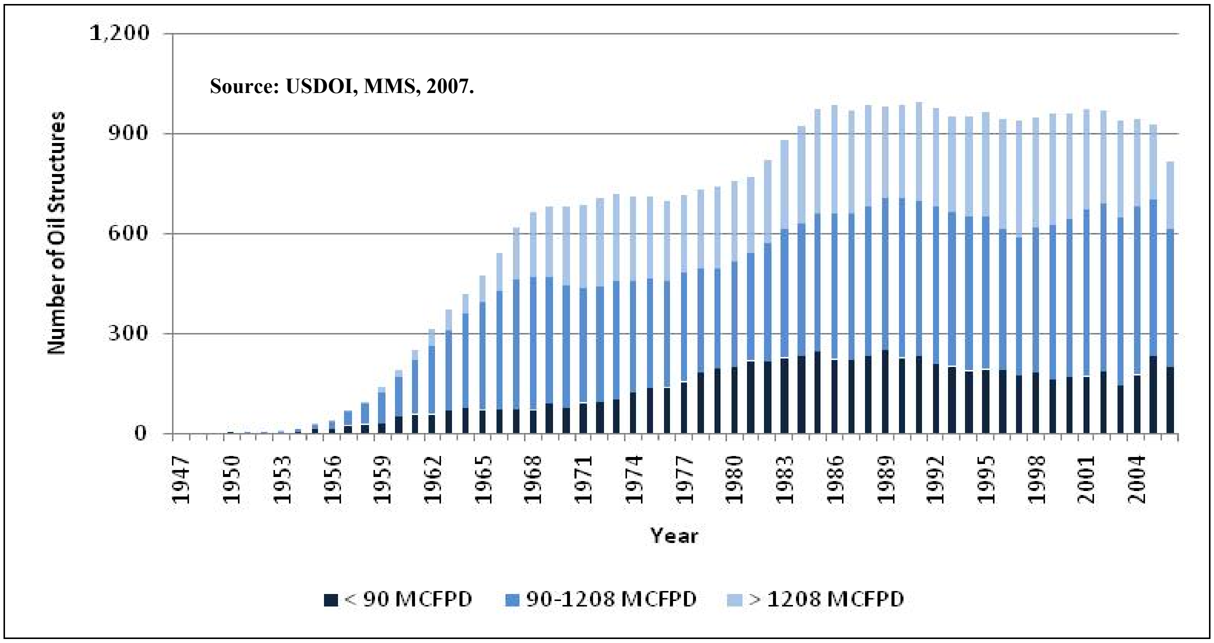


Figure E.51. Stacked Area Graph of Oil Structures Categorized According to Daily Gas Production (1947-2006).

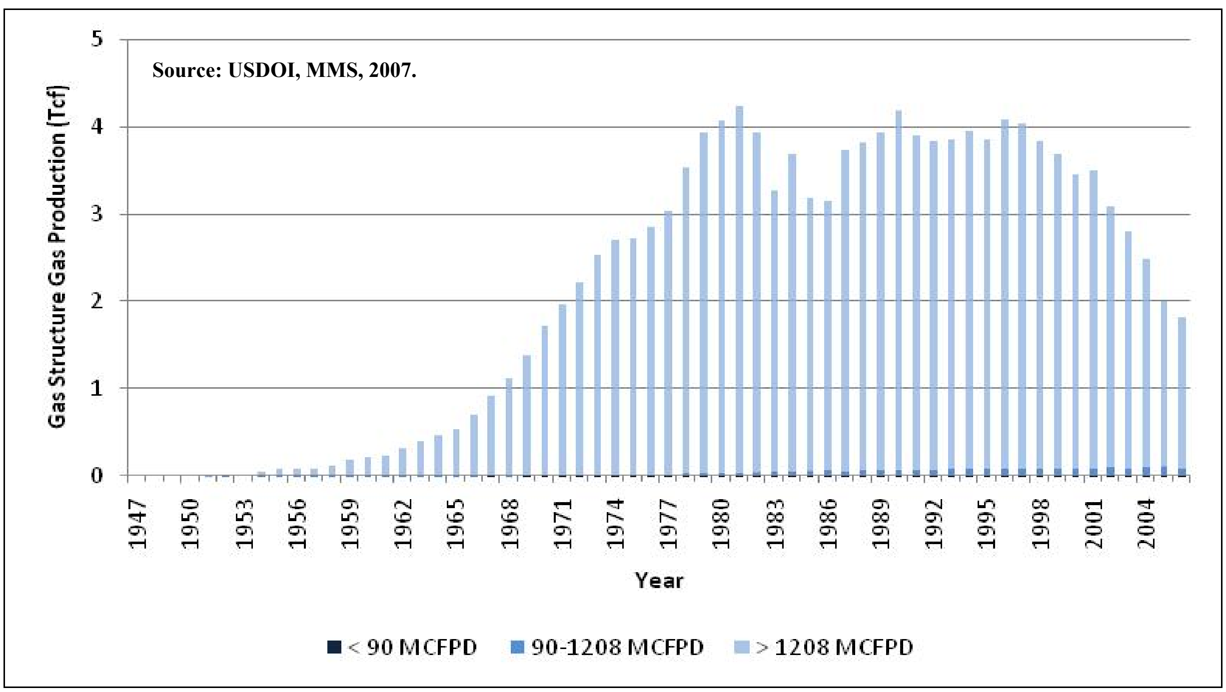


Figure E.52. Gas Structure Gas Production Decomposed According to Production Category (1947-2006).

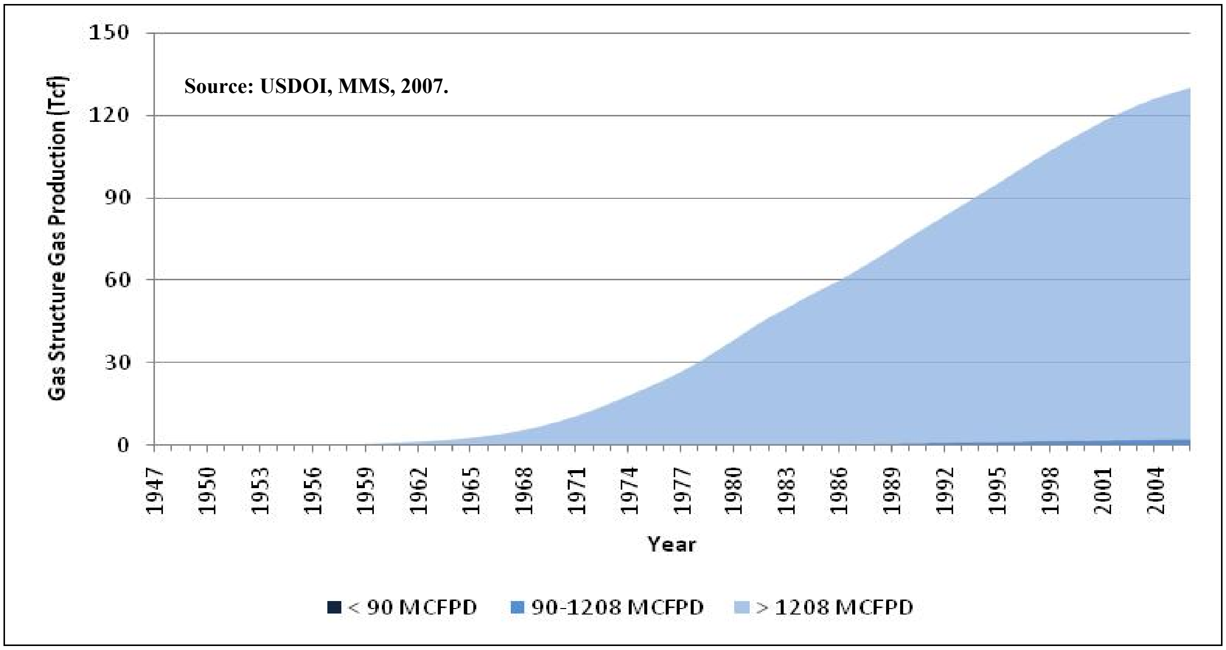


Figure E.53. Cumulative Gas Structure Gas Production Decomposed According to Production Category (1947-2006).

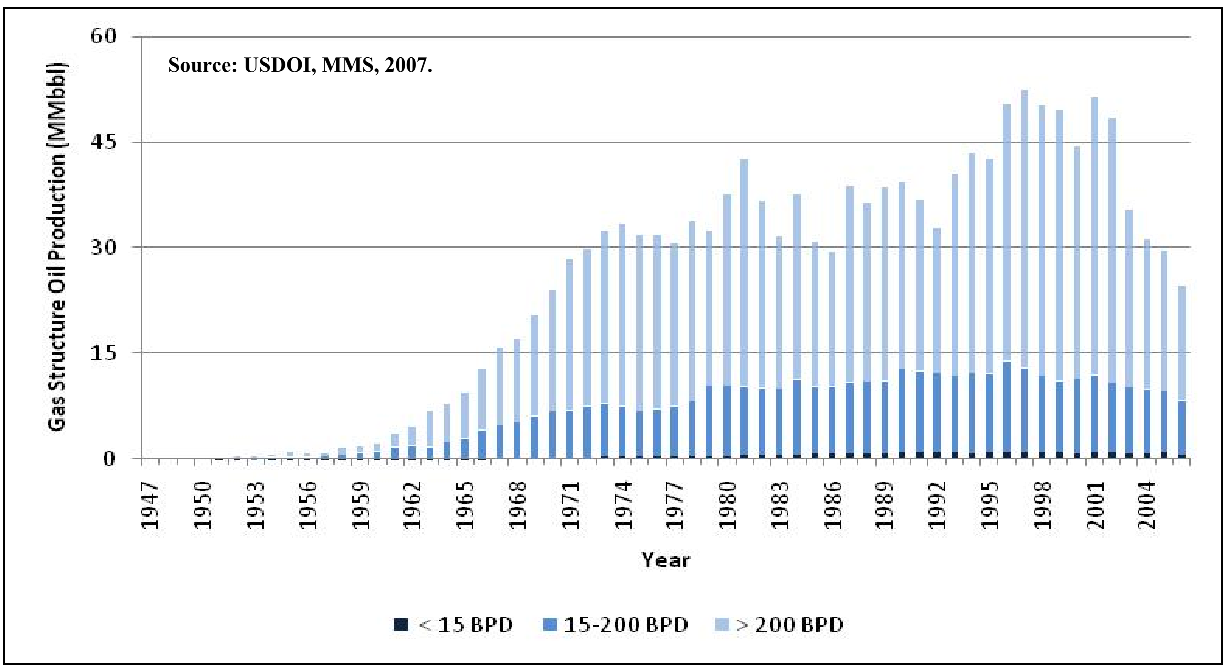


Figure E.54. Gas Structure Oil Production Decomposed According to Production Category (1947-2006).

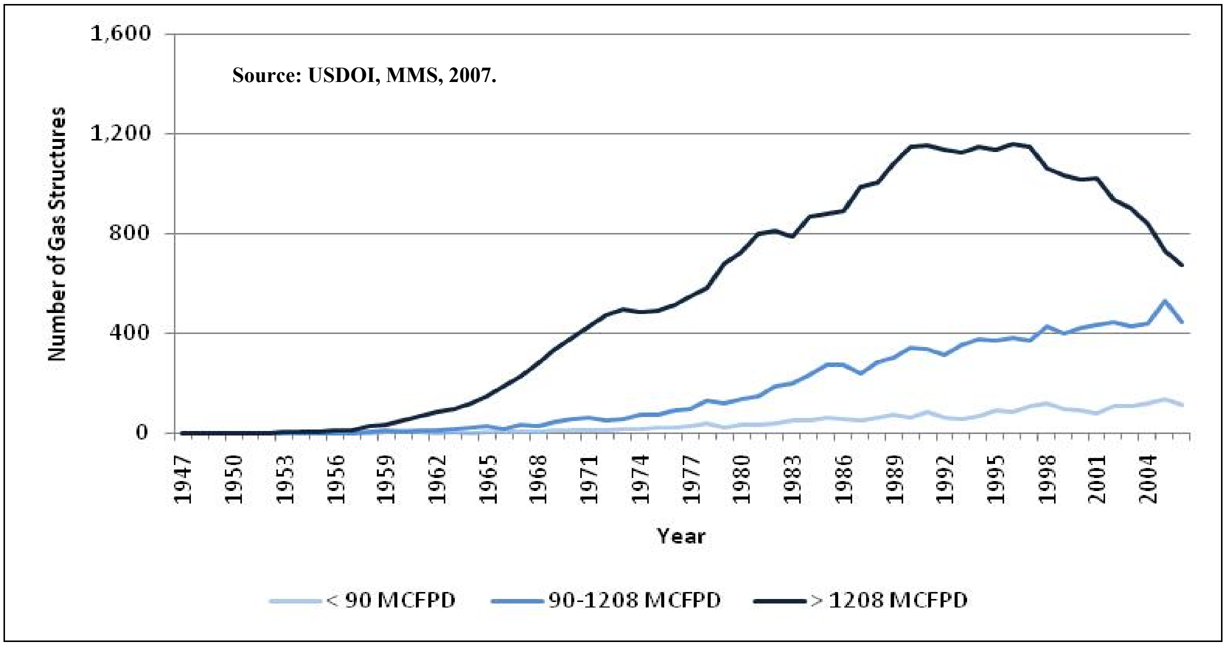


Figure E.55. Gas Structures Categorized According to Daily Gas Production (1947-2006).

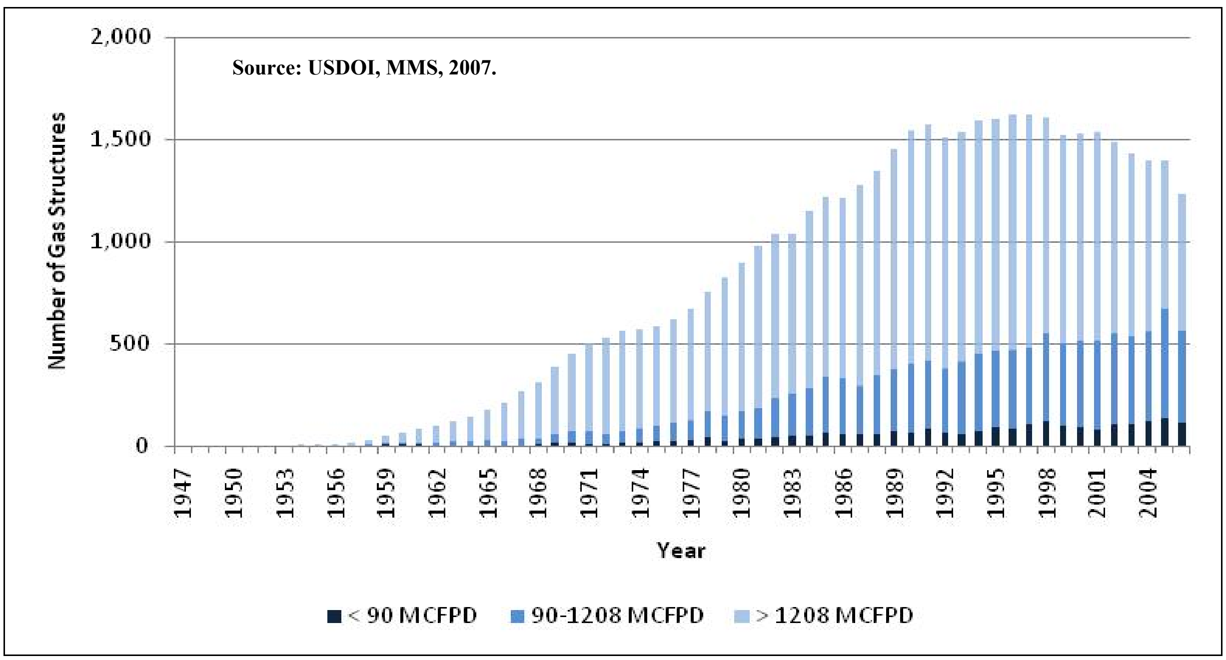


Figure E.56. Stacked Area Graph of Gas Structures Categorized According to Daily Gas Production (1947-2006).

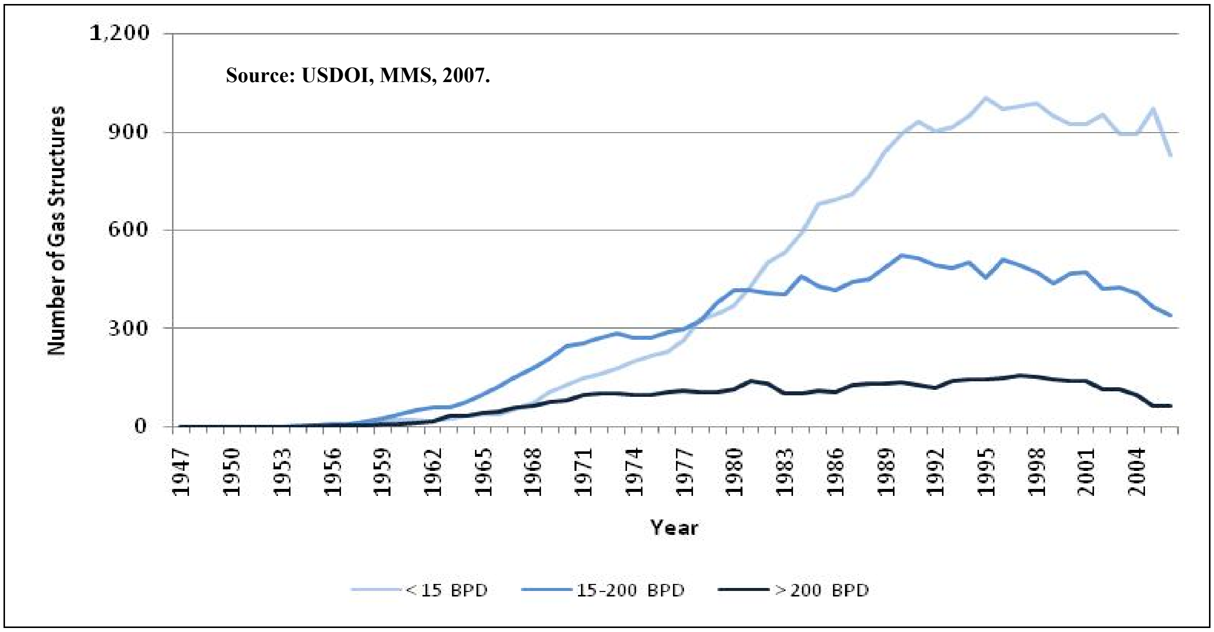


Figure E.57. Gas Structures Categorized According to Daily Oil Production (1947-2006).

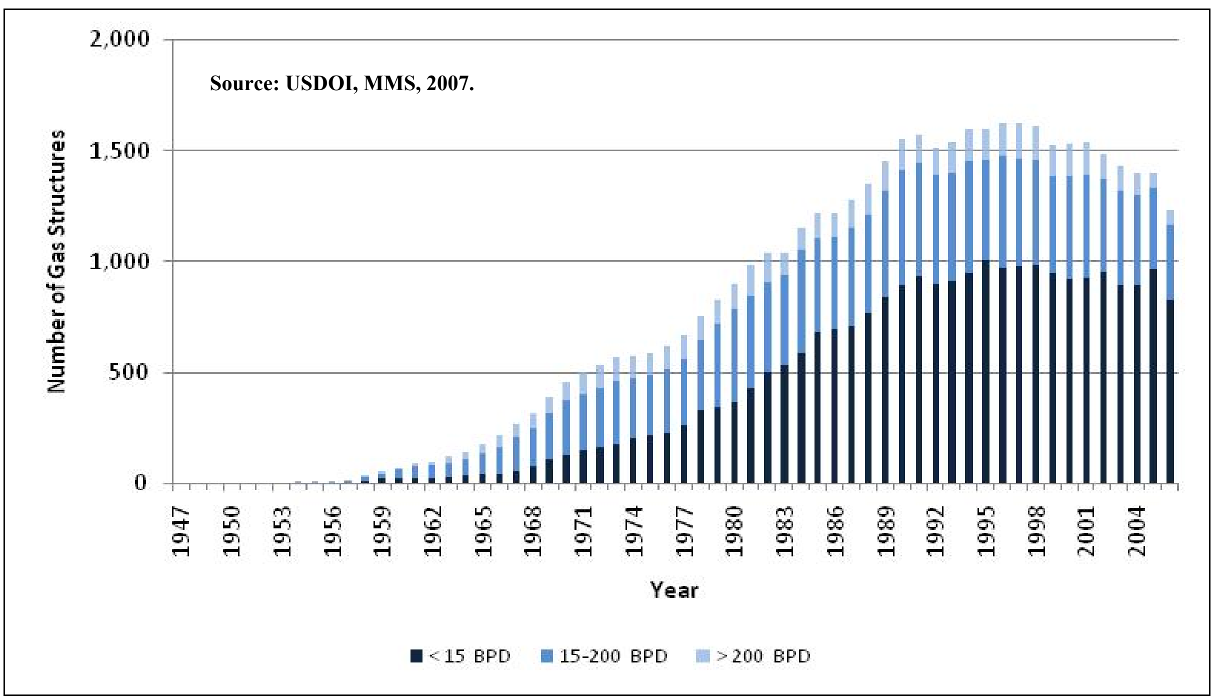


Figure E.58. Stacked Area Graph of Gas Structures Categorized According to Daily Oil Production (1947-2006).

APPENDIX F.

CHAPTER 6 TABLES AND FIGURES

Table F.1.

Active Structures Classified by Primary Production and Structure Type (2006)

Primary Production	Caisson	Fixed Platform	Well Protector	Unknown	Total
Gas	458	1,093	157	27	1,735
Oil	126	416	72	15	629
All	584	1,509	229	42	2,364

Source: USDOI, MMS, 2007.

Table F.2.

Active Structures Classified by Class and Primary Production (2006)

Structure Class	Primary Production		Total
	Gas	Oil	
Young	462	63	525
Normal	854	426	1,280
Chaotic	64	26	90
Latecomer	378	49	427
Unknown	27	15	42
Total	1,735	629	2,364

Table.F 3.

Number of Subcategories Based Upon Removed Structures in the GOM

Primary Production	Water Depth (ft)	Caisson	Well Protector	Fixed Platform
Gas	< 60	10	10	10
	60 - 200	10	10	10
	> 200	-	3	10
Oil	< 60	10	10	5
	60 - 200	3	5	10
	> 200	-	3	3

Table F.4.

History Matching Procedure for Young Structures

Step 1.	For $s \in \Gamma$ at time T, compute $Q(s,T) = \sum_{t=1}^{T} q(s,t)$
Step 2.	Compare $Q(s,T)$ with $\overline{Q}(\Gamma, T)$ and select $\overline{Q}^*(\Gamma, T) = \min_{\gamma} \left\| Q(s,T) - \overline{Q}(\gamma_{ijk}, T) \right\|$
Step 3.	Label the annual production profile corresponding to $\overline{Q}^*(\Gamma, T)$ as $\overline{q}^*(\Gamma, t)$.
Step 4.	Calculate $\alpha = \frac{Q(s,T)}{\overline{Q}(\gamma_{ijk}, T)}$.
Step 5.	Identify s with the production profile $q(s,t) = \alpha\, \overline{q}^*(\Gamma, t)$, $t > T$

Table F.5.

Best Fit Curve Frequency and Average Model Parameters for Normal and Chaotic Structures

Normal Class		Frequency	Coefficients		Curve Fit
Primary Production	Model Type	(%)	a, C	n	R^2
Gas	Exponential	46%	0.415		0.91
	Harmonic	3%	1.8E-05		0.89
	Hyperbolic	51%	0.063	14,331.8	0.91
Oil	Exponential	36%	0.294		0.90
	Harmonic	4%	1.0E-05		0.90
	Hyperbolic	59%	0.023	1,176.9	0.90

Chaotic Class		Frequency	Coefficients		Curve Fit
Primary Production	Model Type	(%)	a, C	n	R^2
Gas	Exponential	22%	0.506		0.54
	Harmonic	63%	1.9E-05		0.58
	Hyperbolic	16%	1.18E-04	1.603	0.56
Oil	Exponential	23%	0.12		0.59
	Harmonic	50%	1.0E-05		0.46
	Hyperbolic	27%	1.19E-03	2.315	0.64

Table F.6.

Cumulative Production in Year Six for the 10 Subcategories of Γ(CAIS, 60-200, OIL)

Subcategory	Cumulative Production (BOE)
1	45,495
2	147,727
3	348,192
4	491,615
5	615,902
6	791,521
7	960,707
8	1,101,116
9	1,555,745
10	2,355,294

Table F.7.

Active Structures Applied in the Model Forecast

Structure Class	Gas	Oil	Total
Uneconomic	321	59	380
Normal	662	380	1,042
Young	394	60	454
Chaotic	53	23	76
Latecomer	279	93	372
Unknown	26	14	40
Total	1,735	629	2,364

Table F.8.

Model Parameters and Distribution Functions

Parameter	Notation (Unit)	Distribution[a]
Decline rate	d (%)	U(5, 30)
Oil price	P^o (\$/bbl)	N(120, 20)
Gas price	P^g (\$/Mcf)	N(12, 2)
Economic limit multiplier	a	U(0.5, 3)
Discount rate	D (%)	U(8, 14)

Footnote: (a) U(a, b) denotes the Uniform distribution with endpoint (a, b). N(μ, σ^2) represents the Normal distribution with mean μ and variance σ^2.

Table F.9.

Model Results for Cumulative Gas, Oil, BOE Production

$Q^i = \alpha_1 d + \alpha_2 P^o + \alpha_3 P^g + \alpha_4 a$			
Coefficient	Gas	Oil	BOE
α_1	-2.1E10(-7.7)	-2.1E9(-9.0)	-5.6E9(-8.2)
α_2	6.4E7(6.8)	5.5E6(6.8)	1.6E7(6.8)
α_3	7.0E8(7.5)	5.6E7(6.9)	1.7E8(7.3)
α_4	2.9E8(1.1)	3.5E7(1.6)	8.3E7(1.3)
R^2	0.97	0.97	0.82

Table F.10.

Present Value of Gas, Oil, and BOE Production

$PV = \alpha_0 + \alpha_1 d + \alpha_2 P^o + \alpha_3 P^g + \alpha_4 a + \alpha_5 D$						
	Gas		Oil		BOE	
Coefficient	$\alpha_0 = 0$	$\alpha_0 \neq 0$	$\alpha_0 = 0$	$\alpha_0 \neq 0$	$\alpha_0 = 0$	$\alpha_0 \neq 0$
α_0		5.1E7(19.0)		4.5E7(15.6)		9.64E7 (19.4)
α_1	-9.3E7(13.5)	-8.9E7(28.3)	-9.3E7(-14.5)	-9.0E7(-26.3)	-1.86E8 (-14.3)	-1.79E8 (-30.6)
α_2	1.2E5(4.7)	-1.7E4(-1.3)	7.0E5(30.2)	5.8E5(40.1)	8.12E5 (17.4)	5.61E5 (22.7)
α_3	8.7E6(36.1)	7.3E6(55.2)	1.3E6(5.6)	2.3E4(0.2)	1.00E7 (22.0)	7.36E6 (29.8)
α_4	-4.5E6(-6.9)	-6.0E6(19.6)	8.3E5(1.4)	-5.5E5(-1.6)	-3.67E6 (-3.0)	-6.59E6 (-11.5)
α_5	-1.6E8(-6.9)	-3.0E8(23.4)	-1.5E8(-7.1)	-2.7E8(-19.9)	-3.08E8 (-7.2)	-5.70E8 (-24.2)
R^2	0.98	0.99	0.99	0.97	0.99	0.98

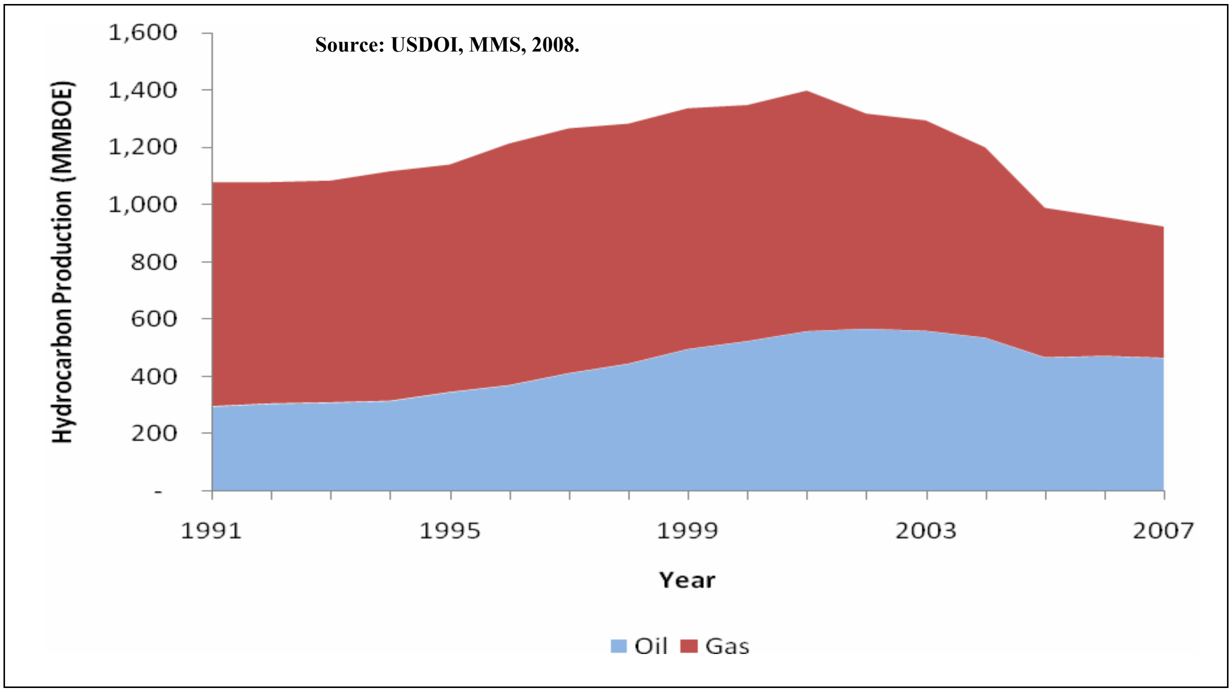


Figure F.1. Hydrocarbon Production on the OCS of the Gulf of Mexico (1991-2007).

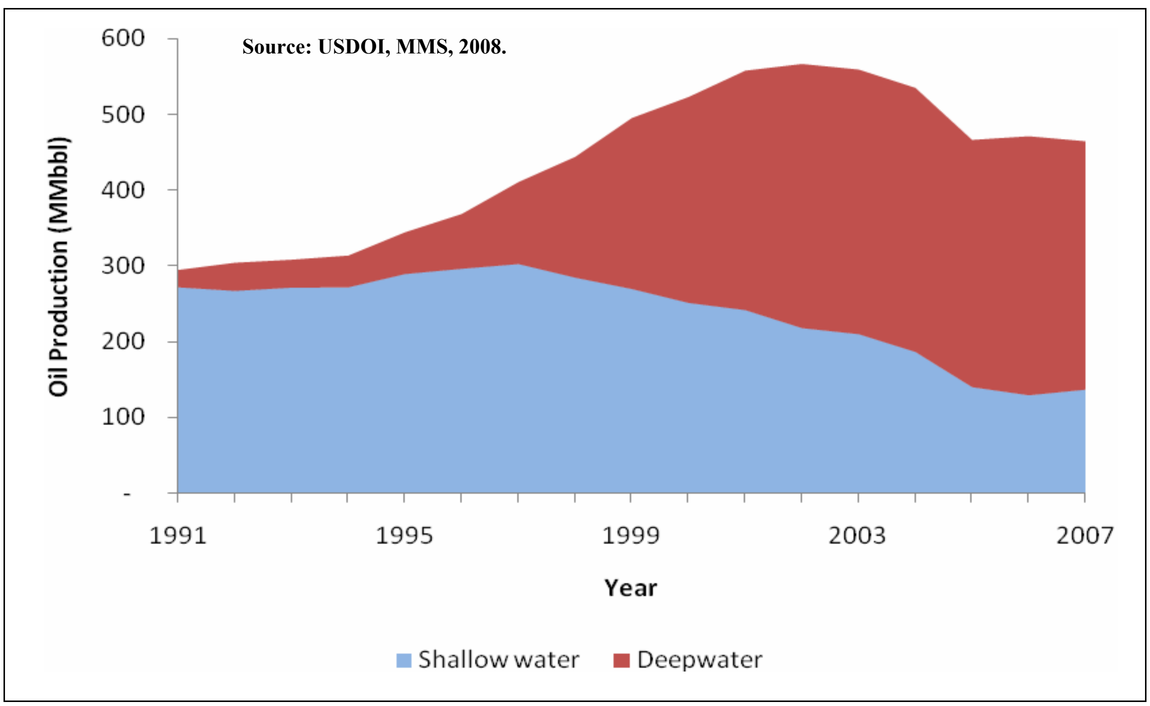


Figure F.2. Oil Production on the OCS in the GOM (1991-2007).

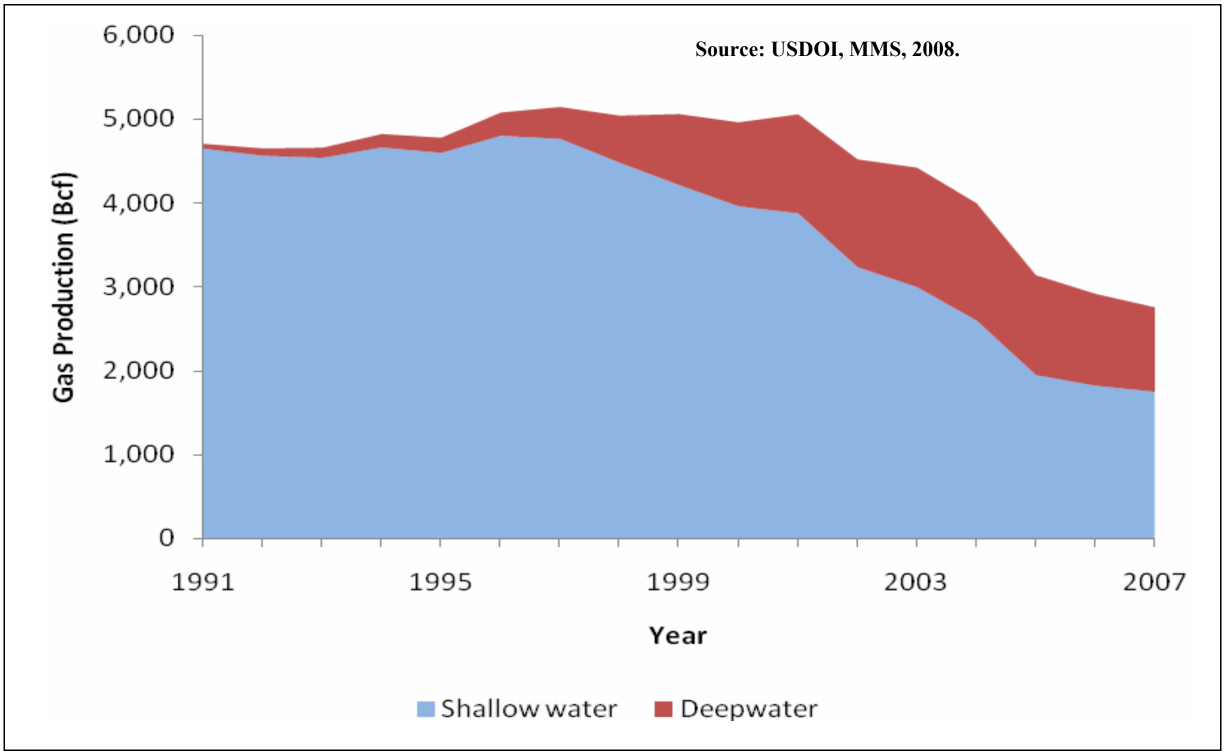


Figure F.3. Gas Production on the OCS in the GOM (1991-2007).

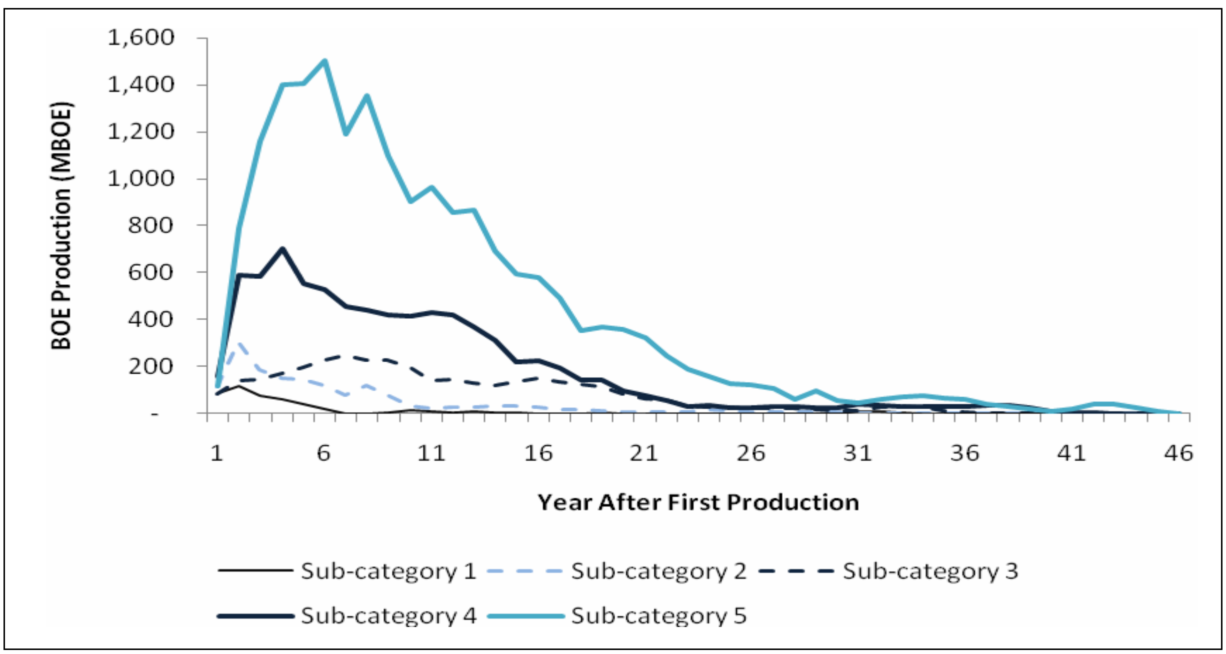


Figure F.4. Average Annual Production Profiles in the Fixed Platform, 0-60 ft Water Depth, Oil Production, Subcategory.

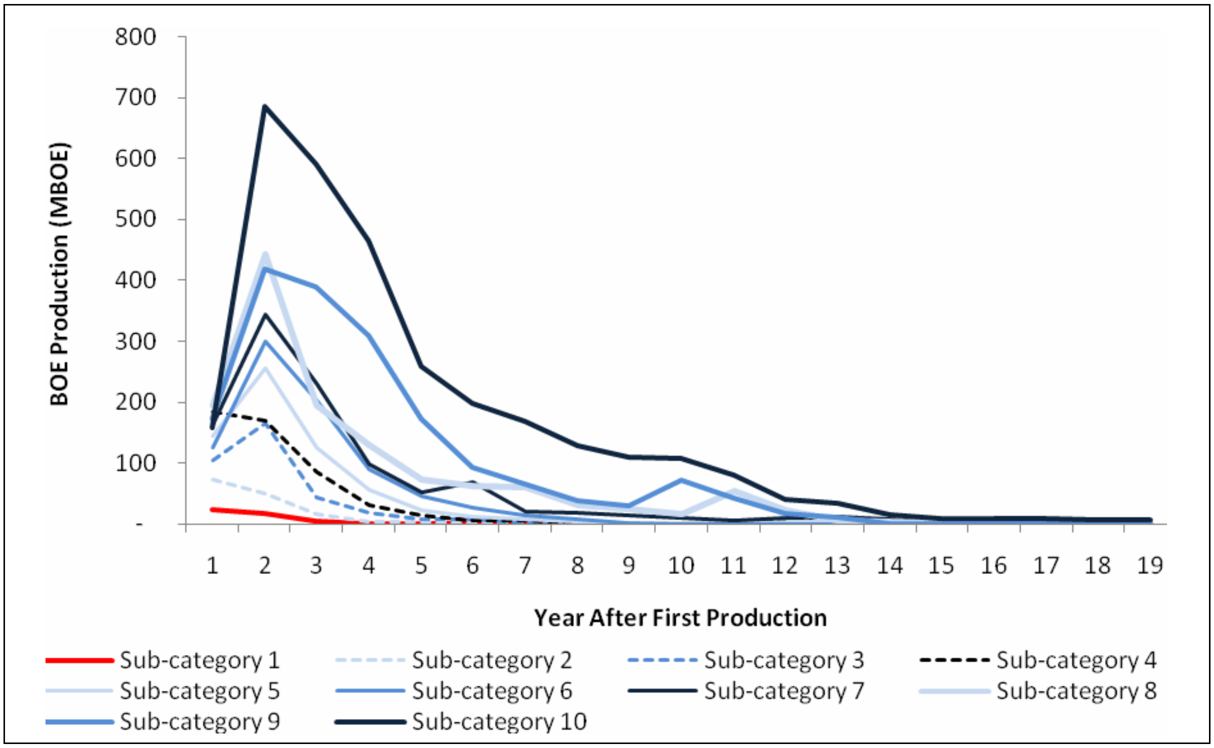


Figure F.5. Average Annual Production Profiles in the Caisson, 60-200 ft Water Depth, Gas Production, Subcategory.

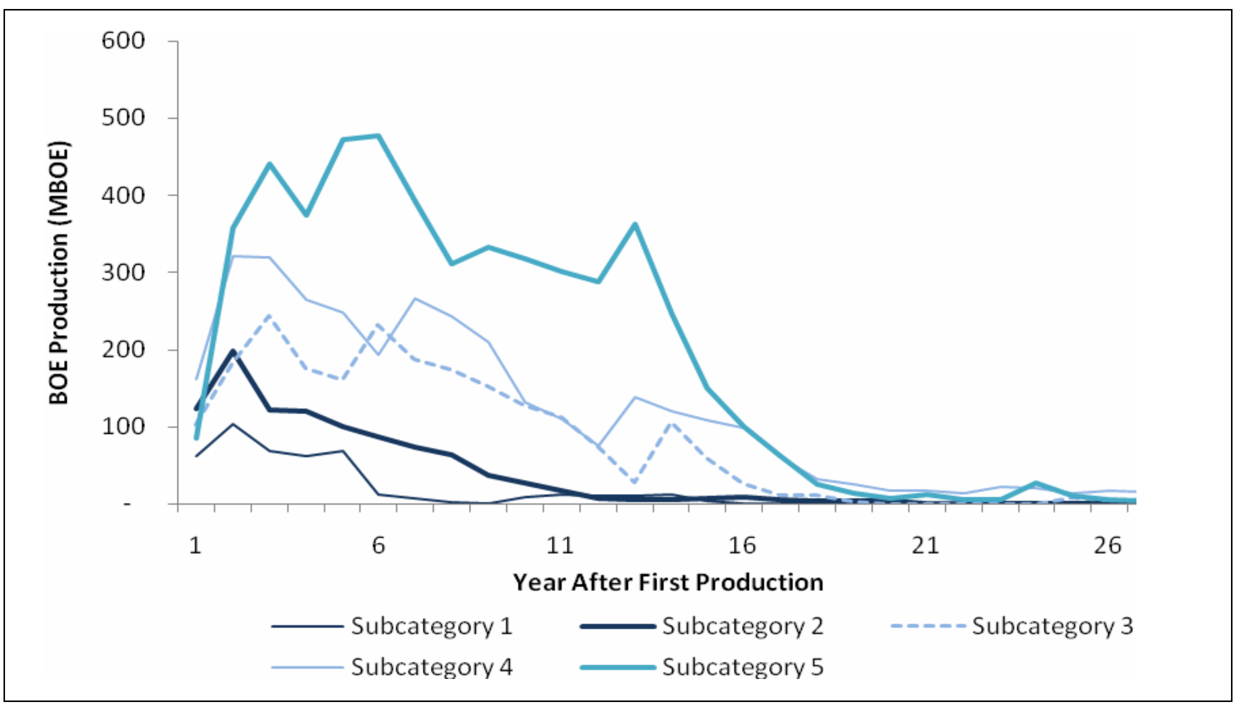


Figure F.6. Average Annual Production Profiles in the Well Protector, 60-200 ft Water Depth, Oil Production, Subcategory.

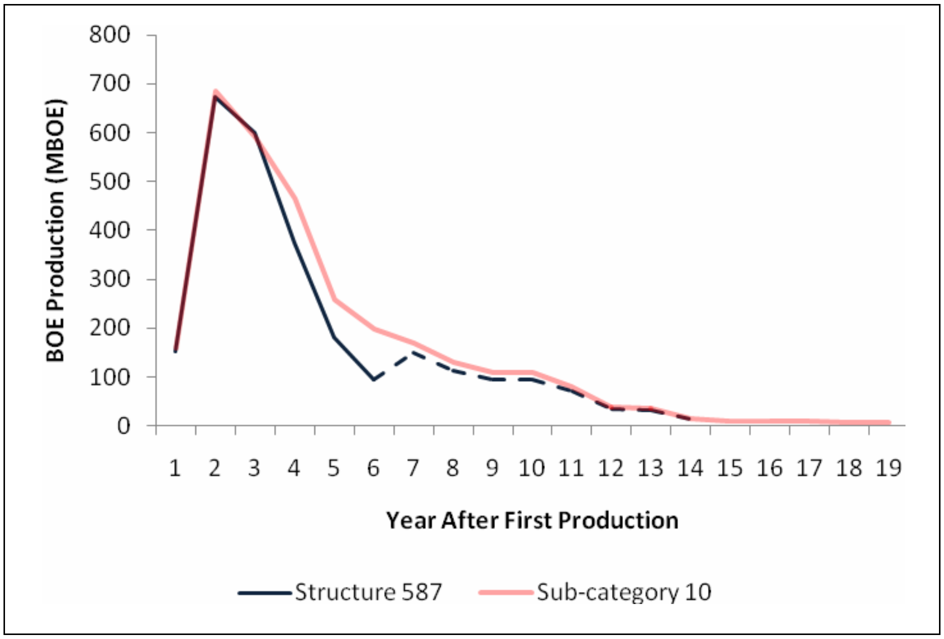


Figure F.7. Historical and Forecast Production of Structure 587.

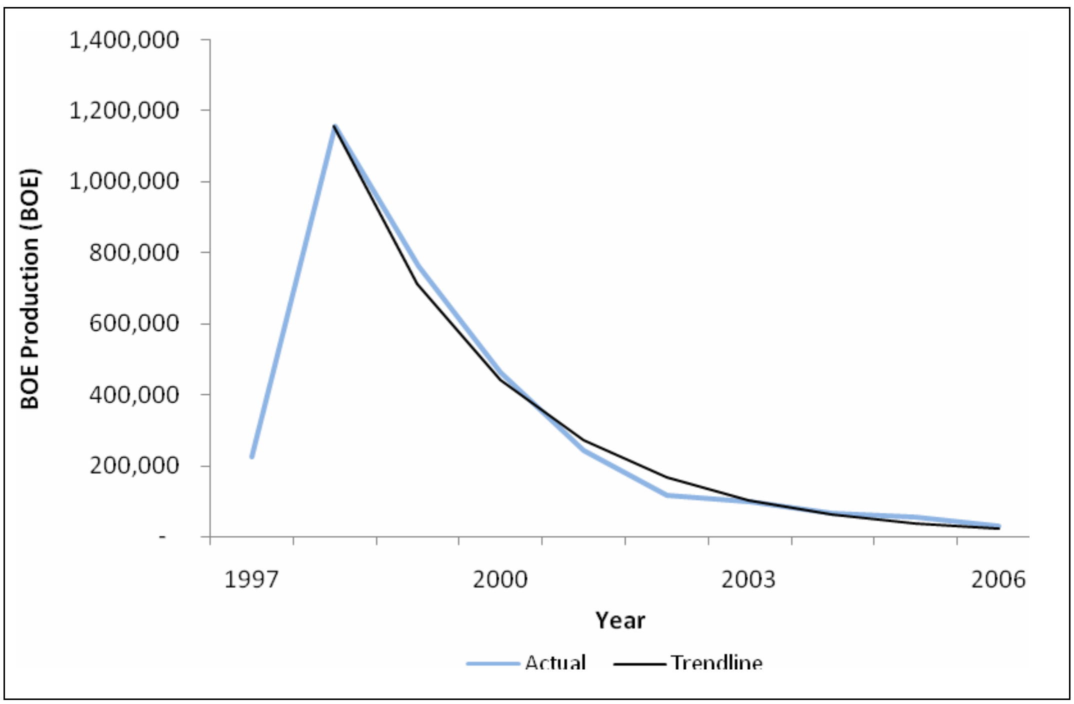


Figure F.8. Annual Production Curve and Best-Fit Regression of Structure 33.

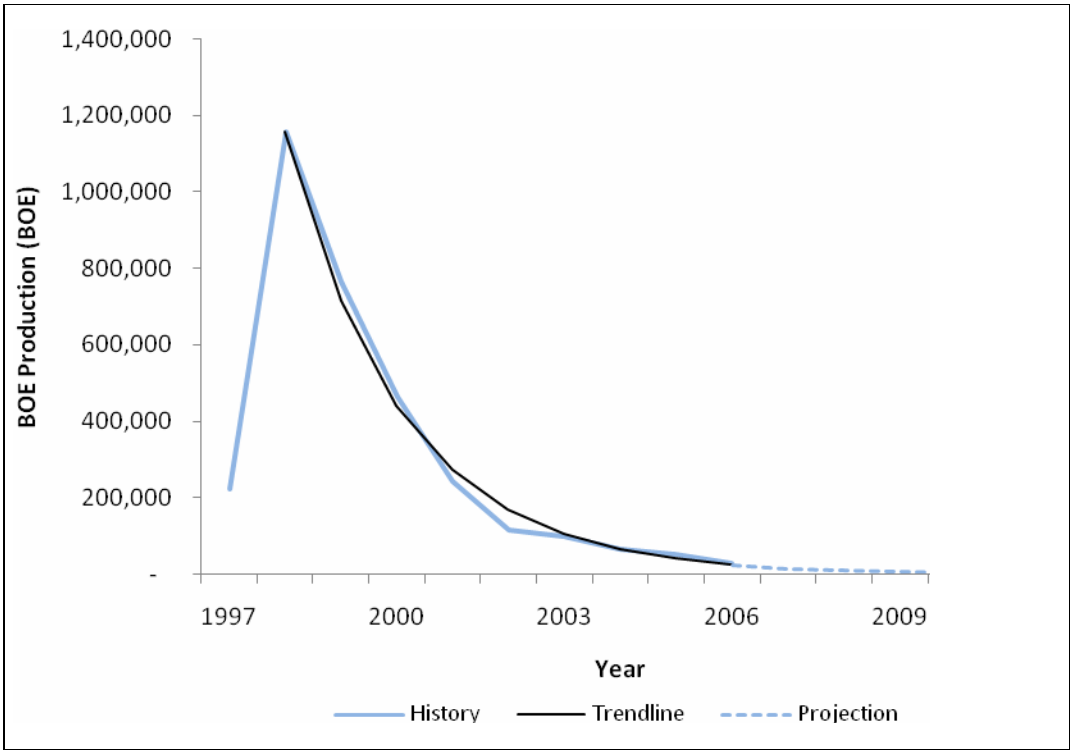


Figure F.9. Historical and Projected BOE Production of Structure 33.

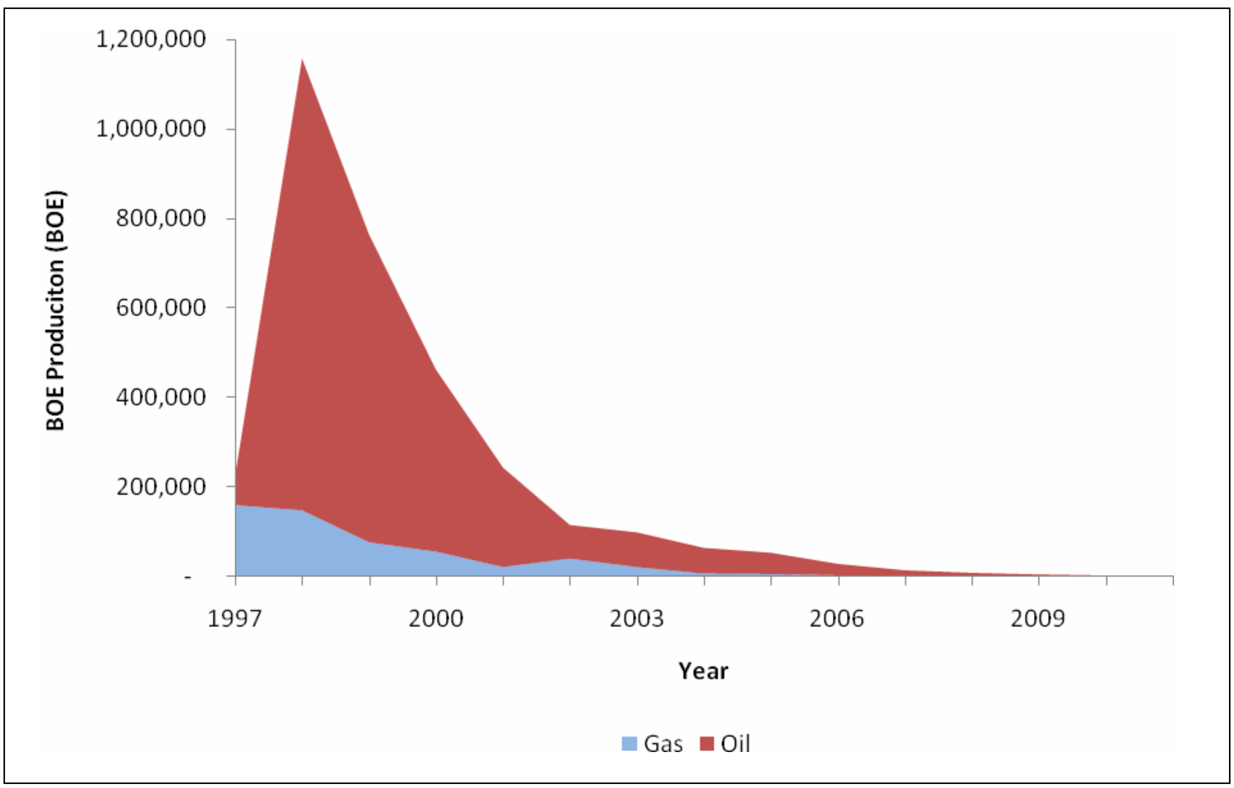


Figure F.10. Historical and Projected Oil and Gas Production of Structure 33.

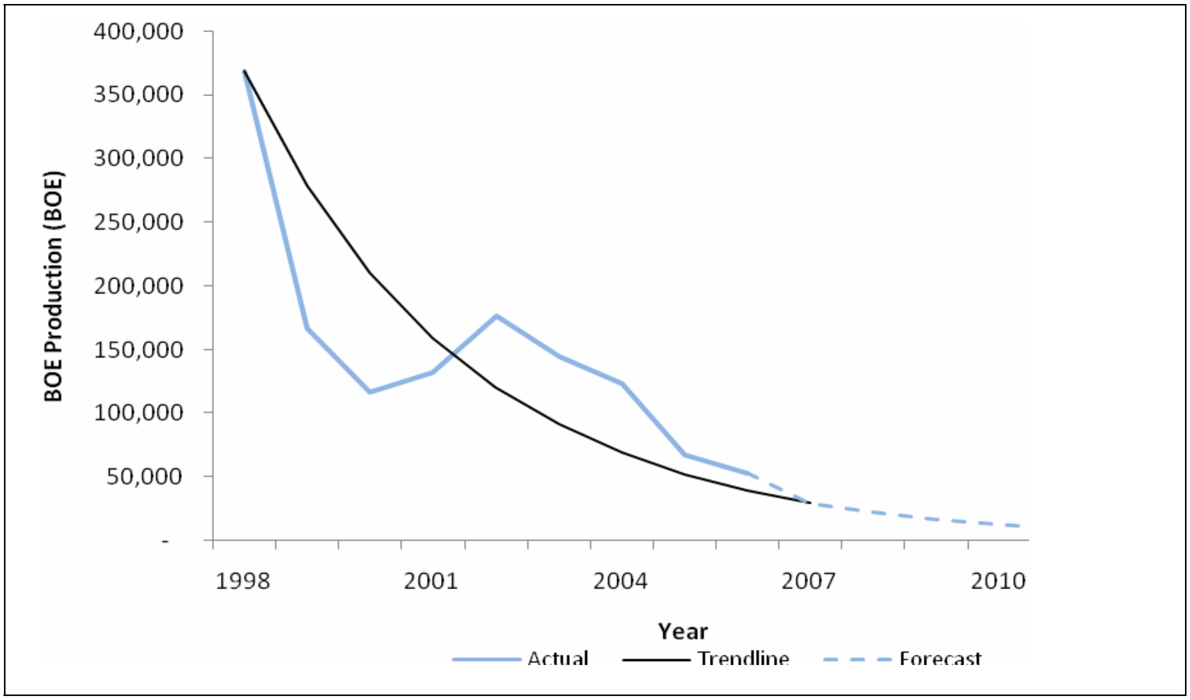


Figure F.11. Historical and Projected BOE Production of Structure 152.

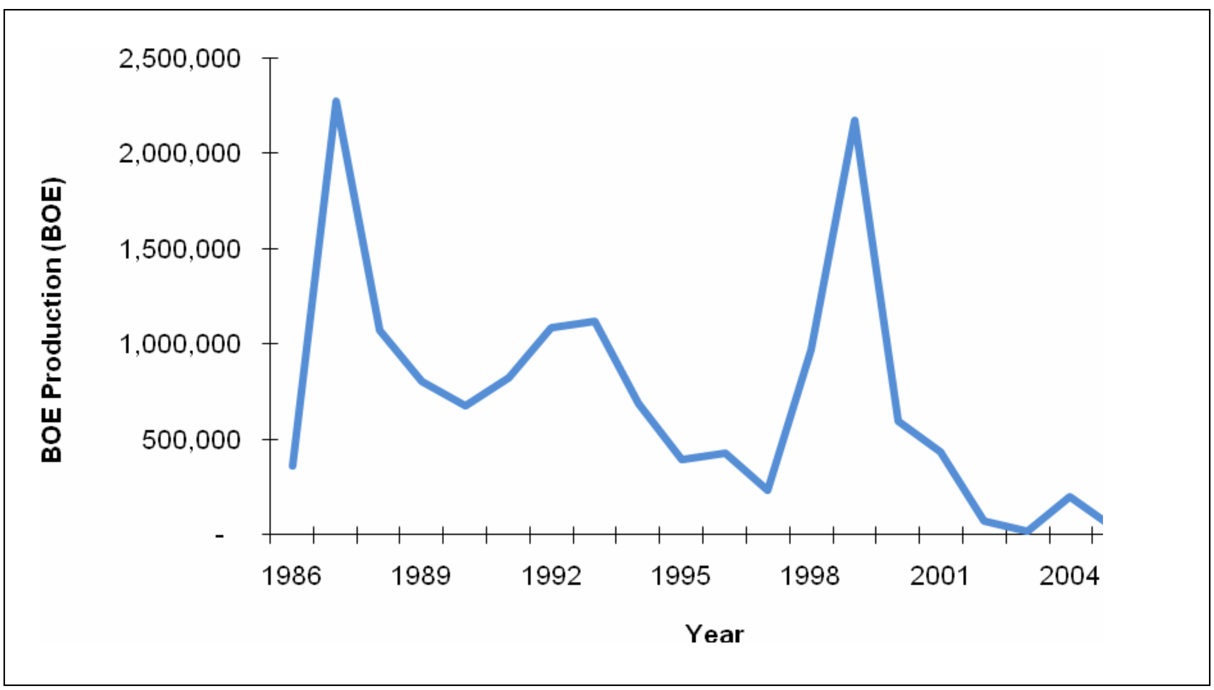


Figure F.12. Production Profile of Structure 23266.

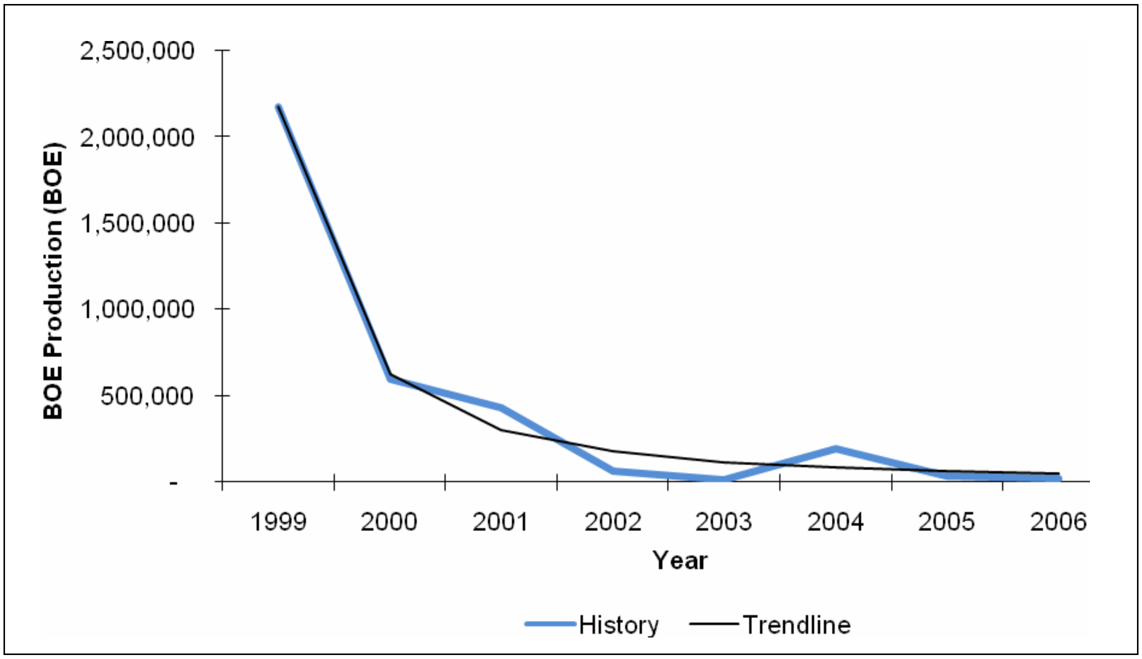


Figure F.13. Historical Production and Best-Fit Regression Curve of Structure 23266.

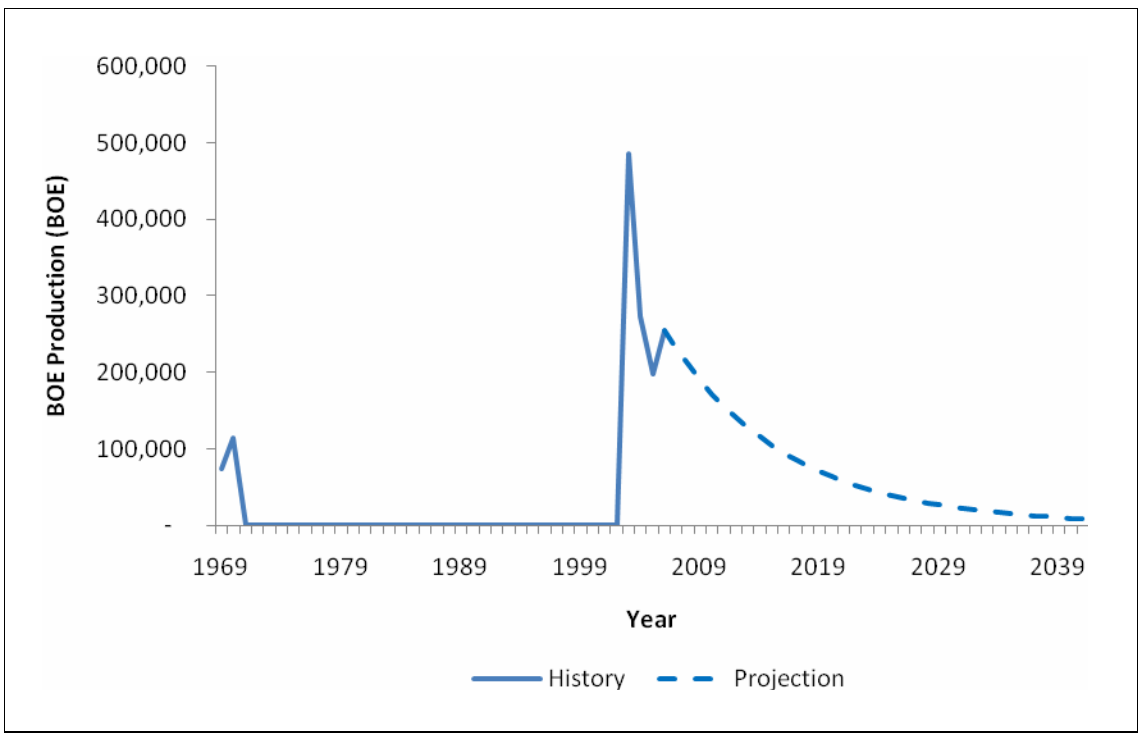


Figure F.14. Projected BOE Production of Structure 10042.

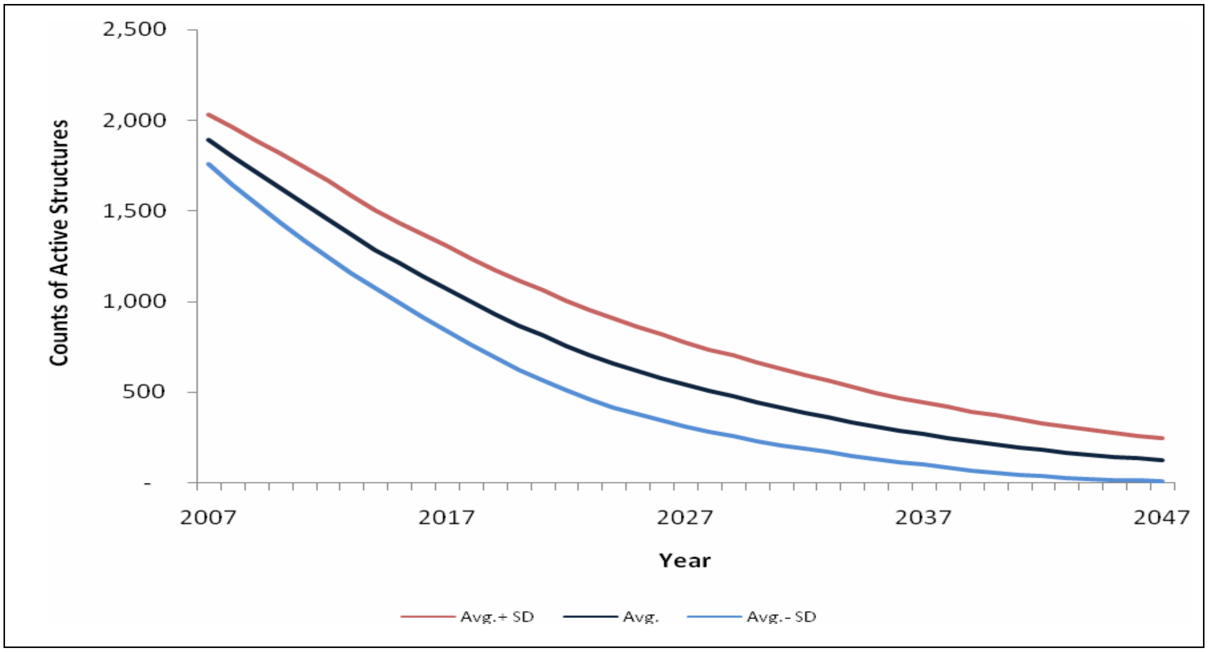


Figure F.15. Forecast of Committed Shallow Water Structures in the GOM (2007-2047).

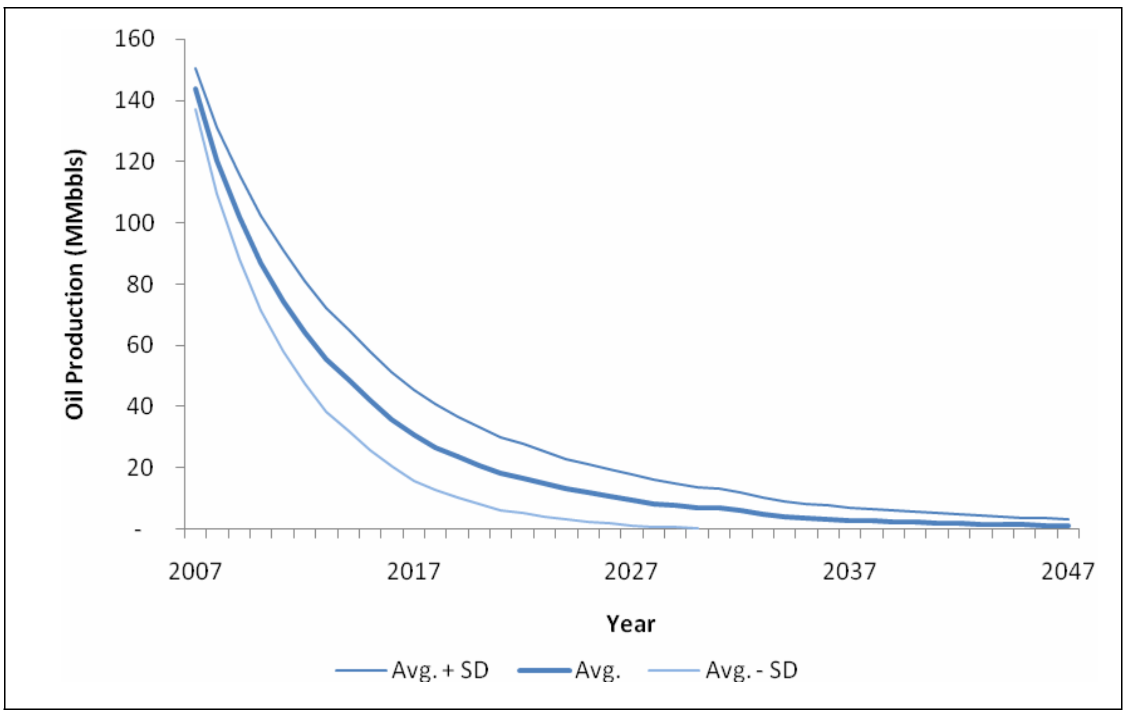


Figure F.16. Annual Oil Production from Active Structures (2007-2047).

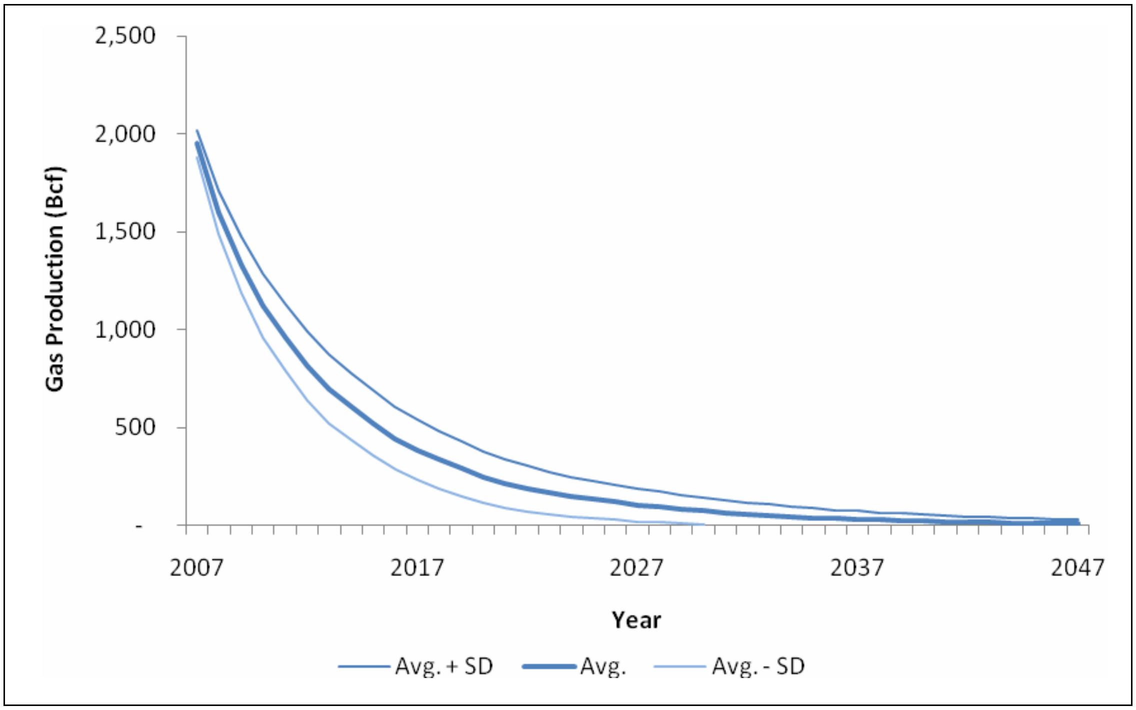


Figure F.17. Annual Gas Production from Active Structures (2007-2047).

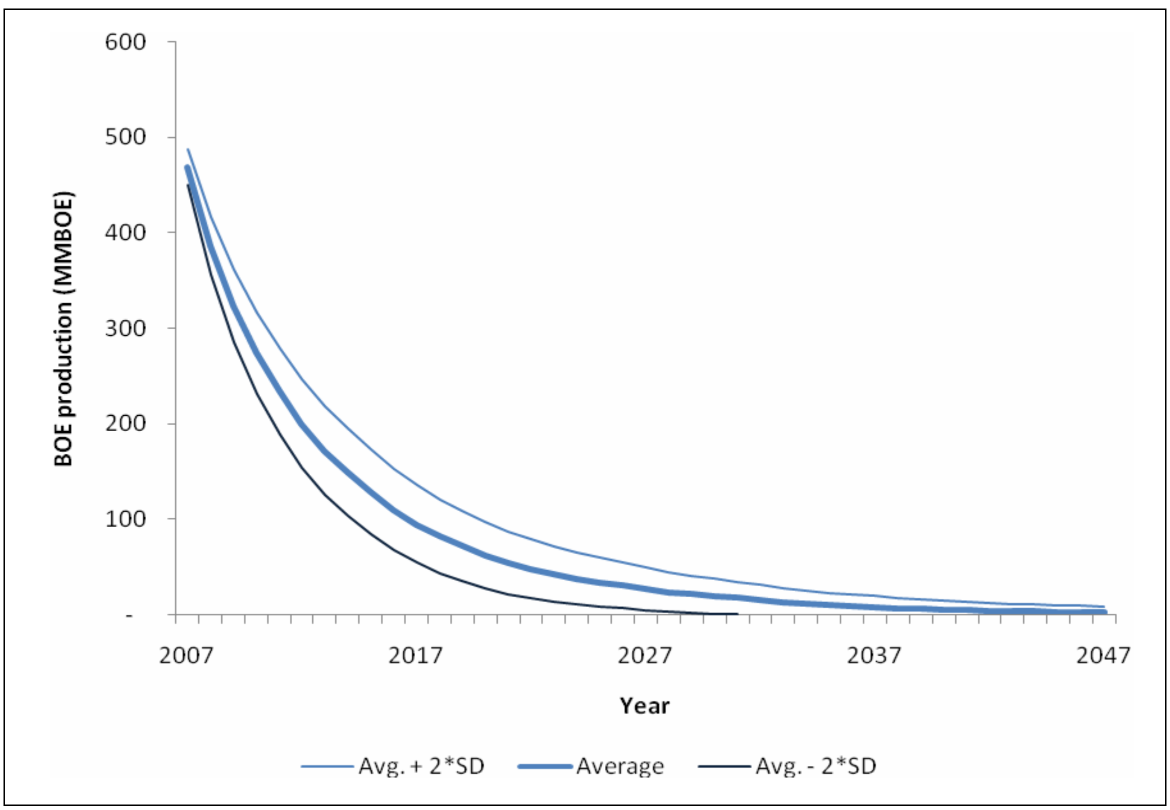


Figure F.18. Annual BOE Production of Active Structures (2007-2047).

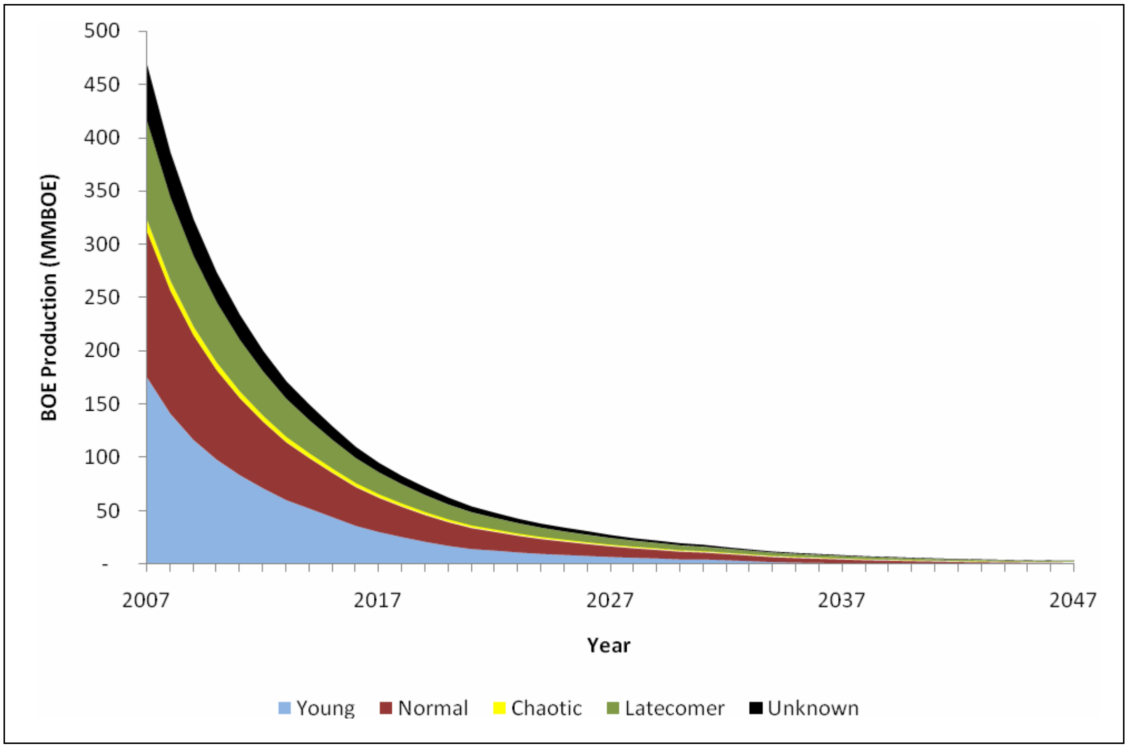


Figure F.19. Annual BOE Production per Asset Category (2007-2047).

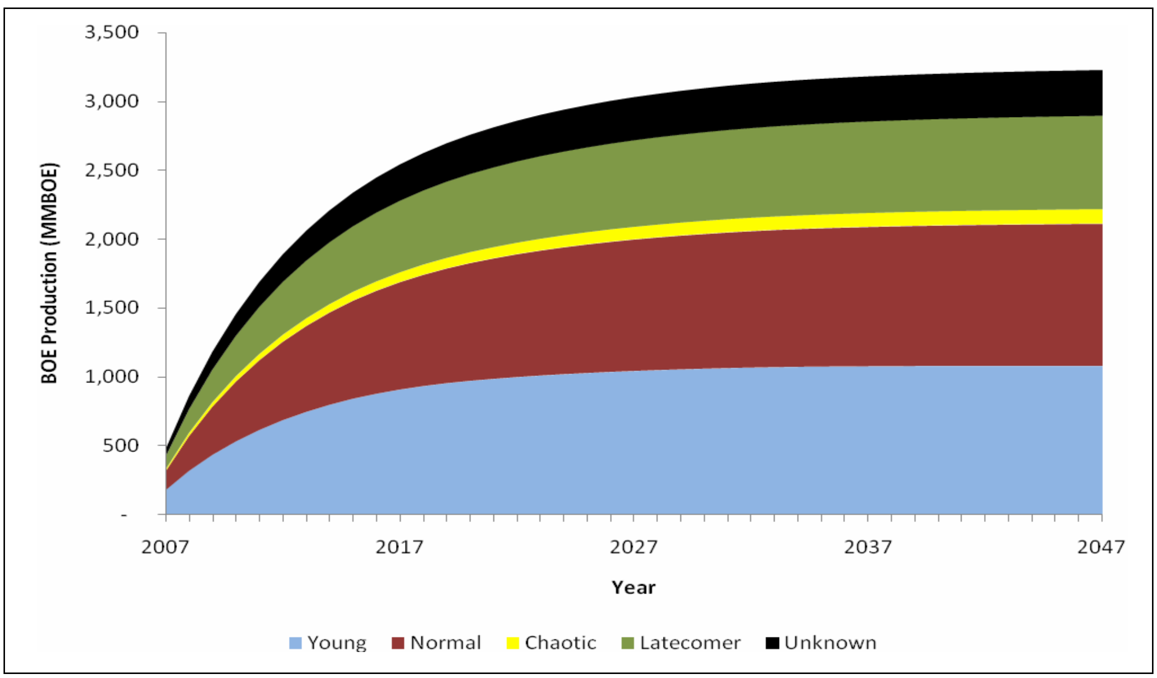


Figure F.20. Cumulative BOE Production per Asset Category (2007-2047).

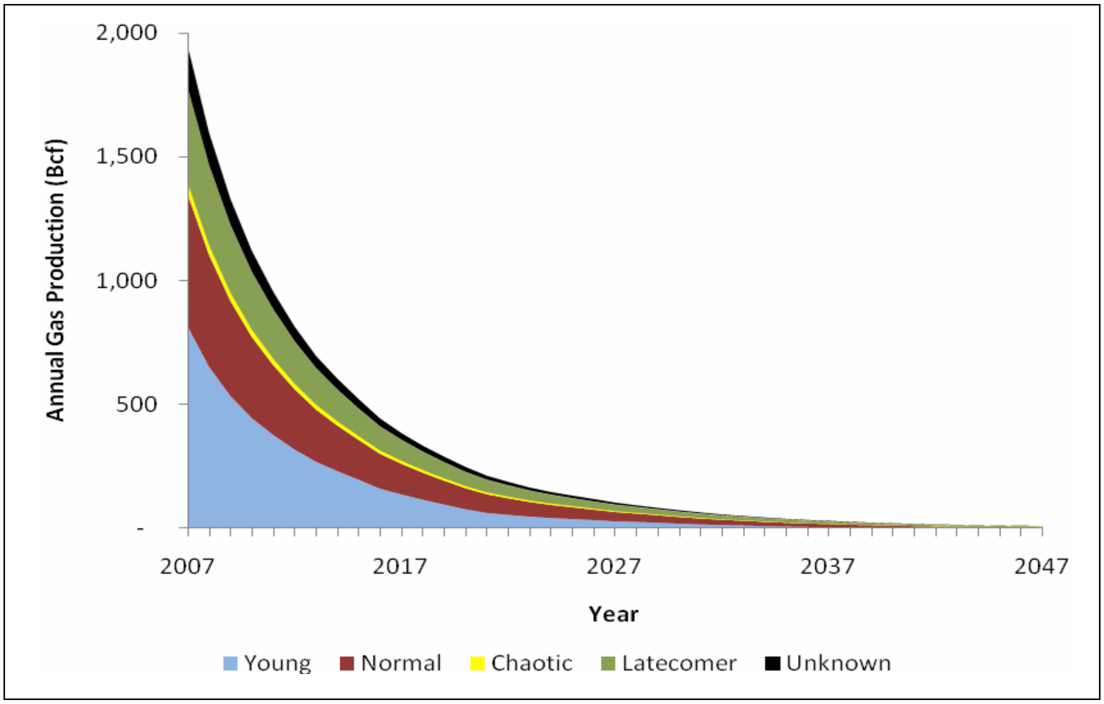


Figure F.21. Annual Gas Production per Asset Category (2007-2047).

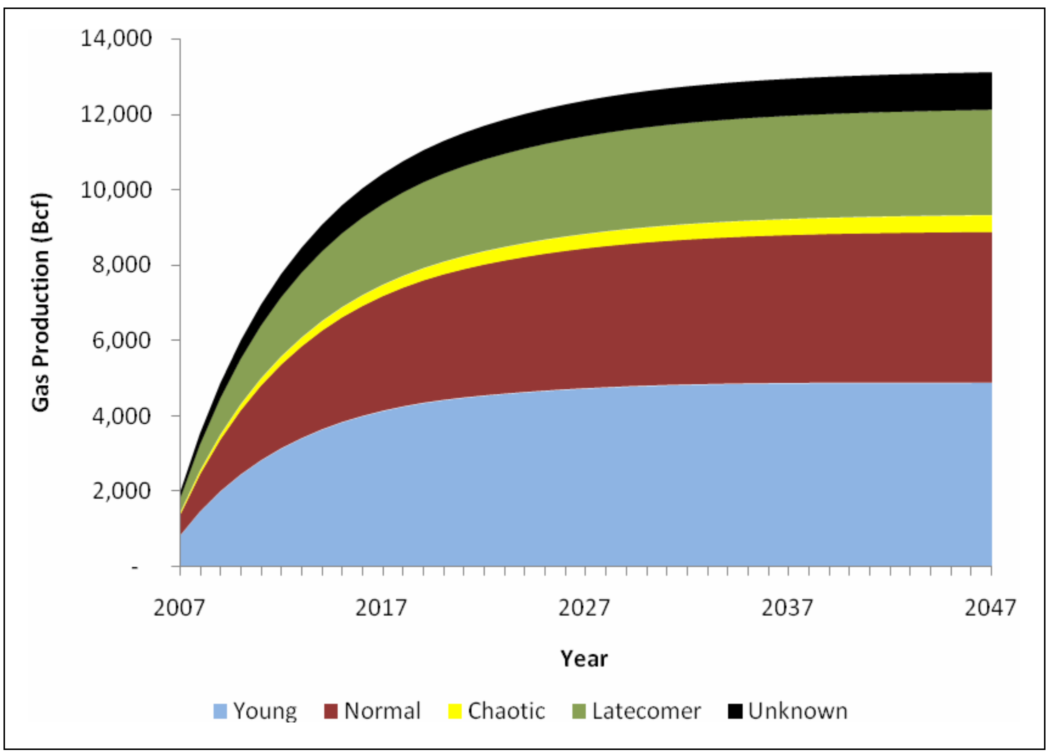


Figure F.22. Cumulative Gas Production per Asset Category (2007-2047).

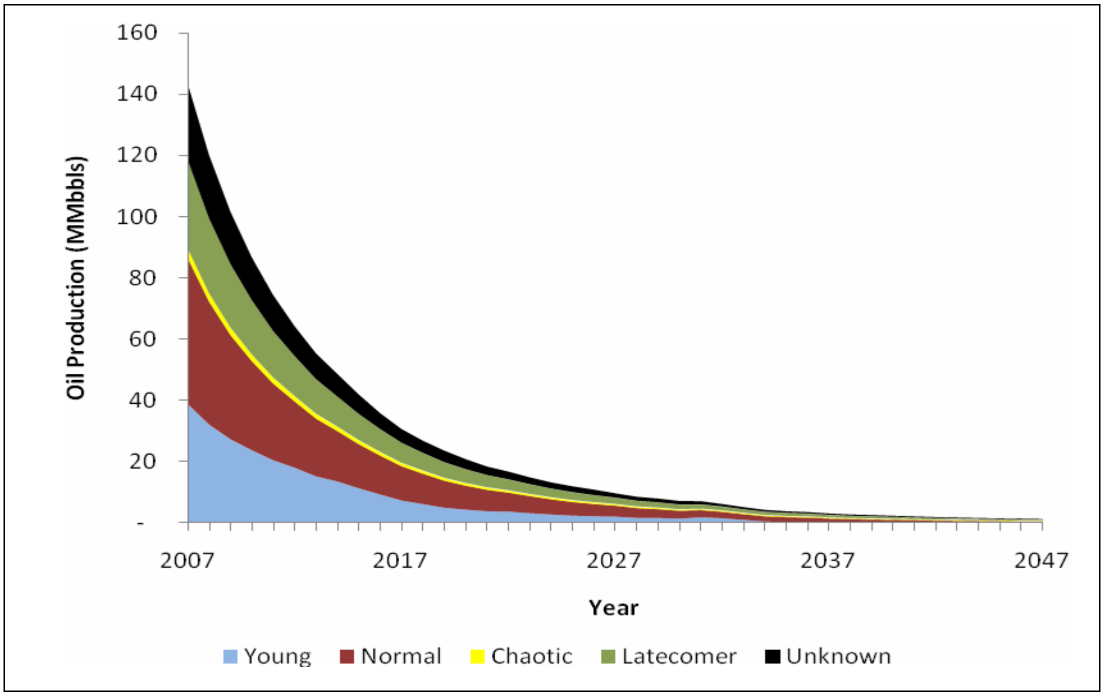


Figure F.23. Annual Oil Production per Asset Category (2007-2047).

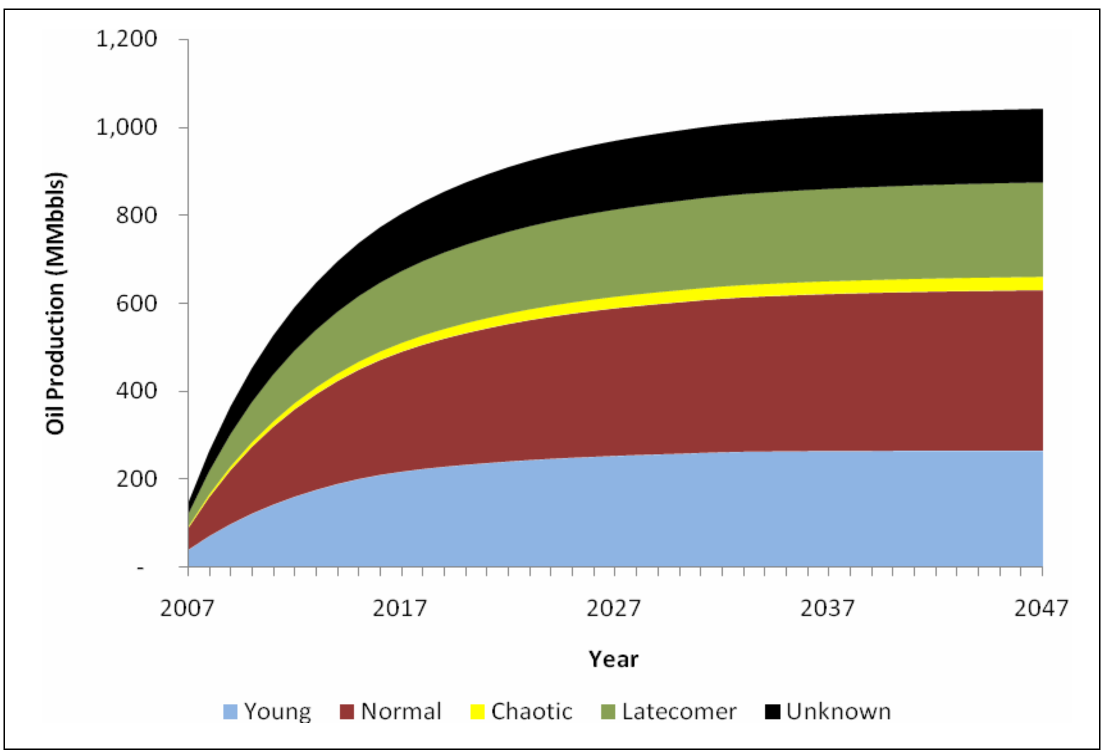


Figure F.24. Cumulative Oil Production per Asset Category (2007-2047).

APPENDIX G.

CHAPTER 7 TABLES AND FIGURES

Table G.1.

Classification of Shallow Water Structures in the Gulf of Mexico (2006)

Structure Class	Production Type		Total
	Gas	Oil	
Young	462	63	525
Normal	854	426	1,280
Chaotic	64	26	90
Latecomer	328	99	427
Unknown	27	15	42
Total	1,735	629	2,364

Table G.2.

Model Parameters and Distribution Functions

Parameter	Notation (Unit)	Distribution[a]
Decline rate	d (%)	U(5, 30)
Oil price	P^o ($/bbl)	N(120, 20)
Gas price	P^g ($/Mcf)	N(12, 2)
Marginal threshold multiplier	m	U(a,6)
Economic limit multiplier	a	U(0.5, 3)
Discount rate	D (%)	U(8, 14)

Footnote: (a) U(a, b) denotes the Uniform distribution with endpoint (a, b). N(μ, σ^2) represents the Normal distribution with mean μ and variance σ^2.

Table G.3.

Summary Statistics for Shallow Water Committed Assets in the GOM (2006)

Production (unit)	Economic	Marginal	Total
Oil (MMbbl)	1,013	44	1,056
Gas (Bcf)	12,622	717	13,338
BOE (MMBOE)	3,116	163	3,279
PV ($ billion)	147.7	1.7	149.4

Table G.4.

Model Results for Total (Cumulative) BOE Production (BOE)

$$Q^i = \alpha_1 d + \alpha_2 P^o + \alpha_3 P^g + \alpha_4 m + \alpha_5 a$$

Coefficient	Economic	Marginal	Total
α_1	-5.3E9(-8.2)	-1.8E8(-5.1)	-5.6E9(-8.2)
α_2	1.5E7(6.7)	4.2E5(3.4)	1.6E7(6.8)
α_3	1.7E8(7.5)	1.1E6(0.9)	1.7E8(7.3)
α_4	2.9E7(0.9)	7.7E7(38.2)	-
α_5	-	-9.1E7(-24.1)	8.3E7(1.3)
R^2	0.89	0.69	0.82

Table G.5.

Model Results for Total (Cumulative) Gas Production (Mcf)

$$Q^g = \alpha_1 d + \alpha_2 P^o + \alpha_3 P^g + \alpha_4 m + \alpha_5 a$$

Coefficient	Economic	Marginal	Total
α_1	-2.0E10(-7.8)	-8.4E8(-5.1)	-2.1E10(-7.7)
α_2	5.9E7(6.7)	2.4E6(4.2)	6.4E7(6.8)
α_3	6.9E8(7.8)	8.0E5(0.1)	7.0E8(7.5)
α_4	8.6E7(0.7)	3.4E8(36.9)	-
α_5	-	-4.0E8(-23.5)	2.9E8(1.1)
R^2	0.97	0.97	0.97

Table G.6.

Model Results for Total (Cumulative) Oil Production (bbl)

$Q^o = \alpha_1 d + \alpha_2 P^o + \alpha_3 P^g + \alpha_4 m + \alpha_5 a$			
Coefficient	Economic	Marginal	Total
α_1	-2.0E9(-9.1)	-4.3E7(-4.7)	-2.1E9(-9.0)
α_2	5.3E6(6.7)	2.0E4(0.6)	5.5E6(6.8)
α_3	5.4E7(6.9)	9.4E5(3.0)	5.6E7(6.9)
α_4	1.5E7(1.3)	2.1E7(41.1)	-
α_5	-	-2.4E7(-25.0)	3.5E7(1.6)
R^2	0.97	0.97	0.97

Table G.7.

Model Results for Present Value of Total Hydrocarbon (Oil and Gas) Production ($1,000)

$PV = \alpha_0 + \alpha_1 d + \alpha_2 P^o + \alpha_3 P^g + \alpha_4 m + \alpha_5 a + \alpha_6 D$						
	Economic		Marginal		Total	
Coefficient	$\alpha_0 = 0$	$\alpha_0 \neq 0$	$\alpha_0 = 0$	$\alpha_0 \neq 0$	$\alpha_0 = 0$	$\alpha_0 \neq 0$
α_0		8.86E7 (13.3)		1.69E6 (2.2)		9.64E7 (19.4)
α_1	-1.90E8 (-14.8)	-1.86E8 (-24.5)	4.45E5 (0.5)	5.58E5 (0.6)	-1.86E8 (-14.3)	-1.79E8 (-30.6)
α_2	8.06E5 (17.4)	5.87E5 (18.4)	2.21E3 (0.7)	-2.01E3 (-0.5)	8.12E5 (17.4)	5.61E5 (22.7)
α_3	9.64E6 (21.2)	7.29E6 (22.7)	7.91E4 (2.5)	3.55E4 (1.0)	1.00E7 (22.0)	7.36E6 (29.8)
α_4	-2.64E5 (-0.4)	-2.11E6 (-5.2)	1.28E6 (26.2)	1.25E6 (25.2)		
α_5			-1.82E6 (19.8)	-1.85E6 (-20.4)	-3.67E6 (-3.0)	-6.59E6 (-11.5)
α_6	-3.20E8 (-7.6)	-5.62E8 (-18.2)	-1.07E7 (-3.7)	-1.52E7 (-4.3)	-3.08E8 (-7.2)	-5.70E8 (-24.2)
R^2	0.99	0.96	0.93	0.90	0.99	0.98

Table G.8.

Model Results for Present Value of Gas Production ($1,000)

$PV = \alpha_0 + \alpha_1 d + \alpha_2 P^o + \alpha_3 P^g + \alpha_4 m + \alpha_5 a + \alpha_6 D$						
	Economic		Marginal		Total	
Coefficient	$\alpha_0 = 0$	$\alpha_0 \neq 0$	$\alpha_0 = 0$	$\alpha_0 \neq 0$	$\alpha_0 = 0$	$\alpha_0 \neq 0$
α_0		4.4E7(8.9)		5.4E5(0.7)		5.1E7(19.0)
α_1	-9.8E7(12.7)	-9.6E7(-16.8)	3.6E5(0.4)	4.0E5(0.5)	-9.3E7(13.5)	-8.9E7(28.3)
α_2	1.2E5(4.4)	1.3E4(0.5)	-3.9E3(-1.3)	-5.2E3(-1.5)	1.2E5(4.7)	-1.7E4(-1.3)
α_3	8.4E6(30.9)	7.2E6(29.9)	8.8E4(3.0)	7.4E4(2.1)	8.7E6(36.1)	7.3E6(55.2)
α_4	-5.1E5(-1.3)	-1.4E6(-4.7)	5.6E5(12.4)	5.5E5(11.7)		
α_5			-1.2E6(-14.6)	-1.3E6(14.5)	-4.5E6(-6.9)	-6.0E6(19.6)
α_6	-1.8E8(-7.1)	-3.0E8(-13.0)	-1.6E6(-0.6)	-3.0E6(-0.9)	-1.6E8(-6.9)	-3.0E8(23.4)
R^2	0.94	0.99	0.73	0.75	0.98	0.99

Table G.9.

Model Results for Present Value of Oil Production ($1,000)

$PV = \alpha_0 + \alpha_1 d + \alpha_2 P^o + \alpha_3 P^g + \alpha_4 m + \alpha_5 a + \alpha_6 D$						
	Economic		Marginal		Total	
Coefficient	$\alpha_0 = 0$	$\alpha_0 \neq 0$	$\alpha_0 = 0$	$\alpha_0 \neq 0$	$\alpha_0 = 0$	$\alpha_0 \neq 0$
α_0		4.4E7(14.8)		1.2E6(6.6)		4.5E7(15.6)
α_1	-9.2E7(14.9)	-9.0E7(-26.5)	8.1E4(0.3)	1.6E5(0.8)	-9.3E7(-14.5)	-9.0E7(-26.3)
α_2	6.8E5(30.6)	5.7E5(40.1)	6.1E3(7.1)	3.2E3(3.9)	7.0E5(30.2)	5.8E5(40.1)
α_3	1.2E6(5.6)	6.1E4(0.4)	-8.4E3(-1.0)	-3.8E4(-4.6)	1.3E6(5.6)	2.3E4(0.2)
α_4	2.4E5(0.8)	-6.8E5(-3.7)	7.1E5(54.4)	6.9E5(61.6)		
α_5			-5.7E5(23.2)	-5.9E5(28.7)	8.3E5(1.4)	-5.5E5(-1.6)
α_6	-1.4E8(-6.9)	-2.6E8(-18.9)	-9.2E6(11.7)	-1.2E7(15.3)	-1.5E8(-7.1)	-2.7E8(-19.9)
R^2	0.99	0.97	0.98	0.98	0.99	0.97

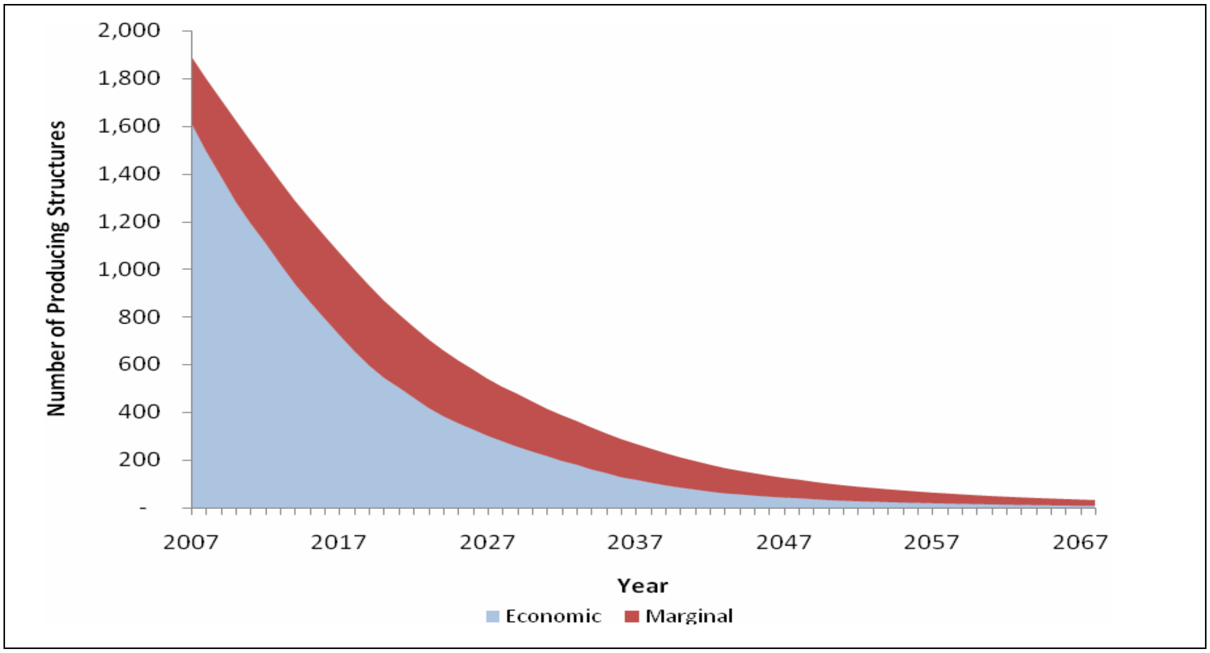


Figure G.1. Number of Producing Structures Decomposed According to Marginal and Economic Status (2007-2067).

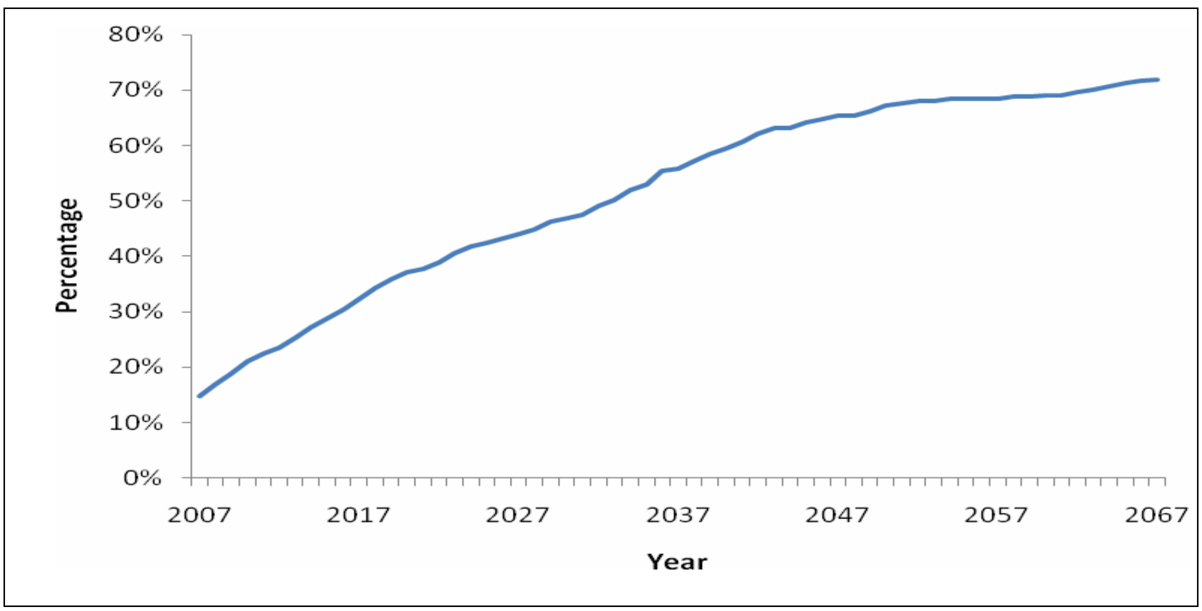


Figure G.2. Marginal Structures as a Percentage of the Committed Asset Inventory Circa 2006 (2007-2067).

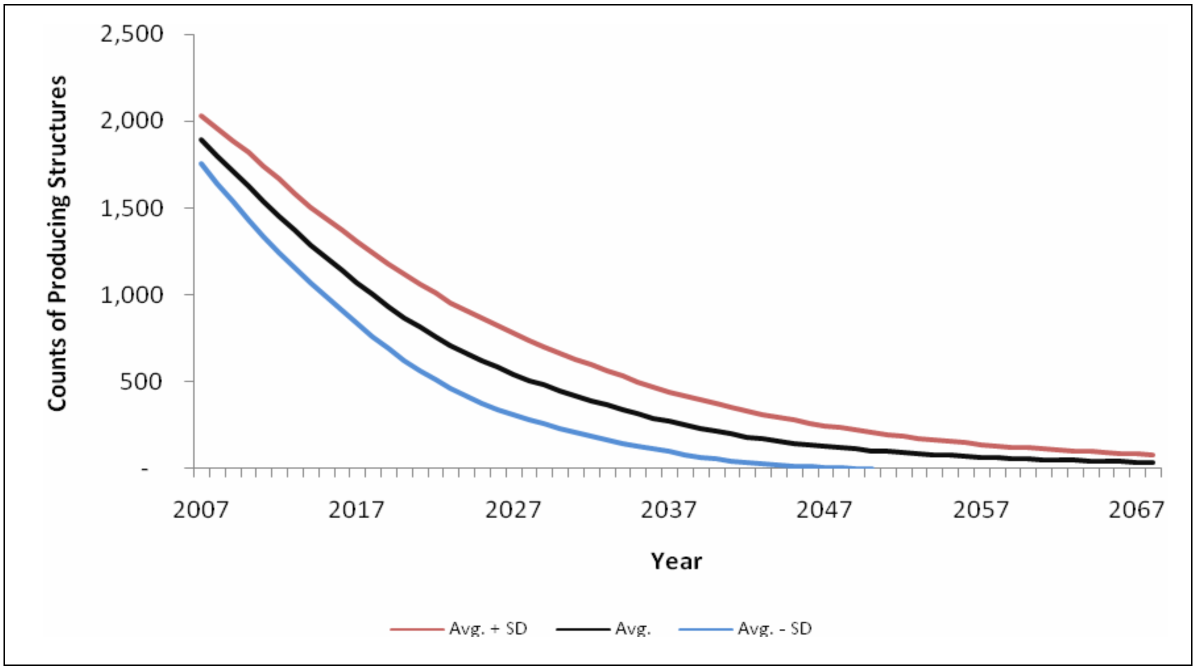


Figure G.3. Average Producing Structure Count and One Standard Deviation Envelope (2007-2067).

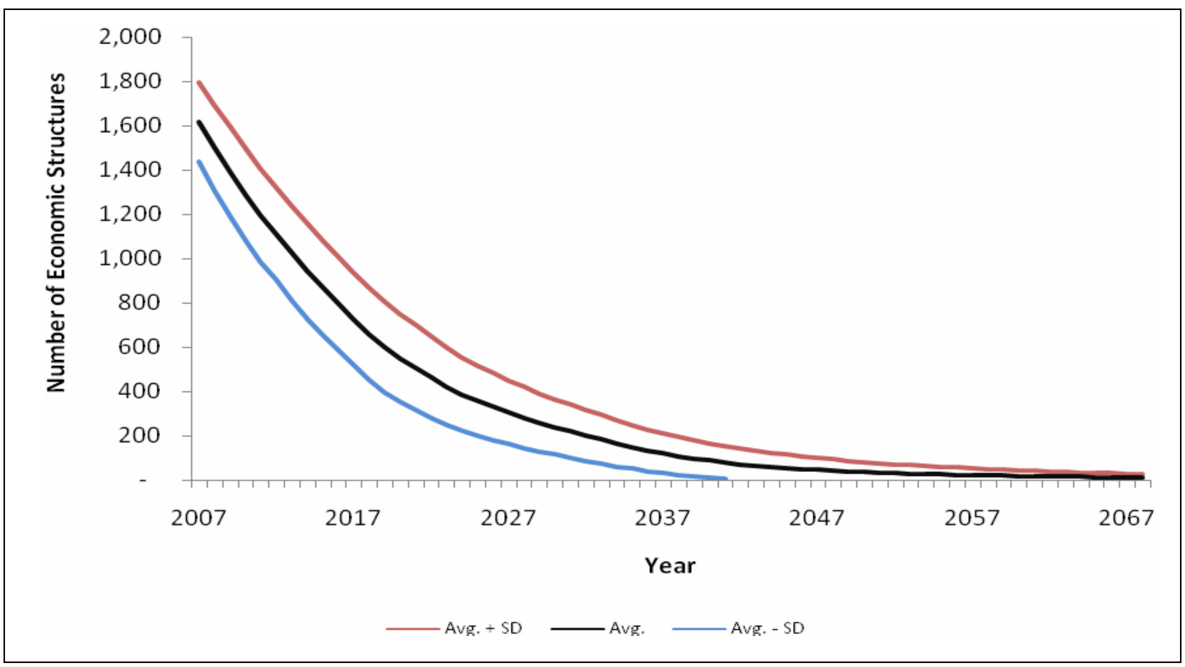


Figure G.4. Average Economic Structure Count and One Standard Deviation Envelope (2007-2067).

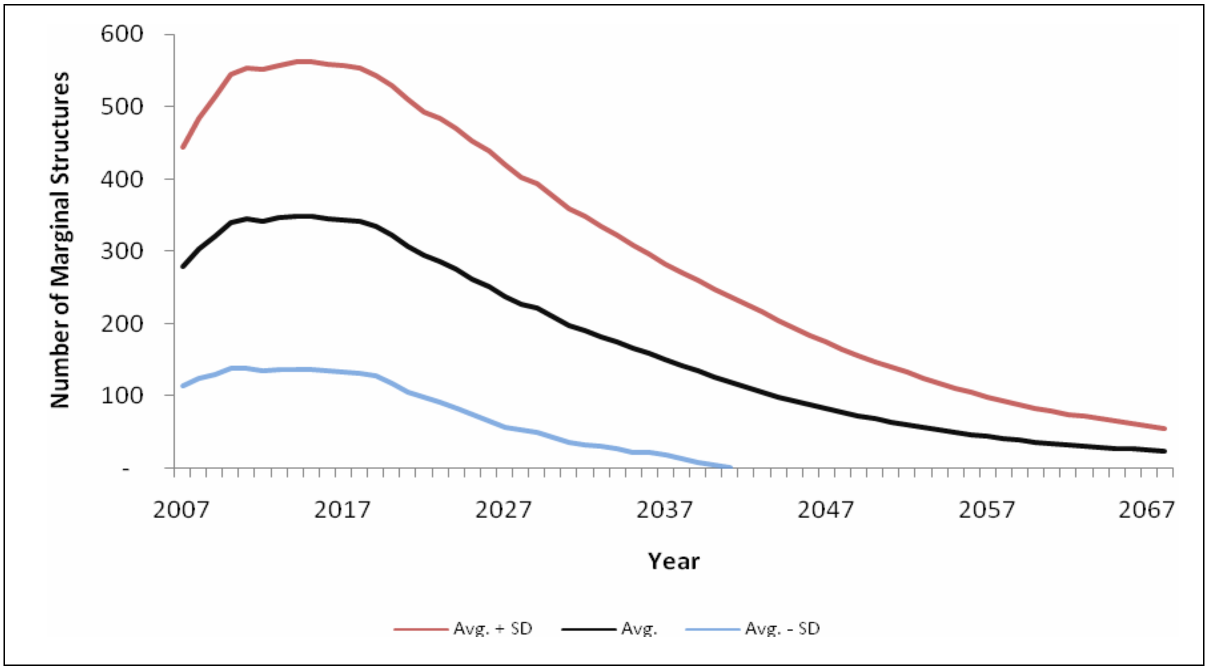


Figure G.5. Average Marginal Structure Count and One Standard Deviation Envelope (2007-2067).

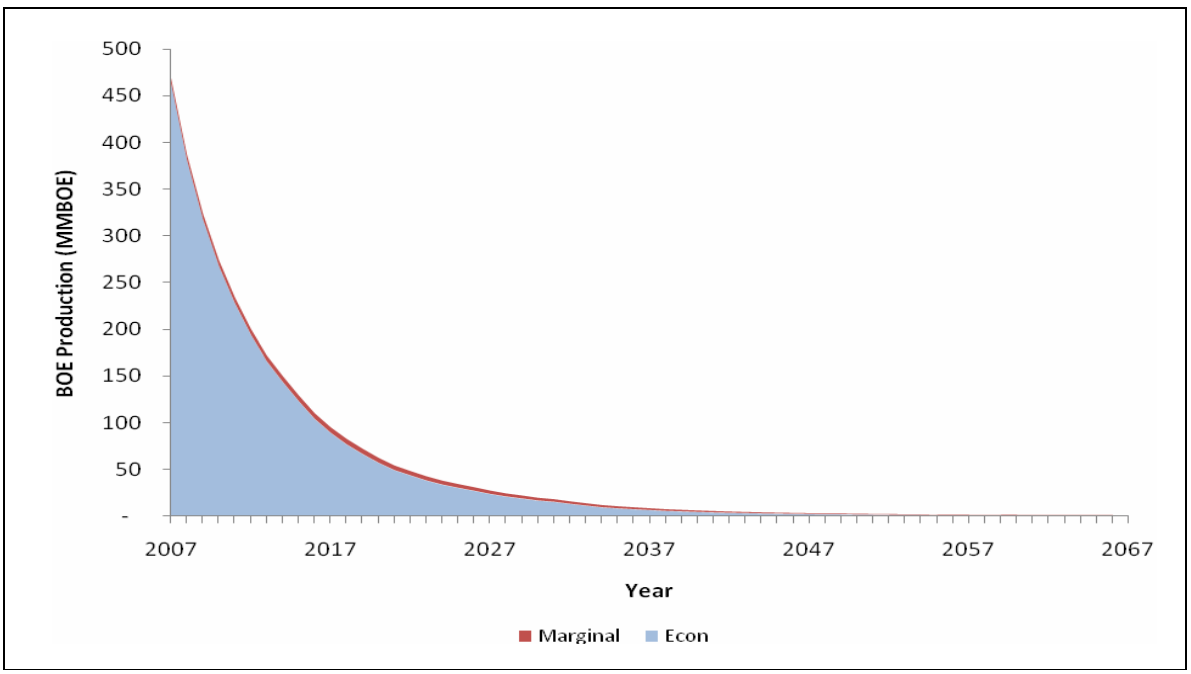


Figure G.6. Average Annual BOE Production Profile of Producing Structures Decomposed According to Economic and Marginal Categories (2007-2067).

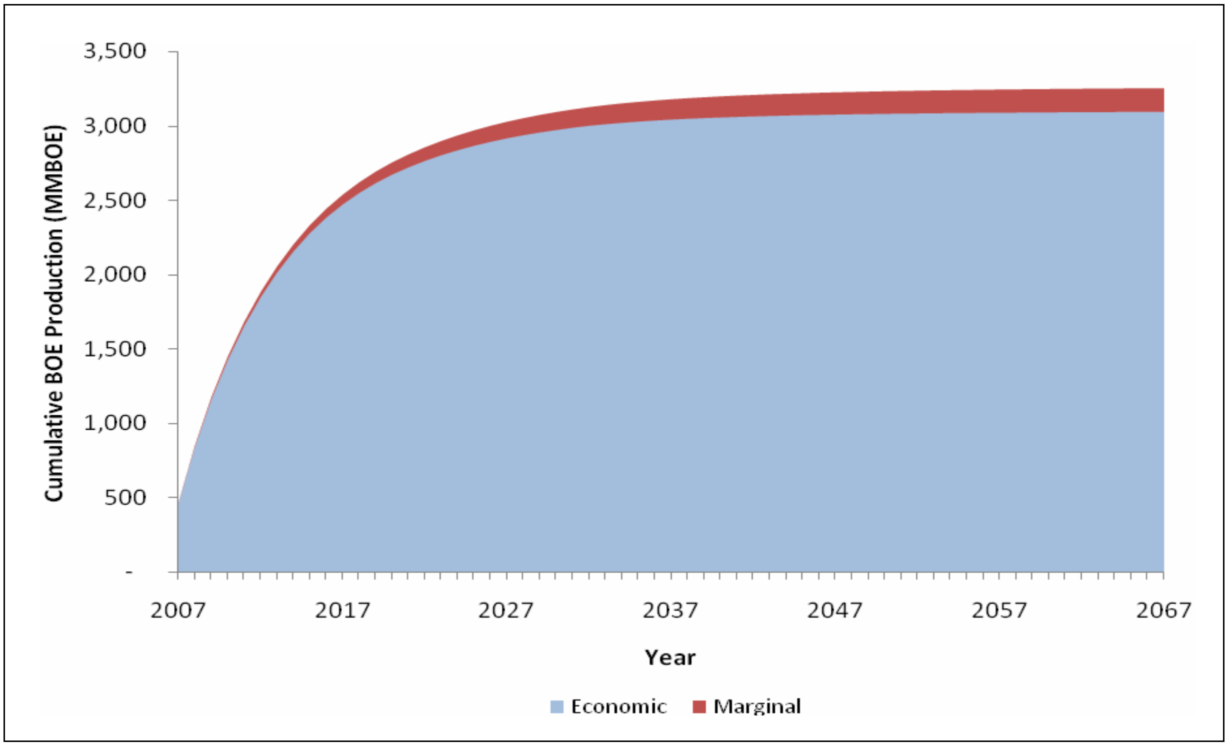


Figure G.7. Average Cumulative BOE Production of Producing Structures Decomposed According to Economic and Marginal Categories (2007-2067).

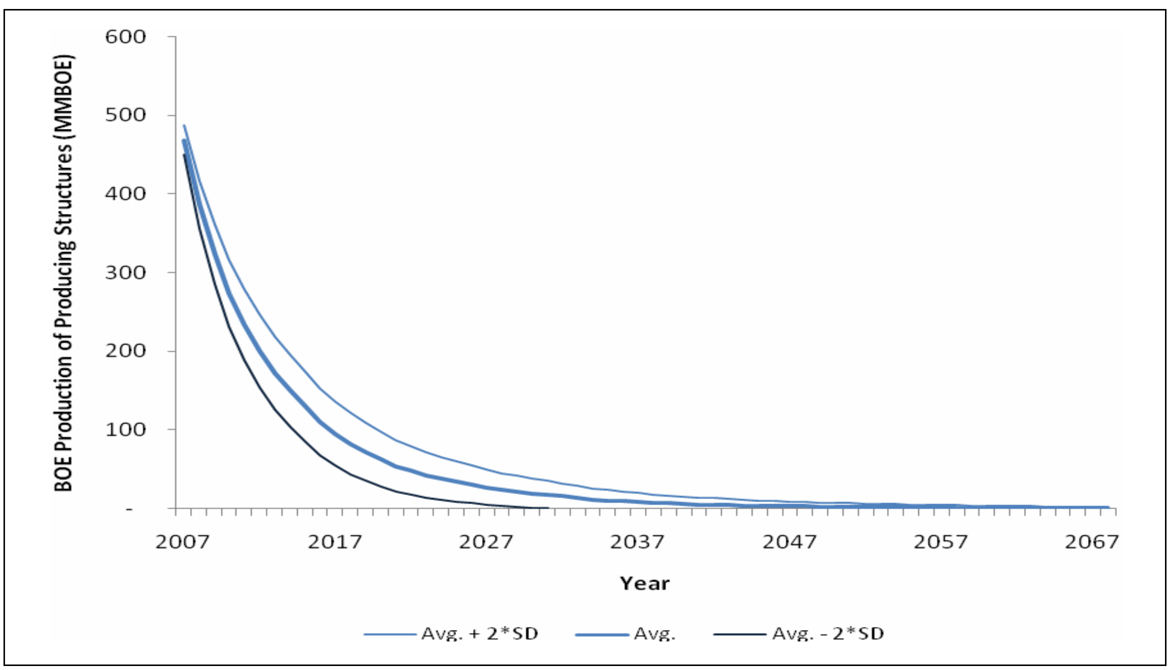


Figure G.8. BOE Production Envelopes of Producing Structures (2007-2067).

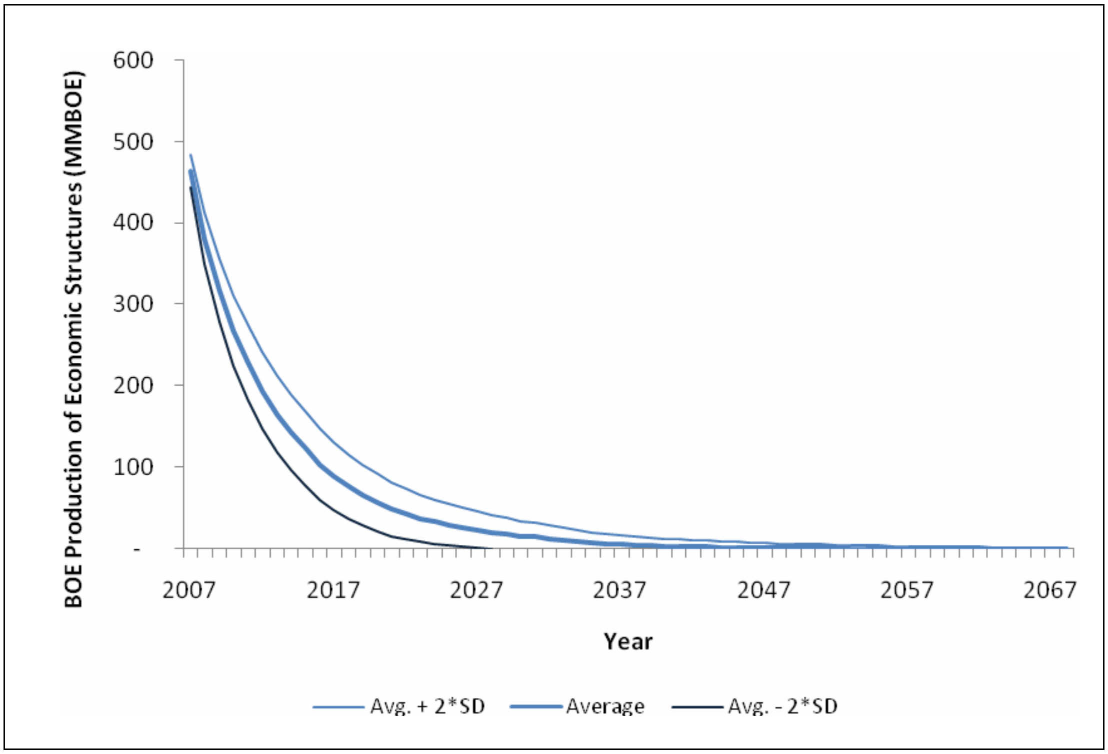


Figure G.9. BOE Production Envelopes of Economic Structures (2007-2067).

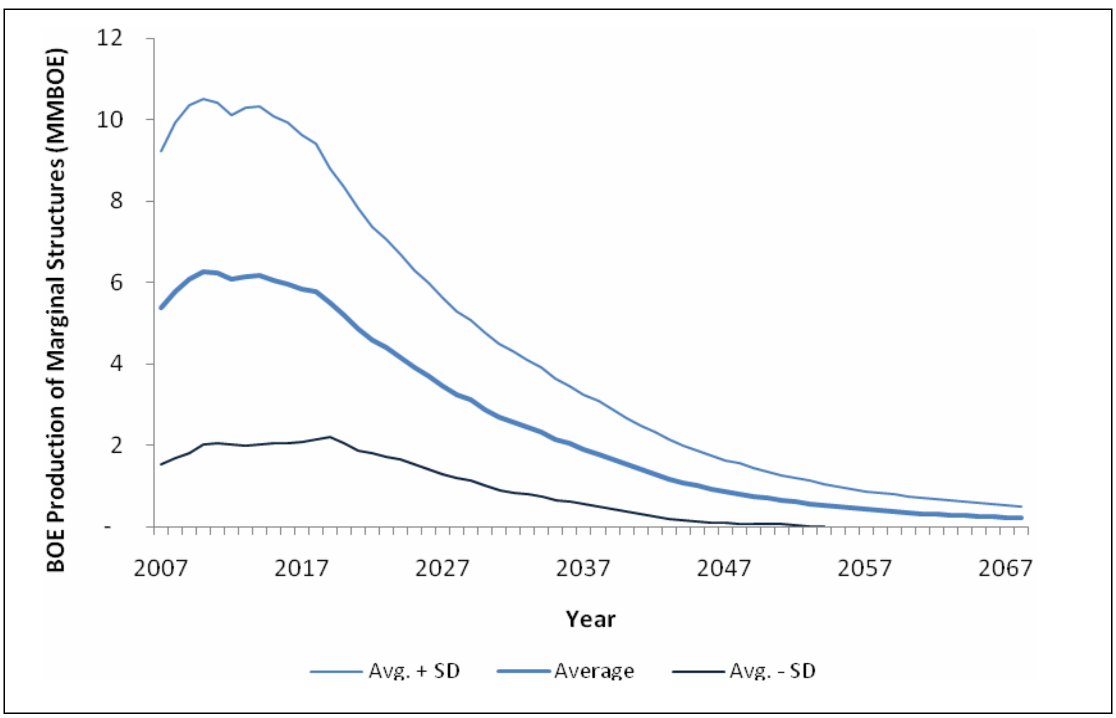


Figure G.10. BOE Production Envelopes of Marginal Structures (2007-2067).

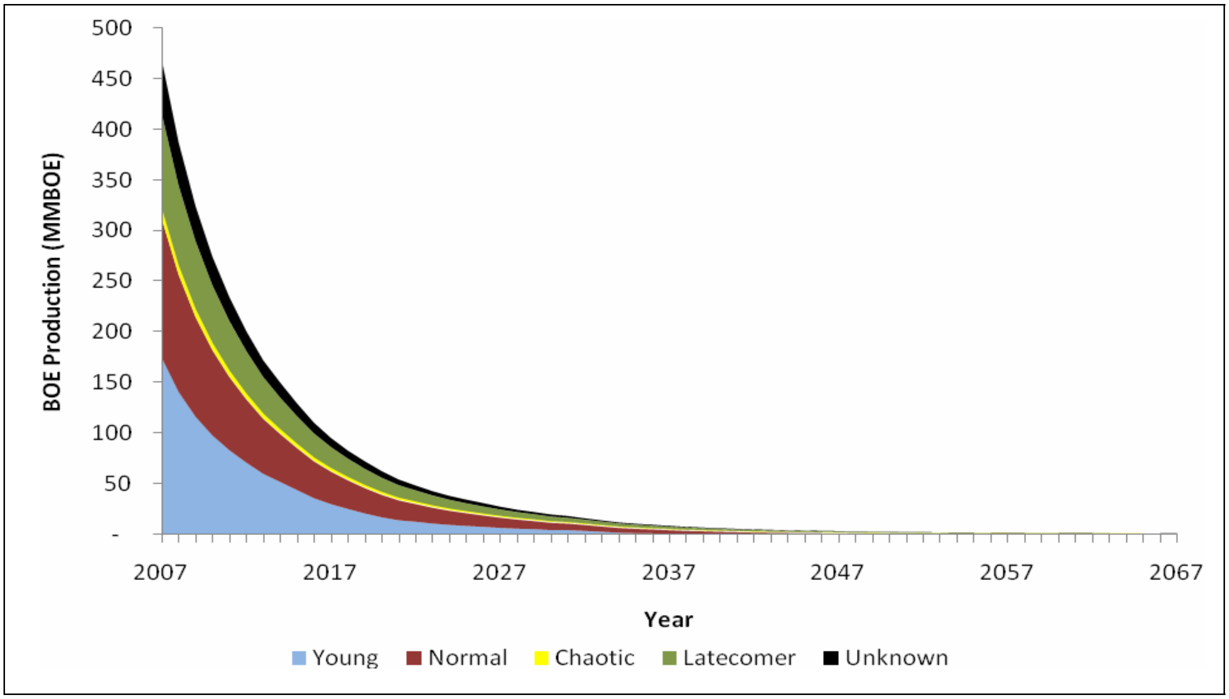


Figure G.11. BOE Production Contribution per Asset Category (2007-2067).

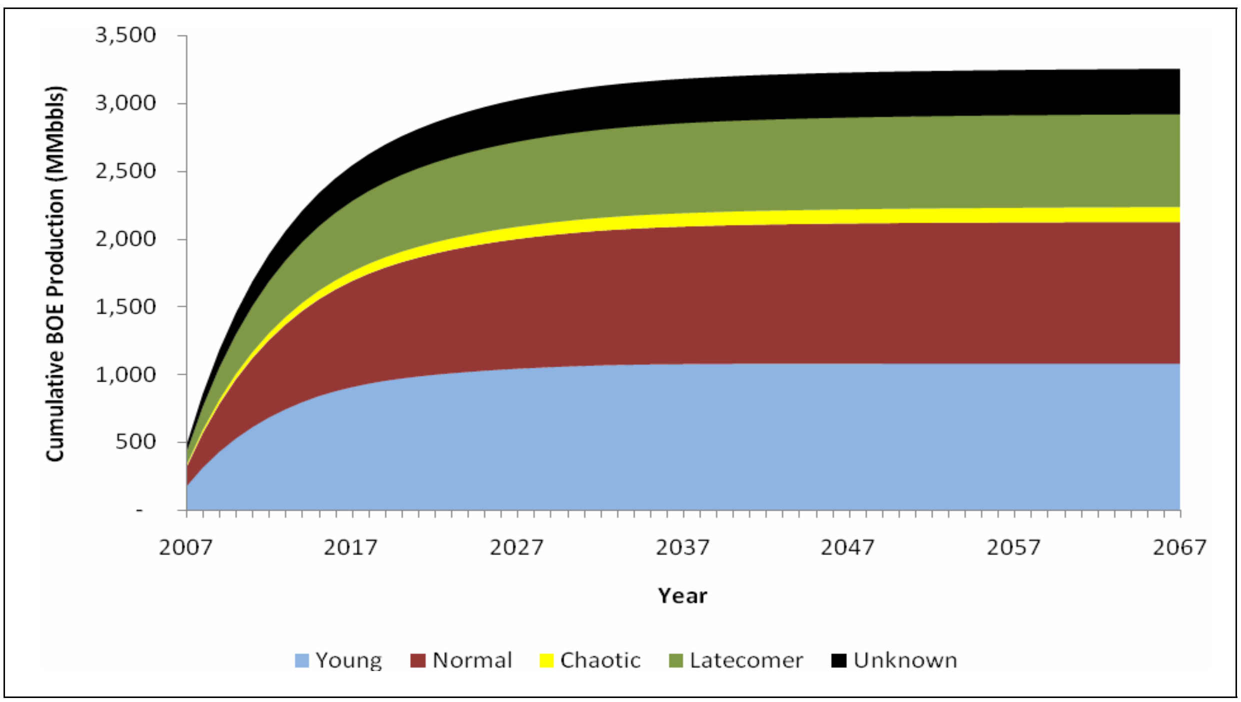


Figure G.12. Cumulative BOE Production Contribution per Asset Category (2007-2067).

The Department of the Interior Mission

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

The Minerals Management Service Mission

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

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

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